Powerlink Queensland

Project Assessment Draft Report

24 October 2022

Managing voltages in South East Queensland

Document Purpose

For the benefit of those not familiar with the National Electricity Rules (the Rules) and the National Electricity Market (NEM), Powerlink offers the following clarifications on the purpose and intent of this document:

1. The Rules require Powerlink to carry out forward planning to identify future reliability of supply requirements[1] and consult with interested parties on the proposed solution as part of the Regulatory Investment Test for Transmission (RIT-T). This includes replacement of network assets in addition to augmentations of the transmission network. More information on the RIT-T process and how it is applied to ensure that safe, reliable and cost effective solutions are implemented to deliver better outcomes to customers is available on Powerlink's website.
2. Powerlink must identify, evaluate and compare network and non-network options (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 consumers.
3. The main purpose of this document is to provide details of the identified need, credible options, and technical characteristics of non-network options and categories of market benefits addressed in the assessment. In particular, it presents the results of the NPV analysis of the credible network options, along with any credible non-network options received and identifies the *preferred option* based upon this analysis. The document also seeks feedback on the *preferred option* along with any further information from potential proponents of feasible non-network options to address the identified need.

[1] Such requirements include, but are not limited to, addressing any emerging reliability of supply issues or relevant *ISP actionable projects* identified in the Australian Energy Market Operator's (AEMO) latest Integrated System Plan (ISP), for which Powerlink has responsibility as the relevant Transmission Network Service Provider (TNSP)

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Summary

An increase in the uptake of roof top solar systems and more efficient energy devices within South East Queensland requires Powerlink to take action

Declining minimum flows and an increasing capacitive contribution from more energy efficient appliances and roof top solar systems in the South East Queensland (SEQ) area are increasing the likelihood of non-compliant over-voltage events. The current strategy of switching out selected feeders to ensure ongoing compliance with the National Electricity Rules (the Rules) "voltage of supply at a connection point"[2] requirements, is at the limit of its technical effectiveness. Continued reliance on increasingly onerous reconfigurations of the network will result in higher market costs, reduced system resilience and compromised system security, hence this is not an effective and sustainable strategy.

Consequently, there is an identified need for reliability corrective action that Powerlink must address to ensure operational safety, reliability and that service standards continue to be met.

On 17 December 2021, AEMO declared a Network Support and Control Ancillary Services (NSCAS) gap in southern Queensland. Powerlink issued an Expression of Interest (EOI) on 19 May 2022 requesting additional system security services to address this gap prior to 2023. This RIT-T is looking at longer-term solutions that can be delivered to ensure compliance with voltage management obligations going forward, while minimising costs incurred from addressing the identified need.

Developments since the start of this RIT-T have changed the timing and extent of investment needed and provide more scope for non-network options

This Project Assessment Draft Report (PADR) reflects the second step in the RIT-T process, and follows the publication of the Project Specification Consultation Report (PSCR) on 30 July 2021.

At the time of publishing the PSCR, Powerlink had intended to adopt the expedited process for this RIT-T, which allow for exemption from the PADR stage. However, there have been a number of developments since the PSCR was published, which impact both the extent and timing of the voltage management issues which form the identified need for this RIT-T, as well as the potential solutions to addressing the identified need. In particular:

- a 200MW Battery Energy Storage System (BESS) at Greenbank approaching committed project status and an early works agreement with the 1,026MW MacIntyre Wind Precinct – the presence of each of these projects will provide reactive support which will assist with voltage management in the SEQ area;
- a change in the Rules that will require all generators and BESS to provide reactive power services as part of the automatic access standards from June 2024; and
- various market-led connection enquires for BESS in the SEQ area over the medium to longer term.

Overall these developments change the timing and extent of the identified need for investment in the SEQ network, and also provide potential proponents for network support arrangements that may prove a more flexible and fit-for-purpose solution than additional network investment. Consequently, Powerlink is publishing this PADR to update stakeholders on the identified need for this investment and to facilitate further engagement with prospective proponents of non-network options (NNO).

Two submissions for non-network solutions were received in response to the PSCR

One confidential submission was received to the PSCR that closed on 29 October 2021. However, this submission was later withdrawn by the proponent. The remaining submission was received from CleanCo Queensland, the details of which are confidential and under discussion at the time of PADR publication.

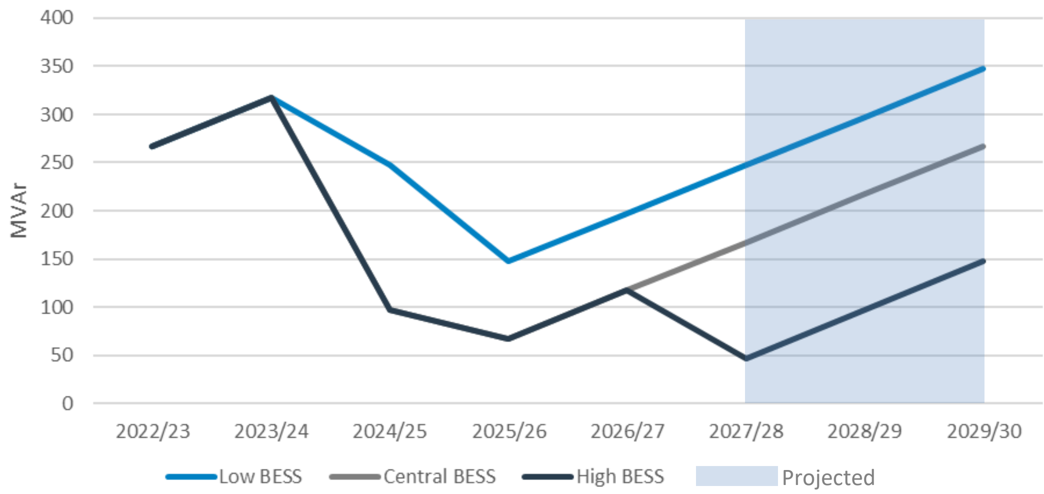
Three options have been considered under three scenarios for future market-led BESS development

In order to reflect uncertainty around future market-led BESS development, Powerlink has developed scenarios reflecting different levels and timing for future BESS developments.

[2] [2] NER, Version 188, 29 September 2022, Schedule 5.1a.4 Power frequency voltage

Figure 1 shows the forecast shortfall in reactive power absorption capability in the SEQ area, under these three scenarios. Under a High BESS scenario, more BESS units are assumed to provide reactive power absorption to the network as part of the Rules automatic access standard requirements. Conversely, the Low BESS scenario assumes only committed and advanced projects eventuate, limiting reactive power absorption from future BESS projects.

Figure 1 Forecast shortfall in reactive power absorption in SEQ



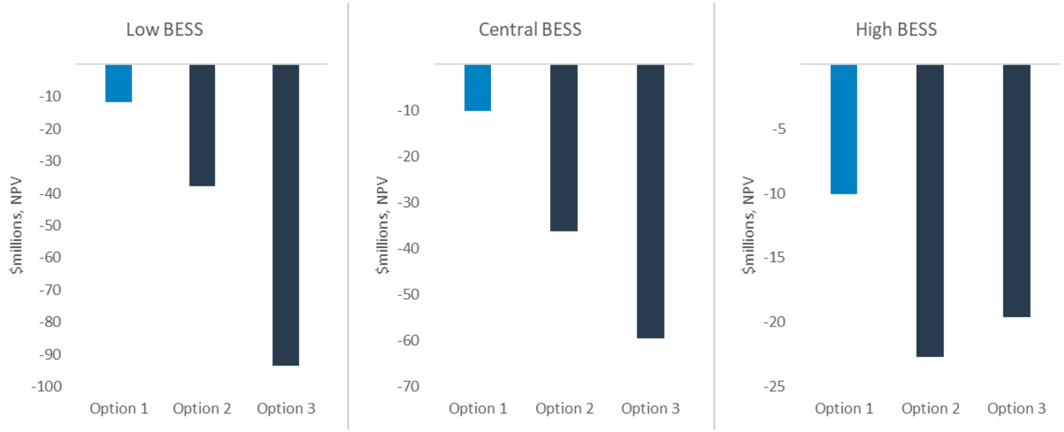
Projected future BESS projects have also allowed consideration of an option that utilises non-network solutions. Powerlink has considered three options in this PADR that all involve a 120MVAr reactor at Belmont to meet the immediate need from 2023/24 onwards, but then approach the identified need with different solutions as voltage issues and reactive power absorption shortfalls evolve.

- Option 1 continues to utilise network support services to address shortfalls capacity for reactive power absorption from either the NSCAS gap network support arrangements and/or BESS units as required.
- Option 2 reflects investment in additional 120MVAr bus reactors in Powerlink's transmission network as required.
- Option 3 involves installing 30MVAr bus reactors in Energex's distribution network as required.

Option 1 has been identified as the preferred network option

Evaluating these options, Option 1 is found to have materially smaller net costs than the other two options under each of the three scenarios and in the weighted scenario relative to the base case. Option 1 minimises costs as it only incurs capital and operating costs for the 120MVAr bus reactor at Belmont and a small amount of fuel costs under the Low BESS scenario for a non-network proponent to provide network support services. Because this option draws on BESS which are expected to enter on a market-led basis, and does not affect the operation of those BESS, there are no additional costs imposed on the market from utilising these non-network solutions. In contrast, Options 2 and 3 involve materially higher capital costs relating to additional reactors, which also attract operating costs.

Figure 2 Net costs under each BESS scenario



Option 1 has therefore been identified as the preferred option. Option 1 involves the installation and commissioning of a 120MVAr bus reactor at Powerlink's Belmont substation for 2023/24, with a capital cost of $13.3 million in 2022/23 prices.

Subsequent to 2023/24, Powerlink would seek to establish network support agreements with non-network option proponents in the SEQ area to meet projected shortfalls in reactive power absorption capability.

Powerlink welcomes submissions to the PADR

Powerlink welcomes submissions from interested stakeholders, including prospective proponents who consider they could offer a non-network solution as part of Option 1.

Lodging a submission with Powerlink

Powerlink is seeking written submissions on this PADR on or before Friday, 9 December 2022.

Please address submissions to:

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Tel: (07) 3860 2328

Submissions can be emailed to: networkassessments@powerlink.com.au

1. Introduction

Powerlink Queensland is a Transmission Network Service Provider (TNSP) in the National Electricity Market (NEM) that owns, develops, operates and maintains Queensland's high-voltage electricity transmission network. This 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.

Powerlink's approach to asset management includes a commitment to sustainable asset management practices that ensure Powerlink provides valued transmission services to its customers by managing risk[3], optimising performance and efficiently managing assets through the whole of asset life cycle[4].

Declining minimum flows and an increasing capacitive contribution from more energy efficient appliances and roof top solar systems in the South East Queensland (SEQ) area are increasing the likelihood of non-compliant over-voltage events. The current strategy of switching out selected feeders to ensure ongoing compliance with the National Electricity Rules' (the Rules) requirements on "*voltage* of *supply* at a *connection point*"[5], is at the limit of its technical effectiveness. As the reactive absorption deficit continues to grow, continued reliance on increasingly onerous reconfiguration of the network[6] will result in reduced system resilience and compromised system security and system strength. This is not an effective and sustainable strategy.

Powerlink must therefore take action to ensure compliance with management of voltages in its transmission network.

On 17 December 2021, AEMO declared a Network Support and Control Ancillary Services (NSCAS) gap in southern Queensland.[7] Powerlink issued an Expression of Interest (EOI) on 19 May 2022 requesting additional system security services to address this gap prior to 2023. This RIT-T is looking at longer-term solutions that can be delivered to ensure compliance with voltage management obligations going forward.

Powerlink has focussed on cost effective options when developing the credible options, delivering positive outcomes for customers. As the proposed credible options to address the identified need include a potential investment in excess of $7 million, Powerlink must assess these options under the Regulatory Investment Test for Transmission (RIT-T).

This Project Assessment Draft Report (PADR) reflects the second step in the RIT-T process, and follows the publication of the Project Specification Consultation Report (PSCR) on 30 July 2021.[8]

At the time of publishing the PSCR, Powerlink had intended to adopt the expedited process for this RIT-T, as allowed for under the Rules, which allow for exemption from the PADR stage. However, there have been a number of developments since the PSCR was published, which impact both the extent and timing of the voltage management issues which form the identified need for this RIT-T, as well as the potential solutions to addressing the identified need. In particular:

- a 200MW Battery Energy Storage System (BESS) at Greenbank[9] approaching committed project status (completion expected in 2024) and an early works agreement with the 1,026MW MacIntyre Wind Precinct[10] (completion expected in 2024) – the presence of each of these projects will provide reactive support which will assist with voltage management in the SEQ area;

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[3] Risk assessments are underpinned by Powerlink's corporate risk management framework and the application of a range of risk assessment methodologies set out in AS/NZS ISO31000:2018 Risk Management Guidelines

[4] Powerlink aligns asset management processes and practices with AS ISO55000:2014 Asset Management – Overview, principles and terminology to ensure a consistent approach is applied throughout the life cycle of assets.

[5] NER, Version 188, 29 September 2022, Schedule 5.1a.4 Power frequency voltage

[6] Switching out more and more 275kV transmission circuits into South East Queensland

[7] Specifically, AEMO declared an immediate Reliability and Security Ancillary Service (RSAS – a type of NSCAS) of approximately 120 megavolt-amperes reactive (MVAr) power absorption, increasing to 250MVAr reactive power absorption by 2026 in southern Queensland. AEMO, *2021 system security reports,* 17 December 2021, p 49.

[8] This RIT-T consultation has been prepared based on the following documents: National Electricity Rules, Version 188, 29 September 2022 and AER, *Regulatory investment test for transmission application guidelines*, August 2020.

[9] See Greenbank Large Scale Battery Connection Project

[10] See MacIntyre Wind Precinct Connection Project

- a change in the Rules that will require all generators and BESS to provide reactive power services as part of the automatic access standards from June 2024, which will assist in managing voltage issues on the network; and
- various market-led connection enquires for BESS in the SEQ area over the medium to longer term. Powerlink expects market-led interest in BESS to be further enhanced by the recently announced Queensland Energy and Jobs Plan, which outlines a number of key renewables targets and actions, to deliver clean, reliable and affordable energy for Queenslanders.[11]

Overall these developments change the timing and extent of the identified need for investment in the SEQ network, and also provide potential proponents for network support arrangements that may prove a more flexible and fit-for-purpose solution than additional network investment. Consequently, Powerlink has elected to publish this PADR to update stakeholders on the identified need for this investment and to facilitate engagement with prospective proponents of non-network options.

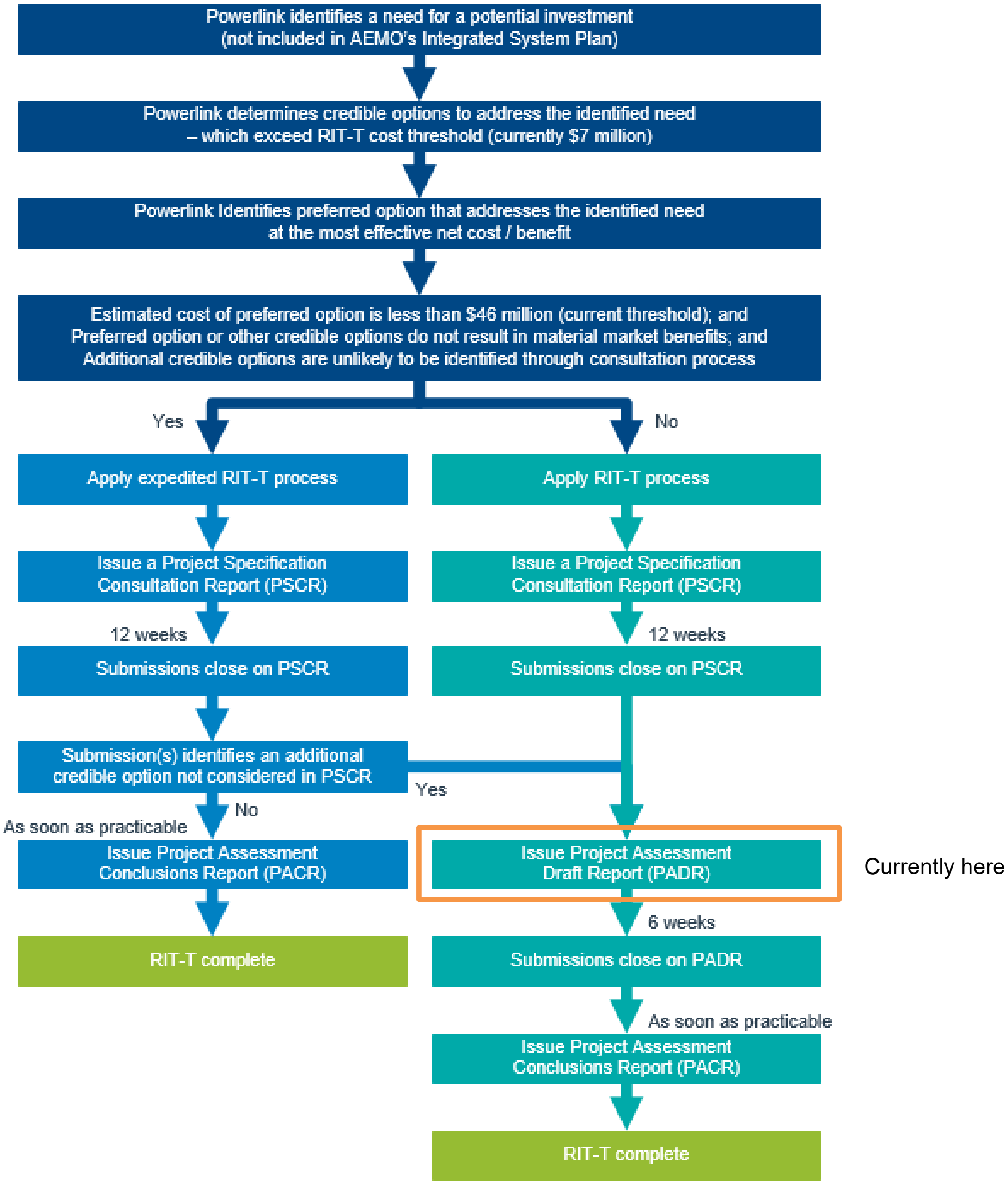
This PADR:

- describes the reasons why Powerlink has determined that investment is necessary (the 'identified need'), and how the extent and timing of the voltage management issues have changed since the PSCR, together with the assumptions used in identifying this need;
- provides a summary of the consultation processes to date and submissions to the PSCR;
- describes the credible options that Powerlink considers may address the identified need, which have been updated since the PSCR;
- discusses why Powerlink does not expect market benefits to be material for this RIT-T;[12]
- presents the Net Present Value (NPV) economic assessment of each of the credible options; compared to the Base Case (as well as the methodologies and assumptions underlying these results) – which is an update of the NPV economic assessment presented in the PSCR;
- identifies and provides a detailed description (including the estimated construction timetable and commissioning date) of the credible option that satisfies the RIT-T, and is therefore the preferred option; and
- provides stakeholders with the opportunity to comment on this assessment so that Powerlink can refine the analysis (if required) as part of the Project Assessment Conclusions Report (PACR), which is the final step in the RIT-T process.

Figure 1-1 sets out both the full RIT-T process and the expedited process for non-actionable ISP RIT-T projects and identifies where this PADR fits within the RIT-T process.

[11] https://www.epw.qld.gov.au/energyandjobsplan
[12] As required by clause 5.16.1(c)(iv) of the Rules.

Figure 1-1 RIT-T process overview for projects not defined as an actionable ISP project



2. Stakeholder engagement and consultation on the PSCR

Powerlink is committed to a proactive approach to engagement with consumers and other stakeholders. Our general approach to engagement throughout the network planning process was set out in section 2 of the PSCR. Powerlink encourages those stakeholders who are interested in understanding our general engagement activities in more detail to refer to the PSCR.

As part of this RIT-T process, Powerlink has undertaken consultation in relation to the PSCR that amongst other things, presented the technical requirements that non network solutions would have to satisfy.[13] Interested parties were invited to submit written submissions as part of the public consultation process on the PSCR, which ended on 29 October 2021.

[13] Required technical characteristics for non-network options can be found in section 4 of the PSCR.

2.1 Summary of submissions received

Powerlink received two submissions to the PSCR, both relating to non-network solutions, one of which was received after the PSCR closure date. Powerlink engaged directly with each potential proponent on their proposals. One of the potential proponents subsequently withdrew their confidential proposal. The remaining potential proponent, CleanCo Queensland, welcomed the opportunity to develop their non-network solution, and we are engaging further at the time of PADR publication to finalise the confidential details of their non-network solution.

Separate to this RIT-T, Powerlink has undertaken an EOI process to meet the near term NSCAS gap identified by AEMO, which reflects a separate regulatory requirement under the Rules (discussed in section 3.4.1). Proponents of non-network solutions from this EOI process have been advised of the publication of this PADR, and are encouraged to make submissions where they consider they may be able to be a proponent for a network support solution under the options considered in this RIT-T.

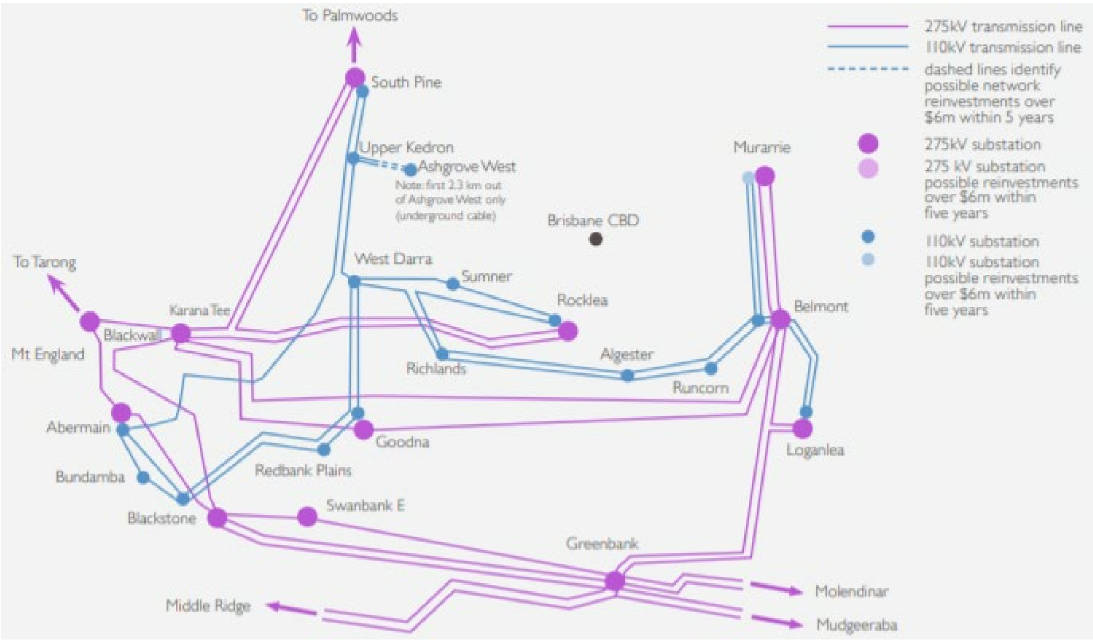
3. Identified need

This section provides a description of the network in the SEQ area, and the context in which the identified need arises, including assumptions and requirements underpinning the identified need. It describes how the identified need has evolved since the publication of the PSCR and the drivers for these changes.

3.1 Geographical and network need

The ongoing impact of over-voltage events in SEQ extends from Woolooga in the north, to Mudgeeraba in the south and west to Blackstone, with the majority of affected substations located within the Moreton and Gold Coast transmission zones[14]. The impacted grid sections service a population of approximately 4 million people and over 190,000 businesses.

Figure 3-1 Greater Brisbane transmission network



3.2 Increasing voltage risks associated with a rapidly transitioning energy system

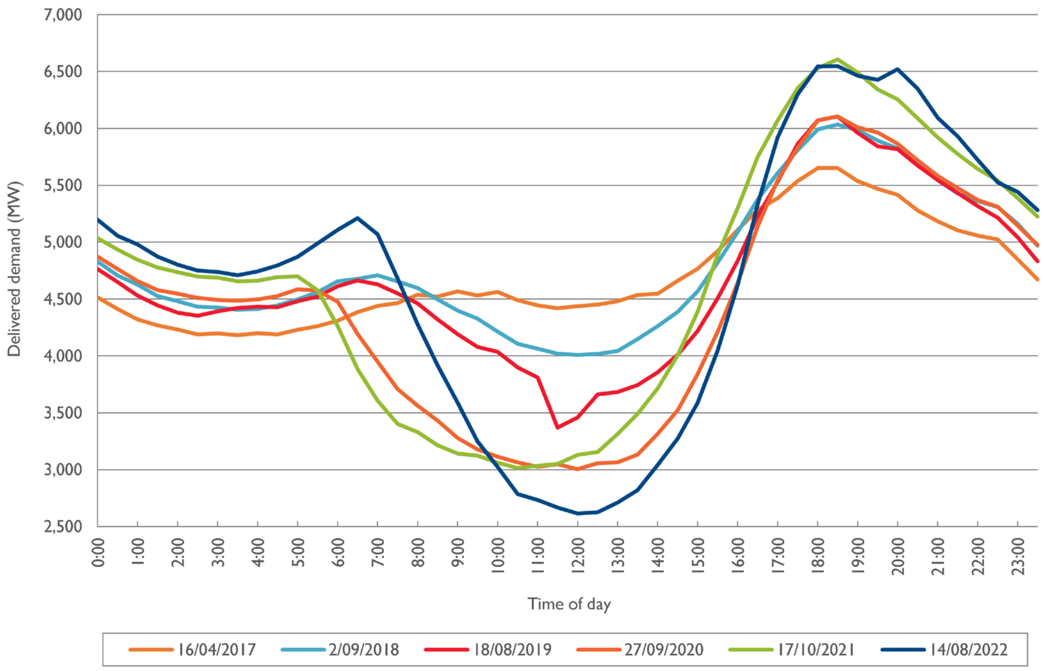
The large scale uptake of roof top solar systems and the use of more efficient energy devices have resulted in a substantial decline in the amount of reactive power being absorbed within the distribution network.

[14] This relates to the standard geographic definitions (zones) identified within Powerlink's Transmission Annual Planning Report (TAPR).

The uptake of rooftop solar systems within Queensland has been one of the highest per capita rates in the world, with over 700,000 installed rooftop PV systems totalling an aggregate state-wide capacity of more than 3,300MW.

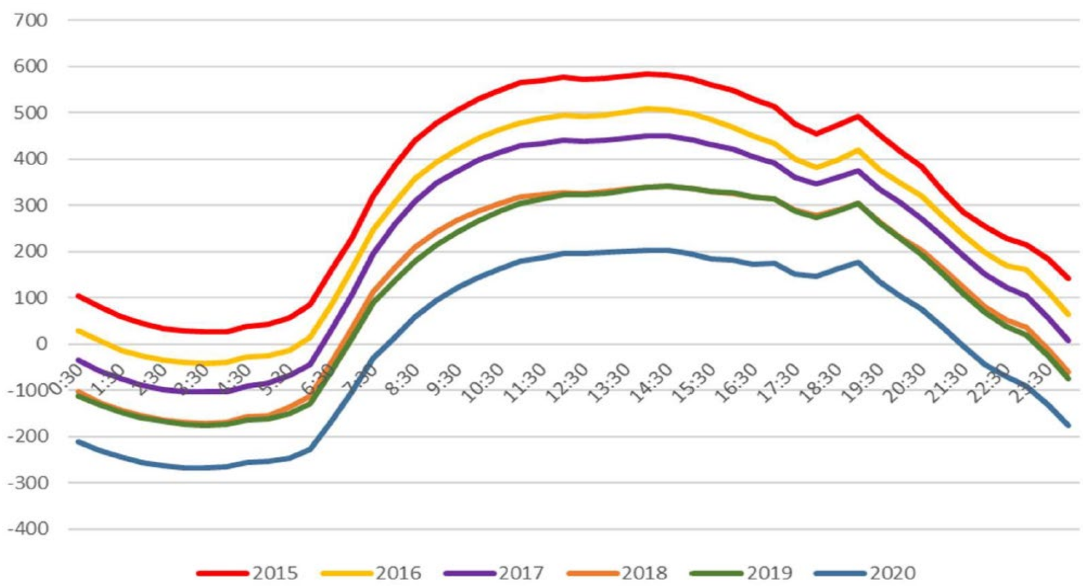
This rapid increase in small scale rooftop PV systems has substantially reduced the overall minimum demand in the system (Figure 3-2).

Figure 3-2 Transmission delivered Queensland minimum demand: 2017 – 2022



Since 2016, the decline in minimum daytime demand has been coupled with an increasing net injection of reactive power to the transmission network across the day. (Figure 3-3)

Figure 3-3 Average spring MVAr load on the Energex distribution network



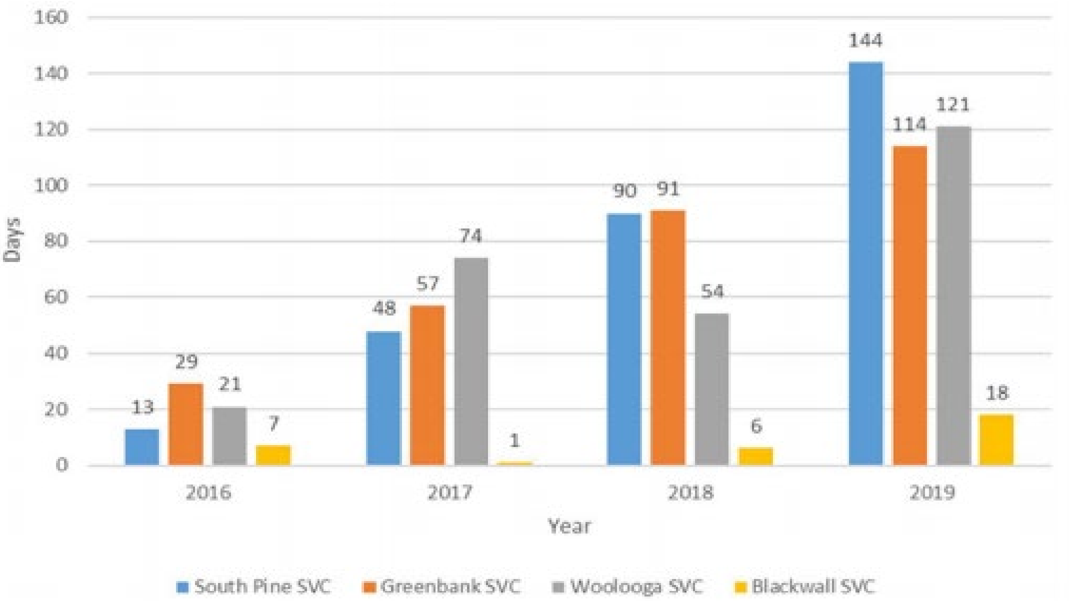
Changes in the load's leading power factor has seen system voltages increasingly approach allowable limits during normal operating conditions. Even though the loads are higher in the early hours of the morning, the greater leading MVArs[15] during the early hours of the morning (refer to Figure 3-3) result in an increased likelihood of over-voltage events during these times following a reactive power contingency. As the loads in the middle of the day continue to reduce, these system conditions may also become more difficult to manage.

The reduction of the nominal low voltage level within the distribution network from 240V to 230 volts further exacerbates this need.

This combination of declining minimum daytime demand and a worsening leading power factor has resulted in a deficit of reactive power absorption capability in the SEQ transmission network. Without additional reactive absorption capacity there is a growing potential for sustained over-voltage events, substantially reducing the network's current ability to operate within the voltage limits prescribed in the Rules[16].

Good electricity industry practice is to maintain sufficient headroom in the system to be able to manage disturbances so that voltages do not exceed allowable safe limits. Under system normal conditions, the dynamic reactive plant (Static Var Compensators or SVCs) at South Pine, Greenbank, Woolooga and Blackwall Substations are increasingly operating at their limits, where they would become ineffective in responding to network disturbances. The instances when these SVCs were at their inductive limits during normal operating conditions are increasing rapidly (Figure 3-4). With the SVCs functioning near capacity, the allowable 275kV operational voltage limits may be exceeded under key reactive plant outages.

Figure 3-4 Number of days where SVCs were at their inductive limit.



In the next seven years, the over voltage issue is expected to worsen as growth in the number of rooftop PV installations and leading MVArs continue in SEQ.

However, counteracting the effect of increased rooftop PV installations are potential future developments in the SEQ area that could reduce the scale of overvoltage issues. These developments are discussed in the following section.

3.3 Developments since the PSCR have changed the scale of over-voltage concerns and the expected deficit in reactive power absorption capacity.

Since the publication of the PSCR, several developments have occurred that have changed the scale of the identified need, including:

- the Greenbank BESS approaching committed project status and an early works agreement being concluded with the MacIntyre Wind Precinct;

[15] Reactive power (MVAr) that is not consumed by the load but rather flows from the load into the transmission network.

[16] The Rules, Schedule 5.1a.4 Power frequency voltage

- application of automatic access standards to BESS connections from June 2024; and
- multiple prospective market-led BESS projects.

These developments affect the level of over-voltage and the expected shortfall in the capacity of the network to absorb reactive power going forward. A discussion of each of these developments and how scenarios have been adopted in this RIT-T to account for uncertainty in future market-led BESS investments are provided below.

3.3.1 Automatic access standards to apply to BESS connections

Changes to the NER due to commence on 3 June 2024 will apply automatic access standards to connections,[17] including renewable generation and BESS connections (referred to in the rule change as an 'integrated resource'), so as to require them to meet certain characteristics with regard to reactive power. Box 3-1 summarises the rules for automatic access standards.

Box 3-1 Incoming rule for automatic access standards[18]

Rules commencing on 3 June 2024, set out automatic access standards for connections to the electricity network, including for reactive power.

Specifically, changes to NER S5.2.5.1(a) provide that:[19]

> *The automatic access standard is [that] a generating system or integrated resource system operating at:*
>
> *(1) any level of active power; and*
>
> *(2) any voltage at the connection point within the limits established under clause S5.1.a.4 without a contingency event,*
>
> *must be capable of supplying and absorbing continuously at its connection point an amount of reactive power of at least the amount equal to the product of the rated active power of the generation system or integrated resource system and 0.395.*

The forthcoming access standards effectively require BESS as well as generating systems to provide reactive power absorption capacity to the network, thereby alleviating over voltage issues.

In practical terms, the new Rule means that connections to the transmission network will be required to maintain the capability to absorb reactive power to a certain level, including new generation or BESS connections. This change will contribute to alleviating over-voltage issues in the SEQ area. Importantly, while the automatic access standards require connections to provide reactive power absorption capability, doing so does not affect the operations of those systems and their ability to participate in the wholesale electricity market.

The extent to which this will alleviate over-voltage issues will depend on the number of BESS that connect in the SEQ area. This is uncertain and this uncertainty is taken into account in this RIT-T through the adoption of scenarios (see section 6.2).

3.3.2 Connection developments since the PSCR

Two connection developments[20] have occurred since the publication of the PSCR which change the extent of the near-term over-voltage issues in the SEQ network:

- Powerlink has signed an early works agreement to connect the MacIntyre Wind Precinct (1,026MW, including MacIntyre and Karara Wind Farms), enabling construction to commence, with completion expected in 2024/25. The MacIntyre Wind Precinct is expected to contribute up

[17] For the purposes of this PADR, Powerlink has assumed that the rule change and the requirement on new connections with respect to reactive power capability commences for the full financial year in 2024/25. See NER S5.2.5 for the requirement on connections.
[18] See Integrating energy storage systems into the NEM | AEMC
[19] See AEMC, *Final consolidated rule*, 2 December 2021, NER S5.2.5.1(a).
[20] These projects satisfy AEMO's committed project criteria, and are further described on the Powerlink web page.

to 150MVAr of reactive power absorption under light load conditions as a consequence of its connection.

- A new 200MW BESS at Greenbank,[21] which has progressed to an agreement between Powerlink and CS Energy, with completion and commissioning anticipated in 2024/25. The Greenbank BESS is expected to provide 120MVAr of reactive power when it connects.

The provision of reactive power absorption capability does not affect the operations of either the MacIntyre Wind Precinct or the Greenbank BESS, or their ability to participate in the wholesale electricity market.

3.3.3 More energy storage systems are expected to be installed going forward

In addition to the MacIntyre Wind Precinct and Greenbank BESS, market-led developments of BESS are expected to increase the amount of energy storage systems in the SEQ area.

Under AEMO's step change scenario in its Integrated System Plan (ISP), 16GW of utility scale battery and pumped hydro storage is projected to connect to the NEM by 2050 to firm renewable generation.[22] For Queensland, AEMO forecasts the need for approximately 2GW of medium and deep storage to support renewable energy developments by 2030/31.[23] This increases to 6GW, complementing over 10GW of shallow storage at utility scale or within the distribution system when all Queensland coal fired generation retire.[24] It follows that at least part of the expected investments in energy storage will be at grid scale in the form of BESS units.

Powerlink is aware of several interested parties (through direct connection enquiries and its separate BESS EOI process[25]) who are investigating BESS investments totalling over 1,000MW in the SEQ area. These projects are currently in various stages of development. As renewable generation continues to develop, the need for grid scale BESS and connections to the network will also increase.

Table 3-1 lists potential BESS systems that Powerlink is aware of at the time of this PADR that may connect into the SEQ area. These potential BESS are expected to connect into the SEQ area around the mid-2020s, if they proceed.

Table 3-1 Potential BESS developments

BESS development	Indicative timing	BESS size	MVAr capacity
BESS A	2025/26	200MW	120MVAr
BESS B	2024/25	200MW	120MVAr
BESS C	2025/26	300MW	180MVAr
BESS D	2027/28	300MW	180MVAr

These prospective projects are indicative of the developments that may occur in the SEQ area, and Powerlink's expectation is that if these particular projects do not proceed, there are likely to be others that would take their place. Any BESS projects from 2024/25 would add to reactive power absorption capability in the SEQ area if and when they connect, as part of their obligation to meet the automatic access standards (see Box 3-1). Similar to the MacIntyre Wind Precinct and Greenbank BESS, the provision of reactive power absorption capability will not affect the operation of prospective BESS units or their capacity to participate in the wholesale electricity market.

Consequently, new BESS and renewable generation connections in the SEQ area are expected to reduce the scale of the identified need into the future, compared with that anticipated at the time of the PSCR. The development of multiple prospective BESS projects means that there will be a redundancy in the provision of reactive power across these developments, such that in the longer term Powerlink does not expect there will be a need to enter into network support agreements to ensure provision of this reactive support. The scale of reduction will depend on the number and size

[21] See Powerlink's Greenbank BESS announcement: https://www.powerlink.com.au/projects/greenbank-large-scale-battery-connection-project.
[22] AEMO, *2022 Integrated System Plan*, June 2022, p 9-10.
[23] AEMO, *2022 Integrated System Plan*, June 2022, p 56.
[24] AEMO, *2022 Integrated System Plan*, June 2022, p 56.
[25] See Powerlink Large-scale Battery Energy Storage System EOI

of BESS developments and the timing of their connections to Powerlink's transmission network, which is uncertain at this time.

While new BESS and generation connections are expected to alleviate the scale of the identified need, they do not by themselves fully resolve over-voltage issues in the SEQ area. Reactive power absorption shortfalls are still forecast to emerge in the near term, which will require a solution prior to the end of 2022/23,[26] as well as over the medium to longer term depending on the size and scale of future BESS and generation connections. Where there are only a limited number of BESS and/or should additional reactive absorption capability be required over and above the automatic access standard, Powerlink may enter into network support agreements with those BESS operators to ensure that the capability is available.

Powerlink has developed scenarios reflecting different levels and timing for potential BESS developments to take account of those uncertainties – discussed further below and in section 6.2.

3.3.4 New BESS connecting in the SEQ area will reduce the deficit in reactive power absorption capability

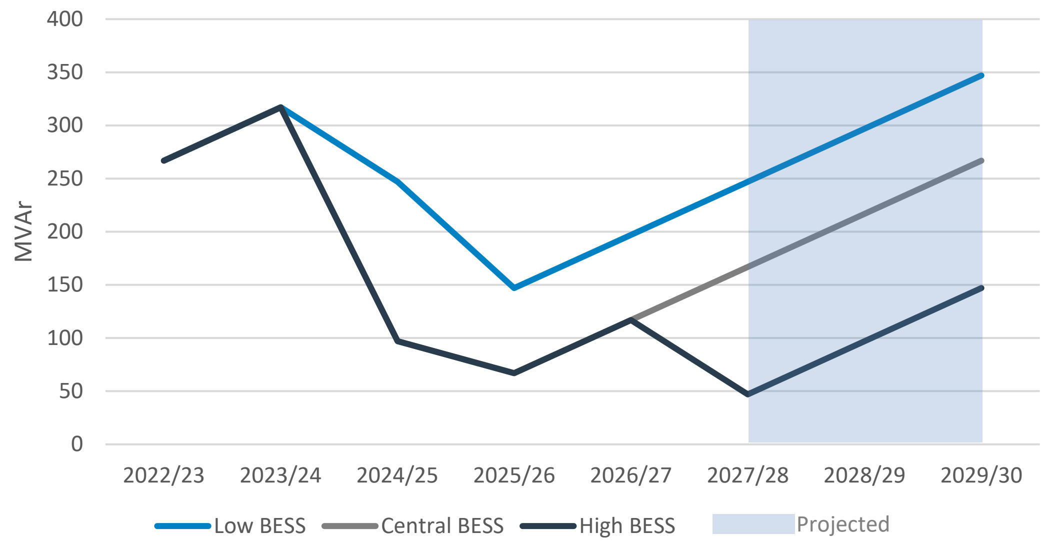
Three scenarios have been developed to account for the uncertainty in future BESS and generation connections that act to reduce reactive power absorption shortfalls.

Figure 3-5 sets out forecasts of shortfalls capacity under each scenario, reflecting the level of shortfall that needs to be addressed to maintain system security at an N-1 secure[27] net gap level from 2022/23 to 2029/30.

Under the central BESS scenario, the required MVAr reduces in the medium term from a peak of 317MVAr in 2022/23 to a low of 67MVAr in 2025/26 as the MacIntyre Wind Precinct, Greenbank BESS and other BESS units are assumed to connect. The required MVAr then increases again as over-voltage issues continue to grow.

Under the low BESS scenario, the decrease in the required MVAr is less pronounced than the other two scenarios as less BESS are assumed to connect. In contrast, the high BESS scenario assumes connections of BESS into 2027/28 and therefore the required MVAr is lower for longer compared to the low or central BESS scenarios.

Figure 3-5 Forecast shortfall in reactive power absorption in SEQ



The forecasts after 2027/28 for each scenario presented in Figure 3-5 do not include any further BESS or generation connections beyond those included in the scenarios, given the lack of information and uncertainty around potential future connections. However, future policy and market-led developments are expected to involve more BESS units or other connections that will further

[26] AEMO has also declared an immediate NSCAS gap, which is discussed further in section 3.4.1.
[27] N-1 secure net gap level is the additional reactive power absorption capability required to cover the loss of a reactive power device and then reposition the power system (allowing for the switching of up to two 275kV transmission circuits) for a further reactive power device contingency.

reduce the shortfall in reactive power absorption capacity in the SEQ area below the levels shown at the end of the period.

Options developed and considered in this PADR will need to meet the identified need by addressing the shortfall in reactive power absorption depicted in Figure 3-5, but also taking into account the three BESS scenarios so as to avoid overinvestment in network solutions where market-led BESS development may instead alleviate the over-voltage issues.

3.4 Description of identified need

The proposed investment addresses the need to ensure Powerlink's ongoing compliance with Schedule 5.1 of the Rules and is categorised as 'reliability corrective action' under the Rules[28].

Schedule 5.1a of the Rules sets minimum standards for network service providers that:

(a) are necessary or desirable for the safe and reliable operation of the *facilities* of *Registered Participants*

(b) are necessary or desirable for the safe and reliable operation of equipment

(c) could reasonably be considered *good electricity industry practice*

S5.1a.4 states that under system normal conditions, the voltage at a connection point must not exceed 1.1 per unit. Following a credible contingency, the voltage at a connection point must be able to be restored to less than 1.1 per unit in less than 1 second. With the SVCs at South Pine, Greenbank, Woolooga and Blackwall Substations being utilised to the point where they would be unable to respond to credible network disturbances following a credible contingency, resulting in non-compliant over-voltages within the associated 275kV network.

S5.1.2.1 of the Rules also states "*Network Service Providers must plan, design, maintain and operate their transmission networks….to allow the transfer of power from generating units to Customers ….*" With reactive plant at capacity, obtaining outages for maintenance work is becoming increasingly difficult. Switching out lines during low load and/or low power transfer periods, to help gain access for reactive plant maintenance, reduces system strength.

Under current system normal conditions, peak operating voltages are at or near Powerlink's operational limits, while dynamic reactive plant is at its limit. Studies indicate that the current reactive capacity of the grid in this area would be unable to provide the necessary management of voltages under the forecast declines in electricity demand and increasing net capacitive load. There is a need for Powerlink to address these emerging issues to ensure ongoing compliance with Schedule 5.1 of the Rules and applicable regulatory instruments, which are designed to ensure Powerlink's customers continue to receive safe, reliable and cost effective electricity services.

The network options were identified through the joint planning project process between Energex and Powerlink. Powerlink is acting as lead party undertaking the regulatory investment test in accordance with Clause 5.14.1(e) of the Rules.

A reliability corrective action differs from that of an increase in producer and consumer surplus (market benefit) driven need in that the preferred option may have a negative net economic outcome because it is required to meet an externally imposed obligation on the network business.

3.4.1 AEMO declaration of a NSCAS gap and interactions with the current RIT-T

AEMO declared an NSCAS gap in southern Queensland on 17 December 2021 after the commencement of this RIT-T in August 2021. Specifically, AEMO declared an immediate Reliability and Security Ancillary Service (RSAS – a type of NSCAS) gap of approximately 120MVAr reactive power absorption, increasing to 250MVAr reactive power absorption by 2026 in southern Queensland.[29][

In the first instance,[30] Powerlink, as the TNSP, is responsible for acquiring NSCAS services to address NSCAS gaps in Queensland as declared by AEMO. Accordingly, Powerlink issued an EOI on 19 May 2022 requesting additional power system security services to address the immediate

[28] The Rules clause 5.10.2 ,Definitions, reliability corrective action
[29] AEMO, *2021 system security reports,* 17 December 2021, p 49. RSAS is a form of NSCAS

[30] The Rules Clause 3.11.1(c)(2)(i) and (ii)

RSAS gap, until the preferred option identified as a result of this RIT-T consultation can be put in place.

The EOI process to address the immediate need is anticipated to be completed by the end of 2022, with a network support agreement in place by this date. Any immediate term solutions delivered through the EOI process have been treated as common across all options and reflected in the base case. Where technically and economically feasible, the immediate term submissions received in the EOI process have also informed Powerlink's consideration of the longer-term options assessed in this PADR.

4. Potential credible options to address the identified need

As the identified need arises from a combination of factors across two networks, Powerlink as the TNSP and Energex as the DNSP, have conducted a joint assessment of the emerging over-voltage issues in SEQ to determine the cause and develop credible network options.[31] This PADR therefore includes network options from both Powerlink and Energex to address the identified need for additional voltage control capacity in SEQ.

Developments described in section 3.3 have meant credible options identified in the PSCR have been revised, to reflect that market-led BESS investments over the next decade are expected to alleviate much of the future deficit in reactive power absorption capacity.

All are technically feasible and address the identified need in a timely manner. The three credible options included in this PADR analysis incorporate varying degrees of flexibility to meet the identified need, depending on the extent of market-led BESS investment in the Base Case under each scenario (see section 3.3).

All three options share the 120MVAr reactor at Belmont with commissioning in 2023/24 as a common component, which will address the immediate identified need from 2023/24 onwards.

In the longer term, the three options considered in this PADR approaches the identified need differently:

- Option 1 continues to utilise network support services to address shortfalls capacity for reactive power absorption from either the NSCAS gap network support arrangements and/or BESS units as required. Option 1 is introduced as a new option in this PADR (from the PSCR) that relies on non-network solutions, which has become feasible due to developments since the publication of the PSCR (see section 3.3);
- Option 2 reflects investment in additional 120MVAr bus reactors in Powerlink's transmission network as required. Option 2 adopts the same approach to Option 2[32] considered in the PSCR, involving the installation of bus reactors located in the transmission network; and
- Option 3 involves installing 30MVAr bus reactors in Energex's distribution network as required. Option 3 adopts the same approach to Option 3 considered in the PSCR, involving the installation of bus reactors in the distribution network.

All options are designed to maintain voltages within operational and design limits and keep the power system in a secure operating state and reduce the impact on network reliability resulting from de-energising the 275kV transmission lines. Each option is discussed below.

4.1 Option 1 - Install a 120MVAr bus reactor and utilise network support contracts as required

This option first involves a 120MVAr bus reactor to be commissioned at Powerlink's Belmont substation in 2023/24. The reactor would be connected into existing bays.

Subsequent to 2023/24, Powerlink would seek to establish network support agreements with non-network option proponents in the SEQ area to meet shortfalls in reactive power absorption capability. The level of network support services required will depend on the extent of market-led BESS connections, which in turn affects the level of reactive power absorption shortfall that has to be addressed. BESS units to be contracted by Powerlink are expected to proceed as market-led

[31] The Rules S5.14.1, Joint planning obligations of Transmission Network Service Providers and Distribution Network Service Providers
[32] Option 1 in the PSCR also adopted this approach, but has been rescoped in this PADR to reflect the increased adoption of non-network solutions, as described above.

developments that are independent of this RIT-T, and so will not have any incremental capex or opex costs outside of the Base Case.

Network support from two BESS units would be contracted for under the central BESS scenario, while network support from only one BESS would be required under the high BESS scenario. In the low BESS scenario, network support would continue to be contracted from the NSCAS gap network support arrangements as it is assumed that there are limited opportunities to contract with BESS under the low BESS scenario.

Contracting with BESS for network support under Option 1 is not expected to influence the ability of the BESS to bid into the wholesale market, and so will have no wholesale market impacts.

Powerlink is the proponent for the bus reactor under this option. Powerlink is seeking potential proponents for the non-network components of this option.

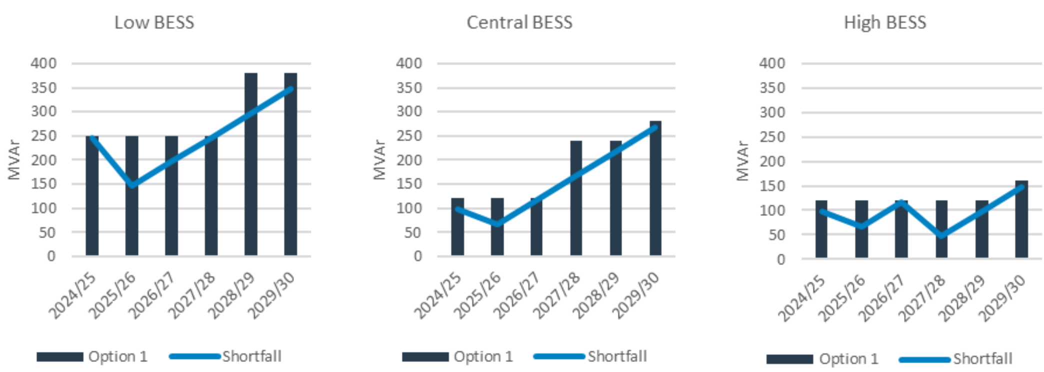
Table 4-1, sets out a summary of Option 1 under each scenario with indicative dates denoting when bus reactors are commissioned or when network support contracts are in effect.

Table 4-1 Summary of Option 1 under each BESS scenario

Option 1	Low BESS scenario	Central BESS scenario	High BESS scenario
Key solutions in Option 1			
120MVAr Belmont reactor	2023/24	2023/24	2023/24
Incremental network support from network support agreement	2023/24 to 2029/30	2023/24	2023/24
Incremental network support from BESS		BESS A in 28/29 BESS B in 29/30	BESS B in 29/30
Option cost estimates			
Total TNSP capital cost	$13.3 million	$13.3 million	$13.3 million
Annual TNSP opex cost	$9,000 to $16,000	$9,000 to $16,000	$9,000 to $16,000
Annual network support costs	Confidential		
Annual NNO incremental opex costs	Confidential		

The network support capability required to absorb reactive power under Option 1 will vary with the shortfall under each scenario. Figure 4-1 illustrates the shortfall under each scenario compared to the incremental MVAr that will be provided under Option 1.

Figure 4-1 Shortfall in each scenario compared to MVAr under Option 1



Option 1 capital costs for Powerlink are estimated to be $13.3 million and relate to the 120MVAr Belmont reactor. Annual operating costs for Powerlink are assumed to be between $9,000 and $16,000.

The incremental network support costs from a network support agreement for Option 1 cannot be reproduced in the PADR analysis at this time for confidentiality reasons. NNO opex costs are assumed to be zero under the Central and High BESS scenario.

4.2 Option 2 - Install a 120MVAr bus reactor, and installation of additional Powerlink reactors as required

Like Option 1, Option 2 will first involve a 120MVAr bus reactor to be established at Powerlink's Belmont substation in 2023/24. After 2023/24, up to two additional 120MVAr SEQ bus reactors could be established in Powerlink's transmission network, depending on the BESS scenario. Powerlink is the proponent of this network option.

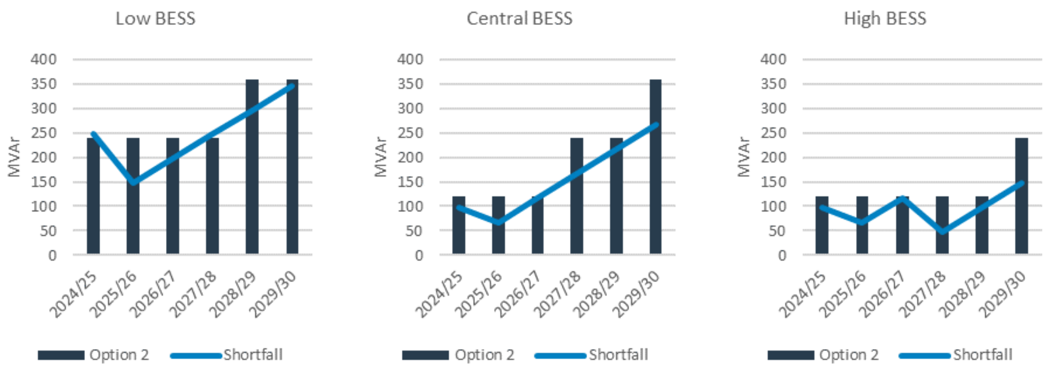
Table 4-2 sets out a summary of Option 2 under each scenario with indicative dates denoting when bus reactors are commissioned or when network support contracts are in effect.

Table 4-2 Summary of Option 2 under each BESS scenario

Option 2	Low BESS scenario	Central BESS scenario	High BESS scenario
Key solutions in Option 2			
120MVAr Belmont reactor	2023/24	2023/24	2023/24
Incremental network support from network support agreement	2023/24	2023/24	2023/24
120MVAr SEQ reactor	1 reactor in 24/25 1 reactor in 28/29	1 reactor in 27/28 1 reactor in 29/30	1 reactor in 29/30
Option cost estimates			
Total TNSP capital cost	$39.8 million	$39.8 million	$26.5 million
Annual TNSP opex cost	$9,000 to $45,000	$9,000 to $46,000	$9,000 to $30,000

Figure 4-2 illustrates the shortfall under each scenario compared to the incremental MVAr under Option 2, showing the capacity developed to absorb reactive power under Option 2 will vary with the shortfall under each scenario.

Figure 4-2 Shortfall in each scenario compared to MVAr under Option 2



Capital costs for Option 2 are estimated to be $39.8 million (central scenario). Annual operating costs for reactor components are assumed range between $9,000 and $46,000 (central scenario).

4.3 Option 3 - Install a 120MVAr bus reactor, and additional 30MVAr bus reactors across the Energex network as required

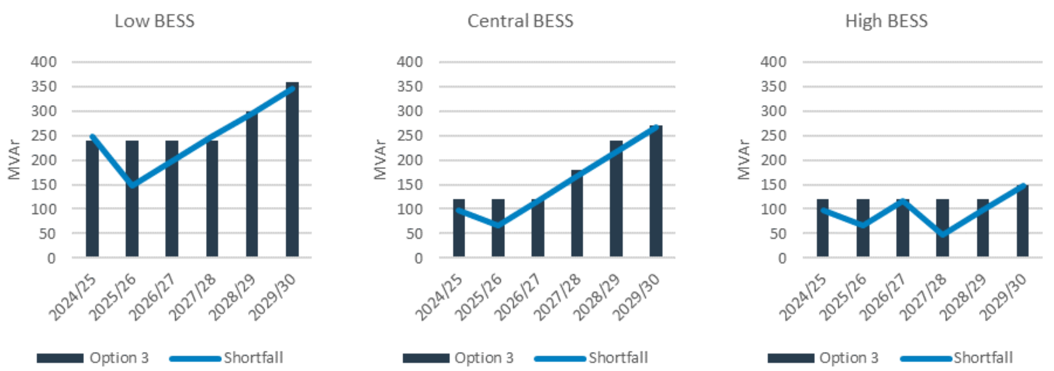
Under this Option, Energex would install up to eight 30MVAr reactors across its distribution networks on the Gold and Sunshine Coasts, as well as the Greater Brisbane area. These would be connected in the distribution network, based upon available substation space across the network. Energex is the proponent of this network option.

Table 4-3 Summary of Option 3 under each BESS scenario

Option 3	Low BESS scenario	Central BESS scenario	High BESS scenario
Key solutions in Option 3			
120MVAr Belmont reactor	2023/24	2023/24	2023/24
Incremental network support from network support agreement	2023/24	2023/24	2023/24
30MVAr DNSP reactors	4 reactors in 24/25 2 reactors in 28/29 2 reactors in 29/30	2 reactors in 27/28 2 reactors in 28/29 1 reactor in 29/30	1 reactor in 29/30
Option cost estimates			
Total TNSP capital cost	$13.3 million	$13.3 million	$13.3 million
Total DNSP capital cost	$80 million	$50 million	$10 million
Annual TNSP opex cost	$9,000 to $16,000	$9,000 to $16,000	$9,000 to $16,000
Annual DNSP opex cost	Up to $45,000	Up to $27,000	Up to $6,000

As with other options, the capacity developed to absorb reactive power under Option 3 will vary with the shortfall under each scenario. Figure 4-3 illustrates the shortfall under each scenario compared to the incremental MVAr under Option 3.

Figure 4-3 Shortfall in each scenario compared to MVAr under Option 3



Capital costs for Option 3 are estimated to be $63.3 million (central scenario). Annual operating costs for reactor components are assumed to range from $9,000 to $43,000 (central scenario).

4.4 Cost of non-network options and network support agreements

Option 1 involves network support from non-network option proponents that attracts network support payments.

The treatment of resource costs (for both capital and operating costs) for non-network options in NPV modelling will depend on whether those costs are incurred as a consequence of credible options or if those costs are or will be incurred independently as a consequence of market-led investment.[33]

4.4.1 Treatment under the RIT-T of resource costs resulting from the RIT-process

If resource costs are incurred directly because an option (or part thereof) is developed as the result of a proponent's submission to the RIT-T process, then those costs are reflected in the RIT-T assessment as part of the cost of the non-network option (as they are not assumed to occur in the Base Case). For example, if an option requires a BESS to be commissioned that would otherwise not exist in order to provide network support services, then the capital cost and operating cost of that BESS would count toward that option.

[33] AER, *Final Decision, Guidelines to make the Integrated System Plan actionable*, August 2020, p 26 and 52.

4.4.2 Treatment of resource cost occurring through market-led development

In contrast, if a BESS was or will be commissioned independently of an option (ie, is a market-led development) but can also provide network support services without incurring incremental costs, then the capital and operating cost of the BESS would be reflected in the Base Case and not in the cost of the option.

4.4.3 Treatment of network support payments

Separately to the treatment of resource cost of non-network options is the treatment of network support payments paid to non-network option proponents.

These payments from Powerlink to non-network option proponents are considered under the RIT-T to be transfers between NEM participants, and therefore are required to be netted off to zero against network support receipts received by non-network option proponents. Consequently, these network support payments and receipts do not influence RIT-T NPV analysis outcomes or the identification of the preferred option.

However, the options need to be both technically feasible and economically feasible to be considered a credible option under the RIT-T. This constrains the amount of network support payments that can be paid to a proponent, as these payments need to be approved by the AER as prudent and efficient in order for the option to be economically feasible.[34] This should encourage non-network proponents to propose reasonable network support costs.

4.5 Options considered but not progressed

The earlier PSCR included two other options. Powerlink has further considered these options in the light of the change in the extent of the forecast voltage issues, and has decided not to progress consideration of these options. The reasons these options are not progressed are summarised in the table below.

Table 4-4 Options considered but not progressed

Option	Reason(s) for not progressing
Install a total of 3x 120MVAr bus reactors at Woolooga, Blackstone and Greenbank Substations in Powerlink's South East Queensland Transmission Network from 2022 (i.e. Option 1 in the PSCR)	Due to connection developments and expected connection developments of BESS in the SEQ area and the change in the automatic access standard, three bus reactors are not necessary, and no longer economically feasible relative to other lower cost options to meet the identified need.
Install a total of 3x 120MVAr bus reactors at Woolooga, Blackstone and Belmont Substations in Powerlink's SEQ Transmission Network from 2022 (i.e. Option 2 in the PSCR)	Due to connection developments and expected connection developments of BESS in the SEQ area and the change in the automatic access standard, three bus reactors are not necessary, and no longer economically feasible relative to other lower cost options to meet the identified need.

4.6 Material inter-network impact

Powerlink does not consider that any of the credible options being considered will have a material inter-network impact, based on AEMO's screening criteria[35].

[34] The AER approves the pass through of network support payments annually under Rule 6A.7.2.
[35] In accordance with Rules clause 5.16.4(b)(6)(ii). AEMO has published guidelines for assessing whether a credible option is expected to have a material inter-network impact.

5. Materiality of market benefits

The Rules require that all categories of market benefits identified in relation to a RIT-T be quantified, unless the TNSP can demonstrate that a specific category is unlikely to be material to the option rankings.[36] This section sets out Powerlink's consideration of the materiality of market benefits.

5.1 Market benefits modelled in this RIT-T assessment

Powerlink's considers that there are no material market benefits that are incremental to the Base Case from the credible options considered.

Benefits modelled in this RIT-T assessment arise from avoided costs compared to those incurred in the Base Case, which informs the identification of the preferred option that minimises net costs. The costs incurred in the Base Case which are avoided by the options are discussed in section 6.2.1

5.2 Market benefits that are not material for this RIT-T assessment

A number of classes of market benefits are not material in the RIT-T assessment and therefore have not been estimated.

In particular, the non-network option (Option 1) considered in the PADR (and the non-network component of other options) will not have an impact on the wholesale electricity market, as the non-network option only relies on generator and BESS assets that are already in the Base Case for network support and only to the extent that it does not affect generator and BESS operations. Consequently, generation and BESS assets operate no differently under the non-network option compared to the Base Case, and therefore the non-network option does not affect the wholesale market so as to give rise to wholesale market benefits.

A discussion of each market benefit under the RIT-T that is considered not material is presented below:

- **changes in fuel consumption arising through different patterns of generation dispatch:** the options do not result in changing patterns of generation dispatch compared to the Base Case as they do not impact patterns of consumption or levels of demand.
- **changes in voluntary and involuntary load curtailment:** while the installation of additional reactive power plant will mitigate against the need to de-energise lines, due to the meshed nature of the network in the area, the impact on load shedding is not considered material.
- **changes in costs for parties, other than the RIT-T proponent:** the proposed installation of reactors on the network by the proponent to meet the requirements of S5.1 of the Rules, does not affect the timing of new plant, capital costs or operational and maintenance costs for other parties.
- **differences in the timing of unrelated network expenditure:** as all three options are designed to provide similar operational outcome and address the potential breach of a mandatory service standard, it is unlikely any potential transmission investment at a future date will be materially impacted differently between the three options.
- **changes in ancillary service costs:** developments in market-led BESS investments since the PSCR has changed the market benefits that can be realised under the options considered. Changes in ancillary service costs are no longer considered likely to be material or to affect the identification of the preferred option.
- **competition benefits:** due to the localised nature of the voltage issues**,** Powerlink does not consider that any of the credible options will materially affect competition between generators, and generators' bidding behaviour and, consequently, considers that the techniques required to capture any changes in such behaviour would involve a disproportionate level of effort compared to the additional insight it would provide.
- **Option value**: the estimation of any option value benefit over and above that already captured via the scenario analysis in the RIT-T would require significant modelling, which would be disproportionate to any additional option value benefit that may be identified. No additional option value has therefore been estimated for this RIT-T.

[36] S3.6.1 Material classes of market benefits, AER, Regulatory investment test for transmission application guidelines, August 2020

- **the negative of any penalty paid or payable:** Powerlink does not consider the reactive plant proposed will in any material way impact its obligation to meet any relevant government-imposed instruments.

6. Base Case

6.1 Modelling a Base Case under the RIT-T

Consistent with the RIT-T Application Guidelines the assessment undertaken in this PADR compares the costs and benefits of the credible options developed to address the risks arising from an identified need, with a Base Case[37].

As characterised in the RIT-T Application Guidelines, the Base Case itself is not a credible option to meet the identified need. In developing the Base Case, the emerging over-voltage issues in SEQ are assumed to be able to be managed by the ongoing switching out of 275kV feeders and the dispatching of off-line synchronous generators to provide reactive support in the system (assumed as part of a continuation of the NSCAS contract). The reactive capability availed by these actions do not meet the full need as the N-1 secure gap continues to grow.

Accordingly, the Base Case provides a clear reference point in the cost benefit analysis to compare any credible options (network or non-network).

6.2 Base Case assumptions and reasonable scenarios adopted for the RIT-T

Given the specific and localised nature of the over-voltage limitations, the detailed market modelling using ISP scenarios from the most recent Input Assumptions and Scenario Report represents a disproportionate cost in relation to the scale of the proposed network investment, and will not materially impact the ranking of options.[38] Furthermore, the size of over-voltage limitations in the SEQ network area will be most affected by the development of renewable generation and BESS facilities over the next decade.

Consequently, Powerlink has chosen to present three scenarios reflecting a range of possible renewable generation and BESS developments between 2024/25 and 2027/28, which in turn will determine the scope of network solutions and non-network solutions for each credible option considered. This approach is consistent with the requirements for reasonable scenarios in the RIT-T instrument [39] and in accordance with the provisions of the RIT-T Application Guidelines.[40]

In calculating the costs required to address emerging over-voltage events during light load conditions, the following measures have been modelled:

- switching of up to two 275kV circuits between south west and south east Queensland. The costs associated with switching of feeders as a strategy to manage over-voltages (advanced equipment replacement and an estimate for increased project costs) has been estimated within the Base Case; and
- dispatch of synchronous generating units within the greater Queensland network to absorb excess reactive power as part of the NSCAS gap agreement currently being established.

Alleviating over-voltages in the Base Case are connecting wind generators and BESS projects that will provide reactive power absorption capacity, both in the near term (ie, the Greenbank BESS and the MacIntyre Wind Precinct), and in the future, as part of the automatic access standards for connections under the NER (see Box 3-1).

Under the Base Case, generation and BESS units have the potential to contribute between 120MVAr and 180MVAr and are assumed to be installed and commissioned between 2024/25 and 2027/28. However, there is uncertainty as to the timing and scale of future BESS connections. Therefore, three Base Case scenarios have been developed that incorporate committed and advanced projects (ie, the Greenbank BESS and the MacIntyre Wind Precinct), and uncertainty relating to future BESS development into the NPV analysis:

[37] AER, Regulatory investment test for transmission application guidelines, August 2020
[38] AER, Final: RIT–T, August 2020, sub-paragraph 20(b)
[39] AER, Final: RIT–T, August 2020, sub-paragraph 22
[40] S3.8.1 Selecting reasonable scenarios, RIT-T Application Guidelines, August 2020

- under the Low BESS scenario, only committed and advanced new generation and BESS projects are assumed: ie, Greenbank BESS is assumed to be commissioned for 2024/25 and MacIntyre Wind Farm is assumed to be commissioned for 2025/26[41];
- under the central BESS scenario, in addition to the Greenbank BESS and MacIntyre Wind Precinct (both assumed to be operational for 2024/25), an additional BESS is assumed to be commissioned for 2024/25, with a further BESS assumed to be commissioned for 2025/26; and
- under the high BESS scenario, in addition to the committed and projected BESS in the central scenario, two further projected BESS units are included: an additional BESS for 2025/26 and a further BESS commissioned for 2027/28.

In the high BESS scenario, less action will need to be taken by Powerlink compared to the central BESS scenario as there are more generating and integrated resource systems to provide reactive power absorption capacity through their connections (as a consequence of the new automatic access standards) that can be used to manage over voltage issues. Conversely, under the low BESS scenario, more action will be required compared to the central BESS scenario as there are fewer generating and integrated resource systems in the Base Case to provide reactive power absorption capacity. Table 6-1 sets out the assumed connections in the Base Case under three BESS scenarios.

Table 6-1: Connection assumptions in the Base Case under each scenario

Connections	Status	MW	MVAr capacity	Low BESS	Central BESS	High BESS
Greenbank BESS	Committed[42]	200	120	24/25	24/25	24/25
MacIntyre Wind Precinct	Early works	1,100	150	25/26	24/25	24/25
BESS A	Projected	200	120		24/25	24/25
BESS B	Projected	200	120		25/26	25/26
BESS C	Projected	300	180			25/26
BESS D	Projected	300	180			27/28
Scenario weighting				25%	50%	25%

The Central BESS scenario is given a weight of 50%, reflecting a view that the Central BESS scenario is most likely to occur. The Low and High BESS scenarios each have a weight of 25%, reflecting the view that these scenarios are less likely to occur than the Central BESS scenario. However we note that the NPV assessment for this RIT-T shows that the option ranking is the same under each of the three scenarios, and so the weightings applied to the scenarios do not affect the RIT-T outcome. For other variables and parameters, Powerlink has elected to adopt the same parameter values across all three scenarios, set out in Table 6-2 as they are unlikely to change the outcome of the analysis.

Table 6-2 Other parameters for reasonable scenarios assumed

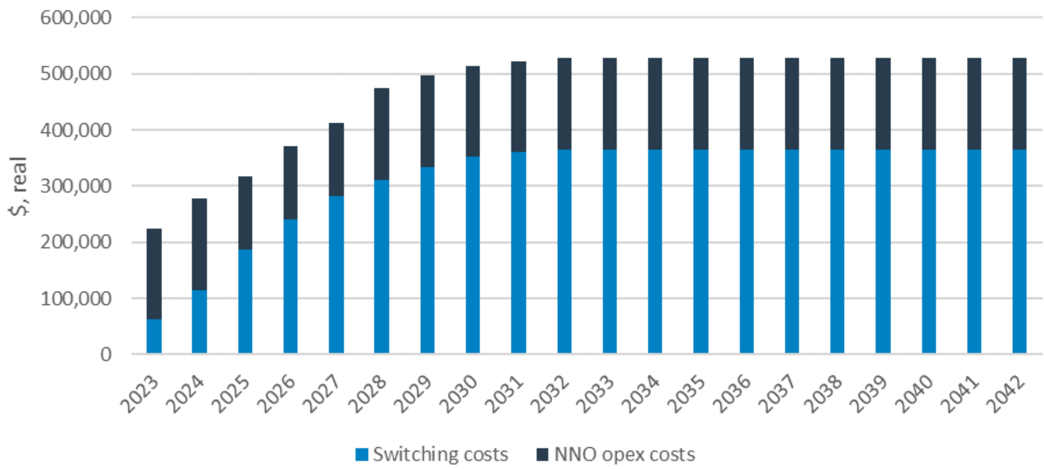
Variables and parameters	Description
Capital costs	100% of baseline capital cost estimate
Discount rate	5.50%
Maintenance costs	100% of baseline maintenance cost estimate
Market benefits	100% of baseline market benefit projection

[41] Powerlink has adopted the convention where, for example, ‘commissioned for 2024/25' means that commissioning occurs between 1 July 2024 and 30 June 2025.
[42] Commercially committed, easement acquisition finalisation pending to achieve RIT-T commitment

6.2.1 Base Case costs

The main cost categories in the base case are changes in the cost of network losses due to increased feeder switching and the operating costs incurred in providing network support services under the network support contract Powerlink in entering into in response to the NSCAS gap. Under the Base Case, this network support arrangement is assumed to continue to be needed and these costs increase over the first 10 years, and are then assumed to level off from 2032/33 at $524,000 per year in real terms.

Figure 6-1 Annual Base Case cost projections



6.3 Modelling of Option costs

All three options have been modelled to deliver the minimum required reactive capacity to meet the identified need.

The costs that are incurred in the Base Case are able to be avoided under the options assessed in this RIT-T, and so are shown in the analysis as ‘avoided costs’ for each option. These avoided costs are included with the capital and operational costs of each option to develop the NPV inputs.

7. General modelling approach adopted to assess net benefits

7.1 Analysis period

The RIT-T analysis has been undertaken over a 20-year period, from 2022/23 to 2041/42. A 20-year period takes into account the size and complexity of the additional reactive plant.

There will be remaining asset life by 2041/42, at which point a residual value[43] is calculated to account for any future benefits that would accrue over the balance of the asset’s life.

7.2 Discount rate

Under the RIT-T, a commercial discount rate is applied to calculate the NPV of the costs and benefits of credible options. Powerlink has adopted a real, pre-tax commercial discount rate of 5.50% as the central assumption for the NPV analysis presented in this report.[44]

Powerlink has 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 2.30%[45] and an upper bound discount rate of 7.5%.[44]

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[43] Residual value was calculated based on remaining asset value using straight-line depreciation over the capital asset life

[44] A central discount rate of 5.5% is based on AEMO’s Integrated System Plan, which represents AEMO’s view of a commercial discount rate for a network business in the NEM. A high discount rate of 7.5% is also provided by AEMO. See AEMO, 2022 Integrated System Plan, June 2022, p 91.

[45] The lower bound pre-tax real discount rate of 2.3% reflects the most recent AER determination for a TNSP, which is from the AER’s Determination 2022-27 for Powerlink, published in April 2022. See AER, *Final decision – Powerlink transmission determination 2022-27 Roll forward model*, April 2022.

8. Net present value results

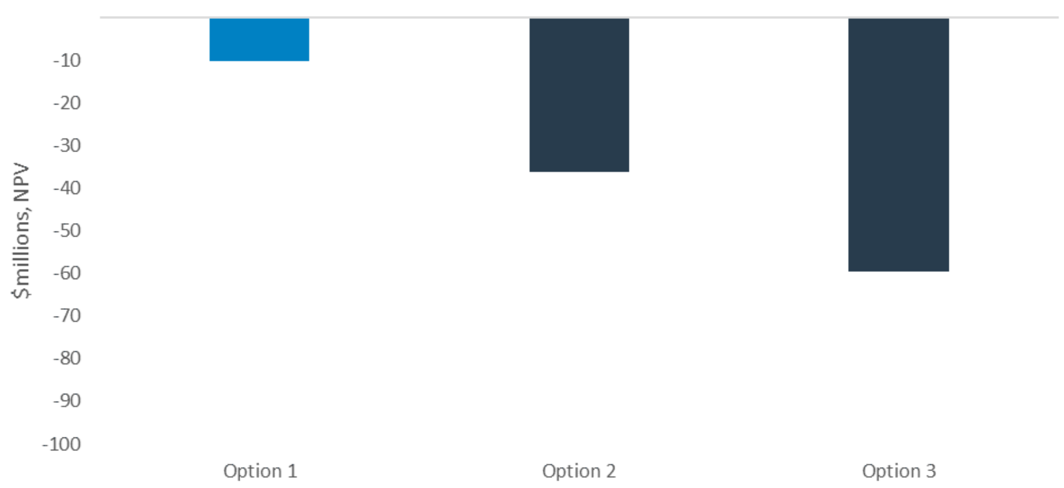
This section outlines the results of the assessment Powerlink has undertaken of the credible options for this RIT-T for each scenario and the weighted outcome.

8.1 Central BESS scenario

The central BESS scenario represents the most likely scenario in terms of future BESS developments, including commissioning of Greenbank BESS (120MVAr), MacIntyre Wind Precinct (150MVAr), and BESS units with 80MVAr capability from 2024/25 and 2025/26 respectively.

Under the central BESS scenario, Option 1 is found to be the top ranked option and delivers approximately $10.2 million in net costs, which is significantly lower than Option 2 (net cost of $36.3 million) or Option 3 (net cost of $59.5 million).

Figure 8-1 Summary of the estimated net benefits under the central BESS scenario

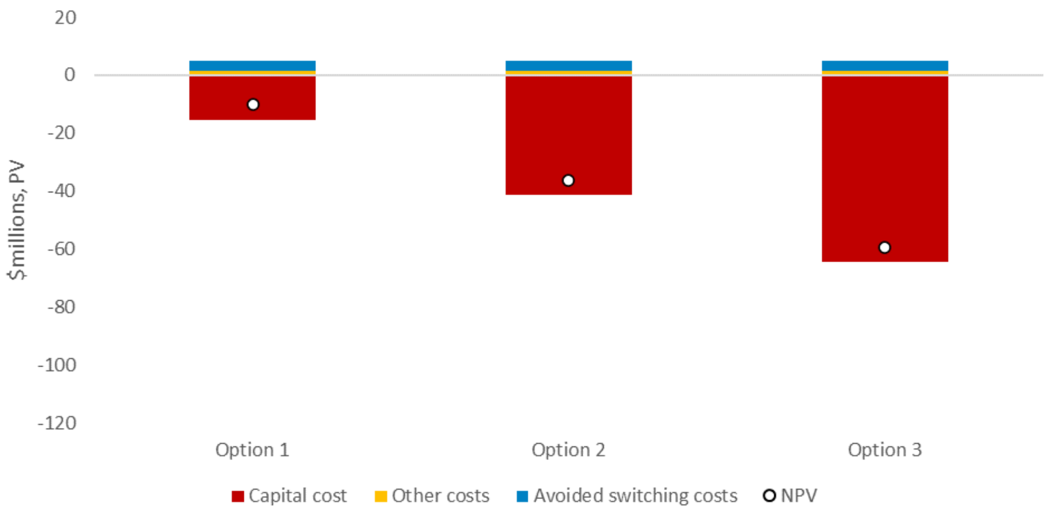


The limited net cost under Option 1 is due to this option only requiring incremental resource costs incurred for the Belmont reactor. In contrast, both Options 2 and 3 have additional network expenditure on the addition reactor elements. Option 3 incurs the most net cost, as the cost of each 30MVAr reactor is higher for each MVAr of capacity when compared to 120MVAr reactors under Option 2.

Figure 8-2 provides a breakdown of each option under the central BESS scenario, where Option 1 is shown to have the lowest cost. Almost all the cost of each option relates to capital cost, with only relatively marginal operating costs incurred.

Benefits under each option relate to avoided switching costs, which are the same across all options considered.

Figure 8-2 Breakdown of present value costs and benefits under the central BESS scenario



8.2 Low BESS scenario

The Low BESS scenario represents a low level of market-lead BESS developments, which includes commissioning of Greenbank BESS in 2024/25 providing 120MVAr, and MacIntyre Wind Precinct in 2025/26 providing 150MVAr.

Under the low BESS scenario, Option 1 is found to be the top ranked option and has approximately $11.8 million in net costs. Option 2 (net cost of $37.9 million) and Option 3 (net cost of $93.4 million) incur higher net costs under the low BESS scenario as more reactors are needed to meet the shortfall in reactive power absorption capacity.

Figure 8-3 Summary of the estimated net benefits under the low BESS scenario

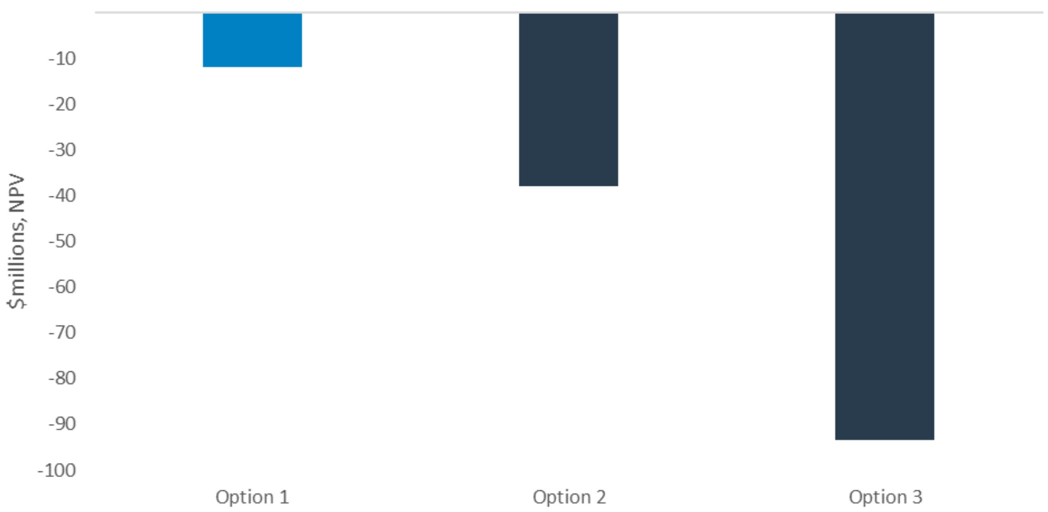
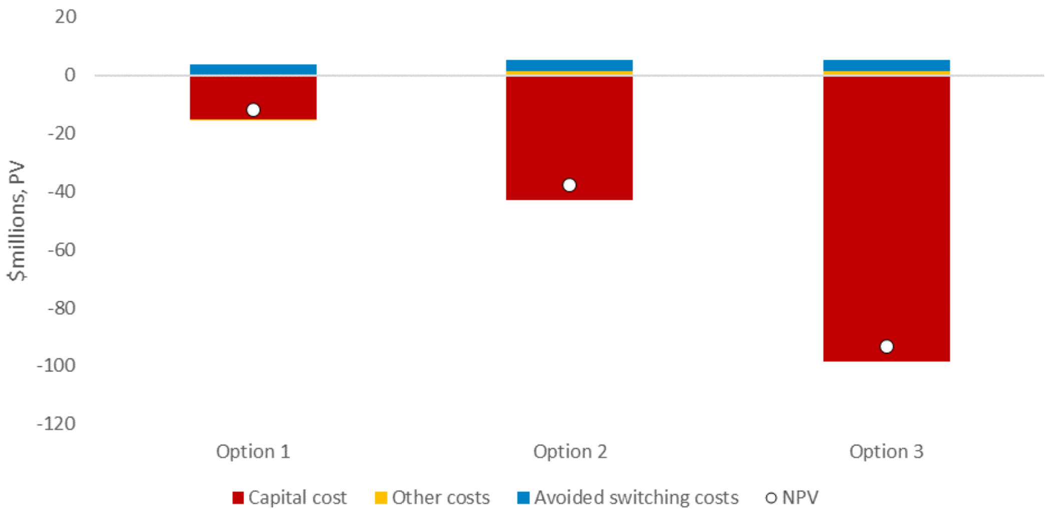


Figure 8-4 provides a breakdown of each option under the low BESS scenario. As in the central BESS scenario, Option 1 has the smallest costs, of which nearly all of the costs relate to capex.

Figure 8-4 Breakdown of present value costs and benefits under the low BESS scenario



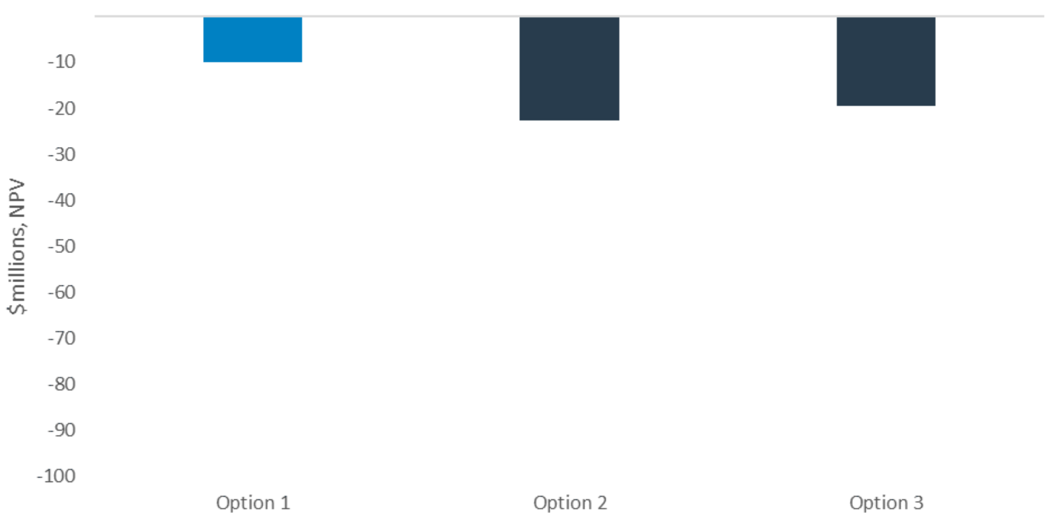
8.3 High BESS scenario

The high BESS scenario represents a high level of market-lead BESS developments, including commissioning of:

- Greenbank BESS (120MVAr), MacIntyre Wind Precinct (150MVAr), and a BESS unit (80MVAr capability) in 2024/25;
- two BESS units in 2025/26 providing 200MVAr in total; and
- one BESS in 2026/27 providing 120MVAr.

Under the high BESS scenario, Option 1 is found to be the top ranked option incurring approximately $10.1 million in net costs that mainly relates to the cost of the Belmont reactor common to all three options.

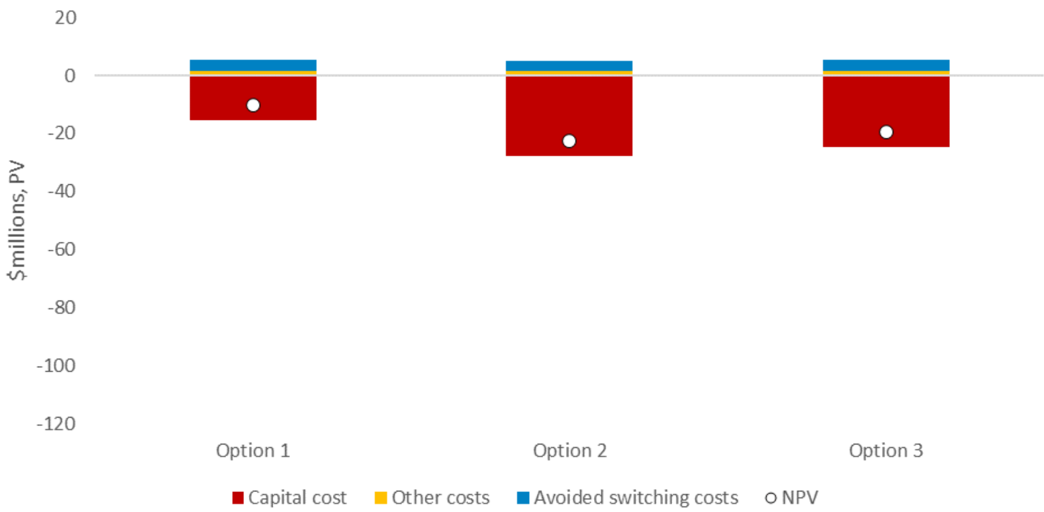
Figure 8-5 Summary of the estimated net benefits under the high BESS scenario



Option 3 under the high BESS scenario has lower net costs than option 2, which arises due to only requiring one 30MVAr reactor additional to the Belmont reactor that costs less than the additional 120MVAR reactor required under Option 2.

Figure 8-6 provides a breakdown of each option under the low BESS scenario. As in the central BESS scenario, Option 1 has the smallest gross costs, and therefore the smallest net costs.

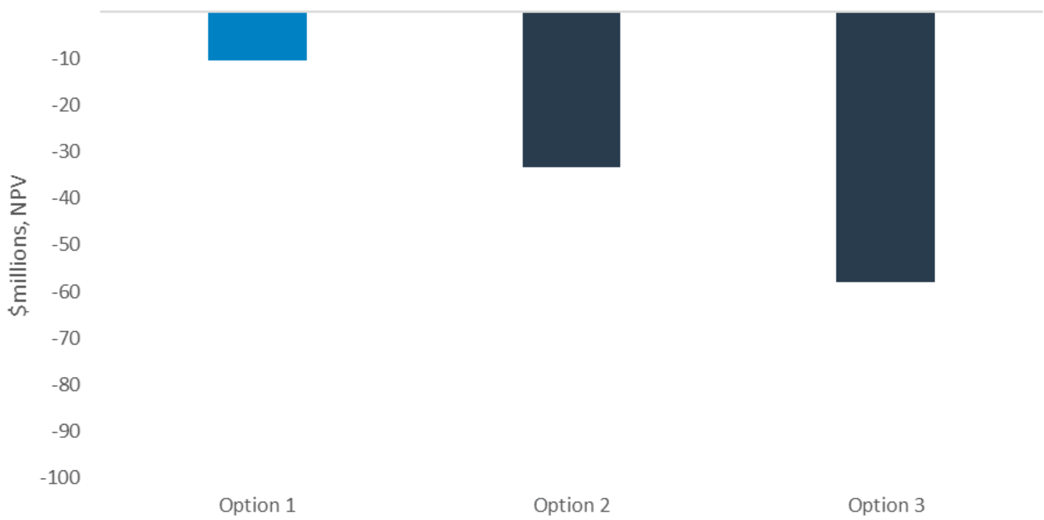
Figure 8-6 Breakdown of present value costs and benefits under the high BESS scenario



8.4 Weighted net benefits

Figure 8-7 shows the estimated net benefits for each of the credible options weighted across the three scenarios investigated (as discussed above) using weightings as set out in Table 6-1.

Figure 8-7 Summary of the estimated net benefits, weighted across three different scenarios



8.5 Sensitivity analysis

Sensitivity analysis was carried out to test the robustness of the analysis resulting in the preferred option and to determine if any factors would change the relative ranking of the credible options assessed:

The following sensitivities on key assumptions were investigated:

- a range from 75% to 125% of base capital expenditure estimates;
- a range from 2.30% to 7.50% for the discount rate; and
- a range from 75% to 125% of maintenance expenditure estimates.[46]

[46] Sensitivity only relates to maintenance expenditures (ie routine and reactive maintenance), and does not include operating costs related to switching.

Table 8-1 show the impacts of varying the discount rate, capital expenditure and operating & maintenance expenditure on the NPV relative to the Base Case. Option 1 (in **bold**) remains the preferred option under all sensitivities tested.

Table 8-1 Sensitivity analysis

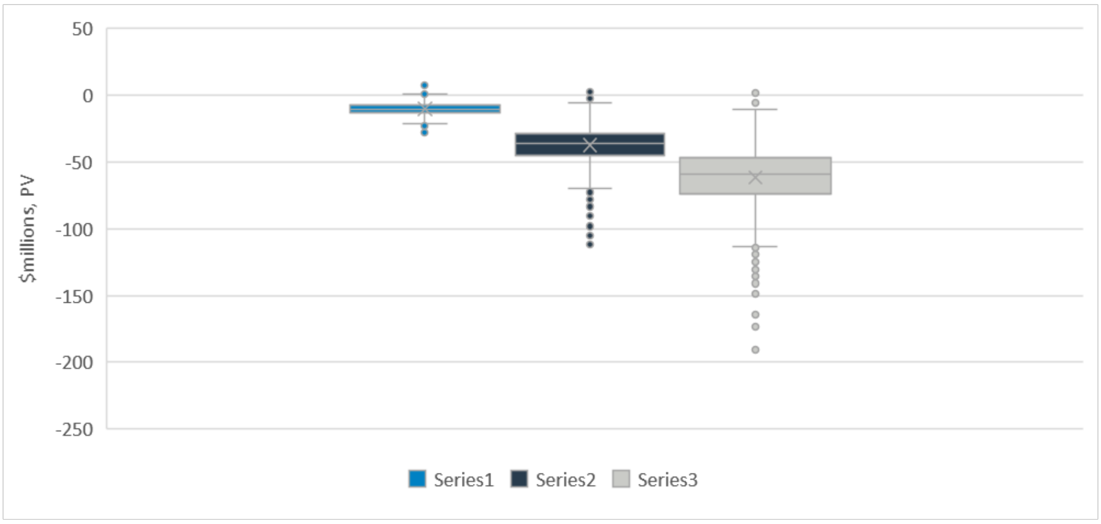
Sensitivity	Option 1	Option 2	Option 3
75% of capex estimate	-$7 million	-$24 million	-$42 million
125% of capex estimate	-$14 million	-$43 million	-$74 million
2.30% discount rate	-$11 million	-$41 million	-$73 million
7.50% discount rate	-$10 million	-$30 million	-$52 million
75% of maintenance expenditure estimate	-$11 million	-$33 million	-$58 million
125% of maintenance expenditure estimate	-$11 million	-$33 million	-$58 million

8.6 Sensitivity to multiple parameters

A Monte Carlo simulation was performed with multiple input parameters (including capital cost, discount rate, operational & maintenance cost, NNO operating costs) generated for the calculation of the NPV for the credible options. This process is repeated over 5,000 iterations, each time using a different set of random variables from a normal distribution probability function. The sensitivity analysis output is presented as a distribution of possible NPVs for the credible option, as illustrated in the figure below.

The Monte Carlo simulation results identify that Option 1 has less statistical dispersion in comparison to the other two options and has a highest mean (i.e. smallest net cost) of the three options. This is a function of Option 1 having the smallest amount of capital and operating costs out of the options considered. The Monte Carlo simulation results confirm that the preferred option, Option 1, is robust over a range of input parameters in combination.

Figure 8-8 NPV sensitivity analysis of multiple key assumptions relative to the Base Case



9. Preferred option

Based on the conclusions drawn from the NPV analysis and the Rules requirements Option 1 is identified as the preferred option which satisfies the RIT-T to manage voltages in South East Queensland.

Sensitivity testing shows that the analysis is robust to variations in discount rates, capital costs and operating costs.

10. Draft recommendation

Based on the conclusions drawn from the economic analysis , it is recommended that Option 1 be implemented to address over-voltage issues in SEQ. Implementing this option will ensure ongoing compliance with relevant standards, applicable regulatory instruments and the Rules.

Option 1 involves the installation and commissioning of a 120MVAr bus reactor at Powerlink's Belmont substation for 2023/24, with a capital cost of $13.3 million in 2022/23 prices.

Subsequent to 2023/24, Powerlink would seek to establish network support agreements with non-network option proponents in the SEQ area to meet projected shortfalls in reactive power absorption capability.

11. Lodging a submission with Powerlink

Powerlink invites submissions and comments in response to this PADR from Registered Participants, AEMO, potential non-network providers and any other interested parties.

Submissions should be presented in a written form and should clearly identify the author of the submission, including contact details for subsequent follow-up if required. If parties prefer, they may request to meet with Powerlink ahead of providing a written response.

11.1 Submissions from non-network providers

The preferred option identified in this PADR involves NNO proponents providing network support services for managing over-voltage issues over the medium and long term in order to provide customers a cost-effective approach to meeting the identified need. Consequently, Powerlink is inviting submissions from NNO proponents interested in engaging with Powerlink to progress discussions on network support agreements.

It is important to note that this is not a tender process.

Submissions from potential non-network providers should contain the following information:

- details of the party making the submission (or proposing the service)
- technical details of the project (capacity, proposed connection point if relevant, etc.) to allow an assessment of the likely impacts on future supply capability
- sufficient information to allow the costs and benefits of the proposed service to be incorporated in a comparison in accordance with AER RIT-T guidelines
- an assessment of the ability of the proposed service to meet the technical requirements of the Rules
- timing of the availability of the proposed service
- other material that would be relevant in the assessment of the proposed service.

As the submissions will be made public, any commercially sensitive material, or material that the party making the submission does not want to be made public, should be clearly identified.

It should be noted that Powerlink is required to publish the outcomes of the RIT-T analysis. If parties making submissions elect not to provide specific project cost data for commercial-in-confidence reasons, Powerlink may rely on cost estimates from independent specialist sources.

11.2 Assessment and decision process

Powerlink intends to carry out the following process to assess what action, if any, should be taken to address future supply requirements:

Part 2	PADR Publication Powerlink's response to any submissions received and identification of the preferred option. Have your say on the draft recommendation and propose any non-network solutions.	24 October 2022
	Submissions due on the PADR	9 December 2022
Part 3	Publication of the PACR Powerlink's response to any further submissions received and final recommendation on the preferred option for implementation.	February 2023

Powerlink reserves the right to amend the timetable at any time. Amendments to the timetable will be made available on the Powerlink website (www.powerlink.com.au).

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