30 JUNE 2025

Addressing System Strength Requirements in Queensland from December 2025

Project Assessment Conclusions Report

Preface

Powerlink Queensland is a Transmission Network Service Provider (TNSP) that owns, develops, operates and maintains Queensland's high-voltage electricity transmission network. The network transfers bulk power from Queensland generators to electricity distributors Energex and Ergon Energy (part of the Energy Queensland Group), and to a range of large industrial customers.

The National Electricity Rules (NER) requires Powerlink to carry out forward planning to identify future reliability of supply requirements, which may include replacement of network assets or augmentations of the transmission network. Powerlink must then identify, evaluate and compare network and non-network solutions (including, but not limited to, generation and demand side management) to identify the preferred option which can address future network requirements at the lowest net cost to electricity customers. Powerlink also has obligations under the NER to address power system security requirements identified by the Australian Energy Market Operator in its annual System Security Reports.

This Project Assessment Conclusions Report (PACR) has been prepared in accordance with version 230 of the NER, and the Regulatory Investment Test for Transmission (RIT-T) Instrument (November 2024) and RIT-T Application Guidelines (November 2024). The RIT-T Instrument and Application Guidelines are made and administered by the Australian Energy Regulator (AER). Powerlink has also had regard to the AER's guidance note for the system strength framework (December 2024).

The main purpose of this report is to provide details of the identified need, credible options, and technical and commercial feasibility of the preferred option to address system strength requirements in Queensland from December 2025. This PACR also provides customers, stakeholders and communities with information on the potential network and non-network investment/s that are required to meet the identified need in this RIT-T, and offers the opportunity to provide input into the future development of the transmission network in Queensland. More information on how Powerlink applies the RIT-T process is available on Powerlink's website.

A copy of this report will be made available to any person within three business days of a request being made. Requests should be directed to the Manager Portfolio Planning and Optimisation, by phone ((07) 3860 2111) or email (networkassessments@powerlink.com.au).

In accordance with clause 5.16B(a) of the NER, energy industry participants, the Australian Energy Market Commission, electricity customers (including their representatives) may, by notice to the AER, dispute conclusions made by Powerlink in this PACR in relation to:

- the application of the RIT-T;
- the basis on which Powerlink has classified the preferred option as a reliability corrective action; or
- Powerlink's assessment of whether the preferred option will have a material inter-network impact.

Notice of a dispute must be given to the AER within 30 days of the publication date of this report. Any parties raising a dispute are also required to simultaneously provide a copy of the dispute notice to Powerlink. Powerlink requests a copy of any dispute notice be sent via email (networkassessments@powerlink.com.au) and marked for the attention of the Head of Legal Services.

Powerlink acknowledges the Traditional Owners and their custodianship of the lands and waters of Queensland and, in particular, the lands on which we operate. We pay our respect to their Ancestors, Elders and knowledge holders and recognise their deep history and ongoing connection to Country.

Contents

1. Introduction

Key Points

- System strength is a measure of the ability of the network to maintain and control the voltage both during steady state operation and in response to a network disturbance, such as a sudden change in generation or load, or fault on the network.
- The Queensland energy system has historically comprised synchronous generation such as coal-fired power stations, gas turbines and hydro-electric plants. These large synchronous generators have provided system strength, and other power system services, as a by-product of their dispatch for energy.
- The increased share of generation from renewable sources means that power system services, including system strength, are less freely available and must be planned for and delivered by other means.
- A range of technologies, including synchronous condensers, grid-forming Battery Energy Storage Systems (BESS), pumped hydro energy storage (PHES) systems that can operate in synchronous condenser mode, and gas turbines with clutches to enable them to operate in synchronous condenser mode, can deliver system strength services largely without affecting their energy dispatch.
- As the System Strength Service Provider (SSSP) for Queensland, Powerlink is required to plan for, procure and make system strength services available to the Australian Energy Market Operator (AEMO) to enable in the operational timeframe from December 2025.
- Powerlink has applied the Regulatory Investment Test for Transmission (RIT-T) to assess the technical and commercial feasibility of options to address Queensland's system strength requirements between December 2025 and December 2030.
- In November 2024, Powerlink published the Project Assessment Draft Report (PADR) for this RIT-T. The preferred option in the PADR included:
    - nine synchronous condensers across Central Queensland and Southern Queensland by June 2034;
    - contracting with synchronous units in Southern and Northern Queensland for minimum level system strength requirements; and
    - contracting for grid-forming BESS in Southern, Central and Northern Queensland for efficient level requirements.
- Powerlink received around 50 proposals for system strength service provision from more than 25 proponents in response to the PADR.
- In January and February 2025, Powerlink undertook a high-level technical assessment of all proposals received in response to the PADR, and shortlisted solutions for further commercial and technical assessment. Powerlink has commenced negotiations for system strength contracts with a number of proponents of system strength solutions.
- This Project Assessment Conclusions Report (PACR) is the final step in the RIT-T process.

1.1 What is System Strength?

System strength is a measure of the ability of the network to maintain and control the voltage both during steady state operation and in response to a network disturbance, such as a sudden change in generation or load, or fault on the network.[1] This includes resisting changes in the magnitude, phase angle, and shape of the voltage waveform. If a transmission network location is:

[1] AEMO, *System Strength in the NEM Explained*, March 2020, page 5.

- 'strong', the change in voltage at that location will be relatively unaffected by a nearby disturbance; or
- 'weak', the voltage at that location will be relatively sensitive to a system disturbance, which could result in a more widespread prolonged voltage recovery.

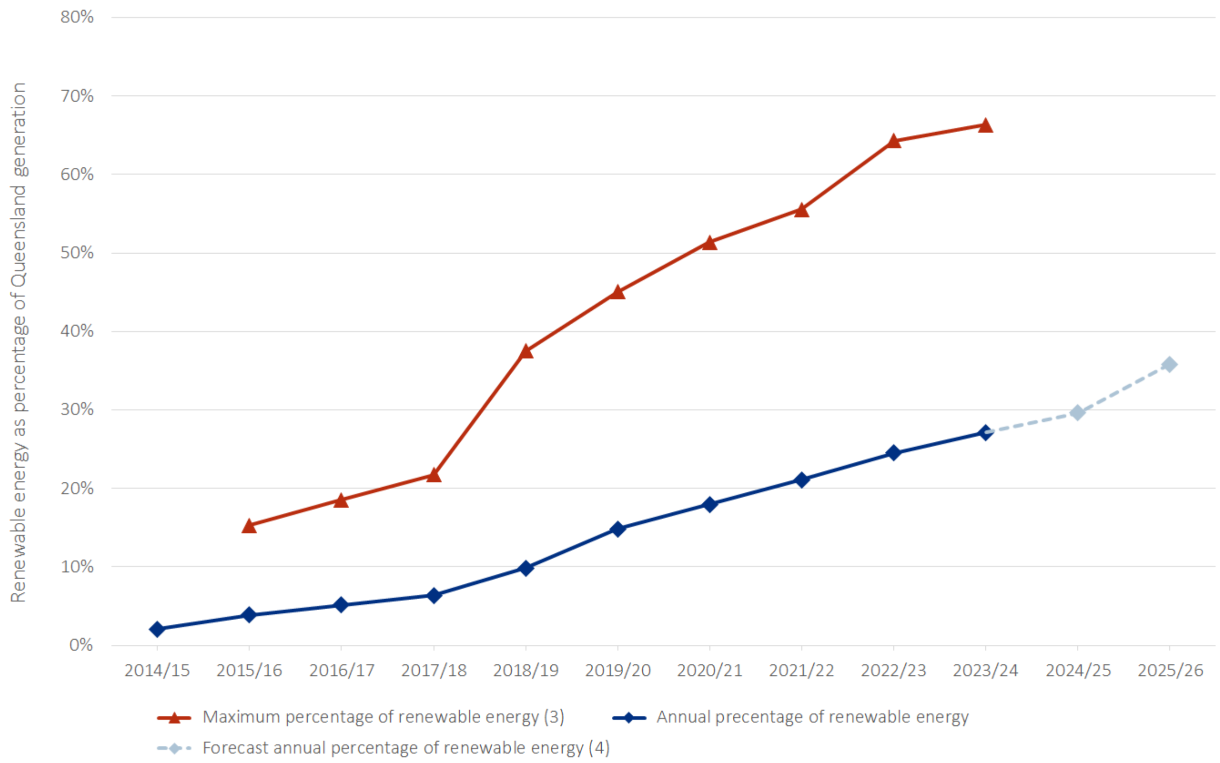
Low system strength in a particular location can adversely affect the security of the broader power system, such as through reducing the ability of generators to operate stably. System strength is also important to support the rapid detection and clearing of system faults, and to ensure acceptable power quality (including harmonics, flicker and negative phase sequence).

There are two components to system strength:

- Maintaining minimum fault level requirements for power system stability (minimum level system strength); and
- Achieving stable voltage waveforms to support inverter-based resources (IBR) (efficient level system strength).

The Queensland energy system has historically comprised synchronous generation such as coal-fired power stations, gas turbines and hydro-electric plants. These large synchronous generators have also provided various services, including system strength, as a by-product of their dispatch for energy, enabling the power system to operate stably. The increased share of generation from renewable sources, particularly solar and wind generation, means that system strength is less freely available and must be planned for and delivered by other means. In Queensland, the maximum percentage of energy generation from renewable sources has been steadily increasing over the last decade, due to construction of a number of large-scale renewable energy projects and the strong uptake of rooftop solar photovoltaic (PV) systems.

Figure 1.1: Queensland percentage of renewable energy generation (1) (2)



Source: Powerlink, 2024 Transmission Annual Planning Report, October 2024, page 26 (figure 2.3).

Notes: (1) Annual average and maximum percentage of renewable energy generation based on AEMO and Clean Energy Regulator data. (2) Percentage of renewable energy calculation methodology as per Queensland Government methodology. (3) Maximum percentage of renewable energy refers to the highest percentage of renewable energy generated in a trading interval during the financial year. (4) Forecast annual percentage of renewable energy includes renewable generation projects currently under construction and undergoing commissioning. Capacity factors for new renewable generating stations are based on existing stations of similar technology within the vicinity. Rooftop PV is included within renewable energy generation with forecasts based on the AEMO 2024 Integrated System Plan Step Change scenario.

Many 'non-synchronous' generators do not inherently provide system strength because they use grid-following inverter technologies to generate electricity. Given the rapid uptake of renewable IBR, finding alternate, safe, reliable and cost-effective solutions to address system strength needs is critical to ensure Queensland's power system remains stable into the future.

A range of technologies, including synchronous condensers, grid-forming BESS, PHES systems that can operate in synchronous condenser mode, and gas turbines with clutches to enable them to operate in synchronous condenser mode, can deliver system strength services largely without affecting their energy dispatch.

1.2 Overview of the Regulatory Investment Test for Transmission

The purpose of a RIT-T is to identify the preferred investment option that meets the 'identified need'. The identified need is essentially the problem that the RIT-T proponent (in this case Powerlink) considers will arise if action is not taken; that is, why investment is considered to be required.[2]

The 'preferred option' is the investment option that maximises the net economic benefits to the National Electricity Market (NEM), taking into account changes to Australia's greenhouse gas emissions where relevant. If the identified need is for a reliability corrective action, the preferred option may have a net economic cost.[3]

Powerlink applies the RIT-T to potential prescribed (regulated) investments in the transmission network where the estimated capital cost of the most expensive option to address the identified need that is technically and economically feasible exceeds $8 million.[4]

1.3 This System Strength RIT-T

The identified need for this RIT-T – to address system strength requirements in Queensland from December 2025 – is not included in the Australian Energy Market Operator's (AEMO) latest Integrated System Plan (ISP), published in June 2024. As such, this RIT-T is subject to the application and consultation process for RIT-T projects that are not actionable ISP projects.[5]

This RIT-T is a key part of Powerlink's implementation of the Efficient Management of System Strength on the Power System Rule (System Strength Rule), made by the Australian Energy Market Commission (AEMC) in October 2021. In order to meet Powerlink's responsibilities as the SSSP for Queensland under the System Strength Rule, Powerlink is applying the RIT-T to procure a portfolio of solutions to ensure that minimum fault

[2] National Electricity Rules (NER), chapter 10 (definition of 'identified need').
[3] NER, clause 5.15A.1(c) and chapter 10 (definition of 'net economic benefit').
[4] NER, clauses 5.15.3(a) and (b)(2) set the threshold at $5 million. The Australian Energy Regulator's (AER) 2024 cost threshold review increased the threshold to $8 million for three years from 1 January 2025.
[5] NER, rule 5.16.

level requirements are met, and system strength above the minimum levels is available to host projected levels of IBR.[6]

AEMO and Powerlink are responsible for the planning and delivery of power system security services in Queensland. AEMO's annual System Security Reports consider the need for power system security and reliability services in Queensland and other regions of the NEM. The reports assess system strength requirements, inertia shortfalls and Network Support and Control Ancillary Services (NSCAS) needs. Where AEMO declares a gap/shortfall for a power system security service(s) in Queensland, Powerlink is obliged to make services available within the timeframe declared by AEMO.

Powerlink commenced this System Strength RIT-T in March 2023 with publication of a Project Specification Consultation Report (PSCR). The PSCR invited proposals from proponents who considered they could offer potential non-network solutions that were both technically and economically feasible by 2030. Powerlink received close to 80 unique non-network solutions from more than 20 proponents in response to the PSCR and accompanying proforma.

In November 2024, Powerlink published the PADR. The preferred option in the PADR included:

- nine synchronous condensers across Central Queensland and Southern Queensland by June 2034;
- contracting with synchronous units in Southern and Northern Queensland for minimum level system strength requirements; and
- contracting for grid-forming BESS in Southern, Central and Northern Queensland for efficient level requirements.

Also in November 2024, Powerlink hosted a webinar to support the release of the PADR; the webinar recording, slides and Q&A document are available on Powerlink's website.

1.4 Submissions and proposals for non-network solutions

Submissions on the PADR, and proposals for non-network solutions, were due in December 2024.

- Powerlink received around 50 (confidential) proposals from more than 25 proponents in response to the PADR. Approximately three-quarters of the proposals were for BESS, and the remainder for synchronous solutions.
- Some proponents updated existing proposals submitted in response to the PSCR, while several new proposals were also received, including some from proponents who had not previously engaged in the RIT-T process.
- Some proposals received in response to the PSCR were not updated, or were withdrawn, by proponents at the PADR stage.
- No proposals for adding clutches to gas generating units in Central Queensland were received that Powerlink considers meet the RIT-T criteria for anticipated or committed projects.[7]
- No proposals were submitted for system strength services from coal generating units, (new) PHES assets, or for a large grid-forming BESS that could (if proven to be technically feasible) contribute to minimum system strength requirements in Central Queensland by 2028/29.

Powerlink received no general submissions on the approach to, or outcomes of, the PADR.

[6] NER, clause S5.1.14(b); AEMC, *Efficient Management of System Strength on the Power System*, final determination, October 2021, pages 107-116.

[7] See AER, *Regulatory Investment Test for Transmission*, November 2024, Glossary (definitions of 'anticipated project' and 'committed project'). See also the 'status of projects' section of Appendix H.

In January and February 2025, Powerlink undertook a high-level technical assessment of all proposals received in response to the PADR, and shortlisted solutions for further commercial and technical assessment. Solutions that were not shortlisted were generally not in a location, and/or of a sufficient size, to be considered feasible for delivering system strength services. Proponents of a solution(s) that was not shortlisted were formally advised of the assessment of their solution(s) in March 2025. Powerlink has commenced negotiations for system strength contracts with a number of proponents of system strength solutions.

Powerlink has also held meetings with a number of proponents of non-network solutions since August 2023. In some cases, multiple meetings have been held with proponents as Powerlink's assessment of system strength requirements has progressed, and/or proponents have sought to update Powerlink on their solution(s).

Powerlink thanks all proponents for their engagement in the RIT-T process, and for their responses to the PSCR proforma and/or PADR information request that further informed and shaped the analysis for this RIT-T.

This PACR is the third and final step in the RIT-T process, and sets out Powerlink's technical and economic assessment of credible options to address system strength requirements from December 2025.

More information on the RIT-T process is in Appendix A, and Powerlink's approach to customer and stakeholder engagement for RIT-Ts is outlined in Appendix B.

2. Identified Need

Key Points

- The identified need in this RIT-T is to make minimum and efficient level system strength services available to AEMO from 2 December 2025.
- The number of coal generating units in service at any point in time is a primary consideration for Powerlink's ability to meet minimum system strength requirements.
- Powerlink has applied AEMO's 2024 ISP coal generation forecasts for Southern and Central Queensland to the analysis for the RIT-T. The 2024 ISP projects all coal generation in Queensland to retire by 2035.
- AEMO's System Strength Reports indicate that there could be periods of time from 2027/28 when insufficient units are online in Central or Southern Queensland for minimum system strength requirements to be met.
- Coal generating unit forecasts can change quickly and materially at sub-regional levels, and there is risk associated with relying on a particular forecast for the purpose of planning for system strength services. Low minimum demand conditions, outages and commercial factors may also force more coal generating units to retire early and/or be offline more frequently than anticipated.
- In April 2025, the Queensland Government announced it would provide funding to upgrade the Callide B1 and B2 coal generating units, and updated the expected closure date of the two units from 2028 to 2031. These decisions will likely increase the availability of system strength in Central Queensland, but there still may be periods of time when either or both units are not online and providing system strength.
- Powerlink considers there is uncertainty about the need for efficient level services in Southern, Central and Northern Queensland regions between 2028 and 2030. Powerlink will re-engage with industry on these requirements closer to the time of need.

2.1 Description of the identified need

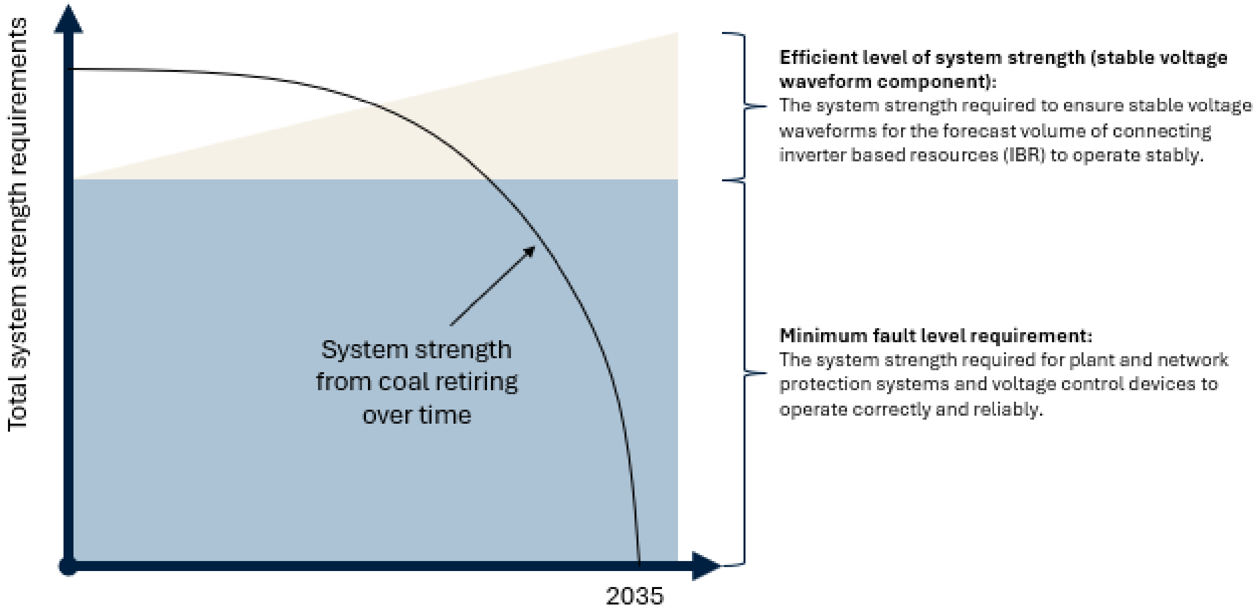
The identified need in this RIT-T is to make system strength services available to AEMO to meet the following requirements in each year from 2 December 2025:

- Maintain the minimum three phase fault level specified by AEMO at each system strength node for the relevant year; and
- Achieve stable voltage waveforms for the level and type of IBR and market network service facilities projected by AEMO at each system strength node for the relevant year in steady state conditions, and following a credible contingency event or protected event.[8]

Figure 2.1 is a conceptual illustration of the minimum and efficient component elements of system strength requirements.

[8] NER, clause S5.1.14(b).

Figure 2.1: Minimum fault level and stability components of system strength



2.2 System Strength Rule

As stated in section 1.3, in October 2021 the AEMC made the System Strength Rule. The new rule:

- evolved the 'do no harm' framework which required connecting generators to self-assess their impact on the local network's system strength levels, and self-remediate any adverse impacts; and
- established a new framework for the supply, demand and coordination of system strength in the NEM.[9]

A key element of the supply side of the framework is the establishment of the System Strength Standard, comprised of the minimum fault level requirement and the stability requirement. The minimum fault level is necessary for system security, and the voltage waveform stability component is required to securely host forecast levels of IBR connection. The System Strength Standard is set out in two schedules in Chapter 5 of the National Electricity Rules (NER):

- the system standard in clause S5.1a.9; and
- the network standard in clause S5.1.14 that specifies specific obligations that SSSPs must meet.[10]

The first date by which Powerlink must comply with the standard in clause S5.1.14 of the NER is 2 December 2025.[11] As the investment in system strength services is to ensure Powerlink's compliance with clause S5.1.14 of the NER, this RIT-T is considered a reliability corrective action under the NER.[12]

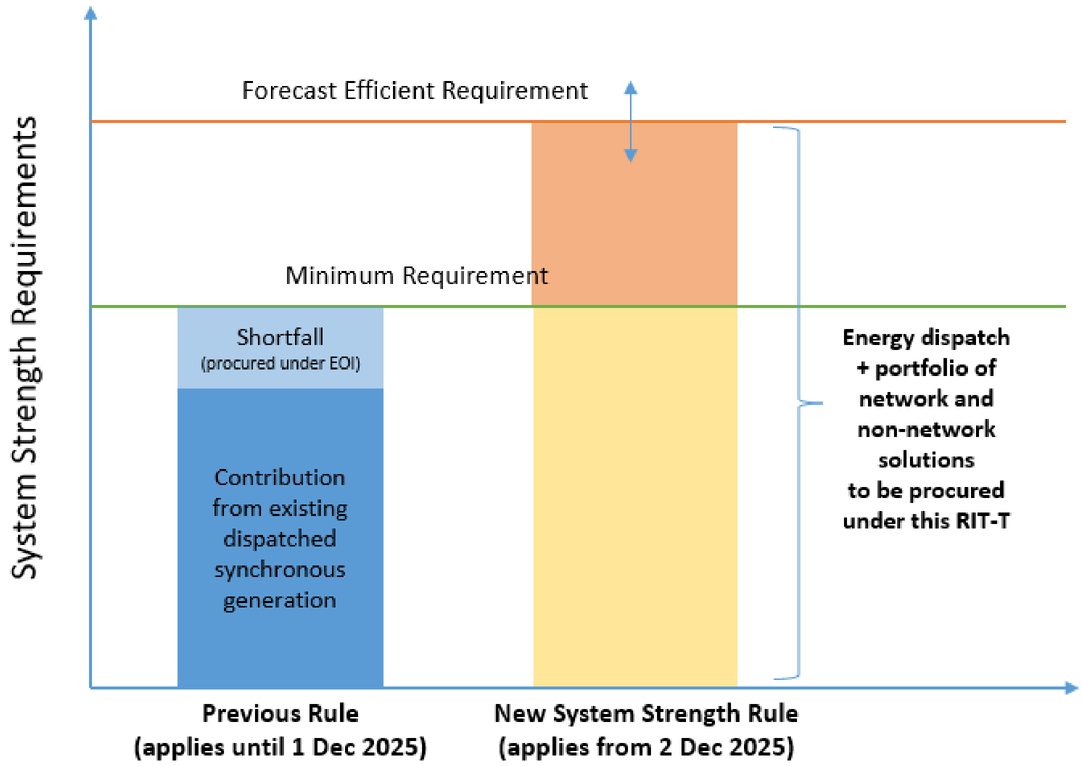
[9] AEMC, *Efficient Management of System Strength on the Power System*, final determination, October 2021, page 13.
[10] Ibid, page 15.
[11] Ibid, page 107.
[12] NER, clause 5.10.2 (definition of 'reliability corrective action').

In the final determination for the System Strength Rule, the AEMC made comments that are directly relevant to Powerlink's response to the rule:

- SSSPs cannot plan to meet the System Strength Standard through the use of constraints or directions given these are operational tools.
- In the operational timeframe, it may be more appropriate to apply constraints to relevant generators to maintain system security when solutions procured by the SSSP are exhausted.
- In the case of planned outages, it may be more efficient to use constraints for the length of the relatively short planned outage than to obtain further services at a significantly higher cost to cover the period.[13]

From December 2022, the System Strength Rule replaced the fault level shortfall process.[14] However, transitional arrangements ensure that Powerlink continued to address the system strength shortfall at the Gin Gin node, declared by AEMO in December 2021.[15] Figure 2.2 illustrates how the differing approaches of both the shortfall mechanism and System Strength Standard apply to meet system strength requirements.

Figure 2.2: Meeting system strength under the shortfall and standard based approaches



[13] AEMC, *Efficient Management of System Strength on the Power System*, final determination, October 2021, page 16.
[14] See *National Electricity Amendment (Efficient Management of System Strength on the Power System) Rule 2021 No. 11*, schedule 2 at [24] omitting clause 5.20C.2 (Fault Level Shortfalls) from the NER.
[15] NER, clauses 11.143.1 (definition of 'system strength transition period') and 11.143.13(a)(1). Further information on Powerlink's response to the declared shortfall is available on the Power System Security Consultation page of Powerlink's website.

2.3 Assumptions and requirements underpinning the identified need

While the overall characterisation of the identified need for this RIT-T has not changed since the PSCR, the specific detail regarding the identified need has changed as AEMO has updated system strength requirements for Queensland.

Minimum level system strength

The number of coal generating units in service at any point in time in Queensland is a primary consideration for Powerlink's ability to meet minimum system strength requirements. There are currently 22 coal generating units in Queensland, of which 14 are in Central Queensland and eight are in Southern Queensland. To provide sufficient system strength in Southern Queensland four units are required to be online at all times, and in Central Queensland six units are required to be online at all times.

Powerlink has applied AEMO's 2024 ISP coal generation forecasts for Southern and Central Queensland to the analysis for the RIT-T. The 2024 ISP projects all coal generation in Queensland to retire by 2035. Further, AEMO's recent System Strength Reports indicate that there could be periods of time from 2027/28 when insufficient units are online in Central or Southern Queensland for minimum system strength requirements to be met. These assumptions have not materially changed since the PADR and are re-presented for completeness in Appendix C.[16]

In April 2025, the Queensland Government:

- announced it would deliver a five-year Energy Roadmap in late 2025;
- announced it would provide funding for the refurbishment of the cooling tower at the Tarong Power Station in Southern Queensland, and to upgrade the Callide B1 and B2 coal generating units in Central Queensland; and
- updated the expected closure date of the Callide B1 and B2 units from 2028 to 2031.[17]

Powerlink expects these developments will lead to an increase in the availability of system strength from energy dispatch within the planning horizon (December 2025 to December 2030) for this RIT-T. However, there are many factors that determine the amount of system strength that can be expected from energy dispatch, of which the expected retirement date of coal generating units is just one. As outlined in Appendix C, low minimum demand conditions, outages and commercial factors may also force more coal generating units to retire early and/or be offline more frequently than anticipated. In response to the government's announcements, Powerlink has added a new 'change in government policy' reopening trigger to the PACR, as discussed in section 5.2.

Figure 2.3 shows the indicative areas for minimum system strength solutions, which are unchanged from the PADR.

[16] The NER, clause 5.16.4(v)(1), requires a PACR for a RIT-T to include the maters detailed in the PADR.

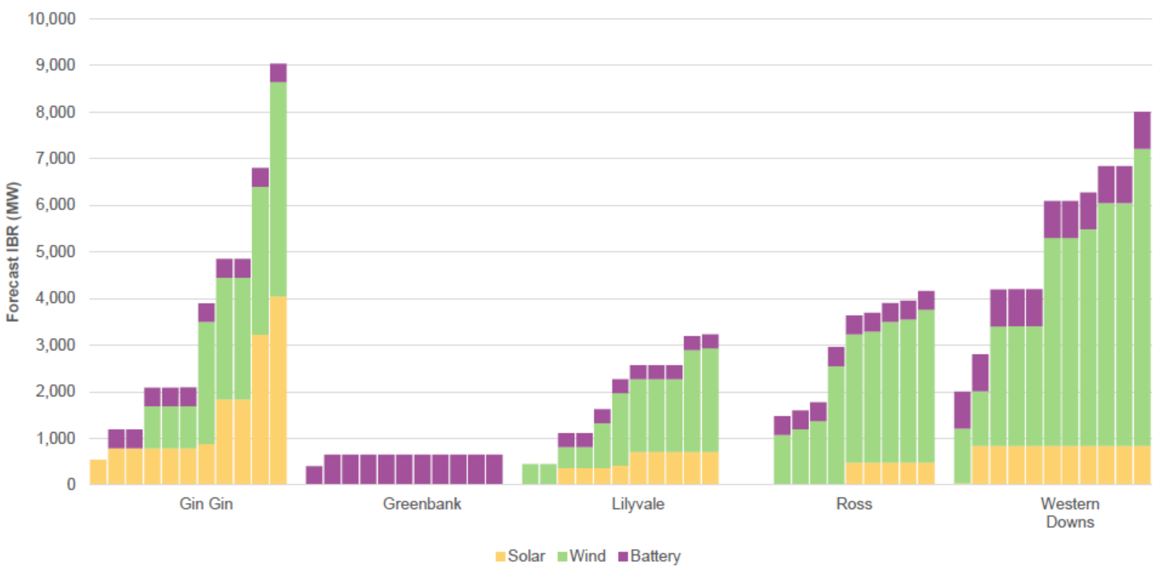
[17] Treasurer, Minister for Energy and Minister for Home Ownership (The Honourable David Janetzki MP), 'Energy Roadmap to deliver affordable, reliable and sustainable electricity', media statement, 8 April 2025; AEMO, Generating Unit Expected Closure Year, April 2025. Under the NER, clause 2.10.1, generators must provide AEMO with at least 42 months' notice of their expected retirement dates.

Figure 2.3: Indicative areas for minimum system strength solutions

Efficient level system strength

AEMO's System Strength Reports also project the level and type of IBR connections at each system strength node. Figure 2.4 shows AEMO's latest 11-year forecast (from 2024/25 to 2034/35 inclusive).

Figure 2.4: AEMO 11-year forecast (from 2024/25) of IBR at system strength nodes, February 2025



Source: AEMO, 2024 System Strength Report, February 2025, page 29 (figure 13).

At an aggregate level, the 2024 forecast shows higher IBR from 2024/25 to 2032/33 than the 2022 and 2023 forecasts. As was the case with AEMO's IBR forecasts in 2022 and 2023, the majority of growth, in terms of megawatts (MW), in the 2024 forecast is for wind projects.[18]

In the PADR, Powerlink indicated that efficient level services would initially be needed in the Northern Queensland Area 1 (Ross), with the majority of services needed in Southern, Central and Northern Queensland between 2028 and 2030. Primarily due to updated wind IBR forecasts, Powerlink considers efficient level services will be needed in the Ross area by 2027 rather than in 2026, and has identified potential BESS solutions for efficient services in the area.

Powerlink considers the need for efficient level services in each region between 2028 and 2030 is uncertain.

- Forecasts for IBR installations are uncertain and commissioning/operational timeframes are difficult to predict, particularly in the 2028 to 2030 timeframe.
- All IBR is effectively treated as grid-following in AEMO modelling.[19] Powerlink is aware that some solar/wind farms are self-remediating their system strength impacts, and it is uncertain how many IBR will choose to purchase system strength services from Powerlink.

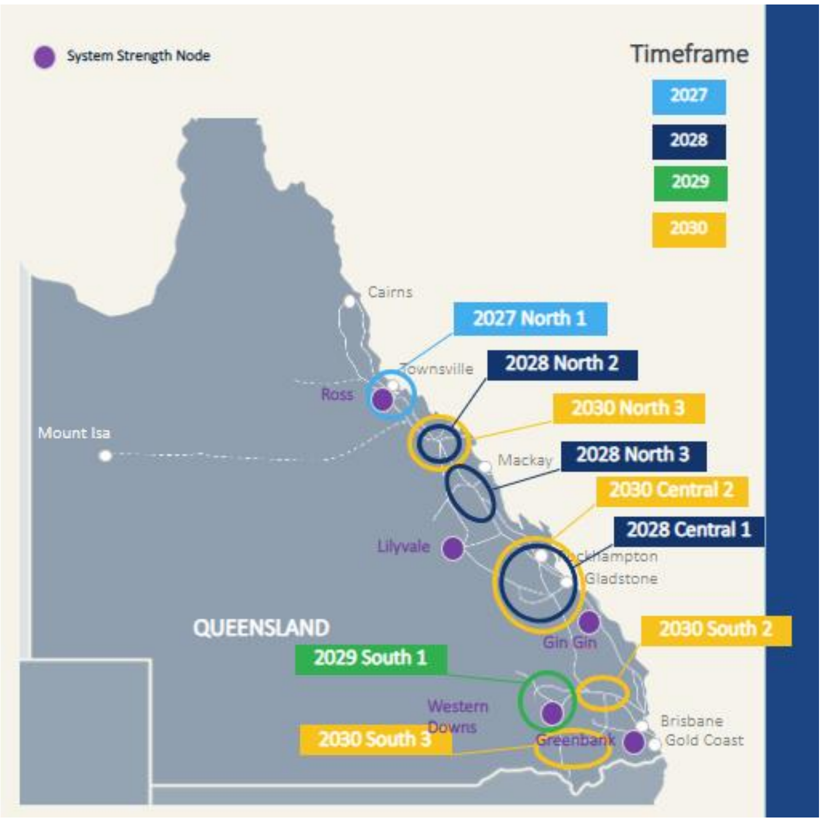
The potential for these factors to lead to an over-estimate of the need for efficient level services creates a risk that Powerlink could over-invest in efficient level system strength services, leading to inefficient expenditure that would not be in the interests of customers.

Since publishing the PADR, Powerlink has undertaken further analysis of the need for efficient level services. The analysis involved comparison of AEMO's 2023 and 2024 IBR forecasts and Powerlink's recent connection information. The analysis found that AEMO's updated 2024 IBR forecasts did not have a material impact on PADR outcomes for efficient services, and further detailed technical studies were not required at the PACR stage. An adjustment to Ross area expected timelines, as discussed above, was the only change that was required as a result of this analysis. Further details of the analysis is in Appendix D.

Figure 2.5 shows the indicative areas for efficient system strength solutions, with the only change from the PADR being the timeframe for the North 1 area changing to 2027 (from 2026).

[18] See AEMO, *2022 System Strength Report*, December 2022, page 39 (figure 16); AEMO, *2023 System Strength Report*, December 2023, page 27 (figure 13).
[19] AEMO, *2023 System Strength Report*, December 2023, page 11.

Figure 2.5: Indicative areas for efficient system strength solutions



For efficient needs beyond 2027, Powerlink anticipates re-engaging with industry at an appropriate time(s).[20] Before a system strength contract could be finalised with any proponent at that stage, further detailed technical assessment will be required. The extent to which the costs of a system strength contract would be likely to represent expenditure that is prudent and efficient will also be an important consideration for Powerlink.

Powerlink also notes that there could also be changes to the need for efficient level services in Southern, Central or Northern Queensland over the planning horizon to 2030.

[20] For clarity, Powerlink does not consider re-engaging for efficient needs beyond 2027 to constitute a material change in circumstances under the NER, clause 5.16.4(z4), assuming no significant increases or decreases in the efficient system strength needs; that is, assuming that re-opening trigger number 6 (see section 5.2) is not met.

3. Credible Options

Key Points

- Powerlink has adopted a portfolio formation approach to develop credible options to address system strength requirements from December 2025 to December 2030.
- Powerlink developed a Balanced Technology portfolio (Portfolio 1) that included a range of different technologies for meeting the minimum system strength requirements going forward, such as existing synchronous generation (including hydro generators), adding clutches to existing and future gas generating units, and synchronous condensers.
- Powerlink also developed four additional portfolios that assume a greater use of a particular technology for meeting the minimum requirements, namely Portfolio 1A (Balanced Technology with BESS in Minimum), Portfolio 2 (Synchronous Condensers), Portfolio 3 (Clutched Gas Turbines) and Portfolio 4 (Pumped Hydro Energy Storage).
- A key issue for Powerlink in this RIT-T is the extent to which grid-forming BESS can be relied on to contribute to minimum fault level requirements. This uncertainty was the basis for developing Portfolio 1A in the PADR, which tested how including grid-forming BESS to assist with the minimum system strength requirements would fare, relative to the other technology choices, if found to be technically feasible.
- For meeting the efficient system strength requirements, anticipated and committed BESS proposals were selected as they are relatively low-cost solutions in the cost-benefit analysis and can be contracted as and when required. Given they are independent of solutions to meet the minimum requirements, each portfolio included the same capacity of grid-forming BESS – both new build and the conversion of existing – to meet the efficient system strength requirements.
- In light of the technology types, locations and expected service start dates for proposed solutions received in response to the PADR, the only portfolio from the options outlined in the PADR that is considered credible at this time is Portfolio 2 (Synchronous Condensers).

3.1 Portfolios of credible options for the PADR

Powerlink has adopted a portfolio formation approach to develop five different credible options to address the system strength requirements in Queensland from December 2025. Each portfolio included a number of common solutions for meeting both the minimum and efficient system strength requirements.

Table 3.1: Solutions common to all five portfolios

Requirements	Solutions
Minimum fault level	One new synchronous condenser in Southern Queensland. Non-network contracts with existing, expected and potential future gas and hydro projects in Southern and Northern Queensland. Powerlink's solution to the system strength shortfall declared by AEMO (in 2021) at the Gin Gin system strength node (being the installation of a clutch at the Townsville Power Station). A non-network contract with an existing (small) synchronous condenser.
Efficient stable voltage waveform	2.15 gigawatts of grid-forming BESS.

For the PADR, Powerlink developed a Balanced Technology portfolio (Portfolio 1) that included investing in or contracting with a range of different technologies for meeting the minimum system strength requirements, such as existing synchronous generation (including hydro generators), adding clutches to existing and future gas generating units, and synchronous condensers. Four additional portfolios each assumed a greater use of a particular technology for meeting the minimum requirements.

The outcome of the portfolio formation process was that the portfolios differed in terms of the following solutions for meeting the minimum fault level requirements.

Table 3.2: Key differences between the five portfolios

Portfolio	Solutions for minimum requirements
1 (Balanced Technology)	Six new synchronous condensers in Central Queensland. Two future clutched gas turbines in Central Queensland.
1A (Balanced Technology: BESS in Minimum)	Five new synchronous condensers + one (large) grid-forming BESS in Central Queensland. Two future clutched gas turbines in Central Queensland.
2 (Synchronous Condensers)	Eight new synchronous condensers in Central Queensland.
3 (Clutched Gas Turbines)	Four new synchronous condensers in Central Queensland. Four future clutched gas turbines in Central Queensland.
4 (Pumped Hydro Energy Storage)	Three new synchronous condensers in Central Queensland. Two future clutched gas turbines in Central Queensland. Three planned pumped hydro energy storage units in Central Queensland.

For all portfolios, all assumed investment in and or contracting with components was complete by 2034. That is, no portfolio involved any new solutions beyond that point.

Each of the portfolios met both the minimum and efficient system strength requirements. The approach of having portfolios assume a greater use of a particular technology for meeting the minimum requirements enabled the PADR assessment to test the relative expected economic benefits of, and interactions between, the different technologies that are able to assist with meeting the minimum system strength requirements.

3.2 Credible portfolio for the PACR

In light of the technology types, locations and expected service start dates for proposed solutions received in response to the PADR, the only portfolio from the options outlined in the PADR that is considered credible at this time is Portfolio 2 (Synchronous Condensers). This position has been directly informed by proposals received in response to the PADR.

Additional detail regarding the portfolio formation at the PADR stage is included in Appendix E.

Further, as Powerlink did not receive sufficient proposals for the grid-forming BESS, clutched gas turbines or PHES portfolios to remain as credible options, Powerlink did not consider it necessary to update the estimation of market benefits undertaken by Ernst and Young (EY) at the PADR stage. Powerlink has also not updated the base case analysis as the avoided involuntary load shedding from insufficient system strength did not affect the ranking of credible options at the PADR stage, and there remains only one credible option at this point in time.

For completeness, detail from the PADR on the base case and market benefits are at Appendices F and G.

4. Preferred Option

Key Points

- The Net Present Value (NPV) analysis at the PADR stage found that Portfolio 2 (Synchronous Condensers) had the greatest expected net economic benefit over the economic assessment period, which extended to 2050.
- It is of the utmost importance that Powerlink meets its system strength obligations, as failing to do so could result in material outages for customers. As outlined in the PADR, Powerlink has commenced investing in or contracting with up to three synchronous condensers needed in Central Queensland by March 2029.
- Given the lead-time to procure synchronous condensers, and the lack of non-network solutions for Central Queensland available at this time, Powerlink will also now commit to investing in or contracting with up to three further synchronous condensers needed in Central Queensland by June 2030.
- The PADR also showed that there were additional low regret non-network solutions for Southern Queensland. These solutions provide prudent insurance against the potential for more accelerated coal retirement in Southern Queensland and remain part of the preferred option for the PACR. Powerlink does not, at this time, consider investing in a synchronous condenser in Southern Queensland to be a low regret solution, and so is not proposing to commit now to this solution.
- Since the PADR was released, Powerlink has issued a tender for supply of synchronous condensers in Central Queensland. However, Powerlink will not have updated cost estimates for synchronous condensers until tender proposals are received and assessed.
- Accordingly, Powerlink has retained the PADR cost estimate for synchronous condensers of $135 million each in the cost-benefit analysis for the PACR. Powerlink does not consider that the absence of a higher-class cost estimate (specifically a class 3 estimate) at this time is a material issue for this RIT-T as the identification of the preferred option is not sensitive to these assumed costs.
- The costs for non-network solutions will ultimately be reviewed by the AER as part of the new network support payment process for system security services.
- Only the prudent and efficient capital costs of the network components of the preferred option will factor into the Regulatory Asset Base (RAB) following this RIT-T. That is, it is not the total capital costs (across network and non-network solutions), nor the estimated net economic benefits, that factor into the RAB.

4.1 Net Present Value Results

For the PADR, Powerlink undertook a cost-benefit analysis in accordance with the requirements of the RIT-T Instrument and RIT-T Application Guidelines. The analysis found Portfolio 2 (Synchronous Condensers) was the top-ranked option and delivered approximately $128 million greater net benefits than the second ranked option (Portfolio 1). The NPV results from the PADR, including details of the key inputs and assumptions used for the analysis, are in Appendix H.

4.2 Preferred Option

The top-ranked option, Portfolio 2 (Synchronous Condensers), involves:

- nine synchronous condensers across Central Queensland and Southern Queensland by June 2034;
- contracting with a range of synchronous units in Southern and Northern Queensland for minimum system strength requirements; and
- contracting for 550MW of grid-forming BESS in Southern Queensland, and 1,600MW of grid-forming BESS in Central Queensland/Northern Queensland, for efficient system strength requirements.[21]

While the preferred option for efficient requirements was expressed in the PADR as being provided by grid-forming BESS, Powerlink recognised that the ultimately preferred solution may be another technology, such as synchronous condensers. For completeness, Powerlink also summarised the indicative efficient system strength requirements as:

- 660 to 1,200 megavolt amperes (MVA) of solutions in Southern Queensland;
- 440 to 800MVA of solutions in Central Queensland; and
- 760 to 1,300MVA of solutions in Northern Queensland.[22]

In addition, given the location, size and operational aspects of system strength requirements, it should also be noted that if proposals for synchronous condenser operation of gas turbines or PHES solutions do reach anticipated or committed status, this may not necessarily reduce the number of synchronous condenser units required.

Powerlink has commenced investing in or contracting with up to three synchronous condensers needed in Central Queensland by March 2029 (tranche 1). As outlined in Powerlink's assessment for the Gladstone Project Priority Transmission Investment, two of the initial synchronous condensers will address the anticipated closure of the Gladstone Power Station.[23] Portfolio 2 also includes the following six synchronous condensers:

- three in Central Queensland, and one in Southern Queensland, by June 2030 (tranche 2);
- one in Central Queensland by June 2033 (tranche 3); and
- one in Central Queensland by June 2034 (tranche 4).

In the PADR, Powerlink indicated that it would not commit to contracting for the delivery of the additional six (tranches 2, 3 and 4) synchronous condensers at the time. The assessment in the PADR showed that the preferred option in this RIT-T would change if alternate solutions became anticipated or committed. Powerlink therefore considered it prudent to allow the opportunity for these alternative solutions to emerge.

However, as stated in section 1.4, in response to the PADR no proposals were submitted:

- for adding clutches to gas generating units in Central Queensland that Powerlink considers meet the RIT-T criteria for anticipated or committed projects; and
- from coal generators or (new) PHES assets, or for a large grid-forming BESS that could (if technically feasible) contribute to minimum system strength requirements in Central Queensland by 2030.

[21] As noted in section 2.3, Powerlink has identified potential BESS solutions for efficient level services in the Ross area needed by 2027, and will continue to monitor 2028 and 2030 needs.

[22] Powerlink also indicated in the PADR that ongoing technical studies had shown that potentially more grid-forming BESS may be required for the efficient requirements (in the order of 10-20% more) and Powerlink intended to review and update this in the PACR.

[23] Powerlink, *Gladstone Project: Candidate Priority Transmission Investment*, final assessment report, June 2025, page 23.

It is of the utmost importance that Powerlink meets its system strength obligations, as failing to do so could result in material outages for customers. As lead-times for procurement and delivery of synchronous condensers are currently around four years from the time of contract award, Powerlink will also now invest in, or contract with, up to three further synchronous condensers needed in Central Queensland by June 2030.

The PADR also showed that there were additional low regret non-network solutions for Southern Queensland. These solutions provide prudent insurance against the potential for more accelerated coal retirement in Southern Queensland and remain part of the preferred option for the PACR. Powerlink does not, at this time, consider investing in a synchronous condenser in Southern Queensland to be a low regret solution, and so is not proposing to commit now to this solution.

4.3 Estimated Costs of Preferred Option

Since the PADR was released, Powerlink has issued a tender for the supply of synchronous condensers in Central Queensland. However, Powerlink will not have updated cost estimates for synchronous condensers until tender proposals are received and assessed (which is currently expected to be in late-2025). Accordingly, Powerlink has retained the PADR cost estimate for synchronous condensers of $135 million each in the cost-benefit analysis for the PACR. Powerlink does not consider that the absence of a higher-class cost estimate (specifically a class 3 estimate) at this time is a material issue for this RIT-T as the identification of the preferred option is not sensitive to these assumed costs. Moreover, Powerlink has included a reopening trigger that captures a material increase in the cost of synchronous condensers, providing there is more than one credible option at that time.

As stated in section 1.4, Powerlink has commenced negotiations for system strength contracts with a number of proponents of system strength solutions. The costs for non-network solutions will ultimately be reviewed by the AER as part of the new network support payment process for system security services.[24]

Powerlink notes that only the prudent and efficient capital costs of the network components of the preferred option will factor into the RAB following this RIT-T. That is, it is not the total capital costs (across network and non-network solutions), nor the estimated net economic benefits, that factor into the RAB.

Detail on Powerlink's approach to estimating costs of network and non-network solutions is in Appendix I.

[24] AEMC, *Improving Security Frameworks for the Energy Transition*, final determination, March 2024, pages 49-53; AER, *System Security Network Support Payment Guideline*, guideline, November 2024; and NER, clauses 6A.6.6A, 6A.7.2, 6A.22.1 and 6A.23.3.

5. Material Changes in Circumstances

Key Points

- Powerlink seeks to maximise flexibility via the RIT-T to commit to investing in or contracting with a small number of synchronous condensers, while leveraging RIT-T reopening triggers to pivot to new system strength solutions as they become available.
- Powerlink has finalised eight reopening triggers for this RIT-T which, if activated, would alter the make-up of the preferred option and allow Powerlink to pivot to alternate solutions for system strength. These are:
    1. Credible evidence of proposals for synchronous condenser operation of gas turbines (such as adding a clutch) or PHES solutions reaching committed or anticipated status (as defined under the RIT-T).
    2. Credible evidence emerging that grid-forming BESS are able to be relied on to contribute to minimum fault level requirements, and proposals reaching anticipated or committed status (as defined under the RIT-T).
    3. Credible evidence that the cost (as considered under the RIT-T) of adding clutches to gas turbines is going to be sufficiently greater than installing synchronous condensers that it changes what is considered optimal in Southern Queensland to meet the minimum requirements.
    4. Credible evidence of expected real synchronous condenser costs increasing by approximately 75% compared to those used in the RIT-T analysis.
    5. Credible evidence of commercial discount rates falling materially below the boundary value (2.15%) identified in this RIT-T.
    6. Credible evidence of the demand for system strength requirements for projected IBR plants significantly increasing, or significantly reducing due to self-remediation and technological advancements in equipment.
    7. Delayed availability of, and/or inability to conclude contracts with, proposed solutions, including contracting for solutions in Southern Queensland to meet the minimum or efficient requirements.
    8. Credible evidence that a change(s) in retirement dates and/or operational arrangements for coal generating units changes the identified need for system strength requirements, and/or the preferred option in this RIT-T.
- The two reopening triggers seeking to capture material changes in the real cost of synchronous condensers and commercial discount rates are only relevant if the second ranked option (Portfolio 1) is considered credible (which it currently is not). Specifically, these triggers are based on the PADR boundary analysis for these two variables that tested when Portfolio 1 would be ranked ahead of Portfolio 2.
- The eighth reopening trigger has been added to the seven proposed at the PADR stage, and responds to the Queensland Government's recent announcements regarding coal-fired power stations in Queensland.
- Overall, Powerlink's proposed approach will result in better outcomes for electricity customers, and also supports the development of non-network solutions in being able to provide system strength services.

5.1 Regulatory requirements

Once six months have passed after completing the analysis for this RIT-T, Powerlink will be required to monitor developments that could be material to the outcome of this RIT-T and consider whether a material change in circumstances has occurred.[25]

A material change in circumstances includes, but is not limited to:

- a change to the key assumptions used to identify the identified need described in the PACR;
- the meeting of any reopening trigger identified in the PACR for this RIT-T; or
- a change in circumstances which, in Powerlink's reasonable opinion, means that the preferred option identified in the PACR may no longer be the preferred option.[26]

If Powerlink considers that a material change in circumstances has occurred, it must:

- notify the AER in writing, and advise any actions it proposes to take and timeframes within which it proposes to complete any actions; and
- provide information to the AER to support any actions it proposes to take, having regard to
    - whether, in Powerlink's opinion, reapplication of the RIT-T is justified;
    - the costs and delay that may result from the actions Powerlink proposes to take as a result of the material change in circumstances; and
    - the costs and delay that may result from a full or partial reapplication of the RIT-T.[27]

If Powerlink submits a material change in circumstances notification to the AER, the AER will be required to accept or reject any actions proposed by Powerlink and specify reasonable timeframes for completion of actions. If the AER decides to reject the actions and/or timeframes proposed by Powerlink, the AER would be able to specify actions for Powerlink to take which may include reapplying the RIT-T, in whole or in part.[28]

5.2 Reopening triggers

The NER state that reopening triggers:

- are the events, factors or circumstances which, if they occur or eventuate, would mean that the RIT-T project may no longer be the preferred option; and
- may include a change in the key assumptions used to identify or rank the credible options.[29]

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[25] NER, clauses 5.16.4(z3) and (z3A). Powerlink is also only required to consider whether a material change in circumstances has occurred if it wishes to proceed with the project. It is not explicitly clear in the NER, RIT-T Instrument or RIT-T Application Guidelines when completion of the analysis that precedes the six-month period commences.

[26] NER, clause 5.16.4(z4). For clarity, TNSPs must consider whether or not a material change in circumstances has occurred for all RIT-T projects, not just those for which the estimated capital cost of the preferred option (at the PADR stage) is greater than $100 million (escalated over time). The AER's 2024 cost threshold review increased the threshold to $103 million for three years from 1 January 2025.

[27] NER, clauses 5.16.4(z3) and (z4A).

[28] NER, clause 5.16.4(z5A).

[29] NER, chapter 10 (definition of 'reopening trigger').

Proposed reopening triggers in the PADR

In the PADR, Powerlink proposed the following (seven) reopening triggers:

1. Credible evidence of proposals for synchronous condenser operation of gas turbines (such as adding a clutch) or PHES solutions reaching committed or anticipated status (as defined under the RIT-T).
2. Credible evidence emerging that grid-forming BESS are able to be relied on to contribute to minimum fault level requirements, and proposals reaching committed or anticipated status (as defined under the RIT-T).
3. Credible evidence that the cost (as considered under the RIT-T) of adding clutches to gas turbines is going to be sufficiently greater than commissioning synchronous condensers that it changes what is considered optimal in Southern Queensland to meet the minimum requirements.
4. Credible evidence of expected real synchronous condenser costs increasing by approximately 75% compared to those used in the RIT-T analysis.
5. Credible evidence of commercial discount rates falling materially below the boundary value (2.15%) identified in this RIT-T.
6. Credible evidence of the demand for system strength requirements for projected IBR plants significantly reducing due to self-remediation and technological advancements in equipment.
7. Delayed availability of, and/or inability to conclude contracts with, proposed solutions, including contracting for solutions in Southern Queensland to meet the minimum requirements.

In relation to the seventh trigger, Powerlink said in the PADR that it intended to include further sensitivity analysis in the PACR on the impact of not being able to contract with key non-network components of the preferred option. Given Portfolio 2 (Synchronous Condensers) is the only credible option at this time, Powerlink has not undertaken this further sensitivity for the PACR. Powerlink considers this sensitivity may be a relevant input to the analysis for a material change in circumstances, should it occur.

Powerlink did not receive any feedback from industry participants or stakeholders on the above reopening triggers in response to the PADR.

Updated reopening triggers

Powerlink has made three minor changes to the triggers for the PACR:

- The third trigger has been updated to refer to installing rather than commissioning synchronous condensers to clarify that the total cost, rather than just the commissioning cost, is captured.
- The sixth trigger has been updated to account for the fact that demand for efficient system strength requirements could significantly increase, or significantly reduce due to self-remediation and technological advancements in equipment.
- The seventh trigger has been updated to account for the delayed availability of, and/or inability to conclude contracts for, minimum or efficient level solutions. Further, as indicated in AER's recent guidance note for the system strength framework, the degree to which Powerlink considers the costs of system strength contracts to represent prudent and efficient expenditure will also be relevant to Powerlink's contracting decisions.[30]

The PADR also indicated that changes to future AEMO System Strength Reports, and/or Queensland coal generating units being repurposed into synchronous condensers, may also feed into additional reopening triggers at the PACR stage.

[30] AER, *The Efficient Management of System Strength*, guidance note, December 2024, page 11.

In December 2024 AEMO increased the percentage of time that minimum system strength requirements must be met before a gap is declared from 99% to 99.87% of the time.[31] For the PACR, Powerlink assessed the preferred option for minimum system strength solutions against the higher threshold, and found that it did not make a material difference to the preferred option.

Powerlink notes that the two reopening triggers above seeking to capture material changes in the real cost of synchronous condensers and commercial discount rates are only relevant if the second ranked option (Portfolio 1) is considered credible (which it currently is not). Specifically, these triggers are based on the PADR boundary analysis for these two variables that tested when Portfolio 1 would be ranked ahead of Portfolio 2.

In addition, in response to the Queensland Government's announcements of April 2025 (see section 2.3) regarding the Tarong and Callide B Power Stations, Powerlink has added a new (eighth) reopening trigger in this PACR:

8. Credible evidence that a change(s) in retirement dates and/or operational arrangements for coal generating units changes the identified need for system strength requirements, and/or the preferred option in this RIT-T.

This new reopening trigger acknowledges the potential impact of government policy on the availability of system strength between December 2025 and December 2030.[32] At this time, Powerlink does not consider the announcement constitutes a material change to the scenario modelling undertaken for the PADR and therefore does not affect the preferred option.

As indicated in the PADR, Powerlink does not consider that a material change in the location and/or timing of reduced coal generation in Southern Queensland to form a reopening trigger for this RIT-T. As outlined in section 4.2, Powerlink is proposing to commit to additional low regret solutions in Southern Queensland in light of the uncertainty surrounding the retirement/de-commitment of coal generators, and the adverse consequences for customers of under-investing in system strength solutions.

If there are short-term delays with any of the solutions included in the ultimately preferred option that would jeopardise Powerlink's ability to meet its system strength requirements, Powerlink may seek to contract with existing synchronous units to ensure customers' reliability is not compromised. Powerlink does not consider this would be a material change in circumstances given that contracting, in the short-term, with existing synchronous units would be the only solution available to Powerlink to ensure system security. At this time, Powerlink holds no information on potential pricing for contracting with coal generating units given no such proposals were submitted in response to the PADR (or PSCR).

In addition, given the location, size and operational aspects of system strength requirements, it should also be noted that if proposals for synchronous condenser operation of gas turbines or PHES solutions do reach anticipated or committed status, this may not necessarily reduce the number of synchronous condenser units required.

Finally, the PADR indicated that Powerlink intended to undertake additional sensitivity analysis, or update sensitivities included in the PADR, for the PACR. These are detailed in Appendix H, and generally related to updating analysis based on proposals for non-network solutions that were anticipated in response to the PADR. However, as no proposals for PHES solutions or gas turbines with clutches were received for Central Queensland

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[31] AEMO, *Network Support and Control Ancillary Services (NSCAS) Description and Quantity Procedure*, November 2024, version 3.0, page 13; AEMO, *Amendments to the NSCAS Description and Quantity Procedure*, final report, November 2024, pages 10-11.

[32] Powerlink notes that 'change in government policy' is an example reopening trigger in the RIT-T Application Guidelines. See AER, *Regulatory Investment Test for Transmission: Application Guidelines*, November 2024, page 113.

that Powerlink considers to be anticipated or committed, the additional sensitivity analysis has not been done for the PACR as the analysis would have no impact on the assessment of credible options.

5.3 Potential responses to a material change in circumstances

As stated in the PADR, it is unlikely that Powerlink would commence a new RIT-T in response to a material change in circumstances, as this would require significant time to complete and may impact Powerlink's ability to deliver system strength services at the required time. Instead, Powerlink is likely to revert to the sensitivity analysis undertaken for this RIT-T to confirm that the action proposed is optimal.

If a material change in circumstances occurs, Powerlink may consider:

- updating the cost-benefit analysis, including sensitivity analysis, of credible options and publishing a report on the results of the new analysis;
- conducting stakeholder consultation and publishing a report that summarises stakeholder views and the conclusions from the consultation; and/or
- initiating an Expression of Interest (EOI) for non-network solutions.

In addition, and as stated above, Powerlink would notify the AER of the material change in circumstances, and outline (for the AER's approval) the actions Powerlink proposes to undertake.[33]

Overall, Powerlink's proposed approach will result in better outcomes for electricity customers, and also supports the development of non-network solutions in being able to provide system strength services.

5.4 Inertia and system strength

AEMO's 2023 Inertia Report changed the identified inertia shortfall in Queensland from a range of 8,200 to 10,352 megawatt seconds (MWs) from 1 July 2026, to up to 1,660MWs from 2027/28. The one-year delay reflected updates to the delivery timing of several major generation, transmission and Renewable Energy Zone development projects which resulted in utilisation of synchronous generation in the near term. AEMO also indicated that the changed assessment represented a deferred onset of the shortfall, rather than a long-term reduction.[34] For the 2024 Inertia Report, AEMO decreased the shortfall to 256MWs in 2027/28, and noted Powerlink was progressing inertia remediation activities in parallel with this System Strength RIT-T.[35]

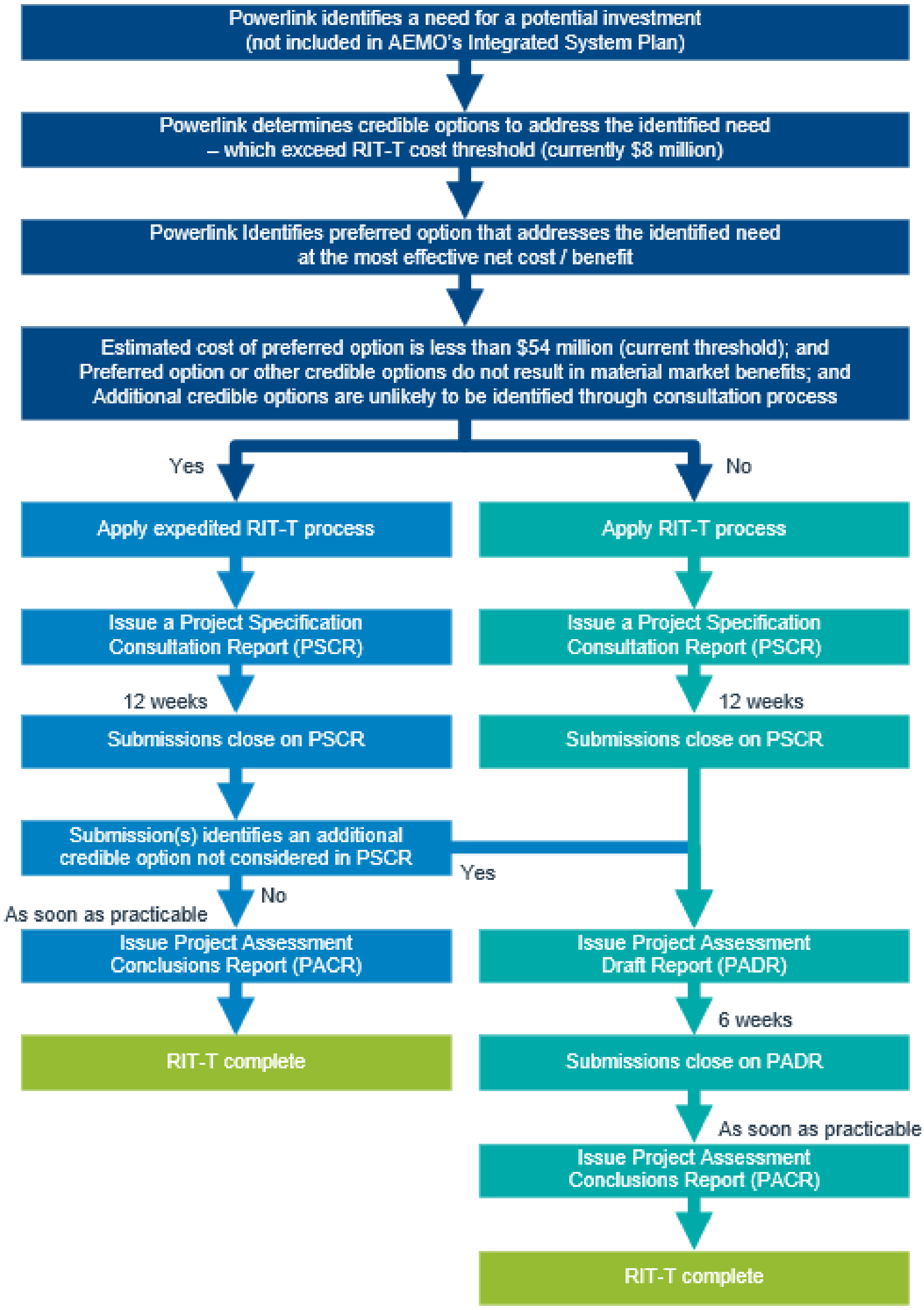
The Improving Security Frameworks for the Energy Transition Rule, made in March 2024, aligned the system strength and inertia procurement frameworks, with Powerlink required to ensure sufficient inertia is continuously available to meet projected inertia needs for Queensland from December 2027. The final rule also included transitional provisions to preserve Powerlink's obligation to address the already declared shortfall.[36]

If the level of inertia is not met through resources contracted through this System Strength RIT-T, a separate RIT-T may be required to procure services, or Powerlink may initiate a new RIT-T to meet system strength and inertia needs concurrently.

[33] NER, clause 5.16.4(z3)(4).
[34] AEMO, *2022 Inertia Report*, December 2022, page 22; AEMO, *2023 Inertia Report*, December 2023, page 26.
[35] AEMO, *2024 Inertia Report*, December 2024, page 14. Powerlink understands the primary change in the 2024 report was an increase in registrations for the one-second Frequency Control Ancillary Services market over the year, which reduces the amount of inertia required during islanded operation of Queensland.
[36] AEMC, *Improving Security Frameworks for the Energy Transition*, final determination, March 2024, page 32, and final rule, schedule 3 at [15] amending clause 5.20B.2, and at [17]-[18] amending clause 5.20B.4, of the NER; NER, clause 11.168.9.

Appendix A: RIT-T Process

The flow chart below illustrates the RIT-T process where the need is not an actionable project in AEMO's ISP.



As the first step in the RIT-T process, the PSCR:

- describes the reasons why Powerlink has determined that investment is necessary (the identified need), together with the assumptions used in identifying this need, including whether the need is as an actionable project in AEMO's latest ISP;
- provides potential proponents of non-network solutions with information on the technical characteristics that a non-network solution would need to deliver, in order to assist proponents to consider whether they could offer an alternative solution;
- describes the credible options that Powerlink currently considers may address the identified need;
- discusses why Powerlink does not expect specific categories of market benefit to be material for this RIT-T;
- presents the NPV assessment of each of the credible options compared to a base case, as well as the methodologies and assumptions underlying these results;
- identifies and provides a detailed description of the credible option that satisfies the RIT-T, and is therefore the preferred option;
- provides information about Powerlink's estimation of costs for each credible option;
- describes how customers and stakeholders have been engaged with regarding the identified need; and
- provides stakeholders with the opportunity to comment on this assessment so that Powerlink can refine the analysis (if required) as part of the PACR.[37]

A PADR and a PACR for a RIT-T must include:

- a description of each credible option assessed;
- a summary of and commentary on submissions received in response to the PSCR or PADR (as relevant);
- a quantification of the costs, including a breakdown of operating and capital expenditure, and classes of material market benefit for each credible option;
- reasons why Powerlink has determined that a class or classes of market benefit are not material;
- the results of NPV analysis for each credible option assessed, together with accompanying explanatory statements;
- the identification of the proposed preferred option, including details of the technical characteristics and the estimated construction timetable and commissioning date; and
- RIT-T reopening triggers if the estimated capital cost of the preferred option is greater than $103 million (as varied via AER cost threshold determinations).[38]

[37] NER, clause 5.16.4(b).
[38] NER, clauses 5.16.4(k) and (v)(1).

Appendix B: Customer and Stakeholder Engagement

Energy Charter

More than five million Queenslanders and 241,000 Queensland businesses depend on the reliability and security of Powerlink's transmission network. Powerlink recognises the importance of engaging with a diverse range of customers and stakeholders who have the potential to affect, or be affected by, Powerlink activities and/or investments.

Together with industry counterparts from across the electricity and gas supply chain, Powerlink has committed to the Energy Charter. The charter is a national CEO-led collaboration that supports the energy sector towards a customer-centric future. Powerlink's Energy Charter Disclosure Statement for 2023/24 shows Powerlink's recent achievements against the principles of the Energy Charter.

Powerlink Customer Panel

Powerlink's Customer Panel provides a face-to-face opportunity for customer representatives to give their input and feedback about Powerlink's decision making, processes and methodologies. The panel also provides Powerlink with a valuable avenue to keep customers and other stakeholders better informed, and to receive feedback about topics of relevance, including RIT-Ts.

The Customer Panel is regularly advised on the publication of Powerlink's RIT-T documents, and is briefed quarterly on the status of current RIT-T consultations as well as upcoming RIT-Ts. This provides an ongoing opportunity for the Customer Panel to ask questions and provide feedback to further inform RIT-Ts, and for Powerlink to better understand the views of customers when undertaking the RIT-T consultation process.

Powerlink will continue to provide updates to and request input from the Customer Panel throughout the RIT-T consultation process.

Transparency on future network requirements

Powerlink's annual planning review findings are published in the Transmission Annual Planning Report (TAPR) and TAPR templates (available via the TAPR portal).[39] It provides early information and technical data to customers and stakeholders on potential transmission network needs over a 10-year outlook period. The TAPR plays an important part in planning Queensland's transmission network and helping to ensure it continues to meet the needs of Queensland electricity customers and participants in the NEM. Powerlink's 2024 TAPR included updated information in relation to system strength locational factors and nodes, and discussed activities undertaken or planned to be undertaken (including the System Strength RIT-T) to meet system strength requirements in Queensland.[40]

Powerlink's annual Transmission Network Forum, held following release of the TAPR, is a primary vehicle used to engage with the community, understand broader customer and industry views and obtain feedback on key topics. It also provides Powerlink with an opportunity to further inform its business network and non-network planning objectives. Forum participants include customers, landholders, environmental groups, Traditional Owners, government agencies, and industry bodies. Engagement activities such as the forum help inform the future

[39] See NER, rule 5.12 for requirements.
[40] NER, clauses 5.12.2(c)(8) and (13). See also Chapter 4 and Appendix H of Powerlink's 2023 and 2024 TAPRs.

development of the transmission network and assist Powerlink in providing services that align with the long-term interests of customers.

Updates to proponents of non-network solutions

Powerlink has met regularly with potential proponents of non-network solutions for the System Strength RIT-T. Further, in December 2023 and May 2024, Powerlink provided formal updates on the technical and economic assessment approaches to proponents.

Powerlink applies a considered approach to RIT-T engagement

Powerlink undertakes a considered and consistent approach to ensure an appropriate level of stakeholder engagement is undertaken for each individual RIT-T consultation. The scope of engagement activities is dependent upon various considerations, such as the characteristics and complexity of the identified need and potential credible options.

For all RIT-Ts, members of Powerlink's Non-network Engagement Stakeholder Register receive email notifications of publication of RIT-T reports. For projects where Powerlink identifies material or significant market benefits, additional activities such as webinars or dedicated engagement forums may be appropriate. For more information, see Powerlink's RIT-T stakeholder engagement matrix.

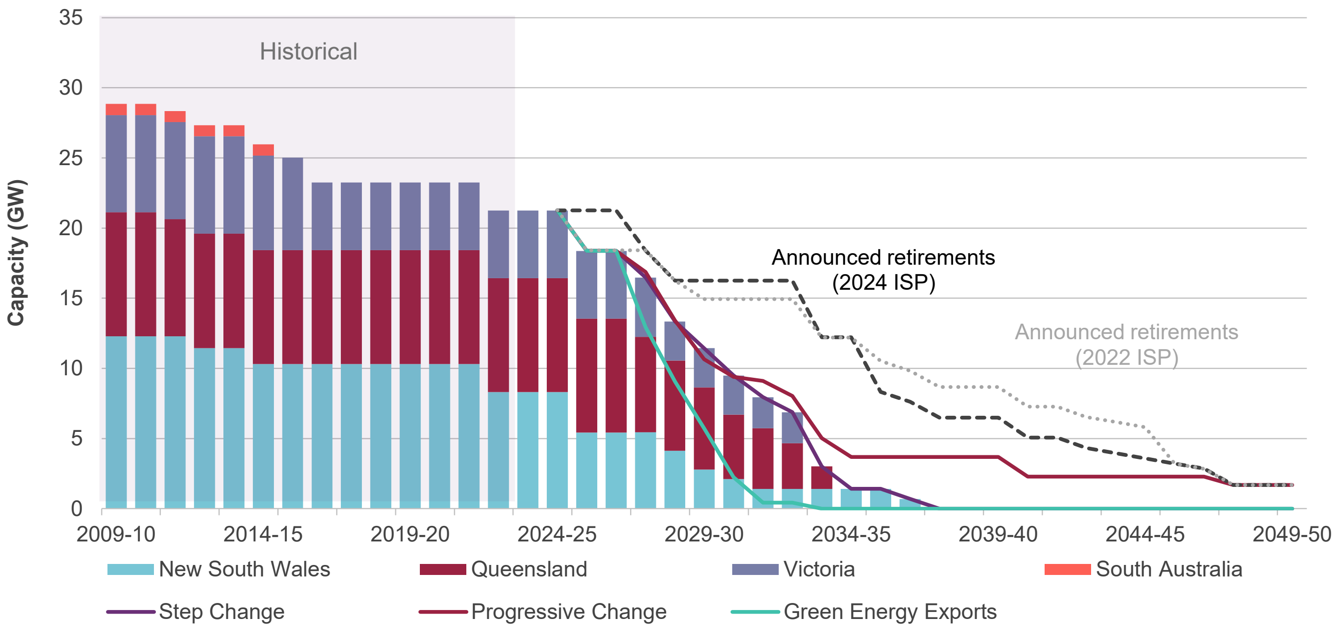
Powerlink intends to hold a webinar in late November 2024 to share the findings of the PADR and next steps with stakeholders.

Appendix C: AEMO Coal Generation and Minimum Fault Level Projections

AEMO forecasts of coal generation

AEMO's 2024 ISP noted that, between 2012 and 2023, 10 major coal-fired power stations had retired across the NEM, and owners of all but one plant of the remaining fleet have announced retirements by 2051 with about half announcing retirements by 2035. The ISP forecasts suggest that the coal fleet will close two to three times faster than those announcements, with about 80-90% of the NEM's coal fleet forecast to retire by 2034/35 in both the Step Change and Progressive Change scenarios (with a combined estimated 85% probability).[41]

Figure C.1: NEM coal capacity 2009/10 to 2049/50, 2024 ISP, June 2024



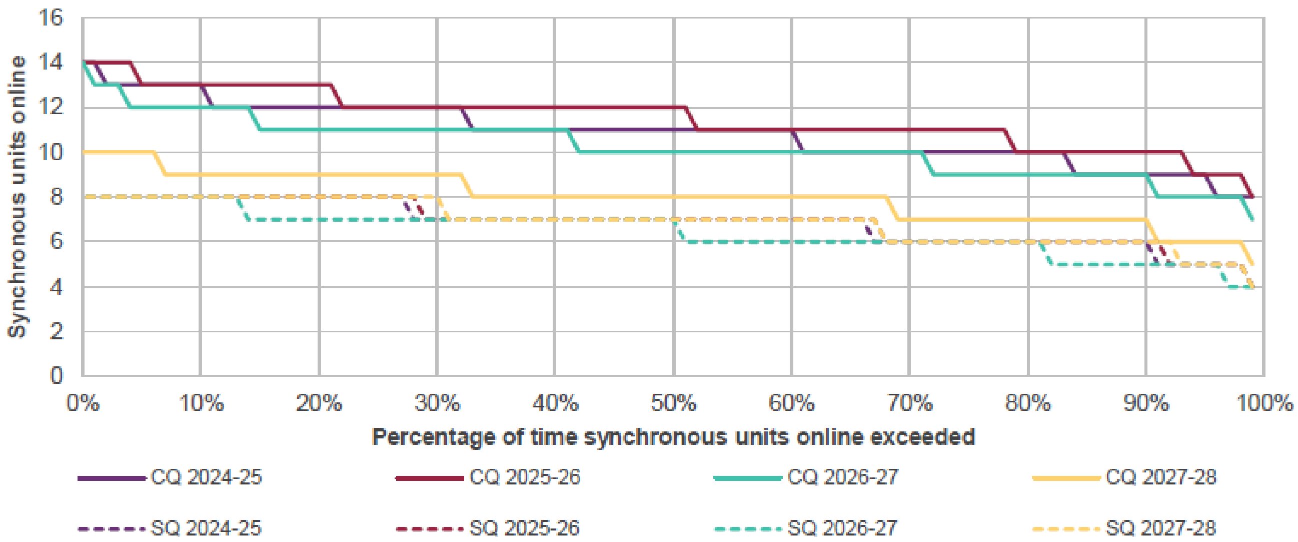
Source: AEMO, 2024 ISP Chart Data, June 2024 (figure 1).

AEMO's 2024 ISP Chart Data shows installed levels of coal generation in Queensland decreasing from 8.13 gigawatts in 2025/26 to 6.785 gigawatts in 2027/28, and to zero watts in 2034/35.[42] Based on the annual changes in coal capacity between 2027/28 and 2034/35, Powerlink has inferred the number of units retired in the 2024 ISP as being four in 2027/28, one in 2028/29, then seven by 2031/32 and the remaining 10 by 2034/35.

The 2024 System Strength Report shows AEMO's projection of the number of large synchronous generating units online in Queensland over the three-year period from December 2024 to December 2027. Figure C.2 shows that, in 2027/28, AEMO projects a minimum of between five and ten units will be online in Central Queensland, and a minimum of between four and eight units will be online in Southern Queensland.

[41] AEMO, *2024 Integrated System Plan*, June 2024, pages 23 and 46.
[42] AEMO, *2024 ISP Chart Data*, June 2024 (figure 1).

Figure C.2: AEMO projection of synchronous units online in Central and Southern Queensland, February 2025



Source: AEMO, 2024 System Strength Report, February 2025, page 27 (figure 12).

Table C.1 compares the number of units AEMO forecasted to be online in Central and Southern Queensland across the 2022, 2023 and 2024 System Strength Reports.

Table C.1: AEMO System Strength Report forecasts of units online in Central / Southern Queensland in 2027/28

Report	Number of units online in Central Queensland	Number of units online in Southern Queensland
2022 System Strength Report	Between ~6 and ~12 units	Between 2 and 4 units
2023 System Strength Report	Between 6 and 12 units	Between 1 and 3 units
2024 System Strength Report	Between 5 and 10 units	Between 4 and 8 units

Note: 2027/28 is selected as the comparison year as it is the only year for which projections are included in each report. The 2023 System Strength Report projections for 2028/29 were the same as for 2027/28 in that report.

Sources: AEMO, 2022 System Strength Report, December 2022, pages 35 (figure 14) and 36 (figure 15); AEMO, 2023 System Strength Report, December 2023, page 25 (figure 12) and AEMO, 2024 System Strength Report, February 2025, page 27 (figure 12).

The System Strength Reports indicate that there could be periods of time from 2027/28 when insufficient units are online in Central or Southern Queensland for minimum system strength requirements to be met. The reports also show that coal generating unit forecasts can change quickly and materially at sub-regional levels, and that there is risk associated with relying on a particular forecast for the purpose of planning for system strength services.

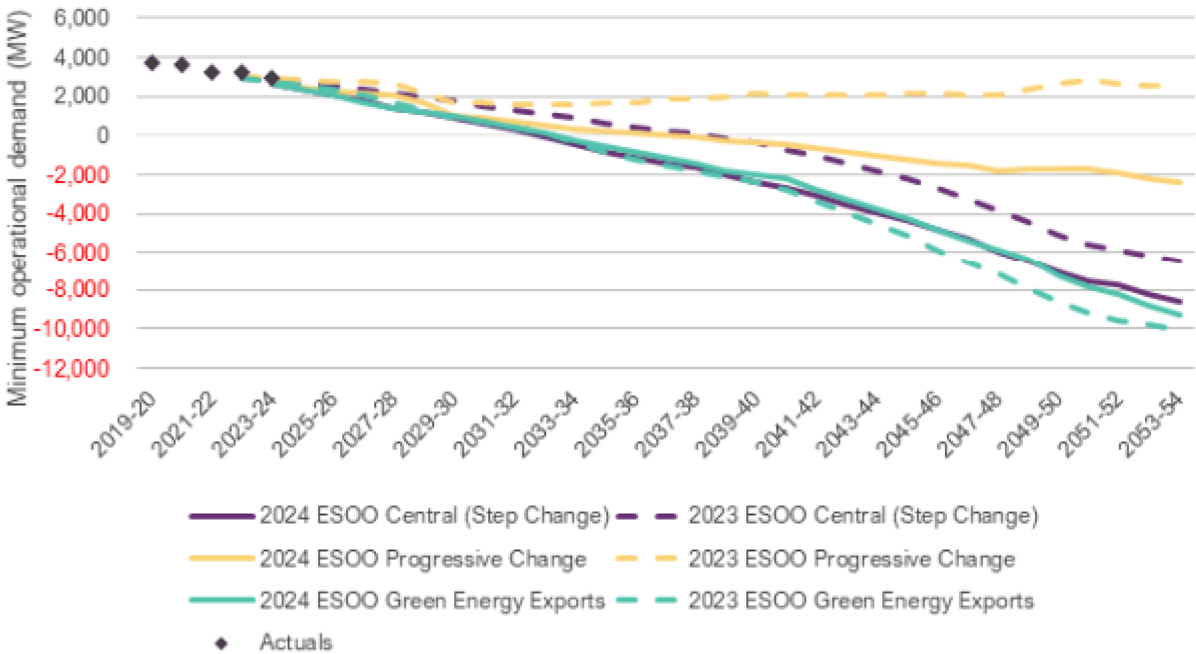
In the 2024 ISP, AEMO noted that, in practice, coal retirements may occur earlier than its own forecasts as continued operation of coal-fired generation becomes less attractive due to higher operating costs, reduced fuel security, high maintenance costs and increased competition from renewable generation.[43]

Powerlink also notes that the factors that will determine which coal generating units decommit seasonally are likely to be influenced by a number of factors. This includes economic withdrawal, which is influenced by the asset owner's decision-making across (potentially) a diverse portfolio of assets, which is not publicly known. Further, as with any integer-based modelling, the specific units chosen for retirement are sensitive to changes in input assumptions. That is, the ISP modelling, and by extension the system strength analysis, could indicate retirements occurring in either Central *or* Southern Queensland.

Minimum demand

Low minimum demand conditions may also force more coal generators to retire early and/or be offline more frequently. In the 2023 Electricity Statement of Opportunities (ESOO), AEMO observed that minimum operational demand is declining across the NEM as distributed (rooftop) solar PV erodes daytime operational demand.[44] Figure C.3 shows historical minimum demand in Queensland from 2019/20 to 2023/24, and AEMO's recent forecasts showing (with one exception) a steady decline in minimum operational demand out to 2053/54.

Figure C.3: AEMO minimum demand forecasts, August 2024



Note: The actuals displayed are not weather-corrected (therefore reflect observed demand under the prevailing weather conditions) or adjusted for system events and exclude DSP. Additionally, this definition excludes demand from scheduled loads, typically pumping load from pumped hydro energy storage or large-scale batteries, as well as hydrogen loads.

Source: AEMO, 2024 Electricity Statement of Opportunities, August 2024, page 135 (figure 60).

43 AEMO, *2024 Integrated System Plan*, June 2024, page 46.
44 AEMO, *2023 Electricity Statement of Opportunities*, May 2023, page 28.

AEMO stated that the rate of decline in minimum operational demand in the 2024 ESOO is higher than in the 2023 ESOO due to slower relative growth in electric vehicles and a higher relative growth of solar PV.[45]

The continued erosion of daytime operational demand due to solar PV may also make it operationally infeasible for coal generators to run, even if directed by AEMO to do so. That is, daytime demand could get to a level that the number of coal generating units available for AEMO to direct online declines as there is insufficient load for the units to run, in which case parts of the network may have to be de-energised due to insufficient system strength, with significant implications to customer reliability.

RIT-T Assumptions

For the PADR, Powerlink aligned its core scenario with the ISP Step Change scenario.[46] Further, to manage the uncertainty and risk around the number and location of coal generating units likely to be dispatched for energy, a separate standalone sensitivity (presented in section 6.2 of the PADR) aligned with the 2023 System Strength Report. The sensitivity included additional low regret solutions for Southern Queensland to mitigate the risk of shortfalls in system strength should retirement of coal generating units in Southern Queensland occur faster than projected in the 2024 ISP.

AEMO projection of fault level requirements and shortfalls

For the 2023 System Strength Report, AEMO reviewed minimum fault level requirements in each region of the NEM. The report did not change the minimum pre-contingent or post-contingent fault levels for system strength nodes in Queensland, compared to the 2022 report, but did include estimates of the typical levels of system strength available. In this context, AEMO noted that ‘typical’ referred to the 99th percentile of availability.[47]

Table C.2: AEMO minimum three phase fault level expected 99% of the time, December 2023

System Strength Node	Pre-contingent minimum fault level (MVA)	Post-contingent minimum fault level (MVA)	Minimum post contingent three phase fault current (MVA) expected 99% of the time, financial year ending					
			2024	2025	2026	2027	2028	2029
Gin Gin	2,800	2,250	2,192	2,201	2,201	2,195	2,083	2,093
Greenbank	4,350	3,750	4,642	4,590	4,679	4,626	3,126	3,205
Lilyvale	1,400	1,150	1,172	1,182	1,183	1,179	1,146	1,149
Ross	1,350	1,175	1,327	1,321	1,336	1,332	1,306	1,300
Western Downs	4,000	2,550	2,858	2,830	2,863	2,843	2,112	2,144

Source: AEMO, 2023 System Strength Report, December 2023, pages 28-32.

Powerlink is required to use reasonable endeavours to comply with the network standard element of the System Strength Standard.[48] At the time the PSCR and PADR for this RIT-T were published, AEMO’s declaration of system strength shortfalls was based on when AEMO forecasted system strength services would fall below the minimum requirements for more than 1% of the time under typical dispatch patterns. In the PSCR and PADR, Powerlink

[45] AEMO, *2024 Electricity Statement of Opportunities*, August 2024, page 134.
[46] See AER, *Regulatory Investment Test for Transmission*, November 2024, paragraph 20(b).
[47] AEMO, *2023 System Strength Report*, December 2023, page 10.
[48] NER, clause S5.1.14(b).

indicated that AEMO's approach aligned with the reasonable endeavours standard, and therefore adopted this approach in considering the credible options for this RIT-T. In December 2024, AEMO increased the percentage of time that minimum system strength requirements must be met before a gap is declared from 99% to 99.87%.[49] This means that, if AEMO projects that minimum requirements will not be met for more than approximately 11 hours in a year, a gap will be declared.

For the 2024 System Strength Report, AEMO chose to assess minimum fault level requirements against pre-contingent, rather than post-contingent, fault level requirements. AEMO explained that fault level projections assessed against:

- post-contingent requirements ensure the power system is in a satisfactory operating state; whereas
- pre-contingent requirements represent a secure operating state, which is aligned more closely with AEMO's System Strength Requirements Methodology (version 2.0).

AEMO added that the change shifted both the availability of, and requirement for, system strength by a consistent amount; that is, by the impact of the worst contingency event considered, and did not represent a change to the fundamental system strength requirements themselves.[50]

AEMO also reduced the number of years it forecast the minimum three phase fault current from six years to four. The table below shows AEMO's minimum fault level requirements and projections for Queensland in its 2024 System Strength Report.

[49] AEMO, *Network Support and Control Ancillary Services (NSCAS) Description and Quantity Procedure*, November 2024, version 3.0, page 13; AEMO, *Amendments to the NSCAS Description and Quantity Procedure*, final report, November 2024, pages 10-11.
[50] AEMO, *2024 System Strength Report*, February 2025, pages 11 and 66.

Table C.3: AEMO minimum three phase fault level expected 99.87% of the time, December 2024

System Strength Node	Parameter	Minimum three phase fault level current (MVA), financial year ending			
		2025	2026	2027	2028
Gin Gin	Pre-contingent	2,800	2,800	2,800	2,800
	Projected 99.87% of time	3,150	3,155	3,088	2,877
	Shortfall	**0**	**0**	**0**	**0**
Greenbank	Pre-contingent	4,350	4,350	4,350	4,350
	Projected 99.87% of time	4,513	4,534	4,199	4,473
	Shortfall	**0**	**0**	**151**	**0**
Lilyvale	Pre-contingent	1,400	1,400	1,400	1,400
	Projected 99.87% of time	1,400	1,400	1,295	1,247
	Shortfall	**0**	**0**	**105**	**153**
Ross	Pre-contingent	1,350	1,350	1,350	1,350
	Projected 99.87% of time	1,350	1,350	1,350	1,350
	Shortfall	**0**	**0**	**0**	**0**
Western Downs	Pre-contingent	4,000	4,000	4,000	4,000
	Projected 99.87% of time	4,121	4,150	3,827	4,078
	Shortfall	**0**	**0**	**173**	**0**

Source: AEMO, 2024 System Strength Report, February 2025, pages 30-35.

AEMO indicated that the shortfalls at the Greenbank, Lilyvale and Western Downs nodes across 2026/27 and 2027/28 were primarily linked to decreased energy exports to New South Wales (NSW) following the delayed retirement of Eraring Power Station in NSW. In AEMO's modelling, the delayed retirement resulted in fewer thermal units expected to be online in Queensland, and lower fault levels than previously projected.[51]

[51] AEMO, *2024 System Strength Report*, February 2025, page 25. See also Origin Energy, *Origin and NSW Government agree to delay closure of Eraring Power Station*, media statement, 23 May 2024.

Appendix D: Technical Considerations

Key Points

- At the PADR stage, Powerlink conducted comprehensive wide-area Electro-magnetic Transient (EMT) studies using the PSCAD software package with detailed models to determine system strength requirements in Queensland for the 2025 to 2030 planning horizon.
- Powerlink also applied AEMO's recommended assessment methods for analysing stable voltage waveforms for the PADR studies.
- Powerlink conducted a comparison of AEMO's 2023 and 2024 System Strength Report IBR forecasts, along with inputs from Powerlink's own connection information. No requirement for conducting further EMT studies has been identified at the PACR stage, and the Northern Queensland Area 1 efficient solution timeframe has been adjusted from 2026 to 2027.

PACR Technical Analysis

At the PADR stage, Powerlink conducted comprehensive wide-area EMT studies using the PSCAD software package with detailed models to determine system strength requirements in Queensland for the 2025 to 2030 planning horizon. The PADR assessment was based on AEMO's 2023 System Strength Report IBR forecasts, being the latest forecasts available to Powerlink at that time. Details of the PADR study methodology and study inputs are included in the following sections of this appendix.

Following the publication of AEMO's 2024 System Strength Report in December 2024 (and updated in February 2025), Powerlink conducted analysis to compare the IBR forecasts published in the 2023 System Strength Report with the updated 2024 report. The analysis also utilised Powerlink's knowledge of projects in various stages of the connection process. The analysis found that AEMO's 2024 wind forecasts were lower or not changed compared to the 2023 forecasts (for all system strength nodes) in the planning horizon to 2029. In 2030, Lilyvale and Gin Gin nodes had immaterial increases (<10MW) in wind forecast compared to the 2023 System Strength Report, and the 2030 wind forecasts for all other nodes were lower or not changed from the 2023 report. However, both solar and BESS were forecast higher in the 2024 report than in the 2023 forecasts. Solar forecasts were higher at the Gin Gin, Western Downs and Lilyvale nodes (although for the Lilyvale node the increase only applied for the early years), and BESS was forecast higher at all nodes.

Accounting for Powerlink's connection information (including enquiries and applications) and the IBRs that were considered in the PADR PSCAD studies (see PADR Study Inputs section below), Powerlink considers AEMO's 2024 IBR forecast does not have a material impact on the studies that were conducted at the PADR stage for the following reasons:

- For the PADR technical assessments Powerlink already considered upcoming (and existing) IBRs (wind, solar) that have either exceeded or have been near to AEMO's 2024 forecast, with the exception of the Western Downs node.
    - For the forecast increase in solar at Western Downs in the early year (2026), Powerlink's connection information indicated further assessments were not warranted at the time of writing this PACR. In this earlier timeframe, Powerlink have more visibility to account for changes to upcoming IBR installations (technology type and connection location) as a result of the information received in the connection process (enquiries and applications).

  - Post 2026, AEMO's forecasted solar increase at Western Downs is offset to an extent by its forecast wind reduction at the same node. Further, Powerlink considered more wind in the PADR analysis than forecasted in AEMO's 2024 System Strength Report. In addition, Powerlink's connection application information indicated that it is prudent to re-assess closer to when a real need is identified at this node. This may mean that the need for efficient level services in Southern Queensland Area 1 for 2029 (as noted in the PADR) may need to be brought forward, which will be confirmed based on any updates to Powerlink's connection information in this area.
- Regarding AEMO's forecasted increase in BESS in the 2024 report, Powerlink's connection information indicated that there was a portion of BESS (either standalone or hybrids) which were likely to be grid-forming and therefore not expected to require system strength support. Other BESS which Powerlink understand to be grid-following were already included in the PADR studies.

Therefore, no further PSCAD studies have been conducted at this PACR stage.

Impacts to minimum system strength requirement

The minimum system strength requirements and combinations of generators (or equivalent) to fulfil this requirement has not changed since the PADR stage, or as a result of AEMO's updated 2024 System Strength Report. The minimum requirements identified in the PADR study outcomes are detailed in the next sections.

Impacts to efficient system strength requirement

The need for efficient level services identified at the PADR stage was assessed against AEMO's 2024 IBR forecasts and Powerlink's connection information. As a result of this assessment, which showed reduced wind IBR forecasts, the expected timeline for services in Northern Queensland Area 1 has been updated from 2026 to 2027. Powerlink has identified potential BESS solutions for efficient services in the area.

Additionally, the Southern Queensland Area 1 expected timeline may need to be brought forward. However, the Southern Queensland efficient needs will require re-assessment based on further updates to AEMO's forecasts, and/or updated connection information, and therefore no contracting/negotiating action will be taken at this stage.

Efficient system strength requirements in all other areas have not been updated from the PADR stage and are detailed in the below sections.

As shown by AEMO's System Strength Reports from 2022 to 2024, IBR forecasts can vary significantly within a two-year period. Additionally, AEMO's forecasts do not differentiate between IBRs that may choose to self-remediate for system strength or those that may sign up for Powerlink's system strength charges. This means that there is uncertainty determining the efficient future need (both quantity and timing), and therefore it is important that Powerlink takes a holistic approach to its technical assessments.[52]

For the future efficient need which is impacted by updated IBR forecasting and IBR proponent choices, regular monitoring of updated forecasts and Powerlink's connection information will be needed to assess (and re-asses) efficient need requirements.

Further, there is the potential for more inverter-based load to connect to Powerlink's network. As those proposals are yet to progress/materialise, Powerlink has not taken them into account in assessing the need for efficient level services.

[52] AER, *The Efficient Management of System Strength Framework*, guidance note, December 2024, pages 15-16.

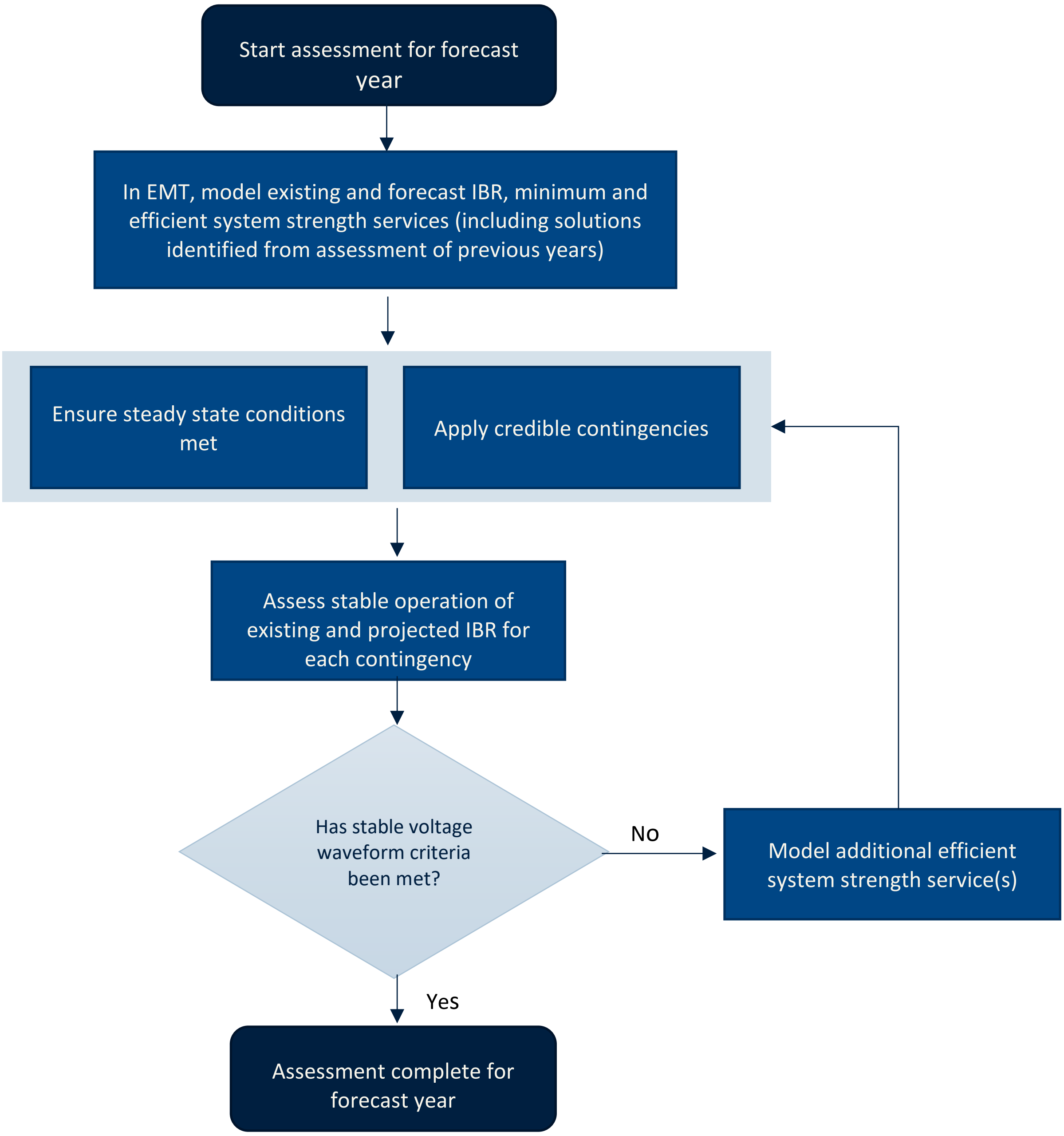
PADR Study Methodology

At the PADR stage, Powerlink conducted comprehensive wide-area EMT studies using the PSCAD software package with detailed models to determine system strength requirements in Queensland for the 2025 to 2030 planning horizon. The high-level PADR study methodology included the following elements:

- IBR forecast from AEMO's 2023 System Strength Report was considered for modelling, as these were the forecasts available during the PADR studies. Forecasted IBR projects were mapped to system strength nodes to match the forecast level and type of IBR.
- Detailed PSCAD models, where available, were integrated into the wide-area network model. For cases lacking project-specific models, generic models were used.
- Powerlink's connection knowledge was factored in to determine the most appropriate way to model the 'typical' performance characteristics of forecast IBR. Specifically, consideration was given to projects at various stages, including:
    - projects that have received connection letters under clause 5.3.4A of the NER;
    - projects in the full impact assessment (FIA) stage of the system strength impact assessment; and
    - active projects that are in the application stage.
- For BESS, information on whether the project was intending to be grid-forming or grid-following was used. For hybrid plants (solar farm plus BESS or wind farm plus BESS), actual project data as at the time of the study was used. For future plants the best available information, such as location and Original Equipment Manufacturer details, were used.
- System strength planning study outcomes were evaluated to ensure stable voltage waveforms, allowing a sufficient amount of IBR to connect and remain stable during steady-state conditions and following credible contingency events.
- Each contingency was assessed for successful fault recovery and post-contingent steady-state voltage at key buses in the system, ensuring the network maintains stable voltage waveforms.
- Evaluation of day and night time conditions was considered.
- Assessment of stable voltage waveform was conducted in accordance with AEMO's System Strength Requirements Methodology (version 2.0) taking into account the following criteria:
    - Voltage magnitude within relevant network limits;
    - Voltage oscillations do not exceed acceptable thresholds; and
    - Change in voltage phase angle is not excessive.
- When detailed modelling was conducted for a specific system strength planning year, known committed and anticipated grid-forming BESS projects were initially excluded from detailed PSCAD modelling, as they can provide stable voltage waveform support to the projected IBR. However, when a need was identified for efficient system strength requirements due to projected IBR connections, the grid-forming BESS were gradually incorporated into the model until satisfactory results were achieved for stable voltage waveform criteria. The required level of efficient system strength for that year was determined based on the amount of grid-forming BESS needed. For the subsequent year, the solutions identified in the previous year remained in place, and detailed modelling continued to assess any additional needs based on the projected IBR for that year.

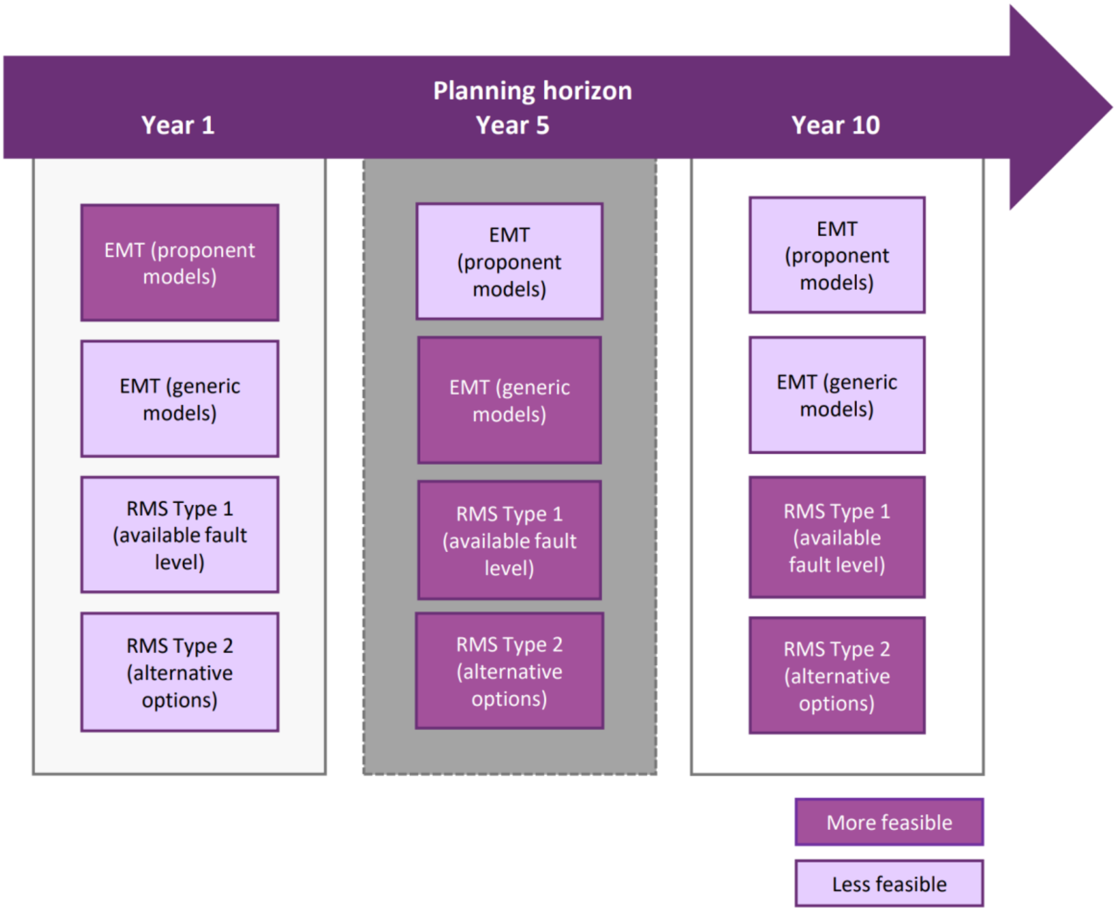
An overview of the PADR technical assessment approach is shown Figure D.1 below.

Figure D.1: PADR technical assessment methodology overview



Powerlink applied AEMO's recommended EMT based analytical option (see figure below) for assessing stable voltage waveforms. Powerlink considered both actual plant and generic EMT models for system strength planning over the five-year period of December 2025 to December 2030.

Figure D.2: Determining best assessment for analysing stable voltage waveforms



Source: AEMO, System Strength Requirements Methodology, September 2022, page 22 (figure 6).

PADR Study Inputs and Assumptions

Table D.1 below lists the key inputs and assumptions used for the PADR EMT technical assessment.

Table D.1: PADR EMT technical assessment inputs and assumptions

Element	Inputs and Assumptions
Minimum fault level requirement	It is considered that the minimum fault level requirements would primarily be met using synchronous based sources, with the exception of Portfolio 1A. This assumption was also used for the PADR technical assessment. Over time, existing synchronous generators will be replaced by alternative synchronous machines, including but not limited to synchronous condensers, gas generating units, and PHES. Consequently, various combinations and different type of synchronous machines can be utilised to satisfy the minimum fault level requirements across different areas.

Element	Inputs and Assumptions
Grid-forming BESS	Grid-forming BESS has limited short-circuit current contribution capabilities, due to its reliance on semiconductor switching devices. To achieve fault levels comparable to traditional synchronous generators, it is necessary to increase the size of a single grid-forming BESS or deploy multiple units. In the portfolios considered, grid-forming BESS have been excluded from meeting minimum fault level requirements, with the exception of Portfolio 1A which includes a grid-forming BESS in Central Queensland in 2028/29. For Portfolio 1A, Powerlink considered one grid-forming BESS in Central Queensland as part of the combination of minimum solutions in the technical assessment. However, the PADR technical assessment only considered impacts to stable voltage waveform, and not other aspects to meet minimum fault level requirements (such as impacts to protection system operation). To incorporate grid-forming BESS as part of minimum fault level requirements, Powerlink considers that several key activities are needed to effectively assess the performance of grid-forming BESS and build confidence in the technology. Powerlink does however consider that grid-forming BESS will play a crucial role in future power system, providing stable voltage waveform support. As such, grid-forming BESS were included as part of efficient system strength solutions when completing the PADR detailed technical studies.
Synchronous condenser size	As outlined in the portfolios of credible options, existing synchronous generators were included in the modelling for the early years to represent the minimum level of system strength support. However, for later years, where applicable, new synchronous condensers were modelled in place of the existing synchronous generators. For the purpose of the PADR study, these synchronous condensers were sized at approximately 220 to 250 MVA and are expected to provide a fault current of greater than 800 MVA at the high voltage terminal.
Grid-forming BESS sizes	When a need for efficient system strength requirements arose due to projected IBR connections, the grid-forming BESS size was progressively increased in the PADR studies until satisfactory results were achieved for the stable voltage waveform criteria. For the modelling purposes, a starting grid-forming BESS size of 250 MVA was utilised. Powerlink considered various grid-forming OEM models as part of the sensitivity analysis for the PADR study.
IBR plant list for system strength planning studies	The IBR plants included in the studies were selected based on AEMO's 2023 forecast, taking into account both the forecast level and the type of IBR in each area. Most of the IBR plants considered for the early years were progressing under the previous system strength framework (i.e., applications submitted before March 2023) and were included in the study with the assumption that they can connect without requiring system strength remediation. Additionally, new IBR plants that would fall under the new system strength framework were also included, as applicable, to fulfil the forecast IBR levels for the studies.
PSCAD models for future IBR plants	Site-specific PSCAD models were utilised whenever available, which was the case for all existing IBR plants and IBR projects currently in progress. In cases where a site-specific model was not available, particularly for future IBR plants, a generic PSCAD model was used, based on a selected plant type (e.g., wind farm, solar farm or BESS) and the corresponding OEM, if known, to model represent the forecasted IBR plants.
IBR connecting in northern NSW	The detailed PADR studies excluded forecasted IBR plants connecting on the southern side of the Queensland – New South Wales Interconnector (QNI); that is, in northern NSW.
CopperString 2032	CopperString 2032 was not included in the PADR assessments.

Minimum system strength requirement

Powerlink assessed minimum system strength requirements as part of the detailed technical assessment conducted at the PADR stage. The analysis primarily relied on synchronous-based sources, with one exception where a grid-forming BESS was included in the minimum generator combinations for Central Queensland.

In the early years, the requirements could be largely satisfied by existing synchronous generation across Southern, Central, and Northern Queensland, based on AEMO's forecast for synchronous generator retirements in these regions. For the later years, it was assumed that alternative synchronous machines, such as synchronous condensers, clutched gas turbines, and pumped hydro, would replace the synchronous generation used to meet the minimum requirements.

Two generator combinations were used in the PADR PSCAD studies as potential options for meeting the minimum system strength requirements for the study period.

Minimum generator combination 1 included:

- Two hydro-electric machines or equivalent online in Northern Queensland in the order of 20 MVA each;
- One Townsville gas turbine or equivalent plant online in Northern Queensland in the order of 200 MVA;
- Six synchronous machines online in Central Queensland in the order of 250 – 350 MVA each; and
- Four synchronous machines online in Southern Queensland in the order of 250 – 400 MVA each.

Minimum generator combination 2 included:

- Two hydro-electric machines or equivalent online in Northern Queensland in the order of 20 MVA each;
- One Townsville gas turbine or equivalent plant online in Northern Queensland in the order of 200 MVA;
- Five synchronous machines online in Central Queensland in the order of 250 – 350 MVA each;
- One grid-forming BESS online in Central Queensland in the order of 400 – 600 MVA; and
- Four synchronous machines online in Southern Queensland in the order of 250 – 400 MVA each.

A simplified illustration of the two minimum generator combinations is shown below.

Figure D.3: Minimum generator combinations

Minimum Combination 1	Minimum Combination 2
NQ Synchronous Machine 3	NQ Synchronous Machine 3
NQ Synchronous Machine 2	NQ Synchronous Machine 2
NQ Synchronous Machine 1	NQ Synchronous Machine 1
CQ Synchronous Machine 6	CQ Gridforming BESS 1
CQ Synchronous Machine 5	CQ Synchronous Machine 5
CQ Synchronous Machine 4	CQ Synchronous Machine 4
CQ Synchronous Machine 3	CQ Synchronous Machine 3
CQ Synchronous Machine 2	CQ Synchronous Machine 2
CQ Synchronous Machine 1	CQ Synchronous Machine 1
SQ Synchronous Machine 4	SQ Synchronous Machine 4
SQ Synchronous Machine 3	SQ Synchronous Machine 3
SQ Synchronous Machine 2	SQ Synchronous Machine 2
SQ Synchronous Machine 1	SQ Synchronous Machine 1

The number of synchronous machines depicted corresponded to the minimum number required to meet system strength requirements for any given time period. However, to ensure a satisfactory overall availability (for example greater than 99%), a greater number of machines than indicated by the two combinations above will be necessary as part of the overall portfolio in each geographical area.

Minimum generator combination 2 included one grid-forming BESS in Central Queensland. However, the technical assessment focused solely on the impacts to stable voltage waveforms and did not address other factors necessary to meet minimum fault level requirements, such as the satisfactory protection system operation. To integrate grid-forming BESS into the minimum fault level requirements, Powerlink considers that several key activities need to be undertaken, which have now commenced. These activities aim to effectively evaluate the performance of grid-forming BESS and enhance confidence in the technology.

Figure 2.3 in body of this report illustrates the indicative Southern, Central and Northern Queensland areas related to minimum system strength solutions. It is important to note that a solution in one area also influences adjacent areas; therefore, the solutions cannot be completely decoupled.

Efficient system strength requirements

For the detailed PADR technical studies, Powerlink considered grid-forming BESS as a key component of efficient system strength solutions, aimed at providing stable voltage waveform support for projected IBR. However, efficient system strength solutions are not restricted to grid-forming BESS only. Alternative technologies, such as synchronous condensers and grid-forming STATCOMs, may also be suitable. Consequently, the required level of system strength was defined as a range to allow for various technological solutions.

Based on the PADR technical studies conducted, the need for efficient system strength solutions in each area is outlined in Table D.2 and Figure 2.5 in the body of this report. The solution size required for efficient system strength support is presented as a range because specific technical details about the actual solution(s) are not yet available.

Note that a slight adjustment has been made to the Northern Queensland Area 1 expected timeline based on analysis of AEMO's 2024 IBR forecasts and Powerlink's recent connection information, as discussed above.

Table D.2: System strength need for efficient level of system strength

Area	Indicative timeline	Grid-forming BESS size considered in technical assessment (MW)[1]	Possible range for solutions considering other technologies including grid-forming BESS (MVA)[2]
Northern Queensland Area 1	2027[3]	200	180 to 300
Northern Queensland Area 2	2028	200	180 to 300
Northern Queensland Area 3	2028	300	220 to 400
Northern Queensland Area 4	2030	200	180 to 300
Central Queensland Area 1	2028	300	220 to 400
Central Queensland Area 2	2030	300	220 to 400
Southern Queensland Area 1	2029[4]	300	220 to 400
Southern Queensland Area 2	2030	300	220 to 400
Southern Queensland Area 3	2030	300	220 to 400

1) Indicative megawatt size utilised in the studies are given here. The operating megawatt level of BESS at any given time is not pertinent to the provision of system strength services. Expected technical performance requirements for grid-forming BESS to deliver the system strength services are detailed in Appendix J. Multiple OEM models have been tested which resulted in a satisfactory performance.

2) A variety of solutions (synchronous condenser, grid-forming STATCOM or grid-forming BESS) can provide the suitable solution. Indicative megavolt ampere range for the potential solutions is presented here. This capacity can be made of multiple projects or a single project. The system strength requirement for each solution can be met through multiple technologies, such as a combination of grid-forming STATCOM and BESS.

3) The Northern Queensland Area 1 expected timeline has been adjusted since the PADR stage. This is based on analysis of Powerlink's connection information and AEMO's updated IBR forecasts in its 2024 System Strength Report.

4) The expected timelines for Southern Queensland may require some adjustment in future depending on further information obtained during the connection process. For example, this is may require the Southern Queensland Area 1 timeline to be brought forward.

Appendix E: Portfolio Formation

Developing portfolio options to meet system strength requirements

Overview of how portfolios have been formed

Powerlink implemented a probabilistic approach to assess the likelihood of maintaining sufficient system strength across the grid. This methodology used binomial probability theory and system modelling, with each power system unit – such as synchronous condensers, gas turbines, and pumped hydro – assigned a reliability value, sourced from AEMO's 2023 Inputs, Assumptions and Scenarios Report (IASR), which reflected the probability of that unit being available when needed. The unit reliability consisted of the forced outage rate and maintenance requirements as per AEMO's 2023 IASR.

Each unit's contribution to system strength was also evaluated based on its system strength equivalency – a measure of how much system strength it provides compared to a retiring coal unit in that region, derived from power system modelling and technical analysis of fault level contributions and stability impacts. In this assessment, Powerlink considered coal retirement projections based on the 2024 ISP retirement outcomes.

While this approach offered robustness, it is sensitive to changes in unit availability, which can lead to notable shifts in the calculated probabilities. Small changes in unit numbers or reliabilities may have disproportionate effects on the outcome. Additionally, assumptions drawn from the IASR and ISP data need to be updated periodically to reflect evolving conditions. External factors, such as policy and market trends, particularly those driven by decarbonisation efforts, will also influence system strength outcomes.

Figures E.1 and E.2 below provide a visual representation of the number of system strength equivalent units available in each region, demonstrating the portfolio solutions alongside forecast online coal capacity according to the 2024 ISP Step Change retirement outcomes.

As noted above, at the time the PADR analysis was undertaken AEMO assessed system strength shortfalls based on the 99th percentile of minimum post-contingent fault levels at each system strength node. The PADR indicated that, to provide sufficient system strength 99% of the time, it was essential to plan for headroom above the minimum required system strength levels to account for forced outages and maintenance activities, ensuring grid resilience under various operating conditions.

Technological diversity

Powerlink considered technological diversity to be an important feature of the portfolio development process:

- Grid-forming BESS can increase system strength and help to support the operation of IBR in a similar way to synchronous condensers[53], and several grid-forming BESS are currently in the connection application stage. However, the technical viability of grid-forming BESS to meet minimum system strength requirements in a large inter-connected power system is yet to be established.
- Synchronous generation is a proven source of system strength when these units are dispatched in the energy market. However, there is material uncertainty around the number and location of coal generating units that are likely to be online for the period December 2025 to December 2030, and the risks associated with having sufficient operational demand to support the dispatch of this generation.
- Synchronous condensers are capable of providing significant fault current contribution and synchronous inertia. Synchronous condensers can offer system strength support comparable to that provided by large existing synchronous generators. However, achieving the same level of support as large base load

[53] Powerlink, *PSCAD Assessment of the Effectiveness of Grid-forming Batteries*, April 2021, page 3.

synchronous machines (such as Millmerran Power Station) may require a greater number of synchronous condensers due to the larger size of the existing base load units. Further, given the international demand for synchronous condensers, there are delivery risks associated with the technology.
- The addition of clutches to gas turbine units, to enable them to operate in synchronous condenser mode when not generating, could be a cost-effective way to provide system strength. The advantage of a gas turbine compared, for example, to a coal generating unit, is its ability to start up relatively quickly to generate electricity to meet a sudden increase in demand or to compensate for the variability on renewable sources. Further, as synchronous machines, hybrid gas generation projects should provide inertia and reactive power support when operating in generating mode. However, there are similar risks associated with the installation of the clutches, and operational challenges can arise due to the time required to operate each clutch.
- PHES projects represent a potentially reliable and cost-effective system strength solution. Operating PHES units in synchronous condenser mode ensures continuous provision of system strength.

For the PADR, Powerlink undertook high-level network planning analysis on the Balanced Technology portfolio (Portfolio 1) to be sufficiently confident that it would deliver minimum and efficient levels of system strength from December 2025. Existing sources of system strength and forecast IBR, combined with the location, size and availability of existing and proposed units, were important factors in determining the technical suitability of the Balanced Technology portfolio. As outlined in section 3.1, the four additional portfolios assume a greater use of a particular technology for meeting the minimum requirements, namely Portfolio 1A (Balanced Technology with BESS in Minimum), Portfolio 2 (Synchronous Condensers), Portfolio 3 (Clutched Gas Turbines) and Portfolio 4 (Pumped Hydro Energy Storage).

Once the desired technology types and quantities required to address system strength requirements were identified for each region under each portfolio, generic placeholder solutions, such as '2-hour 200 megawatt grid-forming BESS CQ', were included in the portfolio. These generic placeholders can be described as 'tranches' of technology need that Powerlink will seek to fill via network solutions and contracting with proponents of non-network solutions. This approach:

- allowed Powerlink to use cost estimates from AEMO's IASR to estimate the costs for non-network solutions, thereby providing an independent and comparable basis for comparing solution costs;
- allowed Powerlink to progress the market modelling and detailed planning studies without explicitly selecting unique proponent solutions; and
- provides flexibility for Powerlink to pivot to more technically and/or commercially feasible options via the RIT-T framework where the status of projects plays a significant role in the cost-benefit analysis of non-network solutions.

None of the portfolios involved additional solutions in Southern Queensland on account of there being sufficient coal generation online as part of the 2024 ISP assumptions. However, and as discussed further in sections 2.5 and 6.2 of the PADR, and Appendix C in this PACR, the level of coal generation in Queensland is a primary consideration for Powerlink's ability to meet minimum system strength requirements, and AEMO's forecasts suggested materially different retirement dates between the 2024 ISP and the 2022 and 2023 System Strength Reports.

Figure E.1 shows how each portfolio differed (at the PADR stage) in terms of the type and timing of solutions included in Central Queensland for meeting the minimum system strength requirements.

Figure E.1: Differences in the timing and type of Central Queensland components included across the portfolios

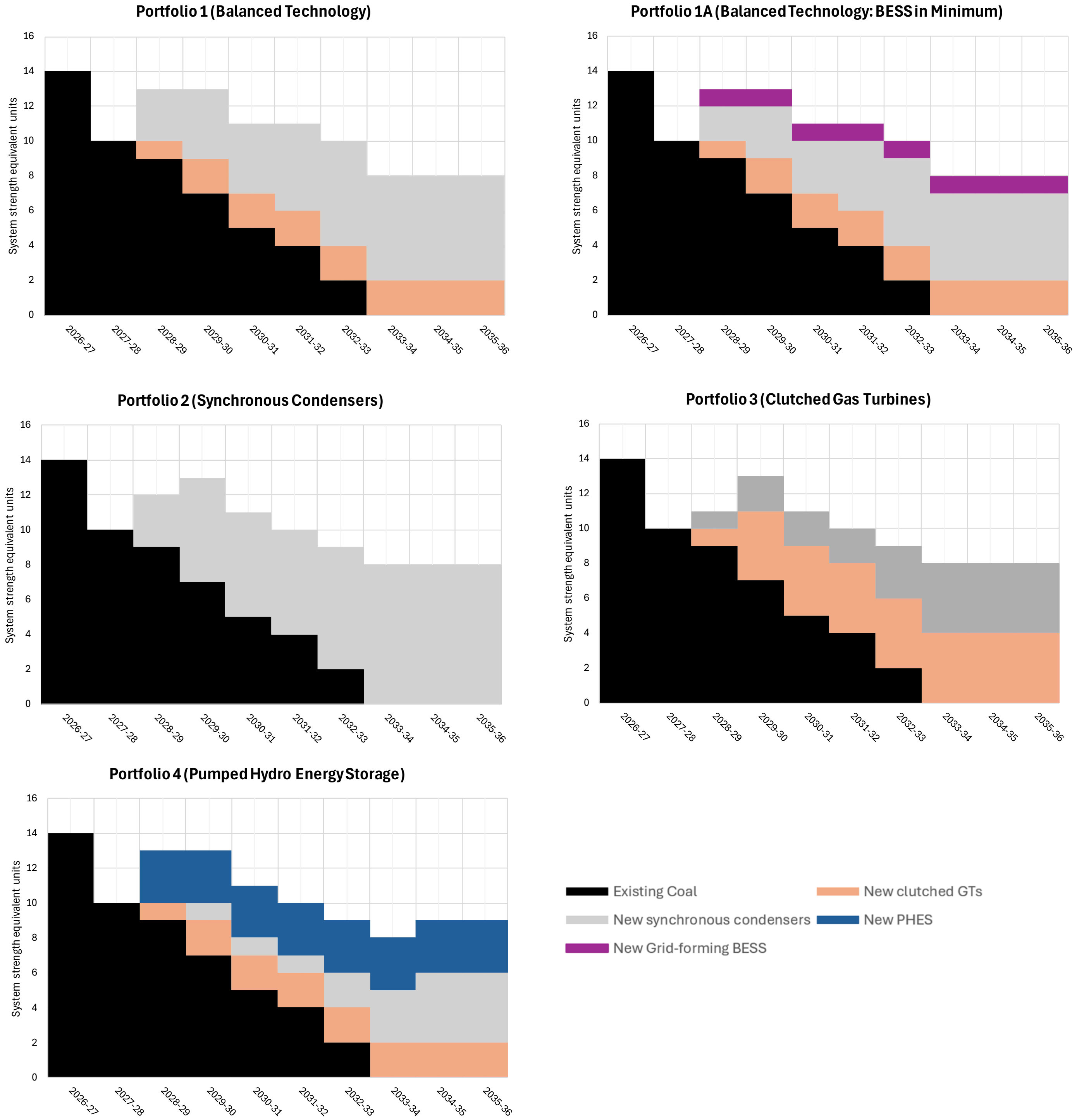
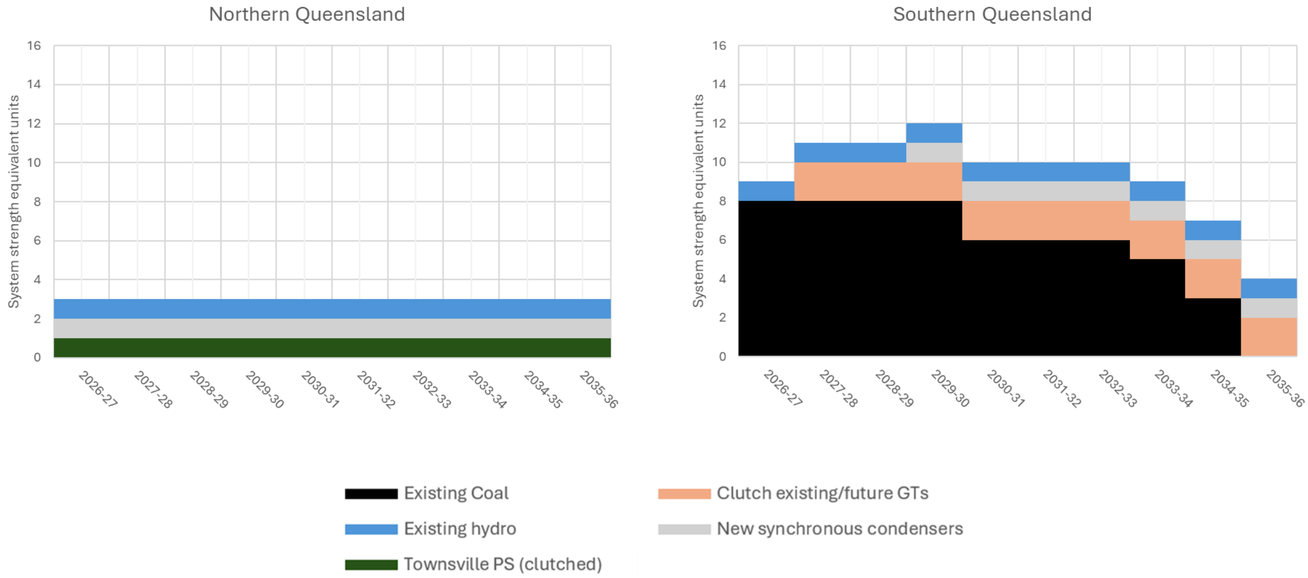


Figure E.2 summarises the type and timing of the common components included in in Northern and Southern Queensland (at the PADR stage) for meeting the minimum system strength requirements.

Figure E.2: The timing and type of common solutions in Northern and Southern Queensland



Ability for grid-forming BESS to contribute to minimum fault level requirements

A key issue for Powerlink (and the industry more broadly) is the extent to which grid-forming BESS can be relied on to contribute to minimum system strength requirements. A minimum level of system strength is required to support a number of critical system services, including (but not limited to) maintaining the stability of IBR, satisfactory operation of protection systems, and stable switching of voltage control devices. Powerlink does not have sufficient knowledge or experience of how the power system would behave if grid-forming BESS replace the existing synchronous generators to meet minimum system strength requirements in the near term. As a result, Powerlink does not consider them to be technically feasible for this application at this time. The uncertainty was the basis for developing Portfolio 1A, which tested how including grid-forming BESS to assist with the minimum system strength requirements would fare, relative to the other technology choices, if found to be technically feasible.

The portfolios did not differ in terms of how the minimum system strength requirements were met for:

- Southern Queensland, due to:
  - AEMO's 2024 ISP assumptions regarding coal retirement suggesting that there would be sufficient system strength in Southern Queensland over the period December 2025 to December 2030; and
  - proposed non-network contracts (based on proposals received in response to the PSCR) with existing, expected and potential future gas and hydro projects being relatively low cost under the RIT-T (meaning that only one new synchronous condenser was assumed to be required in addition to these contracts).
- Northern Queensland, due to the dependency of Northern Queensland on Central Queensland for system strength (meaning that these two regions can effectively be considered as one).

Given that the BESS proposals considered to meet the efficient requirements are independent of the solutions to meet the minimum requirements, each portfolio included the same capacity (2.15GW) of grid-forming BESS to meet the efficient system strength requirements. This common capacity of grid-forming BESS included in each portfolio was made up of both:

- proposals from committed and anticipated BESS – these represented relatively low-cost solutions under the RIT-T given they are also assumed in the base case and it is only incremental costs, if any, that were included in the portfolios; and
- additional proposals (in response to the PSCR) from BESS proponents (both new-build and the conversion of existing to grid-forming) that did not meet the RIT-T criteria for anticipated or committed projects – these were included due to their relatively low costs compared to alternate solutions (such as synchronous condensers).

The project status of each solution at the PADR stage was determined by Powerlink using information provided by proponents, AEMO's Generation Information data of April 2024, and publicly available information for government-backed projects. If a solution was deemed not to meet the RIT-T criteria for anticipated or committed projects, its full cost was included in the assessment, consistent with the RIT-T Application Guidelines in force at the time of the PADR assessment.[54]

Industry positions on grid-forming BESS for system strength

Powerlink's May 2022 EOI for non-network solutions to address the fault level shortfall at the Gin Gin node noted that the contribution of grid-forming BESS toward fault level was limited, and that a combination of grid-forming BESS and synchronous machines could form a solution to the shortfall.[55]

More recently, in May 2024 AEMO highlighted the need for minimum fault level requirements across the NEM to be met by devices that can provide protection-quality levels of fault current. AEMO listed synchronous condensers, service contracts with existing hydro or thermal units, or the retrofit of those existing units, as examples of devices suitable for delivering fault level. Further, AEMO noted that remaining system strength needs to accommodate future IBR could be met by a variety of existing or new technologies, including grid-forming inverters, with the ability to stabilise their local voltage waveforms.[56]

Table E.1 outlines the positions of AEMO Victorian Planning, ElectraNet and Transgrid on the ability of grid-forming BESS to deliver minimum level system strength, from their respective System Strength PADRs.

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[54] AER, *Regulatory Investment Test for Transmission: Application Guidelines*, October 2023, pages 33-35.
[55] Powerlink, *Request for Power System Security Services in Central, Southern and Broader Queensland Regions*, May 2022, page 7.
[56] AEMO, *Update to the 2023 Electricity Statement of Opportunities*, May 2024, page 43.

Table E.1: AEMO Victorian Planning, ElectraNet and Transgrid positions on grid-forming BESS

SSSP	Positions
AEMO Victorian Planning	• Grid-forming BESS are not considered to have reached a level of maturity that they can be relied on to support minimum fault level requirements, but are sufficiently mature to support efficient level system strength.
ElectraNet	• Grid-forming BESS fault current contribution is not of the same protection grade quality as that of a similar rated synchronous generator. • At present, ElectraNet does not consider that grid-forming BESS should be relied upon to provide 'minimum level' of system strength services. • It is possible that grid-forming BESS will be capable, under some circumstances, of providing some of the efficient level of system strength services.
Transgrid	• Grid-forming batteries and inverter technologies are relatively novel and are yet to be deployed at significant scale. • Comprehensive power system and protection studies need to be undertaken to confirm the effectiveness of grid-forming battery technology to provide system strength support. • Transgrid excluded grid-forming batteries from contributing to minimum fault level requirements until 2032/33. • The portfolio of 4.8GW of grid-forming batteries supporting stable voltage waveform would provide Transgrid with a measured and safe approach to test and build confidence in the capabilities of grid-forming batteries for fault current support.

Sources: AEMO Victorian Planning, Victorian System Strength Requirement, PADR, April 2025, page 28; ElectraNet, Meeting System Strength Requirements in SA, PADR, March 2025, pages 20-21; Transgrid, Meeting System Strength Requirements in NSW, PADR, June 2024, pages 35-36. Transgrid also referenced analyses of the ability of grid-forming technologies to provide system strength from Aurecon and Sandia National Laboratories.

Industry-wide actions are underway or have been recommended to progress the use of grid-forming inverter technologies to address system strength needs:

- The Performance of grid-forming BESS activity in AEMO's 2024/25 Engineering Roadmap Priority Actions Report will expand from studying the behaviour patterns of grid-forming BESS to include additional studies for grid-forming BESS Original Equipment Manufacturers (OEMs) not included in the original program.[57]
- AEMO is working with the Australian Renewable Energy Agency (ARENA) on pilot projects that may give further certainty and clarity to grid-forming capabilities implemented by different OEMs. Through joint planning activities, AEMO and SSSPs are also sharing learnings/approaches to the treatment of grid-forming services as a solution to system strength needs.[58]

To provide a potential pathway for the future inclusion of grid-forming BESS into the portfolio of solutions to contribute to minimum fault level requirements, Powerlink indicated in the PADR that it would investigate, as part of the PACR:

[57] AEMO, *Engineering Roadmap, FY2025 Priority Actions Report*, August 2024, pages 24 and 43.
[58] AEMO, *System Strength Framework Status Report*, August 2024, page 3.

- a variant of Portfolio 2, and potentially Portfolio 3, that includes a grid-forming BESS for meeting the minimum system strength requirements (akin to how Portfolio 1A in the PADR is a variant of Portfolio 1); and
- a sensitivity that assumes, not only that grid-forming BESS are technically feasible for assisting with the minimum requirements, but also that one or more reach committed/anticipated status to see whether that affects the overall preferred option for this RIT-T (akin to the sensitivity where the commitment status of proposed clutched gas turbines changes going forward).

The PADR stated the additional analysis regarding grid-forming BESS being able to assist with the minimum requirements expected for the PACR would be economic-only in nature, and Powerlink was not proposing to present any technical assessment of this potential function in the PACR. The additional work outlined the PADR has not been undertaken for the PACR as Powerlink has not updated the estimation of market benefits, as outlined in section 3.2. Powerlink may revisit the need for this analysis in the event of a material change of circumstances, including the activation of a reopening trigger.

Appendix F: Base Case

Regulatory Requirements

The base case is a situation in which the RIT-T proponent does not implement a credible option to meet the identified need, and continues with business-as-usual (BAU) activities. BAU activities are ongoing, economically prudent activities that occur in the absence of a credible option being implemented.[59]

As noted in section 2.2, in the final determination for the System Strength Rule the AEMC indicated that SSSPs could not plan to meet system strength requirements through the use of constraints or AEMO directions given these are operational tools.[60]

Base case to address system strength requirements

The base case for this RIT-T has been developed in line with the RIT-T framework and established planning principles for Queensland's power system. In this state of the world, no credible option is implemented to address system strength shortfalls, and BAU activities continue. The base case assumed compliance with key regulatory obligations and follows the stipulation that prevents Powerlink from planning for constraints or AEMO directions in operational timeframes.

In the absence of credible or operational solutions, the estimation of involuntary load shedding considers the following assumptions:

- The network is intact, meaning no significant network failures or planned outages were applied.
- Cross-border synchronous plants are kept at minimum number of units to minimise reliance on inter-network fault level.
- To ensure power system security and safety (requiring fast and reliable fault clearance by protection systems).
- Minimum synchronous fault levels were calculated for each forecast dispatch interval for the most onerous credible contingency for each system strength node and compared with their respective minimum post-contingent fault level threshold.

Market modelling inputs and assumptions such as generator retirement schedules, as well as associated forced and planned outage rates, are of material importance to the prevalence of minimum fault level violations and, consequently, the estimated involuntary load shedding. As such, AEMO's generator retirement schedules were incorporated from the economic retirement outcomes of the most recent ISP (2024), while forced and planned outage rates were based on the July 2023 IASR generator reliability and maintenance settings. Planned outages were scheduled occur during periods of greatest capacity reserve to minimise market impacts based on a scheduling algorithm developed by EY as part of the market modelling (see Appendix G). Minimum post-contingent fault level thresholds were set by the 2023 AEMO System Strength Report. Involuntary load shedding was valued at the AER's Value of Customer Reliability (VCR) of $46,774 for Queensland per megawatt hour (MWh) in 2023 dollars for native load.

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[59] AER, *Regulatory Investment Test for Transmission*, November 2024, Glossary ('base case'); AER, *Regulatory Investment Test for Transmission: Application Guidelines*, November 2024, page 21.

[60] AEMC, *Efficient Management of System Strength on the Power System*, final determination, October 2021, page 16.

AEMO has a suite of operational tools to mitigate involuntary load shedding due to insufficient system strength, such as:

- reversing planned outages;
- constraining IBR plant;
- constraining non-scheduled generators;
- rooftop PV emergency backstop controls; and
- directing non-dispatched synchronous generators.

Given that these tools are not considered in the base case approach, the base case outcomes presented a conservative estimate of system strength shortfalls and potential involuntary load shedding. This base case formed the foundation for assessing the need for additional system strength solutions, and serves as a reference point to measure the potential benefits of various credible options in addressing system strength deficiencies.

Appendix G outlines how the benefit from avoiding involuntary load shedding under the base case from there being insufficient system strength were estimated for the PADR. Importantly, the avoided involuntary load shedding from insufficient system strength does not affect the ranking of credible options assessed in this RIT-T.

Appendix G: Estimating the Market Benefits

Modelled market benefits from the portfolio options

The RIT-T requires categories of market benefits to be calculated by comparing the state of the world in the base case where no action is undertaken, with the state of the world with each of the credible portfolio options in place, separately.[61] The state of the world is essentially a description of the NEM outcomes expected in each case, and includes the type, quantity and timing of future generation and storage investment as well as unrelated future transmission investment (for example, that required to connect REZs).

Powerlink engaged EY to undertake wholesale market modelling to evaluate the following seven categories of market benefit under the RIT-T for the PADR:

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

Drawing on the hourly market modelling dispatch data from EY, Powerlink also undertook two post-processing modelling exercises to capture two additional sources of market benefit in the assessment:

- the avoided involuntary load shedding under the base case from there being insufficient system strength under the base case; and
- the impact of synchronous condenser losses on Australia's greenhouse gas emissions and NEM fuel costs.

Both of these effects were not captured in the wholesale market modelling undertaken by EY.

Only the two of the market benefit categories estimated were found to be material in the modelling. Specifically:

- the post processing assessment of avoided unserved energy estimates that all options avoid *at least* $3 billion (in present value terms) of unserved energy;[62] and
- the wholesale market modelling undertaken by EY found that the portfolios provide between $900 million and $2,740 million (in present value terms) of benefits from avoiding or deferring capital and operating costs of generation and storage in the NEM due to the options being in place.

While the other five categories of market benefit listed above have been estimated, they are not considered material to the outcome of the assessment. It should be noted though that, while technically the post-processing assessment of avoided unserved energy is also not material under the RIT-T (since it is the same for all portfolios), it is mentioned above as it is such a significant source of market benefit for this RIT-T and should be considered material from the perspective of Queensland electricity customers.

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[61] See AER, *Regulatory Investment Test for Transmission*, November 2024, paragraph 24; AER, *Regulatory Investment Test for Transmission: Application Guidelines*, November 2024, pages 32-35 for a definition and discussion of states of the world in a RIT-T.

[62] Note that 'at least' was used here, and throughout the PADR, on account of the approach taken to capping the avoided unserved energy in the assessment in order to allow for a meaningful comparison across options. If the full unserved energy had been added to the analysis, the expected net benefit of all portfolios would be significantly greater.

EY used a wholesale market modelling approach similar to the approach used in the ISP to estimate the market benefits associated with each credible option included in this RIT-T assessment.[63] While the following section provides further detail on the wholesale market modelling approach taken to estimating the market benefits, it is also discussed in greater detail in EY's market modelling report, available on the System Strength RIT-T page of Powerlink's website.

Market modelling to estimate wholesale market benefits

EY applied a linear optimisation model that performed hourly, time-sequential, long-term modelling for the NEM to estimate categories of wholesale market benefits expected under each of the options. Specifically, EY undertook long-term investment planning to identify the least-cost generation, storage and unrelated transmission infrastructure development schedule, while meeting demand requirements, policy objectives, and technical generator and network performance limitations.

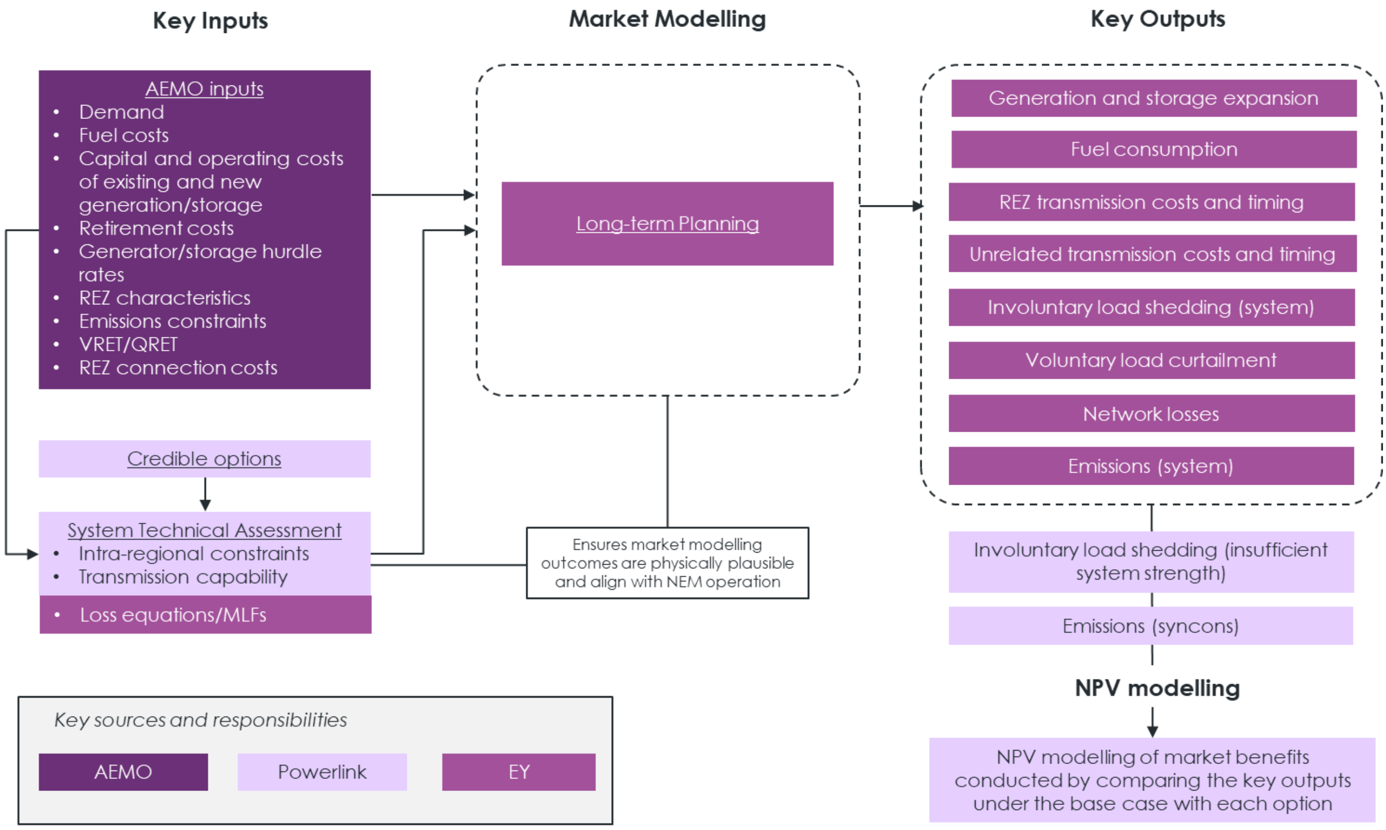
Powerlink undertook analysis of system strength based on the hourly dispatch outcomes from the market modelling to identify load shedding that may be required due to shortfalls in system strength in the base case.

These exercises are consistent with industry-accepted methodology, including within AEMO's ISP.

Figure G.1 illustrates the interactions between the key modelling exercises, as well as the primary party responsible for each exercise and/or where the key assumptions have been sourced.

[63] The RIT-T requires that in estimating the magnitude of market benefits, a market dispatch modelling methodology must be used, unless the TNSP can provide reasons why this methodology is not relevant. See AER, *Regulatory Investment Test for Transmission*, November 2024, paragraph 15(b).

Figure G.1: Overview of the modelling processes and methodologies



The accompanying market modelling report provides additional detail on these modelling exercises, as well as the key modelling assumptions and approach adopted more generally.

Post-processing modelling to estimate two sources of market benefit

The approach to the two post-processing modelling exercises undertaken by Powerlink is outlined in the sections below.

Avoided involuntary load shedding under the base case from there being insufficient system strength

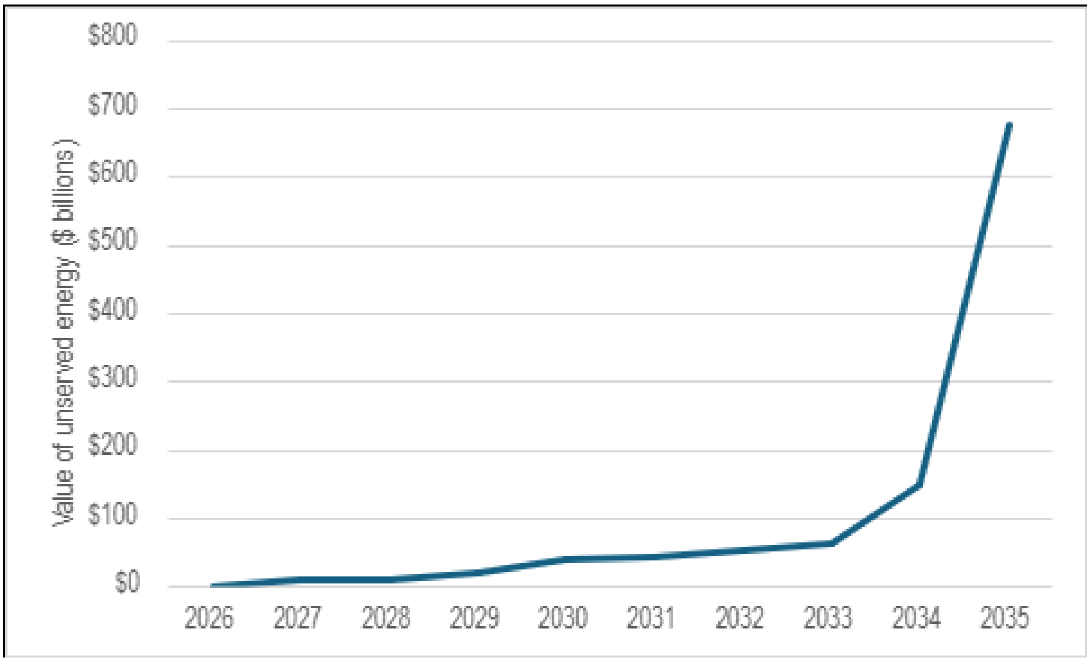
Under the base case where no action is taken to meet Queensland's minimum and efficient level system strength requirements, there would be a significant deficit in system strength because of retiring coal generation and growing renewable connections.

In this hypothetical future, it is expected that AEMO would use operational tools to minimise market impacts; however, as directed by the AEMC these operational tools are not to be assumed at this planning stage (see section 2.2). If the minimum level of system strength is not met, voltage control and protection systems may not operate correctly, which would lead to public safety concerns, cascading failures in the transmission network and, potentially, widespread and extensive power outages. The analysis continues to assume that AEMO would require the safe and secure operation of the power system, thereby requiring the disconnection of parts of the network imposing safety and security risks.

Powerlink did not include in the assessment the substantial unserved energy that would be expected to arise under the base case if no action is taken; for example, the unserved energy associated with catastrophic failure of not meeting the minimum level, or significant breaches in the efficient level. This is due to not knowing exactly how it would unfold and all portfolio options being explicitly designed to avoid it in the same way; that is, it is not material to the RIT-T assessment.

A summary of the exponentially increasing expected involuntary load shedding costs (in undiscounted 2022/23 dollars) under the base case, until 2035, is shown below.[64]

Figure G.2: Value of involuntary load curtailment under base case (undiscounted $2022/23)



The small amount of unserved energy in the early years, before coal exits, is due to an assumption that existing units would only provide system strength under the base case when incentivised to do so via the wholesale energy market. Powerlink considered this consistent with the system strength framework and that it is immaterial to the assessment since all portfolios avoided this unserved energy equally.

While all portfolio options were designed to avoid these outcomes under the base case equally, only the avoided unserved energy for the portfolios until (and including) September 2026 was included. This approach was developed to demonstrate that the portfolios are expected to have strongly positive net benefits (primarily from avoiding this substantial expected unserved energy under the base case), whilst also allowing for a meaningful comparison across options; that is, by not allowing the common value of avoided unserved energy to swamp the

[64] While the base case level of valued unserved energy is very high, it would not be proportionate for Powerlink to try to estimate it with any greater degree of accuracy as it does not have a material impact on the analysis since all options avoid this unserved energy equally. Further, the *value* of unserved energy under the base case is so high in part due to the general statewide VCR being designed to capture the cost of shorter duration outages, resulting in an over-estimate of the true value, when there are broad-based system level issues such as system strength that result in mass load-shedding for longer durations.

other benefit (and cost) differences across the portfolios. Powerlink considered this is consistent with the approach adopted in other RIT-Ts, the Energy Networks Australia (ENA) RIT-T Handbook and advice provided to the AER.[65]

The modelling estimates the megawatt hours of unserved energy in each modelling interval over the modelling period as a result in violations in minimum fault level requirements, and then applies a VCR (expressed in $/MWh) to quantify the estimated value of avoided unserved energy for each option (subject to the approach to capping the avoided unserved energy outlined above). Powerlink has adopted the AER's most recent assumptions for the Queensland VCR for the purposes of the PADR assessment. The capped avoided involuntary load shedding under the base case from insufficient system strength was estimated to be *at least* $3 billion for each portfolio.[66]

The assessment focussed on the expected level of involuntary load shedding under the base case and did not attempt to also model the costs of AEMO directing existing synchronous generators to operate, or to constrain renewable generation to maintain system security. While Powerlink considered that, on a per modelling interval basis, this meant that the estimated amount of involuntary load shedding was overestimated, this is a proportionate approach and not material to this RIT-T due to the majority of the avoided involuntary shedding being excluded from the analysis (as outlined above).

The impact of synchronous condenser losses on Australia's greenhouse gas emissions and NEM fuel costs

Powerlink also modelled the operational losses arising from the operation of synchronous condensers, as well as hybrid plant operating in synchronous condenser mode, via a post-processing process. The key impact of these losses was the additional greenhouse gas emissions and energy consumption resulting from other sources needing to compensate for the energy use of these plant.

Powerlink valued this impact for synchronous condensers, which is actually a negative market benefit impact (a 'market cost'), using the average Queensland emissions intensity factor combined with the assumed operational losses of these units. Powerlink also valued the average marginal fuel consumption to compensate for the losses incurred for utilising the synchronous condensers or synchronous condenser mode at approximately $50/MWh, which was estimated as the volume weighted marginal short-run marginal cost over the year (including coal).

Powerlink considered this was an over-estimate of the impact, as at many times in the year the marginal generating unit will be renewable and have a much lower/zero emissions intensity factor than the state average. However, this a proportionate approach and was not material in the wider PADR assessment. Specifically, Portfolio 2 (Synchronous Condensers) was found to be preferred over the other portfolios at the PADR stage, and so any more refined approach to modelling this impact would be expected to decrease the market cost associated with synchronous condensers and thus further strengthen the conclusion that Portfolio 2 was preferred.

Market benefits not expected to be material

Given the portfolios considered in the PADR did not address network constraints between competing generators, and all portfolios were expected to meet the system strength requirements equally, competition benefits were not expected to be material for the RIT-T assessment.

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[65] Darryl Biggar, *An Assessment of the Modelling Conducted by TransGrid and Ausgrid for the 'Powering Sydney's Future' Program*, report for the AER, May 2017, pages 12-16.

[66] Note that 'at least' was used here, and throughout the PADR, on account of the approach taken to capping the avoided unserved energy in the assessment in order to allow for a meaningful comparison across options. If the full unserved energy is added to the analysis, the expected net benefit of all portfolios would be significantly greater.

While option value was not formally quantified (on account only one scenario being considered relevant for the assessment), each of the portfolios, and the reopening triggers proposed (see section 5.2), provide flexibility to pivot to lower cost solutions if future circumstances change.

While the cost of Frequency Control Ancillary Services (FCAS) may change as a result of changed generation dispatch patterns and changed generation development following any increase to transfer capacity from the portfolios, Powerlink considered that changes in FCAS costs are not likely to be materially *different between the portfolios* under consideration due to:

- the quantity of grid-forming BESS being the same across all portfolios (and only marginally more for Portfolio 1A); and
- any additional market benefits expected for Portfolio 4 (due to the additional PHES) were not expected to outweigh the additional costs associated with that portfolio.

Powerlink did not consider it would be proportionate to develop a model for FCAS for this RIT-T in light of the above two bullet points.

Similarly, it is unlikely there are material changes between portfolio options in relation to NSCAS, or System Restart Ancillary Services (SRAS) costs due to the portfolios being considered.

Appendix H: Cost-benefit Analysis

This appendix outlines the outcomes, key inputs and assumptions used to inform the cost-benefit analysis for the PADR.

Net Present Value results

As outlined in section 3.1, the five portfolios *differed* in terms of the following components for meeting the minimum system strength requirements:

- Portfolio 1 (Balanced Technology):
  - Six new synchronous condensers in Central Queensland.
  - Two future clutched gas turbines in Central Queensland.
- Portfolio 1A (Balanced Technology: BESS in Minimum):
  - Five new synchronous condensers + one (large) grid forming BESS in Central Queensland.
  - Two future clutched gas turbines in Central Queensland
- Portfolio 2 (Synchronous Condensers):
  - Eight new synchronous condensers in Central Queensland.
- Portfolio 3 (Clutched Gas Turbines):
  - Four new synchronous condensers in Central Queensland.
  - Four future clutched gas turbines in Central Queensland.
- Portfolio 4 (Pumped Hydro Energy Storage):
  - Three new synchronous condensers in Central Queensland.
  - Two future clutched gas turbines in Central Queensland.
  - Three planned pumped hydro energy storage units in Central Queensland.

Each portfolio also included a number of *common* solutions for meeting both the minimum and efficient system strength requirements, as summarised in section 3.1.

Table H.1 and Figure H.1 below detail the NPV components of each portfolio, and show that Portfolio 2 (Synchronous Condensers) had the greatest estimated net benefit of the credible options. Portfolio 2 was found to deliver approximately $128 million greater net benefits than the second ranked option (Portfolio 1).

Network support payments to providers of non-network solutions are treated as a transfer under the RIT-T and are not represented in Table H.1 in order to preserve confidentiality.

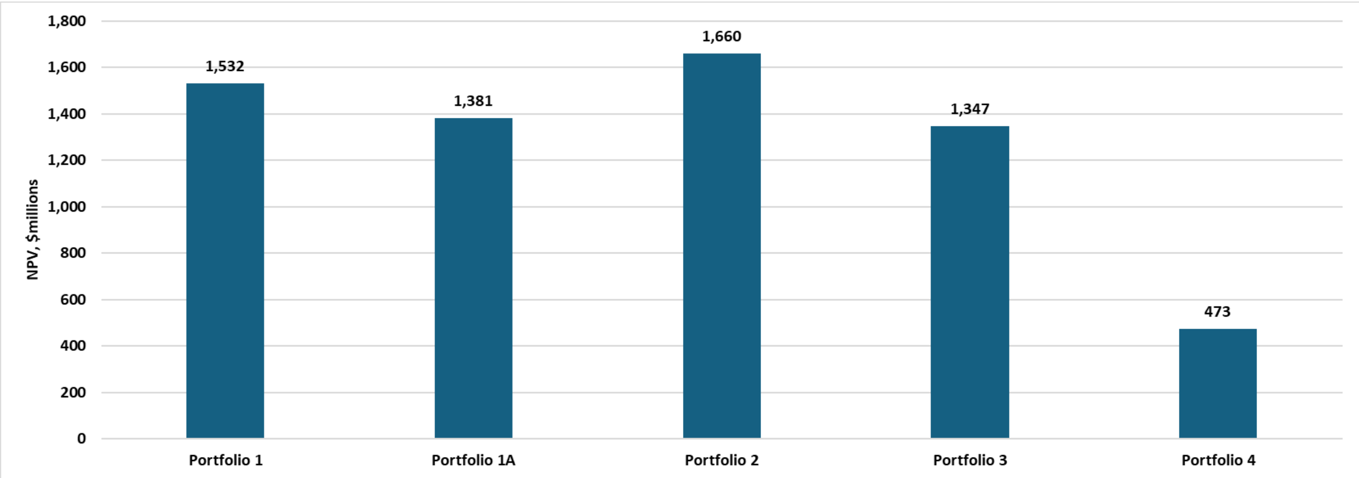
Table H.1: NPV of the portfolio options (2023 dollars, millions)

Portfolio	Description	Costs		Gross economic benefits			Net economic benefit	Rank
		Capex	Opex	Wholesale Market Benefits + emissions	Avoided USE*	Syncon Losses**		
1	Balanced Technology	-$2,047	-$363	$917	$3,090	-$66	$1,532	2
1A	Balanced Technology (BESS in Min.)	-$2,712	-$445	$1,508	$3,090	-$60	$1,381	3
2	**Synchronous Condensers**	**-$1,720**	**-$282**	**$636**	**$3,090**	**-$65**	**$1,660**	**1**
3	Clutched Gas Turbines	-$2,336	-$433	$1,089	$3,090	-$64	$1,347	4
4	Pumped Hydro Energy Storage	-$5,149	-$530	$3,111	$3,090	-$50	$473	5

** Note that this avoided unserved energy reflects the post-processing assessment by Powerlink of the avoided unserved energy during periods of insufficient system strength under the base case (and is capped in the analysis). It is separate from the general system unserved energy estimated by EY in the wholesale market modelling (which is immaterial).*

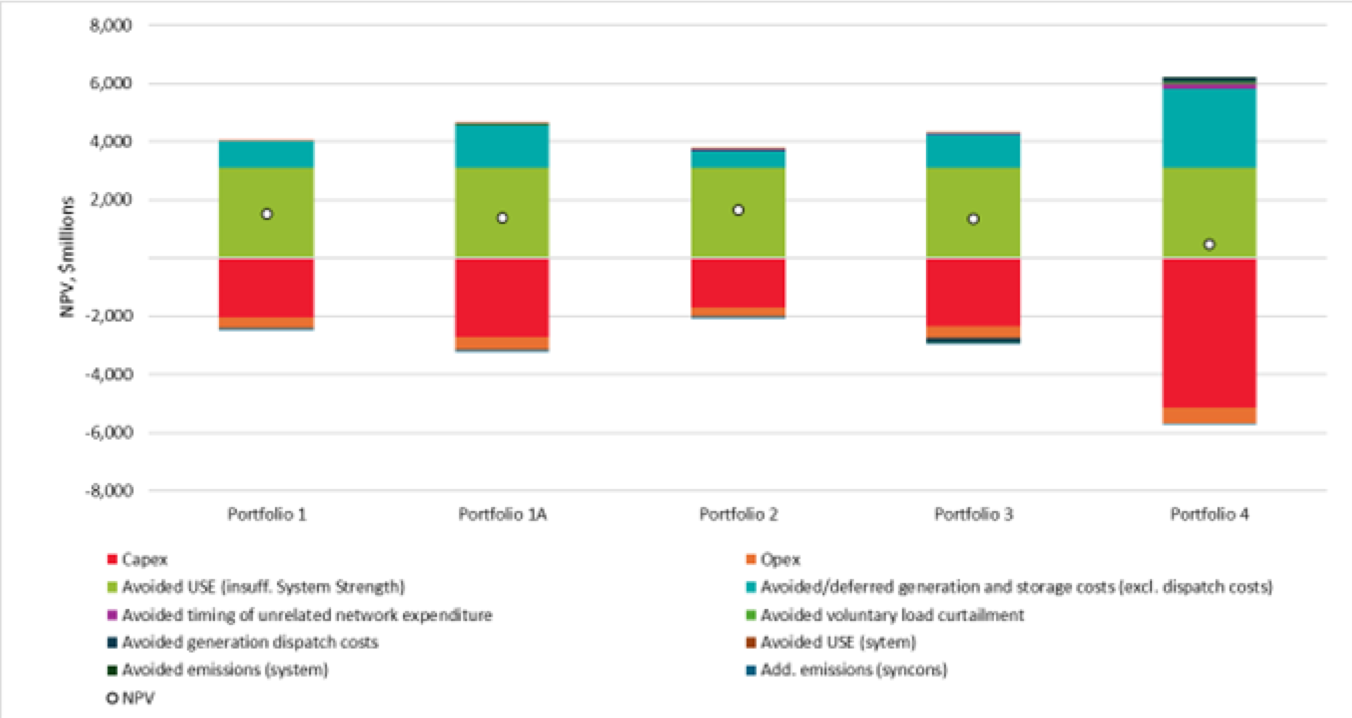
*** This captures the value of the additional emissions from the use of units in synchronous condensers mode due to the energy they consume. It has been estimated via the post-processing assessment by Powerlink, as opposed to as part of the wholesale market modelling undertaken by EY. The value of the additional fuel costs associated with the use of synchronous condensers has been included in the opex column (and is immaterially different between the portfolios).*

Figure H.1: NPV of portfolio options (2023 dollars, millions)



While Portfolio 2 had the lowest estimated gross economic benefits, it had significantly lower costs than all other portfolios, which was the key differentiator between the portfolios at this point in time.[67]

Figure H.2: Breakdown of the NPV of the portfolio options (2023 dollars, millions)



The key findings from the NPV assessment of each option portfolio were:

- The cost differences across the portfolios were a key driver of the portfolio rankings, and total capital and operating costs varied between $2.0 billion and $5.7 billion, in present value terms, across the portfolios.
    - Under the RIT-T framework, the full capital and operating costs of solutions is included in the cost-benefit analysis when solutions are not already in service, anticipated or committed. This means, for instance, that the full capital cost of BESS that are not existing, committed or anticipated projects is included in the analysis even though the projects would be used to provide services other than just system strength.
    - Given the criticality of the status of projects to how the costs of solutions are assessed in the RIT-T, Powerlink investigated a sensitivity that assesses whether the overall preferred portfolio changes if the project status of clutched gas turbines changes going forward (discussed below).
- The avoided involuntary load shedding under the base case from there being insufficient system strength, estimated via the post-processing process, was the largest category of benefit for all portfolios, estimated to be *at least* $3 billion for each portfolio.[68]

[67] While another key differentiator across the portfolios is the significantly greater avoided costs for non-RIT-T proponents for Portfolio 4 (shown in turquoise in the figure above), these are outweighed by its significantly greater capital costs.
[68] Note that 'at least' was used here, and throughout the PADR, on account of the approach taken to capping the avoided unserved energy in the assessment to allow for a meaningful comparison across options. If the full unserved energy was added to the analysis, the expected net benefit of all portfolios would be significantly greater.

    - All options were estimated to avoid load shedding due to not meeting minimum levels of system strength under the base case equally.
- Avoided/deferred generation and storage costs were the largest category of benefit estimated via the wholesale market modelling for all portfolios, making up between $0.6 billion and $2.7 billion, in present value terms, across the portfolios.
    - This was driven by the additional storage, gas and/or PHES units (as part of the portfolios) reducing the need to build more capacity to meet demand.
    - The wholesale market modelling found that under Portfolio 2 wind capacity was primarily deferred or replaced by grid-forming BESS, solar and open cycle gas turbines.
- All other categories of benefits were found to be immaterial in the analysis (as shown in the figure above).

NPV parameters

Analysis period

To take into account the size and complexity of the system strength services that will be required in Queensland over the long-term, the RIT-T analysis extended to 2049/50.[69] Where the capital components of the credible options have asset lives extending beyond the end of the assessment period, the NPV modelling includes a terminal value to capture the remaining asset life. This ensures that the capital cost of long-lived options over the assessment period is appropriately captured, and that all options have their costs and benefits assessed over a consistent period, irrespective of option type, technology or asset life.

Discount rate

Under the RIT-T Instrument:

- RIT-T proponents must adopt the discount rate from AEMO's most recent IASR unless the proponent can demonstrate why variation is necessary; and
- the present value calculations of the costs and benefits of credible options must use a commercial discount rate appropriate for the analysis of a private enterprise investment in the electricity sector.[70]

In this RIT-T Powerlink adopted a real, pre-tax commercial discount rate of 7% as the central assumption for the NPV analysis.[71]

Powerlink tested the sensitivity of the results to changes in this discount rate assumption, and specifically to the adoption of a lower bound discount rate of 3.63% and an upper bound discount rate of 10.5%.[72]

Status of projects

The status of non-network solutions – that is, whether they are committed, anticipated or modelled – is a key input into the analysis under the RIT-T. The RIT-T Instrument defines a committed project as meeting all of the following criteria:

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[69] The PSCR indicated the cost-benefit analysis would be conducted over a 20-year period, which is the standard timeframe for Powerlink's RIT-T analysis. The longer period aligns with EY's modelling of market benefits out to 2049/50.
[70] AER, *Regulatory Investment Test for Transmission*, November 2024, paragraphs 18 and 19.
[71] This indicative commercial discount rate of 7% is based on AEMO, *2023 Inputs, Assumptions and Scenarios Report*, July 2023, page 123.
[72] A discount rate of 3.63% pre-tax Weighted Average Cost of Capital is based on AER, *TasNetworks (Transmission) 2024–29 Final Determination*, April 2024.

- *Land* – The proponent has purchased/settled/acquired land (or commenced legal proceedings to acquire land) for the purposes of construction.
- *Contracts* – Contracts for supply and construction of the major components of the necessary plant and equipment (such as generators, turbines, boilers, transmission towers, conductors, terminal station equipment) have been finalised and executed, including any provisions for cancellation payments.
- *Planning* – The proponent has obtained all required planning consents, construction approvals and licenses, including completion and acceptance of any necessary environmental impact statement.
- *Finance* – The necessary financing arrangements, including any debt plans, have been finalised and contracts executed.
- *Construction* – Construction has either commenced or a firm commencement date has been set.[73]

An anticipated project is one that does not meet all the criteria of a committed project, and is in the process of meeting at least three of the criteria of a committed project. A modelled project is a hypothetical project derived from market development modelling in the presence/absence of the credible option.[74]

Committed and anticipated projects are included in the base case for the cost-benefit analysis, while modelled projects are not. The status of projects under the RIT-T has an important bearing on how their costs are included in the analysis. Specifically, the full capital and operating cost of modelled projects are required to be included in the RIT-T assessment (given they are not included in the base case), while existing, committed and anticipated projects are included either at no cost (where they are already grid-forming), or at their incremental cost to become grid-forming.

In the proforma for non-network solutions (June 2023), and in the subsequent information request (December 2023), Powerlink requested proponents to provide advice on the status of their proposed solutions. Overall, the responses were sufficient for Powerlink to form a view on which projects were committed, progressing toward committed status (that is, anticipated) or modelled for the purpose of undertaking cost-benefit analysis. However, proponent responses were not all equal in terms of clarity, level of detail, or addressing each element of the five RIT-T criteria. To ensure the cost-benefit analysis in the PACR is as robust and up-to-date as possible, Powerlink requested all proponents, via their responses to Tables 7A to 7E in the information request at Appendix B of the PADR, to update/confirm the status of their proposals, and include sufficient information on each of the five RIT-T criteria.

Powerlink also compared the non-network solutions with AEMO's Generation Information Excel workbook (in April 2024), and found the status of the majority of solutions was the same. It is worth noting, however, that AEMO's project commitment criteria are slightly different to the RIT-T criteria. For example, AEMO's planning criteria requires connection contracts (including approval of Generator Performance Standards) to be approved whereas the RIT-T criteria do not. Therefore, Powerlink does not expect complete alignment on the status of projects between the System Strength RIT-T and AEMO's Generation Information.

Key parameters

The table below outlines the inputs Powerlink has used for key parameters for the cost-benefit analysis for this RIT-T.

[73] AER, *Regulatory Investment Test for Transmission*, November 2024, page 10 (glossary).
[74] Ibid.

Table H.2: Input parameters for cost-benefit analysis

Parameter	Source/Assumption
Fixed Date Asset Retirement – Qld coal	AEMO Final 2024 ISP (Step Change scenario)
Fixed Date Asset Retirement – non-Qld coal	AEMO Final 2024 ISP (Step Change scenario)
Fixed Date Asset Retirement – Gas	AEMO 2023 IASR
Fixed Date Non-thermal Asset Retirement	AEMO 2024 IASR
Borumba PHES Pumped Hydro	AEMO Generation Information (May 2024)
New Entrant Build Limits	AEMO 2023 IASR
Generator Energy Limits	AEMO 2023 IASR
Capital Costs	AEMO 2023 IASR
Fixed operating and maintenance cost (real 2023 dollars)	AEMO 2023 IASR (Qld Medium)
Variable operating and maintenance cost (real 2023 dollars)	AEMO 2023 IASR (Qld Medium)
Weighted average cost of capital (WACC)	AEMO 2023 IASR (central assumption)
Existing generation and storage technical parameters	AEMO 2023 IASR
New entrant generators technical parameters	AEMO 2023 IASR
REZ representation	AEMO 2023 IASR
Capacity Factors for new wind and solar availability	AEMO 2023 IASR
Coal fuel cost	AEMO 2023 IASR (Step Change scenario)
Gas fuel cost	AEMO 2023 IASR (Step Change scenario)
Hydro inflows and storage volumes	AEMO 2023 IASR
Group REZ limits	AEMO 2023 IASR
Resource limits	AEMO 2023 IASR
Network representation	AEMO 2023 IASR
Transmission development pathway	Final 2022 ISP ODP with updates to align New South Wales flow path augmentations with the NIS central scenario and Queensland with the SuperGrid Blueprint.
Value of emissions	Portfolio formation (excl. VER sensitivity): Emissions analysis using NSW Treasury Cost of Carbon Emissions. Portfolio Formation VER Sensitivity: Emissions analysis using AER Draft Guidance Valuing Emissions Reduction Modelling of Wholesale Market Benefits Analysis: Emissions Analysis using AER Draft Guidance Valuing Emissions Reduction
Demand Side Participation	AEMO 2023 IASR (Step Change scenario)

Parameter	Source/Assumption
Underlying consumption	Final 2022 Electricity Statement of Opportunities (Step Change scenario)
NEM carbon budget	630 Mt CO2-e for 2024-25 to 2029/30 681 Mt CO2-e for 2024-25 to 2051/52 2023 IASR v5.3 (Step Change scenario)
Commonwealth Renewable Energy Target	82% renewable generation by 2029/30 2023 IASR v5.3
Queensland Renewable Energy Target	50% renewable energy by 2029/30, 70% by 2031/32 and 80% by 2034/35, as a share of Queensland demand. 2023 IASR v5.3
NSW Electricity Infrastructure Roadmap	At least the same amount of electricity at 8 GW in New England REZ, 3 GW in Central West Orana REZ and 1 GW of additional renewable capacity + 2 GW of long duration storage (8 hours or more) by 2029/30. 2023 IASR v5.3
Victoria Renewable Energy Target	40% by 2025, 65% by 2030 and 95% by 2035 as a percentage of Victorian generation. 2023 IASR v5.3
Victoria Energy Storage Target	2.6 GW by 2030 and 6.3 GW by 2035 2023 IASR v5.3
Victoria Offshore Wind Target	2 GW by 2032, 4 GW by 2035, 9 GW by 2040 2023 IASR v5.3

Sensitivity analysis

At the PADR stage, Powerlink tested the robustness of the results of the NPV analysis to changes in a number of key variables and assumptions. These tests were designed to investigate whether the preferred portfolio option changed under these alternate key assumptions.

The range of factors tested as part of the sensitivity analysis in the PADR were:

- Clutched gas turbines becoming anticipated or committed (under the RIT-T framework) going forward;
- A more accelerated assumed coal retirement schedule for Southern Queensland;
- A delay to the completion of the Borumba PHES;
- Changes to the assumed cost of gas;
- Changes to the capital costs of BESS;
- Changes to the capital cost of synchronous condensers; and
- Alternative commercial discount rate assumptions.

Powerlink did not investigate sensitivities:

- involving higher or lower VCR or Value of Emissions Reduction (VER) values as the value of avoided unserved energy and emissions were not found to be materially different across the portfolios (and thus sensitivities on these variables would not change the ranking of the options); or
- that vary the assumed non-network capital (or operating costs).

In the PADR, Powerlink indicated that it would investigate a sensitivity that varied the assumed non-network capital and operating costs for the PACR, based on refined costs for solutions informed by proponents. However, as Portfolio 2 is the only credible option at this time, Powerlink considers there to be no value in undertaking this sensitivity for the PACR.

Only the sensitivity on the change in timing of retirement/de-commitment for coal generating units was investigated across all portfolios. All other sensitivities were only modelled on Portfolio 1A and tested against the base case in order to gauge the effect on gross benefits (which led to no further portfolios being modelled, as outlined in the sections below).

Clutched gas turbines and/or PHES becoming anticipated or committed (under the RIT-T) going forward

Powerlink also investigated whether the overall preferred portfolio would change *if the project status of proposed clutched gas turbines changes going forward*; that is, assuming that currently proposed projects become anticipated or committed in the future.

Under these assumptions, Portfolio 3 (Clutched Gas Turbines) became the preferred option overall. Specifically:

- Portfolio 3 was found to have estimated net benefits of $2.53 billion (in present value terms), which were $388 million more than the second-ranked portfolio under this sensitivity (Portfolio 1) – Portfolio 2 fell to fourth overall and is ranked behind Portfolio 1 (and 1A) due to it involving less clutched gas turbines than those two portfolios.
- This outcome was driven by the costs of the clutched gas turbine component of the options falling significantly if they are considered anticipated or committed – for example, in present value terms the total capital cost of Portfolio 3 fell from approximately $2.34 billion to $1.34 billion.

Given this finding, Powerlink said in the PADR that it intended to closely monitor the development of the proposed gas turbines, and proposed reopening triggers (see section 5.2) that would allow Powerlink to pivot from synchronous condensers to these solutions, if they reach anticipated or committed status under the RIT-T.

The above sensitivity adopted a proportionate assumption for the PADR that the cost of the clutches, in addition to the wider gas turbine plant costs, are anticipated or committed. In the PADR, Powerlink said it intended to further refine this in the PACR and investigate this sensitivity assuming that only the gas turbine plant costs are assumed to be anticipated or committed under the base case and the clutch cost is included in the portfolio (where appropriate). However, as Portfolio 2 is the only credible option at this time, Powerlink considers there to be no value in undertaking this sensitivity for the PACR.

While a similar sensitivity for Portfolio 4 (PHES) was not investigated as part of the PADR, a similar conclusion may hold if these proposals are assumed to become anticipated or committed in the future. However, confirming this position would require significant additional market modelling (which was not able to be accommodated for the PADR) and so Powerlink intended to investigate it further as part of the PACR, if appropriate to do so.

Similarly, Powerlink did not investigate this type of sensitivity for Portfolio 1A (where grid-forming BESS are assumed to be technically feasible for assisting with the minimum requirements) as part of the PADR, and intended to consider this further in the PACR.

Again, as Portfolio 2 is the only credible option at this time, Powerlink considers there to be no value in undertaking these sensitivities for the PACR.

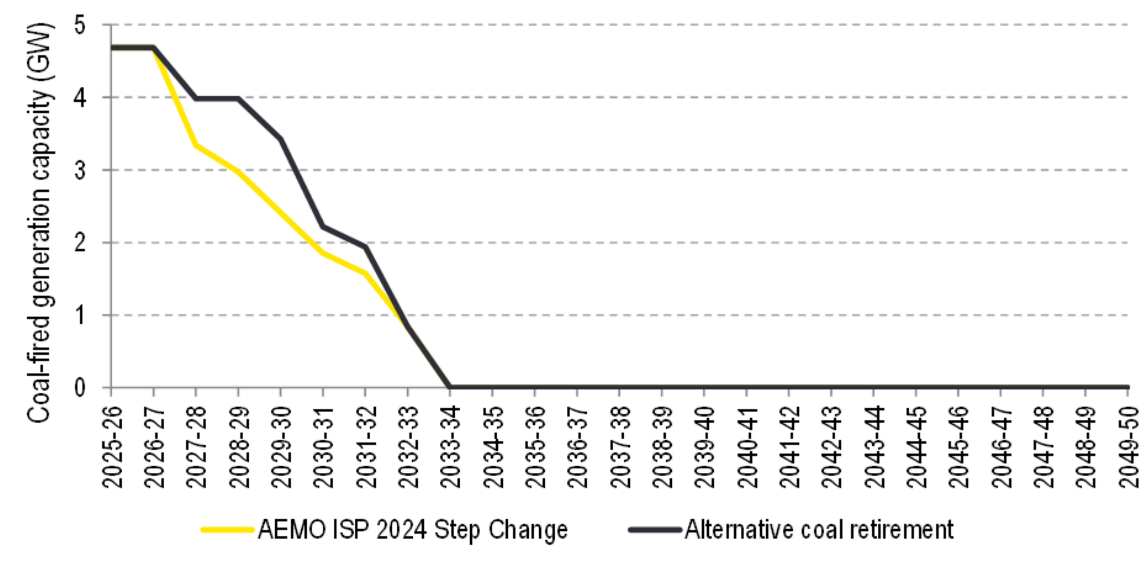
A more accelerated assumed coal retirement schedule for Southern Queensland

The level and location of coal generation in Queensland over the period December 2025 to December 2030 are primary considerations for Powerlink's ability to meet minimum system strength requirements. AEMO's forecasts suggested materially different retirement dates between the 2024 ISP and the 2023 System Strength Report. Appendix C of this PACR, and section 2.5 and Appendix C of the PADR, provide additional detail on the ISP and System Strength reports, their respective approaches to forecast coal retirements and why Powerlink considered that the 2023 System Strength Report forecasts were appropriate for consideration as part of this RIT-T.

The core NPV analysis in the PADR aligned its assumptions regarding Queensland coal retirement with the 2024 ISP, as required under the RIT-T framework.[75] For the PADR, Powerlink also investigated a sensitivity that aligned its assumptions with the 2023 System Strength Report, including the more accelerated retirement profile for coal generation in Southern Queensland, which could occur if Central Queensland coal generators remain online, instead of Southern Queensland coal generators, going forward.

A comparison of the 2024 ISP and 2023 System Strength Report capacity of coal-fired generation for both Central and Southern Queensland is shown in Figures H.3 and H.4 below.

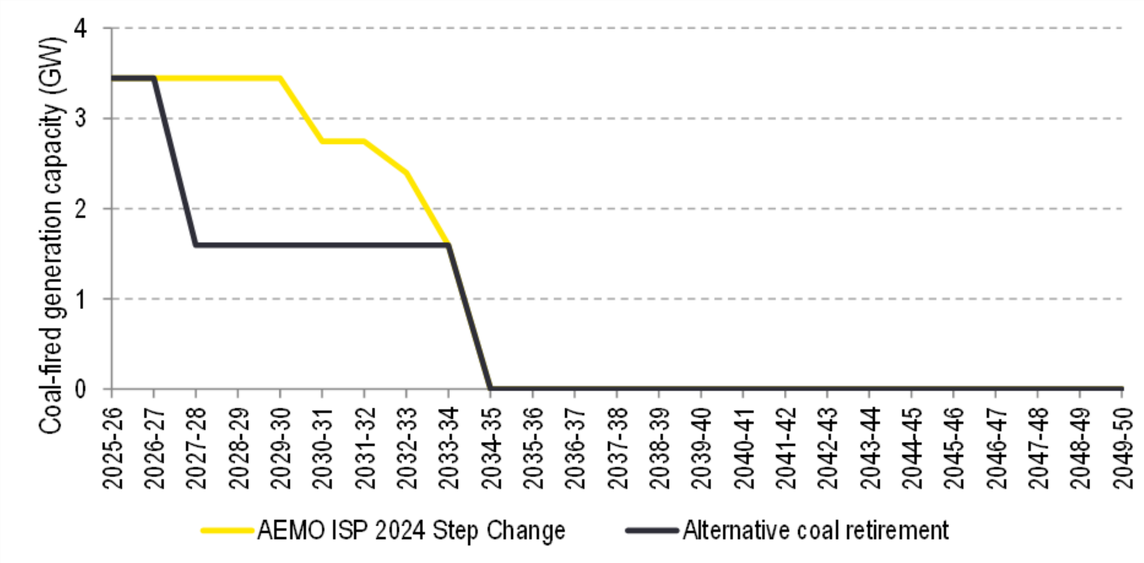
Figure H.3: Coal-fired generation capacity in Central Queensland by year across the 2024 ISP Step Change and the alternative coal retirement sensitivity



Source: EY, Gross Market Benefit Assessment of Queensland System Strength Portfolios, September 2024, page 11 (figure 3).

[75] AER, *Regulatory Investment Test for Transmission*, November 2024, paragraph 20(b).

Figure H.4: Coal-fired generation capacity in Southern Queensland by year across the 2024 ISP Step Change and the alternative coal retirement sensitivity

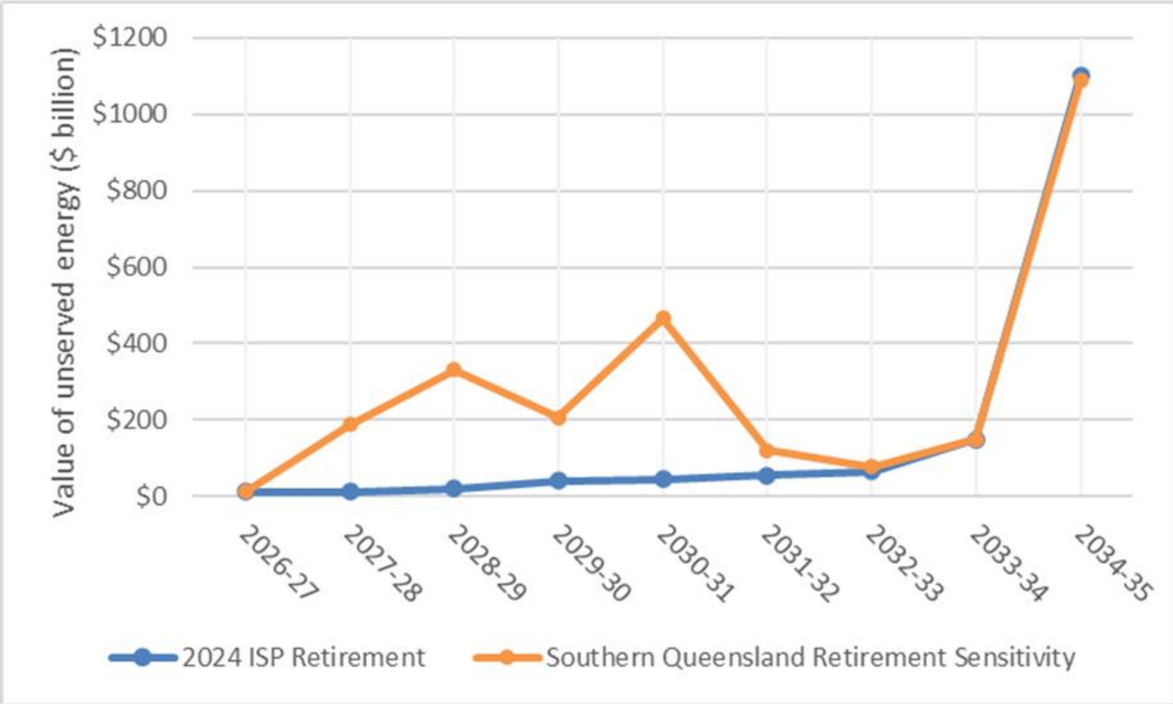


Source: EY, Gross Market Benefit Assessment of Queensland System Strength Portfolios, September 2024, page 11 (figure 4).

A key difference under this sensitivity, compared to the core analysis, is that there was forecast to be a significant amount of unserved energy in Southern Queensland under the base case due to there being insufficient system strength in this region due to the earlier retirement of coal generation under the 2023 System Strength Report assumptions. To avoid this, and ensure that the minimum system strength requirements are met, each of the portfolios needed to include contracts for non-network solutions with existing and planned assets in Southern Queensland. The details about which specific projects are assumed to be contracted with have been redacted to preserve confidentiality and to protect commerciality.

Figure H.5 shows a comparison of estimated unserved energy costs between the 2024 ISP base case and the retirement sensitivity for Southern Queensland. It is clear there were significant amounts of unserved energy between 2027 and 2033 within Southern Queensland under this sensitivity, demonstrating the need for Powerlink to take action in Southern Queensland.

Figure H.5: Estimated unserved energy in Southern Queensland under the 2024 ISP Step Change and the alternative coal retirement sensitivity



The solutions included for Southern Queensland did not differ by portfolio and were considered independent to the other solutions included for Central and Northern Queensland; that is, their inclusion in the portfolios did not offset any other solutions. The inclusion of these solutions did not affect the ranking of the options, and the wholesale market modelling and post-processing were limited to the preferred option for this sensitivity to demonstrate that their inclusion was expected to be net beneficial in a state of the world with more accelerated coal retirement than that forecast in the 2024 ISP.

Under these assumptions, contracting with these projects was strongly justified in Southern Queensland to avoid the significant amount of unserved energy that could otherwise occur there.

In present value terms, the additional Southern Queensland components increased the estimated total cost (that is, capital and operating costs) of Portfolio 2 by $83 million (in present value terms), but avoided the extremely high potential value of unserved energy in Southern Queensland, which more than outweighed the increase in costs.

The additional Southern Queensland components required if coal generators retire faster than forecast in the 2024 ISP were both relatively low-cost solutions (both outright and on a $/MVA basis) and only increased the total cost (that is, capital and operating costs) by approximately 4.3% for Portfolio 2 in present value terms.

Given the uncertainty surrounding the retirement, as well as decreased operation during times when it is uneconomic, for coal generators in Queensland, and the consequences of under-investing in system strength solutions, Powerlink considered the addition of these solutions to the ultimately preferred option to be a prudent low regret decision.

While the 2023 System Strength Report suggested a marginally slower retirement profile for Central Queensland than the 2024 ISP, the scope or timing of components included Central Queensland under this sensitivity was not amended as this the sensitivity was designed to test and develop a prudent risk management approach for Southern Queensland. In addition, Powerlink did not consider that any impact on the Central Queensland components would be material in the analysis and would only defer solutions by a year or two (and equally across the portfolio).

Sensitivity on the completion of the Borumba PHES

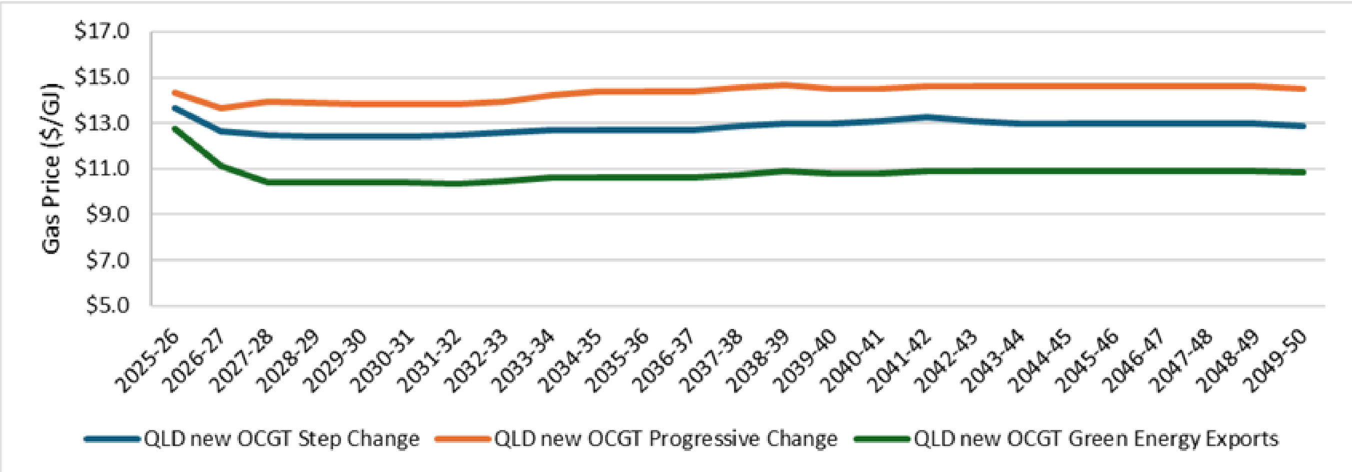
The Borumba PHES could be a source of material amounts of system strength. However, being a major project, there is naturally uncertainty surrounding project delivery and ultimate commissioning.

For the PADR, Powerlink investigated a sensitivity that delayed commissioning by two years. This has been designed as a general test of the impact of the project being delayed from September 2031 to September 2033.[76] The sensitivity covered Portfolio 1A (and the base case) and found that the delayed timing of Borumba PHES had an immaterial impact on the overall estimated net benefits (increasing them approximately 4.8%). The sensitivity was consequently not expanded to cover the other portfolios, and it was not expected that doing so would result in a change in the preferred option overall.

Changes to assumed cost of gas

In addition to the core modelling, which used the 2024 ISP Step Change scenario assumptions, Powerlink also investigated sensitivity tests that increase and decrease the assumed cost of gas by adopting the gas cost parameters from the Progressive Change and Green Energy Exports ISP scenarios, respectively.

Figure H.6: Gas price ($/gigajoule, real July 2023 dollars), comparison of Step, Progressive and Green Energy Export Scenarios



The results of these tests showed that the results of the assessment were highly insensitive to the assumed cost of gas given avoided generation dispatch costs are an immaterial category of market benefit in the core analysis. Specifically, adopting the gas cost assumptions from the Green Energy Exports and Progressive Change scenarios

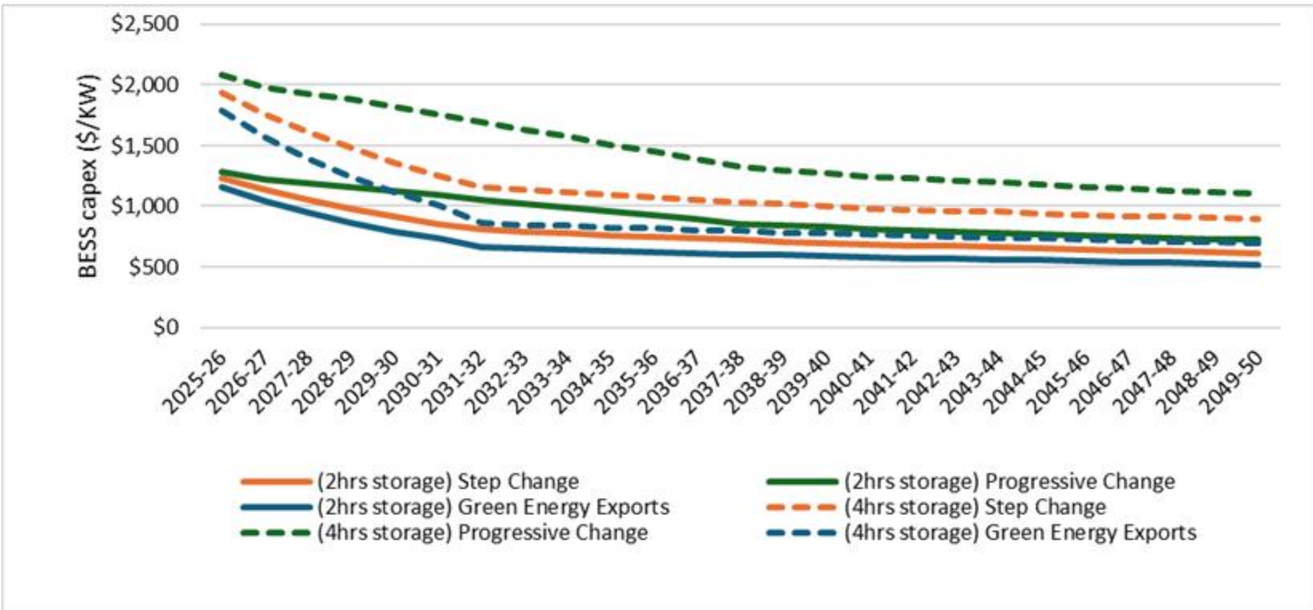
[76] At the time the PADR was published, AEMO's Generation Information of July 2024 indicated the full commercial use date for the Borumba PHES was September 2031. The Generation Information of April 2025 states the full commercial use date as July 2035.

resulted in less than a 0.5% change in the overall estimated net benefits of Portfolio 1A. The sensitivity was consequently not expanded to cover the other portfolios, and it was not expected that doing so would result in a change in the preferred option overall.

Changes to capital cost of BESS

Similar to the assumed cost of gas sensitivities, Powerlink also investigated sensitivity tests that increase and decrease the assumed capital cost of BESS in the analysis by adopting the assumed BESS build cost parameters from the Progressive Change and Green Energy Exports ISP scenarios, respectively, for different duration BESS.

Figure H.7: BESS capital cost ($/kilowatt, real July 2023 dollars), comparison of Step, Progressive and Green Energy Export Scenarios



This sensitivity was undertaken only for Portfolio 1A since it was the only portfolio that included a BESS within its minimum level portfolio and all portfolios have the same composition of components to meet the efficient level.

The market modelling results showed that for Portfolio 1A:

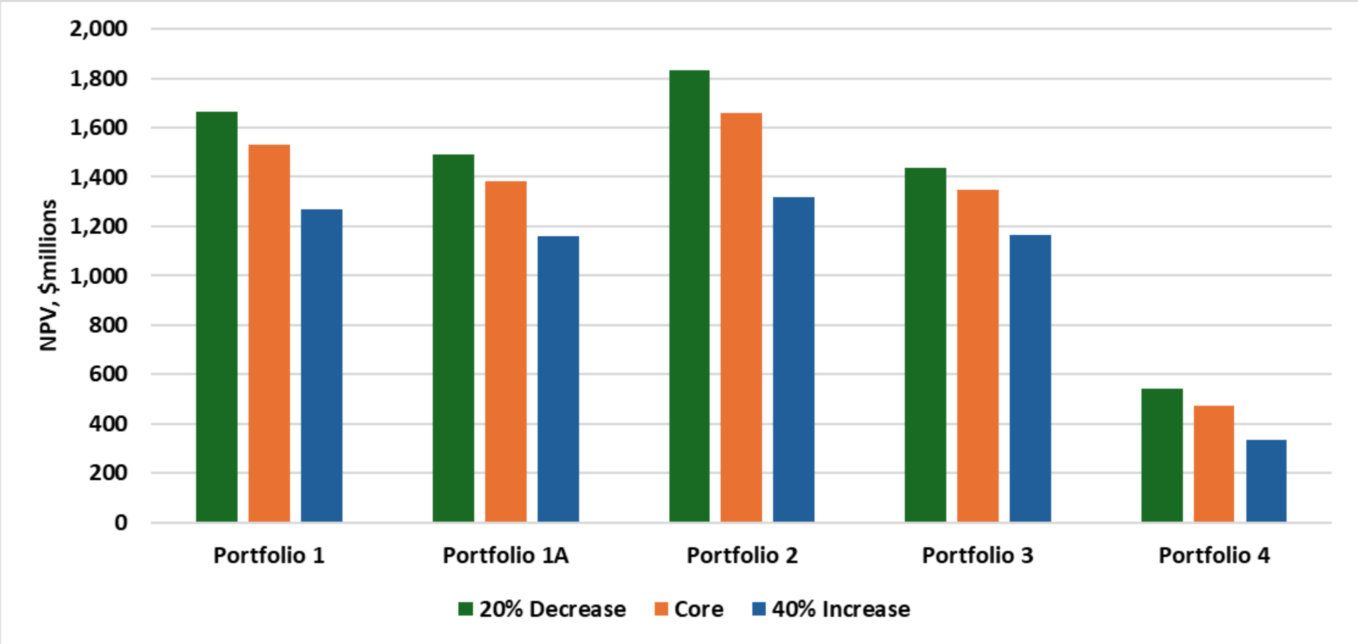
- decreasing BESS build costs to align with the Green Energy Export scenario led to a decrease of $173 million in forecast gross market benefits compared to the core scenario.
- increasing BESS build costs to align with the Progressive Change scenario resulted in only a minor decrease of $2 million in forecast gross market benefits compared to the core scenario.

As BESS were only included in the efficient level (excluding the BESS in Portfolio 1A) which was common across all portfolios, the change in the capital expenditure component would consistent across all portfolios. Powerlink did not consider these observations material overall as, even under the low BESS build cost sensitivity, Portfolio 1A would not be ranked ahead of the preferred option (Portfolio 2).

Changes to the capital cost of synchronous condensers

Figure H.8 presents the results of assuming 40% higher and a 20% lower assumed synchronous condenser costs, consistent with the 'class 5' nature of the estimates. These boundaries align with a class 5 estimate according to the Association for the Advancement of Cost Engineering (AACE) classification system. The results showed that Portfolio 2 continued to be preferred, even under higher assumed synchronous condenser costs.

Figure H.8: NPV of portfolio options – comparison between synchronous condenser costs (2023 dollars, millions)



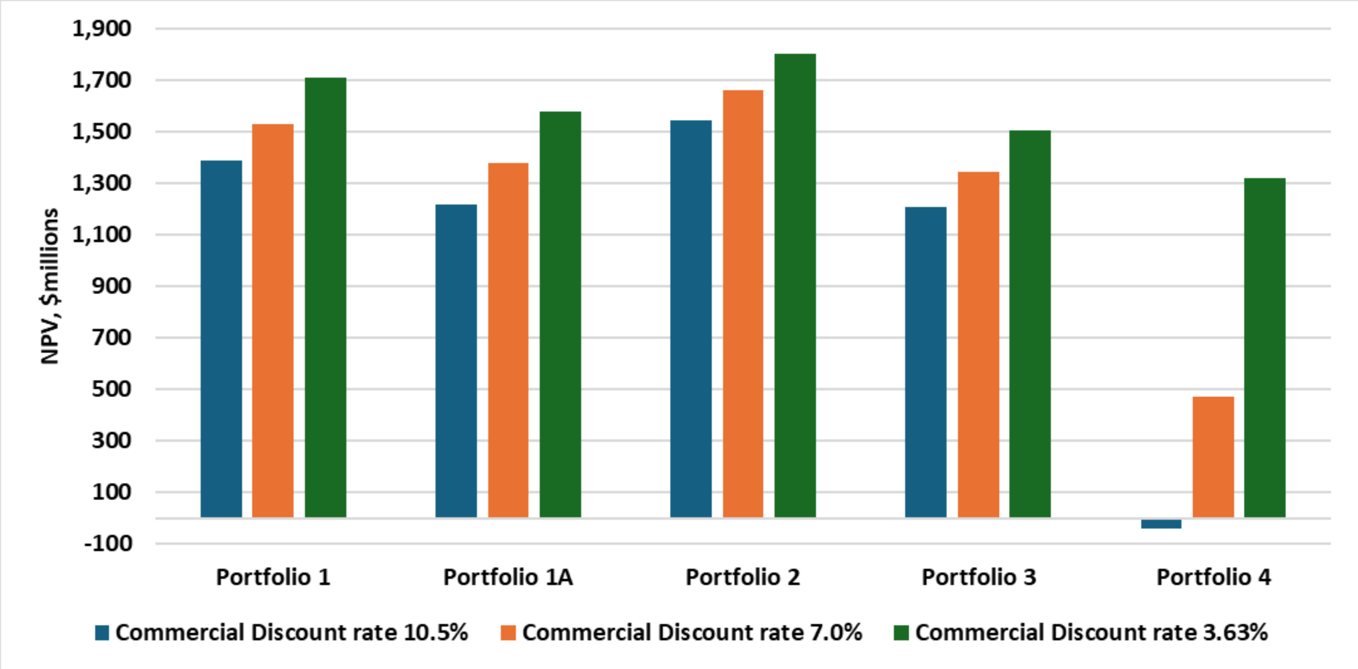
In terms of boundary testing, there would need to be a more than a 72% increase in synchronous condenser costs for Portfolio 2 to no longer be the top-ranked option (and, for all synchronous condenser costs greater than this level, Portfolio 1 would be preferred). As such, the finding that Portfolio 2 is the top-ranked option was robust to the assumed synchronous condenser costs.

Further, and relevant for the proposed reopening trigger covering increased synchronous condenser costs (see section 5.2), while the boundary value testing found that there would need to be a more than a 72% increase in synchronous condenser costs for Portfolio 2 to no longer be the top-ranked option, at this level, Portfolio 2 would have net economic benefits equal to Portfolio 1. Powerlink therefore rounded up to a 75% increase for the reopening trigger in order to have Portfolio 2 no longer the top-ranked option by a material margin (and, at these assumed costs, Portfolio 1 would have net benefits that are $20 million more than Portfolio 2).

Alternative commercial discount rate assumptions.

Figure H.9 shows that Portfolio 2 was preferred under lower and higher assumed commercial discount rates.

Figure H.9: NPV of portfolio options – comparison between lower and higher commercial discount rate (2023 dollars, millions)



In terms of boundary testing, there would need to be a commercial discount rate of less than 2.15% for Portfolio 2 to no longer be the top-ranked option (in which case Portfolio 4 would be preferred). As such, the finding that Portfolio 2 was the top-ranked option was robust to the assumed commercial discount rate.

Reasonable scenarios

In terms of Queensland-specific policies, the 2023 IASR included the following positions:

- Expansion of the QRET to 50% by 2030, 70% by 2032 and 80% by 2035;
- Support for the Borumba PHES as an anticipated project, based on AEMO's generation commitment criteria;
- Support for the Kogan Renewable Hydrogen Project;
- Queensland SuperGrid Infrastructure Blueprint and Queensland REZ infrastructure treated as options;
- CopperString 2032 treated as an anticipated project, with the Townsville to Hughenden connection to be modelled as a REZ network expansion;
- Inclusion of the SuperGrid Landholder Payment Framework; and
- Conversion of publicly owned coal-fired generation into clean energy hubs.[77]

AEMO's 10-year forecast IBR at each system strength node is based on the Step Change scenario from the 2022 ISP and the central scenario demand forecast from the 2022 ESOO.[78] Given Powerlink is required to plan for delivering the efficient level of system strength required to host the forecast IBR, Powerlink considers the Green Energy Exports and Progressive Change scenarios are not relevant to this RIT-T.

[77] AEMO, *2023 Inputs, Assumptions and Scenarios Report*, July 2023, pages 7 and 31.
[78] AEMO, *2022 System Strength Report*, December 2022, page 16.

Appendix I: Cost Estimation

Regulatory requirements

For each credible option, Powerlink is required to quantify:

- costs incurred to construct or provide the option;
- operating and maintenance costs in respect of the credible option; and
- the cost of compliance with laws, regulations and applicable administrative requirements in relation to the construction and operation of the option.[79]

At the PADR and PACR stages of a RIT-T, RIT-T proponents must include a quantification of costs, including a breakdown of operating and capital expenditure for each credible option.[80]

Further, in October 2023, additional information requirements were added to the RIT-T Application Guidelines in cases where the estimated capital cost of the preferred option exceeds $100 million. The guidelines require that, for each credible option, RIT-T must specify to the extent practicable and in a manner that is fit-for-purpose for the stage of the RIT-T:

- key inputs and assumptions adopted to derive the estimate;
- a breakdown of the main components of the cost estimate;
- methodologies and processes applied to derive the cost estimate;
- reasons in support of key inputs and assumptions adopted and methodologies and processes applied; and
- the level of, and basis for, any contingency allowance that has been included in the cost estimate.[81]

Information from non-network solution proponents

The proforma Powerlink published in June 2023 for non-network solutions requested proponents provide the capital cost, external contributions, and indicative annual availability and hourly run charges for solutions. However, not all proponents provided capital cost information for their proposals and, for those that did, Powerlink could not be confident that the costs were provided in a manner consistent with the RIT-T Application Guidelines. In December 2023, Powerlink requested proponents update/confirm their capital, operating and maintenance, and compliance costs (in accordance with the RIT-T requirements noted above). The information request also asked proponents to update/confirm their availability and/or run charges.

Proposed network support costs for non-network solutions are included in the assessment of costs and benefits, but do not have any impact on the identification of the preferred option as the costs are treated as a wealth transfer between energy market participants under the RIT-T framework.[82] These costs for non-network solutions will ultimately be reviewed by the AER as part of the new network support payment process for system security services.[83]

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[79] NER, clause 5.15A.2(b)(8); AER, *Regulatory Investment Test for Transmission*, November 2024, paragraph 5.
[80] NER, clauses 5.16.4(k)(3) and (v)(1).
[81] AER, *Regulatory Investment Test for Transmission: Application Guidelines*, October 2023, page 30. The AER's 2024 cost threshold review increased the threshold to $103 million for three years from 1 January 2025.
[82] AER, *Regulatory Investment Test for Transmission: Application Guidelines*, October 2023, pages 60-62.
[83] See AEMC, *Improving Security Frameworks for the Energy Transition*, final determination, March 2024, pages 49-53. See also AER, *System Security Network Support Payment Guideline*, guideline, November 2024 and NER, clauses 6A.6.6A, 6A.7.2, 6A.22.1 and 6A.23.3.

To provide objective estimates of costs of credible options for the cost-benefit analysis, Powerlink used build, fuel, and fixed and variable operating costs, data from AEMO's 2023 IASR to model the incremental costs of non-network solutions.[84] In terms of how the IASR build costs compared to capital cost information from proponents of non-network solutions, Powerlink observed broad alignment between the two sources of data.

A request for updated technical and commercial information from proponents of non-network solutions was included at Appendix B of the PADR. The request included AEMO's minimum and recommended requirements for system strength contracts, as per its Provisional Security Enablement Procedures, and additional information Powerlink required to complete this RIT-T and progress negotiations with proponents of non-network solutions.

Synchronous condensers

Powerlink prepared a number of high-level estimates for the installation of network synchronous condensers at the PADR stage of this System Strength RIT-T. The estimates drew on (confidential) advice from third-party suppliers of synchronous condensers, with the Powerlink portion of the cost based on recent actual projects. The estimates covered the following elements:

- Design, supply, delivery, installation, testing and commissioning;
- Building and civil works;
- Road works; and
- 275kV bay installation and overhead line works.

An escalation factor was also applied to allow for increases in contract and material costs.

As stated in section 4.3, the cost-benefit assessment for the PADR included a capital cost of $135 million for the supply and installation of 200MVA network synchronous condensers, which was at the upper-end of Powerlink's estimates at that time, and was site-agnostic across the Powerlink network. The PADR also indicated that Powerlink estimated actual network capital costs would be within a range of +40% and -20% of the central capital cost estimate, consistent with a class 5 estimate under the AACE cost estimate classification system. Land and biodiversity costs were not included in the estimated cost of network synchronous condensers as they were assessed as being co-located on existing Powerlink-owned land.

In terms of operating costs for network synchronous condensers, Powerlink assumed annual operating and maintenance costs to be 0.6% of capital expenditure, consistent with the AER's August 2019 decision on ElectraNet's Main Grid System Strength Contingent Project.[85] Powerlink also noted that the value is higher than estimates from suppliers of synchronous condensers.

For cost estimation, the active power consumed by running synchronous condensers was translated to network losses based on the operation of the machine. In this regard Powerlink made assumptions on the percentage of time operating at no load, and cost of energy to run (dollars per kilowatt hour).

These assumptions were applied to manufacturer-supplied technical data on losses at different running conditions to derive the cost of losses. The impact of these losses on emissions in the NEM was also included in the analysis, but was not considered material to the overall outcome of the analysis.

[84] AEMO, *2023 IASR Assumptions Workbook*, September 2023.

[85] AER, *ElectraNet Contingent Project, Main Grid System Strength*, final decision, August 2019, page 29. Transgrid also used the 0.6% value from the AER's decision on ElectraNet's Main Grid System Strength Contingent Project in its PADR (page 29).

In the PADR, Powerlink said:

- it had commenced planning studies for potential sites on its 275kV network in Central Queensland for installation of synchronous condensers;
- as the technical assessment progresses, and updated information from suppliers becomes available, Powerlink would prepare more detailed estimates, in line with Powerlink's cost estimation methodology[86], and provide details in the PACR.

For non-network synchronous condensers, the same approach was used as for network synchronous condensers in the PADR.

As stated in section 4.3, Powerlink will not have updated cost estimates for synchronous condensers until tender proposals are received and assessed (which is currently expected to be in late-2025) and so accordingly Powerlink has not updated the synchronous condenser costs in the cost-benefit analysis for this PACR.

Other network solutions

At the PADR stage, Powerlink investigated other technology options for addressing system strength, such as using grid-forming STATCOM with supercapacitors or STATCOM with synchronous condensers.

Synchronous condensers offer the benefits of providing system strength via additional short circuit capacity, rotating inertia for network stability, dynamic reactive support, overload capability, voltage support, regulation of voltage during fault conditions, absorption of reactive power during light load conditions to avoid overvoltage, and production of reactive power during high load conditions to avoid under-voltage. Apart from synchronous condensers, no other network solutions were deemed able to provide system strength and the other mentioned benefits.

Capital costs for non-network BESS

The current ISP investment modelling does not explicitly distinguish between grid-following and grid-forming technology types, and all IBR (including build costs in the IASR) are effectively treated as grid-following.[87]

In undertaking the PADR analysis, three 'types' of BESS were considered:

- Committed/anticipated BESS;
- Proposed BESS from proposals received in response to Powerlink's PSCR (and the accompanying proforma); and
- Generic BESS from AEMO's IBR forecast.

The three committed/anticipated BESS included in the cost-benefit analysis (see chapter 7 of the PADR) are the Mount Fox BESS (ARENA), Stanwell BESS and Tarong BESS.[88] These BESS are being built as grid-forming and therefore Powerlink did not add any incremental costs to these assets in the cost-benefit assessment; that is, they were assumed to be included in the same manner/cost under the base case and option cases. While these BESS were considered in the PADR analysis, they did not feature in any of the option portfolios as they formed part of the base case, and not changing their operation in any way under the option cases.

[86] Powerlink's cost estimating methodology is available on the RIT-T Consultations page of its website.
[87] AEMO, *System Strength Report*, December 2023, page 11.
[88] AEMO, *Generator Information*, Excel workbook, July 2024. The Mount Fox BESS (ARENA) and Stanwell BESS are listed as anticipated, and the Tarong BESS as committed (highly likely to proceed), in the July workbook.

For BESS proposed in response to the PSCR (and the accompanying proforma), the full cost, based on IASR cost assumptions, is included in the cost-benefit assessment, with an additional 5% added to convert the BESS from grid-following to grid-forming (as Powerlink understood that that the IASR cost assumptions relate to grid-following BESS). Proposed BESS made up all of the BESS capacity included in the portfolios, and they were not assumed to go ahead under the base case.

There were also two existing grid-following BESS, which would satisfy the requirements if they were to be upgraded to grid-forming. Similar to the proposed BESS, the cost to convert these BESS from grid-following to grid-forming was calculated at 5% of the total IASR build cost for a BESS of the same size.

Generic BESS included in the AEMO IBR forecasts (that could upgrade from grid-following to grid-forming, if paid to do so) were considered but ultimately not included in the PADR assessment due to them not being forecast to be available as potential solutions in Queensland. Specifically, the AEMO IBR forecasts for Queensland did not include these ‘generic’ BESS beyond 2027 and, thus, Powerlink did not consider it appropriate to include any such potential solutions in the formation of the portfolios.[89] Powerlink notes that this is in contrast to Transgrid’s PADR assessment, which included these BESS in option portfolios due to the significant amount of generic BESS forecast in New South Wales in the AEMO IBR forecasts.

[89] While the latest AEMO IBR forecasts include a small amount of IBR BESS in the short-term, Powerlink notes that all of this capacity is assumed to be taken up by 2027 by the three committed/anticipated BESS Powerlink has included in the modelling (i.e., the Mount Fox BESS, the Stanwell BESS and the Tarong BESS).

Appendix J: Technical Performance Assessment for Grid-forming BESS

This appendix outlines Powerlink's approach to the technical performance assessment of grid-forming BESS.

Grid-forming BESS technical requirements

The connection of a grid-forming BESS for providing system strength services to Powerlink will adhere to the standard generator connection process. Compliance with the NER and the specified Generator Performance Standards (GPS) is required.

This section outlines the key technical performance requirements that Powerlink will evaluate to ensure the grid-forming BESS delivers 'stable voltage waveform support' which is vital for achieving the efficient level of system strength service. These requirements are in addition to the technical requirements specified in the GPS.

The key technical performance requirements are developed based on the following three criteria for stable voltage waveform, as outlined in AEMO's System Strength Requirements Methodology (version 2.0, effective 1 December 2022):

- Voltage magnitude;
- Change in voltage phase angle; and
- Voltage oscillations.

Documents and study requirements

Powerlink will request the following technical information from the proponents submitting proposals to provide system strength services using a grid-forming BESS:

- A detailed site-specific PSCAD model that meets the requirements of Power System Model Guidelines, a RUG, and minimum DMAT tests.
    - The quality of the model is critical, as the technical assessment of the grid-forming BESS performance relies heavily on model-based evaluations.
- Model documentation from the OEM describing high level inverter control philosophy.
    - The grid-forming BESS inverters are expected to maintain synchronisation with the grid by continuously controlling an internal voltage phasor, including both the magnitude and the angle. **The inverters must respond instantaneously to changes in the external grid without any controller action, provided that current limits are not exceeded. Switching between grid-following (or any other mode) and grid-forming modes is not considered suitable for providing system strength service.** Furthermore, if a Phase-Locked Loop (PLL) is utilised for monitoring, control or protection functions, detailed information must be provided.
    - Details on the current limiting mechanism are preferred.
    - Hardware-in-the-loop (HIL) test results confirming model response are preferred.
- Documentation demonstrating the inverter's short-term overloading capability, which refers to their ability to handle current beyond the continuous rating, must be provided. The overloading capability can be demonstrated through several ways:
    - The selected inverter is designed to have short-term overloading capability (generally in seconds);
    - Plant is sized and designed with an inverter capacity that exceeds the standard requirements (i.e., the plant is oversized); or
    - Active power is curtailed to maintain a margin between the operating output and the maximum output of the plant; that is, maintaining a headroom when in service.

The minimum number of tests needed to evaluate the technical performance of a grid-forming BESS providing system strength services is determined by the criteria outlined under the "stable voltage waveform". Table 1 below specifies the key technical performance tests required to understand the characteristics of the grid-forming inverters. These tests will be conducted using the PSCAD SMIB model, and proponents are expected to provide the results to Powerlink. Additionally, Powerlink will conduct detailed PSCAD WAN studies where applicable.

Powerlink will evaluate the transient and oscillatory stability aspects of the grid-forming BESS as part of the standard generator connection process. This assessment will utilise the models provided by the proponent during the GPS studies.

Table J.1: PSCAD SMIB tests required as part of providing system strength service

Test #	Test description	Additional requirements and evidence
1	Voltage source behaviour Withstand SCR tests conducted at SCR=1.2	Refer withstand SCR test requirements given in Powerlink's Inverter Based Renewable Plant: GPS Connection Study Process and Expectations (Note 1). PSCAD study results should be provided. Tests need to include balanced and unbalanced faults, as well as phase angle jumps. For the phase angle jump tests, tests should be performed up to ±60°, as per the DMAT grid voltage phase angle change test. Noting the expectation is that BESS can remain connected and stable at a minimum of 40 degrees for provision of system strength. It is expected that grid-forming plant should be able to operate stably at SCR =1.2 subject to the limits of power transfer capability depending on its operating mode (i.e. charging or discharging). Unlike S5.2.5.15 requirements, these tests must be conducted using the settings necessary for the plant to meet the GPS requirements. Note that these tests are not intended to demonstrate performance compliance with GPS. For example, the speed of response is not required to meet GPS performance when tested at a SCR = 1.2. Test results should be analysed considering stable voltage waveform support requirements rather than on voltage stability issues.
2	Speed of response Response to ±5% step change in source voltage magnitude conducted at min and max SCR levels applicable to the connection with site specific X/R ratio.	PSCAD study results should be provided. Zoomed-in plots should be provided as part of the results. It is expected that grid-forming BESS should start its response immediately to oppose the change in voltage from the initiation of the voltage step.
3	Voltage oscillation damping Oscillation rejection tests (ORT) conducted at min and max SCR levels applicable to the connection with site specific X/R ratio. If the minimum SCR	Refer "Oscillation Rejection" test requirements given in Powerlink's Inverter Based Renewable Plant: GPS Connection Study Process and Expectations (Note 1). Frequency range: 0.1 - 1 Hz with 0.1Hz steps, 1 – 49 Hz with 1Hz step.

Test #	Test description	Additional requirements and evidence
	is higher than 3, then SCR=3 should be used as minimum SCR.	PSCAD study results should be provided. It is expected that grid-forming BESS provides positive damping to network voltage oscillations in the sub-synchronous frequency range (i.e. attenuation factor less than 1 as per methodology explained in Powerlink's study guide).
4	Response to grid frequency DMAT Test 170 with Pmax (charging) at Qmax and Qmin DMAT Test 174 with Pmax (discharging) at Qmax and Qmin Studies conducted at min and max SCR levels applicable to the connection with site specific X/R ratio.	Test to be conducted with and without PPC frequency control function enabled. PSCAD study results should be provided. It is expected that grid-forming BESS provides an immediate active power response (i.e., inertial response).
5	Short-term overloading capability.	Supporting documents indicating short-term overload capability of inverters to be provided (e.g., xxx% for t1 seconds, yyy% for t2 seconds). Furthermore, PSCAD SMIB study results as indicated below. Phase angle jump tests conducted in PSCAD SMIB model at the maximum SCR applicable to the connection. The following two operating points are to be considered. • Pmax, Qmin • Pmin, Qmax The plant is expected to have sufficient overloading capability to accommodate phase angle jumps of up to ±5° without reaching the inverter's current limit. A short-term overloading duration of up to 1 second is deemed adequate, given the inverter's rapid response to move away from the limit. Zoomed-in plots of three phase instantaneous voltages and currents waveforms at the inverter terminal should also be provided as part of the results. Please refer an example case shown below. Whilst a minimum of ±5° angle jump without reaching the inverter's current limit is to be demonstrated, higher short term overloading capability (~ 1 second) is preferrable.

Note 1: Powerlink's Inverter Based Renewable Plant: GPS Connection Study Process and Expectations document can be provided upon request. Requests should be directed by email to networkassessments@powerlink.com.au.

An illustrative study case is provided in Figure J.1 below, demonstrating that the angle jump (initiated at t=40 seconds) caused the inverters to reach their current limit. In this example, the current limitation resulted in a distorted voltage waveform, that impacts stable voltage waveform support criteria. The plant is typically sized to meet the NER clause S5.2.5.4 requirements for GPS, which includes an approximate 10% margin for overloading.

Our findings suggest that, in addition to meeting S5.2.5.4, an additional 10% short-term overloading capability may be necessary to accommodate a ±5° phase angle jump without reaching the current limit. Figure J.2 illustrates a scenario in which the inverter does not reach its current limit during an angle jump test (initiated at t=20 seconds) demonstrating its ability to provide stable voltage waveform support.

Figure J.1: Inverter's voltage and current waveforms during an angle jump test – reaching current limit

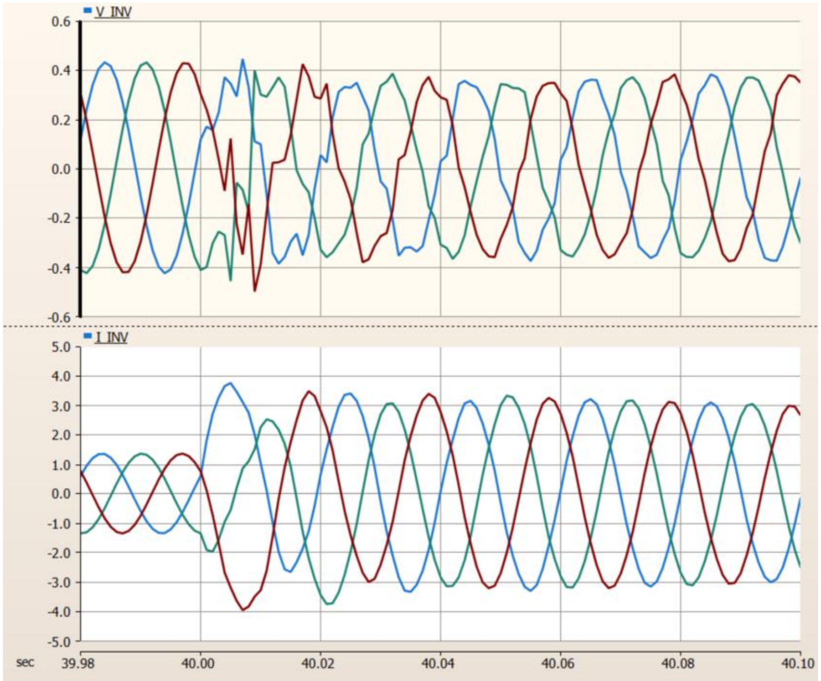
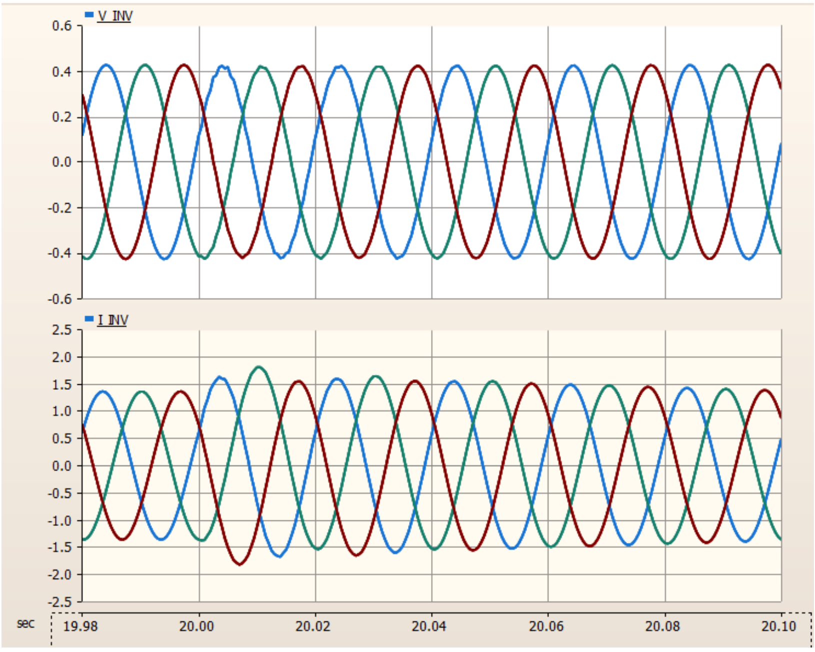


Figure J.2: Inverter's voltage and current waveforms during an angle jump test – not reaching current limit



Appendix K: Compliance Checklists

NER Requirements for RIT-T

Clause 5.16.4(v) of the NER states that a PACR must include the matters detailed in the PADR (as required under clause 5.16.4(k)), and summarise and comment on submissions received on the PADR. This appendix outlines Powerlink's compliance with PADR/PACR content requirements in each sub-paragraph of clause 5.16.4(k).

Table K.1: NER Compliance Checklist

Sub-para	Requirement	Section of PACR
(1)	Description of each credible option	3.2
(2)	Summary of and commentary on submissions to the PSCR/PADR[90]	1.4
(3)	Quantification of costs, including breakdown of operating and capital expenditure Classes of material market benefit for each credible option	Appendix H Appendix G
(4)	Description of methodologies used to quantify each class of material market benefit and cost	Appendix G
(5)	Reasons why a class/classes of market benefit are not material	Appendix G
(6)	Identification and quantification of any class of market benefit estimated to arise outside Queensland	N/A
(7)	Results of NPV analysis for each credible option, and explanation of results	Appendix H
(8)	Identification of preferred option	4.2
(9)	For the preferred option: (i) details of the technical characteristics (ii) the estimated construction timetable and commissioning date (iii) an augmentation technical report from AEMO (iv) a statement that the preferred option satisfies the RIT-T	4.2
(10)	RIT reopening triggers	5.2

N/A denotes not applicable.

[90] Paragraph (v)(2) in clause 5.16.4 requires the PACR to include a response to submissions on the PADR. Powerlink's response to Energy Australia's submission on the PSCR is in section 8.7 of the PADR.

RIT-T Application Guidelines Compliance Checklist

The table below outlines Powerlink's compliance with binding requirements included in the RIT-T Application Guidelines.

Table K.2: RIT-T Application Guidelines Compliance Checklist

Section of Guidelines	Topic	Requirements	Section of PACR
3.2.5	Social licence principles	Consider social licence issues in the identification of credible options, and include information about when and how social licence considerations have affected the identification and selection of credible options.	N/A*
3.4.3	Value of emissions reduction	The VER, reported in dollars per tonne of emissions (CO2 equivalent), is used to value emissions within a state of the world. A RIT-T proponent is required to use the then prevailing VER under relevant legislation or, otherwise, in any administrative guidance.	N/A*
3.5	Valuing costs	Costs are the present value of the following direct costs: • Constructing or providing the credible option; • Operating and maintenance costs; • Costs of complying with relevant laws, regulations and administrative requirements; and • Costs of removing and disposing of existing assets (particularly for asset replacement programs).	Appendix I
3.5.3	Social licence costs	Provide the basis for any social licence costs, including any reference to best practice	N/A*
3.5A.1	Cost estimation accuracy	Outline cost estimation process (as applicable to stage of the RIT-T)	Appendix I
3.5A.2	Cost estimation information	Details of inputs, assumptions and methodologies for each credible option (as applicable to the stage of the RIT-T)[91]	4.3 and Appendix I
3.6	Market benefit classes	Apply classes of market benefits consistently across all credible options	Appendix G
3.7.3	Market benefits	Calculation of changes in Australia's greenhouse gases	N/A*
3.8.2	Sensitivities	Sensitivity analysis on all credible options	Appendix H

[91] Although the provisions in section 3.5A.2 of the RIT-T Application Guidelines are not included in the table of binding requirements at Appendix C of the Guidelines, Powerlink has added them to the compliance checklist as the provisions are expressed as being binding in section 3.5A.2 of the Guidelines.

Section of Guidelines	Topic	Requirements	Section of PACR
3.9.4	Contingency allowance	Details of any contingency allowance included in a cost estimate for a credible option.	N/A*
3.11.2	Concessional finance	Provide sufficient detail about a concessional finance agreement	N/A*
4.1	Community engagement	Description of assessment of requirement for community engagement and, as applicable, how engagement has been undertaken and any relevant concerns sought to be addressed, and how the proponent plans to engage with stakeholder groups.	N/A*

Notes:

N/A denotes not applicable.

* These are new requirements stipulated in revised RIT-T Application Guidelines released by the AER, which came into effect on 6 October 2023 or 21 November 2024. For compliance purposes, the AER only have regard to the guidance that was in effect when Powerlink initiated the RIT-T in question.[92] In this context, initiated means from the publication of a PSCR. As the PSCR was published prior to 6 October 2023, these new requirements are not applicable to this RIT-T for compliance purposes.

[92] AER, *Regulatory Investment Test for Transmission: Application Guidelines*, November 2024, page 7.

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