2021 Transmission Annual Planning Report

Please direct Transmission Annual Planning Report enquiries to:

Dr Stewart Bell
Executive General Manager
Network and Business Development Division
Powerlink Queensland

Telephone: (07) 3860 2801
Email: sbell@powerlink.com.au

Foreword

Connecting Queenslanders to a world-class energy future

The electricity system is rapidly transforming and Powerlink, as the Jurisdictional Planning Body for Queensland, is committed to connecting Queenslanders to a world-class energy future.

Queensland is at the forefront globally with the rapid uptake of rooftop photovoltaic systems and has one of the highest per capita rates in the world. In this new energy world, as we experience unprecedented changes to electricity generation across the State, Powerlink is focussed on ensuring the transmission network is safe, reliable, fit-for-purpose, cost effective and strategically placed to enable the transformation to an energy system with much greater levels of Variable Renewable Energy (VRE) generation.

Queensland continues to be an attractive location for large VRE generation development projects with considerable interest from companies all over the world. Since publication of the 2020 Transmission Annual Planning Report (TAPR), Powerlink has completed five projects to connect new VRE and BESS developments which are expected to add 958MW of potential generation capacity. Powerlink has also received 23 formal applications for further connections.

In collaboration with the Queensland Government and industry, we are enabling the establishment of Queensland's first Renewable Energy Zone by the end of 2023 which will unlock up to 500MW of renewable capacity in northern Queensland. This will provide opportunities for both industry and local communities in the region, drive economic growth and support the Queensland Government's target of 50% renewable energy by 2030.

We are well prepared for the future. Powerlink has actively engaged with key stakeholders exploring new and alternate technologies, distributed energy resources and opportunities for battery storage to develop strategies which identify optimal electricity supply development pathways. This will help realise Queensland's untapped energy potential and drive positive outcomes for Queenslanders throughout the State.

Looking out over a 10-year period, the TAPR provides information on energy and demand forecasts, committed generation and current projects. It identifies key areas of possible future transmission network investments as well as potential non-network solution opportunities, which will guide and inform the development of Queensland's future transmission network topography.

As always, our focus remains on providing safe, reliable and cost effective electricity to five million Queenslanders and 238,000 businesses. I trust our 2021 TAPR provides you with useful information about Powerlink's transmission network and the potential opportunities that await as we shift to the new energy future.

Dr Stewart Bell
Executive General Manager
Network and Business Development
Powerlink Queensland

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Planning and development of the transmission network is integral to Powerlink Queensland meeting its obligations under the National Electricity Rules (NER), Queensland's Electricity Act 1994 and its Transmission Authority.

The Transmission Annual Planning Report (TAPR) is a key part of the planning process and provides stakeholders and customers with important information about the existing and future transmission network in Queensland. The report is targeted at everyone interested or involved in the National Electricity Market (NEM) including the Australian Energy Market Operator (AEMO), Registered Participants and interested parties. The TAPR also provides stakeholders with an overview of Powerlink's planning processes and decision making on potential future investments.

The TAPR includes information on electricity energy and demand forecasts, committed generation and network developments. It also provides estimates of transmission grid capability and potential network and non-network developments required in the future to continue to meet electricity demand in a timely manner and provide a valued service to our customers.

Overview

The 2021 TAPR outlines the key factors impacting Powerlink's transmission network development and operations and discusses how Powerlink continues to adapt and respond to dynamic changes in the external environment to meet the challenges of a rapidly changing energy system.

The forecasts presented in this TAPR indicate low growth for summer maximum demand, and decline in the minimum delivered demand and delivered energy for the transmission network over the 10-year outlook period.

The Queensland transmission network experienced significant growth in the period from the 1960s to the 1980s. The capital expenditure required to manage emerging risks related to assets reaching the end of their technical service life represents the majority of Powerlink's program of work over the outlook period. In line with customer and stakeholder expectations, emphasis will be placed on ensuring that asset reinvestment considers the enduring need and most cost effective option. Network planning studies have focussed on evaluating the enduring need for existing assets and potentially the need for new assets to ensure network resilience in the context of increasing diversity of generation, a relatively flat demand growth outlook and the potential for network reconfiguration, coupled with alternative non-network solutions.

Powerlink's focus on customer and stakeholder engagement has continued over the last year, with a range of activities undertaken to seek feedback and input into our network investment decision making and planning. This includes regular meetings of our Customer Panel, as well as the newly formed Revenue Proposal Reference Group, to seek stakeholder input on planning and decision making across a range of topics. We also held an Energy Industry Update in April to provide further detail on energy transformation activities, and development of Powerlink's forward energy plan for the future.

Since 2018, Powerlink as a founding participant, has committed to the whole of sector Energy Charter initiative. The charter is focussed on driving a customer-centric culture and conduct in energy businesses to create price and service delivery improvements for the benefit of customers.

The transforming energy system

Powerlink is playing an active role in shaping the electricity system, connecting Queenslanders to a world-class energy future by enabling the transformation to a new energy system, underpinned by clean, sustainable and reliable energy. Energy transformation is also presenting new opportunities for communities and local businesses in Queensland along with some technical challenges for the electricity supply chain as Australia moves to an electricity system with much greater levels of Variable Renewable Energy (VRE) generation.

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The rapid uptake of rooftop PV systems is significantly changing the physical nature of daily load flows and the way in which transmission and generation systems are planned and operated. Decreasing minimum demand may lower the amount of synchronous generation that is online and this could further impact on voltage control, system strength and inertia. Additionally, environmental factors, community and corporate expectations and the broader global focus on emissions reduction will drive the decarbonisation and electrification of transport, agriculture, mining and manufacturing sectors. Powerlink has developed the Integrated Electricity Pathways (IEP) to explore key investment options for transmission, energy storage and renewable generation to strategically plan, guide and enable development opportunities in Queensland. This will ensure continued reliability and security of supply of the energy system at the lowest long-run cost to customers.

Powerlink has also been collaborating with the Queensland Government to establish three Queensland renewable energy zones (QREZ) located in northern, central and southern Queensland. In September 2021 Powerlink completed a funded augmentation consultation enabling the development of the first of these QREZ in Northern Queensland, by establishing a third 275kV connection into Woree Substation by November 2023. The development of the Northern QREZ will unlock up to 500MW of renewable capacity.

Electricity energy and demand forecasts

The 2020/21 summer in Queensland had below average daily maximum and minimum temperatures, particularly in the latter summer months, which saw an overall summer peak delivered demand of 8,479MW at 6pm on 22 February, 287MW below the 2019/20 maximum delivered demand. Operational 'as generated' and native maximum annual demands were also recorded at 6pm on 22 February, with operational 'as generated' reaching 9,473MW, and native demand of 8,929MW. After temperature correction, the 2020/21 summer maximum delivered demand was 8,660MW, 3.6% higher than that forecast in the 2020 TAPR.

The 2021 Queensland minimum delivered demand occurred at 11:30am on 3 October 2021, when only 3,053MW was delivered from the transmission grid (refer to Figure 3.5 for load measurement definitions). Operational 'as generated' minimum demand was recorded at the same time and set a new record for Queensland of 3,784MW, passing the previous minimum record of 3,839MW set in July 2021.

Powerlink has adopted AEMO's 2021 ESOO forecasts in its planning analysis for the 2021 TAPR. The forecast captures impacts of COVID-19 pandemic, growth in rooftop photovoltaic (PV) installations, changing Queensland economic growth conditions, energy efficiency initiatives, battery storage and electric vehicles (EV), electrification and tariffs through Steady Progress, Slow Growth and Hydrogen Superpower scenarios. Bottom-up forecasts are derived through reconciliation of AEMO's forecast with those from Distribution Network Service Providers (DNSPs) at each transmission connection supply point.

Electricity energy forecast

Based on the Steady Progress scenario, Queensland's delivered energy consumption is forecast to decrease at an average of 1.1% per annum over the next 10 years from 47,421GWh in 2020/21 to 42,377GWh in 2030/31. The reduction is due to anticipated increases in the capacity of distribution connected renewable generation and rooftop PV.

Electricity demand forecast

Based on the Steady Progress scenario, Queensland's transmission delivered summer maximum demand is forecast to increase at an average rate of 0.8% per annum over the next 10 years, from 8,660MW (weather corrected) in 2020/21 to 9,417MW in 2030/31. Annual minimum transmission delivered demands are expected to decrease in all forecast scenarios presented in the 2021 TAPR. These AEMO 2021 ESOO minimum demand forecasts are provided with simulated solar traces which do not account for economic curtailment or operational measures required to maintain reliability and system security. The anticipated electrification of load, historically supplied by fossil fuels, could see a large increase in demand that may require significant investment in the transmission and distribution networks. Powerlink is committed to working with AEMO and our customers to better understand the future impacts that electrification will have on demand and energy forecasts.

Future network development

Shifts in customer expectation and dynamic changes in the external environment which is transforming to an electricity system with much greater levels of VRE generation, is reshaping the operating environment in which Powerlink delivers its transmission services. In response to the these challenges, Powerlink is focusing on an integrated approach to long-term planning, including the development of suitable Renewable Energy Zones (REZ) in Queensland.

In addition, initiatives such as the Integrated System Plan (ISP) and IEP inform the future development of the power system and the associated transmission network topography in Queensland and the NEM.

As well as responding to the ongoing impacts of COVID-19, Powerlink is also continuing to:

- undertake ongoing active customer and stakeholder engagement for informed decision making and planning
- implement and adopt the recommendations of various market reviews
- adapt to changes in electricity customer behaviour and economic outlook
- ensure its approach to investment decisions delivers positive outcomes for customers
- place considerable emphasis on an integrated, flexible and holistic analysis of future investment needs
- support diverse generation connections
- ensure compliance with changes in legislation, regulations and operating standards
- focus on developing options that deliver a secure, safe, reliable and cost effective transmission network.

Based on the Steady Progress scenario, the planning standard and committed network solutions, there are no significant network augmentations to meet load growth forecast to occur within the 10-year outlook period of this TAPR.

There are proposals for large mining, metal processing and other industrial loads including hydrogen that have not reached a committed development status. These new large loads are within the resource rich areas of Queensland and associated coastal port facilities. These loads have the potential to significantly impact the performance of the transmission network supplying, and within, these areas. This TAPR outlines the potential network investment required in response to these loads emerging in line with a high economic outlook.

Since January 2016, Queensland has seen an unprecedented level of renewable energy investment activity. These investments in VRE generation are changing the energy flows on the transmission network and have increased the utilisation of the Central West to Gladstone and Central Queensland to Southern Queensland (CQ-SQ) grid sections. Depending on the emergence of network limitations it may become economical to increase the power transfer capacity to alleviate constraints across these grid sections. Feasible network solutions are outlined within the TAPR.

The Queensland transmission network experienced significant growth in the period from the 1960s to the 1980s. The capital expenditure needed to manage the condition risks related to this asset base, some of which is now reaching end of technical service life, represents the bulk of Powerlink's program of work within the outlook period.

Considerable emphasis has been given to a flexible and integrated approach to the analysis of future reinvestment needs and options. Powerlink has systematically assessed the enduring need for assets at the end of their technical service life taking into account future renewable generation and considered a broad range of options including network reconfiguration, asset retirement, non-network solutions or replacement with an asset of lower capacity. This incremental development approach potentially defers large capital investment and has the benefit of maintaining the existing topography, transfer capability and operability of the transmission network.

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Renewable energy and generation capacity

To date Powerlink has completed connection of 13 large-scale solar and wind farm projects in Queensland, adding 1,644MW of generation capacity to the grid. In addition, approximately 30 connection applications, totalling about 6,400MW of new generation capacity, have been received and are at varying stages of progress[1]. This includes committed connections for a further 1,635MW of VRE.

To ensure that any adverse system strength impact is adequately addressed, Powerlink is working with customers, suppliers and AEMO to enhance its integrated system strength model for the Queensland network. This work has provided important insights into the complexity of system strength and how it impacts on managing asynchronous connections and the network in general.

Powerlink will apply this integrated system strength model to existing and new connection applications and engage with renewables sector customers to better understand the potential for additional VRE generation in Queensland.

Grid section and zone performance

During 2020/21, the Powerlink transmission network performed reliably. Record peak transmission delivered demand was recorded for the Wide Bay and Surat zones. Record minimum transmission delivered demand was recorded in the majority of zones.

Inverter-based resources in northern Queensland experienced approximately 2,518 hours of constrained operation during 2020/21. The majority of these constraints occurred prior to Powerlink addressing a fault level shortfall in North Queensland and several VRE customers completing their system strength remediation works.

Consultation on network reinvestments

Powerlink is committed to regularly reviewing and developing its transmission network in a timely manner to meet the required levels of reliability and manage the risks arising from aged assets remaining in service.

The TAPR highlights anticipated upcoming Regulatory Investment Test for Transmission (RIT-T) for which Powerlink intends to seek solutions and/or initiate consultation with AEMO, Registered Participants and interested parties in the near future (refer to Section 6.6.2). To enhance the value and outcomes of the RIT-T process to customers, Powerlink undertakes a range of engagement activities for each RIT-T, determined on a case by case basis. This engagement matrix for RIT-Ts was developed in consultation with Powerlink's Customer Panel.

Expanding New South Wales to Queensland transmission transfer capacity

Following the expected completion of the QNI 'minor' upgrade works, the 2020 ISP identified further upgrades to the QNI capacity as part of the optimal development path which would reduce costs and enhance system resilience. The future project was not identified as 'actionable', but may in the future. These development options can also be co-ordinated with REZ developments and can be staged by geography, operating voltage and number of circuits to maximise net economic benefits. Powerlink and TransGrid agreed a lower capacity 330kV transmission line to Armidale South Substation would be more likely to form part of the ISP optimal development path. Therefore, the option developed for the preparatory activities was a staged 330kV double circuit line to the Queensland/NSW border[2].

[1] For the purposes of customer connection statistics, Powerlink defines:
- 'completed projects' as those for which Powerlink's scope of works has been completed. However generation may not be at full capacity as remaining works associated with generation connection may not yet be complete (e.g. construction and/or commissioning)
- 'fully operational' as customer connections where all works are complete, commissioned and capable of delivering to full generation potential.

[2] In lieu of a higher voltage 500kV transmission line.

Future ISP projects in Queensland

The 2020 ISP identified upgrades in Queensland as part of the optimal development path in the NEM. These future ISP projects, anticipated to become 'actionable' in a future ISP include:

- QNI Medium and Large interconnector upgrades (Powerlink and TransGrid consultation)
- Central to Southern Queensland Transmission Link
- Gladstone Grid Reinforcement.

Preparatory activities for these projects have been provided to AEMO to inform the development of the 2022 ISP.

System strength services to address fault level shortfall at Ross

Powerlink issued a request for system strength services in April 2020 seeking expressions of interest (EOI) from market participants for offers for system strength remediation services for a fault level shortfall declared by AEMO at the Ross node. Powerlink received a very positive response to the EOI offering a range of system strength support services and worked closely with AEMO on the proposed remediation approach.

Initially, with AEMO's approval, Powerlink entered into a short-term agreement with CleanCo Queensland to provide system strength services through utilising its assets in Far North Queensland. These contracts were in place until December 2020 giving Powerlink time to develop a longer-term cost effective solution. The contracts also reduced constraints on VRE generators in North Queensland during this period.

In the intervening period, Powerlink worked with several proponents of existing VRE generation plants, and their respective equipment manufacturers, to show that inverter retuning and control system changes could reduce the overall system strength requirement at the Ross node.

Following AEMO's preliminary confirmation in August 2020, Powerlink entered into an agreement with Daydream, Hamilton, Hayman and Whitsunday Solar Farms in northern Queensland to validate the expected positive benefits of inverter tuning. Powerlink also worked with Mt Emerald Wind Farm on control setting changes.

As a result of retuning of the solar farms and an update of the control settings at Mt Emerald Wind Farm, in June 2021 AEMO's analysis found that the system strength requirements at the Ross node had changed and that the minimum fault level requirement at Ross is met and no shortfall remained.

Through consultation and active collaboration with all parties, the outcome of this EOI has delivered positive outcomes to customers by implementing innovative cost-effective technical solutions which removed the need for long-term investment (network or non-network).

Committed and commissioned projects

During 2020/21, having finalised the necessary regulatory processes for the proposed replacement of network assets, the committed projects for reinvestment across Powerlink's network include:

- Woree secondary systems and Static VAr Compensator (SVC) secondary systems replacement
- Ross 275/132kV primary plant replacement
- Line refit works between Townsville South and Clare South substations
- Townsville South primary plant replacement
- Lilyvale primary plant and transformer replacement
- Egans Hill to Rockhampton transmission line refit
- Bouldercombe primary plant and transformer replacement
- Baralaba secondary systems replacement
- Palmwoods secondary systems replacement
- Tarong secondary systems replacement
- Belmont secondary systems replacement

- Abermain secondary systems replacement
- Mudgeeraba secondary systems replacement.

Reinvestment project works in 2020/21 include:

- Ingham South transformers replacement
- Dan Gleeson secondary systems replacement
- Kemmis transformer replacement
- Callide A / Calvale 132kV transmission reinvestment.

Stakeholder consultation for non-network solutions

Powerlink engages with non-network providers to expand the potential use of non-network solutions, addressing the future needs of the transmission network, where technically and economically feasible. These may be in the form of an alternative option to like-for-like replacements, as a partial solution in conjunction with a network solution, or to complement an overall network reconfiguration strategy. Non-network solutions such as demand side management (DSM) or battery installation will be essential in future years to avoid or delay the need to invest in the transmission network in response to changing load flows or an increase in maximum demand.

Since the publication of the 2020 TAPR, Powerlink has continued to engage with non-network providers, customers and other stakeholders. In addition, Powerlink also continued the approach to ongoing informal discussions with multiple potential non-network solution providers in relation to the progress of the expression of interest (EOI) for system strength services in Queensland to address the fault level shortfall at Ross. Sharing information and seeking customer input through activities such as the Transmission Network Forum, webinars and informal meetings assists in broadening customer and stakeholder understanding of our business and provides additional opportunities to seek input on potential non-network solutions.

Customer and stakeholder engagement

Powerlink is committed to proactively engaging with stakeholders and customers and seeking their input into business processes and decision making. All engagement activities are undertaken in accordance with Powerlink's Stakeholder Engagement Framework that sets out the principles, objectives and outcomes Powerlink seeks to achieve in its interactions. In particular, Powerlink undertakes a comprehensive biennial stakeholder survey to gain insights about stakeholder perceptions of key factors, its social licence to operate and reputation. Most recently completed as a comprehensive interview style survey with more than 100 stakeholders in November 2020, it provides comparisons between baseline research undertaken in 2012 and year-on-year trends to inform engagement strategies with individual stakeholders. The latest survey also sought specific insights from existing directly-connected customers and renewable proponents on aspects of customer service and delivery, and Powerlink's responsiveness.

Powerlink's April Energy Industry Update online forum provided an opportunity for stakeholders to hear the latest developments and provide input into our decision making. Powerlink hosts a Customer Panel that provides an interactive forum for our stakeholders and customers to give input and feedback to Powerlink regarding our decision making, processes and methodologies. Comprised of members from a range of sectors including industry associations, resources, community advocacy groups, directly connected customers and distribution representatives, the panel provides an important avenue to keep our stakeholders better informed about operational and strategic topics of relevance. The panel met in November 2020, and during 2021 met in March, May, June and October. Key topics for discussion included the 2023-27 Revenue Determination process, projects under the RIT-T process, Powerlink's most recent Energy Charter Disclosure Statement to customers and stakeholders and the development of a best practice guide for landholders and Powerlink to work together. The panel, and its subset Revenue Proposal Reference Group, met regularly to discuss key matters of interest to Powerlink and our customers, allowing for input into a range of topics and future planning.

Powerlink recognises the importance of transparency for stakeholders and customers, particularly when undertaking transmission network planning and engaging in public consultation under the RIT-T process.

Powerlink hosted a webinar in November 2020 to share the TAPR's highlights and key updates with customers and stakeholders. The online format also provided an opportunity to openly engage with participants through an interactive question and answer session. Powerlink will discuss key highlights of the TAPR with stakeholders at the Transmission Network Forum to be held in November 2021.

Focus on continuous improvement in the TAPR

As part of Powerlink's commitment to continuous improvement, the 2021 TAPR continues to focus on an integrated approach to future network development and contains detailed discussion on key areas of future expenditure.

The 2021 TAPR:

- discusses emerging challenges and opportunities as the network transforms to much greater levels of VRE generation, including the development of Queensland renewable energy zones (refer to chapters 2, 6, 9 and 10)
- provides information in relation to joint planning and Powerlink's approach to asset management (refer to chapters 4 and 5)
- discusses possible future network asset investments for the 10-year outlook period (refer to Chapter 6)
- includes the most recent information for the proposed replacement of network assets which are anticipated to be subject to the RIT-T in the next five years (refer to Chapter 6)
- discusses the potential for generation developments (in particular VRE generation) (refer to Chapter 10)
- highlights potential non-network opportunities in the next five years and discusses Powerlink's approach to assisting the development of non-network solutions – specifically, through the ongoing improvement of engagement practices for non-network solution providers and provision of information (refer to Chapter 7 and Section 1.11.2)
- introduces the TAPR portal, an interactive geographical tool which includes the 2021 TAPR templates data.

CHAPTER 1

Introduction

1 Introduction

Key highlights

- The purpose of Powerlink's Transmission Annual Planning Report (TAPR) under the National Electricity Rules (NER) is to provide information about the Queensland transmission network.
- Powerlink is responsible for planning the shared transmission network within Queensland, including the development of all new connections to the network.
- Rising to the challenge of a transforming energy system, Powerlink continues to take a proactive and integrated approach to network planning by connecting Queenslanders to a world-class energy future.
- Powerlink has developed the Integrated Electricity Pathways (IEP) to support the transformation to a new energy system, underpinned by clean, sustainable and reliable energy.
- Since publication of the 2020 TAPR, Powerlink has continued to proactively engage with customers and stakeholders and seek their input into Powerlink's network development objectives, network operations and investment decisions.
- The 2021 TAPR identifies key areas of the Queensland transmission network forecast to require expenditure in the 10-year outlook period and considers matters relevant to the Queensland transmission network highlighted in the Australian Energy Market Operator's (AEMO) 2020 Integrated System Plan (ISP).
- Based on Powerlink's most recent planning review and information currently available, the 2021 TAPR also provides substantial detailed technical data (TAPR templates), available within Powerlink's TAPR portal, to further inform stakeholders on potential transmission network developments.

1.1 Introduction

Powerlink Queensland is a Transmission Network Service Provider (TNSP) in the National Electricity Market (NEM) and owns, develops, operates and maintains Queensland's high voltage (HV) transmission network. It has also been appointed by the Queensland Government as the Jurisdictional Planning Body (JPB) responsible for transmission network planning for the national grid within the State.

As part of its planning responsibilities, Powerlink undertakes an annual planning review in accordance with the requirements of the NER and publishes the findings of this review in its TAPR, TAPR templates and TAPR portal.

The 2021 TAPR includes information on electricity energy and demand forecasts, the existing electricity supply system, including existing and committed generation and transmission network developments and reinvestments, and forecasts of network capability. Risks arising from the condition and performance of existing assets, as well as emerging limitations in the capability of the network, are identified and possible solutions to address these are discussed. Interested parties are encouraged to provide input to identify the most economic solution (including non-network solutions provided by others) that satisfies the required reliability standard for customers into the future. As in previous years, and through the information and context provided, the 2021 TAPR continues to support the connection of variable renewable energy (VRE) generation to Powerlink's transmission network, enabling the transformation to a low carbon future.

Powerlink's annual planning review and TAPR play an important role helping to ensure the transmission network continues to meet the needs of Queensland electricity customers and participants in the NEM into the future.

1.2 Context of the TAPR

All bodies with jurisdictional planning responsibilities in the NEM are required to undertake the annual planning review and reporting process prescribed in the NER[1].

[1] For the purposes of Powerlink's 2021 TAPR, Version 169 of the NER in place from August 2021.

Information from this process is also provided to AEMO to assist in the preparation of its ISP. The ISP sets out a roadmap for the eastern and south-eastern seaboard's power system over the next two decades by establishing a whole of system plan for an efficient transformation to a renewables-based energy system. The ISP attempts to identify the optimal development path over this planning horizon for the strategic and long-term development of the national transmission system. The ISP identifies actionable and future projects, and informs market participants, investors, policy decision makers and customers on a range of development opportunities.

The 2021 TAPR incorporates AEMO's demand and energy forecasts, consistent with those published for the 2021 Electricity Statement of Opportunity (ESOO). The ESOO examines electricity supply and demand issues across all regions in the NEM.

The primary purpose of the TAPR is to provide information on the short-term to medium-term planning activities of TNSPs, whereas the focus of the ISP is strategic and longer term. Further, the ISP, Network Support and Control Ancillary Service (NSCAS) Report, Inertia Report, System Strength Report and TAPR are intended to complement each other in informing stakeholders and promoting efficient investment decisions. In supporting this complementary approach, the current published versions of these documents and reports are considered in this TAPR and more generally in Powerlink's planning activities.

Interested parties may benefit from reviewing Powerlink's 2021 TAPR in conjunction with AEMO's 2021 ESOO which was published in August 2021. The most recent ISP was released on 30 July 2020. The draft 2022 ISP is due for publication in December 2021.

1.3 Purpose of the TAPR

The purpose of Powerlink's TAPR under the NER is to provide information about the Queensland transmission network to those interested or involved in the NEM including AEMO, Registered Participants and interested parties. The TAPR also provides customers and stakeholders with an overview of Powerlink's planning processes and decision making on future investment.

It aims to provide information that assists to:

- identify locations that would benefit from significant electricity supply capability or demand side management (DSM) initiatives
- identify locations where major industrial loads could be connected
- identify locations where capacity for new generation developments exist (in particular VRE generation)
- understand how the electricity supply system affects customers and stakeholders needs
- understand the transmission network's capability to transfer quantities of bulk electrical energy
- provide input into the future development of the transmission network.

Readers should note this document and supporting TAPR templates and TAPR portal are not intended to be relied upon explicitly for the evaluation of participants' investment decisions. Interested parties are encouraged to contact Powerlink directly for more detailed information.

1.4 Role of Powerlink Queensland

Powerlink has been nominated by the Queensland Government as the entity with transmission network planning responsibility in Queensland, known as the JPB as outlined in Clause 5.22.14 of the NER.

As the owner and operator of the transmission network in Queensland, Powerlink is registered with AEMO as a TNSP under the NER. In this role, and in the context of this TAPR, Powerlink's transmission network planning and development responsibilities include:

- ensuring the network is able to operate with sufficient capability and if necessary, is augmented to provide network services to customers in accordance with Powerlink's Transmission Authority and associated reliability standard

- ensuring the risks arising from the condition and performance of existing assets are appropriately managed
- ensuring the network complies with technical and reliability standards contained in the NER and jurisdictional instruments including the requirement to maintain minimum fault levels as prescribed by AEMO
- conducting annual planning reviews with Distribution Network Service Providers (DNSPs) and other TNSPs whose networks are connected to Powerlink's transmission network, that is Energex and Ergon Energy (part of the Energy Queensland Group), Essential Energy and TransGrid
- advising AEMO, Registered Participants and interested parties of asset reinvestment needs within the time required for action
- developing recommendations to address emerging network limitations or the need to address the risks arising from ageing network assets remaining in service through joint planning with DNSPs and TNSPs, and consultation with AEMO, Registered Participants and interested parties, with potential solutions including network upgrades or non-network options such as local generation (including battery installation) and DSM initiatives
- examining options and developing recommendations to address transmission constraints and economic limitations across intra-regional grid sections and interconnectors through joint planning with other Network Service Providers (NSP), and consultation with AEMO, Registered Participants and interested parties
- assessing whether a proposed transmission network augmentation has a material impact on networks owned by other TNSPs, and in assessing this impact Powerlink must have regard to the objective set of criteria published by AEMO in accordance with Clause 5.21 of the NER
- undertaking the role of the proponent for regulated or funded[2] transmission augmentations and the replacement of transmission network assets in Queensland.

In addition, Powerlink participates in inter-regional system tests associated with new or augmented interconnections.

1.5 Opportunities arising from the energy system transformation

The pace and scale of change to Australia's energy system is one of the fastest in the world and it is widely recognised that the transmission network will play a key role in enabling the transformation to a low carbon future. This is presenting new opportunities for communities and local businesses throughout the State along with some technical challenges for transmission networks, as well as other parts of the electricity supply chain, which are moving to an electricity system with much greater levels of Variable Renewable Energy (VRE) generation.

Broadly these challenges include:

- System strength (refer to chapters 2, 6, 7, 8 and 10)
- Network congestion on the transmission network as generation patterns change (refer to chapters 2, 6, 7 and 8)
- Marginal Loss factors (MLF) (refer to Chapter 10)
- Requirements for large amounts of energy storage including batteries and pumped hydro (refer to Chapter 2)
- Minimum demand (refer to chapters 2, 3, and 4).

Powerlink developed the Integrated Electricity Pathways to explore key investment options for transmission, energy storage and renewable generation against a range of changing sensitivities such as rooftop photovoltaic (PV) installations, generation portfolios, load retirements and developments and future gas prices.

[2] Where applicable, in accordance with Clause 5.18 of the NER.

Powerlink will continue to deliver a secure, safe, reliable and cost-effective service to customers while strategically planning, guiding and enabling opportunities for the development of Queensland's future transmission network by connecting Queenslanders to a world-class energy future during this period of energy transformation.

In August 2020 the Queensland Government committed $145 million to establish three Queensland Renewable Energy Zones (QREZ) given the quality of resources available in regional Queensland and to facilitate the transformation to 50% renewable energy by 2030. The QREZ will be located in Northern (which includes the Far North Queensland region), Central and Southern Queensland. Subsequently in May 2021 it was announced that the Queensland Government would invest $40 million in transmission line infrastructure in North Queensland to establish the Northern QREZ, with Neoen's Kaban Wind Farm identified as the foundational proponent.

Powerlink has recently completed a public consultation 'Developing the Northern Queensland Renewable Energy Zone', receiving significant in-principle support from a broad range of stakeholders. It is anticipated the development of the Northern QREZ will deliver widespread benefits and increase the generator hosting capacity in the region by up to 500MW, opening up North Queensland for further investment. The Northern QREZ establishment works include a minor upgrade to the transmission network, converting one side of the existing coastal 132kV double circuit transmission line between Ross and Woree substations to permanently operate at 275kV.

Further detailed information on the energy transformation is provided in Chapter 2.

1.6 Commitment to connecting Queenslanders to a world-class energy future

Powerlink is committed to connecting Queenslanders to a world-class energy future, undertaking long-term network planning to ensure the optimal performance and utilisation of the transmission network in the State. Where appropriate, this includes the development of suitable Renewable Energy Zones (REZ) and associated network infrastructure, to ensure positive outcomes for our customers.

As well as responding safely to the ongoing impacts of the COVID-19 pandemic and maintaining reliability of supply, Powerlink is also continuing to:

- undertake ongoing active customer and stakeholder engagement for informed decision making and planning
- engage and influence various NEM rule changes and guideline reviews and then adopt and implement the recommendations
- adapt to changes in customer behaviour and economic outlook
- ensure its approach to investment decisions delivers positive outcomes for customers
- place considerable emphasis on an integrated, flexible and holistic analysis of future investment needs
- support diverse generation connections
- ensure compliance with changes in legislation, regulations and operating standards
- focus on developing options that deliver a secure, safe, reliable and cost effective transmission network.

1.7 Overview of approach to asset management

Powerlink is committed to sustainable asset management practices that consider and recognise its customer and stakeholder requirements, ensuring assets are managed in a manner consistent with overall corporate objectives to deliver cost effective and efficient services. Powerlink's asset management system captures significant internal and external drivers in the business and sets out initiatives to be adopted. The Asset Management Policy, Strategic Asset Management Plan and related processes guide Powerlink's network asset planning and reinvestment decisions. Information on the principles and approach which guide Powerlink's analysis of future network investment needs and key investment drivers is provided in Chapter 5.

1.8 Overview of planning responsibilities and processes

1.8.1 Planning criteria and processes

Powerlink has obligations that govern how it should address forecast network limitations. These obligations are prescribed by Queensland's Electricity Act 1994 (the Act), the NER and Powerlink's Transmission Authority.

The Act requires that Powerlink 'ensure as far as technically and economically practicable, that the transmission grid is operated with enough capacity (and if necessary, augmented or extended to provide enough capacity) to provide network services to persons authorised to connect to the grid or take electricity from the grid'.

It is a condition of Powerlink's Transmission Authority that it meets licence and NER requirements relating to technical performance standards during intact and contingency conditions. The NER sets out minimum performance requirements of the network and connections, and requires that reliability standards at each connection point be included in the relevant connection agreement.

New network developments and reinvestments are proposed to meet these legislative and NER obligations. Powerlink may also propose transmission investments that deliver a net market benefit when assessed in accordance with the Regulatory Investment Test for Transmission (RIT-T). The requirements for initiating solutions to meet forecast network limitations or the need to address the risks arising from ageing network assets remaining in service, including new regulated network developments or non-network solutions, are set down in clauses 5.14.1, 5.16.4, 5.16A, 5.20B, 5.20C and 5.22.14 of the NER.

While each of these clauses prescribes a slightly different process, at a higher level the main steps in network planning for transmission investments subject to the RIT-T can be summarised as follows:

- Publication of information regarding the nature of network limitations, the risks related to ageing network assets remaining in service and the need for action which includes an examination of demand growth and its forecast exceedance of the network capability (where relevant).
- Consideration of generation and network capability to determine when additional capability is required.

Consultation on assumptions made and credible options may include:

- network augmentation
- asset replacement
- asset retirement
- network reconfiguration and/or local generation or DSM initiatives
- classes of market benefits considered to be material which should be taken into account in the comparison of options
- analysis and assessment of credible options, which include costs, market benefits, material inter-network impact and material impact on network users[3] (where relevant)
- identification of the preferred option that satisfies the RIT-T, which maximises the present value of the net economic benefit to all those who produce, consume and transport electricity in the market
- consultation and publication of a recommended course of action to address the identified future network limitation or the risks arising from ageing network assets remaining in service.

[3] NER Clause 5.16.3 (a)(5).

1.8.2 Integrated planning of the shared network

Powerlink is responsible for planning the shared transmission network within Queensland, and inter-regionally. The NER sets out the planning process and requires Powerlink to apply the RIT-T to transmission investment proposals for augmentations to the transmission network and the replacement of network assets over $6 million. Powerlink continues to publish information and consult with potential providers of non-network solutions for the provision of system strength and inertia network services as notified by AEMO. Planning processes require consultation with AEMO, Registered Participants and interested parties, including customers, generators, DNSPs and other TNSPs. Section 6.6 discusses current consultations, as well as anticipated future consultations, that will be conducted in line with the relevant processes prescribed in the NER.

Significant inputs to the network planning process are the:

- forecast of customer electricity demand (including DSM) and its location
- location, capacity and arrangement of existing, new and retiring generation (including embedded generation)
- condition and performance of assets and an assessment of risks arising from ageing network assets remaining in service
- assessment of future network capacity to meet the required planning criteria and efficient market outcomes, including limiting transmission losses to the extent possible, system strength and the potential to facilitate future storage requirements to help address minimum demand.

The 10-year forecasts of electrical demand and energy across Queensland are used, together with forecast generation patterns, to determine potential flows on transmission network elements. The location and capacity of existing and committed generation in Queensland is sourced from AEMO, unless modified following advice from relevant participants and is provided in tables 8.1 and 8.2. Information about existing and committed embedded generation and demand management within distribution networks is provided by DNSPs and AEMO.

Powerlink examines the capability of its existing network and the future capability following any changes resulting from:

- committed network projects (for both augmentation and to address the risks arising from ageing network assets remaining in service)
- the impact of coal-fired generation retirements on transmission network power flows
- existing and future renewable developments including REZ
- anomalies in Powerlink's operating environment or changes in technical characteristics such as minimum demand and system strength as the power system continues to evolve.

This includes consultation with the relevant DNSP in situations where the performance of the transmission network may be affected by the distribution network, for example where the two networks operate in parallel.

Where potential flows could exceed network capability, Powerlink notifies market participants of these forecast emerging network limitations. If the capability violation exceeds the required reliability standard, joint planning investigations are carried out with DNSPs (or other TNSPs if relevant) in accordance with Clause 5.14.1 of the NER. The objective of this joint planning is to identify the most cost effective solution, regardless of asset boundaries, including potential non-network solutions (refer to Chapter 4).

Powerlink must maintain its current network so that the risks arising from the condition and performance of existing assets are appropriately managed. Powerlink undertakes a program of asset condition assessments to identify emerging asset condition related risks.

As assets approach the end of their technical service life, Powerlink examines a range of options to determine the most appropriate reinvestment strategy, applying a flexible and integrated approach which takes into account multiple factors. Consideration is given to optimising the topography and capacity of the network, taking into account current and future network needs, including future renewable generation and other developments associated with the transforming energy system.

1 Introduction

In many cases, power system flows and patterns have changed over time. As a result, the ongoing network capacity requirements need to be re-evaluated. Individual asset reinvestment decisions are not made in isolation, and reinvestment in assets is not necessarily undertaken on a like-for-like basis. Rather, asset reinvestment strategies and decisions are made taking into account enduring need, the inter-related connectivity and characteristics of the HV system, and are considered across an area or transmission corridor. The consideration of potential non-network solutions forms an important part of this flexible and integrated planning approach.

The integration of condition and demand based limitations delivers cost effective solutions that address both reliability of supply and risks arising from assets approaching end of technical service life.

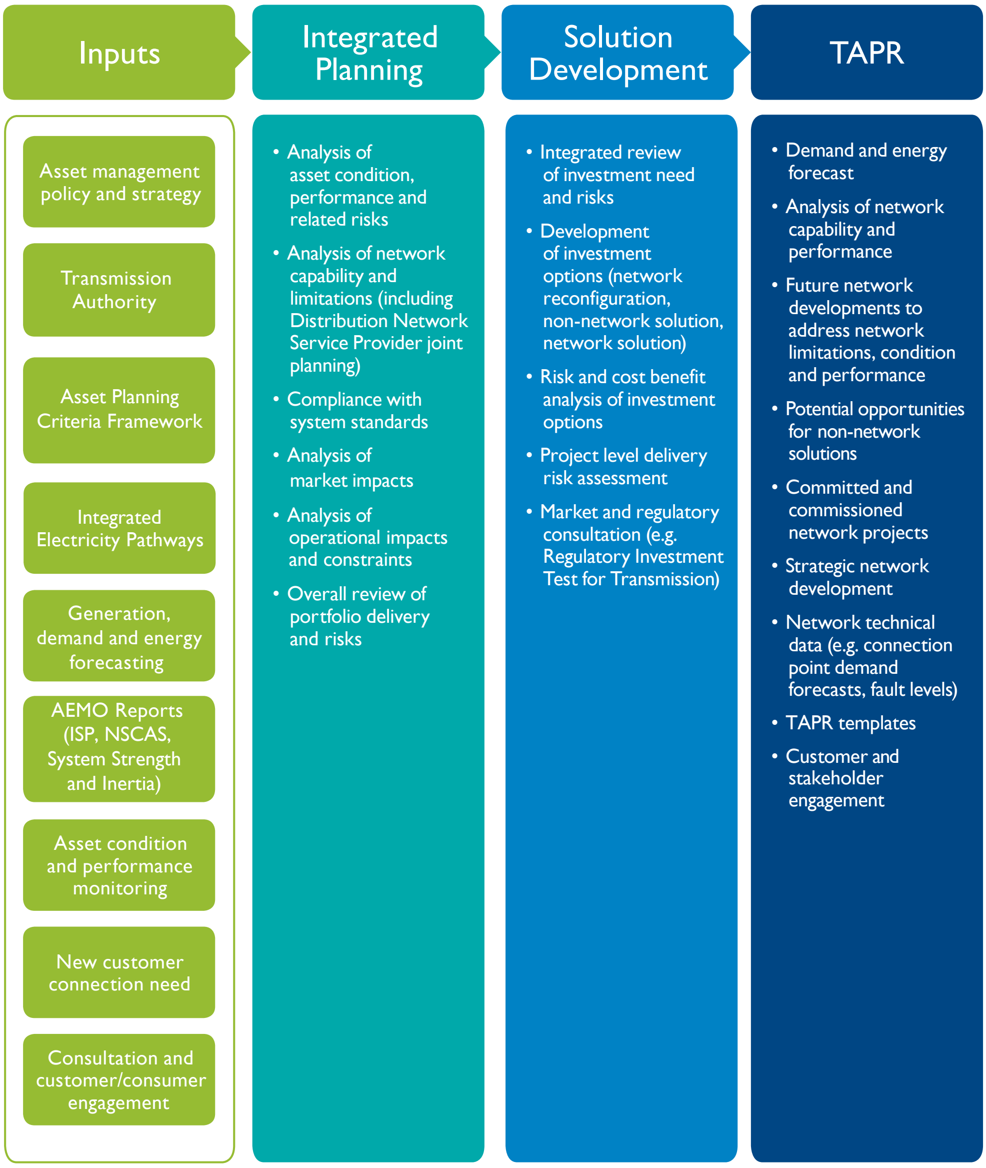
Powerlink considers a range of strategies and options to address emerging asset related condition and performance issues. These strategies include:

- retiring or decommissioning assets where there is unlikely to be an ongoing future need
- reinvesting to extend the service life of assets
- replacing assets of different capacity or type
- changing the topography of the network
- implementing non-network solutions.

Each of these options is considered in the context of future capacity. In accordance with the NER, information regarding proposed transmission reinvestments within the 10-year outlook period must be published in the TAPR and TAPR templates. More broadly, this provides information to the NEM, including AEMO, Registered Participants and interested parties (including non-network providers) on Powerlink's planning processes, anticipated public consultations, and decision making relating to potential future reinvestments. Further information is provided in Section 6.7, Chapter 7 and Appendix B.

A summary of Powerlink's integrated planning approach that takes into account both network capacity needs and end of technical service life related issues is presented in Figure 1.1.

Figure 1.1 Overview of Powerlink's TAPR planning process



1.8.3 Joint planning

Powerlink undertakes joint planning with other NSPs to collaboratively identify network and non-network solutions, which best serve the long-term interests of customers. This process provides a mechanism to discuss and identify technically feasible network and non-network options that provide lowest cost solutions across the network as a whole, regardless of asset ownership or jurisdictional boundaries.

Powerlink's joint planning, while traditionally focussed on the DNSPs (Energex, Ergon Energy and Essential Energy) and TransGrid, also includes consultation with AEMO, other Registered Participants, load aggregators and other interested parties.

Joint planning with AEMO is critical to ensure the best possible jurisdictional inputs are provided to the ISP process in the long-term interests of customers. These inputs include condition drivers for significant intra-regional infrastructure, possible development options and cost of options that increase capacity of critical intra and inter-regional grid sections, together with the associated capacity improvement.

Also, Powerlink undertakes joint planning with AEMO to periodically assess the minimum fault level, system strength and inertia requirements for the Queensland jurisdiction. In April 2020, AEMO published a Notice of Queensland System Strength Requirements and Ross Fault Level Shortfall. AEMO declared an immediate fault level shortfall of 90MVA at the Ross 275kV fault level node. AEMO forecast that, if not addressed, this fault level shortfall would continue beyond 2024-25. In June 2021, as a result of retuning of solar farm inverters and an update of the control settings at Mt Emerald Wind Farm this fault level shortfall was addressed. Powerlink's solution to the declared fault level short fall is discussed further in sections 6.7.1 and 10.4.1.

Information on Powerlink's joint planning framework, and the joint planning activities that Powerlink has undertaken with other NSPs and AEMO since publication of the 2020 TAPR is provided in Chapter 4.

1.8.4 Connections

Participants wishing to connect to the Queensland transmission network include new and existing generators, storage, major loads and other NSPs. New connections or alterations to existing connections involves consultation in accordance with the NER Chapter 5 connection process between Powerlink and the connecting party to negotiate an Offer to Connect and Connection and Access Agreement (CAA). Negotiation of the CAA requires the specification and then compliance by the generator or load to the required technical standards. The process of agreeing to technical standards also involves AEMO. The services provided can be prescribed for DNSPs (regulated), negotiated or non-regulated services in accordance with the definitions in the NER or the framework for provision of such services.

From July 2018 new categories of connection assets were defined, namely Identified User Shared Assets (IUSA) and Dedicated Connection Assets (DCA). All new DCA services, including design, construction, ownership and operation and maintenance are non-regulated services. IUSA assets with capital costs less than $10 million are negotiated services that can only be provided by Powerlink. IUSA assets with capital costs above $10 million are non-regulated services. Powerlink remains accountable for operation of all IUSAs and any above $10 million must enter into a Network Operating Agreement to provide operations and maintenance services.

From July 2021 Large Dedicated Connection Assets (DCA) were replaced with Designated Network Assets (DNA). A DNA is a radial transmission extension greater than 30km in length. DCAs remain for connections less than 30km. A DNA is not a connection asset, but rather transmission network. It differs to the shared transmission network as the design, construction and ownership of the DNA are non-regulated services. As for IUSAs, Powerlink remains accountable for operation and maintenance of all DNAs. A special access framework for DNAs is set out in the NER Chapter 5. Further information in relation to the connection process is available on Powerlink's website (refer to Section 10.5).

1.8.5 Interconnectors

As outlined in Section 1.2, the purpose of the ISP is to establish a strategic whole of system plan for a 20-year planning horizon for efficient power system development in the long-term interests of customers. The ISP also serves the regulatory purpose of identifying actionable projects to meet power system needs. These projects may relate to the potential development of new interconnectors or expanding the capacity of existing interconnectors or intra-regional grid sections. For actionable projects the responsible TNSPs are required to undertake a Regulatory Investment Test for Transmission (RIT-T) and publish a Project Assessment Draft Report (PADR) by a specified date. Under the NER, TNSPs also retain the ability to conduct RIT-Ts outside the ISP framework.

The 2020 ISP did not identify any actionable projects within Queensland. However, the 2020 ISP did identify several projects that may become actionable in future ISPs. Projects identified as part of the optimal development path nominated in the 2020 ISP which relate to Powerlink's transmission network, include:

- QNI Medium and Large interconnector upgrades
- Central to Southern Queensland reinforcement
- Gladstone Grid reinforcement.

Preparatory activity reports for these projects were provided to AEMO on 30 June 2021 (refer to Section 9.3).

1.9 Powerlink's asset planning criteria

The Queensland Government amended Powerlink's N-1 criterion in 2014 to allow for increased flexibility. The planning standard permits Powerlink to plan and develop the transmission network on the basis that load may be interrupted during a single network contingency event. The following limits are placed on the maximum load and energy that may be at risk of not being supplied during a critical contingency:

- will not exceed 50MW at any one time
- will not be more than 600MWh in aggregate.

The risk limits can be varied by:

- a connection or other agreement made by the transmission entity with a person who receives or wishes to receive transmission services, in relation to those services, or
- agreement with the Queensland Energy Regulator (QER).

Powerlink is required to implement appropriate network or non-network solutions in circumstances where the limits set out above are exceeded or when the economic cost of load at risk of not being supplied justifies the cost of the investment. Therefore, the planning standard has the effect of deferring or reducing the extent of investment in network or non-network solutions required. Powerlink will continue to maintain and operate its transmission network to maximise reliability to customers.

As mentioned, Powerlink's transmission network planning and development responsibilities include developing recommendations to address emerging network limitations, or the need to address the risks arising from ageing network assets remaining in service, through joint planning (refer to Section 1.8.3).

Energex and Ergon Energy were issued amended Distribution Authorities from July 2014. The service levels defined in their respective Distribution Authority differ to that of Powerlink's authority. Joint planning accommodates these different planning standards by applying the planning standard consistently with the owner of the asset which places load at risk during a contingency event.

Powerlink has established policy frameworks and methodologies to support the implementation of this standard. These are being applied in various parts of the Powerlink network where possible emerging limitations are being monitored.

1.10 Powerlink's reinvestment criteria

Powerlink is committed to ensuring the sustainable long-term performance of its assets to deliver safe, reliable and cost effective transmission services to customers, stakeholders and communities across Queensland. Powerlink demonstrates this by adopting a proactive approach to asset management that optimises whole of life cycle costs, benefits and risks, while ensuring compliance with applicable legislation, regulations, standards, statutory requirements, and other relevant instruments.

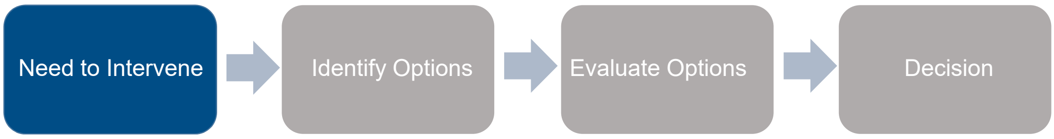
The reinvestment criteria framework defines the methodology that Powerlink uses to assess the need and timing for intervention on network assets to ensure that industry compliance obligations are met. The methodology aims to improve transparency and consistency within the asset reinvestment process, enabling Powerlink's customers and stakeholders to better understand the criteria to determine the need and timing for asset intervention.

The reinvestment criteria framework is relevant where the asset condition changes so it no longer meets its level of service or complies with a regulatory requirement. This category of reinvestment is triggered when the existing asset has degraded over time and no longer provides the required standard of service as prescribed within applicable legislation, regulations and standards.

The trigger to intervene needs to be identified early enough to provide an appropriate lead time for the asset reinvestment planning and assessment process. The need and timing for intervention is defined when business as usual activities (including routine inspections, minor condition based and corrective maintenance and operational refurbishment projects) no longer enable the network asset to meet prescribed standards of service due to deteriorated asset condition.

Powerlink's asset reinvestment process (refer to Figure 1.2) enables timely, informed and prudent investment decisions to be made that consider all economic and technically feasible options including non-network alternatives or opportunities to remove assets where they are no longer required. An assessment of the need and timing for intervention is the first stage of this process.

Figure 1.2 Asset Reinvestment Process



1.11 Stakeholder engagement

Powerlink shares effective, timely and transparent information with its customers and stakeholders using a range of engagement methods. Customers are defined as those who are directly connected to Powerlink's network and electricity consumers, such as households and businesses, who are supplied via the distribution network. There are also stakeholders who can provide Powerlink with non-network solutions. These stakeholders may either connect directly to Powerlink's network, or connect to the distribution networks. As an example, in December 2020 Powerlink continued the approach to ongoing informal discussions with multiple potential non-network solution providers in relation to the progress of the EOI for system strength services in Queensland to address the fault level shortfall at Ross.

The TAPR is just one avenue that Powerlink uses to communicate information about transmission planning in the NEM. Through the TAPR, Powerlink aims to increase stakeholder and customer understanding and awareness of its business practices, including load forecasting and transmission network planning.

1.11.1 Customer and stakeholder engagement

Powerlink is committed to proactively engaging with stakeholders and customers and seeking their input into Powerlink's business processes and decision making. All engagement activities are undertaken in accordance with our Stakeholder Engagement Framework which sets out the principles, objectives and outcomes Powerlink seeks to achieve in its interactions. A number of key performance indicators are used to monitor progress towards achieving Powerlink's stakeholder engagement performance goals. In particular, Powerlink undertakes a comprehensive biennial stakeholder survey to gain insights about stakeholder perceptions of Powerlink, its social licence to operate and reputation. Most recently completed as a comprehensive interview style survey with more than 100 stakeholders in November 2020, it provides comparisons between baseline research undertaken in 2012 and year-on-year trends to inform engagement strategies with individual stakeholders. The latest survey also sought specific insights from existing directly-connected customers and renewable proponents on aspects of customer service and delivery, and Powerlink's responsiveness.

2020/21 Stakeholder engagement activities

Since the publication of the 2020 TAPR, Powerlink has engaged with stakeholders and customers in various ways through a range of activities as outlined below.

2023-27 Revenue Proposal

Powerlink is required to lodge a Revenue Proposal to the AER every five years. As part of its 2023-27 Revenue Determination process, which commenced in 2019, Powerlink has conducted an extensive engagement program, and lodged its Revenue Proposal to the AER on 28 January 2021. Numerous workshops, forums and sessions have been hosted with customers, stakeholders, the AER's Consumer Challenge Panel and AER staff on all key elements of Powerlink's Revenue Proposal. This level of engagement with stakeholders by Powerlink will continue up until the Final Decision is released by the AER in April 2022. This engagement approach has been driven by Powerlink's overarching goal to deliver a Revenue Proposal that is 'capable of acceptance' by Powerlink's customers, the AER and Powerlink itself.

Customer Panel

Powerlink hosts a Customer Panel that provides an interactive forum for its stakeholders and customers to give input and feedback to Powerlink regarding decision making, processes and methodologies. Comprised of members from a range of sectors including industry associations, resources, community advocacy groups, directly connected customers and distribution representatives, the panel provides an important avenue to keep our stakeholders better informed about operational and strategic topics of relevance. The panel met in February, May, July and November 2020, and during 2021 met during March, May and June. Key topics for discussion included the 2023-27 Revenue Determination process, transmission pricing consultation, projects under the RIT-T process and Powerlink's most recent Energy Charter Disclosure Statement to customers and stakeholders.

2020 TAPR webinar

Powerlink hosted a webinar in November 2020 to share the TAPR's highlights and key energy industry updates with customers and stakeholders. The online format also provided an opportunity to openly engage with approximately 100 participants through an interactive question and answer session. A post webinar survey sought feedback about the webinar and content discussed. Feedback received from stakeholders was very positive, particularly around Powerlink's transparent approach to answering questions and the level of detail provided. The questions raised and answers discussed are available on Powerlink's website.

Stakeholder engagement for RIT-Ts

Powerlink recognises the importance of transparency for stakeholders and customers, particularly when undertaking transmission network planning and engaging in public consultation under the RIT-T process.

In relation to engagement activities for RIT-Ts, Powerlink is committed to a balanced approach in the public consultation process as determined with its Customer Panel. In addition, Powerlink will utilise and be guided by the Australian Energy Regulator's (AER) Stakeholder Engagement Framework and Consumer Engagement Guideline for Network Service Providers as the benchmarks when consulting as part of the RIT-T process.

Taking this into account, the appropriate level of engagement for RIT-Ts may most easily be identified through feedback received from stakeholders on proposed investments identified in the TAPR, discussion and consideration of the context of the proposed investment. Engagement activities for RIT-Ts are assessed on a case by case basis. This includes consideration of the:

- potential impacts on stakeholders
- opportunities for network reconfiguration or asset retirement
- estimated capital cost
- type of RIT-T process being undertaken (refer to Section 6.6.1).

Detailed information on proposed engagement activities for RIT-Ts can be found on Powerlink's website.

It is anticipated that the provision and exchange of early information through engagement activities will generate more opportunities for interactions with our customers and stakeholders, during formal or informal consultation processes.

More information on Powerlink's engagement activities is available on our website.

1.11.2 Non-network solutions

Powerlink has established processes for engaging with stakeholders for the provision of non-network services in accordance with the requirements of the NER. These engagement processes centre on publishing relevant information on the need and scope of viable non-network solutions to emerging network limitations and more recently, in relation to the replacement of network assets. For a given network limitation or potential asset replacement, the viability and an indicative specification of non-network solutions are first introduced in the TAPR and TAPR templates. As the identified need date approaches detailed planning analysis is undertaken, and further opportunities are explored in the consultation and stakeholder engagement processes undertaken as part of any subsequent RIT-T.

In the past, these processes have been successful in delivering non-network solutions to emerging network limitations or as more recently demonstrated in 2020, to assist in a short-term solution to address a system strength shortfall in north Queensland until a longer term solution could be assessed and implemented.

Non-network solutions such as DSM will be essential in future years to avoid or delay the need to augment the transmission network in response to any increase in maximum demand.

Powerlink is committed to the ongoing development of its non-network engagement processes to facilitate the identification of optimal non-network solutions:

- to address future network limitations or address the risks arising from ageing assets remaining in service within the transmission network
- more broadly, in combination with network developments as part of an integrated solution to complement an overall network reconfiguration strategy
- to address voltage instability, inertia and system strength requirements, ensuring the secure operation of the transmission network
- to provide demand management and load balancing.

Powerlink's 2021 TAPR includes information for non-network providers that highlights possible future non-network opportunities in key areas of the transmission network in Queensland forecast to require expenditure in the next five years (refer to Chapter 7). In addition, the TAPR templates and TAPR portal published in conjunction with the 2021 TAPR provide detailed technical data on Powerlink's transmission connection points and line segments. This data may be of value to non-network providers when considering opportunities for the development of potential non-network solutions (refer to Appendix B). Powerlink will continue to engage and work collaboratively with non-network providers during the RIT-T or other consultation processes to arrive at the optimal solution for customers.

Powerlink will continue to hold webinars on an ongoing basis as relevant and topical issues arise that are likely to be of interest to non-network providers and other stakeholders. In addition to enabling the delivery of information and providing a discussion platform, other benefits provided through informal activities, such as webinars, include a broadening of communication channels to reach a wider audience and as an aid to fostering positive relationships with non-network providers.

Since publication of the 2020 TAPR, Powerlink has continued its collaboration with Energy Networks Australia (ENA) and the Institute for Sustainable Futures[4] regarding the Network Opportunity Mapping project. This project aims to provide enhanced information to market participants on network constraints and the opportunities for demand side solutions. These collaborations further demonstrate Powerlink's commitment to using a variety of platforms to broaden stakeholder awareness regarding possible commercial opportunities for non-network solutions.

[4] Information available at Network Opportunity Mapping.

Non-network Engagement Stakeholder Register

Powerlink has a non-network Engagement Stakeholder Register (NNESR) to inform non-network providers of the details of emerging network limitations and other future transmission network needs, such as the replacement of network assets, which may have the potential for non-network solutions. The NNESR is comprised of a variety of interested stakeholders who have the potential to offer network support through advancement in technologies, existing and/or new generation or DSM initiatives (either as individual providers or aggregators).

Potential non-network providers are encouraged to register their interest in writing to networkassessments@powerlink.com.au to become a member of Powerlink's NNESR.

1.11.3 Focus on continuous improvement

As part of Powerlink's commitment to continuous improvement, the 2021 TAPR focuses on an integrated approach to future network development, including the development of REZ, and contains detailed discussion on key areas of the transmission network forecast to require expenditure.

In conjunction with condition assessments and risk identification, as assets approach their anticipated replacement dates, possible reinvestment alternatives undergo detailed planning studies to confirm alignment with future reinvestment, optimisation and delivery strategies. These studies have the potential to deliver new information and may provide Powerlink with an opportunity to:

- improve and further refine options under consideration
- consider other options from those originally identified delivering positive outcomes for customers.

Information regarding possible reinvestment alternatives is updated annually within the TAPR and includes discussion on the latest information available as planning studies mature.

The 2021 TAPR:

- discusses emerging challenges as the power system transforms to much greater levels of VRE generation (refer to chapters 2, 3, 6, 9 and 10)
- provides information in relation to joint planning and Powerlink's approach to asset management (refer to chapters 4 and 5)
- discusses possible future network asset investments for the 10-year outlook period (refer to Chapter 6)
- includes the most recent information for the proposed replacement of network assets which are anticipated to be subject to the RIT-T in the next five years (refer to Chapter 6)
- discusses the potential for generation developments (in particular VRE generation) and the challenges related to the management of system strength (refer to chapters 2 and 10)
- contains information on potential non-network opportunities in the next five years, grouped by investment type (refer to Chapter 7) and discusses Powerlink's approach to assisting the development of non-network solutions – specifically, through the ongoing improvement of engagement practices for non-network solution providers and provision of information (refer to sections 1.11.2 and 6.7)
- links to Powerlink's new TAPR portal website incorporating the 2021 TAPR templates and discusses the context, methodology and principles applied for the development of the Queensland transmission network data (refer to Appendix B).

1 Introduction

CHAPTER 2

The transforming energy system

2 The transforming energy system

Key highlights

- This chapter discusses the opportunities and challenges arising as a result of a rapidly evolving energy system.
- In response to energy transformation, Powerlink is strategically planning, guiding and enabling opportunities for the Queensland's future transmission network and continues to deliver a secure, safe, reliable and cost-effective service to customers.
- Powerlink's long-term strategic planning takes into account:
  - the central role the transmission network will play in enabling the transformation to a lower carbon future
  - dynamic changes in the external environment, including load growth, storage and the growth in variable renewable energy (VRE) developments in Queensland
  - the condition and performance of existing assets, planning the network that in such a way that it is best configured to meet current energy needs while maintaining the flexibility to adapt as the future evolves.
- Powerlink is playing an active role in shaping the electricity system of the future enabling the transformation to a new energy system, underpinned by clean, sustainable and reliable energy.
- Powerlink has committed to establishing three Queensland Renewable Energy Zones (QREZ). Working in conjunction with the Queensland Government, these QREZ will exploit the state's high quality renewable resource and encourage economic growth, place downward pressure on electricity prices and support both industry and local communities.
- The rapid uptake of rooftop photovoltaic (PV) systems is significantly changing the physical nature of daily load flows and the way in which transmission and generation systems are planned and operated.

2.1 Introduction

The pace and scale of change of Australia's energy system is one of the fastest in the world. The share of VRE generation is increasingly rapidly with significant growth in grid connected solar and wind farms as well as distributed rooftop PV installed behind the meter. This is presenting new opportunities for communities and local businesses throughout the State, but also driving significant technical challenges for the electricity supply chain.

Customer behaviour is central to the energy transformation. Customers, now more than ever, are demanding choice and the ability to exercise greater control over their energy needs, with expectations of reliability and greater affordability. Given this, the future load is uncertain due to a number of factors including variability of customer uptake, push for net zero emissions, emergence of new technology, composition of distributed energy sources (DER)[1] and the commitment and/or retirement of large industrial and mining loads.

The new energy system, driven by the need to decarbonise and underpinned by VRE, will use technology that is very different to that of most existing traditional large and centralised generation plant. It will not have the same physical and supply characteristics as the existing system. Powerlink is addressing these differences to enable the transformation to a new energy system, underpinned by clean, sustainable, reliable and cost effective energy.

2.2 Integrating energy pathways through collaboration

The transmission system is central to the efficient transformation to a low carbon future, integrating significant customer DER responses with the connection of a balance of grid-scale renewables, storage and dispatchable generation.

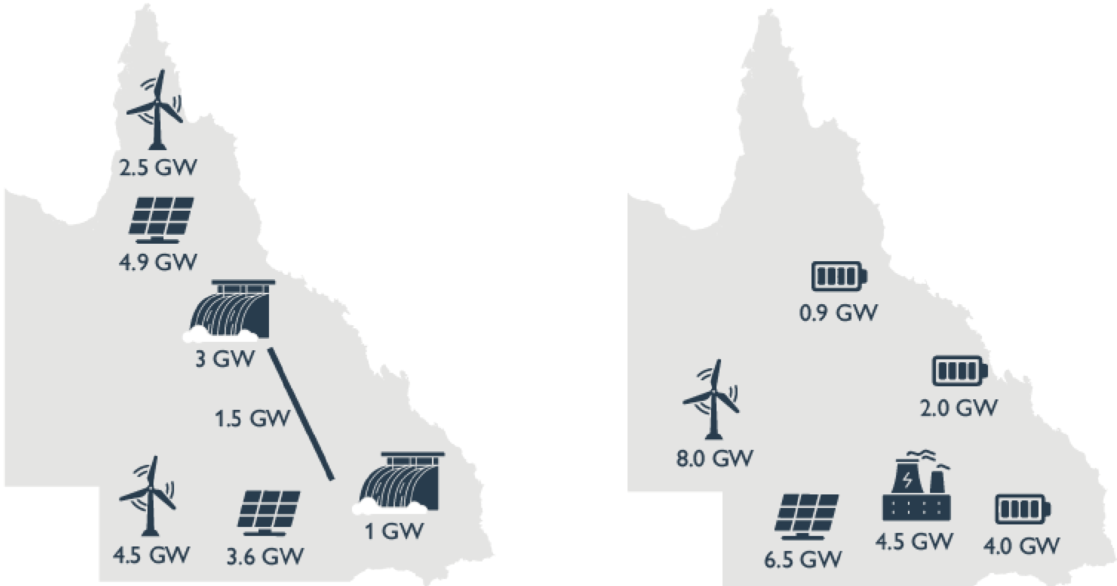
Significant cross collaboration is underway across the industry to inform and respond to the emerging challenges. These include the development of AEMO's 2022 Integrated System Plan (ISP) and its Engineering Frameworks Review, the Energy Security Board's Post 2025 Market Review work and various Australian Energy Market Commission (AEMC) reviews and rule changes including the System Strength Frameworks review.

[1] Common types of DER include 'behind the meter' sources, such as household and business rooftop PV units, battery storage and smart meters.

Powerlink developed the Integrated Electricity Pathways (IEP) and has actively engaged with key stakeholders to explore key investment options for transmission, energy storage and renewable generation against a range of changing sensitivities such as rooftop PV installations, generation portfolios, load developments, and future fuel prices.

Powerlink's IEP identified two broad development pathways that represent the bookends of how the Queensland transmission network could evolve to enable the cost effective transformation to a low carbon future (refer to Figure 2.1). It is anticipated that a mix of the characteristics of both pathways will eventuate over time to meet the changing requirements of the energy system. The pathways presented will frame further policy analysis and future discussions.

Figure 2.1 IEP Development Pathways

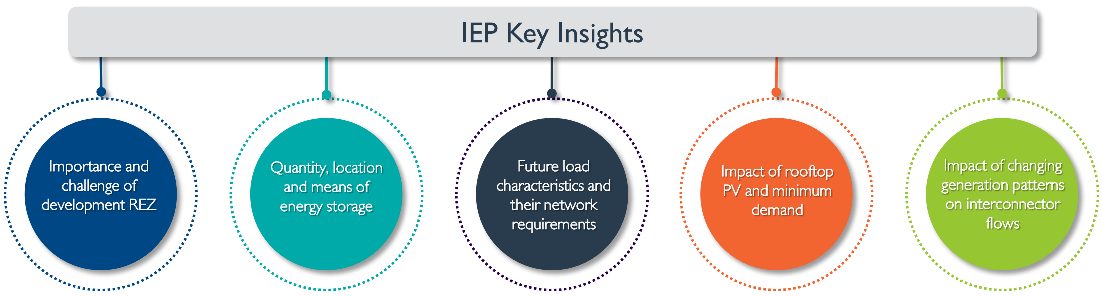


Pathway 1 - Development of significant pumped hydro in southern and northern Queensland, complemented by large-scale solar PV. This pathway, across a number of sensitivities is the optimal least cost option.

Pathway 2 - Development of batteries concentrated around loads in southern Queensland, complemented with additional gas generation.

Powerlink has identified five key insights (refer to Figure 2.2) which are discussed in sections 2.3 to 2.6.

Figure 2.2 IEP Key Insights



2.3 Importance and challenge of developing REZ

A REZ is a geographic area proposed for the efficient development of renewable energy sources and associated electricity infrastructure[2].

Queensland is an attractive location for grid-scale VRE generation development projects as it is rich in a diverse range of renewable resources – solar, wind, geothermal, biomass and hydro.

2.3.1 Economic drivers and future VRE generation development opportunities

While largely driven by changes in customer behaviour, the uptake of VRE generation is also being driven, in part, by the falling cost of solar and wind farm technology. Commonwealth Scientific and Industrial Research Organisation (CSIRO) GenCost report has indicated that the cost of grid connected solar is expected to continue to fall, with the cost of onshore wind also declining[3].

Queensland's first transmission connected solar farm was commissioned in 2018[4] and the number of solar farms has grown rapidly since that time, with 1,024MW operating and a further 1,484MW committed (refer to Table 8.1). Development of grid connected solar farms has slowed in recent years, likely due to the falling spot price of electricity for Queensland during the day time and the expectation of further growth in rooftop PV capacity.

Queensland has practically unlimited potential for the development of additional solar generation. The challenge in utilising this resource is the mismatch between when solar energy is abundant (i.e. during the day time) and the all day demand for electricity. Shifting load demand to times when solar energy is abundant coupled with energy storage will increase the potential for increased solar generation capacity. In Queensland's context, one of the economic merits of deep storage such as pumped hydro is the ability to source a greater share of the State's energy needs from low cost solar.

The development of wind generation has been eclipsed by solar to date (refer to Table 8.1). This is expected to change in the coming years as there is significant interest and activity in developing large-scale on-shore wind generation projects. As wind generation is dispersed throughout the day (i.e. outside of day time), it complements the existing base of solar generation and is less impacted by depressed market prices for energy during the day time.

Queensland's quality wind resource is finite, and concentrated in specific areas. The Queensland Government's Renewable Energy Zone initiative is focussed on developing these areas of wind resource using scale-efficient transmission in a coordinated manner that maximises the capacity and cost efficiency of wind development and delivers genuine benefits to surrounding regional communities. The development of wind resources in Far North Queensland is particularly attractive as the region exhibits less correlation of output to other wind generating stations across the National Electricity Market (NEM). However, wind developments in these locations may be more susceptible to transmission losses (refer to Section 10.8).

REZ development can involve expanding the transmission network or augmenting the capacity of an existing transmission line to increase hosting capacity allowing multiple generators to be connected to the transmission network in a more cost-efficient way. As Queensland has plentiful solar resources coupled with limited quality wind resources, it is important to efficiently coordinate the development of these key resources to transform to a low carbon energy future in an optimal and cost effective manner.

Renewable Firming

The output of wind and PV solar energy sources are intermittent, and vary depending on a range of factors including weather conditions, cloud cover and extent of daylight hours. There is a need to firm renewable energy supply to ensure the supply and demand balance is maintained in a reliable and cost effective manner to customers. There are a number of measures that can be undertaken such as:

2 Version 169 of the NER, page 543.
3 Refer to CSIRO media release June 2021 release June 2021.
4 Clare Solar Farm in North Queensland (100MW).

- both deep and shallow energy storage (e.g. batteries and pumped hydro storage)
- geographic and renewable energy technology diversity
- transmission as an enabler to facilitate access to diverse renewable sources, locations and technologies and
- demand responses (e.g. time of day demand shifting and load controllability).

Each of these has different costs, advantages and capabilities. The optimal solution is likely to involve using all of the responses to varying degrees. The optimal combination of responses will vary over time as the proportion of variable renewable energy (VRE) generation increases and different forms and degrees of firming are required. The value of energy storage is likely to appreciate over time especially deep forms of energy storage such as the potential 24,000MWh Borumba pumped hydro energy storage (PHES) (refer to Section 2.4.2).

2.3.2 Queensland Renewable Energy Zones

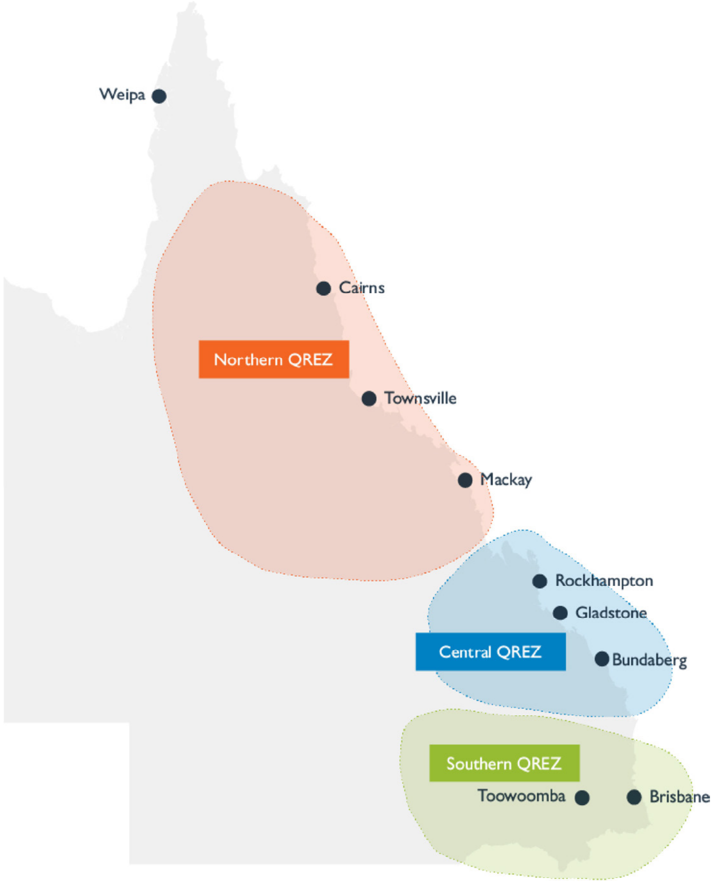
In August 2020, the Queensland Government committed $145 million to establish three Queensland renewable energy zones (QREZ) located in northern, central, and southern Queensland (refer to Figure 2.3)[5]. Powerlink has been working with the Queensland Government to ensure that these developments are coordinated to unlock renewable energy and deliver cost effective network expansion and benefits to host communities by supporting existing and emerging industries within Queensland's regional economies. Powerlink's guiding principles to develop these QREZ are:

- optimising the existing capacity of the transmission network to provide cost effective renewable energy development
- developing QREZ in areas where shared network transmission capacity will enable good access to the market for renewable generators
- efficiently developing QREZ to match regional loads to minimise losses and
- seeking diversity in VRE generation sources to optimise firming services, and ensure continued reliability and security of supply of the energy system at the lowest cost to customers.

The characteristics of the Northern, Central and Southern QREZ is outlined in Figure 2.3.

[5] As published on the Queensland Government website.

Figure 2.3 Queensland Renewable Energy Zones



Northern QREZ

- Good quality wind and capacity factors
- Diverse generation to Southern Queensland and the rest of the NEM
- Queensland Government investing in transmission infrastructure to establish Northern QREZ of up to 500MW capacity
- Neoen's 151MW Kaban Wind Farm as foundational proponent

Central QREZ

- Energy hub of the State with substantial coal fired generation, large loads and export terminals
- Potential renewable energy opportunities and loads converting to renewable energy
- Strong interest in large-scale renewable generation

Southern QREZ

- Large load centres with high capacity interconnector
- Good mixture of energy sources
- Strong transmission network
- Powerlink is working with proponents to develop first stages of Southern QREZ

2.4 Quantity, location and means of energy storage

Energy storage is one of the means of addressing the complexities of demand and supply balance associated with the intermittency of VRE. The types of energy storage available include:

- Large-scale batteries which are most suited to address network needs in shorter timeframes (i.e. hours)
- PHES which may be more suited to larger and longer energy storage requirements and
- Distributed energy resource storage (e.g. residential batteries).

Powerlink's IEP market modelling indicated that there is benefit in building between 4GW and 7GW of energy storage, in stages, as part of the conversion to renewable energy over the next 20 to 30 years. It is expected that approximately 100GWh to 150GWh of energy storage will be required by 2050 to complement VRE sources. Significant long-term storage of at least 24 hours duration will be a critical part of managing the intermittent nature of the rapidly increasing VRE generation. PHES will form a foundation component of energy storage, and other forms of technologies (e.g. hydrogen storage systems) are likely to be candidates in the future.

2.4.1 Residential batteries

Residential battery storage systems, if utilised collectively through 'smart' technology, have the potential to smooth the peaks and troughs of the network across the day, stabilising supply and demand. This could avoid or defer investments in network infrastructure within both the transmission and distribution system[6].

2.4.2 Borumba Dam pumped hydro project

Powerlink is leading a $20 million dollar feasibility study and detailed business case development for the Borumba Pumped Hydro Dam project for the Queensland Government. The project is located near Imbil, south-west of Gympie. Powerlink is working closely with key stakeholders and other Government Owned Corporations to ensure all relevant information is included in the study. The feasibility study and business case is due in late 2023.

2.4.3 Grid-scale batteries and expression of interest (EOI)

Powerlink has recently completed the first customer connected grid-scale battery (100MW and 150MWh) to the transmission network in south-east Queensland. Based on CSIRO GenCost modelling, Powerlink expects additional batteries to connect to the Queensland network over the next decade due to technological advances and the rapid cost reduction of this form of technology[7].

Batteries will play a greater role in the future transmission network providing system security services such as frequency regulation, voltage control, inertia and system strength. Powerlink undertook an investigation with ARENA to improve the awareness of system strength issues and measures that can be addressed through the use of large-scale batteries, including new technology such as grid forming inverters. Grid forming batteries can play a constructive role in increasing the hosting capability of VRE generation within REZs and supporting the operation of the power system (refer to Section 10.3).

Grid-scale batteries can also play a role as virtual transmission lines (VTLs). This offers the potential to alleviate transmission congestion, increase network and REZ utilisation and defer the need for investment in future network augmentations. Battery services can also be deployed to help manage the impact of outages and minimise the constraints on generation which occur during these periods.

In March 2022, Powerlink published an expression of interest (EOI) to engage with external developers, investors and stakeholders in grid-scale Battery Energy Storage Systems (BESS). The EOI is exploring commercial and technical models that would guide the optimal placement of grid-scale battery systems and adopted technology to meet both Powerlink's network technical requirements and investors' requirements for commercial returns.

Powerlink proposes to offer BESS project proponents the opportunity to construct and install their BESS at optimal points in the transmission network. By guiding the optimal development and placement of battery systems, the value to stakeholders is maximised and positive benefits to customers delivered.

2.5 Future load characteristics and their network requirements

The historical pattern of energy consumption in Queensland is changing.

Presently approximately 20% of final energy consumption in Queensland is from electricity, and this electrical energy is predominantly supplied from the interconnected power system. However, moving forward there are two high level trends:

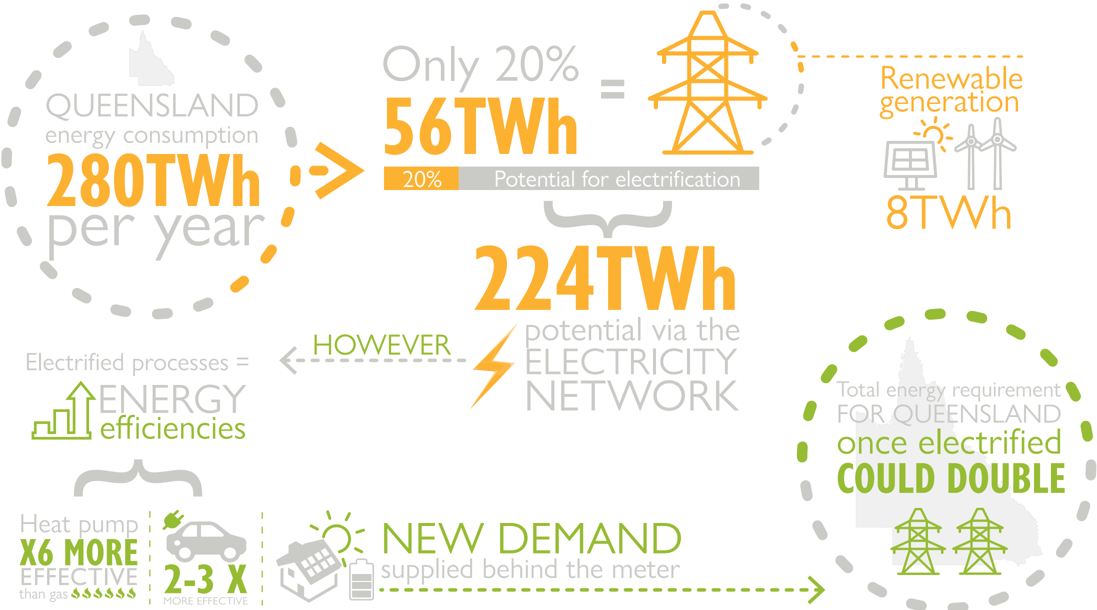
- Electrification of load historically supplied by the combustion of fossil fuels to various sectors of the economy such as transport, agriculture, mining and manufacturing. The drivers for the electrification of these sectors largely relate to the consideration of environmental factors, community and corporate expectations and the broader global focus on emissions reduction. This has been followed closely by the development and commercialisation of new technologies to address these drivers (refer to Section 9.2.1).

[6] Further information on residential batteries is available on the ENA website.
[7] Refer to CSIRO GenCost 20-21 Final Report.

- Decentralisation of electricity supply due to the increasing uptake of rooftop PV with some level of firming provided by residential battery systems. The rapid uptake of rooftop PV in Queensland, coupled with emerging technologies such as batteries means that a growing share of households and small businesses are supplying their own energy needs.

The growth in grid-supplied electricity through electrification will to some extent be offset by the increasing decentralisation from the existing customers of the grid. The relative strength of these two effects is uncertain, but on balance overall energy consumption[8] is expected to increase over the long-term (refer to Figure 2.4). Any additional electrical load in Queensland to facilitate energy renewable exports would be additional to this.

Figure 2.4 Potential combined impact of identified trends in Queensland



However, these effects are not uniformly distributed throughout Queensland. In particular mining and energy-intensive manufacturing activity is concentrated in particular locations. This may require transmission network augmentations in certain locations to deliver reliability to this load even as contraction may occur in other areas. Powerlink will continue to undertake prudent investment and efficient operation of the transmission network to manage potential growth in some areas, while requirements in other areas may decrease. Even in an area where the possibility of decreased supply needs is anticipated, there continues to be a requirement to supply load as long as it exists and to safely and securely operate the network for customers in a cost efficient manner.

2.5.1 Other future technologies

Currently less than 0.15% of cars on Queensland roads are electric vehicles (EVs). However, recent international policies relating to the sale of internal combustion engines (ICE) vehicles[9] and moves by car manufacturers to phase out ICE vehicles will put downward pressure on costs and increase the models of EVs in the Australian market. Supported by the Queensland Zero Emission Vehicle (ZEV) Strategy which is in development, this is expected to materially increase the number of EVs on Queensland roads over time, which will have the potential to impact the energy and demand requirements of the network.

The Australian Renewable Energy Agency (ARENA) in conjunction with industry is currently exploring emerging new technologies such as renewable hydrogen and renewable energy to understand potential future opportunities at a domestic, commercial and export level.

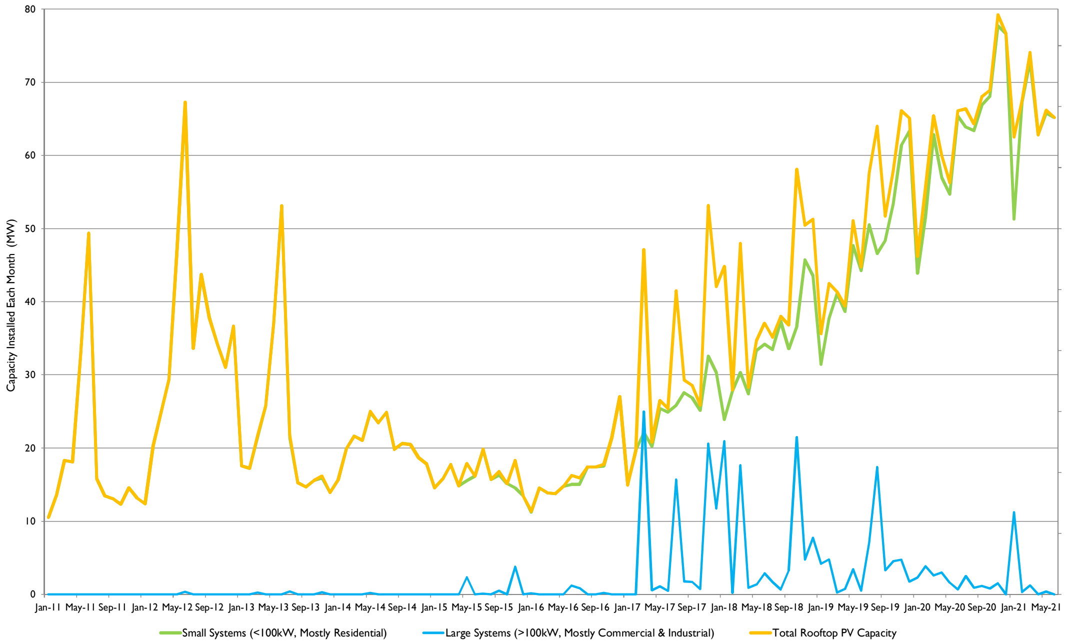
8 Defined in tera watt hours (TWh).
9 UK is banning the sale of ICE vehicles by 2030.

2.6 Impact of rooftop PV and minimum demand

2.6.1 Rooftop PV systems

Queensland has one of the highest penetration of rooftop PV systems in the world with almost 40% of households having installations compared to 25% penetration only five years ago[10]. The installation of rooftop PV in Queensland is increasing at significantly higher rates than recent forecasts. The current installation rate is approximately 800MW per annum (refer to Figure 2.5). Rooftop PV penetration in Queensland is expected to continue with the Queensland Household Energy Survey indicating that 22% of participants intended to purchase new or upgrade existing rooftop PV in the next three years, and 93% indicated they would replace their existing panels with similar sizes or larger.

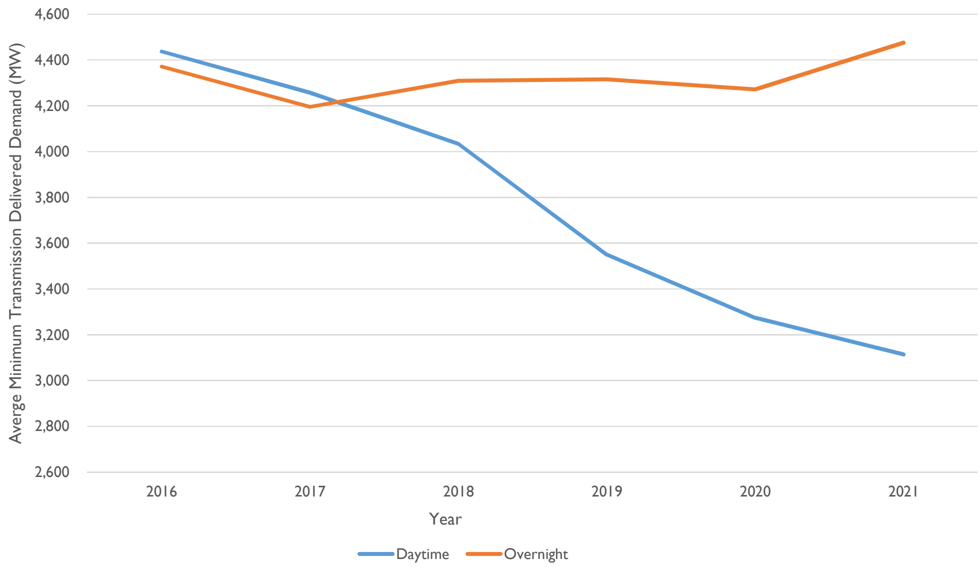
Figure 2.5 New rooftop PV installations



The high uptake of large-scale VRE generation within the distribution networks together with the significant uptake of rooftop PV is changing the transmission delivered daily load (refer Section 3.4.1). These large quantities of solar generation are all highly correlated in output. A noticeable change has been the change in the pattern of minimum demand, shifting from the very early morning to the middle of the day. As embedded and rooftop PV capacity increases, the minimum day time demand set during the winter and spring seasons will continue to decrease. Figure 2.6 shows the shift to day time minimum demands.

10 Australian PV Institute (APVI) Solar Map, funded by the ARENA.

Figure 2.6 Average of the five lowest demand days per calendar year for day time and overnight



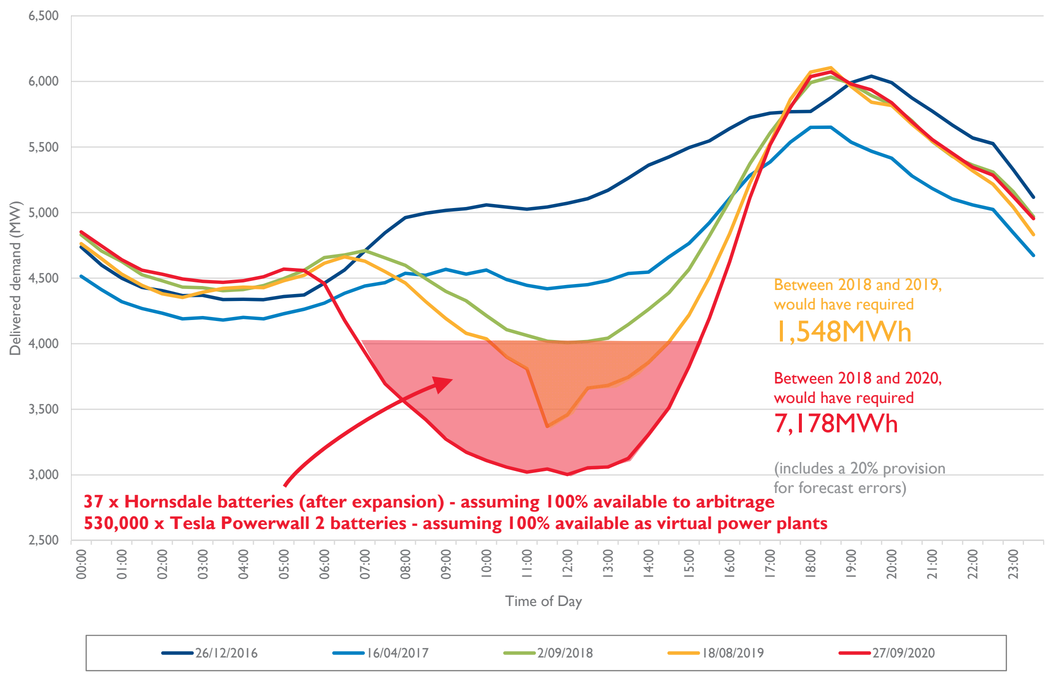
The transmission delivered demand is also partially supplied from transmission connected grid-scale VRE. Therefore, the load available for supply by the traditional synchronous generation or 'residual demand' is reducing. While the minimum demand decline is generally most observable in spring, the overall trend of minimum demand across the year is also decreasing.

This trend is likely to present technical challenges to the power system requiring future investment in network or non-network solutions (such as battery storage). The scale of investment in storage to mitigate medium term adverse impacts of falling minimum demand on the secure operation of the power system is significant. The minimum demand decrease from 2018 to 2020 would be equivalent to over 7,178MWh of storage. This is equivalent to 37 Hornsdale batteries or around 530,000 Tesla Powerwalls. The rate of decrease of minimum demand is the key reason why batteries alone are unlikely to be able to provide the storage capability to manage this issue.

Once adequate deep storage exists, large-scale solar generation can again become a key ingredient in the low-cost electricity supply by providing the capacity to charge the storage facilities through the day where excess generation exists. This then allows the storage to discharge (generate) to meet peak demand at night.

Complementing this is the diversity of wind generation that can also support peak demand and provide renewable energy outside of day time peak PV generation periods. Therefore, in the interim, the wind resources need to be fully exploited to support Queensland's QRET target at least cost (refer to Figure 2.7).

Figure 2.7 Energy required to offset reduction in minimum demand



Powerlink is monitoring and assessing the impacts of changing load profiles and generation mix on the transmission network, and continues to take an integrated planning approach to address emerging issues and challenges with the transforming power system.

The broader technical challenges arising from minimum demand cannot be addressed by a single organisation and will require a cross-industry collaboration to ensure customer centric solutions deliver a safe reliable transition to 50% renewables by 2030 and beyond. The transmission network is increasingly impacted by customer decisions regarding DER adoption occurring in the distribution network. Powerlink, EQL and the Queensland Government recognise the need to ensure that investments to support minimum demand mitigation in either the transmission or distribution network are complementary and ensure that solutions maximise customer benefits whilst not adversely affecting customer cost.

Powerlink, EQL and the Queensland government recognise that likely solutions to manage the impacts of minimum demand include:

- energy storage across the supply chain that operates complementary and coordinated to the system needs (transmission, distribution and behind the meter connected).
- encouragement of the local use of generated energy to limit the need for energy to minimise the flows back and forth between the transmission and distribution system.
- continued refinement for the connection of DER in a manner that ensures the overall reliability and security of the transmission and distribution networks.

2.6.2 Impact of changing generation patterns on interconnector flows

Queensland has historically exported energy to New South Wales and other NEM states over the Queensland to New South Wales Interconnector (QNI). The development of significant VRE resources in other states as well as Queensland has the potential to significantly alter the flows on both inter and intra connectors.

For example, through the NSW Energy Infrastructure Roadmap (EIR), NSW is expecting to deliver around 12GW of additional renewable generation by 2030. If the NSW EIR is implemented to its full extent, southerly flows across QNI would materially reduce or potentially reverse.

2.7 Ongoing transformation

The power system of the future will present many operational, planning, regulatory and market challenges. New frameworks, strategies and infrastructure are required to enable the orderly transformation to a power system which is underpinned by clean, sustainable, resilient and reliable energy at the lowest long run cost to consumers.

Powerlink is keeping abreast of new technological developments and formulating strategies with AEMO, the Queensland Government, Energy Queensland, and other market participants. This will ensure that the high voltage transmission grid is capable of unlocking opportunities and benefits associated with a decarbonised low emissions energy system to power economic growth, enable market efficiencies and reduce cost to customers.

Powerlink will continue to proactively plan for the future and update the IEP to make certain that electricity pathways include new developments and remain relevant for the changing environment. Regular assessments will focus on delivering positive outcomes for customers by addressing shifts in physical, technical and economic environments.

CHAPTER 3

Energy and demand projections

3 Energy and demand projections

Key highlights

- This chapter describes the historical energy and demand, and provides forecast regional data disaggregated by zone.
- The 2020/21 summer maximum transmission delivered demand of 8,479MW occurred at 6pm on 22 February 2021, was 287MW lower than the maximum delivered demand in 2019/20 and 490MW lower than the record demand set in 2018/19.
- Queensland set a record minimum operational 'as generated' demand of 3,784MW on 3 October 2021 at 11:30am. This coincided with the minimum transmission delivered demand for 2021 of 3,053MW.
- Native plus rooftop photovoltaic (PV) energy increased by approximately 1.4% between 2019/20 and 2020/21.
- Powerlink has adopted the Australian Energy Market Operator's (AEMO) 2021 Electricity Statement of Opportunity (ESOO) forecasts in its planning analysis for the 2021 Transmission Annual Planning Report (TAPR). Powerlink is focussed on working with AEMO to understand the potential future impacts of emerging technologies so transmission network services are developed in ways that are valued by customers.
- Based on AEMO's Steady Progress scenario forecast, Queensland's delivered maximum demand is expected to maintain low growth with an average annual increase of 0.8% per annum over the next 10 years.
- The uptake of rooftop PV and distribution connected solar systems is further reducing delivered demand during the day to the point where this is now lower than night time light load conditions. The rate at which minimum demand declines over the coming years will be closely related to the rate at which rooftop PV systems are installed. Falling minimum demand will result in a variety of impacts on the power system, some of which may necessitate investment on the transmission system.
- Queensland's transmission delivered energy is expected to decline over the next 10 years predominantly due to continued installation of variable renewable energy (VRE) generation embedded within distribution networks and continuing installations of rooftop PV. Based on AEMO's Steady Progress scenario, transmission delivered energy consumption is expected to decline at an average rate of 1.1% per annum over the next 10 years.

3.1 Overview

The 2020/21 summer Queensland maximum delivered demand occurred at 6pm on 22 February 2021, when 8,479MW was delivered from the transmission grid (refer to Figure 3.5 for load measurement definitions). Operational 'as generated' and native demand peaks were recorded at this same time, with operational 'as generated' reaching 9,473MW and native demand reaching 8,929MW. After weather correction, the 2020/21 summer maximum transmission delivered demand was 8,660MW, 3.6% higher than that forecast in the 2020 ESOO Central scenario.

Figure 3.1 shows observed temperatures for Brisbane during summer 2020/21 compared with long-term averages, revealing a slightly cooler summer than average in south east Queensland, with daily maximum temperatures subdued in March.

Figure 3.1 Brisbane temperature ranges over summer 2020/21 (1)

Note:
(1) Long-term average based on years 2000 to 2020/21.

The 2021 Queensland minimum delivered demand occurred at 11:30am on 3 October 2021, when only 3,053MW was delivered from the transmission grid (refer to Figure 3.5 for load measurement definitions). Operational 'as generated' minimum demand was recorded at the same time and set a new record for Queensland of 3,784MW, passing the previous minimum record of 3,839MW set in July 2021. Direct connect loads made up about 60% of the transmission delivered demand with Distribution Network Service Provider (DNSP) customers only making up 40%. Mild weather conditions, during a weekend (Sunday) in combination with strong contribution from rooftop PV were contributors to this minimum demand.

Powerlink has worked with AEMO to derive transmission delivered equivalent demand and energy forecasts based on the forecast operational sent out quantities defined in AEMO's 2021 ESOO. Further information on the development of AEMO's 2021 ESOO is available on AEMO's website[1].

The AEMO 2021 ESOO forecasts provide the top-down, whole of state maximum demand forecast for the Queensland region. These are reconciled with bottom-up forecasts from DNSPs and directly connected customers to create the granular models needed to inform zonal or more localised issues.

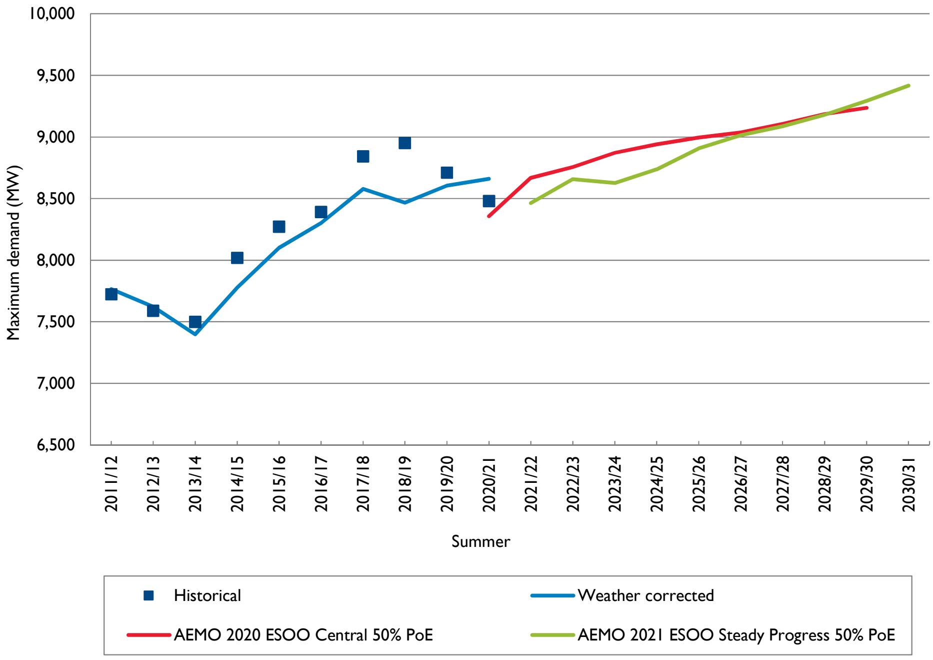
The Queensland Government's 50% renewable energy target by 2030 Queensland Renewable Energy Target (QRET) has driven renewable capacity in the form of solar PV and wind farms to connect to the Queensland transmission and distribution networks (refer to Table 8.1 and Table 8.2). Additional uncommitted distribution connected solar and wind farm capacity has been included into the 10-year outlook period from 2026 to model the Queensland Government's target.

At the end of June 2021, Queensland reached 4,074MW of installed rooftop PV capacity[2]. Growth in rooftop PV capacity increased from around 59MW per month in 2019/20 to 65MW per month in 2020/21. An impact of rooftop PV, has been the time shift of the state's maximum demand, which now occurs around 6:00pm. As a result of significant capacity of rooftop PV and small-scale PV non-scheduled generation (PVNSG), maximum demand is unlikely to occur in the day time, it is now expected to occur in the early evening.

1 AEMO, 2021 Electricity Demand Forecasting Methodology Paper, August 2021.
2 Clean Energy Regulator, Postcode data for small-scale installations – all data, data as at 31/08/2021, September 2021. Whilst RET legislation allows a 12 month creation period for registered persons to create their certificates, updates for the first 9 months of this window are generally not material.

Figure 3.2 shows a comparison of AEMO's 2020 ESOO delivered summer maximum demand forecast based on the Central scenario with AEMO's 2021 ESOO based on the Steady Progress scenario, both with 50% Probability of Exceedance (PoE).

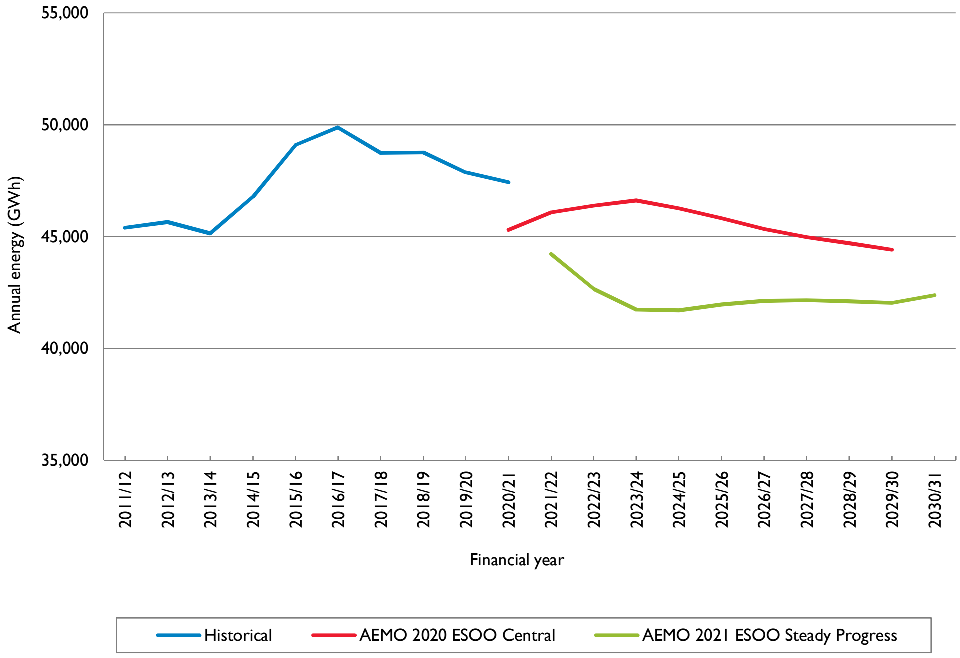
Figure 3.2 Comparison of AEMO's 2020 ESOO Central scenario delivered demand forecast with the 2021 ESOO Steady Progress scenario (1)



Note:
(1) AEMO's 2021 ESOO forecast has been converted from 'operational sent-out' to 'transmission delivered' for the purposes of comparison. Refer to Figure 3.5 for further details.

Figure 3.3 shows a comparison of AEMO's 2020 ESOO delivered energy forecast based on the Central scenario with AEMO's 2021 ESOO based on the Steady Progress scenario. Section 3.4 discusses updates included in AEMO's 2021 ESOO forecasts.

Figure 3.3 Comparison of AEMO's 2020 ESOO Central scenario delivered energy forecast with the 2021 ESOO Steady Progress scenario (1)



Note:

(1) AEMO's 2021 ESOO forecast has been converted from 'operational sent-out' to 'transmission delivered' for the purposes of comparison. Refer to Figure 3.5 for further details.

3.2 Future forecasting challenges

Decentralisation, driven by future developments in battery storage technology coupled with rooftop PV and EVs, could see significant changes to future electricity usage patterns. This could reduce the need to develop transmission services to cover short duration peaks.

However, presently only approximately 20% of final energy consumption in Queensland is from electricity and this electrical energy is predominantly supplied from the interconnected power system. Therefore, the electrification of load historically supplied by the combustion of fossil fuels to various sectors of the economy such as transport, agriculture, mining and manufacturing may require a significant investment in the transmission and distribution networks. The drivers for the electrification of these sectors largely relate to the need to reduce carbon emissions for a variety of reasons (environmental factors, community and corporate expectations or the international treatment of exports with implicit emissions).

The growth in grid-supplied electricity through electrification will, to some extent, be offset by reductions in grid-supplied energy due to decentralisation. However, the geospatial distribution of these two effects are not expected to be uniform. There may be areas where net demand for grid-supplied electricity is likely to significantly increase, and other areas where it is likely to decrease.

Powerlink is committed to understanding the future impacts of emerging technologies and electrification and to work with our customers and AEMO so that these are accounted geospatially within future forecasts. This will allow transmission network services to be developed in ways that are valued by customers.

3.3 Customer consultation

In accordance with the National Electricity Rules (NER), Powerlink has obtained summer and winter maximum demand forecasts over a 10-year outlook period from Queensland's DNSPs, Energex and Ergon Energy (part of the Energy Queensland group). These connection supply point forecasts are presented in Appendix A. Also in accordance with the NER, Powerlink has obtained summer and winter maximum demand forecasts from other customers that connect directly to the Powerlink transmission network.

Powerlink, Energex and Ergon Energy jointly conduct the Queensland Household Energy Survey (QHES) to improve understanding of consumer behaviours and intentions. This survey provides comprehensive insights on consumer intentions on electricity usage.

Transmission customer forecasts

New large loads

No new large loads have connected or have committed to connect in the outlook period.

Possible new large loads

There are several proposals under development for large mining, metal processing and other industrial loads. These have not been included in AEMO's 2021 ESOO Steady Progress scenario. These developments totalling nearly 1,250MW, are listed in Table 3.1.

Table 3.1 Possible large loads excluded from the Slow Growth, Steady Progress and Hydrogen Superpower scenario forecasts

Zone	Description	Possible load
Ross	Connection to North West Minerals Province (Mt Isa)	Up to 350MW
North	Further port expansion at Abbot Point	Up to 100MW
North	CSG load (Bowen Basin area)	Up to 80MW
North and Central West	New coal mining load (Galilee Basin area)	Up to 400MW
Surat	CSG load and coal mining projects (Surat Basin area)	Up to 300MW

3.4 Demand forecast outlook

The following sections outline the Queensland forecasts for energy, summer maximum demand, winter maximum demand and annual minimum demand. Annual maximum demands continue to be expected in the summer period. Annual minimum demands have generally occurred in winter and more recently in the shoulder periods.

The annual minimum demand has moved from overnight to the day time since 2018 (this is described in Section 3.4.1). The forecast for minimum delivered demand is now closely correlated to rooftop PV installations and embedded variable renewable energy (VRE) generators. Forecasts in this chapter are provided without predicting market outcomes, directions or constraints which may be imposed to ensure system security but impact on the output of these embedded VRE generators.

The 2021 TAPR reports on the Slow Growth, Steady Progress and Hydrogen Superpower scenario forecasts provided by AEMO and aligned to the 2021 ESOO. Demand forecasts are also prepared to account for seasonal variation. These seasonal variations are referred to as 10% PoE, 50% PoE and 90% PoE forecasts. They represent conditions that would expect to be exceeded once in 10 years, five times in 10 years and nine times in 10 years respectively.

The forecast average annual growth rates for the Queensland region over the next 10 years under Slow Growth, Steady Progress and Hydrogen Superpower scenarios are shown in Table 3.2. These growth rates refer to transmission delivered quantities as described in Section 3.4.2. For summer and winter maximum demand, growth rates are based on 50% PoE corrected values for 2020/21 and 2020 respectively.

Table 3.2 Average annual growth rate over next 10 years

	AEMO future scenario growth outlooks		
	Slow Growth	Steady Progress	Hydrogen Superpower
Delivered energy	-3.9%	-1.1%	0.8%
Delivered summer maximum demand (50% PoE)	-0.6%	0.8%	2.2%
Delivered winter maximum demand (50% PoE)	-0.7%	0.7%	2.3%

3.4.1 Changing load profiles

Historically, the daily load profile as delivered by the Powerlink transmission grid has seen daily maximum demand occur in the mid afternoon during the summer seasons, and during evening periods within the cooler winter seasons. Daily minimum demands have typically occurred during the night time (typically 4am or so) when industries and commercial premises are mostly closed and households are sleeping.

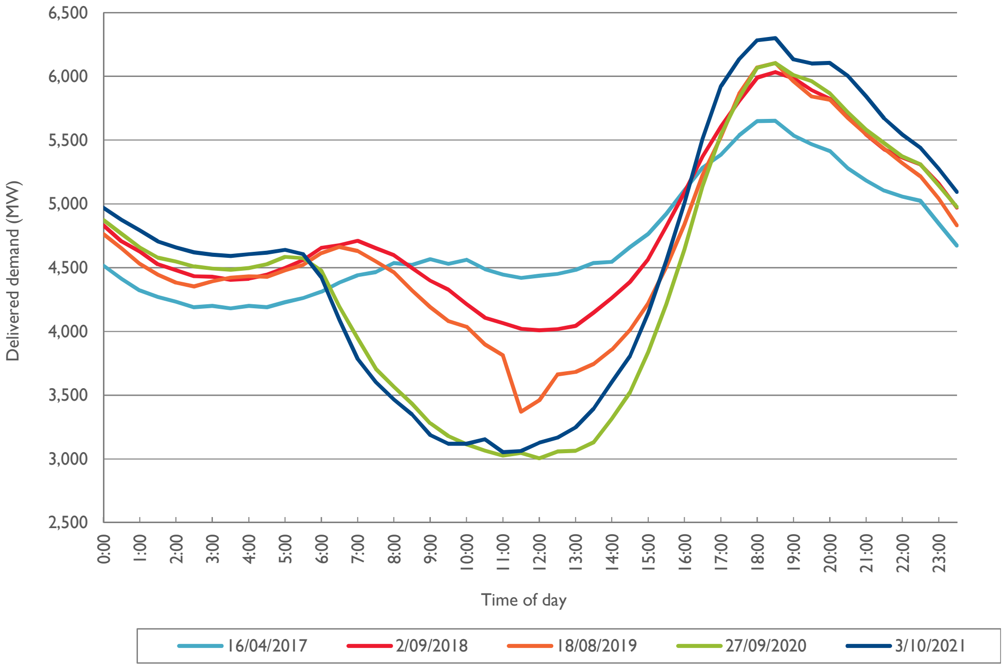
However, the installation of small scale rooftop PV systems and distribution connected solar farms is progressively changing the characteristics of daily demand required to be supplied by the Powerlink transmission system. The uptake of rooftop PV systems within Queensland continues to be one of the highest per capita rates in the world, and there are now over 800,000 installed solar PV systems with an aggregate state-wide capacity of more than 4,074MW[3].

While the cumulative effect of small-scale renewable energy has reduced maximum demand and energy consumption, power produced by embedded solar installations has the effect of 'hollowing' the daily demand profile during the day time period. This contribution ceases during the evening when the sun sets. This effect is more likely to be prominent within Queensland during the lower day time demand winter and spring seasons. The term 'duck curve' was first coined by the Californian Independent System Operator to describe the effects of embedded solar power generation on the shape of the daily load profile, and is a characteristic experienced by transmission networks globally where there has been a significant level of embedded, highly correlated PV renewable energy systems.

Figure 3.4 depicts the change in daily load profile of the transmission delivered minimum demand daily profile. The duck curve can be seen to emerge creating a new annual minimum demand in the middle of the day from 2018.

[3] Clean Energy Regulator, Postcode data for small-scale installations – all data, data as at 31/08/2021, September 2021.

Figure 3.4 Transmission delivered annual minimum demand for the Queensland region (1)(2)



Notes:

(1) Minimum demand can be caused by abnormal conditions, as depicted in the 2019 trace when lowest demand coincided with a large industrial load being out of service.

(2) 3 October 2021 trace based on preliminary metering data.

Minimum demand during the day has continued to decrease with the progressive installation of rooftop PV systems. However, maximum daily demand has continued to increase in line with underlying load growth since the contribution of rooftop PV tapers off towards the evening. This has resulted in an increasing divergence between minimum and maximum demand which needs to be met and managed by generation and the transmission network.

This change in load profile has also meant that day time minimum demand is now lower than night time for a significant portion of the year. This has meant that reactive power devices historically installed to manage night time minimum demand may no longer be sufficient to manage voltages during day time periods.

The uptake of rooftop PV systems is expected to continue within residential and commercial premises. Should this trend progress in the absence of energy storage devices (such as household battery systems) or significant levels of demand time of day shifting, minimum demand is expected to further decrease with continued widening between maximum and minimum demand. The installation of additional reactive devices and/or non-network solutions are likely to be required to manage voltages during minimum demand conditions (refer to sections 11.1 and 6.7.10).

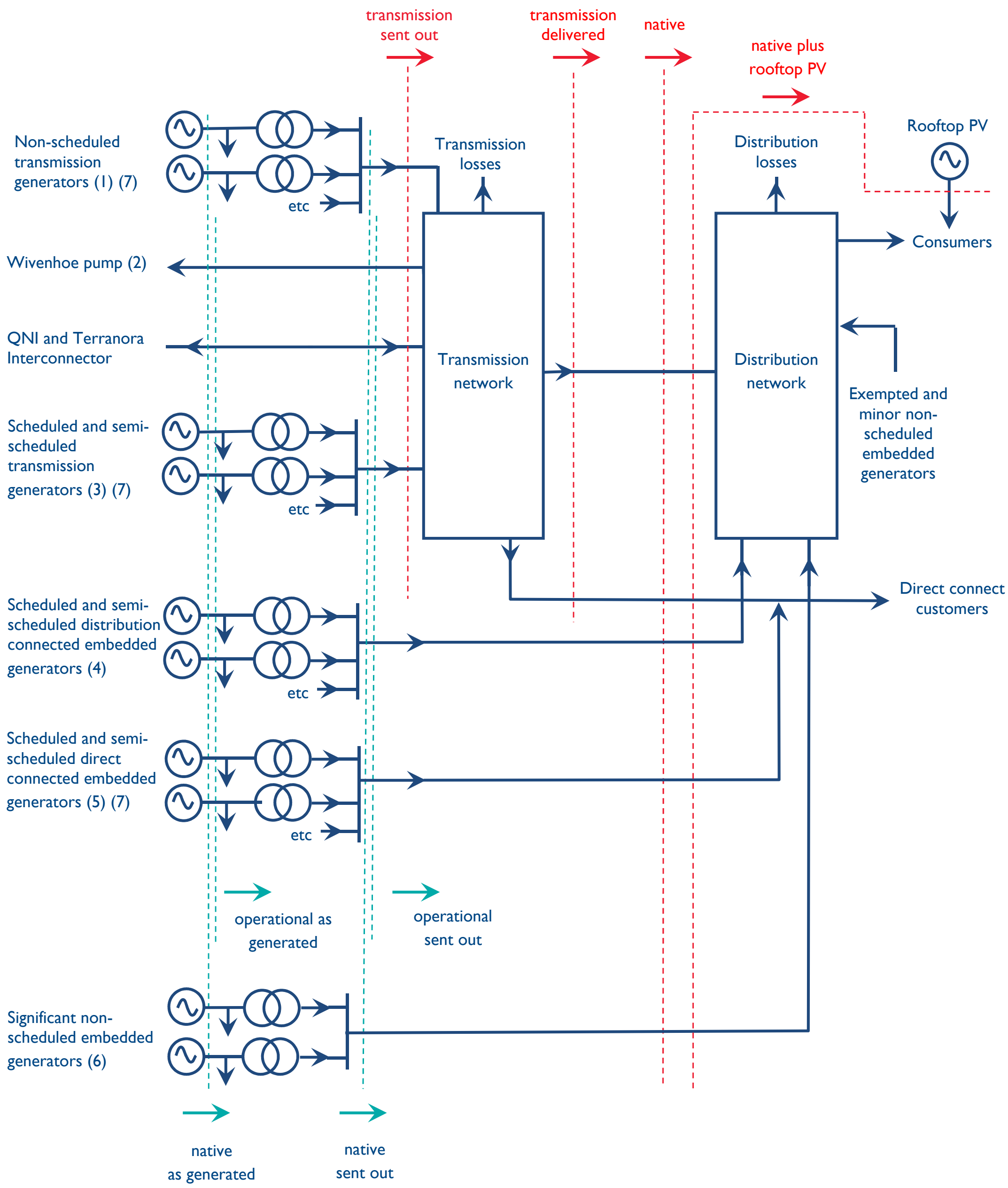
Continuation of this trend is likely to present further challenges to the energy system. Generating stations will be required to ramp up and down in response to daily demand variations more frequently. Decreasing minimum demand may lower the amount of synchronous generation that is able to be on-line and this could further impact on voltage control, system strength, inertia and the ability for available generators to meet evening peak demand. However, there may be opportunities for new technologies and non-network solutions to assist with managing the daily peaks and troughs. Demand shifting and storage solutions have the potential to smooth the daily load profile. These type of services could offer a number of benefits to the electricity system including reducing the need for additional transmission investment.

Powerlink is continuing to monitor and assess the impacts of changing load profiles on the transmission network, and is taking an integrated planning approach to address emerging issues and challenges with the transforming energy system.

3.4.2 Demand and energy terminology

The reported demand and energy on the network depends on where it is being measured. Individual stakeholders have reasons to measure demand and energy at different points. Figure 3.5 shows the common ways demand and energy measurements are defined, with this terminology used consistently throughout the TAPR.

Figure 3.5 Load measurement definitions



Notes:

(1) Includes Invicta and Koombooloomba.

(2) Depends on Wivenhoe generation.

(3) Includes Yarwun which is non-scheduled.

(4) For a full list of scheduled and semi-scheduled distribution connected generators refer to Table 8.2.

(5) Sun Metals Solar Farm and Condamine.

(6) Lakeland Solar and Storage, Hughenden Solar Farm, Pioneer Mill, Moranbah North, Moranbah, Racecourse Mill, Barcaldine Solar Farm, Longreach Solar Farm, German Creek, Oaky Creek, Isis Central Sugar Mill, Baking Board Solar Farm, Daandine, Sunshine Coast Solar Farm, Bromelton and Rocky Point.

(7) For a full list of transmission network connected generators and scheduled and semi-scheduled direct connected embedded generators refer to Table 8.1.

3.4.3 Energy forecast

Historical Queensland energy measurements are presented in Table 3.3. They are recorded at various levels in the network as defined in Figure 3.5.

Transmission losses are the difference between transmission sent out and transmission delivered energy. Scheduled power station auxiliaries are the difference between operational 'as generated' and operational sent out energy.

Table 3.3 Historical energy (GWh)

Financial Year	Operational as generated	Operational sent out	Native as generated	Native sent out	Transmission sent out	Transmission delivered	Native	Native plus rooftop PV
2011/12	51,147	47,724	52,206	48,920	46,980	45,394	47,334	47,334
2012/13	50,711	47,368	52,045	48,702	47,259	45,651	47,090	47,090
2013/14	49,686	46,575	51,029	47,918	46,560	45,145	46,503	46,503
2014/15	51,855	48,402	53,349	50,047	48,332	46,780	48,495	49,952
2015/16	54,238	50,599	55,752	52,223	50,573	49,094	50,744	52,509
2016/17	55,101	51,323	56,674	53,017	51,262	49,880	51,635	53,506
2017/18	54,538	50,198	56,139	51,918	50,172	48,739	50,925	53,406
2018/19	54,861	50,473	56,381	52,118	50,163	48,764	51,240	54,529
2019/20	54,179	50,039	55,776	51,740	49,248	47,860	50,804	54,449
2020/21	53,415	49,727	54,710	51,140	48,608	47,421	50,107	55,232

The transmission delivered energy forecasts are presented in Table 3.4.

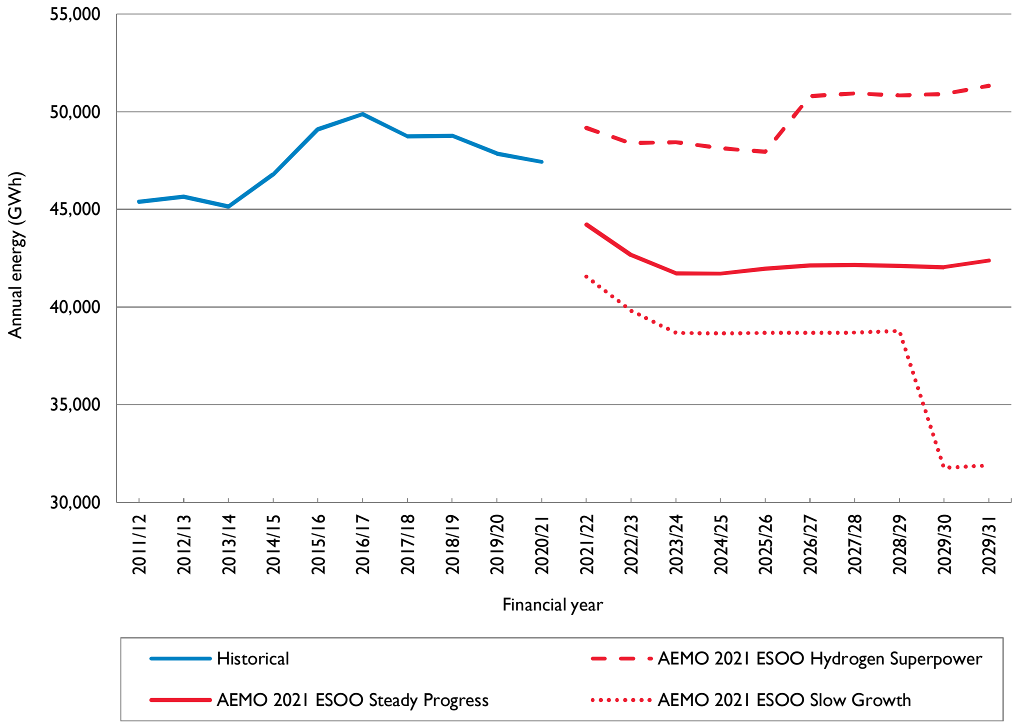
Table 3.4 Forecast annual transmission delivered energy (GWh)

Financial Year	Slow Growth	Steady Progress	Hydrogen Superpower
2021/22	41,554	44,221	49,163
2022/23	39,818	42,665	48,377
2023/24	38,672	41,726	48,437
2024/25	38,639	41,704	48,121
2025/26	38,669	41,960	47,948
2026/27	38,673	42,120	50,798
2027/28	38,684	42,159	50,940
2028/29	38,769	42,105	50,833
2029/30	31,760 (1)	42,035	50,910
2030/31	31,882	42,377	51,326

Note:
(1) AEMO assumes the shutdown of a large industrial load in the Slow Growth scenario in the latter half of winter 2029.

The historical annual transmission delivered energy from Table 3.3 and the forecast transmission delivered energy for the Slow Growth, Steady Progress and Hydrogen Superpower scenarios from Table 3.4 are shown in Figure 3.6.

Figure 3.6 Historical and forecast transmission delivered energy



The native energy forecasts are presented in Table 3.5.

Table 3.5 Forecast annual native energy (GWh)

Financial Year	Slow Growth	Steady Progress	Hydrogen Superpower
2021/22	45,281	47,949	52,890
2022/23	44,209	47,056	52,769
2023/24	43,438	46,492	53,203
2024/25	43,400	46,465	52,882
2025/26	43,319	46,609	53,298
2026/27	43,325	46,954	57,019
2027/28	43,341	47,362	56,997
2028/29	43,421	47,745	57,103
2029/30	36,411 (1)	48,120	57,384
2030/31	36,534	48,461	58,398

Note:
(1) AEMO assumes the shutdown of a large industrial load in the Slow Growth scenario in the latter half of winter 2029.

3.4.4 Summer maximum demand forecast

Historical Queensland summer maximum demand measurements at time of transmission delivered peak are presented in Table 3.6.

Table 3.6 Historical summer maximum demand at time of transmission delivered peak (MW)

Summer	Operational as generated	Operational sent out	Native as generated	Native sent out	Transmission sent out	Transmission delivered	Transmission delivered corrected to 50% PoE	Native	Native plus solar PV
2011/12	8,707	8,143	8,790	8,226	7,890	7,722	7,765	8,058	8,058
2012/13	8,278	8,208	8,448	8,427	8,113	7,597	7,638	7,911	7,911
2013/14	8,445	7,596	8,587	7,749	7,514	7,559	7,436	7,794	8,086
2014/15	8,809	8,360	9,024	8,623	8,276	7,983	7,737	8,330	8,524
2015/16	9,154	8,620	9,332	8,850	8,532	8,222	8,050	8,541	9,021
2016/17	9,412	8,856	9,572	9,078	8,694	8,347	8,257	8,731	8,817
2017/18	9,798	9,211	10,015	9,489	9,080	8,789	8,515	9,198	9,602
2018/19	10,010	9,433	10,173	9,666	9,248	8,969	8,488	9,387	9,523
2019/20	9,836	9,283	10,052	9,544	9,056	8,766	8,662	9,255	9,453
2020/21	9,473	8,954	9,627	9,161	8,711	8,479	8,660	8,929	9,256

The summer transmission delivered maximum demand forecasts are presented in Table 3.7.

Table 3.7 Forecast summer transmission delivered maximum demand (MW)

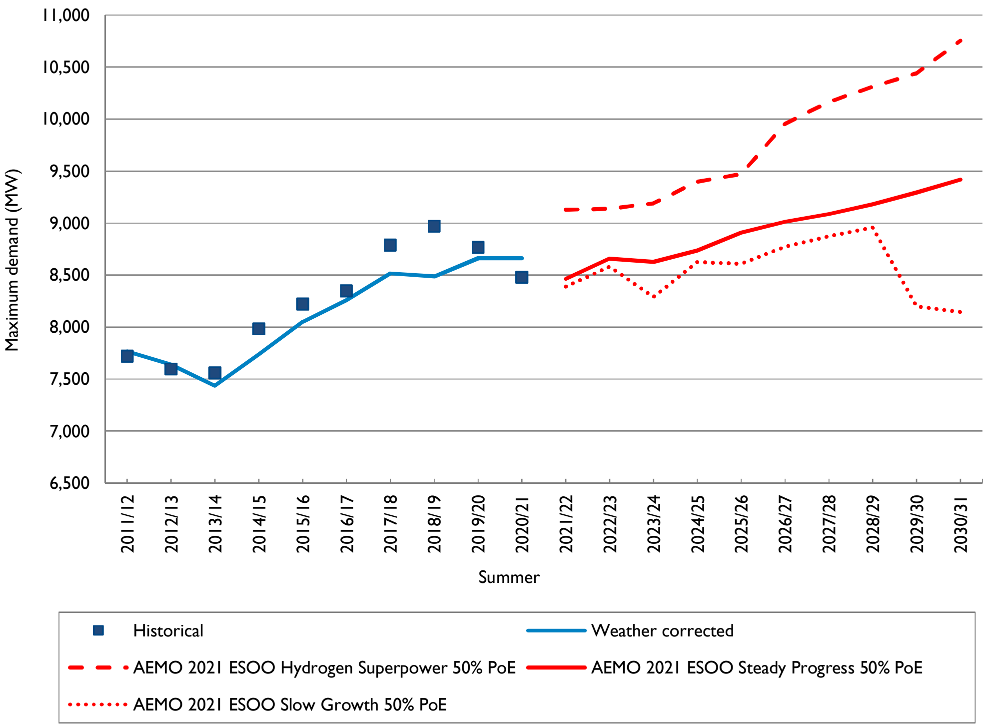
Summer	Slow Growth			Steady Progress			Hydrogen Superpower		
	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE
2021/22	8,050	8,389	8,843	8,138	8,463	8,912	8,774	9,127	9,554
2022/23	8,225	8,579	9,031	8,310	8,658	9,088	8,775	9,137	9,507
2023/24	7,981	8,291	8,793	8,316	8,626	9,120	8,852	9,191	9,633
2024/25	8,283	8,625	9,093	8,400	8,737	9,199	9,065	9,398	9,861
2025/26	8,257	8,608	9,070	8,601	8,906	9,389	9,133	9,470	9,875
2026/27	8,427	8,771	9,252	8,703	9,013	9,513	9,645	9,957	10,360
2027/28	8,517	8,873	9,356	8,760	9,086	9,569	9,853	10,166	10,576
2028/29	8,601	8,957	9,411	8,856	9,180	9,685	9,993	10,310	10,701
2029/30 (1)	7,857	8,199	8,678	8,999	9,293	9,804	10,156	10,440	10,840
2030/21	7,799	8,145	8,610	9,118	9,417	9,895	10,462	10,752	11,137

Note:

(1) Shutdown of a large industrial load is assumed in the Slow Growth scenario in the latter half of winter 2029.

The summer historical transmission delivered maximum demands from Table 3.6 and the forecast 50% PoE summer transmission delivered maximum demands for the Slow Growth, Steady Progress, and Hydrogen Superpower scenarios from Table 3.7 are shown in Figure 3.7.

Figure 3.7 Historical and forecast transmission delivered summer maximum demand



Historical Queensland summer maximum demand measurements at time of native peak are presented in Table 3.8.

Table 3.8 Historical summer maximum demand at time of native peak (MW)

Summer	Operational as generated	Operational sent out	Native as generated	Native sent out	Transmission sent out	Transmission delivered	Native	Native plus solar PV	Native corrected to 50% PoE
2011/12	8,714	8,236	8,769	8,319	7,983	7,723	8,059	8,059	8,101
2012/13	8,479	8,008	8,691	8,245	7,920	7,588	7,913	7,913	7,952
2013/14	8,374	7,947	8,531	8,114	7,780	7,498	7,831	7,831	7,731
2014/15	8,831	8,398	9,000	8,589	8,311	8,019	8,326	8,512	8,084
2015/16	9,154	8,668	9,272	8,848	8,580	8,271	8,539	8,783	8,369
2016/17	9,412	8,886	9,584	9,062	8,698	8,392	8,756	8,899	8,666
2017/18	9,796	9,262	10,010	9,480	9,133	8,842	9,189	9,594	8,924
2018/19	10,044	9,450	10,216	9,626	9,240	8,951	9,415	9,685	8,930
2019/20	9,853	9,294	10,074	9,515	9,011	8,710	9,268	9,652	9,163
2020/21	9,473	8,954	9,627	9,161	8,711	8,479	8,929	9,254	9,110

The summer native maximum demand forecasts are presented in Table 3.9.

Table 3.9 Forecast summer native maximum demand (MW)

Summer	Slow Growth			Steady Progress			Hydrogen Superpower		
	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE
2021/22	8,643	8,983	9,436	8,790	9,116	9,564	9,192	9,545	9,972
2022/23	8,640	8,994	9,446	8,809	9,157	9,587	9,301	9,662	10,032
2023/24	8,651	8,961	9,463	8,838	9,148	9,642	9,450	9,789	10,231
2024/25	8,706	9,047	9,515	8,916	9,253	9,714	9,546	9,879	10,342
2025/26	8,779	9,130	9,591	9,027	9,333	9,815	9,718	10,055	10,460
2026/27	8,847	9,191	9,672	9,129	9,439	9,939	10,313	10,624	11,027
2027/28	8,940	9,295	9,778	9,269	9,596	10,078	10,462	10,775	11,185
2028/29	9,016	9,372	9,826	9,381	9,705	10,209	10,619	10,936	11,327
2029/30 (1)	8,274	8,617	9,095	9,533	9,827	10,338	10,841	11,125	11,525
2030/31	8,352	8,697	9,163	9,659	9,957	10,435	11,127	11,418	11,803

Note:
(1) Shutdown of a large industrial load is assumed in the Slow Growth scenario in the latter half of winter 2029.

3.4.5 Winter maximum demand forecast

Historical Queensland winter maximum demand measurements at time of transmission delivered peak are presented in Table 3.10. As winter demand normally peaks after sunset, solar PV has no impact on winter maximum demand.

Table 3.10 Historical winter maximum demand at time of transmission delivered peak (MW)

Winter	Operational as generated	Operational sent out	Native as generated	Native sent out	Transmission sent out	Transmission delivered	Transmission delivered corrected to 50% PoE	Native	Native plus rooftop PV
2012	7,244	7,466	7,356	7,576	7,337	6,525	6,502	6,764	6,764
2013	7,131	6,488	7,273	6,649	6,507	6,551	6,753	6,693	6,693
2014	7,288	6,895	7,448	7,091	6,853	6,642	6,761	6,879	6,879
2015	7,816	7,334	8,027	7,624	7,299	7,090	6,976	7,415	7,415
2016	8,017	7,469	8,176	7,678	7,398	7,176	7,198	7,456	7,456
2017	7,595	7,063	7,756	7,282	7,067	6,870	7,138	7,085	7,085
2018	8,172	7,623	8,295	7,803	7,554	7,331	7,654	7,580	7,580
2019	7,898	7,446	8,096	7,735	7,486	7,296	7,289	7,544	7,544
2020	8,143	7,671	8,320	7,941	7,673	7,483	7,276	7,751	7,751
2021	8,143	7,677	8,279	7,901	7,659	7,472	(1)	7,714	7,725

Note:
(1) The winter 2021 weather corrected demand was not available at time of publication.

The winter transmission delivered maximum demand forecasts are presented in Table 3.11.

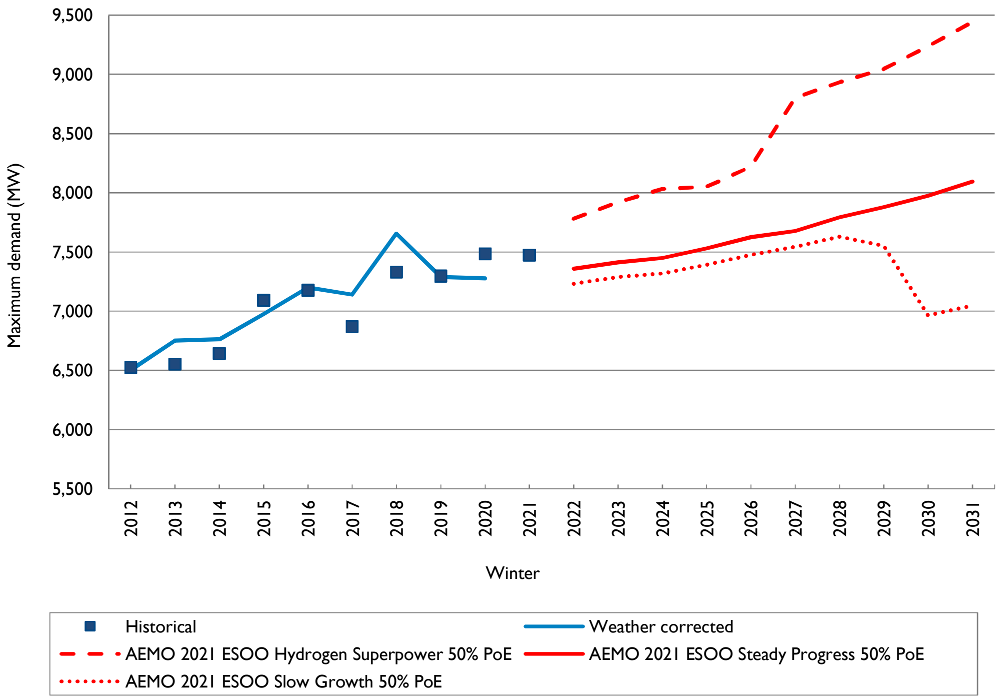
Table 3.11 Forecast winter transmission delivered maximum demand (MW)

Winter	Slow Growth			Steady Progress			Hydrogen Superpower		
	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE
2022	6,974	7,231	7,526	7,101	7,359	7,661	7,546	7,782	8,102
2023	7,023	7,287	7,593	7,166	7,412	7,717	7,678	7,921	8,239
2024	7,058	7,318	7,638	7,202	7,449	7,757	7,785	8,032	8,345
2025	7,140	7,392	7,707	7,274	7,530	7,838	7,811	8,050	8,359
2026	7,216	7,475	7,794	7,375	7,625	7,936	7,982	8,220	8,527
2027	7,283	7,545	7,853	7,420	7,678	7,992	8,566	8,804	9,107
2028	7,370	7,629	7,937	7,532	7,792	8,109	8,699	8,934	9,250
2029	7,251	7,550	7,883	7,624	7,877	8,185	8,796	9,044	9,353
2030 (1)	6,708	6,964	7,283	7,732	7,975	8,283	8,996	9,238	9,548
2031	6,784	7,048	7,366	7,844	8,094	8,396	9,197	9,443	9,765

Note:
(1) Shutdown of a large industrial load is assumed in the Slow Growth scenario in the latter half of winter 2029.

The winter historical transmission delivered maximum demands from Table 3.10 and the forecast 50% PoE summer transmission delivered maximum demands for the Slow Growth, Steady Progress, and Hydrogen Superpower scenarios from Table 3.11 are shown in Figure 3.8.

Figure 3.8 Historical and forecast winter transmission delivered maximum demand



Historical Queensland winter maximum demand measurements at time of native peak are presented in Table 3.12. As winter demand normally peaks after sunset, solar PV has no impact on winter maximum demand.

Table 3.12 Historical winter maximum demand at time of native peak (MW)

Winter	Operational as generated	Operational sent out	Native as generated	Native sent out	Transmission sent out	Transmission delivered	Native	Native plus rooftop PV	Native corrected to 50 % PoE
2012	7,469	7,081	7,520	7,128	6,955	6,761	6,934	6,934	6,908
2013	7,173	6,753	7,345	6,947	6,699	6,521	6,769	6,769	6,983
2014	7,307	6,895	7,470	7,077	6,854	6,647	6,881	6,881	6,999
2015	7,822	7,369	8,027	7,620	7,334	7,126	7,411	7,412	7,301
2016	8,017	7,513	8,188	7,686	7,439	7,207	7,454	7,454	7,479
2017	7,723	7,221	7,874	7,374	7,111	6,894	7,157	7,157	7,433
2018	8,172	7,623	8,295	7,750	7,554	7,383	7,633	7,633	7,904
2019	8,073	7,559	8,286	7,778	7,416	7,208	7,624	7,624	7,617
2020	8,143	7,671	8,320	7,885	7,673	7,441	7,708	7,708	7,544
2021	8,162	8,065	8,328	8,319	8,029	7,468	7,758	7,758	(1)

Note:
(1) The winter 2021 weather corrected demand was not available at time of publication.

The winter native maximum demand forecasts are presented in Table 3.13.

Table 3.13 Forecast winter native maximum demand (MW)

Winter	Slow Growth			Steady Progress			Hydrogen Superpower		
	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE
2022	7,386	7,644	7,939	7,515	7,773	8,075	7,955	8,191	8,511
2023	7,429	7,693	7,999	7,571	7,818	8,123	8,084	8,327	8,644
2024	7,464	7,723	8,043	7,607	7,855	8,163	8,248	8,495	8,808
2025	7,541	7,793	8,109	7,680	7,936	8,244	8,328	8,567	8,876
2026	7,622	7,881	8,200	7,791	8,041	8,352	8,531	8,769	9,076
2027	7,697	7,959	8,267	7,909	8,167	8,481	9,136	9,374	9,676
2028	7,780	8,040	8,347	8,025	8,285	8,602	9,291	9,527	9,842
2029	7,672	7,971	8,304	8,139	8,392	8,700	9,458	9,706	10,015
2030 (1)	7,122	7,378	7,697	8,251	8,494	8,802	9,688	9,930	10,240
2031	7,194	7,458	7,777	8,381	8,632	8,933	9,966	10,212	10,535

Note:
(1) Shutdown of a large industrial load is assumed in the Slow Growth scenario in the latter half of winter 2029.

3.4.6 Annual minimum demand forecast

Historical Queensland annual minimum demand measurements at time of transmission delivered minimum are presented in Table 3.14.

Table 3.14 Historical annual minimum demand (MW)

Annual	Operational as generated	Operational sent out	Native as generated	Native sent out	Transmission sent out	Transmission delivered	Native	Native plus rooftop PV
2012	4,095	4,075	4,220	4,188	4,064	3,610	3,734	3,734
2013	4,176	4,097	4,305	4,237	4,108	3,702	3,831	3,831
2014	4,073	3,780	4,274	4,027	3,768	3,664	3,923	3,923
2015	4,281	3,946	4,476	4,178	3,983	3,884	4,079	4,079
2016	4,944	4,470	5,101	4,686	4,471	4,336	4,552	4,552
2017	4,791	4,313	4,942	4,526	4,318	4,181	4,389	4,389
2018	4,647	4,165	4,868	4,501	4,143	4,008	4,366	5,572
2019	4,211	3,712	4,441	4,112	3,528	3,370	3,953	5,323
2020	3,897	3,493	4,094	3,767	3,097	3,006	3,675	5,882
2021 (1)	3,784	3,386	3,895	3,565	3,120	3,053	3,498	6,490

Note:

(1) 2021 minimum based on prelimary data up to 3 October 2021.

Annual transmission delivered minimum demand forecasts are presented in Table 3.15.

Table 3.15 Forecast annual transmission delivered minimum demand (MW) (1)

Annual	Slow Growth			Steady Progress			Hydrogen Superpower		
	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE
2022	1,355	1,573	1,774	1,547	1,788	1,974	1,953	2,175	2,371
2023	925	1,164	1,372	1,185	1,427	1,616	1,589	1,823	2,018
2024	666	909	1,124	872	1,132	1,344	1,252	1,511	1,745
2025	467	718	957	653	911	1,134	748	1,035	1,287
2026	296	553	798	366	638	877	438	707	972
2027	84	368	619	141	434	680	484	790	1,085
2028	-56	204	451	1	268	502	101	385	679
2029	-979	-698	-422	-128	166	439	-329	5	323
2030 (2)	-1,108	-832	-573	-280	31	291	-672	-314	21
2031	-1,206	-916	-644	-374	-58	205	-1,185	-826	-474

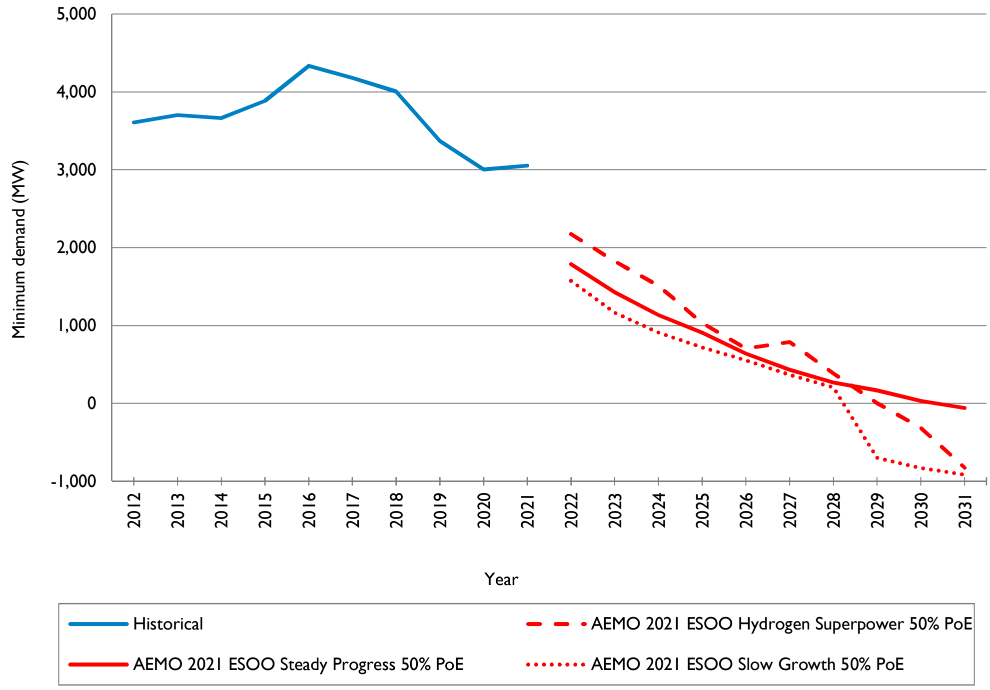
Notes:

(1) Forecasts provided without predicting market outcomes, directions or constraints which may be imposed to ensure system security but will impact output of embedded VRE generators and, as a consequence, transmission delivered demand.

(2) Shutdown of a large industrial load is assumed in the Slow Growth scenario in the latter half of winter 2029.

The annual historical transmission delivered minimum demands from Table 3.14 and the forecast 50% PoE summer transmission delivered minimum demands for the Slow Growth, Steady Progress, and Hydrogen Superpower scenarios from Table 3.15 are shown in Figure 3.9.

Figure 3.9 Historical and forecast transmission delivered annual minimum demand



Annual native minimum demand forecasts are presented in Table 3.16.

Table 3.16 Forecast annual native minimum demand (MW) (1)

Annual	Slow Growth (2)			Steady Progress			Hydrogen Superpower		
	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE
2022	2,538	2,756	2,957	2,730	2,971	3,156	3,125	3,347	3,543
2023	2,105	2,343	2,551	2,368	2,610	2,799	2,773	3,008	3,202
2024	1,850	2,094	2,308	2,057	2,317	2,529	2,472	2,731	2,965
2025	1,654	1,906	2,145	1,839	2,097	2,320	2,011	2,298	2,550
2026	1,480	1,737	1,982	1,666	1,938	2,177	1,718	1,987	2,253
2027	1,270	1,553	1,805	1,493	1,785	2,032	1,776	2,082	2,377
2028	1,127	1,386	1,634	1,387	1,655	1,889	1,447	1,731	2,025
2029	205	486	762	1,252	1,546	1,819	1,092	1,426	1,744
2030	77	353	611	1,107	1,417	1,678	753	1,111	1,446
2031	-18	272	544	1,017	1,333	1,597	590	948	1,300

Notes:

(1) Forecasts provided without predicting market outcomes, directions or constraints which may be imposed to ensure system security but impact on the output of these embedded VRE generators.

(2) Shutdown of a large industrial load is assumed in the Slow Growth scenario in the latter half of winter 2029.

3.5 Zone forecasts

AEMO's 2021 ESOO provides forecasts for Queensland as a single region. Forecasts from DNSPs and directly connected customers at each transmission connection supply point have been used to apportion the demand and energy forecasts into the 11 zones referenced throughout this TAPR. The 11 geographical zones are defined in Table C.1 and illustrated in Figure C.1 in Appendix C. Each zone normally experiences its own maximum demand, which is usually greater than that shown in tables 3.20 to 3.23.

Table 3.17 shows the average ratios of zone maximum transmission delivered demand to zone transmission delivered demand at the time of Queensland region maximum delivered demand. These values can be used to multiply demands in tables 3.20 and 3.22 to estimate each zone's individual maximum transmission delivered demand, the time of which is not necessarily coincident with the time of Queensland region maximum transmission delivered demand. The ratios are based on historical trends.

Table 3.17 Average ratios of zone maximum delivered demand to zone delivered demand at time of Queensland region maximum delivered demand

Zone	Winter	Summer
Far North	1.09	1.23
Ross	1.25	1.67
North	1.11	1.14
Central West	1.13	1.23
Gladstone	1.03	1.04
Wide Bay	1.03	1.08
Surat	1.14	1.16
Bulli	1.03	1.08
South West	1.04	1.10
Moreton	1.03	1.01
Gold Coast	1.03	1.03

Tables 3.18 and 3.19 show the historical and forecast of transmission delivered energy and native energy for the Steady Progress scenario for each of the 11 zones in the Queensland region.

Table 3.18 Annual transmission delivered energy by zone (GWh)

Financial Year	Far North	Ross	North	Central West	Gladstone	Wide Bay	Surat	Bulli	South West	Moreton	Gold Coast	Total
Actuals												
2011/12	1,792	2,723	2,611	3,463	10,286	1,323		105	1,196	18,629	3,266	45,394
2012/13	1,722	2,693	2,732	3,414	10,507	1,267		103	1,746	18,232	3,235	45,651
2013/14	1,658	2,826	2,828	3,564	10,293	1,321	338	146	1,304	17,782	3,085	45,145
2014/15	1,697	2,977	2,884	3,414	10,660	1,266	821	647	1,224	18,049	3,141	46,780
2015/16	1,724	2,944	2,876	3,327	10,721	1,272	2,633	1,290	1,224	17,944	3,139	49,094
2016/17	1,704	2,682	2,661	3,098	10,196	1,305	4,154	1,524	1,308	18,103	3,145	49,880
2017/18	1,657	2,645	2,650	3,027	9,362	1,238	4,383	1,497	1,315	17,873	3,092	48,739
2018/19	1,648	2,338	2,621	2,996	9,349	1,198	4,805	1,519	1,376	17,849	3,065	48,764
2019/20	1,594	2,466	2,495	2,859	9,303	1,031	5,025	1,580	1,141	17,395	2,971	47,860
2020/21	1,519	2,569	2,413	2,813	9,383	970	5,241	1,491	993	16,807	3,222	47,421
Forecasts												
2021/22	1,380	2,317	2,371	2,298	9,279	862	5,103	1,671	652	15,665	2,623	44,221
2022/23	1,330	2,300	2,297	2,209	9,262	566	4,617	1,662	726	15,141	2,555	42,665
2023/24	1,309	2,271	2,269	2,182	9,256	405	4,401	1,661	673	14,814	2,485	41,726
2024/25	1,295	2,254	2,258	2,165	9,258	385	4,434	1,673	650	14,840	2,492	41,704
2025/26	1,299	2,257	2,265	2,282	9,259	381	4,434	1,673	651	14,945	2,514	41,960
2026/27	1,296	2,246	2,259	2,283	9,265	382	4,382	1,654	654	15,145	2,554	42,120
2027/28	1,277	2,206	2,221	2,252	9,270	378	4,278	1,614	644	15,412	2,607	42,159
2028/29	1,246	2,150	2,173	2,217	9,274	364	4,151	1,567	628	15,673	2,662	42,105
2029/30	1,218	2,095	2,126	2,182	9,279	351	4,021	1,519	613	15,918	2,713	42,035
2030/31	1,231	2,108	2,147	2,208	9,283	347	4,022	1,520	617	16,135	2,759	42,377

Table 3.19 Annual native energy by zone (GWh)

Financial Year	Far North	Ross	North	Central West	Gladstone	Wide Bay	Surat	Bulli	South West	Moreton	Gold Coast	Total
Actuals												
2011/12	1,792	3,217	2,901	3,710	10,286	1,348		105	2,014	18,695	3,266	47,334
2012/13	1,722	3,080	3,064	3,767	10,507	1,292		103	1,988	18,332	3,235	47,090
2013/14	1,658	3,067	3,154	3,944	10,293	1,339	402	146	1,536	17,879	3,085	46,503
2014/15	1,697	3,163	3,434	3,841	10,660	1,285	1,022	647	1,468	18,137	3,141	48,495
2015/16	1,724	3,141	3,444	3,767	10,721	1,293	2,739	1,290	1,475	18,011	3,139	50,744
2016/17	1,704	2,999	3,320	3,541	10,196	1,329	4,194	1,524	1,549	18,134	3,145	51,635
2017/18	1,667	2,935	3,296	3,493	9,362	1,259	4,853	1,497	1,527	17,944	3,092	50,925
2018/19	1,670	2,894	3,211	3,608	9,349	1,266	5,163	1,519	1,550	17,945	3,065	51,240
2019/20	1,614	2,899	3,159	3,656	9,303	1,282	5,395	1,580	1,479	17,466	2,971	50,804
2020/21	1,539	2,904	2,982	3,552	9,383	1,234	5,451	1,491	1,476	17,152	2,943	50,107
Forecasts												
2021/22	1,409	3,057	2,981	3,206	9,279	1,161	5,368	1,671	1,466	15,729	2,622	47,949
2022/23	1,358	3,097	2,907	3,116	9,262	1,113	5,374	1,662	1,412	15,202	2,553	47,056
2023/24	1,337	3,070	2,879	3,091	9,255	1,090	5,368	1,661	1,385	14,873	2,483	46,492
2024/25	1,323	3,051	2,868	3,073	9,257	1,068	5,399	1,673	1,362	14,901	2,490	46,465
2025/26	1,327	3,054	2,875	3,080	9,259	1,063	5,399	1,673	1,362	15,005	2,512	46,609
2026/27	1,340	3,072	2,897	3,108	9,264	1,068	5,400	1,674	1,372	15,207	2,552	46,954
2027/28	1,354	3,086	2,916	3,130	9,269	1,074	5,402	1,674	1,381	15,472	2,604	47,362
2028/29	1,363	3,096	2,938	3,159	9,273	1,067	5,402	1,675	1,382	15,732	2,658	47,745
2029/30	1,376	3,107	2,960	3,188	9,278	1,063	5,402	1,676	1,386	15,975	2,709	48,120
2030/31	1,388	3,121	2,981	3,215	9,282	1,059	5,403	1,676	1,389	16,192	2,755	48,461

Tables 3.20 and 3.21 show the historical and forecast of transmission delivered summer maximum demand and native summer maximum demand for each of the 11 zones in the Queensland region. It is based on the Steady Progress scenario and average (50% PoE) summer weather.

Table 3.20 State summer maximum transmission delivered demand by zone (MW)

Summer	Far North	Ross	North	Central West	Gladstone	Wide Bay	Surat	Bulli	South West	Moreton	Gold Coast	Total
Actuals												
2011/12	296	376	404	525	1,191	249		18	217	3,788	658	7,722
2012/13	278	297	373	546	1,219	233		14	231	3,766	627	7,597
2013/14	296	401	427	504	1,152	248	13	17	267	3,597	637	7,559
2014/15	278	381	399	466	1,254	263	96	81	227	3,846	692	7,983
2015/16	308	392	411	443	1,189	214	265	155	231	3,953	661	8,222
2016/17	258	222	378	429	1,193	270	421	178	286	3,993	719	8,347
2017/18	304	376	413	463	1,102	278	504	183	301	4,147	718	8,789
2018/19	342	339	400	484	1,096	285	526	191	312	4,270	724	8,969
2019/20	286	325	391	368	1,080	263	610	191	267	4,276	709	8,766
2020/21	254	405	431	471	1,111	298	588	165	248	3,894	614	8,479
Forecasts												
2021/22	265	329	413	403	1,091	233	557	191	234	4,093	654	8,463
2022/23	268	344	425	439	1,091	266	555	189	280	4,143	658	8,658
2023/24	268	340	425	438	1,091	268	535	185	284	4,140	652	8,626
2024/25	268	347	432	447	1,092	273	551	184	290	4,194	659	8,737
2025/26	275	359	439	486	1,094	283	537	181	312	4,270	670	8,906
2026/27	280	364	444	498	1,095	288	537	181	317	4,331	678	9,013
2027/28	283	366	445	506	1,095	289	531	180	319	4,386	686	9,086
2028/29	286	364	447	512	1,096	291	550	180	320	4,439	695	9,180
2029/30	292	375	454	524	1,098	298	536	180	327	4,504	705	9,293
2030/31	299	381	461	532	1,099	304	538	180	335	4,572	716	9,417

Table 3.21 State summer maximum native demand by zone (MW)

Summer	Far North	Ross	North	Central West	Gladstone	Wide Bay	Surat	Bulli	South West	Moreton	Gold Coast	Total
Actuals												
2011/12	296	449	434	598	1,191	249		18	378	3,788	658	8,059
2012/13	277	417	422	568	1,213	241		14	328	3,799	634	7,913
2013/14	271	423	386	561	1,147	260	88	21	316	3,755	603	7,831
2014/15	278	399	479	548	1,254	263	189	81	254	3,889	692	8,326
2015/16	308	423	491	519	1,189	214	370	155	257	3,952	661	8,539
2016/17	269	364	512	559	1,088	276	498	175	329	3,974	712	8,756
2017/18	310	480	486	508	1,102	278	617	183	328	4,179	718	9,189
2018/19	338	456	432	562	1,104	293	630	191	340	4,338	731	9,415
2019/20	287	451	441	530	1,084	277	660	191	305	4,322	720	9,268
2020/21	256	508	483	596	1,111	314	681	165	307	3,894	614	8,929
Forecasts												
2021/22	267	527	459	520	1,089	263	729	190	326	4,093	653	9,116
2022/23	269	492	469	524	1,089	271	728	189	330	4,140	656	9,157
2023/24	269	498	469	529	1,088	272	720	185	329	4,139	650	9,148
2024/25	269	504	476	537	1,090	277	731	183	334	4,194	658	9,253
2025/26	275	473	482	550	1,091	282	724	181	340	4,267	668	9,333
2026/27	280	478	488	561	1,092	287	724	181	345	4,327	676	9,439
2027/28	284	484	492	574	1,102	291	727	181	349	4,421	691	9,596
2028/29	288	489	496	586	1,105	294	729	182	352	4,483	701	9,705
2029/30	295	494	503	594	1,107	300	731	182	359	4,550	712	9,827
2030/31	302	501	510	603	1,110	307	733	182	367	4,619	723	9,957

Tables 3.22 and 3.23 show the historical and forecast of transmission delivered winter maximum demand and native winter maximum demand for each of the 11 zones in the Queensland region. It is based on the Steady Progress scenario and average (50% PoE) winter weather.

Table 3.22 State winter maximum transmission delivered demand by zone (MW)

Winter	Far North	Ross	North	Central West	Gladstone	Wide Bay	Surat	Bulli	South West	Moreton	Gold Coast	Total
2012	212	175	276	474	1,187	207		21	259	3,065	567	6,525
2013	209	300	344	433	1,195	192	75	21	262	2,964	556	6,551
2014	226	344	355	463	1,200	204	16	51	257	2,975	551	6,642
2015	192	289	332	429	1,249	203	137	137	258	3,267	597	7,090
2016	226	249	370	417	1,242	206	390	181	279	3,079	537	7,176
2017	241	368	366	377	1,074	216	513	187	248	2,797	483	6,870
2018	242	366	335	439	1,091	235	475	186	336	3,086	540	7,331
2019	234	284	362	419	1,037	239	615	195	293	3,078	540	7,296
2020	227	306	327	449	1,104	246	531	191	313	3,274	515	7,483
2021	204	296	334	383	1,075	250	592	179	339	3,275	545	7,472
Forecasts												
2022	209	241	343	422	1,098	227	504	191	310	3,275	539	7,359
2023	209	243	359	423	1,098	232	509	190	311	3,306	532	7,412
2024	209	242	365	426	1,098	235	501	186	309	3,343	535	7,449
2025	213	247	371	433	1,099	239	511	184	314	3,382	537	7,530
2026	212	251	377	445	1,101	243	497	182	318	3,452	547	7,625
2027	215	240	381	455	1,102	247	497	181	322	3,487	551	7,678
2028	217	245	382	465	1,103	248	497	181	324	3,567	563	7,792
2029	220	246	384	476	1,104	252	496	181	328	3,617	573	7,877
2030	224	250	388	480	1,105	255	492	181	331	3,686	583	7,975
2031	234	259	403	498	945	266	504	185	346	3,845	609	8,094

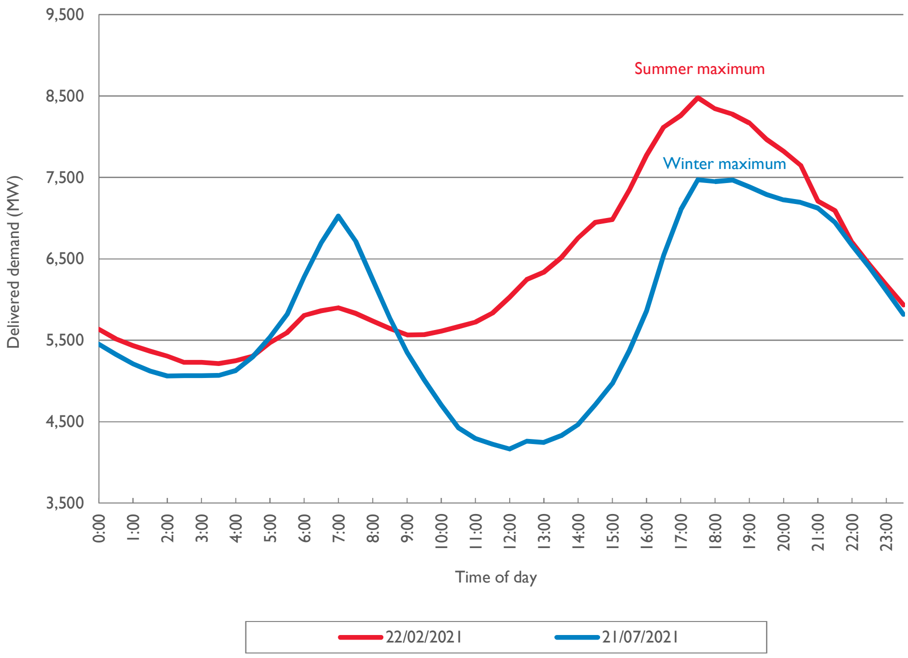
Table 3.23 State winter maximum native demand by zone (MW)

Winter	Far North	Ross	North	Central West	Gladstone	Wide Bay	Surat	Bulli	South West	Moreton	Gold Coast	Total
Actuals												
2012	214	289	360	460	1,201	215		20	375	3,206	594	6,934
2013	195	291	374	499	1,200	195	89	17	290	3,040	579	6,769
2014	226	369	420	509	1,200	204	90	51	286	2,975	551	6,881
2015	192	334	404	518	1,249	203	208	137	288	3,281	597	7,411
2016	216	358	419	504	1,229	200	467	193	310	3,008	550	7,454
2017	218	367	416	415	1,070	220	554	182	276	2,913	526	7,157
2018	242	360	410	494	1,091	235	654	186	336	3,085	540	7,633
2019	230	307	408	483	1,066	241	628	207	346	3,176	532	7,624
2020	227	329	406	492	1,104	247	624	191	342	3,231	515	7,708
2021	206	255	366	459	1,079	232	691	181	357	3,373	559	7,758
Forecasts												
2022	207	327	418	473	1,089	226	723	189	336	3,250	535	7,773
2023	208	328	433	473	1,089	230	721	188	337	3,283	528	7,818
2024	207	328	439	477	1,088	233	713	184	335	3,320	531	7,855
2025	211	333	446	484	1,090	237	723	182	340	3,357	533	7,936
2026	210	337	451	496	1,092	241	716	180	344	3,431	543	8,041
2027	215	331	460	510	1,103	247	722	181	352	3,494	552	8,167
2028	217	334	461	521	1,105	249	720	181	354	3,579	564	8,285
2029	221	338	464	533	1,108	253	722	181	358	3,639	575	8,392
2030	225	342	468	537	1,109	256	723	181	362	3,705	586	8,494
2031	235	356	485	557	949	268	741	186	377	3,866	612	8,632

3.6 Summer and winter maximum and annual minimum daily profiles

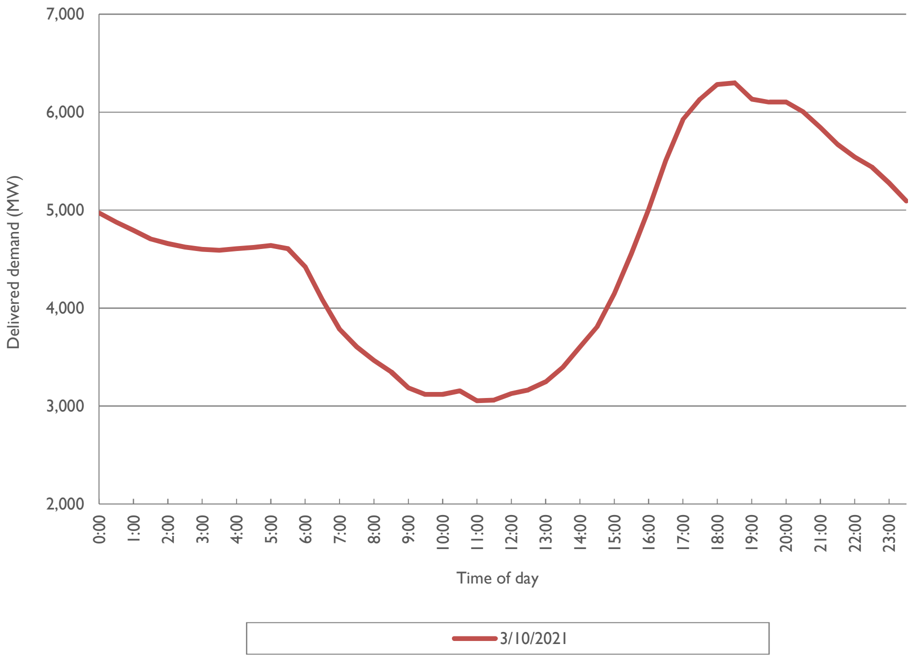
The daily load profiles (transmission delivered) for the Queensland region on the days of summer 2020/21 and winter 2021 maximum demands are shown in Figure 3.10.

Figure 3.10 Daily load profile of summer 2020/21 and winter 2021 maximum transmission delivered demand days



The 2021 annual minimum (transmission delivered) daily load profile for the Queensland region is shown in Figure 3.11.

Figure 3.11 Daily load profile of 2021 minimum transmission delivered day (1)

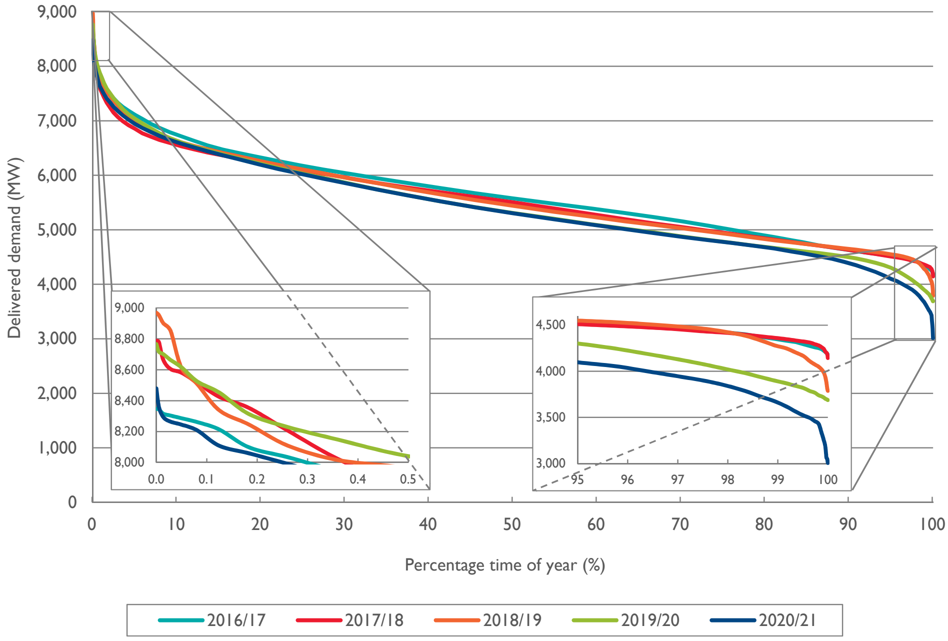


Note:
(1) Based on preliminary meter data up to 3 October 2021.

3.7 Annual load duration curves

The annual historical load duration curves for the Queensland region transmission delivered demand since 2016/17 is shown in Figure 3.12.

Figure 3.12 Historical transmission delivered load duration curves



CHAPTER 4

Joint planning

4 Joint planning

Key highlights

- Joint planning provides a mechanism for Network Service Providers (NSPs) to discuss and identify technically feasible, cost effective network or non-network options that address identified network needs regardless of asset ownership or jurisdictional boundaries.
- Key joint planning focus areas since the publication of the 2020 Transmission Annual Planning Report (TAPR) include:
  - The changing nature of load with embedded rooftop photovoltaic (PV), improved load power factors and reducing minimum demand. This includes the challenges of managing high voltages associated with minimum demand
  - Deferment of transformer augmentation projects at Kamerunga in FNQ and Goodna in Moreton area, by Energy Queensland (EQL) load transfers – either as part of an over load management system (OLMS) or permanent transfers
  - Ensuring reliability to customers while expanding the opportunities for renewables as part of the renewable energy zones (REZ) discussions in Chapter 2.

4.1 Introduction

Powerlink's joint planning framework with the Australian Energy Market Operator (AEMO) and other NSPs is in accordance with the requirements set out in Clause 5.14.3 and 5.14.4 of National Electricity Rules (NER).

Joint planning begins several years in advance of an investment decision. The nature and timing of future investment needs are reviewed at least on an annual basis utilising an interactive joint planning approach.

> The objective of joint planning is to collaboratively identify network and non-network solutions to limitations which best serve the long-term interests of customers, irrespective of the asset boundaries (including those between jurisdictions).

The joint planning process results in integrated area and inter-regional strategies which optimise asset investment needs and decisions consistent with whole of life asset planning.

The joint planning process is intrinsically iterative. The extent to which this occurs will depend upon the nature of the limitation or asset condition driver to be addressed and the complexity of the proposed corrective action. In general, joint planning seeks to:

- understand the issues collectively faced by the different network owners and operators
- understand existing and forecast congestion on power transfers between neighbouring NSPs
- help identify the most efficient options to address these issues, irrespective of the asset boundaries (including those between jurisdictions)
- influence how networks are managed, and what network changes are required.

Projects where a feasible network option exists which is greater than $6 million are subject to a formal consultation process under the applicable regulatory investment test mechanism. The owner of the asset where the limitation emerges will determine whether a Regulatory Investment Test for Transmission (RIT-T) or Regulatory Investment Test for Distribution (RIT-D) is used as the regulatory instrument to progress the investment recommendation under the joint planning framework. This provides customers, stakeholders and interested parties the opportunity to provide feedback and discuss alternative solutions to address network needs. Ultimately, this process results in investment decisions which are prudent, transparent and aligned with stakeholder expectations.

4.2 Working groups and regular engagement

Powerlink regularly undertakes joint planning meetings with AEMO, Energy Queensland and Jurisdictional Planning Bodies (JPB) from across the National Electricity Market (NEM). There are a number of working groups and reference groups in which Powerlink contributes to:

- Executive Joint Planning Committee
- Joint Planning Committee
- Regulatory Working Group
- Forecasting Reference Group
- Power System Modelling Reference Group
- NEM Working Groups of the Energy Networks Association (ENA)
- AEMO on the 2020 PSFRR (refer to Section 8.3)
- AEMO on the Network Support and Control Ancillary Service (NSCAS)
- AEMO and other jurisdictional planners in the development of inputs for the 2022 Integrated System Plan (ISP) including submissions to the ISP Input Assumptions and Scenarios, ISP Methodology and development of ISP Preparatory Activity reports (refer to sections 9.1 and 9.3)
- AEMO National Planning to determine the minimum system strength requirements in the Queensland region and the subsequent notification of a fault level shortfall at the new Ross node
- TransGrid when assessing the economic benefits of expanding the power transfer capability between Queensland and NSW
- Energex and Ergon Energy (as part of the Energy Queensland Group) for the purposes of efficiently planning developments and project delivery in the transmission and sub-transmission network.

4.2.1 Executive Joint Planning Committee

The Executive Joint Planning Committee (EJPC) coordinates effective collaboration and consultation between JPBs and AEMO on electricity transmission network planning issues. The EJPC directs and coordinates the activities of the Forecasting Reference Group, and the Regulatory Working Group. These activities ensure effective consultation and coordination between JPB, Transmission System Operators and AEMO on a broad spectrum of perspectives on network planning, forecasting, market modelling, and market regulatory matters in order to deal with the challenges of a rapidly changing energy industry.

4.2.2 Joint Planning Committee

The Joint Planning Committee (JPC) is a working committee supporting the EJPC in achieving effective collaboration, consultation and coordination between JPB, Transmission System Operators and AEMO on electricity transmission network planning issues.

4.2.3 Forecasting Reference Group

The Forecasting Reference Group (FRG) is a monthly forum with AEMO and industry forecasting specialists. The forum seeks to facilitate constructive discussion on matters relating to gas and electricity forecasting and market modelling. It is an opportunity to share expertise and explore new approaches to addressing the challenges of forecasting in a rapidly changing energy industry.

4.2.4 Regulatory Reference Group

The Regulatory Working Group (RWG) is a working group to support the EJPC in achieving effective collaboration, consultation and coordination between JPBs, Transmission System Operators and AEMO on key areas related to the application of the regulatory transmission framework and suggestions for improvement.

4.2.5 Power System Modelling Reference Group

This is a technical expert reference group which focuses on power system modelling and analysis techniques to ensure an accurate power system model is maintained for power system planning and operational analysis, establishing procedures and methodologies for power system analysis, plant commissioning and model validation.

4.3 AEMO Integrated System Plan (ISP)

Powerlink is working closely with AEMO to support the development of the 2022 ISP. The ISP sets out a roadmap for the eastern seaboard's power system over the next two decades by establishing a whole of system plan for efficient development that achieves system needs through a period of transformational change.

During 2021 Powerlink has provided feedback on the proposed ISP methodology and inputs, assumptions and scenarios. As requested in AEMO's 2020 ISP (published in July 2020) Powerlink has also prepared Preparatory Activity reports for two intra-regional projects and for an interconnector upgrade (refer to Section 9.3). This involvement is critical to ensure the best possible jurisdictional inputs are provided to the ISP process in the long-term interests of customers.

Process

Powerlink continues to provide a range of network planning inputs to AEMO's ISP consultation and modelling processes, through joint planning processes and regular engagement, workshops and various formal consultations. This engagement helps underpin the inputs, assumptions and methodology for the ISP.

Methodology

More information on the 2020 ISP including methodology and assumptions is available on AEMO's website.

Outcomes

The ISP attempts to identify a long-term plan for the efficient development of the NEM transmission network, and the connection of Renewable Energy Zones (REZ) over the coming 20 years. It is based on a set of assumptions and a range of scenarios.

4.4 AEMO national planning – fault level shortfall

System strength is a critical requirement for a stable and secure power system. A minimum level of system strength is required for the power system to remain stable under normal conditions and to return to a steady state condition following a system disturbance.

Under the NER, Powerlink as the TNSP and JPB for the region, has an obligation to maintain a minimum fault level at key nodes. These key nodes, and prescribed minimum fault levels, are defined by AEMO in consultation with Powerlink. Powerlink works closely with AEMO to review the Queensland fault level nodes and their minimum three phase fault levels annually to assess whether there is or is likely to be a fault level shortfall in the Queensland region, and a forecast of the period over which any fault level shortfall might exist.

Process

Powerlink and AEMO carried out detailed Electromagnetic Transient-type (EMT-type) analysis to determine the system strength requirements for the Queensland region. Using the outcomes from these studies (for example, minimum required synchronous generator combinations), minimum three phase fault levels at the fault level nodes are defined.

Methodology

AEMO applies the System Strength Requirements Methodology[1] to determine the Queensland fault level nodes and their minimum three phase fault levels for 2020.

More information on the System Strength Requirements Methodology, System Strength Requirements and Fault Level Shortfalls is available on AEMO's website.

1 AEMO, System Strength Requirements Methodology and System Strength Requirements and Shortfalls, July 2018.

Outcomes

AEMO published a Notice of Queensland System Strength Requirements and Ross Fault Level Shortfall in April 2020. There were two significant changes since their initial report in 2018:

- The replacement of the Nebo 275kV fault level node with the Ross 275kV node. In consultation with Powerlink, AEMO determined that the Ross 275kV node was a better representation for system strength conditions in North Queensland (NQ) compared to the original Nebo 275kV node.
- AEMO declared an immediate fault level shortfall of 90MVA at the Ross 275kV fault level node. AEMO forecast that, if not addressed, this fault level shortfall will continue beyond 2024-25.

These outcomes and Powerlink's solution to the declared fault level short fall are discussed in sections 6.7.1 and 10.4.

4.5 Power System Frequency Risk Review (PSFRR)

The PSFRR is an integrated, periodic review of power system frequency risks associated with non-credible contingency events in the NEM.

Process

In accordance with Clause 5.20A.1 of the NER, AEMO in consultation with TNSPs prepares a PSFRR for the NEM, considering:

- Non-credible contingency events which AEMO expects could likely involve uncontrolled frequency changes leading to cascading outages or major supply disruption.
- Current arrangements for managing such non-credible contingency events.
- Options for future management of such events.
- The performance of existing Emergency Frequency Control Schemes (EFCS).

For 2020, AEMO undertook the PSFRR in two stages. Stage 1 reviewed the status of actions recommended in the 2018 PSFRR, reviewed power system events and identified non-credible contingency events and associated management arrangements to be prioritised. Stage 2, published in December 2020, included more detailed assessment and option analysis.

Methodology

With support from Powerlink, AEMO assessed the performance of existing EFCS. AEMO also assessed high priority non-credible contingency events identified in consultation with Powerlink. From these assessments AEMO determines whether further action may be justified to manage frequency risks.

Outcomes

The Final 2020 PSFRR report:

- Recommended an expansion of Powerlink's Central Queensland to South Queensland (CQ-SQ) Special Protection Scheme (SPS). The effectiveness of the existing scheme is limited to transfers up to approximately 1,700MW and relies on the ability to disconnect, up to two, high output generating units at Callide Power Stations for the unplanned trip of both Calvale to Halys 275kV feeders.
- Concluded that there was no immediate need to implement an Over Frequency Generation Shedding (OFGS) scheme as a result of the QNI Minor (refer to Section 4.6) upgrade to manage frequency increases within the frequency operating standard (FOS).
- Concluded that the existing Under Frequency Load Shed (UFLS) controls are able to manage the frequency disturbance when exporting at the secure transfer limit. However, as embedded distributed energy resources (DER) continue to increase the risk needs to be reassessed as part of the 2022 PSFRR.

In response to the PSFRR, Powerlink commissioned a project in July 2021 to implement a new Wide Area Monitoring Protection and Control (WAMPAC) scheme architecture to operate in parallel with the existing CQ-SQ SPS. The WAMPAC scheme adds the ability to trip approximately 600MW of renewable generators in north Queensland and approximately up to 700MW of load in South Queensland (refer to Section 8.3).

4.6 Joint planning with TransGrid – Expanding the transmission transfer capacity between New South Wales and Queensland

In December 2019, Powerlink and TransGrid released a Project Assessment Conclusions Report (PACR) on 'Expanding NSW-Queensland transmission transfer capacity'. The recommended option includes uprating the 330kV Liddell to Tamworth 330kV lines, and installing Static VAr Compensators (SVCs) at Tamworth and Dumaresq substations and static capacitor banks at Tamworth, Armidale and Dumaresq substations. All material works associated with this upgrade are within TransGrid's network.

AEMO's ISP continues to investigate opportunities for expansion of interconnector capacity. In the 2020 ISP, AEMO identified QNI Medium and Large projects as future ISP projects, requiring Powerlink and TransGrid to undertake preparatory activities by 30 June 2021 (refer to sections 6.9.1 and 9.3).

AEMO also flagged in the 2020 ISP that it will work with Powerlink and TransGrid to explore further options in relation to virtual transmission lines (VTLs). The 2020 ISP outlined that VTLs, coupled with suitable wide area protection schemes, could provide a technically feasible solution to increase the capacity of QNI.

4.7 Joint planning with Energex and Ergon Energy

Queensland's Distribution Network Service Providers (DNSPs) Energex and Ergon Energy (part of the Energy Queensland group) participate in regular joint planning and coordination meetings with Powerlink to assess emerging limitations, including asset condition drivers, to ensure the recommended solution is optimised for efficient expenditure outcomes[2]. These meetings are held regularly to assess, in advance of any requirement for an investment decision by either NSP, matters that are likely to impact on the other NSP. Powerlink and the DNSPs then initiate detailed discussions around addressing emerging limitations as required. Joint planning also ensures that interface works are planned to ensure efficient delivery.

Table 4.1 provides a summary of activities that are utilised in joint planning. During preparation of respective regulatory submissions, the requirement for joint planning increases significantly and the frequency of some activities reflect this.

[2] Where applicable to inform and in conjunction with the appropriate RIT-T consultation process.

Table 4.1 Joint planning activities

Activity	Frequency		
	Week-to-week	Monthly	Annual
Sharing and validating information covering specific issues	Y	Y	
Sharing updates to network data and models	Y	Y	
Identifying emerging limitations	Y		
Developing potential credible solutions	Y		
Estimating respective network cost estimates	Y		
Developing business cases	Y		
Preparing relevant regulatory documents	Y		
Sharing information for joint planning analysis	Y	Y	
Sharing information for respective works plans			Y
Sharing planning and fault level reports			Y
Sharing information for Regulatory Information Notices			Y
Sharing updates to demand forecasts			Y
Joint planning workshops			Y

4.7.1 Matters requiring joint planning

The following is a summary of projects where detailed joint planning with Energex and Ergon Energy (and other NSPs as required) has occurred since the publication of the 2020 TAPR (refer to Table 5.2). There are a number of projects where Powerlink, Energex and Ergon Energy interface on delivery, changes to secondary systems or metering, and other relevant matters which are not covered in this Chapter. Further information on these projects, including timing and alternative options is discussed in Chapter 6.

Table 4.2 Joint planning project references

Project	Reference
Kamerunga 132/22kV transformer replacement	Section 6.7.1
275kV upgrade for Northern QREZ	Section 6.7.1
SEQ reactive power and voltage control	Section 6.7.10

In addition there was joint planning between Energex and Powerlink regarding an OLMS operational project at Goodna within the 10-year outlook period.

4 Joint planning

CHAPTER 5

Asset management overview

5 Asset management overview

Key highlights

- Powerlink is committed to sustainable asset management practices that consider and recognise our customer and stakeholder requirements.
- Powerlink's asset management practices provide safe, reliable, secure and environmentally conscious services that provide the platform to enable the transformation to a more sustainable, cost effective, and climate resilient energy system.
- Powerlink's approach to asset management:
  - delivers value to our customers and stakeholders by optimising whole of life cycle costs, benefits and risks while ensuring compliance with relevant legislation, regulations and standards
  - is underpinned by Powerlink's corporate risk management framework and good practice international risk assessment methodologies
  - is aligned with Powerlink's corporate objectives.

5.1 Introduction

Powerlink's asset management system captures significant internal and external drivers on the business and sets out initiatives to be adopted.

Factors that influence network development, such as energy and demand forecasts, generation development (including asynchronous generation development and potential synchronous generation withdrawal), emerging industry trends and technology, and risks arising from the condition and performance of the existing asset base are analysed collectively in order to form an integrated network investment outlook over a 10-year period.

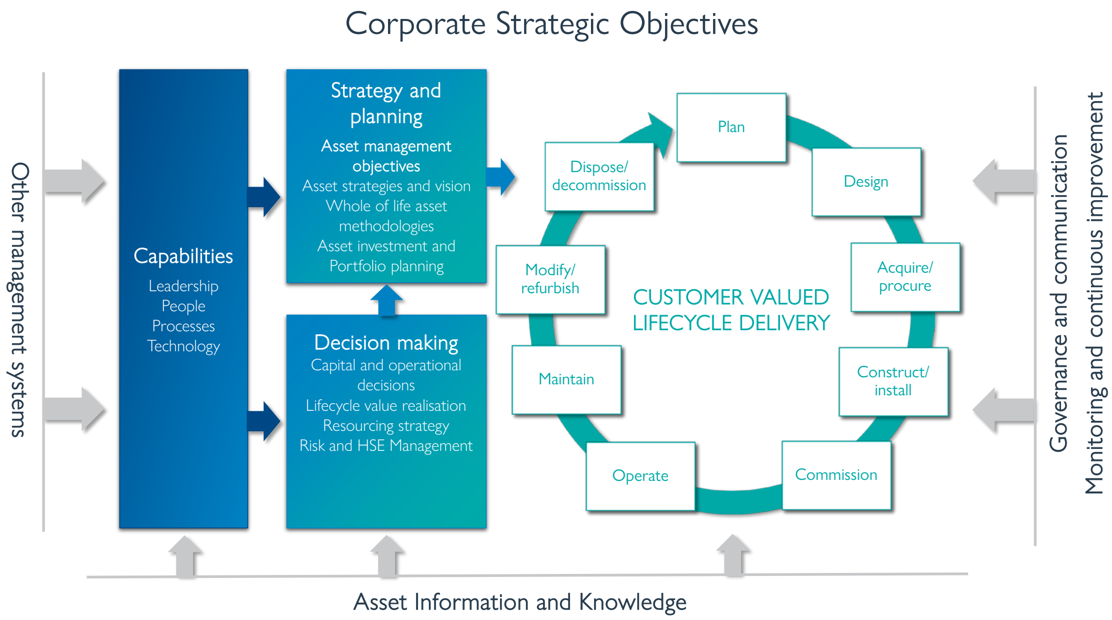
5.2 Overview of approach to asset management

Powerlink's asset management approach ensures assets are managed in a manner consistent with overall corporate objectives to deliver cost effective and efficient services. Powerlink's asset management system is adapted from the Institute of Asset Management (IAM) and aligns with ISO55000 Asset Management Standards (refer to Figure 5.1) to ensure a consistent approach is applied throughout the life cycle of assets. The Asset Management System guides Powerlink's analysis of future network investment needs and key investment drivers.

Powerlink's asset management and joint planning approaches ensure asset reinvestment needs are not just considered on a like-for-like basis, rather the enduring need and most cost effective options are considered. A detailed analysis of both asset condition and network capability is performed prior to proposed reinvestment and where applicable, a Regulatory Investment Test for Transmission (RIT-T) is undertaken in order to bring about optimised solutions that may involve network reconfiguration, retirement and/or non-network solutions.

Powerlink's asset management is committed to achieve sustainable practices that ensure Powerlink provides a valued transmission service to meet our customers' needs by optimising whole of life cycle costs, benefits and risks while ensuring compliance with applicable legislation, regulations and standards.

Figure 5.1 Powerlink's Asset Management approach



5.2.1 Strategy and planning

Powerlink considers obligations across a wide range of legislation and regulation, including the expectations of Powerlink's customers and stakeholders at the asset management strategy and planning stage. The asset management objectives set the context and performance measures for life cycle decisions. The strategy and vision sets the roadmap for assets, coupled with methodologies for asset management and investment plans. Development of asset management objectives based on a whole of life approach with a long-term vision guides efficient asset investment and portfolio planning.

5.2.2 Decision making

Key decisions assist to achieve the strategy and decision making throughout the life cycle stages. This includes decisions on capital investment and operational expenditure, resourcing, life cycle value realisation, risk and health and safety management.

Powerlink's asset management decision framework is fundamental in supporting the appraisal of future reinvestment needs, particularly in relation to:

- monitoring and analysis of asset health, condition and performance
- identifying the emerging needs for asset intervention to enable considered and prudent decision making
- consideration of all economic and technically feasible options (including non-network options)
- assessment of benefits, risks and costs
- whole of life cycle planning.

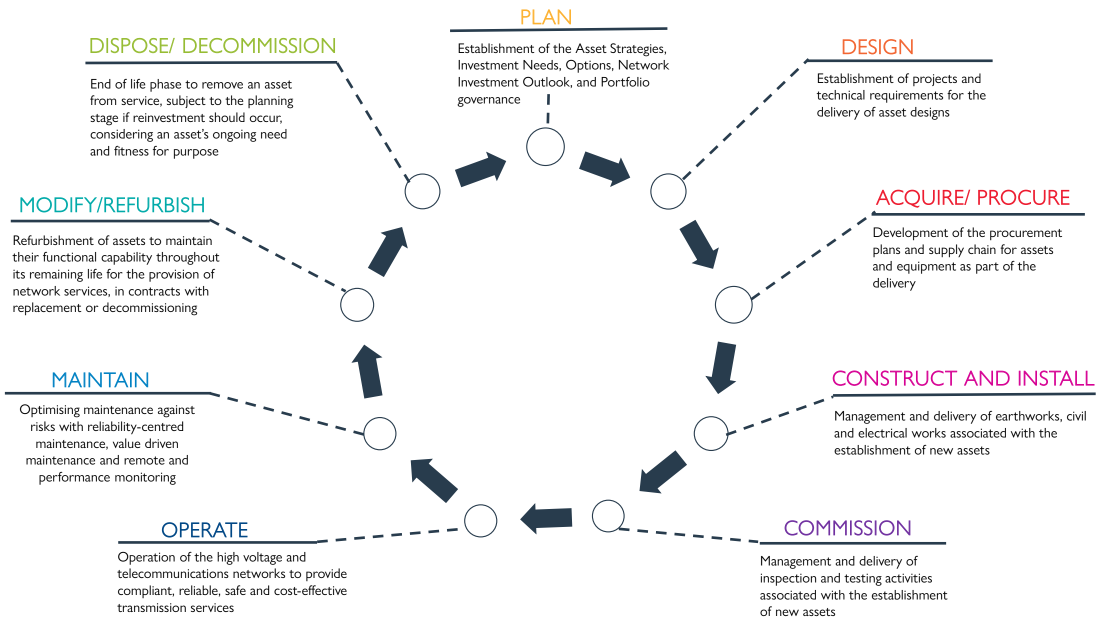
Reinvestment in assets approaching the end of their technical service life forms a substantial part of Powerlink's future network investment plans across the 10-year outlook period. Accordingly, the assessment of risk associated with the condition and performance of these assets is of particular importance. In order to inform such risk assessments, Powerlink undertakes periodic reviews of network assets considering a broad range of factors, including physical condition, capacity constraints, performance and functionality, statutory compliance and ongoing supportability.

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 ISO 31000:2018 Risk Management Guidelines.

5.2.3 Life cycle delivery

Life cycle delivery establishes how and what is needed to achieve the decisions made for assets in consideration of the Asset Management System. Powerlink defines asset life cycle and main activities throughout nine stages shown in Figure 5.2

Figure 5.2 Powerlink's asset life cycle stages



5.2.4 Asset information and knowledge

Asset information is key for Powerlink's asset decisions as asset data and asset knowledge is used for option assessments and to understand the cost and benefits based on risk. Asset information comes from analysis of asset data which is used to inform decisions on how Powerlink's assets are managed both for short-term operational purposes and long-term strategic plans.

5.2.5 Capabilities

Capabilities of people and the organisation set how the business is able to achieve the strategy and plans. Leadership is essential in managing and optimising Powerlink's assets and value to customers. Executive sponsorship of asset management strategy, objectives and processes is essential to lead decisions, performance, risk management, and improvement. For each stage of the asset life cycle it is critical to define roles and responsibilities, systems and processes to be successful in the implementation of asset management. Leadership, structure, culture, supply chain management and competency framework underpin this function.

5.2.6 Governance and communication

Powerlink's Asset Management governance ensures asset management is applied by using multidisciplinary and integrated activities. The objective of Asset Management Governance is to enable Powerlink individuals and teams to understand their roles in improving and enhancing services. Powerlink promotes better asset management practices by monitoring current progress, providing support and direction.

5.2.7 Monitoring and continuous improvement

Powerlink continuously monitors and reviews network, asset and business performance outcomes. It focuses on reviewing the implementation of strategies to identify and adopt improvements by ensuring that strategies deliver to organisational obligations and the expectations of customers.

5.3 Flexible and integrated network investment planning

A fundamental element of the Asset Management System involves the adoption of processes to manage the life cycle of assets, from planning and investment to operation, maintenance and refurbishment, to end of technical service life.

A range of options are considered as part of a flexible and integrated approach to network investment planning. These options may include retiring or decommissioning assets where there is unlikely to be an ongoing future need, refurbishing to maintain the service life of assets, replacing assets with different capacity or type to match needs, alternate network configuration opportunities, and non-network solutions.

The purpose of Powerlink's network investment planning is to:

- apply the principles set out in Powerlink's Asset Management Policy, Strategic Asset Management Plan and related processes to guide network asset planning and reinvestment decisions
- provide an overview of asset condition and health, life cycle plans and emerging risks related to factors such as safety, network reliability, resilience and obsolescence
- provide an overview and analysis of factors that impact network development, including energy and demand forecasts, generation developments, forecast network performance and capability, and the condition and performance of Powerlink's existing asset base
- identify potential opportunities for optimisation of the transmission network and
- provide the platform to enable the transformation to a more sustainable, cost efficient and climate resilient energy system.

5.4 Asset management implementation

Powerlink has adopted implementation strategies across its portfolio of projects and maintenance activities aimed at efficiently delivering the overall work program including prudent design standardisation by considering emerging trends in technology, portfolio management and supply chain management.

One of Powerlink's objectives includes the efficient implementation of work associated with network operation, field maintenance and project delivery. Powerlink continues to pursue innovative work techniques that:

- reduce risk to personal safety
- optimise maintenance and/or operating costs and
- reduce the requirement for and minimise the impacts of planned outages on the transmission network.

In line with good practice, Powerlink also undertakes regular auditing of work performed to facilitate the continuous improvement of the overall Asset Management System.

5.5 Further information

Further information on Powerlink's Asset Management System may be obtained by emailing networkassessments@powerlink.com.au.

5 Asset management overview

CHAPTER 6

Future network development

6 Future network development

Key highlights

- Powerlink continues to be proactive and adapt to shifts in an increasingly uncertain operating environment, which has been further impacted by the restrictions of the COVID-19 pandemic.
- To deliver positive outcomes for customers, Powerlink applies a flexible and integrated approach to efficient investment decision making, taking into consideration multiple factors including:
  - assessing whether an enduring need exists for assets and investigating alternate network configuration opportunities and/or non-network solutions, where feasible, to manage asset and network risks
  - assessing dynamic changes in Powerlink's operating environment to ensure network resilience
  - enabling opportunities for the connection of new generation, including variable renewable energy (VRE) where technically and economically feasible to deliver positive benefits to customers
  - actively seeking opportunities to implement more cost effective prudent solutions whenever possible, such as transmission line refits, that avoid or delay the need to establish new transmission network infrastructure.
- The changing generation mix may lead to increased constraints across critical grid sections. Powerlink will consider these potential constraints holistically as part of the planning process and in conjunction with the findings of the most recent Integrated System Plan (ISP).
- As recommended by the 2020 ISP and since the publication of the 2020 Transmission Annual Planning Report (TAPR), Powerlink has undertaken the necessary preparatory activities to inform the analysis for the 2022 ISP.

6.1 Introduction

Powerlink Queensland as a Transmission Network Service Provider (TNSP) in the National Electricity Market (NEM) and as the appointed Jurisdictional Planning Body (JPB) by the Queensland Government is responsible for transmission network planning for the national grid within Queensland. Powerlink's obligation is to plan the transmission system to reliably and economically supply load while managing risks associated with the condition and performance of existing assets in accordance with the requirements of the National Electricity Rules (NER), Queensland's Electricity Act 1994 (the Act) and its Transmission Authority.

The NER (Clause 5.12.2(c)(3)) requires the TAPR to provide 'a forecast of constraints and inability to meet the network performance requirements set out in schedule 5.1 or relevant legislation or regulations of a participating jurisdiction over one, three and five years'. In addition, there is a requirement (Clause 5.12.2(c)(4)) to provide estimated load reductions that would defer forecast limitations for a period of 12 months and to state any intent to issue request for proposals for augmentation, replacement of network assets or non-network alternatives. The NER (Clause 5.12.2(c)) also requires the TAPR to be consistent with the TAPR Guidelines and include information pertinent to all proposed:

- augmentations to the network (Clause 5.12.2(c)(5))
- replacements of network assets (Clause 5.12.2(c)(5))
- network asset retirements or asset de-ratings that would result in a network constraint in the 10-year outlook period (Clause 5.12.2(c)(1A)).

This chapter on proposed future network developments contains:

- discussion on Powerlink's integrated planning approach to network development
- information regarding assets reaching the end of their service life and options to address the risks arising from ageing assets remaining in service, including asset reinvestment, non-network solutions, potential network reconfigurations, asset retirements or de-ratings

- identification of emerging future limitations[1] with potential to affect supply reliability including estimated load reductions required to defer these forecast limitations by 12 months (Clause 5.12.2(c)(4)(iii))
- a statement of intent to issue request for proposals for augmentation, the proposed replacement of ageing network assets or non-network alternatives identified as part of the annual planning review (Clause 5.12.2(c)(4)(iv))
- a summary of network limitations over the next five years (Clause 5.12.2.(c)(3))
- details in relation to the need to address the risks arising from ageing network assets remaining in service and those limitations for which Powerlink intends to address or initiate consultation with market participants and interested parties
- the manner in which proposed augmentations and the replacement of network assets relate to the Australian Energy Market Operator (AEMO)'s most recent ISP (Clause 5.12.2.(c)(6)) and
- a table summarising possible connection point proposals.

Where appropriate, all transmission network, distribution network or non-network alternatives are considered as options for investment or reinvestment. Submissions for non-network alternatives are invited by contacting networkassessments@powerlink.com.au

6.2 ISP alignment

The 2020 ISP published by AEMO in July 2020 provides an independent, strategic view of the efficient development of the NEM transmission network over a 20-year planning horizon. AEMO's draft 2022 ISP is anticipated to be published in December 2021.

Powerlink will proactively monitor the changing outlook for the Queensland region and take into consideration the impact of emerging technologies, withdrawal of gas and coal-fired generation and the integration of variable renewable energy (VRE) generation in future transmission plans. These plans may include:

- reinvesting in assets to extend their end of technical service life
- removing some assets without replacement
- determining optimal sections of the network for new connection (in particular renewable generation) as discussed in detail in Chapter 10 and where applicable, in conjunction with the ISP
- replacing existing assets with assets of a different type, configuration or capacity
- investing in assets to maintain planning standards, including Powerlink's obligations for system strength and voltage control
- non-network solutions.

6.3 Flexible and integrated approach to network development

Powerlink's planning for future network development will focus on pursuing flexible solutions which can adapt to the changing environment. This includes maximising opportunities for the connection of new generation, including VRE where technically and economically feasible. This approach will deliver positive outcomes for customers while ensuring the ongoing safe and reliable supply of electricity and may also include optimising the network topography based on the analysis of future network needs due to:

- forecast demand
- new customer access requirements including possible Renewable Energy Zones (REZ)
- potential power system development pathways signalled in the ISP
- anomalies in Powerlink's operating environment or changes in technical characteristics (e.g. minimum demand, system strength, inertia, voltage limitations) during the transformation to more VRE generation

[1] Identification of forecast limitations in this chapter does not mean that there is an imminent supply reliability risk. The NER requires identification of limitations which are expected to occur some years into the future, assuming that demand for electricity is consistent with the forecast in this TAPR.

- existing network configuration
- safety, condition and compliance based risks related to existing assets.

This planning process includes consideration of a broad range of options to address identified needs described in Table 6.1. Irrespective of the option or range of options used to address an identified need, where Powerlink identifies that there is a credible option greater than $6 million, Powerlink is required to undertake a Regulatory Investment Test for Transmission (RIT-T). The RIT-T describes the need, the credible options identified and provides the requirements for non-network alternatives.

Table 6.1 Examples of planning options

Option	Description
Augmentation	Increases the capacity of the existing transmission network, e.g. the establishment of a new substation, installation of additional plant at existing substations or construction of new transmission lines. This is driven by the need to meet prevailing network limitations and customer supply requirements, or where there may be net economic benefits to customers. An increase in network capacity may also unlock synergies to support the development of REZ.
System services	The assessment of future network requirements to meet overall power system performance standards and support the secure operation of the power system. This includes the provision of system strength services and inertia services.
Reinvestment	Asset reinvestment planning ensures that existing network assets are assessed for their enduring network requirements in a manner that is economic, safe and reliable. This may result in like-for-like replacement, network reconfiguration, asset retirement, line refit or replacement with an asset of lower capacity. Condition and risk assessment of individual components may also result in the staged replacement of an asset where it is technically and economically feasible.
Network reconfiguration	The assessment of future network requirements may identify the reconfiguration of existing assets as the most economical option. This may involve asset retirement coupled with the installation of plant or equipment at an alternative location that offers a lower cost substitute for the required network functionality.
Asset de-rating or retirement	May include strategies to de-rate, decommission and/or demolish an asset and is considered in cases where needs have diminished in order to achieve long-term economic benefits.
Line refit	Powerlink utilises a line reinvestment strategy called line refit to extend the service life of a transmission line and provide cost benefits through the deferral of future transmission line rebuilds. Line refit may include structural repairs, foundation works, replacement of line components and hardware, abrasive blasting and painting.
Non-network alternatives	Non-network solutions are not limited to, but may include network support and system services from existing and/or new generation, demand side management (DSM) initiatives (either from individual providers or aggregators), and other forms of technologies (such as battery installations). These solutions may reduce, negate or defer the need for network investments.
Operational measures	Network constraints may be managed during specific periods using short-term operational measures, e.g. switching of transmission lines or redispatch of generation in order to defer or negate network investment.

6.4 Forecast capital expenditure

The energy industry is going through a period of transformation driven by shifts in economic outlook, customer behaviour, government policy and regulation and emerging technologies that have reshaped the environment in which Powerlink delivers its transmission services. This has been further impacted by the COVID-19 pandemic.

In this changed environment, Powerlink is focussing on assessing the enduring need for key ageing assets that are approaching the end of their service life, and maintaining network resilience. Powerlink is also seeking alternative investment options through network reconfiguration to manage asset condition and/or non-network solutions where economic and technically feasible.

Powerlink has a focussed and strategic approach in determining when it is appropriate to refit or replace ageing transmission assets and how to implement these works cost effectively, such as targeted asset replacement or staged works that avoid or delay the need to establish new transmission network infrastructure. This approach is aimed at delivering positive outcomes for customers.

6.5 Forecast network limitations

As outlined in Section 1.7.1, under its Transmission Authority, Powerlink must plan and develop its network so that it can supply the forecast maximum demand with the system intact. The planning standard, which came into effect from July 2014, permits Powerlink to plan and develop the network on the basis that some load may be interrupted during a single network contingency event. Forward planning allows Powerlink adequate time to identify emerging limitations and to implement appropriate network and/or non-network solutions to maintain transmission services which meet the planning standard.

Emerging limitations may be triggered by thermal plant ratings (including fault current ratings), protection relay load limits, voltage stability and/or transient stability. Appendix E lists the indicative maximum short circuit currents and fault rating of the lowest rated plant at each Powerlink substation and voltage level, accounting for committed projects listed in Chapter 11 and existing and committed generation listed in Chapter 8.

Based on AEMO's Steady Progress scenario forecast discussed in Chapter 3, the maximum demand for electricity remains relatively flat in the next five years. Powerlink does not anticipate undertaking any significant augmentation works during this period based on load growth alone. However, the changing generation mix may lead to increased constraints across critical grid sections. Powerlink will consider these potential constraints, including the effects of falling minimum demand, holistically with the emerging condition based drivers as part of the planning process and in conjunction with the most recent ISP.

In Powerlink's Revenue Determination 2023-27[2], projects that could be triggered by the commitment of large mining or industrial block loads were identified as contingent projects. Contingent projects and their triggers are discussed in detail in Chapter 9.

In accordance with the NER, Powerlink undertakes consultations with AEMO, Registered Participants and interested parties on feasible solutions to address forecast network limitations through the RIT-T process. Solutions may include provision of network support from existing and/or new generators, DSM initiatives (either from individual providers or aggregators), other forms of technology (such as battery installations) and network augmentations.

6.5.1 Summary of forecast network limitations within the next five years

Powerlink has identified that due to declining minimum demand and increasing penetration of VRE generation, there is an emerging need for additional reactive plant in various zones in Queensland to manage potential over-voltages. Table 6.2[3] summarises limitations identified in Powerlink's transmission network and noted in AEMO's 2019 and 2020 Network Support and Control Ancillary Services (NSCAS) reports.

[2] Information on Powerlink's Revenue Proposal for the regulatory period is available on Powerlink's website.
[3] Refer to NER Clause 5.12.2(c)(3).

Table 6.2 Limitations in the five-year outlook period

Limitation	Zone	Reason for anticipated limitation	Time limitation may be reached: 1-year outlook (2021/22)	3-year outlook (up to 2024/25)	5-year outlook (up to 2026/27)	Reference
Managing voltages in Queensland	Central West		2020/21 project in progress (1)			Table 11.6
	Moreton			2022/23 (2)		Section 6.7.10

Notes:

(1) The network risk associated with this limitation is currently being managed through a range of short-term operational measures until such time as the preferred option identified in the RIT-T, installation of a 275k bus reactor at Broadsound Substation, is commissioned in June 2023.

(2) The network risk associated with this limitation is currently being managed through a range of operational measures until such time as the preferred option identified in the RIT-T which is currently underway (i.e. the staged installation of 120MVAr bus reactors at Woolooga, Blackstone and Belmont substations from June 2022 to December 2025, is complete) and/or a non-network solution identified through the RIT-T process is implemented.

Based on AEMO's Steady Progress scenario forecast discussed in Chapter 3 there are no other network limitations forecast to occur in Queensland in the next five years[4].

6.5.2 Summary of forecast network limitations beyond five years

The timing of forecast network limitations may be influenced by a number of factors such as load growth, industrial developments, new and retiring generation, the planning standard and joint planning with other Network Service Providers (NSP). As a result, it is possible for the timing of forecast network limitations identified in a previous year's TAPR to change from the previously identified timing. However, there were no forecast network limitations identified in Powerlink's transmission network in the 2020 TAPR which fall into this category in 2021.

6.6 Consultations

Network development to meet forecast demand is dependent on the location and capacity of generation developments and the pattern of generation dispatch in the competitive electricity market. Uncertainty about the generation pattern creates uncertainty about the power flows on the network and subsequently, which parts of the network will experience limitations. This uncertainty is a feature of the competitive electricity market and historically has been particularly evident in the Queensland region. Notwithstanding the discussion in Section 6.7.6, Powerlink has not anticipated any material changes to network power flows which may require any major augmentation driven network development. This is due to a combination of several factors including a relatively flat maximum demand forecast in the 10-year outlook period and Powerlink's planning criteria (refer to chapters 1 and 3).

Proposals for transmission investments and reinvestments over $6 million are progressed under the provisions of clauses 5.16.3 and 5.16.4 (not actionable ISP projects) and 5.16A (actionable ISP projects) of the NER. In particular, for projects which are not actionable ISP projects, and where action is considered necessary, Powerlink will:

- notify of anticipated limitations or risks arising from ageing network assets remaining in service within the timeframe required for action
- seek input, initially via the TAPR, on potential solutions to network limitations which may result in transmission network or non-network investments in the 10-year outlook period
- issue detailed information outlining emerging network limitations, including system strength and inertia shortfalls, or the risks arising from ageing network assets remaining in service to assist non-network solutions as possible genuine alternatives to network investments to be identified

[4] Refer to NER Clause 5.12.2(c)(3).

- consult with AEMO, Registered Participants and interested parties on credible options (network or non-network) to address emerging limitations or the risks arising from ageing network assets remaining in service
- carry out detailed analysis on credible options that Powerlink may propose to address identified network limitations or the risks arising from ageing network assets remaining in service
- consult with AEMO, Registered Participants and interested parties on all credible options (network and non-network) and the preferred option
- implement the preferred option in the event an investment (network and/or non-network) is found to satisfy the RIT-T.

Alternatively, transmission investments may be undertaken under the funded augmentation provisions of the NER (Clause 5.18).

It should be noted that the information provided regarding Powerlink's network development plans may change and should be confirmed with Powerlink before any action is taken based on the information contained in this TAPR or the accompanying TAPR templates[5].

6.6.1 Current consultations – proposed transmission investments

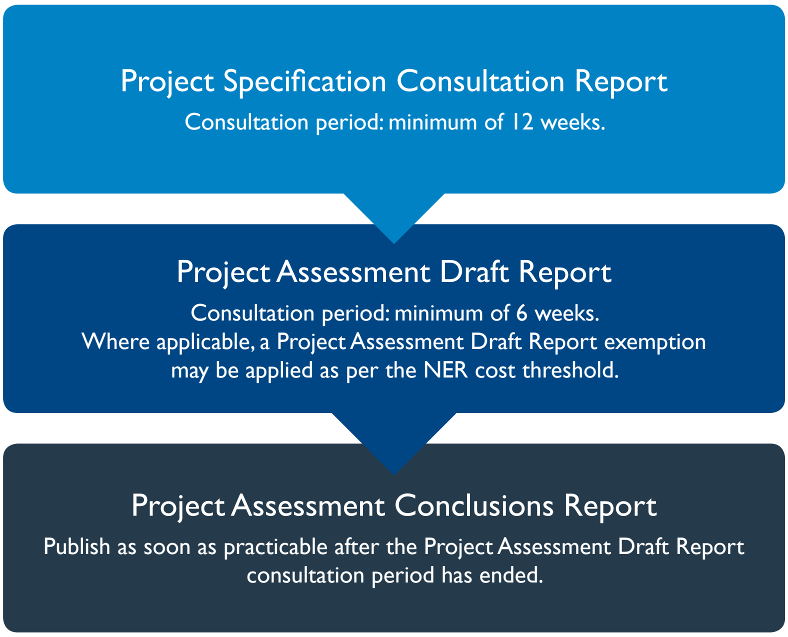
Commencing August 2010 proposals for transmission investments over $6 million addressing network limitations (augmentation works) are progressed under the provisions of Clause 5.16.4 of the NER. In September 2017 this NER requirement, to undertake a RIT-T, was extended[6] to include the proposed replacement of network assets. In July 2018 this was further extended to include proposed investments required to meet system strength and inertia shortfalls[7]. More recently, from 1 July 2020 a new process is in place for projects which have been identified in AEMO's ISP as actionable ISP projects (Clause 5.16A).

Powerlink carries out separate consultation processes for each proposed new transmission investment or reinvestment over $6 million by utilising the applicable RIT-T consultation process. The majority of RIT-T consultations undertaken by Powerlink relate to projects which are not actionable ISP projects (refer to Figure 6.1).

5 In accordance with the AER's TAPR Guidelines published in December 2018 and made available in Powerlink's TAPR portal.
6 Replacement expenditure planning arrangements Rule 2017 No. 5.
7 A RIT-T exemption applies if the inertia or system strength services must be made available less than 18 months after the notice is given by AEMO under clauses 5.20B.3(c) and 5.20C.2(c).

6 Future network development

Figure 6.1 Overview of the RIT-T consultation process for projects which are not actionable ISP projects



The consultations completed since publication of the 2020 TAPR are listed in Table 6.3 (refer also to Table 11.6).

Table 6.3 RIT-T consultations completed since publication of the 2020 TAPR

Consultation
Managing voltage control in Central Queensland

RIT-T consultations currently underway are listed in Table 6.4

Table 6.4 RIT-T consultations currently underway

Consultation	Reference
Maintaining reliability of supply in the Cairns region – Stage 1	Section 6.7.1
Addressing the secondary systems condition risks at Innisfail	Section 6.7.1
Maintaining reliability of supply in the Tarong and Chinchilla local areas	Section 6.7.7
Managing voltages in South East Queensland	Section 6.7.10

Note:

(1) The consultations reflect the RIT-T status as at 30 September 2021.

Other consultations (non RIT-T) completed since publication of the 2020 TAPR are listed in Table 6.5.

Table 6.5 Other consultations completed since publication of the 2020 TAPR

Consultation	Reference
Request for system strength services in Queensland to address fault level shortfall at Ross	Section 6.7.1
Developing the Northern Queensland Renewable Energy Zone	Section 6.7.1

Registered Participants and interested parties are referred to the consultation documents which are published and made available on Powerlink's website for further information.

6.6.2 Future consultations – proposed transmission investments

Anticipated consultations

Reinvestment in the transmission network to manage the risks arising from ageing assets remaining in service will form the majority of Powerlink's capital expenditure program of work moving forward. These emerging risks over the 10-year outlook period are discussed in Section 6.7. Table 6.6 summarises consultations Powerlink anticipates undertaking within the next 12 months under the Australian Energy Regulator's (AER) RIT-T to address either the proposed reinvestment in a network asset or limitation.

Table 6.6 Anticipated consultations in the forthcoming 12 months (to October 2022) (1)

Consultation	Reference
Maintaining reliability of supply at Nebo	Section 6.7.3
Maintaining reliability of supply in the Gladstone region	Section 6.7.5
Maintaining reliability to Gladstone South	Section 6.7.5
Managing power transfer capability and reliability of supply at Redbank Plains	Section 6.7.10
Addressing the secondary systems condition risks at Mudgeeraba	Section 6.7.11

Note:
(1) The anticipated consultations listed in Table 6.6 reflect the RIT-T status as at 30 September 2021.

Future ISP projects

The 2020 ISP did not identify any 'actionable' projects within Queensland. However, the 2020 ISP did identify several projects that are part of the optimal development path and may become actionable in future ISPs. Three such projects were nominated for Preparatory Activities. These include:

- QNI Medium and Large interconnector upgrades
- Central to Southern Queensland transmission link
- Gladstone grid reinforcement.

Preparatory activity reports for these projects were provided to AEMO on 30 June 2021 and are discussed further in Section 9.3. The commencement for consultation for these projects will be triggered by future ISPs[8].

6.6.3 Connection point proposals

Planning of new or augmented connections involves consultation between Powerlink and the connecting party, determination of technical requirements and completion of connection agreements. New connections can result from joint planning with the relevant Distribution Network Service Provider (DNSP)[9] or be initiated by generators or customers.

Table 6.7 lists possible connection works that may be required within the 10-year outlook period.

8 Refer to Clause 9.16A.4(c).
9 In Queensland, Energex and Ergon Energy (part of the Energy Queensland Group) and Essential Energy are the DNSPs.

6 Future network development

Table 6.7 Connection point commitments[10]

Connection point name	Proposal	Zone
Kaban Green Power Hub	New wind farm	North
Kidston Pumped Storage Hydro	New pumped hydro energy storage	North
Moura Solar Farm	New solar farm	Central West
Rodds Bay Solar Farm	New solar farm	Gladstone
Bluegrass Solar Farm	New solar farm	Surat
Wandoan South Battery	New BESS	Surat
Edenvale Solar Farm	New solar farm	Bulli

Notes:

(1) When Powerlink constructs a new line or substation as a non-regulated customer connection (e.g. conventional generator, renewable generator, mine or industrial development), the costs of acquiring easements, constructing and operating the transmission line and/or substation are paid for by the company making the connection request.

(2) The listed connection point commitments are at various stages of progress, including the completion of Wandoan South Battery (refer to tables 11.1 and 11.2).

Table 6.8 summarises connection point activities[11] undertaken by Powerlink since publication of the 2020 TAPR. Additional details on potential new generation connections are available in the relevant TAPR template located on Powerlink's TAPR portal as noted in Appendix B.

Table 6.8 Connection point activities

Generator Location	Number of Applications	Number of Connection Agreements	Generator Type and Technology
North	3	2	Solar, Wind, Hydro, Storage
Central	9	0	Solar, Wind, Storage
South	11	2	Solar, Wind, Storage
Total	**23**	**4**	

6.7 Proposed network developments

As the Queensland transmission network experienced considerable growth in the period from 1960 to 1980, there are now many transmission assets between 40 and 60 years old. It has been identified that a number of these assets are approaching the end of their technical service life and reinvestment in some form is required within the 10-year outlook period in order to manage emerging risks related to safety, reliability and other factors. Moving forward, Powerlink's capital expenditure program of work focuses on reinvestment in the transmission network to manage the identified risks arising from the condition of these ageing assets.

In conjunction with condition assessments and risk identification, as assets approach their anticipated end of technical service life, possible reinvestment options undergo detailed planning studies to confirm alignment with future reinvestment, optimisation and delivery strategies. These studies have the potential to provide Powerlink with an opportunity to:

- improve and further refine options under consideration
- consider other options from those originally identified which may deliver a greater benefit to customers.

[10] AEMO's definition of 'committed' from the System Strength Impact Assessment Guidelines (effective 1 July 2018) has been adopted in the 2021 TAPR.

[11] More broadly, key connection information in relation to the NEM can be found on AEMO's website.

Information regarding possible reinvestment alternatives and anticipated timing is updated annually within the TAPR and includes discussion on significant changes which have occurred since publication of the previous year's TAPR together with the latest information available at the time.

Where applicable, in relation to proposed expenditure for the replacement of network assets or network augmentations, Powerlink will consult with AEMO, Registered Participants and interested parties on feasible solutions identified through the RIT-T. The latest information on RIT-T publications can be found on Powerlink's website.

Proposed network developments discussed within this chapter identify the most likely network solution, although as mentioned, this has the potential to change with ongoing detailed analysis of asset condition and risks, network requirements or as a result of RIT-T consultations.

Other than the emerging high voltage conditions discussed in the 2019 NSCAS Report[12] and based on the current information available, Powerlink considers all of the possible network developments discussed in this chapter are outside of the scope of the most recent ISP, NSCAS Report and Power System Frequency Risk Review (PSFRR)[13]. Powerlink also reviews the rating of assets throughout the transmission network periodically and has not identified any required asset de-ratings that would result in a system limitation as part of the 2021 annual planning review[14].

An analysis of reinvestment needs and potential limitations has been performed across Powerlink's standard geographic zones (refer to sections 6.7.1 to 6.7.11). For clarity, possible network reinvestments have been separated into two periods.

Possible network reinvestments within five years

This includes the financial period from 2021/22 to 2026/27 for possible near-term reinvestments when:

- confirmation of the enduring network need and timing occurs
- detailed planning studies are underway or have recently been finalised.

Possible network reinvestments within six to 10 years

This includes the financial period from 2027/28 to 2031/32, for possible medium to long-term reinvestments. Powerlink takes a balanced, prudent and proportionate approach to the consideration of reinvestment needs to address the risks arising from network assets in the medium to long-term and undertakes detailed planning analysis and condition assessment closer to the possible reinvestment date, typically within five years.

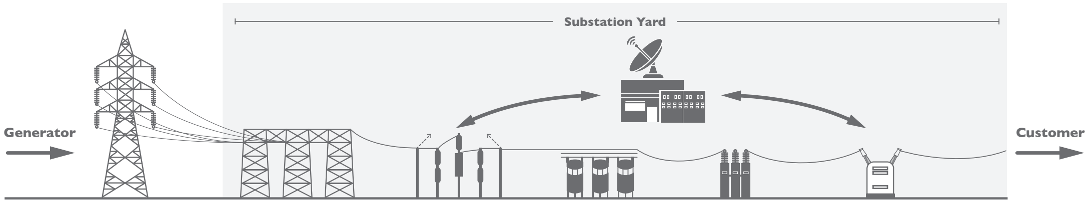
In addition, due to the current dynamic operating environment, there is less certainty regarding the needs or drivers for reinvestments in these later years of the annual planning review period. As a result, considerations in this period have a greater potential to change when compared to near-term investments. Possible reinvestment considerations within six to 10 years will need to be flexible in order to adapt to externally driven changes as the NEM evolves and customer behaviours change. Any significant adjustments which may occur as a result of changes will be updated and discussed in subsequent TAPRs.

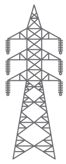
Powerlink also takes a value-driven approach to the management of asset risks to ensure an appropriate balance between reliability and the cost of transmission services which ultimately benefits customers. Each year, taking the most recent assessment of asset condition and risk into consideration, Powerlink reviews possible commissioning dates and where safe, technically feasible and prudent, capital expenditure is delayed. As a result, there may be timing variances between the possible commissioning dates identified in the 2020 TAPR and 2021 TAPR and TAPR Templates. Significant timing differences are noted in the analysis of the program of work within this chapter (refer to sections 6.7.1 to 6.7.11).

The functions performed by the major transmission network assets discussed in this chapter and which form the majority of Powerlink's capital expenditure in the 10-year outlook period are illustrated in Figure 6.2.

[12] AEMO's 2019 NSCAS Report December 2019, page 9.
[13] NER Clauses 2.12.2(6) and (6A).
[14] NER Clause 5.12.2(c)(1A).

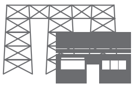
Figure 6.2 The functions of major transmission assets





Transmission line

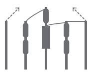
A transmission line consists of tower structures, high voltage conductors and insulators and transports bulk electricity via substations to distribution points that operate at lower voltages.



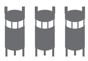
Substation

A substation, which is made up of primary plant, secondary systems, telecommunications equipment and buildings, connects two or more transmission lines to the transmission network and usually includes at least one transformer at the site.

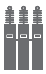
A substation that connects to transmission lines, but does not include a transformer, is known as a switching station.



- **Substation bay**
  A substation bay connects and disconnects network assets during faults and also allows maintenance and repairs to occur. A typical substation bay is made up of a circuit breaker (opened to disconnect a network element), isolators and earth switches (to ensure that maintenance and repairs can be carried out safely), and equipment to monitor and control the bay components.



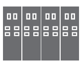
- **Static VAR Compensator (SVC)**
  A SVC is used where needed, to smooth voltage fluctuations, which may occur from time-to-time on the transmission network. This enables more power to be transferred on the transmission network and also assists in the control of voltage.



- **Capacitor Bank**
  A capacitor bank maintains voltage levels by improving the 'power factor'. This enables more power to be transferred on the transmission network.

- **Transformer**
  A transformer is used to change the voltage of the electricity flowing on the network. At the generation connection point, the voltage is 'stepped up' to transport higher levels of electricity at a higher voltage, usually 132kV or 275kV, along the transmission network. Typically at a distribution point, the voltage is 'stepped down' to allow the transfer of electricity to the distribution system, which operates at a lower voltage than the transmission network.

- **Bus reactor**
  A bus reactor is used to control voltages on the high voltage system. Bus reactors are used especially during light load conditions to manage high voltages which may occur on the network.



Secondary systems

Secondary systems equipment assists in the control, protection and safe operation of transmission assets that transfer electricity in the transmission network.

Telecommunication systems

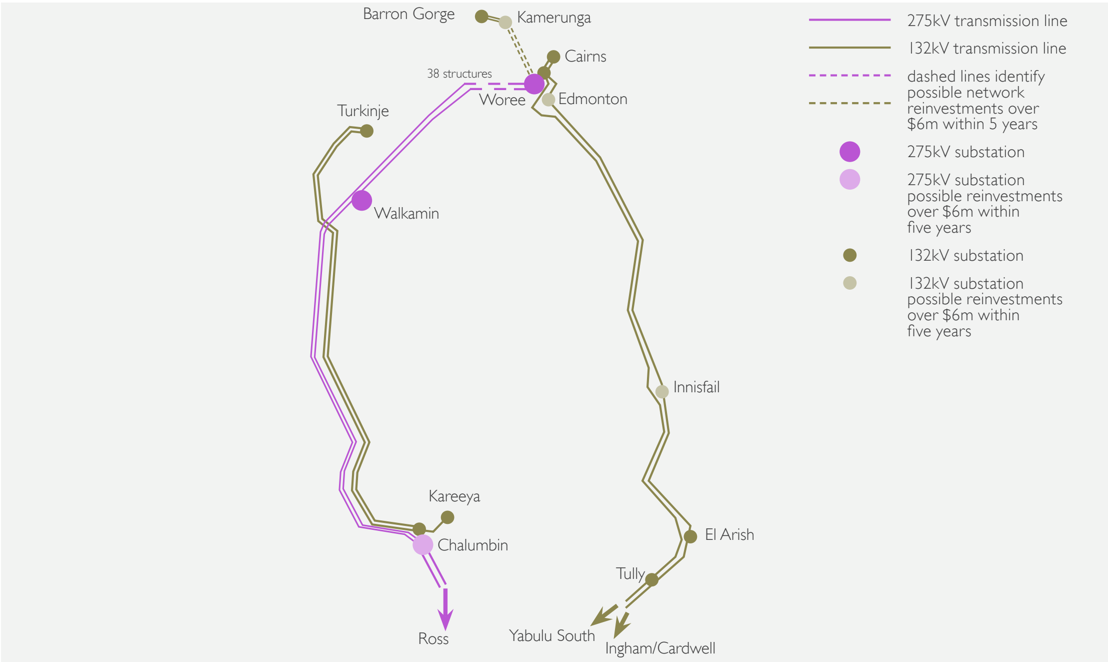
Telecommunication systems are used to transfer a variety of data about the operation and security of the transmission network including metering data for AEMO.

6.7.1 Far North zone

Existing network

The Far North zone is supplied by a 275kV transmission network with major injection points at Chalumbin and Woree, and a coastal 132kV network from Yabulu South to Tully to Woree. This network supplies the Ergon Energy distribution network feeding the surrounding areas of Turkinje and Cairns, from Tully to Cooktown. The network also connects various renewable generators including the hydro power stations at Barron Gorge and Kareeya, and Mt Emerald Wind Farm near Walkamin (refer to Figure 6.3).

Figure 6.3 North zone transmission network



Possible load driven limitations

Based on AEMO's Steady Progress scenario forecast discussed in Chapter 3, there is no additional capacity forecast to be required as a result of network limitations in the Far North zone within the next five years to meet reliability obligations.

Update on previously reported non-load driven network constraints

On 9 April 2020, the AEMO published a report 'Notice of Queensland System Strength Requirements and Ross Fault Level Shortfall' to the National Electricity Market (NEM) under Clause 5.20C.2(c) of the National Electricity Rules (NER). The report declared an immediate fault level shortfall at the Ross 275kV node and advised that system strength services should be in place to meet this shortfall by 31 August 2021. At that time, the shortfall was forecast by AEMO to continue beyond 2024-25.

Powerlink commenced an expression of interest (EOI) process for both short and long-term solutions to address the Queensland Fault Level Shortfall at Ross in April 2020 and received a very strong response offering a range of system strength support services.

In June 2020, AEMO approved the approach for the short-term solution under NER Clause 5.20C.4(e), up until the end of December 2020. As a result, Powerlink entered into a short-term agreement with CleanCo Queensland to provide system strength services through utilising its assets in Far North Queensland.

6 Future network development

During August 2020 AEMO provided preliminary confirmation that, subject to the final exchange of modelling and other details, inverter tuning could reduce the overall system strength requirement at Ross. Consequently Powerlink entered into an agreement with Daydream, Hamilton, Hayman and Whitsunday solar farms in North Queensland to validate the expected positive benefits of inverter tuning during the day time. Powerlink also worked with Mt Emerald Wind Farm and AEMO on changes to control settings.

In December 2020, Powerlink engaged with proponents on the status of the EOI prior to publishing an update document. The update discussed the encouraging results of modelling which indicated that these innovative technical solutions could significantly reduce the overall system strength requirement at Ross, subject to more robust analysis and AEMO's approval.

As a result of retuning of the solar farms and an update of the control settings at Mt Emerald Wind Farm, AEMO's due diligence assessment found that the system strength requirements at the Ross node have changed since the 2020 notice was issued, and that the minimum fault level requirement at Ross is met and no shortfall remained. Please refer to AEMO's Notice published on 28 June 2021.

Based on AEMO's most recent assessment, Powerlink's regional System Strength Service Provider obligations have now been fulfilled in relation to the notice issued in April 2020 under the NER.

Through consultation and active collaboration with all parties, the outcome of this EOI has delivered positive outcomes to customers by implementing innovative cost-effective technical solutions which removed the need for long-term investment (network or non-network).

A summary of Powerlink's EOI process is available in the Final Report published in June 2021.

Developing the Northern Queensland Renewable Energy Zone

The Rules describe a REZ as a geographic area proposed for the efficient development of renewable energy sources and associated electricity infrastructure. REZ development may involve expanding the transmission network or augmenting the capacity of an existing transmission line to increase hosting capacity.

Powerlink has been working with the Queensland Government on strategies to identify opportunities to unlock renewable energy potential in Queensland. Development of the strategy included consideration of the existing transmission network topography in Far North Queensland. The identification of the Northern Queensland Renewable Energy Zone (Northern QREZ) included consideration of the existing transmission network topography in North Queensland, particularly the coastal 132kV double circuit transmission line between Ross and Woree substations which, with modification, has the potential to enable more hosting capacity for renewable generation (refer to Figure 6.4) . The development of the Northern QREZ will potentially unlock up to 500MW of renewable capacity.

In May 2021 the Queensland Government announced that it would invest $40 million in transmission line infrastructure to establish a Northern QREZ, with Neoen's 151MW Kaban Wind Farm identified as the foundational proponent. Given the external nature of the majority of the funding, in June 2021 Powerlink commenced a funded augmentation[15] consultation Developing the Northern Queensland Renewable Energy Zone. Powerlink has also committed approximately $5 million of regulated capital investment to the establishment of the QREZ, the benefits of which, including improved reliability of supply to Cairns, exceed Powerlink's commitment.

All submissions received throughout the consultation process were positive and in support of the development of the Northern QREZ. A Final Report published in September 2021 included the determination to enable the development of the Northern QREZ by establishing a third 275kV connection into Woree Substation by November 2023, with all associated works to commence Quarter 4 2021 and to be completed by November 2023. The scope of work includes:

- Conversion of one side of the coastal 132kV double circuit transmission line to permanently operate at 275kV as the third transmission line between Ross Woree
- Construction of a 275kV bay at Ross Substation
- Installation of a 275/132kV transformer at Tully Substation
- Installation of a 275kV busbar at Woree Substation with associated bays and a line reactor.

[15] Refer to Section 5.18 of the NER.

Figure 6.4 Northern Queensland Renewable Energy Zone

Possible network reinvestments within five years

Network reinvestments in Far North zone are related to addressing the risks arising from the condition of the existing network assets, which without corrective action, would result in Powerlink being exposed to breaching a number of its jurisdictional network, safety, environmental and Rules obligations.

By addressing the condition of these existing assets, Powerlink is seeking to ensure it can deliver a safe, cost effective and reliable supply of electricity to meet the load requirements of customers in the Far North zone into the future. This may result in like-for-like replacement, non-network solutions, network reconfiguration, asset retirement, line refit or replacement with an asset of lower capacity.

Transmission lines

Woree to Kamerunga 132kV transmission lines

Potential consultation	Maintaining reliability of supply to Cairns northern beaches area
Project driver	Emerging condition risks due to structural corrosion
Project timing	December 2026
Proposed network solution	Maintaining 132kV network topology by replacing the existing double circuit transmission line with a new double circuit transmission line on a new easement from Woree to Kamerunga substations at an estimated cost of $40 million, by December 2026.

The Woree to Kamerunga 132kV double circuit transmission lines were constructed in 1963. Originally connected to Cairns, it provides critical supply to the Cairns northern beaches region, as well as connecting the Barron Gorge Hydro Power Station to the 275kV network.

In 2014, life extension works were performed on certain components of this transmission line that were nearing the end of their technical service life. However, it is anticipated that reinvestment will again be required by 2026. The location of the existing structures poses access and construction work challenges. A possible end of technical service life strategy for this transmission line is replacement on a new easement. Investigations for easement alternatives are currently underway.

Possible network solutions

- Maintaining the existing 132kV network topography by replacing the existing double circuit transmission line with a new double circuit transmission line from Woree and Kamerunga substations by December 2026[16]
- Network reconfiguration by establishing two single circuit 132kV transmission lines between Woree and Kamerunga substations, or via Cairns North Substation, by December 2026.

Powerlink considers the proposed network solution will not have a material inter-network impact.

Possible non-network solutions

Potential non-network solutions would need to provide supply to the 22kV network of up to a peak 70MW, and up to a peak 1,200MWh per day on a continuous basis. It should be noted that this transmission line also facilitates the Barron Gorge Hydro Power Station connection in the area.

[16] This excludes easement costs yet to be determined.

Ross to Chalumbin to Woree 275kV transmission lines

Current consultation	Maintaining reliability of supply in the Cairns region Stage 1 - Addressing the condition risks of the transmission towers between Davies Creek and Bayview Heights
Project driver	Emerging condition risks due to structural corrosion
Project timing	December 2023
Proposed network solution	Refurbishment of the 37 towers between Davies Creek and Bayview Heights through the selected replacement of corroded members and components, along with the painting of all 37 towers by October 2023. The indicative capital cost of the preferred option is approximately $38 million.

Potential consultation	Maintaining reliability of supply in the Cairns region Stage 2 - Addressing the condition risks of the transmission towers between Ross and Chalumbin
Project driver	Emerging condition risks due to structural corrosion
Project timing	December 2029
Proposed network solution	Refit the double circuit transmission line between Ross and Chalumbin substations, at an estimated cost of $72 million, by December 2029.

The bulk supply of electricity to the Cairns region in Far North Queensland is provided by generators in Central and Northern Queensland, via a 132kV coastal network and a 275kV inland network, as well as a 'run of the river' hydro power station north of Cairns at Barron Gorge, which is connected to the 132kV network. The majority of supply to the Cairns region is delivered through the inland 275kV network to Ross, near Townsville. From Ross it is transferred via a 275kV transmission line to Chalumbin, continuing via a second 275kV transmission line from Chalumbin to the Woree Substation on the outskirts of Cairns. These 275kV transmission lines also provide connections to the Mt Emerald Wind Farm and Kareeya Power Station.

Due to the environmental sensitivities and geographic conditions which occur in the Cairns region, to ensure reliability of supply to customers, the delivery of the required renewal works will be complex and need to be completed outside of summer peak load and the wet season.

Given the non-homogenous condition of sections of the 384km of transmission line, Powerlink has identified an opportunity to optimise potential reinvestments by applying a prudent and staged approach to address higher risk components in the nearer term. This approach is anticipated to deliver the most economic outcome for customers while providing a uniform end of technical service life for all towers on the transmission line.

The Chalumbin to Woree section of line was built in 1998 and is approximately 140km in length. While the condition of a large majority of the line is consistent with its age, this is not the case for the final 16km into Cairns between Davies Creek and Bayview Heights. This final section contains 37 steel lattice towers that traverse the environmentally sensitive World Heritage Wet Tropics area and terminates near Trinity Inlet Marine Park. These towers have been designed to allow over spanning to minimise corridor clearing. Their extended height resulted in increasing exposure to coastal winds and accelerated degradation.

- The deteriorating condition of 16km of the 275kV Chalumbin to Woree transmission line, from Davies Creek to Bayview Heights, in particular the existing 37 steel lattice towers, require priority action to address their more complex and advanced condition risks and have been proposed under the current Stage 1 RIT-T (Maintaining reliability of supply in the Cairns region – Addressing the condition risks of the transmission towers between Davies Creek and Bayview Heights).

6 Future network development

The double circuit 275kV transmission line between Ross and Chalumbin substations is 244km in length and comprises 528 steel lattice towers. The line was commissioned in 1989 and traverses the rugged terrain of the NQ tropical rain forest, passing through environmentally sensitive, protected areas and crossing numerous regional roads and rivers. Those sections of the line that are elevated and bordering on the Wet Tropics are exhibiting higher levels of atmospheric corrosion than sections in the more protected or dryer areas.

- This section of the transmission line is deteriorating at a slightly slower rate than assets addressed under Stage 1 works, due to its location on the western side of the Great Dividing Range. Additional condition assessment and option analysis has been performed and a potential reinvestment for this section is expected around 2029 compared to 2026 as reported in 2020 TAPR. Hence, Powerlink is proposing this reinvestment to be assessed under a subsequent Stage 2 RIT-T (Maintaining reliability of supply in the Cairns region – Addressing the condition risks of the transmission towers between Ross and Chalumbin).

Undertaking a staged approach to address the risks takes into account:

- the condition and network connectivity of both of the 275kV transmission lines
- ongoing network supply needs in the North and Ross zones
- the complexity of undertaking works in environmentally sensitive areas and
- the associated delivery of any potential network solutions in the required timeframe including consideration of the impact of outages.

Possible network solutions

Maintaining the existing 275kV network topography and capacity through staged line refits or selected rebuild on:

- (Stage 1 RIT-T): Chalumbin to Woree 275kV transmission line (section between Davies Creek and Bayview Heights) by 2023
- (Stage 2 RIT-T): Ross to Chalumbin 275kV transmission line by 2029.

In accordance with the requirements of the RIT-T, Powerlink published a PSCR (with PADR exemption) in March 2021 for the Stage 1 RIT-T which identified two network options:

- Replace critical components and members displaying advanced and early onset of corrosion without painting by October 2023, followed by progressive replacement.
- One-off replacement of critical components displaying signs of advanced corrosion, followed by the complete painting of each tower.

Submissions to the PSCR closed on 8 July 2021.

Subject to the outcome of the RIT-T consultation currently underway, the proposed network solution for Stage 2 is to maintain the 275kV network topology through staged line refit projects of the Ross to Chalumbin 275kV transmission line at an estimated cost of $72 million by December 2029.

Powerlink considers the proposed network solutions will not have a material inter-network impact.

Possible non-network solutions

The Chalumbin to Woree transmission lines provide injection to the Cairns area of up to 270MW at peak and approximately 900MWh per day. A non-network solution must be capable of operating on a continuous basis. Voltage stability governs the maximum supportable power transfer that can be injected into the Cairns and FNQ area.

The Ross to Chalumbin transmission lines provide injection to the north area of close to 400MW at peak and up to 3,000MWh per day.

It should be noted that the network configuration also facilitates generator connections in the area and provides system strength and voltage support for the region.

Substations

Innisfail 132kV Substation

Current consultation	Addressing the secondary systems condition risks at Innisfail
Project driver	Condition driven replacement to address emerging obsolescence and compliance risks on 132kV secondary systems.
Project timing	December 2024
Proposed network solution	Full replacement of all secondary systems and associated panels in a new building at an estimated cost of $12 million by December 2024.

Innisfail Substation is a 132/22kV bulk supply point for Ergon Energy in FNQ. The 132kV assets were built as part of the Kareeya Power Station hydro-electricity project during the late 1950s, which established the 132kV transmission system to provide electricity to expanding coastal communities in the region. Innisfail Substation was rebuilt in 2003 and the secondary systems installed as part of this rebuild are anticipated to reach end of technical service life around 2024.

Possible network solutions

- Full replacement of all secondary systems within the existing building by December 2024
- Full replacement of all secondary systems in a new building by December 2024.

In accordance with the requirements of the RIT-T, Powerlink published a PSCR (with PADR exemption) in November 2020. Submissions to the PSCR closed on 5 March 2021.

Powerlink considers the proposed network solution will not have a material inter-network impact.

Possible non-network solutions

Potential non-network solutions would need to provide supply to the 22kV network at Innisfail of up to a peak of 27MW, and up to a 550MWh per day on a continuous basis. This would facilitate the removal of Innisfail Substation and connection of the Innisfail to Edmonton transmission line to the Innisfail to El Arish transmission line.

Chalumbin 275/132kV Substation

Potential consultation	Addressing the secondary systems condition risks at Chalumbin
Project driver	Condition driven replacement to address emerging obsolescence and compliance risks on 275kV and 132kV secondary systems.
Project timing	December 2025
Proposed network solution	Selected replacement of secondary systems at an estimated cost of $10 million by December 2025.

Chalumbin Substation was established in 1988 and is an essential bulk supply point for 275kV power transfer into FNQ. The substation has undergone feeder and bay extensions and modifications as well as full 132kV and selected 275kV secondary systems replacement since its original construction between 2012 and 2014. The remaining 275kV secondary systems are anticipated to reach end of technical service life around 2025.

Possible network solutions

- Selected replacement of secondary systems components by December 2025
- Full replacement of secondary systems components by December 2025.

Powerlink considers the proposed network solution will not have a material inter-network impact.

Possible non-network solutions

Potential non-network solution must be capable of delivering up to 390MW of power at peak and up to 3,000MWh per day on a continuous basis. It should be noted that the Chalumbin 275/132kV Substation is one of the major injection points to the Far North zone. It also facilitates the Kareeya Power Station connection, and provides voltage support for the region.

Edmonton 132/22kV Substation

Potential consultation	Addressing the secondary systems condition risks at Edmonton
Project driver	Condition driven replacement to address emerging obsolescence and compliance risks on 132kV secondary systems.
Project timing	June 2026
Proposed network solution	Selected replacement of secondary systems at an estimated cost of $6 million by June 2026.

Edmonton Substation, established in 2005, is an essential 132kV switching station and bulk supply point for Ergon Energy that provides supply to coastal communities between Townsville and Cairns and support to the Cairns area in the event of a contingency on the 275kV lines supplying FNQ. The majority of Edmonton secondary systems are anticipated to reach end of technical service life around 2026.

Possible network solutions

- Selected replacement of secondary systems components by June 2026
- Full replacement of secondary systems components by June 2026.

Powerlink considers the proposed network solution will not have a material inter-network impact.

Possible non-network solutions

Potential non-network solutions would need to provide supply to the 22kV network at Edmonton of up to 55MW at peak and up to 770MWh per day. The non-network solution would be required for a contingency and to be able to operate on a continuous basis until normal supply is restored. Supply would also be required for planned outages.

Possible network reinvestments in the Far North zone within five years

Against the backdrop of a rapidly changing electricity sector, Powerlink's planning overview (10-year outlook period of the TAPR) includes consideration of a range of options to address the identified needs in the Far North zone. In this context, when considering the replacement of existing assets in conjunction with the broader network topography, Powerlink may identify potential network reconfigurations or other options which would be economically assessed under the RIT-T (if applicable). These options may identify opportunities to develop the transmission network in such a way as to realise synergies and efficiencies as the energy system is transformed, underpinned by VRE generation, delivering positive outcomes for customers.

As assets approach their anticipated end of technical service life, the potential projects and alternatives (options) listed in Table 6.9 will be subject to detailed analysis to confirm alignment with future reinvestment, optimisation and delivery strategies. This analysis provides Powerlink with an additional opportunity to assess the needs and timing of asset replacement works, further refine options or consider other options, including the associated delivery strategies, from those described in Table 6.9.

Information in relation to potential projects, alternatives and possible commissioning needs will be revised annually within the TAPR based on the latest information available at the time.

Table 6.9 Possible network reinvestments in the Far North zone within five years

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Transmission lines					
Line refit works on the 275kV transmission lines between Chalumbin and Woree substations (section between Davies Creek and Bayview Heights)	Staged line refit works on steel lattice structures	Maintain supply reliability to the Far North and Ross zones	Staged works by December 2023 (1)	New transmission line (2)	$38m (3)
Rebuild the 132kV transmission line between Woree and Kamerunga substations	New 132kV double circuit transmission line	Maintain supply reliability to the Far North zone	December 2026	Two 132kV single circuit transmission lines (2)	$40m
Substations					
Tully 132/22kV transformer replacement	Replacement of the transformer	Maintain supply reliability to the Far North zone	June 2024	Life extension of the existing transformer	$5m
Innisfail 132kV secondary systems replacement	Full replacement of 132kV secondary systems	Maintain supply reliability to the Far North zone	December 2024	Replacement of selected secondary systems equipment (2)	$12m (3)
Chalumbin 275/132kV secondary systems replacement	Selected replacement of 132kV secondary systems	Maintain supply reliability to the Far North zone	December 2025	Full replacement of 132kV secondary systems (2)	$10m (3)
Edmonton 132kV secondary systems replacement	Full replacement of 132kV secondary systems	Maintain supply reliability to the Far North zone	June 2026	Selected replacement of 132kV secondary systems (2)	$6m
Barron Gorge 132kV secondary systems replacement	Full replacement of 132kV secondary systems	Maintain supply reliability to the Far North zone	December 2026	Selected replacement of 132kV secondary systems	$3m
Turkinje 132kV primary plant replacement	Selected replacement of 132kV primary plant	Maintain supply reliability to the Far North zone	December 2026	Full replacement of 132kV primary plant	$3m

Notes:

(1) The change in timing of the network solution from the 2020 TAPR is based upon updated information on the condition of the assets.

(2) The envelope for non-network solutions is defined in Section 6.7.1.

(3) Compared to the 2020 TAPR, the change in the estimated cost of the proposed network solution is based upon updated information in relation to the construction costs of recently completed projects.

Possible network reinvestments within six to 10 years

As a result of the annual planning review, Powerlink has identified that the following reinvestments are likely to be required to address the risks arising from network assets reaching end of technical service life and to maintain reliability of supply in the North zone from around 2027/28 to 2031/32 (refer to Table 6.10).

Table 6.10 Possible network reinvestments in the Far North zone within six to 10 years

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative costs
Transmission Lines					
Line refit works on the 275kV transmission lines between Ross and Chalumbin substations	Staged line refit works on steel lattice structures	Maintain supply reliability to the North and Ross zones	Staged works by December 2029 (1)	New transmission line (2)	$72m (3)
275/132kV substation establishment to maintain supply to Turkinje substation (4)	Establishment of 275/132kV switching substation near Turkinje including two transformers	Maintain supply reliability to Turkinje area	June 2029	Refit of the Chalumbin to Turkinje 132kV transmission line	$37m
Substations					
Kamerunga 132/22kV transformer replacement	Replacement of the transformer	Maintain supply reliability to Cairns northern beaches area	December 2028	Significant load transfers in distribution network Early replacement with higher capacity transformer by 2023 triggered by load growth	$5m
Chalumbin 275kV and 132kV primary plant replacement	Selected replacement of 275kV and 132kV primary plant	Maintain supply reliability to the Far North zone	December 2028	Full replacement of all 275kV and 132kV primary plant and secondary systems	$7m
Woree 275kV and 132kV secondary systems replacement	Selected replacement of 275kV and 132kV secondary systems	Maintain supply reliability to the Far North zone	June 2029	Full replacement of 275kV and 132kV secondary systems	$16m
El Arish 132kV secondary systems replacement	Selected replacement of 132kV secondary systems	Maintain supply reliability to the Far North zone	June 2031	Full replacement of 275kV and 132kV secondary systems	$5m

Notes:

(1) The change in timing of the network solution from the 2020 TAPR is based upon updated information on the condition of the assets.

(2) The envelope for non-network solutions is defined in Section 6.7.1.

(3) Compared to the 2020 TAPR, the change in the estimated cost of the proposed network solution is based upon updated information in relation to the construction costs of recently completed projects.

(4) Operational works, such as asset retirements, do not form part of Powerlink's capital expenditure budget.

Possible asset retirements in the 10-year outlook period[17]

Retirement of one of the 132/22kV transformers at Cairns Substation.

Planning analysis has shown that, based on AEMO's Steady Progress scenario forecast discussed in Chapter 3, there is no enduring need for one of the three transformers at Cairns Substation, which is approaching end of technical service life within the next five years. Retirement of the transformer provides cost savings through the avoidance of capital expenditure to address the condition and compliance risks arising from the asset remaining in service. Some primary plant reconfiguration may be required to realise the benefits of these cost savings at an indicative cost of $3 million. There may also be additional works and associated costs on Ergon Energy's network which requires joint planning closer to the proposed retirement in December 2022 (refer to Table 6.9).

Retirement of the 132kV transmission line between Chalumbin and Turkinje substations.

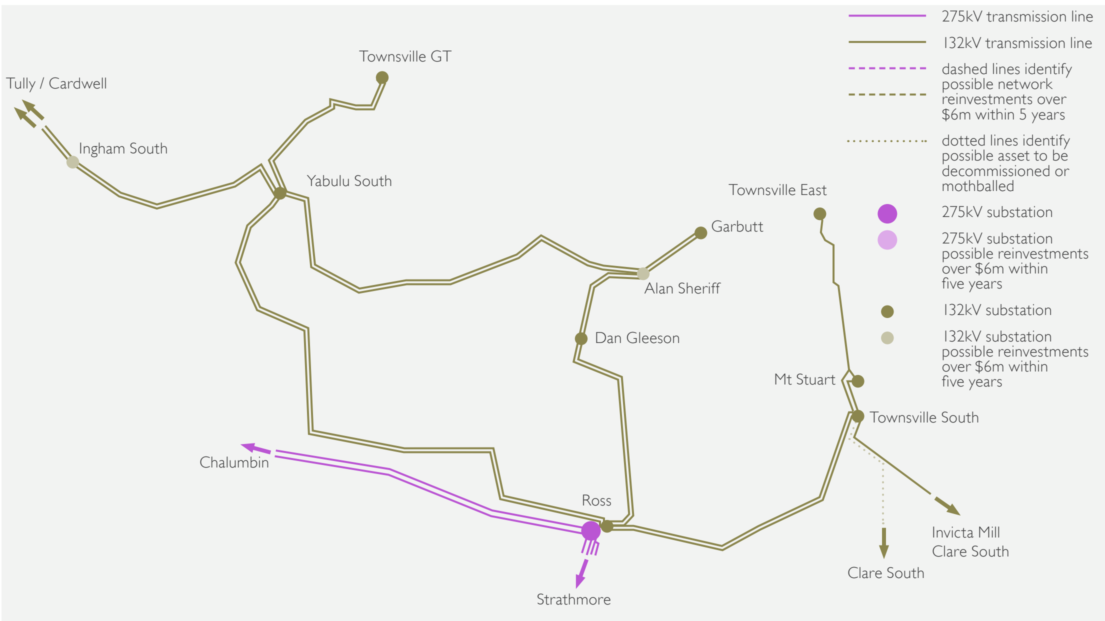
Condition assessment has identified emerging condition risks arising from the condition of the 132kV transmission line between Chalumbin and Turkinje around 2029. At this time, an option would be to establish a 275/132kV switching station near Turkinje to provide 132kV connection and retirement of the existing 132kV transmission line.

6.7.2 Ross zone

Existing network

The 132kV network between Collinsville and Townsville was developed in the 1960s and 1970s to supply mining, commercial and residential loads. The 275kV network within the zone was developed more than a decade later to reinforce supply into Townsville and FNQ. Parts of the 132kV network are located closer to the coast in a high salt laden wind environment leading to accelerated structural corrosion (refer to figures 6.5 and 6.6).

Figure 6.5 Northern Ross zone transmission network



17 Operational works, such as asset retirements, do not form part of Powerlink's capital expenditure budget.

Figure 6.6 Southern Ross zone transmission network

Possible load driven limitations

Based on AEMO's Steady Progress scenario forecast discussed in Chapter 3, there is no additional capacity forecast to be required as a result of network limitations in the Ross zone within the next five years to meet reliability obligations.

Possible network reinvestments within five years

Network reinvestments in the Ross zone are related to addressing the risks arising from the condition of the existing network assets, which without corrective action, would result in Powerlink being exposed to breaching a number of its jurisdictional network, safety, environmental and Rules' obligations.

By addressing the condition of these existing assets, Powerlink is seeking to ensure it can safely deliver an adequate, economic, and reliable supply of electricity to meet the load requirements of customers in the Ross zone into the future. This may result in like-for-like replacement, non-network solutions, network reconfiguration, asset retirement, line refit or replacement with an asset of lower capacity.

Substations

Alan Sherriff 132kV Substation

Potential consultation	Addressing the secondary systems condition risks at Alan Sherriff
Project driver	Condition driven replacement to address emerging obsolescence and compliance risks on 132kV secondary systems.
Project timing	June 2025
Proposed network solution	Selected replacement of secondary systems at estimated cost of $11 million by June 2025.

Alan Sherriff Substation was established in 2002 as a two transformer substation, and replaced the 132kV switching functions at Garbutt in 2004. The substation is a major injection point into Ergon Energy's 66kV distribution network providing supply to the Townsville area.

Possible network solutions

- Selected replacement of secondary systems.
- Full replacement of all secondary systems.

Powerlink considers the proposed network solution will not have a material inter-network impact.

Possible non-network solutions

Potential non-network solutions would need to provide supply to the 11kV network in north east Townsville of up to 25MW at peak and up to 450MWh per day. Reconfiguration of the 132kV network at Alan Sherriff, and of the Townsville 66kV network around Townsville, would be required to facilitate removal of Alan Sherriff Substation.

Ingham South 132kV Substation

Potential consultation	Addressing the secondary systems condition risks at Ingham South
Project driver	Condition driven replacement to address emerging obsolescence and compliance risks on 132kV secondary systems.
Project timing	June 2026
Proposed network solution	Full replacement of secondary systems at an estimated cost of $6 million by June 2026.

Ingham South Substation was established in 2005 and is a major injection point into Ergon Energy's 66kV distribution network providing supply to the Ingham area. The secondary systems installed are anticipated to reach end of technical service life around 2026.

Possible network solutions

- Selected replacement of the secondary systems components by June 2026.
- Full replacement of all secondary systems and associated panels in a new building by June 2026.

Powerlink considers the proposed network solution will not have a material inter-network impact.

Possible non-network solutions

Potential non-network solutions would need to provide supply to the 66kV network at Ingham South of up to 20MW and up to 280MWh per day. The non-network solution would be required for a contingency and to be able to operate on a continuous basis until normal supply is restored. Supply would also be required for planned outages.

Possible network reinvestments in the Ross zone within five years

Against the backdrop of a rapidly changing electricity sector, Powerlink's planning overview (10-year outlook period of the TAPR) includes consideration of a broad range of options to address the identified needs in the Ross zone. In this context, when considering the replacement of existing assets in conjunction with the broader network topography, Powerlink may identify potential network reconfigurations or other options which would be economically assessed under the RIT-T (if applicable). These options may identify opportunities to develop the transmission network in such a way as to realise synergies and efficiencies as the energy system is transformed, underpinned by VRE generation, delivering positive outcomes for customers.

As assets approach their anticipated end of technical service life, the potential projects and alternatives (options) listed in Table 6.10 will be subject to detailed analysis to confirm alignment with future reinvestment, optimisation and delivery strategies. This analysis provides Powerlink with an additional opportunity to assess the needs and timing of asset replacement works, further refine options or consider other options, including the associated delivery strategies, from those described in Table 6.11.

Information in relation to potential projects, alternatives and possible commissioning needs will be revised annually within the TAPR based on the latest information available at the time.

Table 6.11 Possible network reinvestments in the Ross zone within five years

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Substations					
Garbutt 132kV secondary systems replacement	Full replacement of 132kV secondary systems	Maintain supply reliability to the Ross zone	June 2025	Selected replacement of 132kV secondary systems	$5m
Alan Sherriff 132kV secondary systems replacement	Selected replacement of 132kV secondary systems	Maintain supply reliability to the Ross zone	June 2025	Full replacement of 132kV secondary systems (1)	$11m
Ingham South 132kV secondary systems replacement	Full replacement of 132kV secondary systems	Maintain supply reliability to the Ross zone	June 2026 (2)	Selected replacement of 132kV secondary systems (1)	$6m

Notes:

(1) The envelope for non-network solutions is defined in this Section 6.7.2.

(2) The change in timing of the network solution from the 2020 TAPR is based upon updated information on the condition of the assets.

Possible network reinvestments within six to 10 years

As a result of the annual planning review, Powerlink has identified that the following reinvestments are likely to be required to address the risks arising from network assets reaching end of technical service life and to maintain reliability of supply in the Ross zone from around 2027/28 to 2031/32 (refer to Table 6.12).

Table 6.12 Possible network reinvestments in the Ross zone within six to 10 years

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Transmission lines					
Line refit works on the 132kV transmission line between Townsville South and Ross substations	Targeted line refit works on steel lattice structures	Maintain supply reliability to the Ross zone	June 2028	New 132kV transmission line Targeted line refit works on steel lattice structures with painting	$2m
Line refit works on the 132kV transmission line between Ross and Dan Gleeson substations	Line refit works on steel lattice structures	Maintain supply reliability to the Ross zone	June 2028	New 132kV transmission line	$8m
Line refit works on the 132kV transmission line between Dan Gleeson and Alan Sheriff substations	Line refit works on steel lattice structures	Maintain supply reliability to the Ross zone	December 2028	New 132kV transmission line	$4m
Substations					
Townsville East 132kV secondary systems replacement	Staged replacement of secondary systems	Maintain supply reliability to the Ross zone	June 2028	Full replacement of secondary systems	$3m
Townsville South 132kV secondary systems replacement	Selected replacement of 132kV secondary systems	Maintain supply reliability to the Ross zone	June 2028	Full replacement of 132kV secondary systems	$15m
Yabulu South 132kV secondary systems replacement	Selected replacement of 132kV secondary systems	Maintain supply reliability to the Ross zone	June 2029	Full replacement of 132kV secondary systems	$7m
Clare South 132kV secondary systems replacement	Selected replacement of 132kV secondary systems	Maintain supply reliability to the Ross zone	June 2029	Full replacement of 132kV secondary systems	$11m
Ross 275/132kV secondary systems replacement	Selected replacement of secondary systems	Maintain supply reliability to the Ross zone	June 2030	Full replacement of secondary systems	$8m
Bowen North 132kV secondary systems replacement	Selected replacement of secondary systems	Maintain supply reliability to the Ross zone	June 2031	Full replacement of 132kV secondary systems	$3m

Possible asset retirements in the 10-year outlook period

Current planning analysis has not identified any potential asset retirements in the Ross zone within the 10-year outlook period.

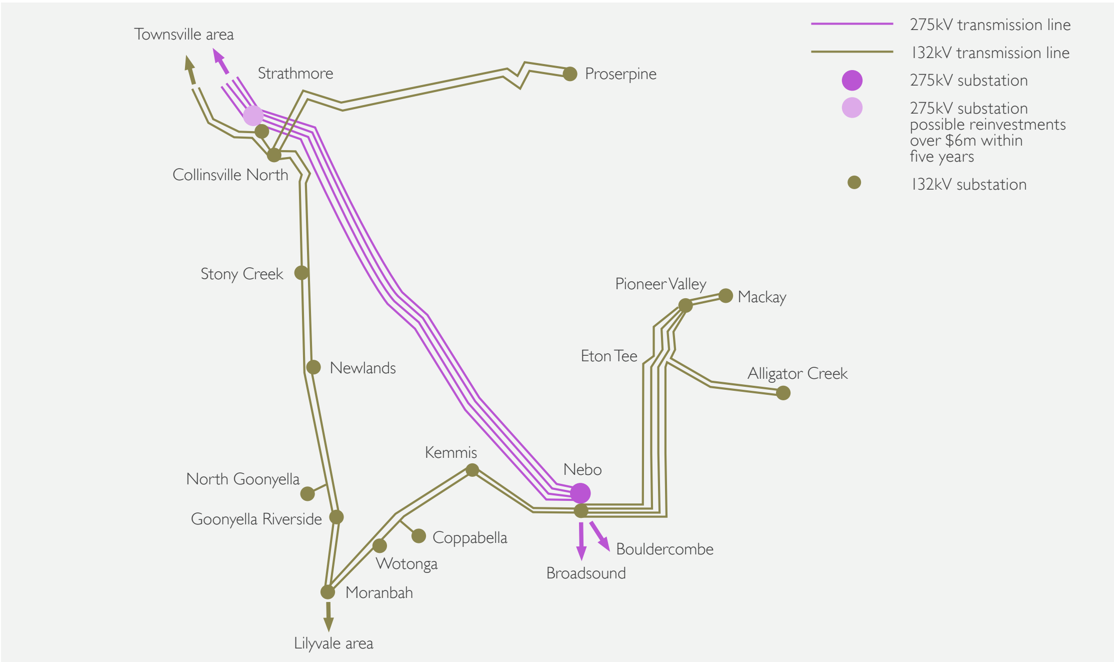
6.7.3 North zone

Existing network

Three 275kV circuits between Nebo (in the south) and Strathmore (in the north) substations form part of the 275kV transmission network supplying the North zone. Double circuit inland and coastal 132kV transmission lines supply regional centres and infrastructure related to mines, coal haulage and ports arising from the Bowen Basin mines (refer to Figure 6.7).

The coastal network in this zone is characterised by transmission line infrastructure in a corrosive environment which make it susceptible to premature ageing.

Figure 6.7 North zone transmission network



Possible load driven limitations

Based on AEMO's Steady Progress scenario forecast discussed in Chapter 3, there is no additional capacity forecast to be required as a result of network limitations in the North zone within the next five years to meet reliability obligations.

High voltages associated with light load conditions are currently managed with existing reactive sources. However, midday power transfer levels are forecast to reduce as additional VRE generators are commissioned in north Queensland. As a result, voltage control is forecast to become increasingly challenging for longer durations. This is discussed in Section 8.7.3.

Possible network reinvestments within five years

Network reinvestments in the North zone are related to addressing the risks arising from the condition of the existing network assets, which without corrective action, would result in Powerlink being exposed to breaching a number of its jurisdictional network, safety, environmental and Rules' obligations.

By addressing the condition of these existing assets, Powerlink is seeking to ensure it can safely deliver an adequate, economic, and reliable supply of electricity to meet the load requirements of customers in the North zone into the future. This may result in like-for-like replacement, non-network solutions, network reconfiguration, asset retirement, line refit or replacement with an asset of lower capacity.

Substations

Strathmore 275/132kV Substation

Potential consultation	Addressing the Static VAr Compensator (SVC) secondary systems condition risks at Strathmore
Project driver	SVC secondary systems condition risks at Strathmore Substation
Project timing	June 2026
Proposed network solution	Full replacement of secondary systems associated with the SVC at Strathmore at an estimated cost of $6 million by June 2026.

Strathmore Substation was established in 2001. The substation is a major injection point into Ergon Energy's 66kV distribution network. It consists of 275kV and 132kV switchyards.

Possible network solutions

- Selected replacement of the secondary systems associated with the SVC
- Full replacement of all secondary systems associated with the SVC
- Full replacement of secondary systems associated with the SVC and selected secondary systems for the 275kV and 132kV switchyard.

Powerlink considers the proposed network solution will not have a material inter-network impact.

Possible non-network solutions

Potential non-network solutions would need to provide dynamic voltage support of up to 150MVAr capacitive and 80MVArs inductive.

Nebo 132kV Substation

Anticipated consultation	Maintaining reliability of supply at Nebo
Project driver	Transformer condition risks at Nebo Substation
Project timing	June 2024
Proposed network solution	Replacement of two 132/11kV transformers at an estimated cost of $5 million by June 2026.

Nebo Substation was established in the late 1970s. Nebo was chosen as a location where 275kV marshalling would be required and also as a transformation point to 132kV, to supply local loads in the Moranbah and Mackay area. Two of the transformers have now been in operation for 38 years and are anticipated to reach end of technical service life around 2024.

Possible network solutions

- Replacement of two 132/11kV transformers
- Establish 11kV supply from surrounding network.

Powerlink considers the proposed network solution will not have a material inter-network impact.

Possible non-network solutions

Potential non-network solutions would need to provide supply to the 11kV network at Nebo up to 3MW at peak and up to 50MWh per day. The non-network solution would be required for a contingency and able to operate on a continuous basis until normal supply is restored. Supply would also be required for planned outages.

Possible network reinvestments in the North zone within five years

Against the backdrop of a rapidly changing electricity sector, Powerlink's planning overview (10-year outlook period of the TAPR) includes consideration of a range of options to address the identified needs in the North zone. In this context, when considering the replacement of existing assets in conjunction with the broader network topography, Powerlink may identify potential network reconfigurations or other options which would be economically assessed under the RIT-T (if applicable). These options may identify opportunities to develop the transmission network in such a way as to realise synergies and efficiencies as the energy system is transformed, underpinned by VRE generation, delivering positive outcomes for customers.

As assets approach their anticipated end of technical service life, the potential projects and alternatives (options) listed in Table 6.13 will be subject to detailed analysis to confirm alignment with future reinvestment, optimisation and delivery strategies. This analysis provides Powerlink with an additional opportunity to assess the needs and timing of asset replacement works, further refine options or consider other options, including the associated delivery strategies, from those described in Table 6.13.

Information in relation to potential projects, alternatives and possible commissioning needs will be revised annually within the TAPR based on the latest information available at the time.

Table 6.13 Possible network reinvestments in the North zone within five years

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Substations					
Nebo 132/11kV transformer replacements	Replacement of two 132/11kV transformers	Maintain supply reliability to the North zone	June 2024 (2)	Establish 11kV supply from surrounding network	$5m
Alligator Creek 132kV primary plant replacement	Selected replacement of 132kV primary plant	Maintain supply reliability to the North zone	June 2024 (2)	Full replacement of 132kV primary plant	$4m
North Goonyella 132kV secondary systems replacement	Full replacement of 132kV secondary systems	Maintain supply reliability to the North zone	December 2023	Selected replacement of 132kV secondary systems	$5m (3)
Strathmore SVC secondary systems replacement	Full replacement of secondary systems	Maintain supply reliability to the Ross zone	June 2026	Staged replacement of secondary systems (1)	$6m

Notes:

(1) The envelope for non-network solutions is defined in this Section 6.7.3.

(2) The change in timing of the network solution from the 2020 TAPR is based upon updated information on the condition of the assets.

(3) Compared to the 2020 TAPR, the change in the estimated cost of the proposed network solution is based upon updated information in relation to condition and scope of works.

Possible network reinvestments within six to 10 years

As a result of the annual planning review, Powerlink has identified that the following reinvestments are likely to be required to address the risks arising from network assets reaching end of technical service life and to maintain reliability of supply in the North zone from around 2027/28 to 2031/32 (refer to Table 6.14).

Table 6.14 Possible network reinvestments in the North zone within six to 10 years

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Transmission lines					
Line refit works on the 132kV transmission line between Nebo Substation and Eton tee	Line refit works on steel lattice structures	Maintain supply reliability to the North zone	December 2027 (1)	New transmission line	$31m
Substations					
Kemmis 132/66kV transformer replacement	Replacement of one 132/66kV transformers	Maintain supply reliability to the North zone	June 2028	Establish 66kV supply from surrounding network	$4m
Alligator Creek SVC and 132kV secondary systems replacement	Full replacement of 132kV secondary systems	Maintain supply reliability to the North zone	June 2028	Staged replacement of 132kV secondary systems	$15m
Pioneer Valley 132kV primary plant replacement	Selected replacement of 132kV secondary systems equipment	Maintain supply reliability to the North zone	December 2028	Full replacement of 132kV secondary systems	$4m (2)
Strathmore 275kV and 132kV secondary systems	Selected replacement of 275 and 132kV secondary systems in a new prefabricated building	Maintain supply reliability to the North zone	December 2028	Selected replacement of 275kV and 132kV secondary systems in existing panels	$14m
Mackay 132/33kV transformer replacement	Replacement of one 132/33kV transformer	Maintain supply reliability to the North zone	June 2030	Establish 33kV supply from surrounding network	$5m

Notes:

(1) The revised timing from the 2020 TAPR is based upon the latest condition assessment.

(2) Compared to the 2020 TAPR, the change in the estimated cost of the proposed network solution is based upon updated information in relation to the construction costs of recently completed projects.

Possible asset retirements within the 10-year outlook period

Pioneer Valley to Eton tee 132kV transmission line

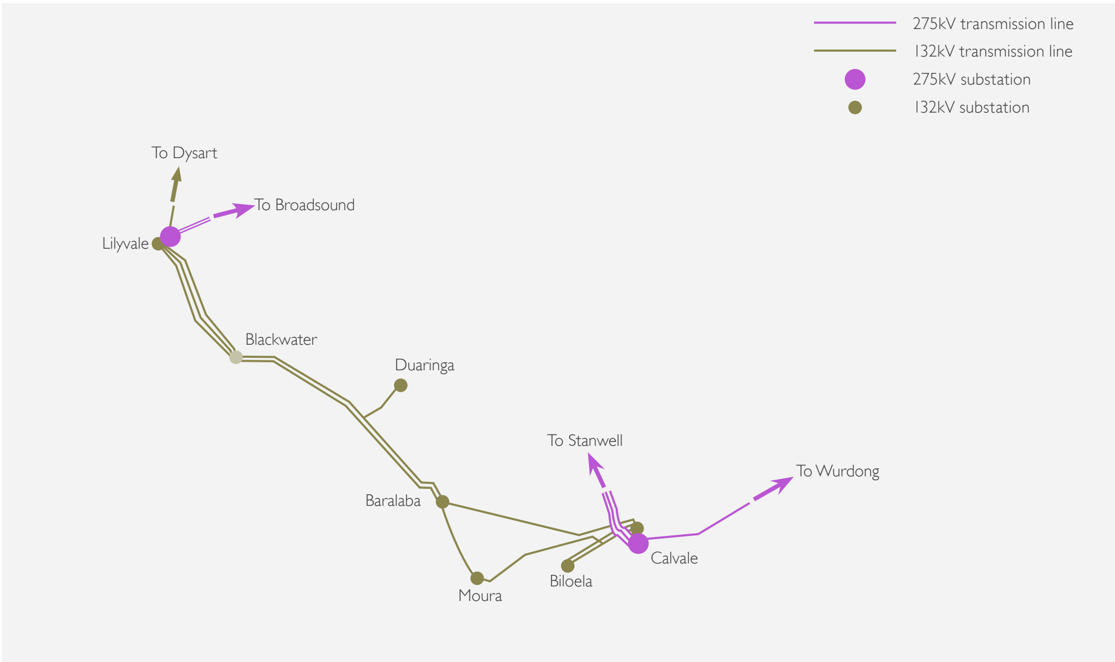
Subject to the outcome of further analysis, Powerlink may retire this inland transmission line at the end of its service life anticipated around 2027, which will also result in the 132kV network reconfiguration from Nebo to Pioneer Valley and Alligator Creek substations, essentially creating a separate double circuit line into each substation.

6.7.4 Central West zone

Existing network

The Central West 132kV network was developed between the mid-1960s and late 1970s to meet the evolving requirements of mining activity in the southern Bowen Basin. The 132kV injection points for the network are taken from Calvale and Lilyvale 275kV substations. The network is located more than 150km from the coast in a dry environment making infrastructure less susceptible to corrosion. As a result transmission lines and substations in this region have met (and in many instances exceeded) their anticipated service life and will require replacement or rebuilding in the near future (refer to Figure 6.8).

Figure 6.8 Central West 132kV transmission network



Possible load driven limitations

Based on AEMO's Steady Progress scenario forecast discussed in Chapter 3 and the committed generation described in tables 8.1 and 8.2, there is no additional capacity forecast to be required in the Central West zone within the next five years to meet reliability obligations.

Possible network reinvestments within five years

Network reinvestments in the Central West zone are related to addressing the risks arising from the condition of the existing network assets, which without corrective action, would result in Powerlink being exposed to breaching a number of its jurisdictional network, safety, environmental and Rules' obligations.

By addressing the condition of these existing assets, Powerlink is seeking to ensure it can safely deliver an adequate, economic, and reliable supply of electricity to meet the load requirements of customers in the Central West zone into the future. This may result in like-for-like replacement, non-network solutions, network reconfiguration, asset retirement, line refit or replacement with an asset of lower capacity.

Substations

Calvale 275/132kV Substation

Potential consultation	Maintaining reliability of supply at Calvale
Project driver	Addressing the 275kV primary plant condition risks
Project timing	December 2026
Proposed network solution	Selected primary plant replacement at Calvale Substation at an estimated cost of $13 million by December 2026.

Calvale Substation was established in the 1980s and is a critical part of the Central West Queensland transmission network and provides connection to Callide B and C generators. Selected primary plant is anticipated to reach end of technical service life around 2026.

Possible network solutions

- Selected primary plant replacement by December 2026
- Full primary plant replacement by December 2026.

Powerlink considers the proposed network solution will not have a material inter-network impact.

Possible non-network solutions

Potential non-network solutions would need to provide supply to Moura and Biloela loads of more than 100MW on the 132kV network, and up to 2,000MWh per day on a continuous basis. However Calvale Substation is primarily a major transmission node in Central Queensland connecting power flows between North, Central and Southern Queensland. It also facilitates Callide B and C generation connection, and also provides voltage support for the region.

Broadsound 275kV Substation

Potential consultation	Maintaining reliability of supply at Broadsound
Project driver	Addressing the 275kV primary plant condition risks
Project timing	December 2026
Proposed network solution	Selected primary plant replacement at Broadsound Substation at an estimated cost of $15 million by December 2026.

Broadsound Substation was first established in 1983. Further extensions have been made with additions of 275kV feeders to the West, South and North. Selected primary plant is anticipated to reach end of technical service life around 2026.

Possible network solutions

- Selected primary plant replacement by December 2026
- Full primary plant replacement by December 2026.

Powerlink considers the proposed network solution will not have a material inter-network impact.

Possible non-network solutions

Potential non-network solutions would need to provide supply to Lilyvale and Blackwater loads of up to 250MW, and up to 6,000MWh per day on a continuous basis. Broadsound Substation is primarily a major transmission node connecting power flows between North and Central Queensland, and also provides voltage support for the region.

Possible network investments in the Central West zone within five years

Against the backdrop of a rapidly changing electricity sector, Powerlink's planning overview (10-year outlook period of the TAPR) includes consideration of a range of options to address the identified needs in the region. In this context, when considering the replacement of existing assets in conjunction with the broader network topography, Powerlink may identify potential network reconfigurations or other options which would be economically assessed under the RIT-T (if applicable). These options may identify opportunities to develop the transmission network in such a way as to realise synergies and efficiencies as the energy system is transformed, underpinned by VRE generation, delivering positive outcomes for customers.

As assets approach their anticipated end of technical service life, the potential projects and alternatives (options) listed in Table 6.15 will be subject to detailed analysis to confirm alignment with future reinvestment, optimisation and delivery strategies. This analysis provides Powerlink with an additional opportunity to assess the needs and timing of asset replacement works, further refine options or consider other options, including the associated delivery strategies, from those described in Table 6.14.

Information in relation to potential projects, alternatives and possible commissioning needs will be revised annually within the TAPR based on the latest information available at the time.

Table 6.15 Possible network investments in the Central West zone within five years

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Substations					
Blackwater 132kV primary plant replacement	Selected replacement of 132kV primary plant	Maintain supply reliability to the Central West zone	June 2025	Full replacement of 132kV primary plant	$3m
Biloela 132kV secondary systems replacement	Selected replacement of 132kV secondary systems	Maintain supply reliability to the Central West zone	June 2025	Full replacement of 132kV secondary systems	$4m
Lilyvale 132kV secondary systems replacement	Selected replacement of 132kV secondary systems	Maintain supply to the Central West zone	June 2025	Full replacement of 132kV secondary systems	$3m
Line refit works on the 132kV transmission line between Calvale, Biloela and Moura	Line refit works on the 132kV transmission line and repair selected foundations	Maintain supply reliability to the Central West zone	June 2025 (1)	Rebuild the 132kV transmission lines as a double circuit from Callide A to Moura	$5m
Calvale 275kV primary plant replacement	Selected replacement of 275kV primary plant	Maintain supply reliability to the Central West zone	December 2026	Full replacement of 275kV primary plant	$13m (2)
Broadsound 275kV primary plant replacement	Selected replacement of 275kV primary plant	Maintain supply reliability to the Central West zone	December 2026	Full replacement of 275kV primary plant	$15m
Broadsound 275kV secondary systems replacement	Selected replacement of 275kV secondary systems	Maintain supply reliability to the Central West zone	June 2027	Full replacement of 275kV secondary systems	$4m

Notes:

(1) The change in timing of the network solution from the 2020 TAPR is based upon updated information on the condition of the assets.

(2) Compared to the 2020 TAPR, the change in the estimated cost of the proposed network solution is based upon updated information in relation to condition and scope of works.

Possible network reinvestments within six to 10 years

As a result of the annual planning review, Powerlink has identified that the following reinvestments are likely to be required to address the risks arising from network assets reaching end of technical service life and to maintain reliability of supply in the Central West zone from around 2027/28 to 2031/32 (refer to Table 6.16).

Table 6.16 Possible network reinvestments in the Central West zones within six to 10 years

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Transmission lines					
Line refit works on the 275kV transmission line between Bouldercombe and Nebo substations	Line refit works on the 275kV transmission line	Maintain supply reliability in the Central West zone	December 2027	Stanwell to Broadsound 2nd side stringing New 275kV transmission line between Bouldercombe and Broadsound substation	$24m
Substations					
Blackwater 132kV secondary systems replacement	Selected replacement of 132kV secondary systems	Maintain supply reliability in the Central West zone	June 2029	Full replacement of 132kV secondary systems	$13m

Possible asset retirements within the 10-year outlook period[18]

Subject to the outcome of further analysis and RIT-T consultation, Powerlink may retire the single circuit transmission lines between Callide and Baralaba, and Baralaba and Moura at the end of its technical service life anticipated around 2025, if a new 132kV double circuit transmission line is constructed between Calvale and Moura substations.

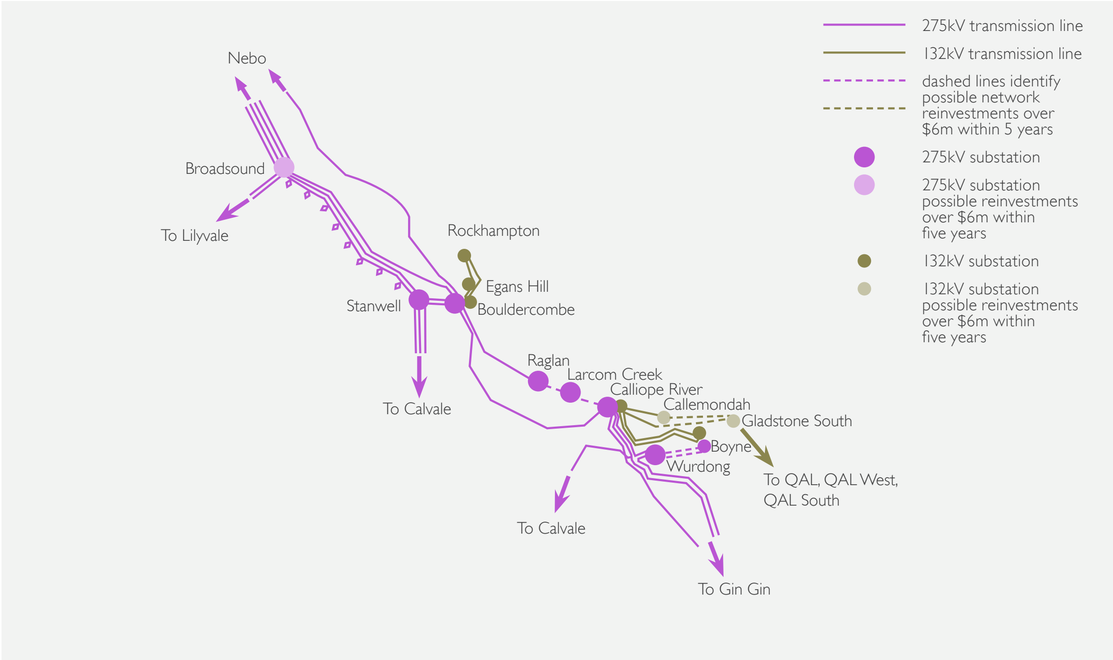
6.7.5 Gladstone zone

Existing network

The Gladstone 275kV network was initially developed in the 1970s with the Gladstone Power Station and has evolved over time with the addition of the Wurdong Substation and supply into Boyne Smelters Limited (BSL) in the early 1990s (refer to Figure 6.9).

[18] Operational works, such as asset retirements, do not form part of Powerlink's capital expenditure budget.

Figure 6.9 Gladstone transmission network



Possible load driven limitations

Based on AEMO's Steady Progress scenario forecast discussed in Chapter 3, there is no additional capacity forecast to be required in the Gladstone zone within the next five years to meet reliability obligations.

Possible network reinvestments within five years

Network reinvestments in Gladstone zone are related to addressing the risks arising from the condition of the existing network assets, which without corrective action, would result in Powerlink potentially breaching a number of its jurisdictional network, safety, environmental and Rules obligations.

By addressing the condition of these existing assets, Powerlink is seeking to ensure it can deliver a safe, cost effective and reliable supply of electricity to meet the load requirements of customers in the Gladstone zone into the future. This may result in like for like replacement, non-network solutions, network reconfiguration, asset retirement, line refit or replacement with an asset of lower capacity.

Transmission lines

Larcom Creek to Calliope 275kV transmission lines

Potential consultation	Maintaining reliability of supply in the Gladstone region
Project driver	Emerging condition risks due to structural corrosion
Project timing	June 2024
Proposed network solution	Line refit works between Larcom Creek and Calliope River (Mt Miller) at an estimated cost of $10 million, by June 2024.

The transmission line between Calliope River and Larcom Creek was constructed in 1977 and is located in CQ immediately adjacent to the Gladstone industrial area. This built section covers the distance between Calliope River and Larcom Creek via Yarwun substations. A proportion of the transmission line traverses tidal marine environment and due to its proximity to the large-scale industrial areas and the coast it is constantly exposed to high levels of salt laden air and industrial pollutants.

Possible network solutions

- Line refit works on steel lattice structures
- Rebuild the 275kV transmission line between Calliope River and Larcom Creek as single circuit transmission line construction
- Rebuild the 275kV transmission line between Calliope River and Larcom Creek as double circuit transmission line construction.

Powerlink considers the proposed network solution will not have a material inter-network impact.

Possible non-network solutions

Potential non-network solutions would need to provide supply to 66kV and 132kV loads at Yarwun and Raglan of up to 160MW and up to 3,200MWh per day. The non-network solution would be required for a contingency and to be able to operate on a continuous basis until normal supply is restored. Supply would also be required for planned outages.

Wurdong to Boyne Island 275kV transmission line

Anticipated consultation	Maintaining reliability of supply in the Gladstone region
Project driver	Emerging condition risks due to structural corrosion
Project timing	December 2025
Proposed network solution	Refit the single circuit transmission line between Wurdong and Boyne substations, at an estimated cost of $10 million, by December 2025.

The transmission line provides supply to the Boyne Smelter from the Wurdong substation and was constructed in 1991, Due to its proximity to Boyne Smelter, Gladstone industrial precinct and the coast, it is constantly exposed to high levels of salt laden air and industrial pollutants. As a result, particularly in the more exposed locations, a high percentage of galvanised tower bolts and members are exhibiting evidence of extensive corrosion. The line receives additional maintenance to keep it in a serviceable condition.

Possible network solutions

- Line refit works on steel lattice structures
- Rebuild the 275kV transmission line between Wurdong and Boyne as single circuit transmission line construction
- Rebuild the 275kV transmission line between Wurdong and Boyne as double circuit transmission line construction.

Powerlink considers the proposed network solution will not have a material inter-network impact.

Possible non-network solutions

Potential non-network solutions would need to provide supply to the 275kV network at Boyne Island of approximately 400MW and approximately 10,000MWh per day. The non-network solution would be required for a contingency and to be able to operate on a continuous basis until normal supply is restored. Supply would also be required for planned outages.

Callemondah to Gladstone South 132kV transmission lines

Anticipated consultation	Maintaining reliability of supply to Gladstone South
Project driver	Emerging condition risks due to structural corrosion
Project timing	December 2023
Proposed network solution	Rebuild the double circuit transmission line between Callemondah and Gladstone South substations, at an estimated cost of $17 million, by December 2023.

The Callemondah to Gladstone South 132kV double circuit transmission line was constructed in 1977. The transmission line facilitates supply to Gladstone South Substation which is an Ergon Energy bulk supply point and the connection point for Queensland Alumina Limited (QAL).

Possible network solutions

- Rebuild the 132kV transmission line between Callemondah and Gladstone South substations
- Line refit works on steel lattice structures.

Powerlink considers the proposed network solution will not have a material inter-network impact.

Possible non-network solutions

Potential non-network solutions would need to provide supply to the 132kV network at Gladstone South of up to 160MW at peak and up to 1,820MWh per day. The non-network solution would be required for a contingency and to be able to operate on a continuous basis until normal supply is restored. Supply would also be required for planned outages.

Substations

Callemondah 132kV Substation

Potential consultation	Maintaining reliability of supply at Callemondah
Project driver	Addressing the 132kV primary plant and secondary systems condition risks
Project timing	June 2024
Proposed network solution	Selected primary plant and secondary systems replacement at Callemondah Substation at an estimated cost of $7 million by June 2024.

Callemondah Substation was established in 1985 and provides supply to the Aurizon supply network. The secondary systems are anticipated to reach end of technical service life around 2024.

Possible network solutions

- Full primary plant and secondary systems replacement by June 2024
- Selected primary plant and secondary systems replacement by June 2024.

Powerlink considers the proposed network solution will not have a material inter-network impact.

Possible non-network solutions

Potential non-network solutions would need to provide supply to the 132kV network at Gladstone South and/or Aurizon load at Callemondah, totalling up to 180MW and up to 2,500MWh per day. The non-network solution would be required for a contingency and be able to operate on a continuous basis until normal supply is restored. Supply would also be required for planned outages.

Possible network reinvestments in the Gladstone zone within five years

Against the backdrop of a rapidly changing electricity sector, Powerlink's planning overview (10-year outlook period of the TAPR) includes consideration of a range of options to address the identified needs in the Gladstone zone. In this context, when considering the replacement of existing assets in conjunction with the broader network topography, Powerlink may identify potential network reconfigurations or other options which would be economically assessed under the RIT-T (if applicable). These options may identify opportunities to develop the transmission network in such a way as to realise synergies and efficiencies as the energy system is transformed, underpinned by VRE generation, delivering positive outcomes for customers.

As assets approach their anticipated end of technical service life, the potential projects and alternatives (options) listed in Table 6.17 will be subject to detailed analysis to confirm alignment with future reinvestment, optimisation and delivery strategies. This analysis provides Powerlink with an additional opportunity to assess the needs and timing of asset replacement works, further refine options or consider other options, including the associated delivery strategies, from those described in Table 6.17.

Information in relation to potential projects, alternatives and possible commissioning needs will be revised annually within the TAPR based on the latest information available at the time.

Table 6.17 Possible network reinvestments in the Gladstone zone within five years

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Transmission lines					
Line refit works on the 132kV transmission line between Callemondah and Gladstone South substations	Rebuild the 132kV transmission line between Callemondah and Gladstone South Substation	Maintain supply reliability in the Gladstone zone	December 2023	Line refit works on steel lattice structures (1)	$17m
Line refit between Larcom Creek and Mt Miller substation	Line refit works on steel lattice structures	Maintain supply reliability in the Gladstone zone	June 2024 (2)	Rebuild the 275kV transmission line between Mt Miller and Larcom Creek substation (1)	$10m
Line refit works on the 275kV transmission line between Wurdong and Boyne Island	Line refit works on steel lattice structures	Maintain supply reliability in the Gladstone zone	December 2025 (2)	Rebuild the 275kV transmission line between Wurdong and Boyne Island (1)	$10m (3)
Substations					
Callemondah selected 132kV primary plant and secondary systems replacement	Selected replacement of 132kV primary plant and secondary systems	Maintain supply reliability in the Gladstone zone	June 2024	Full replacement of 132kV primary plant and secondary systems (1)	$7m
Rockhampton 132kV secondary systems replacement	Selected replacement of 132kV secondary systems	Maintain reliability in Rockhampton	December 2026	Full replacement of 132kV secondary systems	$4m

Notes:
(1) The envelope for non-network solutions is defined in Section 6.7.5.
(2) The change in timing of the network solution from the 2020 TAPR is based upon updated information on the condition of the assets.
(3) Compared to the 2020 TAPR, the change in the estimated cost of the proposed network solution is based upon updated information in relation to the construction costs of recently completed projects.

Possible network reinvestments within six to 10 years

As a result of the annual planning review, Powerlink has identified that the following reinvestments are likely to be required to address the risks arising from network assets reaching end of technical service life and to maintain reliability of supply in the Gladstone zone from around 2027/28 to 2031/32 (refer to Table 6.18).

Table 6.18 Possible network reinvestments in the Gladstone zone within six to 10 years

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Transmission lines					
Line refit works on 275kV transmission line between Mt Miller and Bouldercombe substations	Line refit works on steel lattice structures	Maintain supply reliability in the Gladstone zone	December 2027	Advancement of the rebuild the 275kV transmission line between Mt Miller and Bouldercombe as a DCST and dismantle the inland circuit	$5m
Rebuild the 275kV transmission line between Raglan and Larcom Creek substations	Rebuild the 275kV transmission line between Raglan and Larcom Creek as a double circuit line	Maintain supply reliability in the Gladstone zone	June 2030	Line refit works on steel lattice structures Rebuild the 275kV transmission line between Raglan and Larcom Creek as a single circuit line	$40m (2)
Line refit works on the 132kV transmission line between Bouldercombe substation and Bouldercombe Tee	Line refit works on steel lattice structures	Maintain supply reliability in the Gladstone zone	December 2030	Rebuild the 275kV transmission line between Bouldercombe and Bouldercombe Tee	$3m
Rebuild the 275kV transmission line between Raglan and Bouldercombe substations	Rebuild the 275kV transmission line between Raglan and Bouldercombe	Maintain supply reliability in the Gladstone zone	June 2032 (1)	Line refit works on steel lattice structures Rebuild the 275kV transmission line between Raglan and Bouldercombe as a single circuit line	$75m
Substations					
Larcom Creek 275kV secondary systems replacement	Selected replacement of 275kV secondary systems	Maintain supply reliability in the Gladstone zone	June 2029	Full replacement of the 275kV secondary systems	$8m
Yarwun 132kV secondary systems replacement	Full replacement of the 132kV secondary systems	Maintain supply reliability in the Gladstone zone	June 2029	Selected replacement of 132kV secondary systems	$10m
Pandoin 132kV secondary systems replacement	Full replacement of the 132kV secondary systems	Maintain supply reliability in the Gladstone zone	June 2030	Selected replacement of 132kV secondary systems	$5m

Notes:

(1) The change in timing of the network solution from the 2020 TAPR is based upon updated information on the condition of the assets.

(2) Compared to the 2020 TAPR, the change in the estimated cost of the proposed network solution is based upon updated information in relation to the construction costs of recently completed projects.

Possible asset retirements within the 10-year outlook period[19]

Callide A to Gladstone South 132kV transmission double circuit line

The 132kV transmission line was constructed in the mid-1960s to support the loads in the Gladstone area. Due to reconfiguration in the area, this transmission line will be retired from service at the end of technical service life within the 10-year outlook period.

6.7.6 Wide Bay zone

Existing network

The Wide Bay zone supplies loads in the Maryborough and Bundaberg region and also forms part of Powerlink's eastern Central Queensland to South Queensland (CQ-SQ) transmission corridor. This corridor was constructed in the 1970s and 1980s and consists of single circuit 275kV transmission lines between Calliope River and South Pine (refer to Figure 6.10). These transmission lines traverse a variety of environmental conditions and as a result exhibit different corrosion rates and risk profiles.

Figure 6.10 CQ-SQ transmission network

Possible load driven limitations

Based on AEMO's Steady Progress scenario forecast discussed in Chapter 3, there is no additional capacity forecast to be required in the Wide Bay zone within the next five years to meet reliability obligations.

Transmission network overview

In the NEM, generators compete for dispatch. Briefly, a generator's dispatch level depends on its bid in relation to other generators' bids, demand and available transmission capacity. Congestion occurs when transmission capacity prevents the optimum economic dispatch. Affected generators are said to be 'constrained' by the amount unable to be economically dispatched. Forecast of market constraint durations and levels are sensitive to highly uncertain variables including changes in bidding behaviour, investment patterns, fuel cost dynamics, plant outages, environmental conditions and demand levels. It is important to note that there is no load at risk or potential for loss of supply to customers associated with network congestion.

[19] Operational works, such as asset retirements, do not form part of Powerlink's capital expenditure budget.

In its current form, the CQ-SQ transmission network offers a great deal of flexibility for possible generation dispatches, however occasionally imposes constraints to market operation. Over time the utilisation of the CQ-SQ grid sections may increase when new NQ and CQ VRE generating systems connect to the transmission network. In addition, the incidence of congestion may increase as additional southerly transfer capacity on QNI is released following the completion of the QNI upgrade project currently underway, or decrease with retirement of CQ generation or new NQ/CQ load (refer to Section 6.9.1). The incidence of congestion may increase if further upgrades to QNI are shown to be economically justified (refer to Section 8.6.10).

The 2020 ISP identified a Central to Southern Queensland network project as a Future ISP project with a timing in the mid-2030s. Powerlink provided preparatory activities information to AEMO in June 2021 to better inform the optimal timing in future revisions of the ISP. The 2022 draft ISP is anticipated to be published by AEMO in December 2021 (refer to Section 9.3.1).

Possible network reinvestments within five years

Network reinvestments in Wide Bay zone are related to addressing the risks arising from the condition of the existing network assets, which without corrective action, would result in Powerlink potentially breaching a number of its jurisdictional network, safety, environmental and Rules' obligations.

By addressing the condition of these existing assets, Powerlink is seeking to ensure it can safely deliver an adequate, economic, and reliable supply of electricity to meet the load requirements of customers in the Wide Bay zone into the future. This may result in like-for-like replacement, non-network solutions, network reconfiguration, asset retirement, line refit or replacement with an asset of lower capacity.

Transmission Lines

CQ-SQ transmission lines

Potential consultation	Maintaining reliability of supply between central and southern Queensland
Project driver	Emerging condition and compliance risks related to structural corrosion
Project timing	December 2024 to December 2029
Proposed network solution	Rebuild of two of the three single circuit transmission lines between Calliope River and Wurdong Tee as a double circuit at an estimated cost of $27 million by June 2026. Line refit works on the remaining single circuit 275kV transmission line between Calliope River Substation and Wurdong Tee at an estimated cost of $6 million by June 2026. Targeted refit of the three single circuit transmission lines between Calliope River (Wurdong Tee) and Gin Gin substations at an estimated cost of $75 million by December 2027. Line refit works on the 275kV transmission single circuit transmission line between Woolooga and South Pine substations at an estimated cost of $36 million by June 2026.

The coastal CQ-SQ transmission network between Calliope River and South Pine substations was progressively developed in the 1970s and 1980s to facilitate power transfer between central and southern Queensland. This corridor provides the major injection points at Gin Gin, Teebar Creek, Woolooga and Palmwoods 275/132kV for the Wide Bay and Sunshine Coast areas. The Ergon Energy 132kV and Energex 132/110kV sub-transmission systems supply bulk supply points in these areas.

The coastal CQ-SQ transmission network assets are expected to reach the end of their technical service life within the next 20 years. A key consideration is that this corridor is comprised solely of single circuit 275kV towers that may make cost effective refit strategies less viable compared to double circuit tower rebuilds.

With varying distance from the ocean, and localised industrial pollution, the Calliope River to South Pine 275kV single circuit transmission lines are subject to different environmental and atmospheric conditions and have, over time, experienced structural degradation at different rates.

Emerging condition and compliance risks have been identified on the following assets:

Within the next five years:

- Three 275kV single circuit transmission lines from Calliope River to Wurdong Tee built in 1972, 1976 and 1981 (structural repair due to above ground corrosion)
- One 275kV single circuit transmission line from Woolooga to South Pine built in 1972 (structural repair due to above ground corrosion).

Within the next six to 10 years:

- One 275kV single circuit transmission lines from Woolooga to Gin Gin built in 1972 (structural repair due to above ground corrosion)
- Three 275kV single circuit transmission lines from Wurdong Tee to Gin Gin built in 1972, 1976 and 1981 (structural repair due to above ground corrosion)
- One 275kV single circuit transmission line form South Pine to Palmwoods built in 1976 (structural repair due to above ground corrosion).

Possible network solutions

The current long-term network solution strategy based on existing network topology and requirements, is to rebuild two of the 275kV single circuit transmission lines from Calliope River to South Pine as a double circuit. The third circuit between Calliope and Woolooga substations is expected to be economic to maintain in the medium term through targeted refit, and if this circuit is dismantled in the longer term, supply to Wurdong from Calliope River via a dedicated 275kV double circuit would need to be established. This strategy will be economically assessed and adjusted to align with future generation and network developments, in particular if further planning analysis identify triggers to increase capacity or alternative network configuration options.

Strategies to address the transmission line sections with advanced corrosion in the five-year outlook will be economically assessed in consideration of long-term options for reconfiguring the 275kV transmission lines. The longer term network solution options include:

- network rationalisation (potentially three single circuits to one double circuit) involving a staged program of line rebuild of the coastal corridor as a new double circuit 275kV transmission line at the end of the technical service life of the existing circuits
- network rationalisation (potentially three single circuits to one double circuit) involving a staged rebuild of the coastal corridor as a new double circuit 275kV transmission line at the end of the technical service life of the existing circuits, using a program of targeted line refits to defer rebuild of individual CQ-SQ sections (where this deferral is economic)
- maintaining the existing three single circuit 275kV transmission lines through a combination of stage rebuild and line refit projects, or
- network rationalisation (potentially three single circuits to one double circuit in sections) of the coastal corridor involving staged line refit and rebuild on the coastal corridor, and reinforcement of the CQ-SQ section via reinforcement of the western CQ-SQ transmission corridor.

Possible non-network solutions

The coastal CQ-SQ transmission network provides essential supply between the generation in central and north Queensland and the loads in southern Queensland. Powerlink would consider proposals from non-network providers that can significantly contribute to reducing the requirement in this region, as this may present opportunities in reconfiguring the network that would otherwise not be able to meet Powerlink's planning standard. Non-network solutions may include, but are not limited to local generation or DSM initiatives in the area.

Possible network reinvestments in the Wide Bay zone within five years[20]

Against the backdrop of a rapidly changing electricity sector, Powerlink's planning overview (10-year outlook period of the TAPR) includes consideration of a broad range of options to address the identified needs in the Wide Bay zone. In this context, when considering the replacement of existing assets in conjunction with the broader network topography, Powerlink may identify potential network reconfigurations or other options which would be economically assessed under the RIT-T (if applicable). These options may identify opportunities to develop the transmission network in such a way as to realise synergies and efficiencies as we transform to an energy system underpinned by VRE generation, delivering positive outcomes for customers.

As assets approach their anticipated end of technical service life, the potential projects and alternatives (options) listed in Table 6.19 will be subject to detailed analysis to confirm alignment with future reinvestment, optimisation and delivery strategies. This analysis provides Powerlink with an additional opportunity to assess the needs and timing of asset replacement works, further refine options or consider other options, including the associated delivery strategies, from those described in Table 6.19.

Information in relation to potential projects, alternatives and possible commissioning needs will be revised annually within the TAPR based on the latest information available at the time.

Table 6.19 Possible network reinvestments in the Wide Bay zone within five years

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Transmission lines					
Rebuild of the transmission line between Calliope River Substation and the Wurdong Tee (1)	New double circuit transmission line for the first 15km out of Calliope River substation	Maintain supply reliability to the CQ-SQ transmission corridor (and Gladstone zone)	June 2026 (2)	Refit the two single circuit 275kV transmission lines	$27m
Line refit works on the 275kV transmission line between Calliope River Substation and Wurdong Tee (1)	Refit the single circuit 275kV transmission line between Calliope River Substation and Wurdong Tee	Maintain supply reliability in the CQ-SQ transmission corridor (and Gladstone zone)	June 2026	Rebuild the 275kV transmission line as a double circuit	$6m
Line refit works on the 275kV transmission line between Woolooga and South Pine substations	Refit the 275kV transmission line between Woolooga and South Pine substations	Maintain supply reliability to the Moreton zone	June 2026	Rebuild the 275kV transmission line between Woolooga and South Pine substations	$36m (3)

Notes:

(1) These reinvestments have been combined into one template "Targeted reinvestment in the 275kV transmission line between Calliope River and (Wurdong Tee) Wurdong substations".

(2) The revised timing from the 2020 TAPR is based upon the latest condition assessment.

(3) Compared to the 2020 TAPR, the change in the estimated cost of the proposed network solution is based upon updated information in relation to the construction costs of recently completed projects.

[20] Subject to the outcome of a regulatory consultation, one of the proposed solutions to address voltage limitations in SE Queensland involves the installation of bus reactors at multiple locations in the transmission network, including one at Woolooga Substation (refer to Section 6.7.10).

Possible network reinvestments within six to 10 years

As a result of the annual planning review, Powerlink has identified that the following reinvestments are likely to be required to address the risks arising from network assets reaching end of technical service life and to maintain reliability of supply in the Wide Bay zone from around 2027/28 to 2031/32 (refer to Table 6.20).

Table 6.20 Possible network reinvestments in the Wide Bay zone within six to 10 years

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Transmission lines					
Targeted reinvestment in the 275kV transmission lines between Wurdong Tee and Gin Gin substation	Refit the 275kV transmission line between Wurdong Tee and Gin Gin Substation	Maintain supply to the Wide Bay zone	December 2027	Targeted refit and partial double circuit rebuild of the 275kV transmission line between Wurdong Tee and Gin Gin Substation New 275kV DCST transmission line	$75m
Line refit works on the 275kV transmission line between South Pine and Palmwoods substations	Line refit works on steel lattice structures	Maintain supply to the Wide Bay zone	June 2032 (1)	Rebuild 275kV transmission line between South Pine and Palmwoods substations	$12m
Line refit works on the 275kV transmission line between Gin Gin and Woolooga substations	Rebuild the 275kV transmission line between Gin Gin and Woolooga substations	Maintain supply to the Wide Bay zone	December 2032 (1)	Refit the 275kV transmission line between Gin Gin and Woolooga substations	$40m (2)
Substations					
Palmwoods 275kV and 132kV selected primary plant and secondary system replacement	Selected replacement of 275kV and 132kV primary plant and secondary system	Maintain supply to the Wide Bay zone	June 2030 (1)	Full replacement of 275kV and 132kV primary plant and secondary system	$33m (3)
Teebar Creek secondary systems replacement	Full replacement of 132kV and 275kV secondary systems	Maintain supply to the Wide Bay zone	June 2028	Selected replacement of 132kV and 275kV secondary systems	$18m
Woolooga 275kV and 132kV selected primary plant and secondary systems replacement	Selected replacement of 275kV and 132kV primary plant and full replacement of 132kV and 275kV secondary systems (including SVC)	Maintain supply to the Wide Bay zone	June 2029	Selected replacement of 275kV and 132kV secondary systems	$38m
Gin Gin 275kV secondary systems replacement	Selected replacement of 275kV secondary systems	Maintain supply to the Wide Bay zone	June 2031	Full replacement of 275kV secondary systems	$10m

Notes:

(1) The change in timing of the network solution from the 2020 TAPR is based upon updated information on the condition of the assets.

(2) Compared to the 2020 TAPR, the change in the estimated cost of the proposed network solution is based upon updated information in relation to the construction costs of recently completed projects.

(3) Compared to the 2020 TAPR, the change in the estimated cost of the proposed network solution is based upon updated information in relation to the condition and scope of works.

Possible asset retirements within the 10-year outlook period

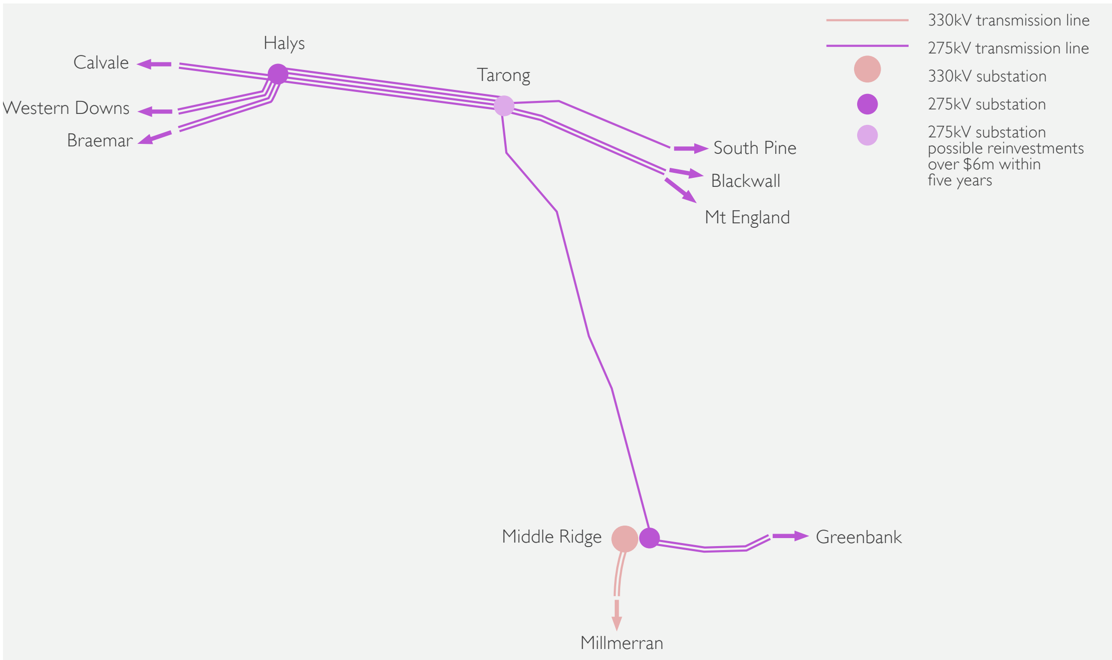
Current planning analysis has not identified any potential asset retirements in the Wide Bay zone within the next 10 years.

6.7.7 South West zone

Existing network

The South West zone is defined as the Tarong and Middle Ridge areas west of Postman's Ridge (refer to Figure 6.11).

Figure 6.11 South West area 330kV and 275kV network



Possible load driven limitations

Based on AEMO's Steady Progress scenario forecast discussed in Chapter 3, there is no additional capacity forecast to be required as a result of network limitations in the South West zone within the next five years to meet reliability obligations.

Possible network reinvestments within five years

Network reinvestments in South West zone are related to addressing the risks arising from the condition of the existing network assets, which without corrective action, would result in Powerlink potentially breaching a number of its jurisdictional network, safety, environmental and Rules' obligations.

By addressing the condition of these existing assets, Powerlink is seeking to ensure it can safely deliver an adequate, economic, and reliable supply of electricity to meet the load requirements of customers in the South West zone into the future. This may result in like-for-like replacement, non-network solutions, network reconfiguration, asset retirement, line refit or replacement with an asset of lower capacity.

Substations

Chinchilla 132kV Substation[21]

Current consultation	Maintaining reliability of supply in the Tarong and Chinchilla areas
Project driver	Emerging condition and compliance risks
Project timing	December 2025
Proposed network solution	Transformer ending Chinchilla Substation from Columboola Substation at an estimated cost of $11 million by December 2025. Network reconfiguration by replacement of the two 275/66kV transformers at Tarong Substation at an estimated cost of $17 million by December 2025. Decommissioning of the two 275/132kV transformers at Tarong Substation.[22]

Chinchilla Substation was commissioned in 1986 to supply bulk electricity to the distribution network in the area and is supplied via double circuit 132kV transmission lines from Tarong and Columboola substations.

Chinchilla's secondary systems and the majority of primary plant are approaching the end of their respective technical lives. The substation's secondary systems and circuit breakers have become obsolete and are no longer supported by the manufacturer, with only limited spares available.

Tarong 275kV Substation

Tarong Substation is located in the South West Queensland transmission network and is a critical part of the 275kV network supplying South East Queensland (SEQ). Located approximately 130km north-west of Brisbane, Tarong Substation is a major part of the 275kV transmission system connecting generators to the major load centres in the south-east of the State. It also provides the major injection point for local, rural and bulk mining loads in south-west Queensland.

The Tarong Substation was established in conjunction with the Tarong Power Station in 1982. The substation consists of one switchyard of 275kV operating voltage and one switchyard of 132kV and 66kV operating voltages. Powerlink owns the 275kV, 132kV and 66kV assets on site.

Emerging risks have been identified from the condition of the existing 275/66kV and 275/132kV transformers at Tarong Substation. All four transformers are nearing the end of their respective service lives, with recent condition assessments revealing a range of increasing network and safety risks arising from their continued operation. The fault level rating of these original transformers is also below the present fault level of the substation and operational constraints are required to manage this following a credible contingency event under particular network conditions.

Possible network solutions

- Replacement of all at-risk transformers and primary plant at Tarong and Chinchilla substations and secondary systems at Chinchilla Substation
- Reconfigure Chinchilla Substation such that supply is from the Surat Basin network, by replacing selected primary plant and secondary systems, and replacing only two of the four transformers at Tarong. The Chinchilla to Tarong transmission line will be mothballed under this option.

In accordance with the requirements of the RIT-T, Powerlink published a PSCR (with PADR exemption) in August 2021 which identified reconfiguration of the Chinchilla Substation such that supply is from the Surat Basin network, by replacing selected primary plant and secondary systems, and replacing only two of the four transformers at Tarong Substation by 2025 as the preferred option.

Submissions to the PSCR close on 22 November 2021 and Powerlink anticipates publication of the Project Assessment Conclusions Report (PACR) in December 2021.

21 While Chinchilla Substation is not located within the South West zone, as part of Powerlink's integrated planning approach, a RIT-T to consider the benefits of a potential network reconfiguration at Tarong Substation.

22 While included in the RIT-T cost benefit analysis, operational works, such as asset retirements, do not form part of Powerlink's capital expenditure budget.

Possible non-network solutions

Non-network solution	Criteria specific to this RIT-T
Replace the functionality of both of the existing 275/66kV transformers	• up to 50MW and up to 850MWh per day on a continuous basis and • auxiliary supply to Tarong Power Station of up to 38MVA
Replace the functionality of one of the existing 275/66kV transformers	• up to 50MW and up to 850MWh per day on a continuous basis following an outage of the remaining transformer • in service within six hours following a contingency • provide supply for planned outages and • auxiliary supply to Tarong Power Station of up to 38MVA

Possible network reinvestments in the South West zone within five years

Against the backdrop of a rapidly changing electricity sector, Powerlink's planning overview (10-year outlook period of the TAPR) includes consideration of a broad range of options to address the identified needs in the South West zone. In this context, when considering the replacement of existing assets in conjunction with the broader network topography, Powerlink may identify potential network reconfigurations or other options which would be economically assessed under the RIT-T (if applicable). These options may identify opportunities to develop the transmission network in such a way as to realise synergies and efficiencies as the energy system is transformed, underpinned by VRE generation, delivering positive outcomes for customers.

As assets approach their anticipated end of technical service life, the potential projects and alternatives (options) listed in Table 6.21 will be subject to detailed analysis to confirm alignment with future reinvestment, optimisation and delivery strategies. This analysis provides Powerlink with an additional opportunity to assess the needs and timing of asset replacement works, further refine options or consider other options, including the associated delivery strategies, from those described in Table 6.21.

Information in relation to potential projects, alternatives and possible commissioning needs will be revised annually within the TAPR based on the latest information available at the time.

Table 6.21 Possible network reinvestments in the South West zone within five years

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Substations					
Chinchilla 132kV Substation replacement	Selected replacement of 132kV secondary systems and primary plant and transformer ending from Columboola (1)	Maintain supply reliability in the South West zone	December 2025 (2)	Replacement of the entire 132kV secondary systems and switchyard (3)	$11m (4)
Tarong 275/66kV transformers replacement	Replacement of 275/66kV transformers and decommissioning the 275/132kV transformers at Tarong Substation (1)	Maintain supply reliability in the South West zone	December 2025 (2)	Life extension of existing transformers (3)	$17m (4)
Tarong 275kV primary plant replacement	Selected replacement of 275kV primary plant	Maintain supply reliability in the South West zone	June 2025	Full replacement of 275kV primary plant	$5m (5)

Notes:

(1) Operational works, such as asset retirements, do not form part of Powerlink's capital expenditure budget.

(2) The change in timing of the network solution from the 2020 TAPR is based upon updated information on the condition of the assets.

(3) The envelope for non-network solutions is defined in Section 6.7.7.

(4) Compared to the 2020 TAPR, the increase in the estimated cost of the proposed network solution is based upon updated information in relation to the construction costs of recently completed projects.

(5) Compared to the 2020 TAPR, the change in the estimated cost of the proposed network solution is based upon updated information in relation to condition and scope of works.

Possible network reinvestments within six to 10 years

As a result of the annual planning review, Powerlink has identified that the following reinvestments are likely to be required to address the risks arising from network assets reaching end of technical service life and to maintain reliability of supply in the South West zone from around 2027/28 to 2031/32 (refer to Table 6.22).

Table 6.22 Possible network reinvestments in the South West zone within six to 10 years

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Substations					
Oakey 110kV secondary systems replacement (1)	Full replacement of 110kV secondary systems	Maintain supply reliability in the South West zone	June 2029	Staged replacement of 110kV secondary system	$3m
Tarong 275kV, 132kV and 66kV secondary systems replacement	Selected replacement of 275kV, 132kV and 66kV secondary systems	Maintain supply reliability in the South West zone	June 2030	Full replacement of 275kV, 132kV and 66kV secondary systems	$28m (2)
Middle Ridge 275kV and 110kV secondary systems replacement	Selected replacement of 275kV and 110kV secondary systems	Maintain supply reliability in the South West zone	December 2030 (3)	Full replacement of 275kV and 110kV secondary systems	$38m

Notes:

(1) Currently being evaluated as part of a broader assessment to understand the potential for network optimisation or alternate investment strategies given the potential for VRE generation in south west Queensland.

(2) Compared to the 2020 TAPR, the change in the estimated cost of the proposed network solution is based upon updated information in relation to the scope of works.

(3) The change in timing of the network solution from the 2020 TAPR is based upon updated information on the condition of the assets.

Possible asset retirements within the 10-year outlook period [23]

Condition assessment has identified emerging condition risks arising from the condition of two 275/132kV transformers at Tarong Substation by 2025 in Table 6.21. Planning studies have confirmed the potential to subsequently retire both transformers based on AEMO's Steady Progress scenario forecast discussed in Chapter 3. Consequently, it is considered likely the 275/132kV transformers at Tarong Substation will be retired at end of technical service life.

Condition assessment has identified emerging condition risks arising from the condition of 132kV primary plant at Chinchilla Substation by 2025. At this time, an option would be a reduced scope replacement that would involve transformer ending from Columboola 132kV Substation, and retirement of the 132kV primary plant arising from the connection to Tarong Substation.

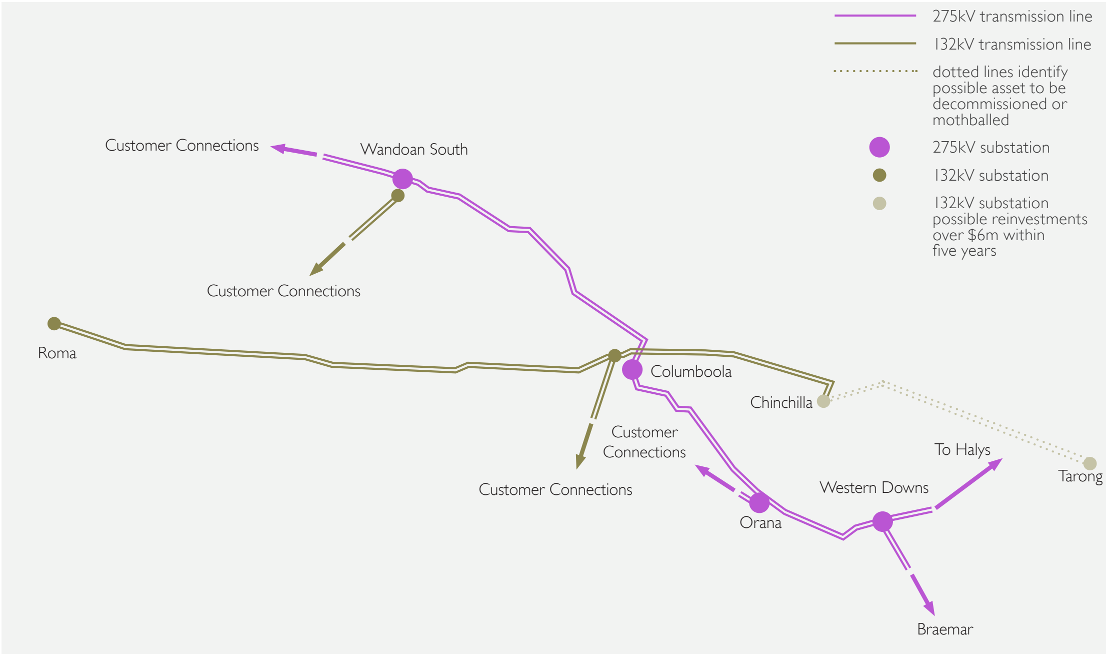
[23] Operational works, such as asset retirements, do not form part of Powerlink's capital expenditure budget.

6.7.8 Surat zone

Existing network

The Surat Basin zone is defined as the area north west of Western Downs Substation. The area has significant development potential given the vast reserves of gas and coal and more recently VRE. Utilisation of assets in the area is forecast to continue due to new developments of VRE projects, coal seam gas (CSG) upstream processing facilities by multiple proponents, together with the supporting infrastructure and services (refer to Figure 6.12).

Figure 6.12 Surat Basin North West area transmission network



Possible load driven limitations

Based on AEMO's Steady Progress scenario forecast discussed in Chapter 3, there is no additional capacity forecast to be required as a result of network limitations in the Surat zone within the next five years to meet reliability obligations.

Possible network reinvestments within the 10-year outlook period

Against the backdrop of a rapidly changing electricity sector, Powerlink's planning overview (10-year outlook period of the TAPR) includes consideration of a broad range of options to address the identified needs in the Surat zone. In this context, when considering the replacement of existing assets in conjunction with the broader network topography, Powerlink may identify potential network reconfigurations or other options which would be economically assessed under the RIT-T (if applicable). These options may identify opportunities to develop the transmission network in such a way as to realise synergies and efficiencies as we transform to an energy system underpinned by VRE generation, delivering positive outcomes for customers.

As assets approach their anticipated end of technical service life, the potential projects and alternatives (options) listed in Table 6.23 will be subject to detailed analysis to confirm alignment with future reinvestment, optimisation and delivery strategies. This analysis provides Powerlink with an additional opportunity to assess the needs and timing of asset replacement works, further refine options or consider other options, including the associated delivery strategies, from those described in Table 6.23.

Information in relation to potential projects, alternatives and possible commissioning needs will be revised annually within the TAPR based on the latest information available at the time.

As a result of the annual planning review, Powerlink has identified that the following reinvestments are likely to be required to address the risks arising from network assets reaching end of technical service life and to maintain reliability of supply in the Surat zone towards the end of the 10-year outlook period, from around 2027/28 to 2031/32 (refer to Table 6.23).

Table 6.23 Possible network reinvestments in the Surat zone within six to 10 years

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Substations					
Columboola 132kV secondary system replacement	Selected replacement of 132kV secondary systems	Maintain supply reliability in the Surat zone	June 2031	Full replacement of secondary systems	$15m

Possible asset retirements within the 10-year outlook period

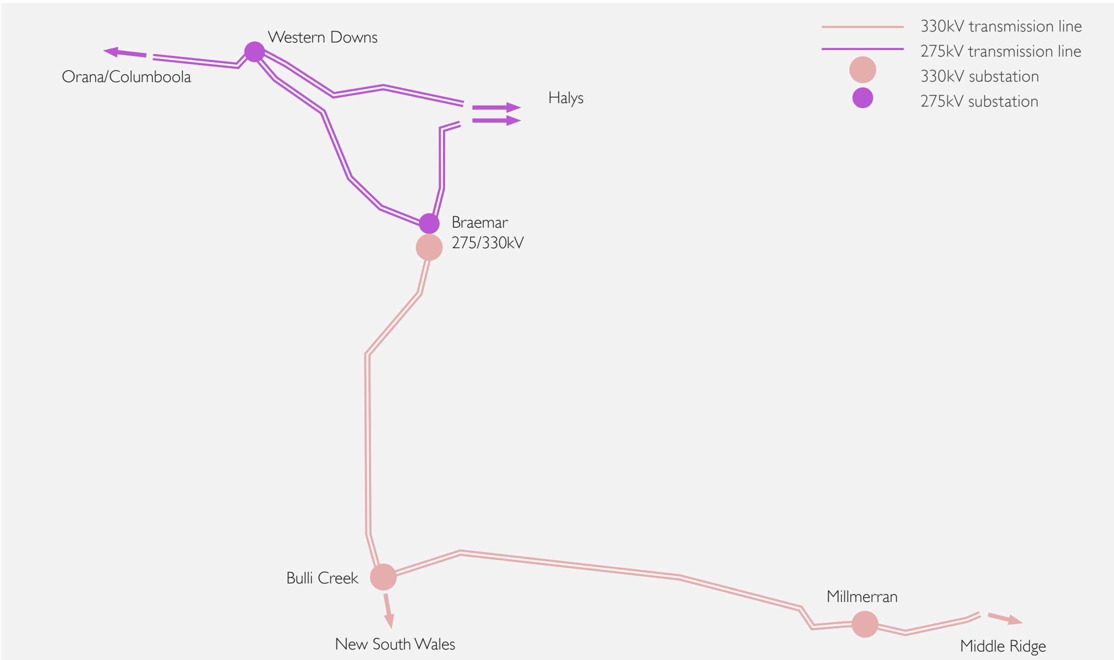
Current planning analysis has not identified any potential asset retirements in the Surat zone within the 10-year outlook period.

6.7.9 Bulli zone

Existing network

The Bulli zone is defined as the area surrounding Goondiwindi and the 330kV and 275kV network south of Kogan Creek and west of Millmerran (refer to Figure 6.13).

Figure 6.13 Bulli area transmission network



Possible load driven limitations

Based on AEMO's Steady Progress scenario forecast discussed in Chapter 3, there is no additional capacity forecast to be required as a result of network limitations in the Bulli zone within the next five years to meet reliability obligations.

Possible network reinvestments in the Bulli zone within five years

Against the backdrop of a rapidly changing electricity sector, Powerlink's planning overview (10-year outlook period of the TAPR) includes consideration of a broad range of options to address the identified needs in the Bulli zone. In this context, when considering the replacement of existing assets in conjunction with the broader network topography, Powerlink may identify potential network reconfigurations or other options which would be economically assessed under the RIT-T (if applicable). These options may identify opportunities to develop the transmission network in such a way as to realise synergies and efficiencies as we transform to an energy system underpinned by VRE generation, delivering positive outcomes for customers.

As assets approach their anticipated end of technical service life, the potential projects and alternatives (options) listed in Table 6.24 will be subject to detailed analysis to confirm alignment with future reinvestment, optimisation and delivery strategies. This analysis provides Powerlink with an additional opportunity to assess the needs and timing of asset replacement works, further refine options or consider other options, including the associated delivery strategies, from those described in Table 6.24.

Information in relation to potential projects, alternatives and possible commissioning needs will be revised annually within the TAPR based on the latest information available at the time.

Network reinvestments in the Bulli zone are related to addressing the risks arising from the condition of the existing network assets, which without corrective action, would result in Powerlink potentially breaching a number of its jurisdictional network, safety, environmental and Rules' obligations.

By addressing the condition of these existing assets, Powerlink is seeking to ensure it can safely deliver an adequate, economic, and reliable supply of electricity to meet the load requirements of customers in the Bulli zone into the future. This may result in like for like replacement, non-network solutions, network reconfiguration, asset retirement, line refit or replacement with an asset of lower capacity.

Table 6.24 Possible network reinvestments in the Bulli zone within five years

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Substations					
Millmerran 330kV secondary systems replacement	Selected replacement of 330kV secondary systems	Maintain supply reliability in the Bulli zone	June 2025	Full replacement of secondary systems	$5m

Possible network reinvestments within six to 10 years

As a result of the annual planning review, Powerlink has identified that the following reinvestments are likely to be required to address the risks arising from network assets reaching end of technical service life and to maintain reliability of supply in the Bulli zone from around 2027/28 to 2031/32 (refer to Table 6.25).

Table 6.25 Possible network reinvestments in the Bulli zone within six to 10 years

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Substations					
Bulli Creek 330/132kV transformer replacement	Replace one 330/132kV transformer at Bulli Creek Substation	Maintain supply reliability in the Bulli zone	June 2031	Retirement of 330/132kV transformers with non-network support	$7m

Possible asset retirements within the 10-year outlook period

Current planning analysis has not identified any potential asset retirements in the Bulli zone within the 10-year outlook period.

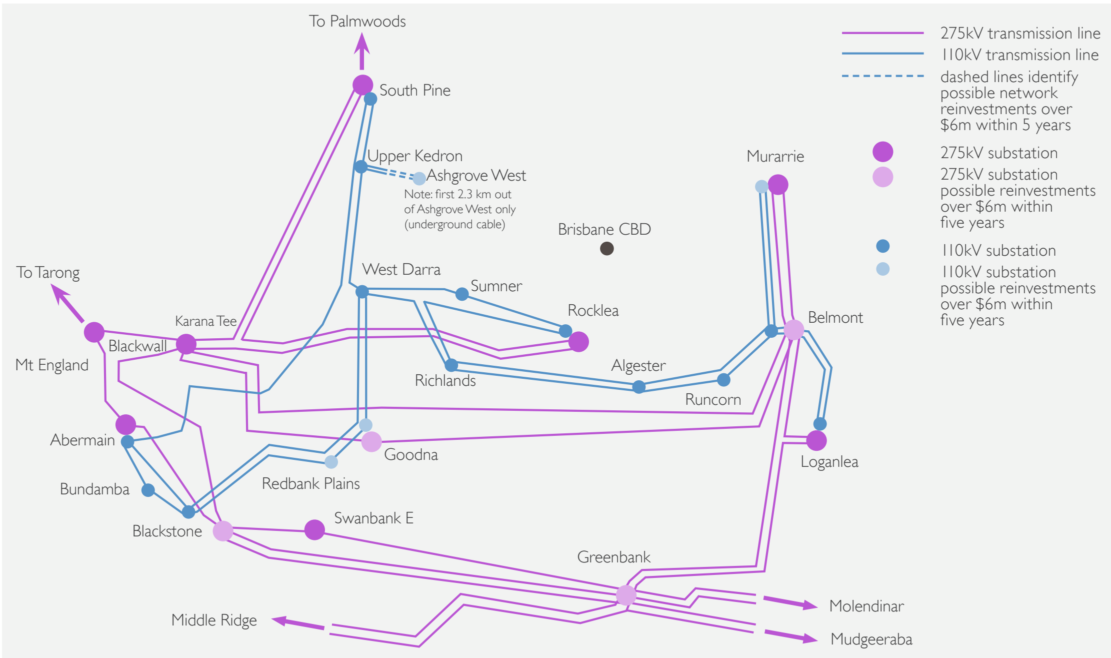
6.7.10 Moreton zone

Existing network

The Moreton zone includes a mix of 275kV and 110kV transmission networks servicing a number of significant load centres in SEQ, including the Sunshine Coast, greater Brisbane, Ipswich and northern Gold Coast regions (refer to Figure 6.14).

Future investment needs in the Moreton zone are substantially arising from the condition and performance of 275kV and 110kV assets in the greater Brisbane area. The 110kV network in the greater Brisbane area was progressively developed from the early 1960s and 1970s, with the 275kV network being developed and reinforced in response to load growth from the early 1970s. Multiple Powerlink 275/110kV injection points now interconnect with the Energex network to form two 110kV rings supplying the Brisbane Central Business District (CBD).

Figure 6.14 Greater Brisbane transmission network



Possible load driven limitations

Based on AEMO's Steady Progress scenario forecast discussed in Chapter 3 and the committed generation described in tables 8.1 and 8.2, there is no additional capacity forecast to be required in the Moreton zone within the next five years to meet reliability obligations.

Possible network investments to address non-load driven network constraints in the next five years

Current consultation	Managing voltages in South East Queensland
Project driver	Voltage control during light load conditions
Project timing	December 2025
Proposed network solution	Installation of three 120MVAr bus reactors, one each at Woolooga, Blackstone and Belmont substations, at an estimated cost of $30 million by December 2025.

The combination of a declining minimum demand during the day, increasing capacitive nature of the load and the loss of system capacity to absorb reactive power, has created a growing reactive power surplus in both the distribution and transmission networks, during low demand periods. This has resulted in an increased voltage profile and a growing potential for sustained over-voltage events.

High voltages associated with light load conditions are currently managed in South East Queensland (SEQ) with existing reactive sources and operational methods. Voltage control is forecast to become increasingly challenging for longer durations, as minimum demand continues to fall.

Powerlink has identified a need for additional reactive support to:

- Maintain voltages within operational and design limits during minimum demand periods, to maintain the power system in a secure operating state
- Reduce reliability and system strength impacts from the de-energisation of transmission lines.

Possible network solutions

- Installation of three bus reactors, one each at Woolooga, Blackstone and Greenbank substations
- Installation of three bus reactors, one each at Woolooga, Blackstone and Belmont substations
- Installation of 11 reactors on the Energex Network in the Sunshine Coast, Gold Coast and Brisbane areas.

In accordance with the requirements of the RIT-T, Powerlink published a PSCR (with PADR exemption) in July 2021 which identified the installation of 120MVAr bus reactors at Woolooga, Blackstone and Belmont substations by 2025 as the preferred network option. Submissions to the PSCR closed on 29 October 2021 and Powerlink anticipates the publication of the PACR in December 2021.

Powerlink considers the proposed network solution will not have a material inter-network impact.

Possible non-network solutions

Under system normal conditions, a complete network support solution would need to provide voltage control equivalent to the proposed three reactors across SEQ, at a nominal 360MVArs. Reactive support would be required to be available on a continuous basis, and not coupled to generation output.

Partial network support solutions designed to address either the declining minimum day time demand or the increasing early morning leading power factor are also encouraged. Where technically and economically feasible, the relevant detailed requirements will be refined with proponents through the submission process to the PSCR and assessed on a case by case basis given the nature of the identified need.

The network support must continue to operate as per system normal for planned and unplanned outages. Outages of the network support must be coordinated to ensure that Powerlink is able to maintain system security at all times.

Possible network reinvestments within five years

Network reinvestments in Moreton zone are related to addressing the risks arising from the condition of the existing network assets, which without corrective action, would result in Powerlink being exposed to breaching a number of its jurisdictional network, safety, environmental and Rules' obligations.

By addressing the condition of these existing assets, Powerlink is seeking to ensure it can safely deliver an adequate, economic, and reliable supply of electricity to meet the load requirements of customers in the Moreton zone into the future. This may result in like-for-like replacement, non-network solutions, network reconfiguration, asset retirement, line refit or replacement with an asset of lower capacity.

Transmission lines

The 110kV and 275kV transmission lines in the greater Brisbane area are located between 20km and 40km from the coast, traversing a mix of industrial, high density urban and semi-urban areas. The majority of assets are reasonably protected from the prevailing coastal winds and are exposed to moderate levels of pollution related to the urban environment. These assets have, over time, experienced structural corrosion at similar rates, with end of technical service life for most transmission line assets expected to occur towards to end of the 2020s and into the early 2030s.

With the maximum demand forecast relatively flat in the next five years, and based on the development of the network over the last 40 years, planning studies have identified a number of 110kV transmission line assets that could potentially be retired. Given the uncertainty in future demand growth, Powerlink proposes to implement low cost maintenance strategies to keep the transmission lines in service for a reasonable period. Future decommissioning remains an option once demand growth is better understood.

Detailed analysis will be ongoing to evaluate the possible retirement of the following transmission lines at the end of technical service life:

- West Darra to Upper Kedron
- West Darra to Goodna
- Richlands to Algester.

This ongoing review, together with further joint planning with Energex, may result in a future RIT-T in the late 2020s.

Underground 110kV cable between Upper Kedron and Ashgrove West

Potential consultation	Maintain reliability of supply to the Brisbane metropolitan area
Project driver	Emerging condition, end of technical service life and compliance risks for the Upper Kedron to Ashgrove West underground cables.
Project timing	June 2026
Proposed network solution	Replacement of the oil-filled cables with new cables in a new easement at an estimated cost of $13 million by June 2026.

The 110kV transmission line between Upper Kedron and Ashgrove West substations was established in 1978, as one of the principal sources of supply to the north-west Brisbane area. The transmission line is predominantly an overhead, with the final 2.3km long section to Ashgrove West Substation being an underground cable.

Possible network solutions

- Replacement of the existing cables with new cables in a new easement by June 2026
- Replacement of existing cables with new cables by June 2026.

Powerlink considers the proposed network solution will not have a material inter-network impact.

Possible non-network solutions

The Upper Kedron to Ashgrove West cables provide supply of up to 220MW at peak to Brisbane's inner north-west suburbs. Powerlink would consider proposals from non-network providers that can significantly contribute to reducing the requirement in this region, as this may present opportunities in reconfiguring the network that would otherwise not be able to meet Powerlink's planning standard. Non-network solutions may include, but are not limited to local generation or DSM initiatives in the area.

Substations

Redbank Plains 110kV Substation

Anticipated consultation	Maintaining power transfer capability and reliability of supply at Redbank Plains Substation
Project driver	Emerging condition risks of the 110kV primary plant and 110/11kV transformers
Project timing	June 2024
Proposed network solution	Replacement of selected 110kV primary plant and life extension of both 110/11kV transformers at Redbank Plains Substation at an estimated cost of $8 million by June 2024.

Redbank Plains Substation was established to provide electricity to the expanding communities west of Brisbane in 1986 and serves as a bulk supply injection point to the Energex distribution network.

Redbank Plains 110/11kV 25MVA transformers 1 and 2 were installed in 1985 and 1984 respectively. The transformers exhibit aged paper insulation and increased moisture levels in oil, possibly due to the numerous oil leaks from the main tanks. The high voltage bushings are the original porcelain housed oil insulated paper bushings, which have been in service well past their technical service life.

Possible network solutions

- Replacement of selected 110kV primary plant by June 2024
- Full replacement of 110kV primary plant by June 2024
- Life extend both 110/11kV transformers by June 2024
- Replace/life extend one 110/11kV transformer and engage non-network support by June 2024.

Powerlink considers the proposed network solution will not have a material inter-network impact.

Possible non-network solutions

Potential non-network solutions would need to provide supply to the 11kV network at Redbank Plains of up to 25MW at peak and up to 400MWh per day. The non-network solution would be required for a contingency and to be able to operate on a continuous basis until normal supply is restored. Supply would also be required for planned outages.

Goodna 275/110kV secondary systems replacement

Potential consultation	Addressing the secondary systems condition risks at Goodna
Project driver	Emerging condition and 275kV and 110kV secondary systems compliance risks
Project timing	December 2026
Proposed network solution	Full replacement of the 275kV and 110kV secondary systems at Goodna Substation at an estimated cost of $20 million by December 2026

Goodna Substation was established in 2006 to meet increased demand in the western suburbs of Brisbane, including the emerging Springfield residential and commercial development.

Possible network solutions

- Full replacement of all of the 275kV and 110kV secondary systems by December 2026
- Staged replacement of the 275kV and 110kV secondary systems by December 2026.

Powerlink considers the proposed network solution will not have a material inter-network impact.

Possible non-network solutions

Potential non-network solution would need to provide up to 200MW and 3,200MWh of energy each day. The non-network solution would be required to be capable of operating during a contingency or outage on a continuous basis until normal supply can be restored.

Ashgrove West 110kV Substation

Potential consultation	Addressing the secondary systems condition risks at Ashgrove West
Project driver	Emerging condition and 110kV secondary systems compliance risks
Project timing	June 2025
Proposed network solution	Full replacement of the 110kV secondary systems at Ashgrove West Substation at an estimated cost of $6 million by June 2025.

Ashgrove West Substation was established in 1979 to meet increased demand in the Brisbane CBD and the expanding residential areas to the north and west of Brisbane.

Possible network solutions

- Full replacement of all of the 110kV secondary systems upfront by June 2025
- Staged replacement on 110kV secondary systems by June 2025.

Powerlink considers the proposed network solution will not have a material inter-network impact.

Possible non-network solutions

Ashgrove West is a key substation and part of the network supplying of up to 220MW at peak to Brisbane's inner north-west suburbs. Powerlink would consider proposals from non-network providers that can significantly contribute to reducing the requirement in this region, as this may present opportunities in reconfiguring the network that would otherwise not be able to meet Powerlink's planning standard. Non-network solutions may include, but are not limited to local generation or DSM initiatives in the area.

Murarrie 110kV Substation secondary systems replacements

Potential consultation	Addressing the secondary systems condition risks at Murarrie
Project driver	Emerging condition and 110kV secondary systems compliance risks
Project timing	June 2027
Proposed network solution	Full replacement of the 110kV secondary systems at Murarrie Substation at an estimated cost of $21 million by June 2027.

Murarrie Substation was established in 2003 as a bulk supply point to service the industrial load around the Brisbane River and port areas. Murarrie secondary systems were commissioned between 2003 and 2006.

Possible network solutions

- Full replacement of all of the 110kV secondary systems upfront by June 2027
- Staged replacement on 110kV secondary systems by June 2027.

Powerlink considers the proposed network solution will not have a material inter-network impact.

Possible non-network solutions

Murarrie Substation provides injection and switching to the CBD and south-eastern suburbs of Brisbane of over 300MW at peak. Powerlink would consider proposals from non-network providers that can significantly contribute to reducing the requirement in this region, as this may present opportunities in reconfiguring the network that would otherwise not be able to meet Powerlink's planning standard. Non-network solutions may include, but are not limited to local generation or DSM initiatives in the area.

Possible network reinvestments in the Moreton zone within five years

Against the backdrop of a rapidly changing electricity sector, Powerlink's planning overview (10-year outlook period of the TAPR) includes consideration of a broad range of options to address the identified needs in the Moreton zone. In this context, when considering the replacement of existing assets in conjunction with the broader network topography, Powerlink may identify potential network reconfigurations or other options which would be economically assessed under the RIT-T (if applicable). These options may identify opportunities to develop the transmission network in such a way as to realise synergies and efficiencies as we transform to an energy system underpinned by VRE generation, delivering positive outcomes for customers.

As assets approach their anticipated end of technical service life, the potential projects and alternatives (options) listed in Table 6.26 will be subject to detailed analysis to confirm alignment with future reinvestment, optimisation and delivery strategies. This analysis provides Powerlink with an additional opportunity to assess the needs and timing of asset replacement works, further refine options or consider other options, including the associated delivery strategies, from those described in Table 6.26.

Information in relation to potential projects, alternatives and possible commissioning needs will be revised annually within the TAPR based on the latest information available at the time.

Table 6.26 Possible network reinvestments in the Moreton zone within five years

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Transmission Lines					
Replacement of the 110kV underground cable between Upper Kedron and Ashgrove West substations	Replace the 110kV underground cable between Upper Kedron and Ashgrove West substations using an alternate easement	Maintain supply reliability in the Moreton zone	June 2026	In-situ replacement of the 110kV underground cable between Upper Kedron and Ashgrove West substations (1)	$13m
Substations					
Redbank Plains 110kV primary plant and 110/11kV transformers replacement	Selected replacement of 110kV primary plant and life extension of two 110/11kV transformers	Maintain reliability of supply at Redbank Plains Substation	June 2024	Full replacement of 110kV primary plant, replace one 110/11kV transformer and engage non-network support (1)	$8m
Ashgrove West 110kV secondary systems replacement	Full replacement of 110kV secondary systems	Maintain supply reliability in the Moreton zone	June 2025	Staged replacement of 110kV secondary systems (1)	$6m
South Pine 275/110kV transformer life extension	Life extension of a single 275kV/110kV transformer	Maintain supply reliability in the Moreton zone	June 2025 (2)	Retirement of a single 275kV/110kV transformer with non-network support	$2m
South-east Queensland bus reactors	Install 275kV bus reactors at Woolooga, Blackstone and Belmont substations	Maintain system voltages within limits	December 2025 (3)	Install 275kV bus reactors at Woolooga, Blackstone and Greenbank substations Non-network solution yielding the same voltage control capacity (1)	$30m (4)
Goodna 275kV and 110kV secondary systems replacement	Full replacement of 275kV and 110kV secondary systems	Maintain supply reliability in the Moreton zone	December 2026	Staged replacement of 275kV and 110kV secondary systems (1)	$20m (3)
Sumner 110kV secondary systems replacement	Full replacement of 110kV secondary systems	Maintain supply reliability in the Moreton zone	June 2027	Staged replacement of 110kV secondary systems	$4m
Murarrie 110kV secondary systems replacement	Full replacement of 110kV secondary systems	Maintain supply reliability in the CBD and Moreton zone	June 2027 (1)	Staged replacement of 110kV secondary systems (1)	$21m

Notes:

(1) The envelope for non-network solutions is defined in Section 6.7.10.

(2) The change in timing of the network solution from the 2020 TAPR is based upon updated information on the condition of the assets.

(3) The change in timing of the network solution from the 2020 TAPR is because on a staged approach in delivery of multiple reactors.

(4) Compared to the 2020 TAPR, the change in the estimated cost of the proposed network solution is based upon updated information in relation to the scope of works and the construction costs of recently completed projects.

Possible network reinvestments in the Moreton zone within six to 10 years

As a result of the annual planning review, Powerlink has identified that the following reinvestments are likely to be required to address the risks arising from network assets reaching end of technical service life and to maintain reliability of supply in the Moreton zone from around 2027/28 to 2031/32 (refer to Table 6.27).

Table 6.27 Possible network reinvestments in the Moreton zone within six to 10 years

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Transmission lines					
Line refit works on the 110kV transmission line between Belmont and Murarrie substations	Line refit works on steel lattice structures	Maintain supply reliability in the Moreton zone	June 2028	Rebuild the 110kV transmission lines between Belmont and Murarrie substations	$2m
Line refit works on the 110kV transmission line between Richlands and Algester substations	Refit the 110kV transmission line between Richlands and Algester substations	Maintain supply reliability in the Moreton zone	June 2028	Potential retirement of the transmission line between Richlands and Algester substations	$2m
Line refit works on the 110kV transmission line between Blackstone and Abermain substations	Refit the 110kV transmission line between Blackstone and Abermain substations	Maintain supply reliability in the Moreton zone	June 2029	Rebuild the 110kV transmission line between Blackstone and Abermain substations	$8m
Line refit works on the 275kV transmission line between Bergins Hill and Karana Downs	Refit the 275kV transmission line between Bergins Hill and Karana Downs substations	Maintain supply reliability in the Moreton zone	June 2030	Rebuild or replace the transmission line between Bergins Hill and Karana Downs substations	$4m
Line refit works on the 275kV transmission line between Karana Downs and South Pine	Refit the 275kV transmission line between Karana Downs and South Pine substations	Maintain supply reliability in the Moreton zone	June 2030	Rebuild the 275kV transmission line between Karana Downs and South Pine substations	$8m
Line refit works on the 110kV transmission lines between Swanbank, Redbank Plains and West Darra substations	Refit the 110kV transmission lines between Swanbank, Redbank Plains and West Darra substations	Maintain supply reliability in the Moreton zone	June 2030	Rebuild the 110kV transmission lines between Swanbank, Redbank Plains and West Darra substations	$11m
Line refit works on the 275kV transmission line between Bergins Hill, Goodna and Belmont substations	Refit the 275kV transmission line between Bergins Hill, Goodna and Belmont substations	Maintain supply reliability in Moreton zone	December 2030	Rebuild the 275kV transmission line between Bergins Hill, Goodna and Belmont substations	$36m
Line refit works on the 110kV transmission line between West Darra and Upper Kedron substations	Refit the 110kV transmission line between West Darra and Upper Kedron substations	Maintain supply reliability in Moreton zone	June 2032	Rebuild the 110kV transmission line between West Darra and Upper Kedron substations	$5m

Table 6.27 Possible network reinvestments in the Moreton zone within six to 10 years (*continued*)

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Substations					
South Pine SVC secondary systems replacement	Full replacement of SVC secondary systems	Maintain supply reliability in the Moreton zone	June 2028	Staged replacement of SVC secondary systems	$6m
Goodna 110/332kV transformer augmentation	Installation of a 100MVA 110/33kV transformer	Maintain supply reliability in the Moreton zone	June 2029 (1)	Installation of a smaller 110/33kV transformer and non-network support	$6m
Algester 110kV secondary systems replacements	Full replacement of 110kV secondary systems	Maintain supply reliability in the Moreton zone	June 2028	Staged replacement of 110kV secondary systems	$10m
West Darra 110kV secondary systems replacement	Full replacement of 110kV secondary systems	Maintain supply reliability in the Moreton zone	June 2028	Staged replacement of 110kV secondary systems	$10m
Rocklea 275/110kV transformer replacement	Replacement of one 275/110kV transformer at Rocklea	Maintain supply reliability in the Moreton zone	June 2028	Life extension of one 275/110kV transformer at Rocklea	$6m
Rocklea 110kV primary plant replacement	Full replacement of 110kV primary plant	Maintain supply reliability in the Moreton zone	June 2028	Staged replacement of 110kV primary plant	$5m
Loganlea 275kV primary plant replacement	Full replacement of 275kV primary plant	Maintain supply reliability in the Moreton zone	June 2028	Staged replacement of 275kV primary plant	$5m
Bundamba 110kV secondary systems replacement	Full replacement of 110kV secondary systems	Maintain supply reliability in the Moreton zone	June 2028	Staged replacement of 110kV primary plant	$6m
Greenbank SVC and 275kV secondary systems replacement	Full replacement of 275kV SVC and secondary systems	Maintain supply reliability in the Moreton and Gold Coast zones	June 2029 (1)	Staged replacement of 275kV SVC and secondary systems	$31m
South Pine 275kV primary plant replacement	Staged replacement of 275kV primary plant	Maintain supply reliability in the Moreton zone	June 2030	Full replacement of 275kV primary plant	$5m
Abermain 110kV secondary systems and primary plant replacement	Full replacement of 110kV secondary systems and staged replacement of primary plant	Maintain supply reliability in the Moreton zone	June 2030	Staged replacement of 110kV secondary systems and primary plant	$13m
Belmont 33kV and 11kV primary plant replacement	Full replacement of 33kV and 11kV primary plant	Maintain supply reliability in the Moreton zone	December 2029	Staged replacement of 22kV and 11kV primary plant	$5m

Note:

(1) The change in timing of the network solution from the 2020 TAPR is based upon updated information on the condition of the assets.

Possible asset retirements within the 10-year outlook period

Loganlea 110/33kV transformer

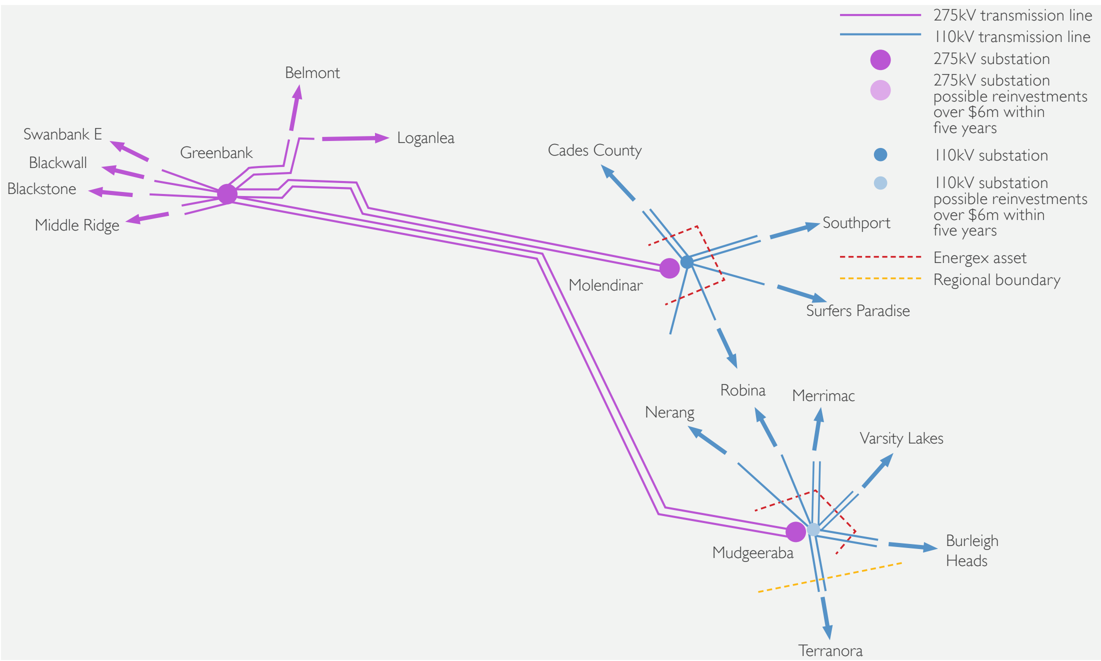
Based on the condition of one of the 110/33kV transformers at Loganlea, it is proposed to retire this transformer at the end of technical service life by June 2023. Powerlink considers that this will not impact on the ability to meet the obligations of Powerlink's reliability criteria. Further joint planning will be undertaken prior to a final decision being made.

6.7.11 Gold Coast zone

Existing network

The Powerlink transmission system in the Gold Coast zone was originally constructed in the 1970s and 1980s. The Molendinar and Mudgeeraba substations are the two major injection points into the area via a double circuit 275kV transmission line between Greenbank and Molendinar substations, and two single circuit 275kV transmission lines between Greenbank and Mudgeeraba substations (refer to Figure 6.15).

Figure 6.15 Gold Coast transmission network



Possible load driven limitations

Based on AEMO's Steady Progress scenario forecast discussed in Chapter 3, there is no additional capacity forecast to be required as a result of network limitations in the Gold Coast zone within the next five years to meet reliability obligations.

Possible network reinvestments within five years

Network reinvestments in Gold Coast zone are related to addressing the risks arising from the condition of the existing network assets, which without corrective action, would result in Powerlink being exposed to breaching a number of its jurisdictional network, safety, environmental and Rules' obligations.

By addressing the condition of these existing assets, Powerlink is seeking to ensure it can safely deliver an adequate, economic, and reliable supply of electricity to meet the load requirements of customers in the Gold Coast zone into the future. This may result in like-for-like replacement, non-network solutions, network reconfiguration, asset retirement, line refit or replacement with an asset of lower capacity.

Transmission lines

Greenbank to Mudgeeraba 275kV transmission lines

Potential consultation	Maintaining reliability of supply to the southern Gold Coast area
Project driver	Emerging condition risks due to structural corrosion
Project timing	December 2028
Proposed network solution	Maintain the existing topography by way of a targeted line refit at an estimated cost of $30 to $52 million by December 2028.

The two 275kV single circuit transmission lines were constructed in the mid-1970s and support the supply to Gold Coast and northern NSW.

Possible network solutions

Feasible network solutions to address the risks arising from these transmission lines may include:

- Maintaining the existing 275kV transmission line topography and capacity by way of a targeted line refit by December 2028.
- Replacement at the end of technical service life of the existing single circuits between Mudgeeraba and Greenbank with a new double circuit line, through staged rebuild.
- Decrease in transfer capacity into the Gold Coast and rationalisation of the transmission lines supplying the Gold Coast through a combination of line refit projects and decommissioning of some assets.

To ensure reliability of supply to customers, the required renewal works will need to be completed in stages outside of summer peak load and outage co-ordination will be complex due to the significant renewal program in the Gold Coast area within the 10-year outlook period. Due to these challenges it has been identified that an extended delivery timeframe of at least four years would be required with the potential for works to commence within the next five years.

Powerlink considers the proposed network solution will not have a material inter-network impact.

Possible non-network solutions

The Greenbank to Mudgeeraba 275kV transmission lines provide injection to the southern Gold Coast and northern NSW area. Powerlink is not aware of any non-network proposals in this area that can address this requirement in its entirety. Powerlink would consider proposals from non-network providers that can significantly contribute to reducing the requirement in this region, as this may present opportunities in reconfiguring the network that would otherwise not be able to meet Powerlink's planning standard. Non-network solutions may include, but are not limited to local generation or DSM initiatives in the area.

Substations

Mudgeeraba 275/110kV Substation

Mudgeeraba 110kV Substation was established in 1972 and extended from the 1980s to 2000s to meet load growth and is located within the southern end of zone of the Gold Coast. Further extensions included the establishment of a 275kV switchyard and associated secondary systems in 1992, which was further expanded in 2002. Mudgeeraba 275/110kV Substation is a major connection point for supply to the Gold Coast and northern NSW with the 110kV substation supplying distribution points including Robina, Nerang, Broadbeach, Burleigh and Terranora.

Mudgeeraba 110kV secondary systems

Anticipated consultation	Addressing the secondary systems condition risks at Mudgeeraba
Project driver	Emerging condition risks arising from the condition of the 110kV secondary systems.
Project timing	December 2025
Proposed network solution	Staged replacement of secondary systems at an estimated cost of $11 million by December 2025.

Possible network solutions

- Staged replacement of the secondary systems components by December 2025
- Full replacement of all secondary systems by December 2025.

Powerlink considers the proposed network solution will not have a material inter-network impact.

Potential consultation	Addressing the primary plant condition risks at Mudgeeraba
Project driver	Emerging risks arising from the condition of the 110kV primary plant.
Project timing	December 2025
Proposed network solution	Selected replacement of primary plant at an estimated cost of $20 million by December 2025.

Possible network solutions

- Selected replacement of primary plant by December 2025
- Full replacement of all primary plant by December 2025.

Powerlink considers the proposed network solution will not have a material inter-network impact.

Possible non-network solutions

Mudgeeraba Substation provides injection and switching to the southern Gold Coast and northern NSW area. Powerlink would consider proposals from non-network providers that can significantly contribute to reducing the requirement in this region, as this may present opportunities in reconfiguring the network that would otherwise not be able to meet Powerlink's planning standard. Non-network solutions may include, but are not limited to local generation or DSM initiatives in the area.

Molendinar 275/110kV Substation

Molendinar 275kV Substation was established in 2003 and is located in the northern end of Gold Coast zone. The Molendinar Substation is supplied from Greenbank Substation by a 275kV double circuit transmission line. There is currently no 275kV bus at Molendinar, with two 275/110kV transformers supplied transformer ended. There is a long-term enduring need to supply the Gold Coast region through Molendinar Substation.

Molendinar 275/110kV Substation

Potential consultation	Addressing the 275kV secondary systems condition risks at Molendinar
Project driver	Emerging condition risks arising from the condition of the 275kV secondary systems.
Project timing	December 2026
Proposed network solution	Full replacement of secondary systems at an estimated cost of $22 million by December 2026.

Possible network solutions

- Staged replacement of the secondary systems components by December 2026
- Full replacement of all secondary systems by December 2026.

Powerlink considers the proposed network solution will not have a material inter-network impact.

Possible non-network solutions

The Molendinar Substation facilitates supply to the Energex loads of Cades County, Molendinar, Southport, Surfers Paradise and Nerang.

To meet the Molendinar demand, the non-network solution must be capable of delivering up to 336MW of power and 3,490MWh of energy each day.

Possible network reinvestments in the Gold Coast zone within five years

Against the backdrop of a rapidly changing electricity sector, Powerlink's planning overview (10-year outlook period of the TAPR) includes consideration of a broad range of options to address the identified needs in the Gold Coast zone. In this context, when considering the replacement of existing assets in conjunction with the broader network topography, Powerlink may identify potential network reconfigurations or other options which would be economically assessed under the RIT-T (if applicable). These options may identify opportunities to develop the transmission network in such a way as to realise synergies and efficiencies as we transform to an energy system underpinned by VRE generation, delivering positive outcomes for customers.

As assets approach their anticipated end of technical service life, the potential projects and alternatives (options) listed in Table 6.28 will be subject to detailed analysis to confirm alignment with future reinvestment, optimisation and delivery strategies. This analysis provides Powerlink with an additional opportunity to assess the needs and timing of asset replacement works, further refine options or consider other options, including the associated delivery strategies, from those described in Table 6.28.

Information in relation to potential projects, alternatives and possible commissioning needs will be revised annually within the TAPR based on the latest information available at the time.

Table 6.28 Possible network reinvestments in the Gold Coast zone within five years

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Substations					
Mudgeeraba 110kV secondary systems replacement	Partial replacement of 110kV secondary systems	Maintain supply reliability in the Gold Coast zone	December 2025	Full replacement of 110kV secondary systems (1)	$11m
Mudgeeraba 110kV primary plant replacement	Selected replacement of 110kVequipment	Maintain supply reliability in the Gold Coast zone	December 2025	Staged replacement of 110kV primary plant in existing bays and selected 275kV equipment (1)	$20m
Molendinar 275kV secondary systems replacement	Full replacement of 275kV secondary systems	Maintain supply reliability in the Gold Coast zone	December 2026	Selected replacement of 275kV secondary systems (1)	$22m (2)

Notes:

(1) The envelope for non-network solutions is defined in Section 6.7.11.

(2) Compared to the 2020 TAPR, the change in the estimated cost of the proposed network solution is based upon updated information in relation to the scope of works and the construction costs of recently completed projects.

Possible network reinvestments in the Gold Coast zone within six to 10 years

As a result of the annual planning review, Powerlink has identified that the following reinvestments are likely to be required to address the risks arising from network assets reaching end of technical service life and to maintain reliability of supply in the Gold Coast zone from around 2027/28 to 2031/32 (refer to Table 6.29).

Table 6.29 Possible network reinvestments in the Gold Coast zone within six to 10 years

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Transmission lines					
Line refit works on the 110kV transmission line between Mudgeeraba Substation and Terranora	Targeted line refit works on steel lattice structures	Maintain supply reliability from Queensland to NSW Interconnector	December 2028	Full line refit New transmission line	$5m
Targeted line refit works on sections of the 275kV transmission line between Greenbank and Mudgeeraba substations	Targeted line refit works on steel lattice structures	Maintain supply reliability in the Gold Coast zone	December 2028	New double circuit 275kV transmission line	$30m to $52m (1)
Substations					
Mudgeeraba 275/110kV Transformer Replacement	Replacement of the transformer	Maintain supply reliability to the Gold Coast Region	December 2030	Life extension of the existing transformer	$10m

Note:
(1) Compared to the 2020 TAPR, the increase in the estimated cost of the proposed network solution is based upon updated information in relation to required scope of works and the construction costs of recently completed projects.

Possible asset retirements within the 10-year outlook period

Current planning analysis has not identified any potential asset retirements in the Gold Coast zone within the 10-year outlook period.

6.8 Supply demand balance

The outlook for the supply demand balance for the Queensland region was published in the AEMO 2020 Electricity Statement of Opportunity (ESOO)[24]. Interested parties who require information regarding future supply demand balance should consult this document.

6.9 Existing interconnectors

The Queensland transmission network is interconnected to the NSW transmission system through the QNI transmission line and Terranora Interconnector transmission line.

The QNI maximum southerly capability is limited by voltage stability, transient stability, oscillatory stability, and line thermal rating considerations (as detailed in Section 8.6.10).

[24] Published by AEMO in August 2021.

The combined QNI plus Terranora Interconnector maximum northerly capability is limited by thermal ratings, voltage stability, transient stability and oscillatory stability (as detailed in Section 8.6.10).

The capability of these interconnectors can vary significantly depending on the status of plant, network conditions, weather and load levels in both Queensland and NSW. It is for these reasons that interconnector capability is regularly reviewed, particularly when new generation enters or leaves the market or transmission projects are commissioned in either region.

6.9.1 Expanding NSW-Queensland transmission transfer capacity

A RIT-T process to consider investment options on the QNI commenced in November 2018 and was completed in December 2019 with the publication of the 'Expanding NSW-Queensland transmission transfer capacity' PACR. This RIT-T focussed on consideration of the 2018 ISP recommended Group 1 QNI 'minor' upgrade and investigated the near-term options to increase overall net market benefits in the NEM through relieving congestion on the transmission network between NSW and Queensland. The PACR identified uprating the Liddell to Tamworth transmission lines, installing new dynamic reactive support at Tamworth and Dumaresq, and shunt capacitor banks at Tamworth, Dumaresq and Armidale as the preferred option which is expected to deliver the greatest net market benefits.

The 2020 ISP identified further upgrades to the QNI capacity as part of the optimal development path. These projects are discussed in detail in Section 9.3.

6 Future network development

CHAPTER 7

Non-network solution opportunities

7 Non-network solution opportunities

Key highlights

- Powerlink recognizes that non-network solutions have the potential to deliver positive outcomes for customers.
- Non-network solutions, in part or full, may also contribute to an overall network strategy by maintaining a balance between reliability and the cost of transmission services.
- With the continued uptake of rooftop photovoltaic (PV) systems, increased opportunities for non-network solutions are likely to become available to assist in managing voltages during minimum demand conditions.
- Opportunities may also be available to assist in managing daily peaks and troughs where economic.
- This chapter summarises potential non-network opportunities which may become available in the next five years.

7.1 Introduction

Powerlink has established processes for engaging with stakeholders for the provision of non-network services in accordance with the requirements of the National Electricity Rules (NER). For a given network limitation or potential asset replacement, the viability and an indicative specification of non-network solutions are first introduced in the TAPR and TAPR templates. As the identified need date approaches and detailed planning analysis is undertaken, further opportunities are explored in the consultation and stakeholder engagement processes undertaken as part of the Regulatory Investment Test for Transmission (RIT-T).

Historically, through regulatory consultation processes, Powerlink has implemented a range of non-network solutions in various areas in Queensland to assist, support or augment the power transfer capability of the high voltage transmission grid. Most recently, in June 2020, Powerlink entered into a short-term network support agreement with CleanCo to assist with a system strength shortfall in north Queensland (declared at the Ross node). This support was in place until December 2020.

7.2 Increased opportunities for non-network solutions

The uptake of rooftop PV systems is expected to continue within residential and commercial premises. Should this trend progress in the absence of energy storage devices (such as household battery systems) or significant levels of demand time of day shifting, minimum demand will further decrease and there will be a continued widening between maximum and minimum demand. The installation of additional reactive devices and/or non-network solutions are likely to be required to manage voltages during minimum demand conditions.

Continuation of this trend is likely to present further challenges to the energy system. Generating stations will be required to ramp up and down in response to daily demand variations more frequently. Decreasing minimum demand may lower the amount of synchronous generation that is on-line and this could further impact on voltage control, system strength, inertia and the ability for available generators to meet evening peak demand.

There may be opportunities for new technologies and non-network solutions to assist with managing the daily peaks and troughs. Demand shifting and storage solutions have the potential to smooth the daily load profile. These type of services could offer a number of benefits to the electricity system including reducing the need for additional transmission investment. More information on these emerging issues is available in chapters 2 and 3.

Powerlink is committed to understanding the future potential of non-network solutions and implementing where possible and economical to do so:

- to address future network limitations or address the risks arising from ageing assets remaining in service within the transmission network
- more broadly, in combination with network developments as part of an integrated solution to complement an overall network reconfiguration strategy

- to address voltage instability, inertia and system strength requirements, ensuring the secure operation of the transmission network
- to provide demand management and load balancing.

7.3 Non-network solution providers are encouraged to register with Powerlink

Powerlink has established a non-network engagement stakeholder register (NNESR) to convey non-network solution providers the details of potential non-network solution opportunities. Interested parties are encouraged to register their interest in writing to networkassessments@powerlink.com.au to become a member of Powerlink's NNESR.

More information on potential non-network solutions is available on Powerlink's website, including details regarding Powerlink's Network Support Contracting Framework, RIT-T and System Strength consultation processes.

7 Non-network solution opportunities

Table 7.1 Potential non-network solution opportunities within the next five years

Potential project	Indicative cost (most likely network option)	Zone	Indicative non-network requirement	Possible commissioning date	TAPR Reference
Transmission lines					
Woree to Kamerunga 132kV transmission line replacement	$40m	Far North	Up to 70MW at peak and up to 1,200MWh per day on a continuous basis to provide supply to the 22kV network	December 2026	Section 6.7.1
Line refit works on the 275kV transmission lines between Chalumbin and Woree substations (between Davies Creek and Bayview Heights)	$30m	Far North	Over 268MW at peak and up to 910MWh per day to provide supply to the Cairns area, facilitating the provision of system strength and voltage control	October 2023	Section 6.7.1 RIT-T in progress
Line refit works on the 275kV transmission lines between Ross and Chalumbin substations (1)	$72m	Far North	Over 400MW at peak and up to 7,000MWh to provide supply to northern Queensland, facilitating the provision of system strength and voltage control	December 2029	Section 6.7.1
Line refit works on the 275kV transmission line between Calliope River and Larcom Creek	$10m	Gladstone	Up to 160MW at peak and up to 3,200MWh per day on a continuous basis to provide supply to the 66kV and 132kV loads at Yarwun and Raglan	June 2024	Section 6.7.5 Anticipated RIT-T
Line refit works on the 275kV transmission line between Wurdong and Boyne	$10m	Gladstone	Up to 400MW at peak and up to 10,000MWh per day on a continuous basis to supply the 275kV network at Boyne Island	December 2025	Section 6.7.5
Line refit works on the 132kV transmission line between Callemondah and Gladstone South substations	$17m	Gladstone	Up to 160MW and up to 1,820MWh per day	December 2023	Section 6.7.5 Anticipated RIT-T
Rebuild of two of the three transmission lines between Calliope River and Wurdong tee as a double circuit	$27m	Gladstone	Powerlink would consider proposals from non-network providers that can significantly contribute to reducing the load requirement in this region. However, this would result in material intra-regional impacts and other impacts.	From December 2024 to December 2029	Section 6.7.6

Table 7.1 Potential non-network solution opportunities within the next five years (*continued)*

Potential project	Indicative cost (most likely network option)	Zone	Indicative non-network requirement	Possible commissioning date	TAPR Reference
Line refit works on the remaining single circuit 275kV transmission line between Calliope River Substation and Wurdong Tee	$6m	Gladstone	Powerlink would consider proposals from non-network providers that can significantly contribute to reducing the load requirement in this region. However, this would result in material intra-regional and other impacts.	June 2026	Section 6.7.6
Line refit works on the 275kV transmission line between Woolooga and South Pine substations	$36m	Wide Bay	Powerlink would consider proposals from non-network providers that can significantly contribute to reducing the load requirement in this region. However, this would result in material intra-regional other impacts.	June 2026	Section 6.7.6
Replacement of the 110kV underground cable between Upper Kedron and Ashgrove West substations	$13m	Moreton	Up to 220MW at peak to Brisbane's inner north-west suburb (potentially coupled with network reconfiguration)	June 2026	Section 6.7.10
Line refit works on sections of the 275kV transmission line between Greenbank and Mudgeeraba substations	$30-52m	Gold Coast	Proposals which may significantly contribute to reducing the requirements in the southern Gold Coast and northern NSW area	December 2028	Section 6.7.11
Substations - primary plant and secondary systems					
Innisfail 132kV secondary systems replacement	$12m	Far North	Up to 27MW at peak and 550MWh per day on a continuous basis to provide supply to the 22kV network at Innisfail	December 2024	Section 6.7.1 RIT-T in progress
Chalumbin 132kV secondary systems replacement	$10m	Far North	Up to 400MW at peak and up to 7,000MWh per day on a continuous basis to supply the 275kV network	December 2025	Section 6.7.1
Edmonton 132kV secondary systems replacement	$6m	Far North	Up to 55MW at peak and up to 770MWh per day on a continuous basis to provide supply to the 22kV network at Edmonton	June 2026	Section 6.7.1

Table 7.1 Potential non-network solution opportunities within the next five years (*continued*)

Potential project	Indicative cost (most likely network option)	Zone	Indicative non-network requirement	Possible commissioning date	TAPR Reference
Alan Sherriff 132kV secondary systems replacement	$11m	Ross	Up to 25MW at peak and up to 450MWh per day to provide supply to the 11kV network in north-east Townsville	June 2025	Section 6.7.2
Ingham South 132kV secondary systems replacement	$6m	Ross	Up to 20MW at peak and up to 280MWh per day on a continuous basis to provide supply to the 66kV network at Ingham South	June 2025	Section 6.7.2
Strathmore SVC secondary systems replacement	$6m	North	Up to 150MVArs capacitive and 80MVArs reactive dynamic voltage support at Strathmore	June 2026	Section 6.7.2
Calvale 275kV primary plant replacement	$13m	Central West	More than 100MW and up to 2,000MWh per day on a continuous basis to provide supply to the 132kV network at Moura and Biloela	December 2026	Section 6.7.4
Broadsound 275kV primary plant replacement	$15m	Central West	Up to 250MW and up to 6,000MWh per day on a continuous basis to provide supply to the 275kV network at Broadsound	December 2026	Section 6.7.4
Callemondah Substation primary plant and secondary systems replacement	$7m	Central West	Up to 180MW at peak and up to 2,500MWh per day on a continuous basis to provide supply to the 132kV network at Gladstone South and/or Aurizon load at Callemondah	June 2024	Section 6.7.4
Network reconfiguration by replacement of the two 275/66kV transformers at Tarong Substation Transformer ending Chinchilla Substation from Columboola substation Chinchilla 132kV primary plant and secondary systems replacement	$28m	South West	Up to 50MW and up to 850MWh per day on a continuous basis, auxiliary supply to Tarong Power Station of up to 38MVA Additional requirements for a partial non-network solution to replace one transformer include the requirement to be in service within six hours following a contingency and to provide supply for planned outages.	December 2025	Section 6.7.7 RIT-T in progress

Table 7.1 Potential non-network solution opportunities within the next five years (*continued)*

Potential project	Indicative cost (most likely network option)	Zone	Indicative non-network requirement	Possible commissioning date	TAPR Reference
One bus reactor each at Woolooga, Blackstone and Belmont substations	$27m	Moreton	Proposals which provide voltage control equivalent to the proposed three reactors across South East Queensland, at a nominal 360MVars. Reactive support would be required to be available on a continuous basis, and not coupled to generation output. Partial solutions to address either the declining minimum day time demand or the increasing early morning leading power factor would be considered on a case by case basis.	December 2022 to December 2025	Section 6.7.10 RIT-T in progress
Goodna 275/110kV secondary systems replacement	$20m	Moreton	Up to 220MW at peak to Brisbane's inner north-west suburbs potentially coupled with network reconfiguration)	December 2026	Section 6.7.10
Ashgrove West 110kV secondary systems replacement	$6m	Moreton	Up to 220MVA at peak to Brisbane's inner north-west suburb (potentially coupled with network reconfiguration)	June 2025	Section 6.7.10
Murarrie 110kV secondary systems replacement	$21m	Moreton	Proposals which may significantly contribute to reducing the requirements in the transmission network into the CBD and south-eastern suburbs of Brisbane of over 300MW	June 2027	Section 6.7.10
Mudgeeraba 110kV secondary systems replacement	$11m	Gold Coast	Proposals which may significantly contribute to reducing the requirements in the transmission into the southern Gold Coast and northern NSW area	December 2025	Section 6.7.11 Anticipated RIT-T

Table 7.1 Potential non-network solution opportunities within the next five years (*continued*)

Potential project	Indicative cost (most likely network option)	Zone	Indicative non-network requirement	Possible commissioning date	TAPR Reference
Mudgeeraba 275kV and 110kV primary plant replacement	$20m	Gold Coast	Proposals which may significantly contribute to reducing the requirements in the transmission into the southern Gold Coast and northern NSW area	December 2025	Section 6.7.11
Substations - transformers					
Nebo 132/11kV transformers replacement	$5m	North	Provide support to the 11kV network of up to 3MW at peak and up to 50MWh per day	June 2026	Section 6.7.2 Anticipated RIT-T
Redbank Plains 110kV primary plant and 110/11kV transformers replacement	$8m	Moreton	Provide support to the 11kV network of up to 25MW and up to 400MWh per day	June 2024	Section 6.7.10 Anticipated RIT-T

Notes:

(1) Due to the complexity of the potential network project, a RIT-T may be undertaken several years in advance to allow for the delivery of a solution.

(2) More generally, TAPR template data associated with emerging constraints which may require future capital expenditure, including potential projects which fall below the RIT-T cost threshold, is available on Powerlink's TAPR portal (refer to Appendix B, in particular transmission connection points and transmission line segments, regarding Powerlink's methodology for template data development).

CHAPTER 8

Network capability and performance

8 Network capability and performance

Key highlights

- Generation commitments since the 2020 Transmission Annual Planning Report (TAPR) add 470MW to Queensland's semi-scheduled variable renewable energy (VRE) generation capacity taking the total existing and committed semi-scheduled VRE generation capacity to 4,444MW.
- Storage commitments since the 2020 TAPR include the 250MW 8 hour Kidston Pumped Hydro Energy Storage (PHES) and 100MW 1.5 hour Wandoan South Battery Energy Storage System (BESS).
- Record peak transmission delivered demands were recorded in the Wide Bay and Surat zones during 2020/21.
- Record minimum transmission delivered demands and transmission delivered annual energy were recorded in the majority of zones during 2020/21.
- The transmission network has performed reliably during 2020/21, with Queensland grid sections largely unconstrained.

8.1 Introduction

This chapter on network capability and performance provides:

- an outline of existing and committed generation capacity over the next three years
- a summary of network control facilities configured to disconnect load as a consequence of non-credible events
- single line diagrams of the existing high voltage (HV) network configuration
- background on factors that influence network capability
- zonal energy transfers for the two most recent years
- historical constraint times and power flow duration curves at key sections of Powerlink Queensland's transmission network
- a qualitative explanation of factors affecting power transfer capability at key sections of Powerlink's transmission network
- historical system normal constraint times and load duration curves at key zones of Powerlink's transmission network
- a summary of the management of high voltages associated with light load conditions
- double circuit transmission lines categorised as vulnerable by the Australian Energy Market Operator (AEMO).

The capability of Powerlink's transmission network to meet forecast demand is dependent on a number of factors. Queensland's transmission network is predominantly utilised more during summer than winter. During higher summer temperatures, reactive power requirements are greater and transmission plant has lower power carrying capability. Also, higher demands occur in summer as shown in Figure 3.10.

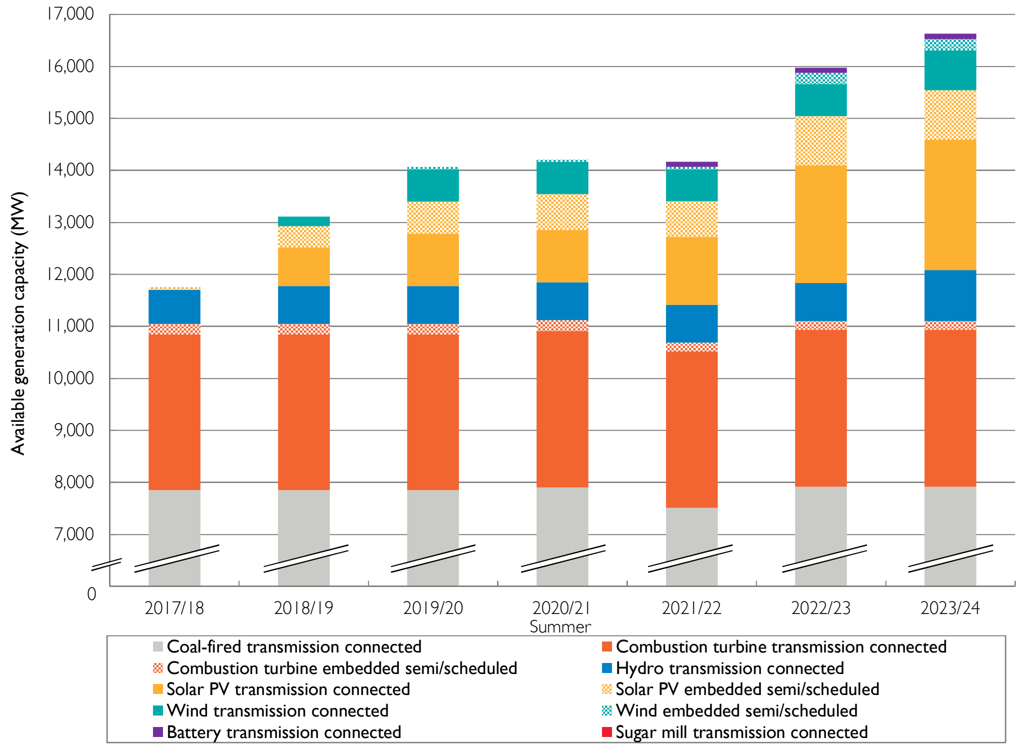
The location and pattern of generation dispatch influences power flows across most of the Queensland network. Future generation dispatch patterns and interconnector flows are uncertain in the deregulated electricity market and will vary substantially due to output of VRE generation and due to the effect of planned or unplanned outages of generation plant. Power flows can also vary substantially with planned or unplanned outages of transmission network elements. Power flows may also be higher at times of local area or zone maximum demands (refer to Table 3.17) and/or when embedded generation output is lower.

8.2 Available generation capacity

Scheduled generation in Queensland is predominantly a combination of coal-fired, gas turbine and hydro-electric generators.

AEMO's definition of 'committed' from the System Strength Impact Assessment Guidelines[1] (effective 1 July 2018) has been adopted for the purposes of this year's TAPR. During 2020/21, commitments have added 470MW of semi-scheduled VRE capacity, taking Queensland's semi-scheduled VRE generation capacity to 4,444MW. Figure 8.1 illustrates the expected changes to available and committed generation capacity in Queensland from summer 2017/18 to summer 2023/24.

Figure 8.1 Summer available generation capacity by energy source



8.2.1 Existing and committed transmission connected and direct connect embedded generation

Table 8.1 summarises the available generation capacity of power stations connected, or committed to be connected to Powerlink's transmission network (including the non-scheduled generators at Yarwun, Invicta and Koombooloomba) or to Powerlink's direct connect customers.

Scheduled transmission connected Genex PHES and Wandoan South BESS have reached committed status since the 2020 TAPR.

Semi-scheduled transmission connected Edenvale Solar Farm and Kaban Wind Farm have reached committed status since the 2020 TAPR. A replacement of Sun Metals solar farm's inverters sees its capacity increase by 14MW since the 2020 TAPR.

Information in this table has been provided to AEMO by the owners of the generators. Details of registration and generator capacities can be found on AEMO's website. In accordance with Clause 5.18A of the National Electricity Rules (NER), Powerlink's Register of Large Generator Connections with information on generators connected to Powerlink's network can be found on Powerlink's website.

[1] AEMO, System Strength Impact Assessment Guidelines, June 2018.

Table 8.1 Available generation capacity – existing and committed generators connected to the Powerlink transmission network or direct connect customers

Generator	Location	Available generation capacity (MW) (1)					
		Summer 2021/22	Winter 2022	Summer 2022/23	Winter 2023	Summer 2023/24	Winter 2024
Coal-fired							
Stanwell	Stanwell	1,460	1,460	1,460	1,460	1,460	1,460
Gladstone	Calliope River	1,680	1,680	1,680	1,680	1,680	1,680
Callide B	Calvale	700	700	700	700	700	700
Callide Power Plant	Calvale	434	886	854	886	854	886
Tarong North	Tarong	443	443	443	443	443	443
Tarong	Tarong	1,400	1,400	1,400	1,400	1,400	1,400
Kogan Creek	Kogan Creek PS	720	720	710	750	710	750
Millmerran	Millmerran PS	672	852	672	852	672	852
Total coal-fired		7,509	8,141	7,919	8,171	7,919	8,171
Combustion turbine							
Townsville 132kV	Townsville PS	150	165	150	165	150	165
Mt Stuart	Townsville South	387	400	387	400	387	400
Yarwun (2)	Yarwun	160	155	160	155	160	155
Condamine (3)	Columboola	139	144	139	144	139	144
Braemar 1	Braemar	491	543	501	543	501	543
Braemar 2	Braemar	480	519	480	519	480	519
Darling Downs	Braemar	563	630	563	630	563	630
Oakey (4)	Tangkam	288	346	288	346	288	346
Swanbank E	Swanbank E PS	350	365	350	365	350	365
Total combustion turbine		3,008	3,267	3,018	3,267	3,018	3,267
Hydro-electric							
Barron Gorge	Kamerunga	66	66	66	66	66	66
Kareeya (including Koombooloomba) (5)	Chalumbin	93	93	93	93	93	93
Wivenhoe (6)	Mt. England	570	570	570	570	570	570
Kidston Pumped Hydro Storage	Kidston					250	250
Total hydro-electric		729	729	729	729	979	979
Solar PV (7)							
Ross River	Ross	116	116	116	116	116	116
Sun Metals (3)	Townsville Zinc	121	121	121	121	121	121
Haughton	Haughton River	100	100	100	100	100	100

Table 8.1 Available generation capacity – existing and committed generators connected to the Powerlink transmission network or direct connect customers (*continued*)

Generator	Location	Available generation capacity (MW) (1)					
		Summer 2021/22	Winter 2022	Summer 2022/23	Winter 2023	Summer 2023/24	Winter 2024
Clare	Clare South	100	100	100	100	100	100
Whitsunday	Strathmore	57	57	57	57	57	57
Hamilton	Strathmore	57	57	57	57	57	57
Daydream	Strathmore	150	150	150	150	150	150
Hayman	Strathmore	50	50	50	50	50	50
Rugby Run	Moranbah	65	65	65	65	65	65
Lilyvale	Lilyvale	100	100	100	100	100	100
Moura	Moura		82	82	82	82	82
Rodds Bay	South of Wurdong				250	250	250
Woolooga Energy Park	Woolooga		176	176	176	176	176
Bluegrass	Chinchilla		148	148	148	148	148
Columboola	Columboola	162	162	162	162	162	162
Gangarri	Wandoan South	120	120	120	120	120	120
Edenvale Solar Park	Orana			146	146	146	146
Western Downs Green Power Hub	Western Downs		400	400	400	400	400
Darling Downs	Braemar	108	108	108	108	108	108
Total solar PV		1,306	2,112	2,258	2,508	2,508	2,508
Wind (7)							
Mt Emerald	Walkamin	180	180	180	180	180	180
Kaban	Tumoulin				151	151	151
Coopers Gap	Coopers Gap	440	440	440	440	440	440
Total wind		620	620	620	771	771	771
Battery (7)							
Wandoan South 1.5h BESS	Wandoan South	100	100	100	100	100	100
Total battery		100	100	100	100	100	100
Sugar mill							
Invicta (5)	Invicta Mill	0	34	0	34	0	34
Total sugar mill		0	34	0	34	0	34
Total all stations		**13,271**	**14,054**	**14,371**	**15,123**	**14,631**	**15,123**

Notes:

(1) Synchronous generator capacities shown are at the generator terminals and are therefore greater than power station net sent out nominal capacity due to station auxiliary loads and step-up transformer losses. The capacities are nominal as the generator rating depends on ambient conditions. Some additional overload capacity is available at some power stations depending on ambient conditions.

(2) Yarwun is a non-scheduled generator, but is required to comply with some of the obligations of a scheduled generator.

(3) Condamine and Sun Metals are direct connected embedded generators.

(4) Oakey Power Station is an open-cycle, dual-fuel, gas-fired power station. The generated capacity quoted is based on gas fuel operation.

(5) Koombooloomba and Invicta are transmission connected non-scheduled generators.

(6) Wivenhoe Power Station is shown at full capacity (570MW). However, output can be limited depending on water storage levels in the dam.

(7) VRE generators and battery are shown at maximum capacity at the point of connection.

8.2.2 Existing and committed scheduled and semi-scheduled distribution connected embedded generation

Table 8.2 summarises the available generation capacity of embedded scheduled and semi-scheduled power stations connected, or committed to be connected to Queensland's distribution network.

Scheduled embedded Mackay GT was decommissioned since the 2020 TAPR.

Semi-scheduled embedded Dulacca Wind Farm has reached committed status since the 2020 TAPR.

Information in this table has been provided to AEMO by the owners of the generators. Details of registration and generator capacities can be found on AEMO's website.

Table 8.2 Available generation capacity – existing and committed scheduled or semi-scheduled generators connected to the Ergon Energy and Energex (part of the Energy Queensland Group) distribution networks.

Generator	Location	Available generation capacity (MW)					
		Summer 2021/22	Winter 2022	Summer 2022/23	Winter 2023	Summer 2023/24	Winter 2024
Combustion turbine (1)							
Townsville 66kV	Townsville PS	78	82	78	82	78	82
Barcaldine	Barcaldine	34	37	34	37	34	37
Roma	Roma	54	68	54	68	54	68
Total combustion turbine		166	187	166	187	166	187
Solar PV (2)							
Kidston	Kidston	50	50	50	50	50	50
Kennedy Energy Park	Hughenden	15	15	15	15	15	15
Collinsville	Collinsville North	42	42	42	42	42	42
Clermont	Clermont	75	75	75	75	75	75
Middlemount	Lilyvale	26	26	26	26	26	26
Emerald	Emerald	72	72	72	72	72	72
Aramara	Aramara			104	104	104	104
Susan River	Maryborough	75	75	75	75	75	75
Childers	Isis	56	56	56	56	56	56
Munna Creek	Kilkivan			120	120	120	120
Kingaroy	Kingaroy			40	40	40	40
Maryrorough	Yarranlea	27	27	27	27	27	27
Yarranlea	Yarranlea	103	103	103	103	103	103
Oakey 1	Oakey	25	25	25	25	25	25
Oakey 2	Oakey	55	55	55	55	55	55
Warwick	Warwick	64	64	64	64	64	64
Total solar PV		685	685	949	949	949	949
Wind (2)							
Kennedy Energy Park	Hughenden	43	43	43	43	43	43
Dulacca	Roma			173	173	173	173
Total wind		43	43	216	216	216	216
Total all stations		**894**	**915**	**1,331**	**1,352**	**1,331**	**1,352**

Notes:

(1) Synchronous generator capacities shown are at the generator terminals and are therefore greater than power station net sent out nominal capacity due to station auxiliary loads and step-up transformer losses. The capacities are nominal as the generator rating depends on ambient conditions. Some additional overload capacity is available at some power stations depending on ambient conditions.

(2) VRE generators shown at maximum capacity at the point of connection.

8.3 Network control facilities

Powerlink participated in the second Power System Frequency Risk Review[2] (PSFRR) in 2020. The PSFRR, as part of the Emergency Frequency Control Schemes (EFCS) rule change[3], placed an obligation on AEMO to undertake, in collaboration with Transmission Network Service Providers (TNSPs), an integrated, periodic review of power system frequency risks associated with non-credible contingency events.

AEMO published the Final 2020 PSFRR – Stage 2 Report on 22 December 2020. For Queensland, the recommendation involved the expansion of Powerlink's CQ-SQ Special Protection Scheme (SPS). The conventional SPS disconnects one or two highest generating Callide units, depending on CQ-SQ transfer, for the unplanned loss of both Calvale to Halys 275kV feeders. The likely success of this scheme was limited to transfers lower than 1,700MW and relied on the ability to disconnect high output Callide units. Powerlink has enhanced the scheme with a new Wide Area Monitoring Protection and Control (WAMPAC) architecture to operate in parallel with the existing SPS. The WAMPAC scheme was first armed in July 2021. The WAMPAC scheme avails approximately 600MW of northern VRE generation and up to 700MW[4] of southern loads to be tripped along with the existing SPS. Whilst this scheme reduces the exposure to CQ-SQ separation for this non-credible event, it does not cover the full operational spectrum of the CQ-SQ grid section flow. Powerlink is in the process of designing a second tranche of the scheme to further reduce the exposure. The commissioning of the second tranche will also see the decommissioning of the conventional scheme.

The Stage 2 Report also considered the non-credible loss of the double-circuit Queensland – New South Wales Interconnector (QNI). The assessment reviewed the effectiveness of the existing under-frequency load shedding (UFLS) scheme (for QNI northerly transfer) and the potential need to implement an over-frequency generator shedding (OFGS) scheme (for QNI southerly transfer) to contain the respective maximum frequency deviations to within the frequency operating standard (FOS) limits.

The studies of the non-credible loss of QNI while on a southerly limit did not identify an immediate need to implement an OFGS scheme in Queensland to cater for QNI contingencies, if the semi-scheduled inverter-based renewable (IBR) generators provide primary frequency response (PFR) consistent with the NER requirement.

The studies of the non-credible loss of QNI while on a northerly limit indicate that the existing UFLS controls are able to manage the frequency disturbance when exporting at the secure transfer limit. However, this requires significant levels of UFLS. The ongoing effectiveness of UFLS in Queensland should be reassessed as part of the 2022 PSFRR with specific consideration given to whether declaration of a protected event is warranted to manage the risk associated with the non-credible loss of QNI while transferring power into Queensland. This may be necessary if planned measures to address the declining UFLS effectiveness are unsuccessful. Declaration of a protected event under conditions with low levels of UFLS available in Queensland and high transfers into Queensland across QNI would enable a number of options to manage the risk posed by the non-credible loss of QNI, including specifying a local requirement for frequency raise FCAS in Queensland or constraining northerly transfers across QNI.

Stage 2 of the 2020 PSFRR references the Frequency Control Work Plan[5] that reviews Under Frequency Load Shedding (UFLS) schemes NEM-wide.

Powerlink owns other network control facilities which minimise or reduce the consequences of multiple contingency events. Network control facilities owned by Powerlink which may disconnect load following a multiple non-credible contingency event are listed in Table 8.3.

[2] AEMO, 2020 PSFRR – Stage 2 – Final Report, December 2020.

[3] AEMC, Rule Determination National Electricity Amendment (Emergency Frequency Control Schemes) Rule 2017, March 2017.

[4] Includes both 250MW Wivenhoe Power Station units (if operating in pumping mode).

[5] AEMO, Frequency Control Work Plan, September 2020.

Table 8.3 Powerlink owned network control facilities configured to disconnect load as a consequence of non-credible events during system normal conditions

Scheme	Purpose
FNQ Under Voltage Load Shed (UVLS) scheme	Minimise risk of voltage collapse in FNQ
North Goonyella Under Frequency Load Shed (UFLS) relay	Raise system frequency
Dysart UVLS	Minimise risk of voltage collapse in Dysart area
Eagle Downs UVLS	Minimise risk of voltage collapse in Eagle Downs area
Boyne Island UFLS relay	Raise system frequency
Queensland UFLS inhibit scheme	Minimise risk of QNI separation for an UFLS event for moderate to high southern transfers on QNI compared to Queensland demand
CQSQ N-2 Wide Area Monitoring Protection and Control (WAMPAC) scheme	Minimise risk of CQSQ separation for a non-credible loss of the Calvale to Halys 275kV double circuit transmission line
Tarong UFLS relay	Raise system frequency
Middle Ridge UFLS relays	Raise system frequency
Mudgeeraba Emergency Control Scheme (ECS)	Minimise risk of voltage collapse in the Gold Coast zone

8.4 Existing network configuration

Figures 8.2, 8.3, 8.4 and 8.5 illustrate Powerlink's system intact network as of July 2021.

Figure 8.2 Existing HV network July 2021 – North Queensland

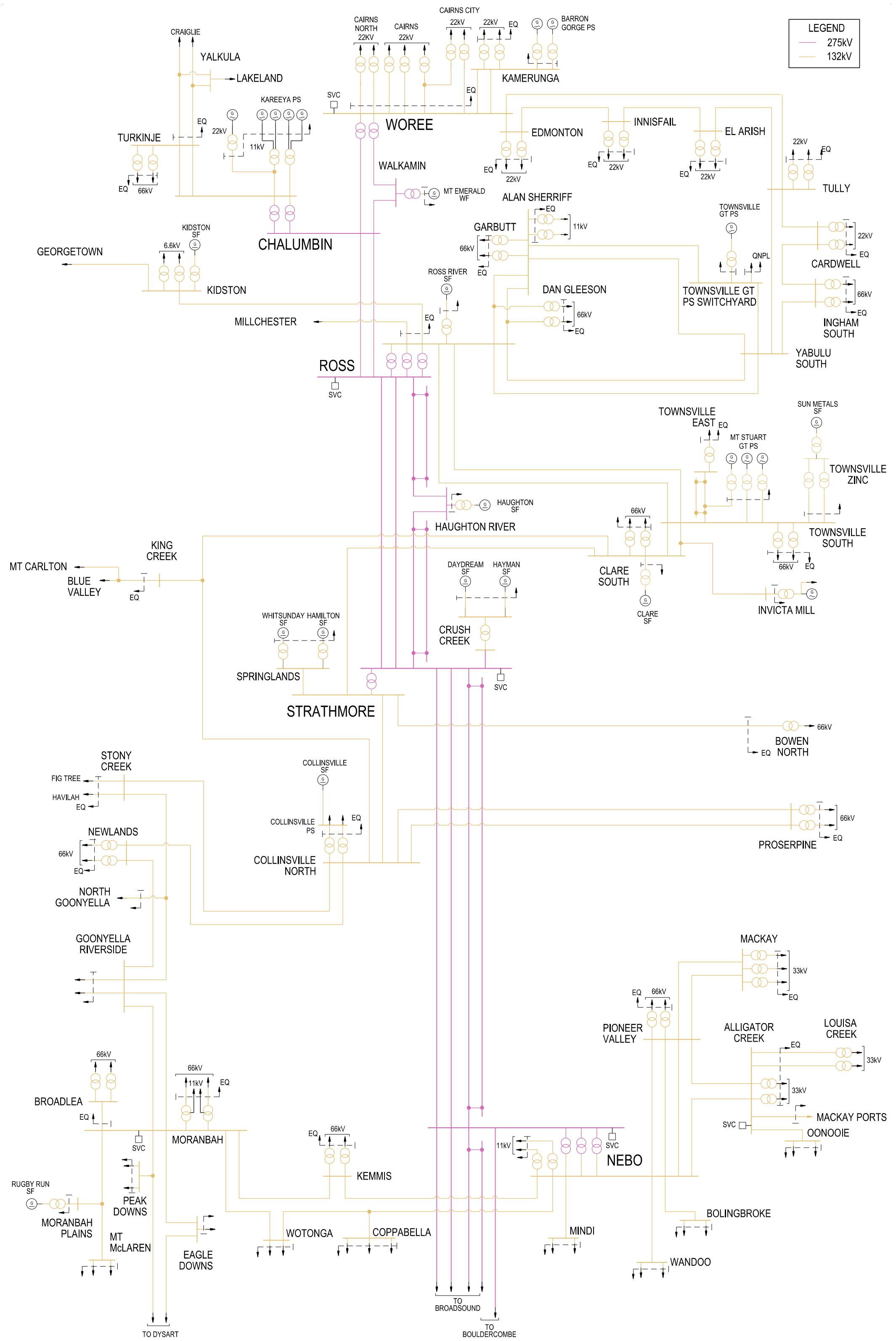


Figure 8.3 Existing HV network July 2021 – Central Queensland

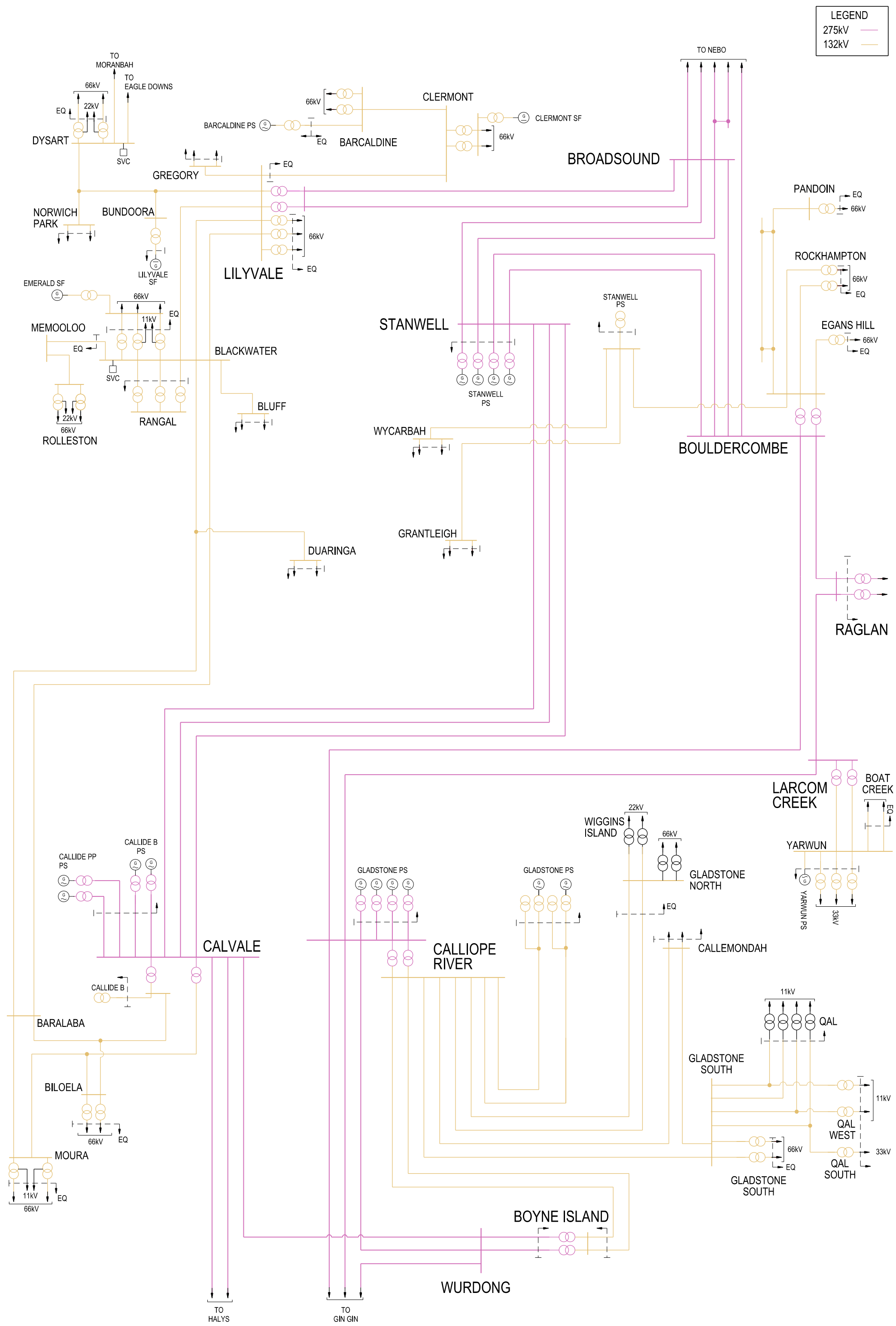


Figure 8.4 Existing HV network July 2021 - South West Queensland

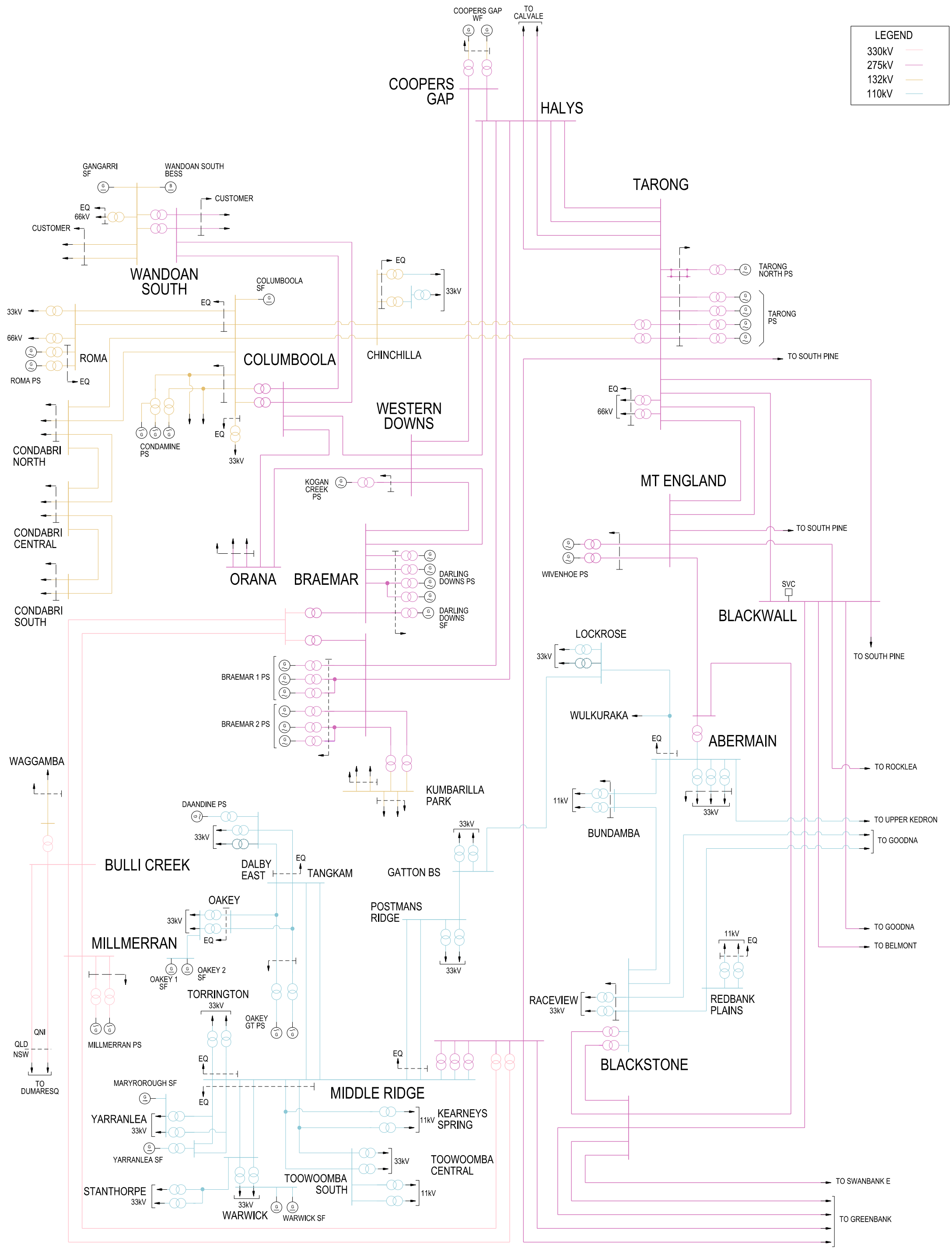
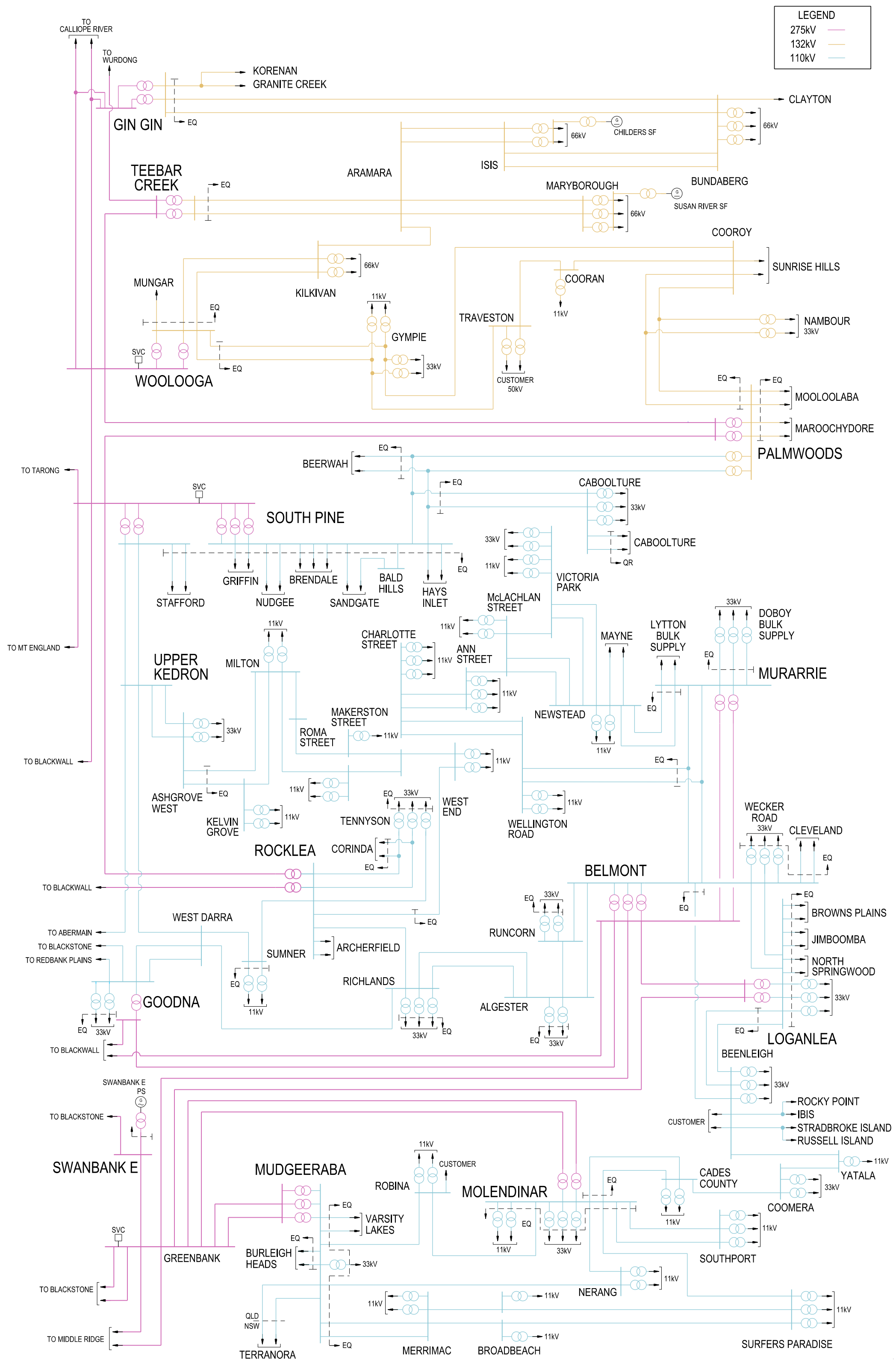


Figure 8.5 Existing HV network July 2021 - South East Queensland



8.5 Transfer capability

8.5.1 Location of grid sections

Powerlink has identified a number of grid sections that allow network capability and forecast limitations to be assessed in a structured manner. Limit equations have been derived for these grid sections to quantify maximum secure power transfer. Maximum power transfer capability may be set by transient stability, voltage stability, thermal plant ratings or protection relay load limits. AEMO has incorporated these limit equations into constraint equations within the National Electricity Market Dispatch Engine (NEMDE). Table C.2 provides definitions and Figure C.2 in Appendix C shows the location of relevant grid sections on the Queensland network.

8.5.2 Determining transfer capability

Transfer capability across each grid section varies with different system operating conditions. Transfer limits in the National Electricity Market (NEM) are not generally amenable to definition by a single number. Instead, TNSPs define the capability of their network using multi-term equations. These equations quantify the relationship between system operating conditions and transfer capability, and are implemented into NEMDE, following AEMO's due diligence, for optimal dispatch of generation. In Queensland the transfer capability is highly dependent on which generators are in service and their dispatch level. The limit equations maximise transmission capability available to electricity market participants under prevailing system conditions.

Limit equations derived by Powerlink which are current at the time of publication of this TAPR are provided in Appendix D. Limit equations will change over time with demand, generation and network development, and/or network reconfiguration. For example, AEMO and Powerlink are currently investigating an update to dynamic load models which include aggregate representation of rooftop photovoltaic (PV) systems. Such detailed and extensive analysis on limit equations has not been carried out for future network and generation developments for this TAPR. However, expected limit improvements for committed works are incorporated in all future planning. Section 8.6 provides a qualitative description of the main system conditions that affect the capability of each grid section.

8.6 Grid section performance

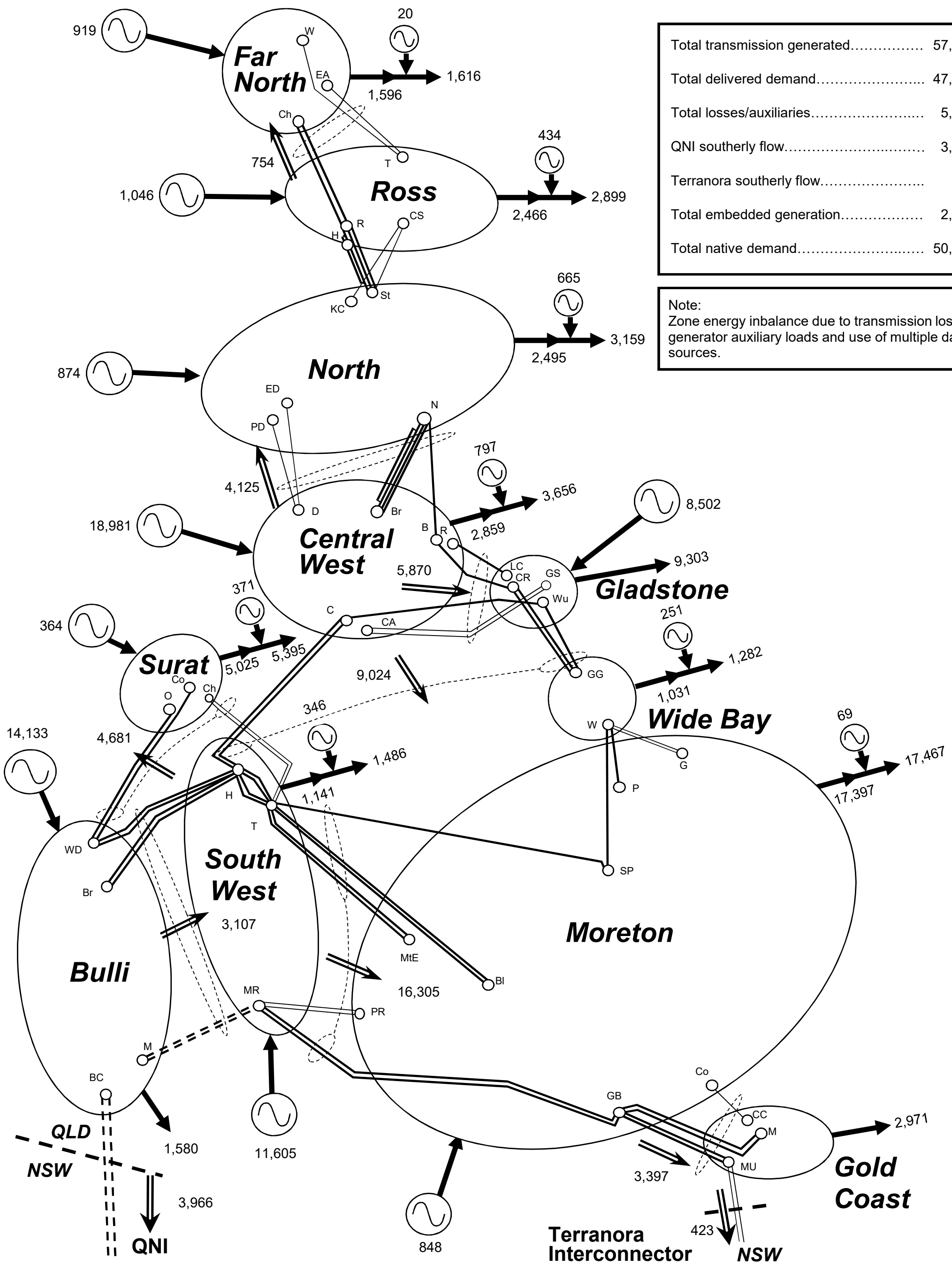
This section is a qualitative summary of system conditions with major effects on transfer capability across key grid sections of the Queensland network.

For each grid section, the time that the relevant constraint equations have bound over the last 10 years is provided categorised as occurring during intact or outage conditions based on AEMO's constraint description. Constraint times can be associated with a combination of generator unavailability, network outages, unfavourable dispatches and/or high loads. Constraint times do not include occurrences of binding constraints associated with network support agreements. Binding constraints whilst network support is dispatched are not classed as congestion. Although high constraint times may not be indicative of the cost of market impact, they serve as a trigger for the analysis of the economics for overcoming the congestion.

Binding constraint information is sourced from AEMO. Historical binding constraint information is not intended to imply a prediction of constraints in the future.

Historical transfer duration curves for the last five years are included for each grid section. Grid section transfers are predominantly affected by load, generation and transfers to neighbouring zones. Figures 8.6 and 8.7 provide 2019/20 and 2020/21 zonal energy as generated into the transmission network (refer to Figure C.1 in Appendix C for generators included in each zone) and by major embedded generators, transmission delivered energy to Distribution Network Service Providers (DNSPs) and direct connect customers and grid section energy transfers. Figure 8.8 provides the changes in energy transfers from 2019/20 to 2020/21. These figures assist in the explanation of differences between 2019/20 and 2020/21 grid section transfer duration curves.

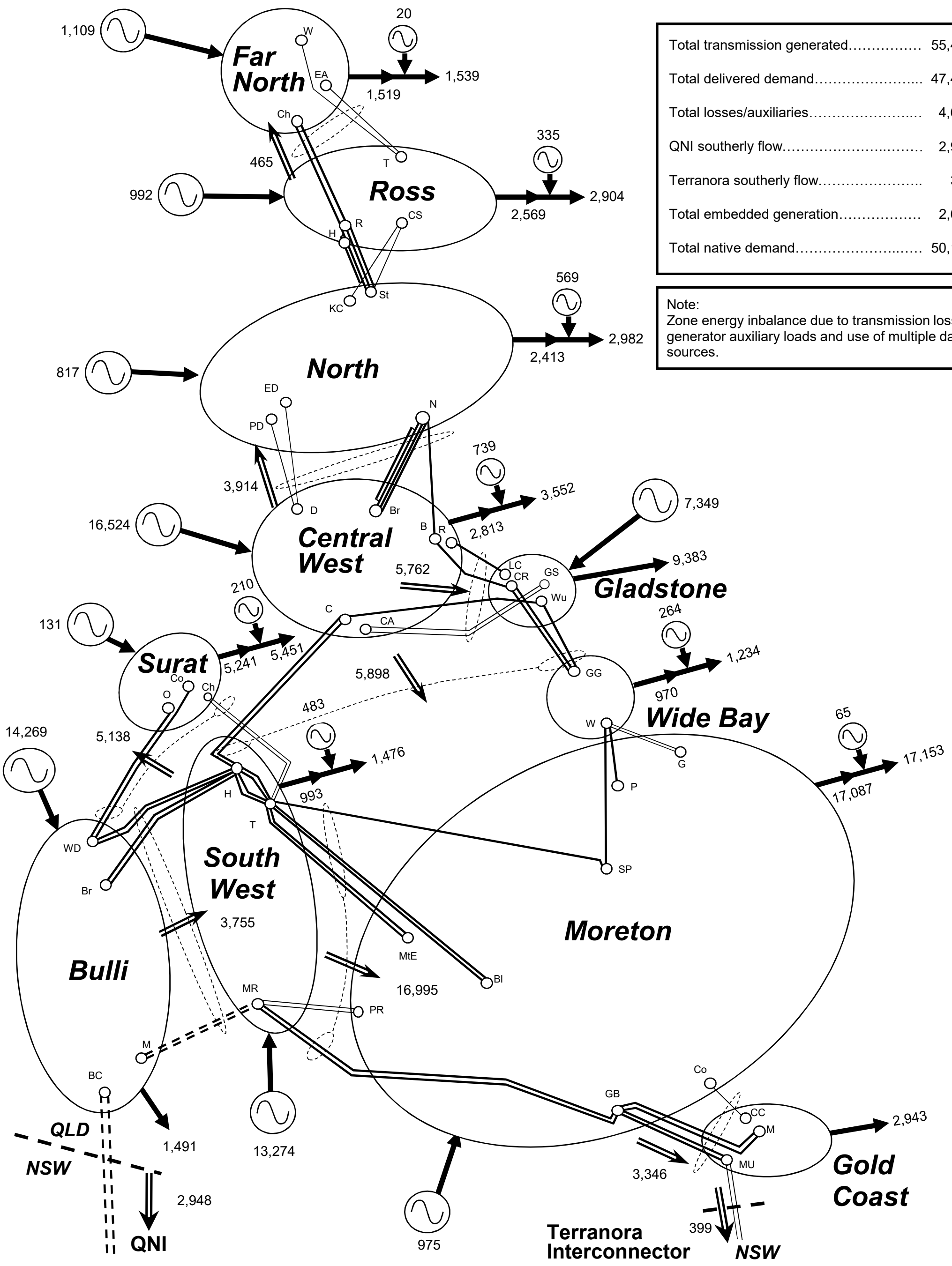
Figure 8.6 2019/20 zonal electrical energy transfers (GWh)



Total transmission generated	57,272 GWh
Total delivered demand	47,862 GWh
Total losses/auxiliaries	5,020 GWh
QNI southerly flow	3,966 GWh
Terranora southerly flow	423 GWh
Total embedded generation	2,952 GWh
Total native demand	50,814 GWh

Note:
Zone energy inbalance due to transmission losses, generator auxiliary loads and use of multiple data sources.

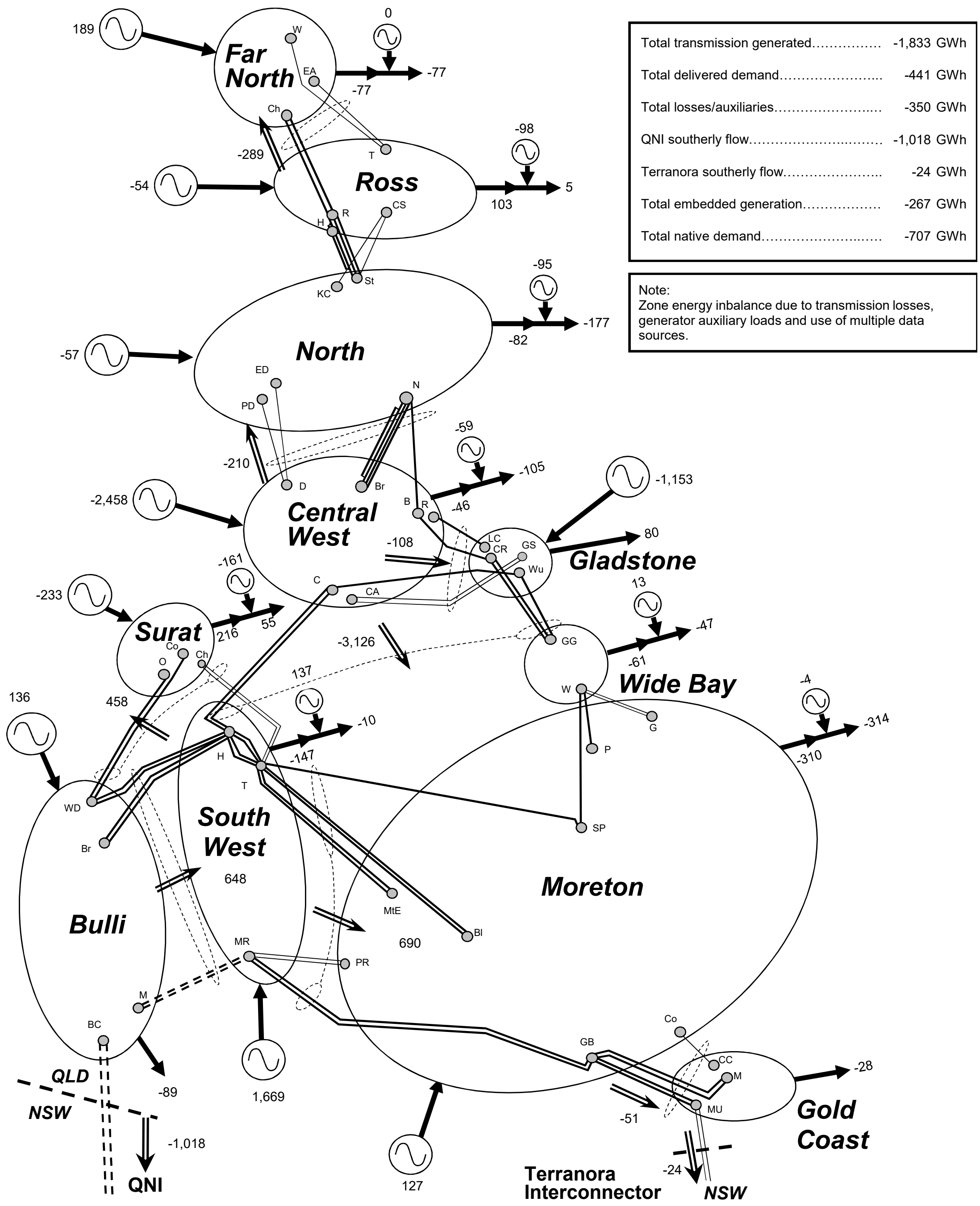
Figure 8.7 2020/21 zonal electrical energy transfers (GWh)



Total transmission generated................	55,438 GWh
Total delivered demand........................	47,421 GWh
Total losses/auxiliaries.........................	4,670 GWh
QNI southerly flow................................	2,948 GWh
Terranora southerly flow.......................	399 GWh
Total embedded generation..................	2,686 GWh
Total native demand............................	50,107 GWh

Note:
Zone energy inbalance due to transmission losses, generator auxiliary loads and use of multiple data sources.

Figure 8.8 Change in zonal electrical energy transfers (GWh)



8.6.1 Far North Queensland (FNQ) grid section

Maximum power transfer across the FNQ grid section is set by voltage stability associated with an outage of a Ross to Chalumbin 275kV circuit or the interim Ross to Woree 275kV circuit[6].

The limit equation in Table D.1 of Appendix D shows that the following variables have a significant effect on transfer capability:

- Far North and Ross zones generation
- Far North zone shunt compensation levels.

Local hydro and wind generation reduces transfer capability but allows more demand to be securely supported in the Far North zone. This is because reactive margins increase with additional local generation, allowing further load to be delivered before reaching minimum allowable reactive margins. However, due to its distributed and reactive nature, increases in delivered demand erode reactive margins at greater rates than they were created by the additional local generation. Limiting power transfers are thereby lower with the increased local generation but a greater load can be delivered.

The FNQ grid section did not constrain operation during 2020/21. Information pertaining to the historical duration of constrained operation for the FNQ grid section is summarised in Figure 8.9.

Figure 8.9 Historical FNQ grid section constraint times

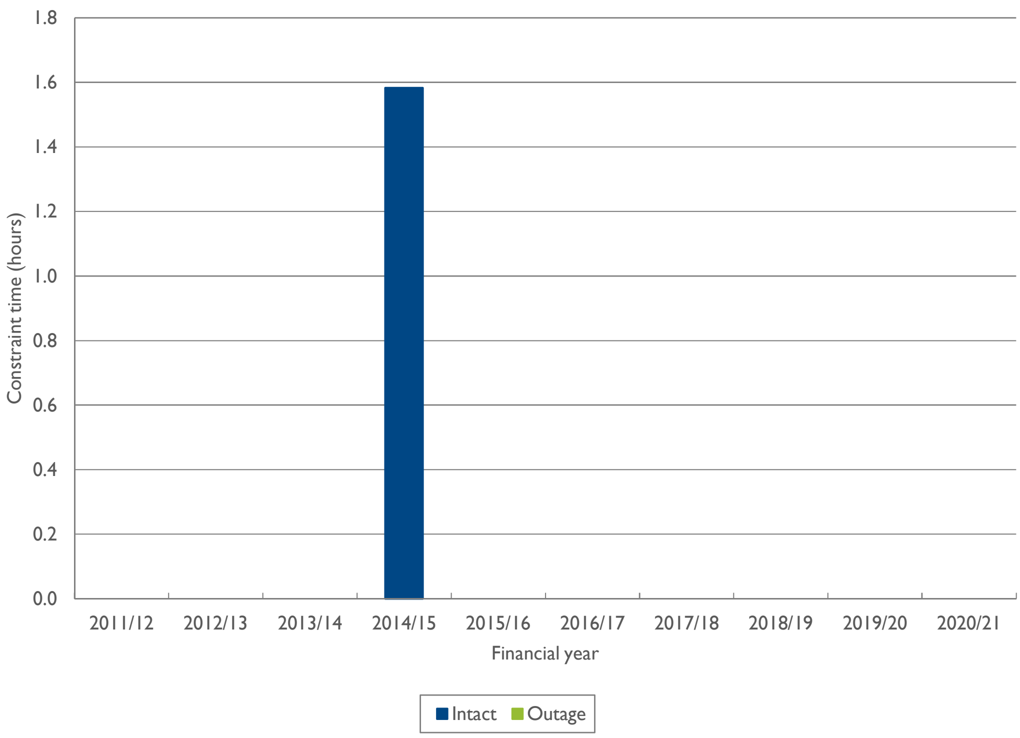
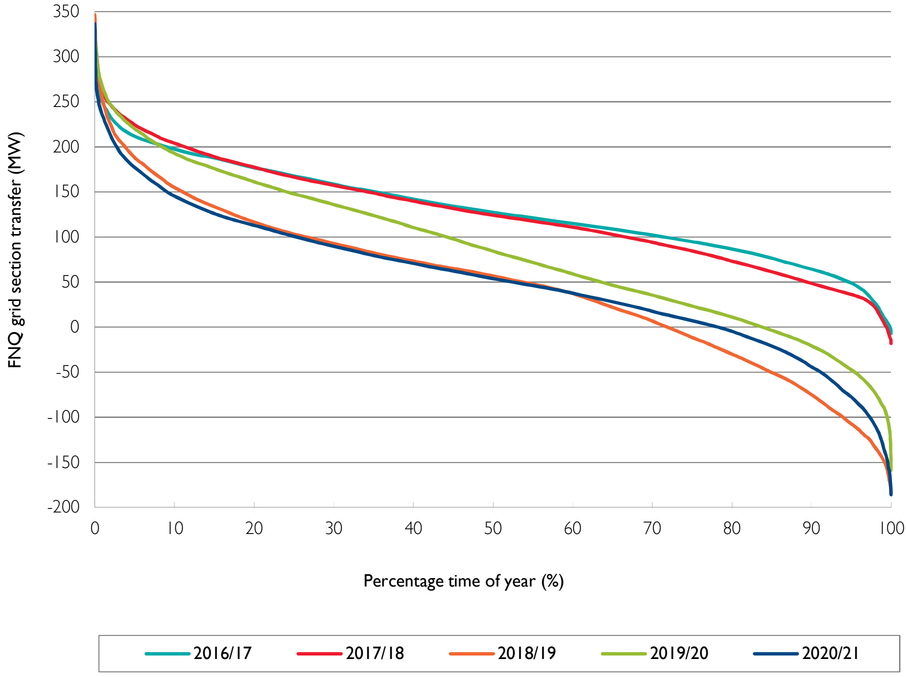


Figure 8.10 provides historical transfer duration curves showing a large decrease in energy transfer but similar peak transfers over 2020/21. This is predominantly attributed to the recent commissioning of Mount Emerald Wind Farm located between Chalumbin and Woree substations. Historically, changes in peak flow and energy delivered to the Far North zone by the transmission network have been dependant on the Far North zone load and generation from the hydro generating power stations at Barron Gorge and Kareeya. These vary depending on rainfall levels in the Far North zone. The combined hydro generating power station capacity factor has increased between 2019/20 and 2020/21 further lowering northerly energy transfers (refer to figures 8.6, 8.7 and 8.8).

[6] In November 2020, Powerlink reconfigured the FNQ grid section to maximise reliability to Cairns during rectification works at Bayview Heights overhead to underground transition station on a Chalumbin to Woree 275kV circuit. This reconfiguration required new limit equations listed in Table D.1 of Appendix D.

Figure 8.10 Historical FNQ grid section transfer duration curves



In May 2021 it was announced that the Queensland Government would invest $40 million in transmission line infrastructure in North Queensland to establish a Queensland REZ (QREZ), with Neoen's Kaban Wind Farm identified as the foundational proponent.

The proposed transmission augmentation works are to energise one side of the existing 132kV coastal double circuit transmission line, originally constructed to accommodate transmission at 275kV. This results in the establishment of a third 275kV transmission line into Woree. Work on the proposed transmission augmentation is expected to be completed by November 2023.

8.6.2 Central Queensland to North Queensland (CQ-NQ) grid section

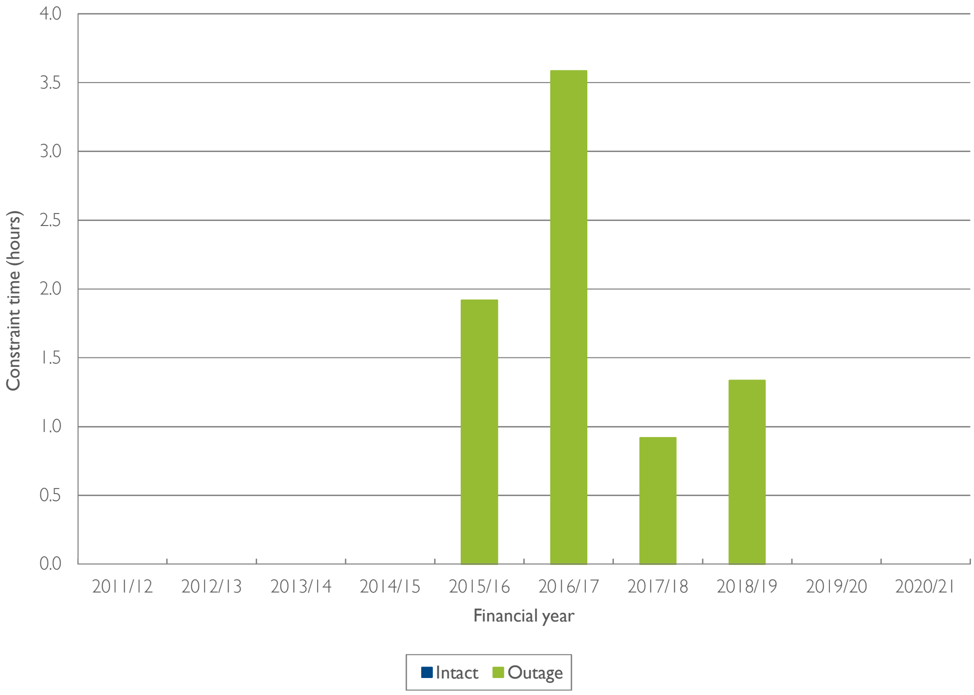
Maximum power transfer across the CQ-NQ grid section may be set by thermal ratings associated with an outage of a Stanwell to Broadsound 275kV circuit, under certain prevailing ambient conditions. Power transfers may also be constrained by voltage stability limitations associated with the contingency of the Townsville gas turbine or a Stanwell to Broadsound 275kV circuit.

The limit equations in Table D.2 of Appendix D show that the following variables have a significant effect on transfer capability:

- level of Townsville gas turbine generation
- Ross and North zones shunt compensation levels.

The CQ-NQ grid section did not constrain operation during 2020/21. Information pertaining to the historical duration of constrained operation for the CQ-NQ grid section is summarised in Figure 8.11.

Figure 8.11 Historical CQ-NQ grid section constraint times



The staged commissioning of double circuit lines from Broadsound to Ross completed in 2010/11 provided increased capacity to this grid section. Since this time constraint times were associated with thermal constraint equations during planned outages to ensure operation within plant thermal ratings.

Figure 8.12 provides historical transfer duration curves showing decreases in energy transfer but similar peak continued in 2020/21. This is predominantly attributed to the addition of solar and wind farms in the Far North, Ross and North zones. The curves illustrate the ramping with commissioning activities over the last three years. Notably, peak transfers continue to be maintained at similar levels, as high net loading conditions continue to coincide (refer to figures 8.6, 8.7 and 8.8).

Figure 8.12 Historical CQ-NQ grid section transfer duration curves

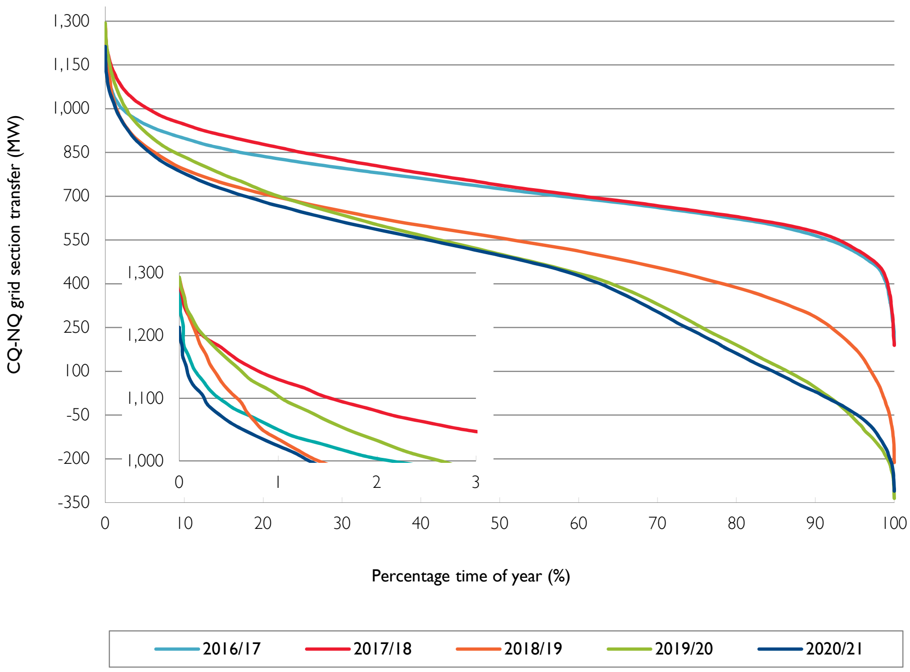
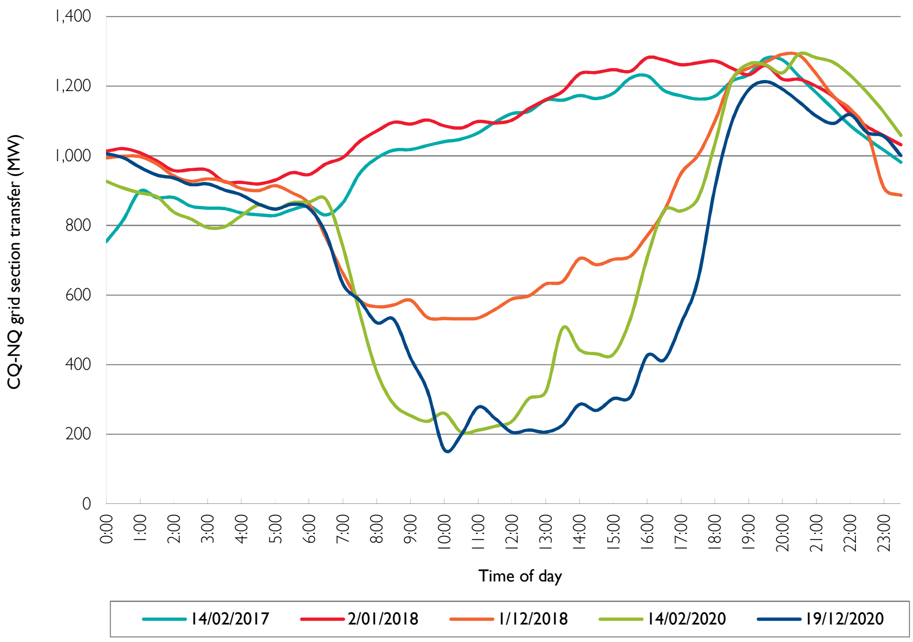


Figure 8.13 provides a different view of the altered power flows experienced over the last years for the day corresponding to the annual peak CQ-NQ transfer.

Figure 8.13 Historical CQ-NQ peak grid section transfer daily profile



These midday reductions in transfers are introducing operational challenges in voltage control. Midday transfers are forecast to continue reducing with integration of additional rooftop PV in NQ. Correspondingly, voltage control is forecast to become increasingly challenging for longer durations.

In February 2021, Powerlink completed the Project Assessment Conclusions Report (PACR)[7] recommending the establishment of a 150MVAr 300kV bus reactor at Broadsound by June 2023.

[7] Powerlink, Project Assessment Conclusions Report - Managing voltage control in Central Queensland, February 2021.

8.6.3 NQ System Strength

System strength is a measure of the ability of a power system to remain stable under normal conditions and to return to a steady state condition following a system disturbance. System strength can be considered low in areas with low levels of local synchronous generation and deteriorates further with high penetration of inverter-based resources.

Powerlink has determined that the dominant limitation to VRE hosting capacity is the potential for multiple generators, and other transmission-connected dynamic plant, to interact in an unstable manner. These dynamic plant control interactions manifest as an unstable or undamped oscillation in the power system voltage. The frequency of the oscillation is dependent on the participating plants, but is broadly characterised as between 8Hz and 15Hz.

As a result of these control interactions, in April 2020 AEMO declared an immediate fault level shortfall in NQ at the Ross node. As Queensland's TNSP, and therefore System Strength Service Provider, Powerlink responded to this short fall by initially entering into an interim arrangement with CleanCo Queensland to utilise its assets in FNQ for system strength and then ultimately by retuning inverter controls at several solar farms in North Queensland and the Mt Emerald Wind Farm.

As a result of retuning of the solar farms and changes to the control settings at Mt Emerald Wind Farm the system strength requirements at the Ross node has been met (refer Section 10.4). The limit equations in Table D.3 of Appendix D reflect the impact of these changes. The limit equations show that the following variables have a significant effect on NQ system strength:

- number of synchronous units online in Central and NQ
- NQ demand.

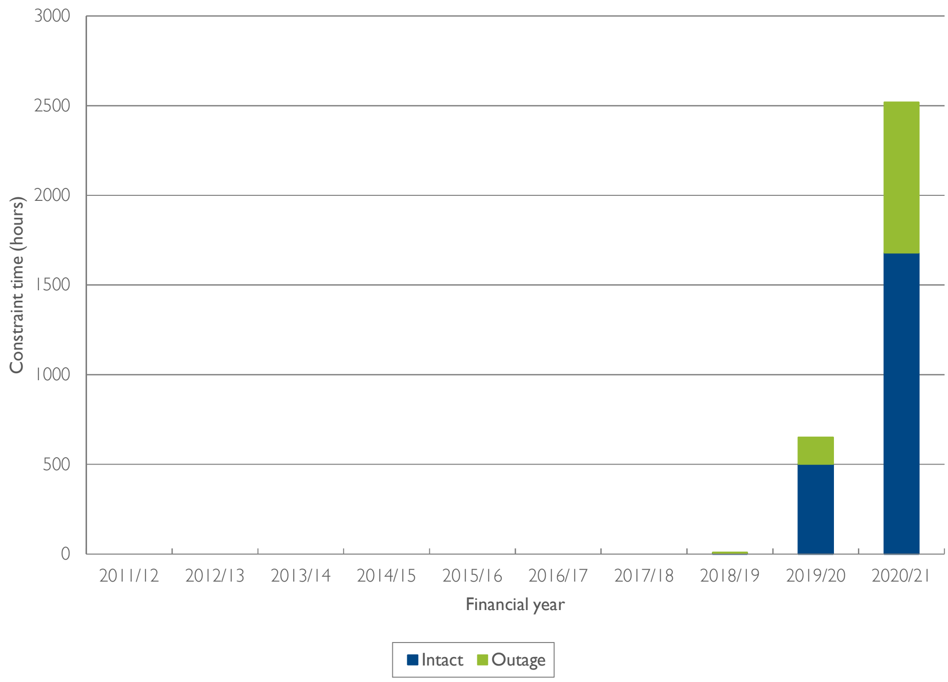
Information pertaining to the historical duration of constrained operation for inverter-based resources in NQ is summarised in Figure 8.14. During 2020/21, inverter-based resources in NQ experienced 2,518 hours of constrained operation, of which 1,680 hours occurred during intact system conditions. Constrained operation during intact system conditions has occurred for a number of reasons:

- abnormal power system dispatches resulting in fault levels in NQ below minimum fault level requirements[8]
- Powerlink was in the process of addressing a system strength shortfall in NQ that was declared by AEMO in April 2020 (refer to sections 6.7.1 and 10.4.1)
- Two solar farms in NQ have a system strength remediation obligation and until these are in place these plant may be subject to constraints depending on the synchronous dispatch in Central and NQ.

Since the limit advice for the retuning of Mt Emerald was implemented in mid-November 2020 there have been approximately 315 hours of constrained operation, of which 35 hours occurred during intact system conditions. The limit advice for the retuning of Daydream, Hayman, Whitsunday and Hamilton solar farms was implemented in early June. The combination of these activities is expected to have a material impact in reducing constrained operation due to NQ system strength during intact system conditions.

[8] AEMO, Notice of Queensland System Strength Requirements and Ross Fault Level Shortfall, July 2018.

Figure 8.14 Historical NQ system strength constraint times



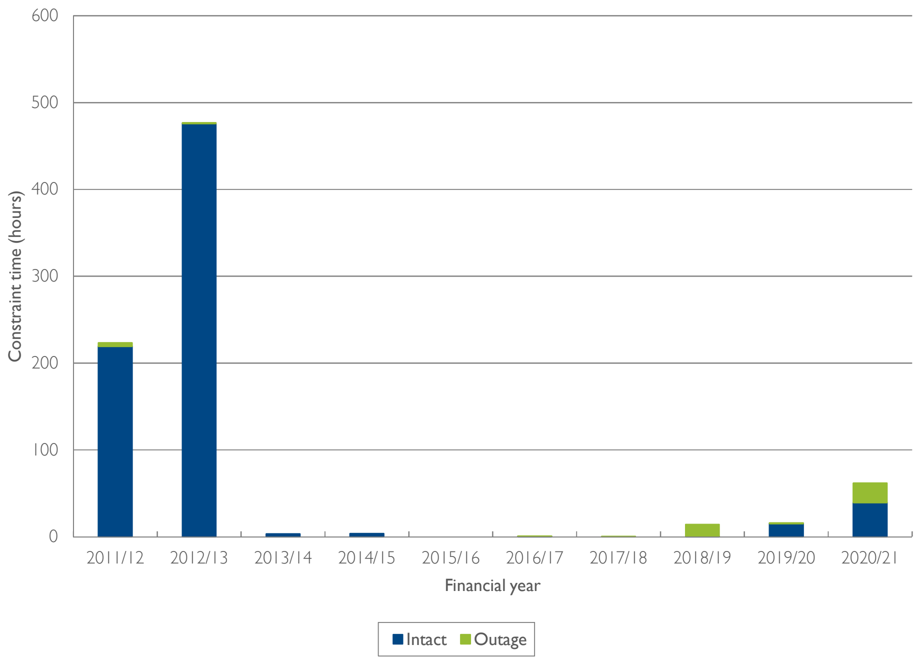
8.6.4 Gladstone grid section

Maximum power transfer across the Gladstone grid section is set by the thermal rating of the Bouldercombe to Raglan, Larcom Creek to Calliope River, Calvale to Wurdong or the Calliope River to Wurdong 275kV circuits.

If the rating would otherwise be exceeded following a critical contingency, generation is constrained to reduce power transfers. Powerlink makes use of dynamic line ratings and rates the relevant circuits to take account of real time prevailing ambient weather conditions to maximise the available capacity of this grid section and, as a result, reduce market impacts. The appropriate ratings are updated in National Electricity Market Dispatch Engine (NEMDE).

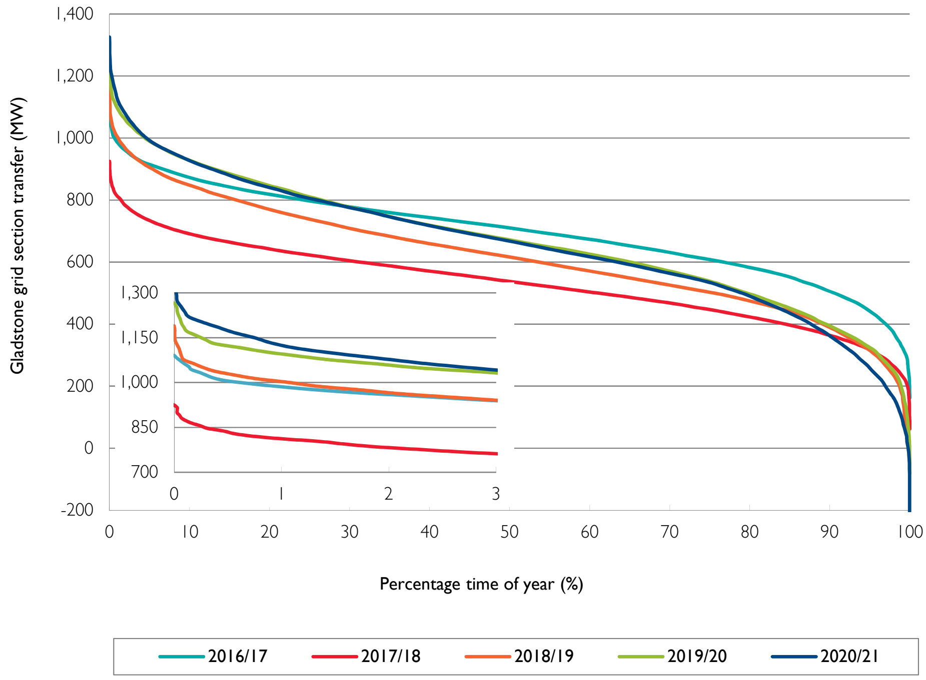
Information pertaining to the historical duration of constrained operation for the Gladstone grid section is summarised in Figure 8.15. During 2020/21, the Gladstone grid section experienced 62 hours of constrained operation, 40 hours during intact system conditions due to low Gladstone Power Station generation.

Figure 8.15 Historical Gladstone grid section constraint times



Power flows across this grid section are highly dependent on the dispatch of generation in CQ and transfers to southern Queensland. Figure 8.16 provides historical transfer duration curves showing increased utilisation in 2020/21 compared to 2019/20. Reduced capacity factor from Gladstone Power Station is predominantly responsible for the increase in transfer through this grid section (refer to figures 8.6, 8.7 and 8.8).

Figure 8.16 Historical Gladstone grid section transfer duration curves



The utilisation of the Gladstone grid section is expected to continue to increase if the recently committed generators displace Gladstone zone generation.

8.6.5 CQ-SQ grid section

Maximum power transfer across the CQ-SQ grid section is set by transient or voltage stability following a Calvale to Halys 275kV circuit contingency.

The voltage stability limit is set by insufficient reactive power reserves in the Central West and Gladstone zones following a contingency. More generating units online in these zones increase reactive power support and therefore transfer capability.

The limit equation in Table D.4 of Appendix D shows that the following variables have significant effect on transfer capability:

- number of generating units online in the Central West and Gladstone zones
- level of Gladstone Power Station generation.

Information pertaining to the historical duration of constrained operation for the CQ-SQ grid section is summarised in Figure 8.17. During 2020/21, the CQ-SQ grid section experienced 54 hours of constrained operation. Constrained operation was mainly associated with planned maintenance outages, with only 5 hours constrained during system normal operation.

Figure 8.17 Historical CQ-SQ grid section constraint times

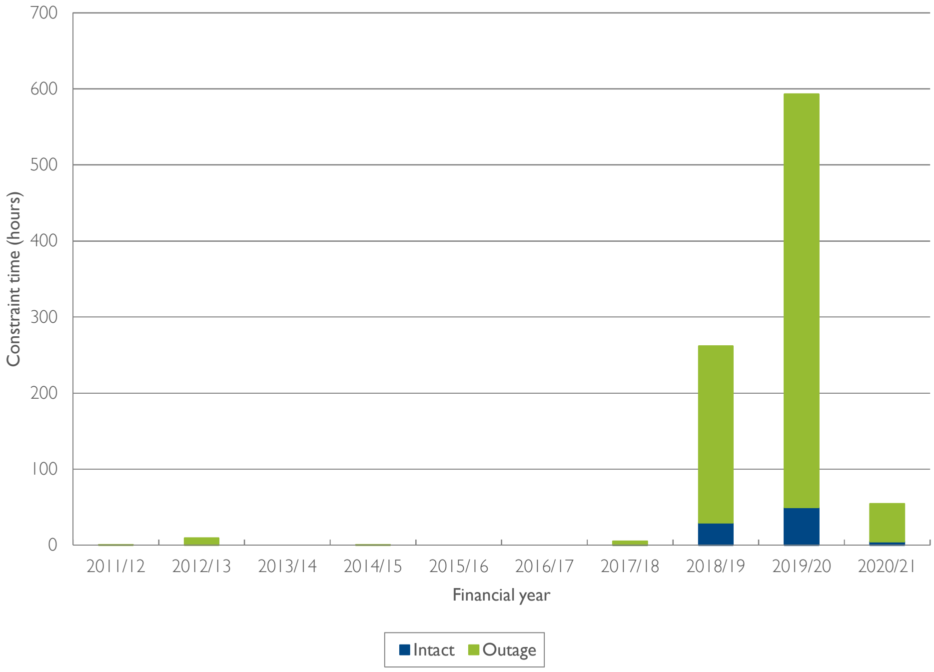
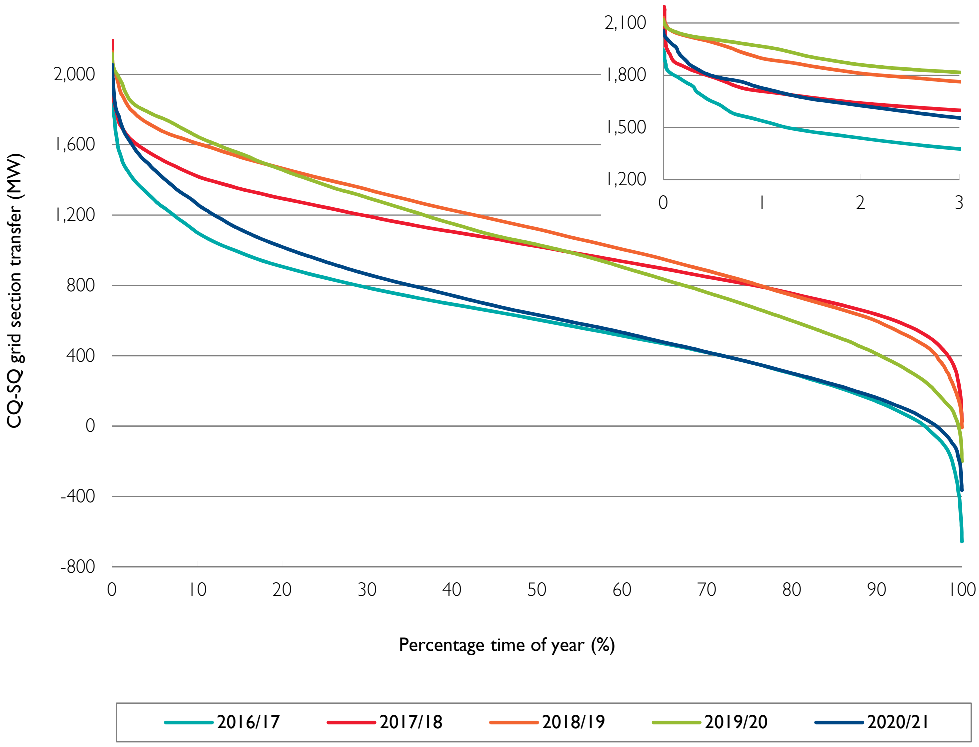


Figure 8.18 provides historical transfer duration curves showing continued increase in utilisation since 2015, then reducing over 2020/21. This increase in transfer has been predominantly due to a significant reduction in generation from the gas fuelled generators in the Bulli zone and higher interconnector transfers sourced predominantly by generation in central and north Queensland. Over 2020/21 output from the large thermal generators in central Queensland markedly reduced (refer to figures 8.6, 8.7 and 8.8). The utilisation of the CQ-SQ grid section is highly dependent on the operation of central Queensland thermal generation.

Figure 8.18 Historical CQ-SQ grid section transfer duration curves



The eastern single circuit transmission lines of CQ-SQ traverse a variety of environmental conditions that have different rates of corrosion resulting in varied risk levels across the transmission lines. Depending on transmission line location, it is expected that sections of lines will be at end of technical service life from the next five to 10 years. This is discussed in Section 8.7.6.

8.6.6 Surat grid section

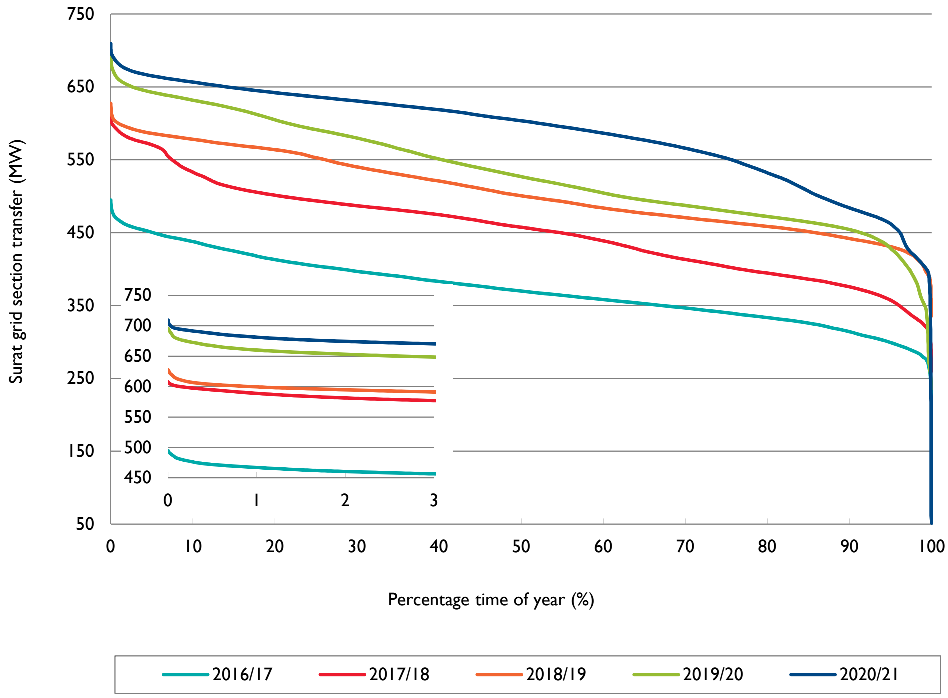
The Surat grid section was introduced in the 2014 TAPR in preparation for the establishment of the Western Downs to Columboola 275kV transmission line, Columboola to Wandoan South 275kV transmission line and Wandoan South and Columboola 275kV substations. These network developments were completed in September 2014 and significantly increased the supply capacity to the Surat Basin north west area.

The maximum power transfer across the Surat grid section is set by voltage stability associated with insufficient reactive power reserves in the Surat zone following an outage of a Western Downs to Orana 275kV circuit[9]. More generating units online in the zone increases reactive power support and therefore transfer capability. Local generation reduces transfer capability but allows more demand to be securely supported in the Surat zone. There have been no constraints recorded over the brief history of the Surat grid section.

Figure 8.19 provides the transfer duration curve since the zone's creation. Grid section transfers depict the ramping of coal seam gas (CSG) load. The zone has transformed from a net exporter to a significant net importer of energy. Energy transfers are expected to reduce with the commitment of Bluegrass, Columboola, Gangarri and Edenvale solar farms and Dulacca Wind Farm.

[9] The Orana Substation is connected to one of the Western Downs to Columboola 275kV transmission lines (refer to Figure 8.4).

Figure 8.19 Historical Surat grid section transfer duration curve



Network augmentations are not planned to occur as a result of network limitations across this grid section within the five-year outlook period.

The development of large loads in Surat (additional to those included in the forecasts), without corresponding increases in generation, can significantly increase the levels of Surat grid section transfers. This is discussed in Section 9.2.5.

8.6.7 South West Queensland (SWQ) grid section

The SWQ grid section defines the capability of the transmission network to transfer power from generating stations located in the Bulli zone and northerly flow on QNI to the rest of Queensland. Maximum power transfer across the SWQ grid section is set by the thermal rating of the Middle Ridge 330/275kV transformer.

The SWQ grid section did not constrain operation during 2020/21. Information pertaining to the historical duration of constrained operation for the SWQ grid section is summarised in Figure 8.20.

Figure 8.20 Historical SWQ grid section constraint times

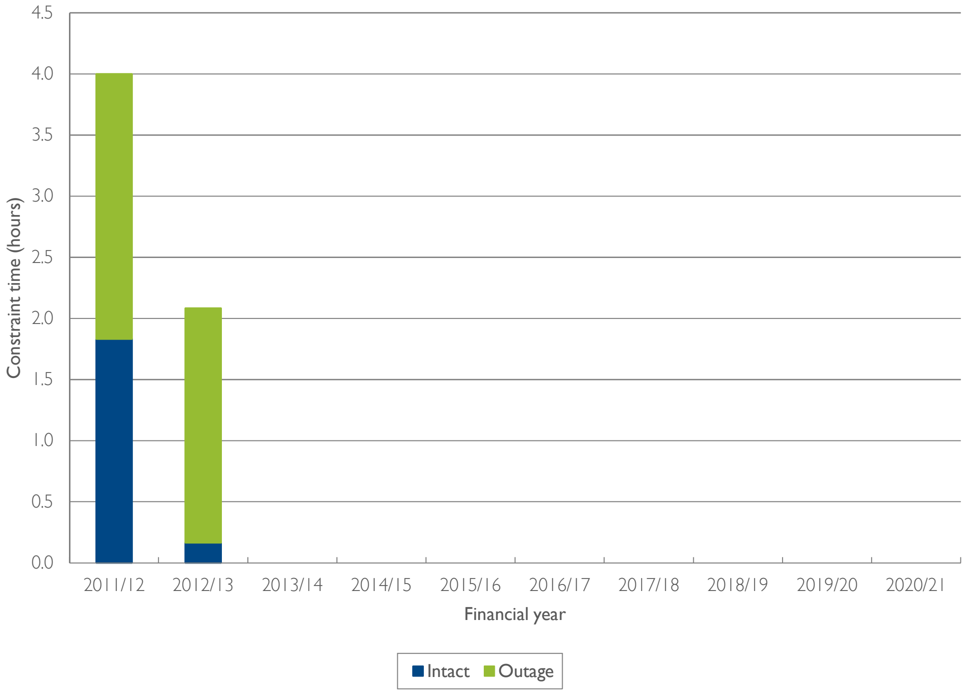
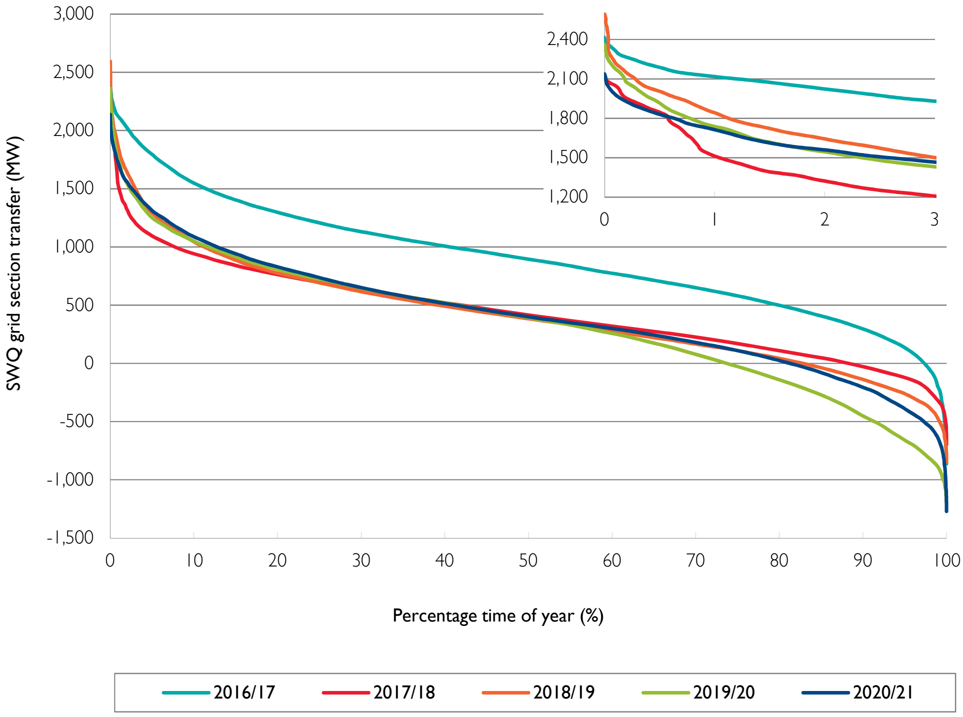


Figure 8.21 provides historical transfer duration curves showing reductions in energy transfer since 2016/17. Reductions in South West, Wide Bay, Moreton and Gold Coast delivered demands and increases in transmission connected generation in the South West zone (refer to figures 8.6, 8.7 and 8.8) are predominantly responsible for the reduction in SWQ utilisation.

Figure 8.21 Historical SWQ grid section transfer duration curves



Network augmentations are not planned to occur as a result of network limitations across this grid section within the five-year outlook period.

8.6.8 Tarong grid section

Maximum power transfer across the Tarong grid section is set by voltage stability associated with the loss of a Calvale to Halys 275kV circuit. The limitation arises from insufficient reactive power reserves in southern Queensland.

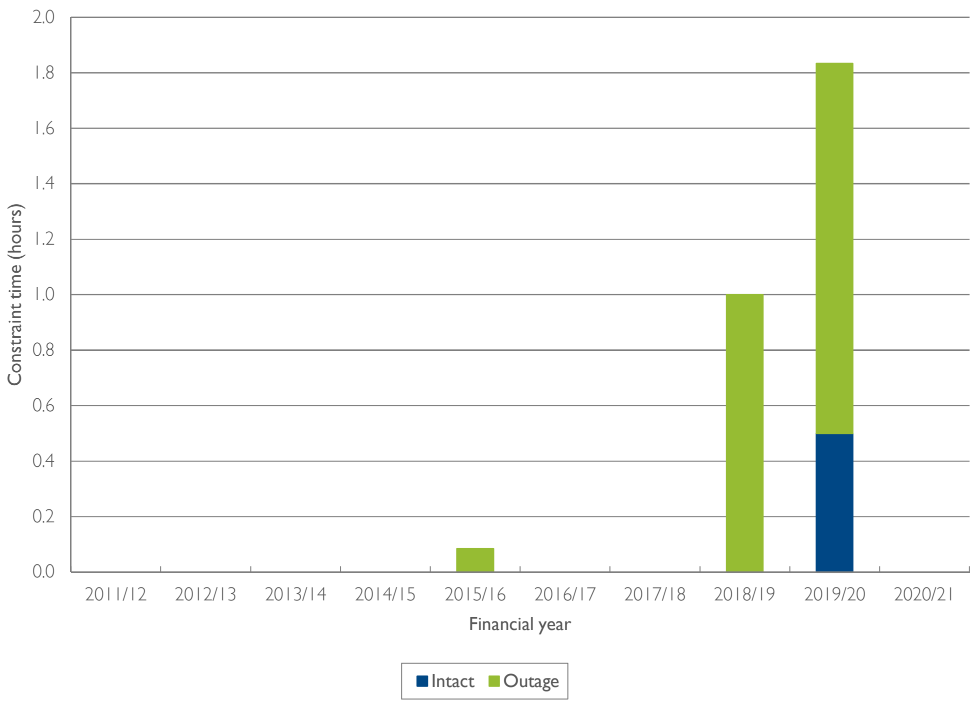
Limit equations in Table D.5 of Appendix D show that the following variables have a significant effect on transfer capability:

- QNI transfer and South West and Bulli zones generation
- level of Moreton zone generation
- Moreton and Gold Coast zones capacitive compensation levels.

Any increase in generation west of this grid section, with a corresponding reduction in generation north of the grid section, reduces the CQ-SQ power flow and increases the Tarong limit. Increasing generation east of the grid section reduces the transfer capability, but increases the overall amount of supportable South East Queensland (SEQ) demand. This is because reactive margins increase with additional local generation, allowing further load to be delivered before reaching minimum allowable reactive margins. However, due to its distributed and reactive nature, increases in delivered demand erode reactive margins at greater rates than they were created by the additional local generation. Limiting power transfers are thereby lower with the increased local generation but a greater load can be delivered.

The Tarong grid section did not constrain operation during 2020/21. Information pertaining to the historical duration of constrained operation for the Tarong grid section is summarised in Figure 8.22.

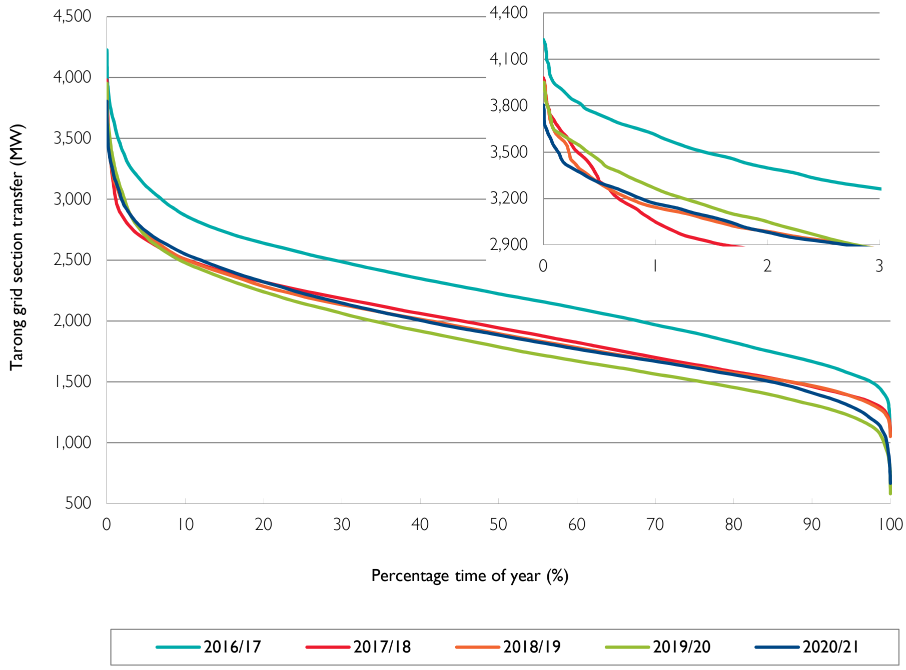
Figure 8.22 Historical Tarong grid section constraint times



Constraint times have been minimal over the last 10 years.

Figure 8.23 provides historical transfer duration curves showing small annual differences in grid section transfer demands. The reduction in transfer between 2016/17 and 2017/18 is predominantly attributed to the return to service of Swanbank E from its mothballed state. The 2020/21 trace reflects slight increase over 2019/20 energy transfers into SEQ as a result of lower CQSQ transfers (refer to figures 8.6, 8.7 and 8.8).

Figure 8.23 Historical Tarong grid section transfer duration curves



Network augmentations are not planned to occur as a result of network limitations across this grid section within the five year outlook period.

8.6.9 Gold Coast grid section

Maximum power transfer across the Gold Coast grid section is set by voltage stability associated with the loss of a Greenbank to Molendinar 275kV circuit, or Greenbank to Mudgeeraba 275kV circuit.

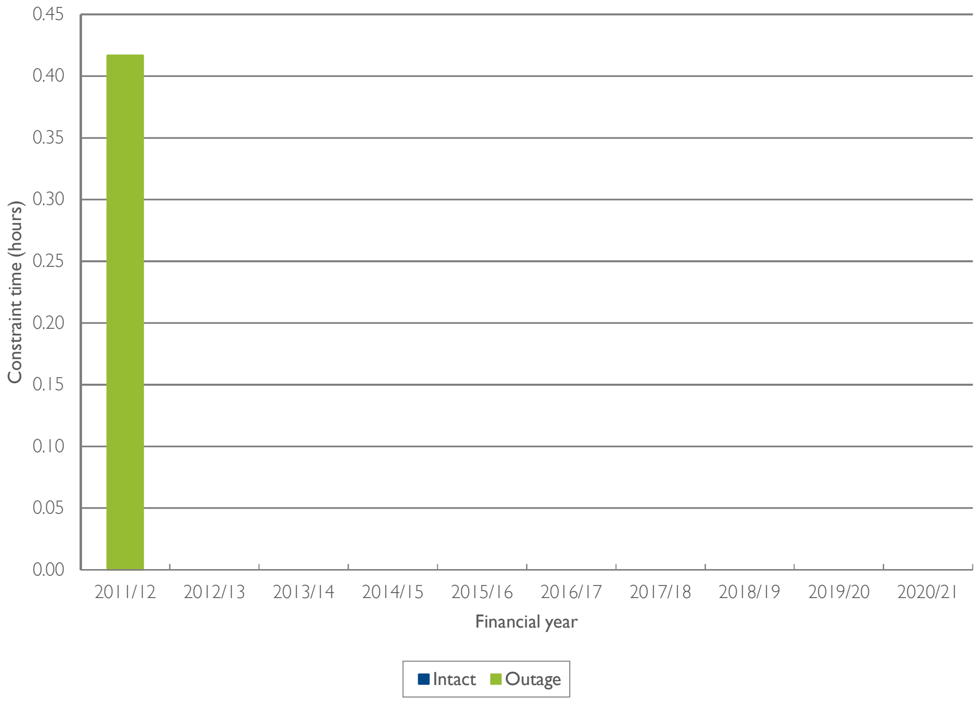
The limit equation in Table D.6 of Appendix D shows that the following variables have a significant effect on transfer capability:

- number of generating units online in Moreton zone
- level of Terranora Interconnector transmission line transfer
- Moreton and Gold Coast zones capacitive compensation levels
- Moreton zone to the Gold Coast zone demand ratio.

Reducing southerly flow on Terranora Interconnector reduces transfer capability, but increases the overall amount of supportable Gold Coast demand. This is because reactive margins increase with reductions in southerly Terranora Interconnector flow, allowing further load to be delivered before reaching minimum allowable reactive margins. However, due to its distributed and reactive nature, increases in delivered demand erode reactive margins at greater rates than they were created by the reduction in Terranora Interconnector southerly transfer. Limiting power transfers are thereby lower with reduced Terranora Interconnector southerly transfer but a greater load can be delivered.

The Gold Coast grid section did not constrain operation during 2020/21. Information pertaining to the historical duration of constrained operation for the Gold Coast grid section is summarised in Figure 8.24.

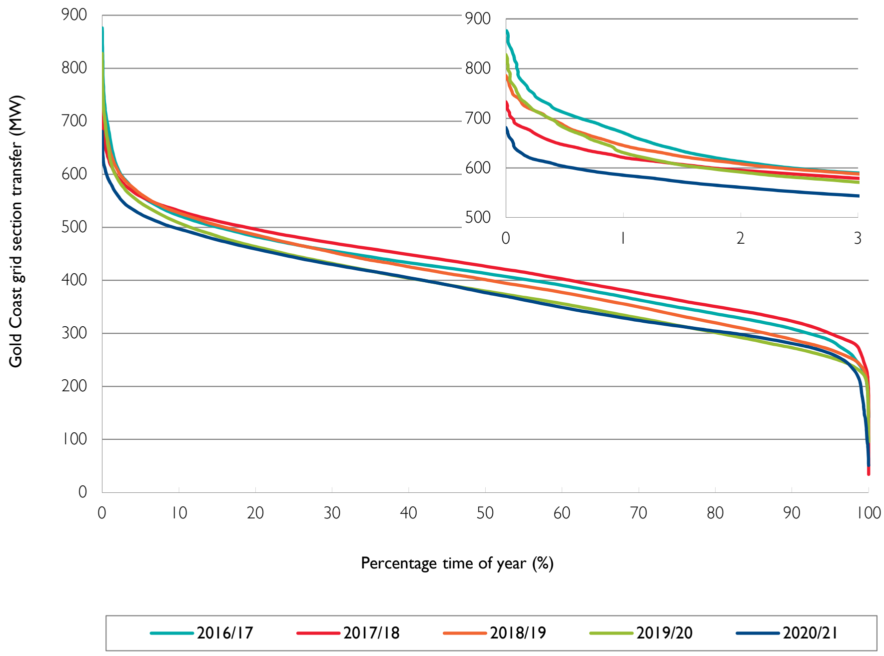
Figure 8.24 Historical Gold Coast grid section constraint times



Constraint times have been minimal over the last 10 years.

Figure 8.25 provides historical transfer duration curves showing changes in grid section transfer demands and energy in line with changes in transfer to northern NSW and changes in Gold Coast loads. Northern NSW transfers and Gold Coast zone demand were lower in 2020/21 compared to 2019/20 (refer to figures 8.6, 8.7 and 8.8).

Figure 8.25 Historical Gold Coast grid section transfer duration curves



Due to condition drivers, Powerlink is retiring one of the aging 275/110kV transformers at Mudgeeraba Substation by June 2022. This is listed in Table 11.7.

8.6.10 QNI and Terranora interconnector

The transfer capability across QNI is limited by voltage stability, transient stability, oscillatory stability, and line thermal rating considerations. The capability across QNI at any particular time is dependent on a number of factors, including demand levels, generation dispatch, status and availability of transmission equipment, and operating conditions of the network.

AEMO publish Monthly Constraint Reports which includes a section examining each of the NEM interconnectors, including QNI and Terranora Interconnector. Information pertaining to the historical duration of constrained operation for QNI and Terranora Interconnector is contained in these Monthly Constraint Reports. The Monthly Constraint Report can be found on AEMO's website.

For intact system operation, the southerly transfer capability of QNI is most likely to be set by the following:

- voltage stability associated with a fault on the Sapphire to Armidale 330kV transmission line in NSW
- transient stability associated with transmission faults near the Queensland border
- transient stability associated with the trip of a smelter potline load in Queensland
- transient stability associated with transmission faults in the Hunter Valley in NSW
- transient stability associated with a fault on the Hazelwood to South Morang 500kV transmission line in Victoria
- thermal capacity of the 330kV transmission network between Armidale and Liddell in NSW
- oscillatory stability upper limit of 1,200MW.

For intact system operation, the combined northerly transfer capability of QNI and Terranora Interconnector is most likely to be set by the following:

- transient and voltage stability associated with transmission line faults in NSW
- transient stability and voltage stability associated with loss of the largest generating unit in Queensland
- thermal capacity of the 330kV and 132kV transmission network within northern NSW
- oscillatory stability upper limit of 700MW.

In December 2019, Powerlink and TransGrid finalised a Project Assessment Conclusion Report (PACR) on 'Expanding NSW-Queensland transmission transfer capacity', identifying the preferred option which includes uprating the 330kV Liddell to Tamworth 330kV lines, and installing Static VAr Compensators (SVC) at Tamworth and Dumaresq substations and static capacitor banks at Tamworth, Armidale and Dumaresq substations. The project is expected to be completed by mid 2022.

AEMO's Integrated System Plan (ISP) continues to investigate opportunities for expansion of interconnector capacity. In the 2020 ISP AEMO identified QNI Medium and Large projects as future ISP projects, requiring Powerlink and TransGrid to undertake preparatory activities (refer to Section 9.3.1). As requested, Powerlink and TransGrid submitted preparatory activities to AEMO by 30 June 2021[10].

8.7 Zone performance

This section presents, where applicable, a summary of:

- the capability of the transmission network to deliver loads
- historical zonal transmission delivered loads
- intra-zonal system normal constraints
- double circuit transmission lines categorised as vulnerable by AEMO[11]
- Powerlink's management of high voltages associated with light load conditions.

Double circuit transmission lines that experience a lightning trip of all phases of both circuits (where its magnitude or degree is not considered an Exceptional Event[12]) are categorised by AEMO as vulnerable. A double circuit transmission line in the vulnerable list is eligible to be reclassified as a credible contingency event during a lightning storm if a cloud to ground lightning strike is detected close to the line. A double circuit transmission line will remain on the vulnerable list until it is demonstrated that the asset characteristics have been improved to make the likelihood of a double circuit lightning trip no longer reasonably likely to occur or until the Lightning Trip Time Window (LTTW) expires from the last double circuit lightning trip. The LTTW is three years for a single double circuit trip event or five years where multiple double circuit trip events have occurred during the LTTW.

Zonal transmission delivered energy, in general, has declined in 2020/21, compared to 2019/20 (refer to Figure 8.8), significant increases in embedded VRE generation and Queensland region's installed rooftop PV reaching approximately 4,074MW by 30 June 2021[13]. Figure 3.12 provides annual transmission delivered demand load duration curves for the Queensland region.

8.7.1 Far North zone

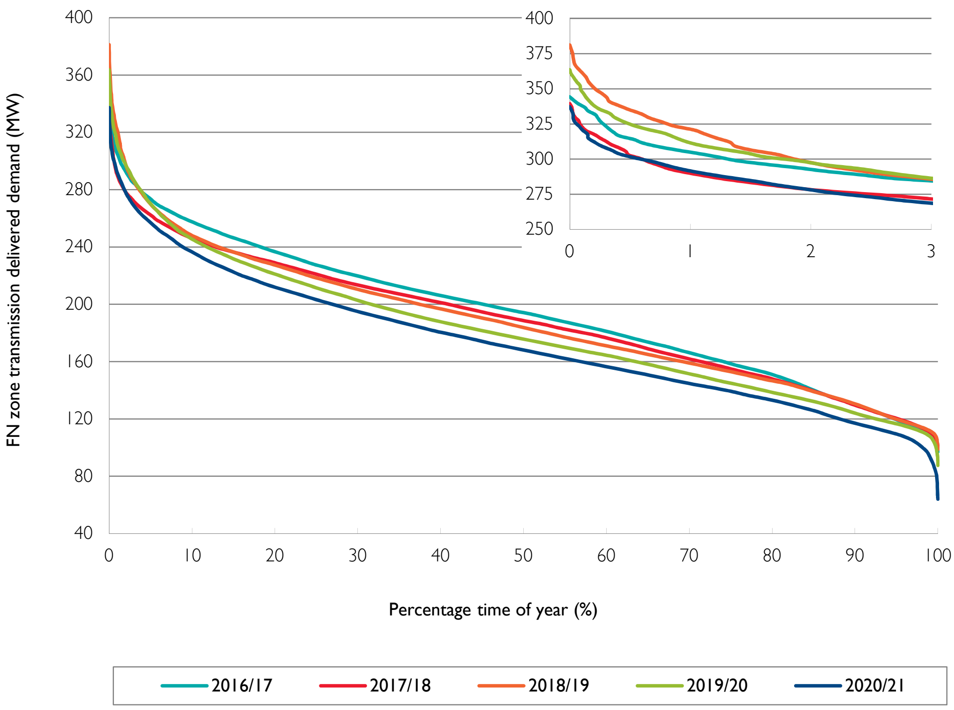
The Far North zone experienced no load loss for a single network element outage during 2020/21.

The Far North zone includes the non-scheduled embedded generator Lakeland Solar and Storage as defined in Figure 3.5. This embedded generator provided approximately 20GWh during 2020/21.

[10] Powerlink, Powerlink Preparatory Activities QNI Medium and Large, June 2021.
[11] AEMO, SO_OP_3715 – Power System Security Guidelines, April 2021.
[12] An Exception Event is defined in AEMO's Power System Security Guidelines (SO_OP_3715) as a simultaneous trip of a double circuit transmission line during a lightning storm caused by an event that is far beyond what is usual in magnitude or degree for what could be reasonably expected to occur during a lightning storm.
[13] Clean Energy Regulator, Postcode data for small-scale installations – all data, data as at 31/08/2021, September 2021.

Figure 8.26 provides historical transmission delivered load duration curves for the Far North zone. Energy delivered from the transmission network continues to reduce at 4.8% between 2019/20 and 2020/21, to the lowest level in the last decade. The maximum transmission delivered demand in the zone was 337MW, which is below the highest maximum demand over the last five years of 381MW set in 2018/19. The minimum transmission delivered demand in the zone was 64MW, which is the lowest minimum demand over the last five years.

Figure 8.26 Historical Far North zone transmission delivered load duration curves



High voltages associated with light load conditions continue to become increasingly challenging for longer durations. Energy Queensland will, over time, lower off-load tap settings on many distribution transformers. This requires localised network outages, and in many instances will be set to the last remaining tap setting.

AEMO has, this year, removed Chalumbin to Turkinje 132kV transmission line from the vulnerable list. There are currently no double circuits in the Far North zone in AEMO's lightning vulnerable transmission line list.

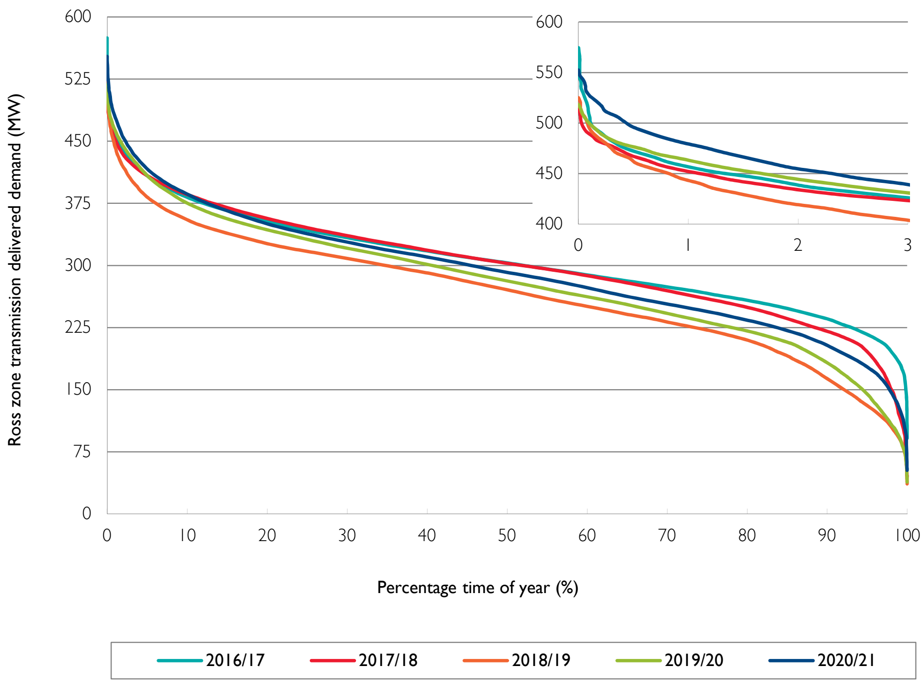
8.7.2 Ross zone

The Ross zone experienced no load loss for a single network element outage during 2020/21.

The Ross zone includes the scheduled embedded Townsville Power Station 66kV component (steam turbine component of the CCGT), semi-scheduled distribution connected embedded Kidston Solar Farm, Kennedy Energy Park and direct connected embedded Sun Metals Solar Farm, and the significant non-scheduled embedded generators Hughenden Solar Farm and Pioneer Mill as defined in Figure 3.5. These embedded generators provided approximately 335GWh during 2020/21.

Figure 8.27 provides historical transmission delivered load duration curves for the Ross zone. Energy delivered from the transmission network has increased by 4.2% between 2019/20 and 2020/21. The increase in energy delivered is predominantly due to the reduction in energy from embedded generation. The peak transmission delivered demand in the zone was 552MW which is below the highest maximum demand over the last five years of 574MW set in 2016/17. The minimum transmission delivered demand in the zone was 59MW, which is above the lowest demand over the last five years of 36MW set in 2018/19.

Figure 8.27 Historical Ross zone transmission delivered load duration curves



High voltages associated with light load conditions are managed with existing reactive sources.

As a result of double circuit outages associated with lightning strikes, AEMO includes the Ross to Chalumbin 275kV double circuit transmission line in the vulnerable list. This double circuit tripped due to lightning in January 2020.

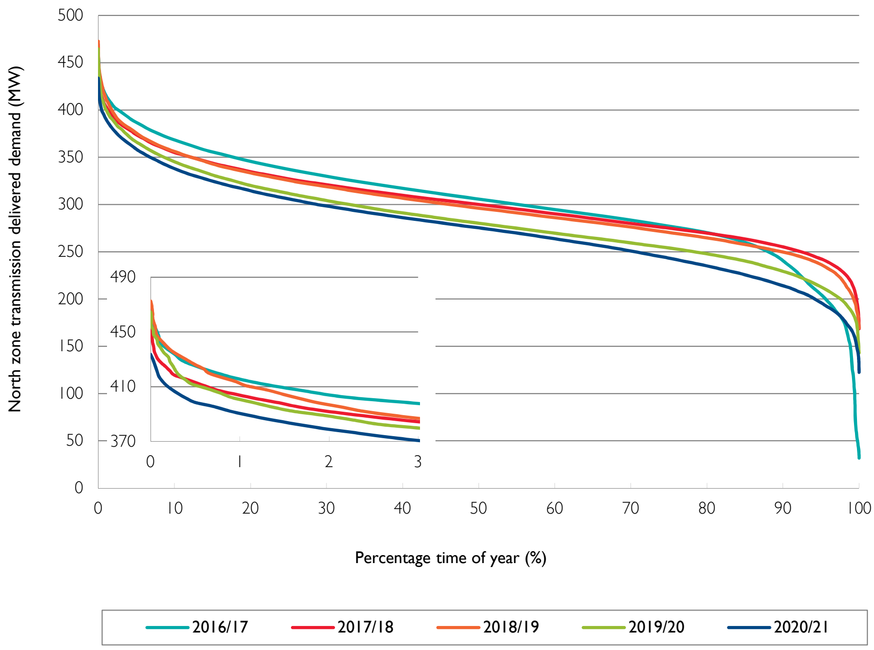
8.7.3 North zone

The North zone experienced no load loss for a single network element outage during 2020/21.

The North zone includes the scheduled embedded Mackay generator, semi-scheduled embedded generator Collinsville Solar Farm and significant non-scheduled embedded generators Moranbah North, Moranbah and Racecourse Mill as defined in Figure 3.5. These embedded generators provided approximately 569GWh during 2020/21.

Figure 8.28 provides historical transmission delivered load duration curves for the North zone. Energy delivered from the transmission network has reduced by 3.3% between 2019/20 and 2020/21, to the lowest level in the last decade. The peak transmission delivered demand in the zone was 434MW, which is below the highest maximum demand over the last five years of 473MW set in 2018/19. The minimum transmission delivered demand in the zone was 122MW, which is the lowest minimum demand in the last five years when excluding the minimum of 32MW set in 2016/17 as a result of lost load following Ex-Tropical Cyclone Debbie.

Figure 8.28 Historical North zone transmission delivered load duration curves



High voltages associated with light load conditions are currently managed with existing reactive sources. However, midday power transfer levels continue to reduce as capacity is released from commissioning activities of VRE generators and additional rooftop PV is installed in NQ. As a result, voltage control is forecast to become increasingly challenging for longer durations. This is discussed in Section 8.6.2.

As a result of double circuit outages associated with lightning strikes, AEMO includes the following double circuits in the North zone in the vulnerable list:

- Strathmore to Clare South and Collinsville North to King Creek to Clare South 132kV double circuit transmission line, last tripped January 2019
- Collinsville North to Proserpine 132kV double circuit transmission line, last tripped February 2018.

The following double circuits have, this year, been removed from the vulnerable list:

- Collinsville North to Stony Creek and Collinsville North to Newlands 132kV double circuit transmission line, last tripped February 2016
- Goonyella to North Goonyella and Goonyella to Newlands 132kV double circuit transmission line, last tripped February 2018.

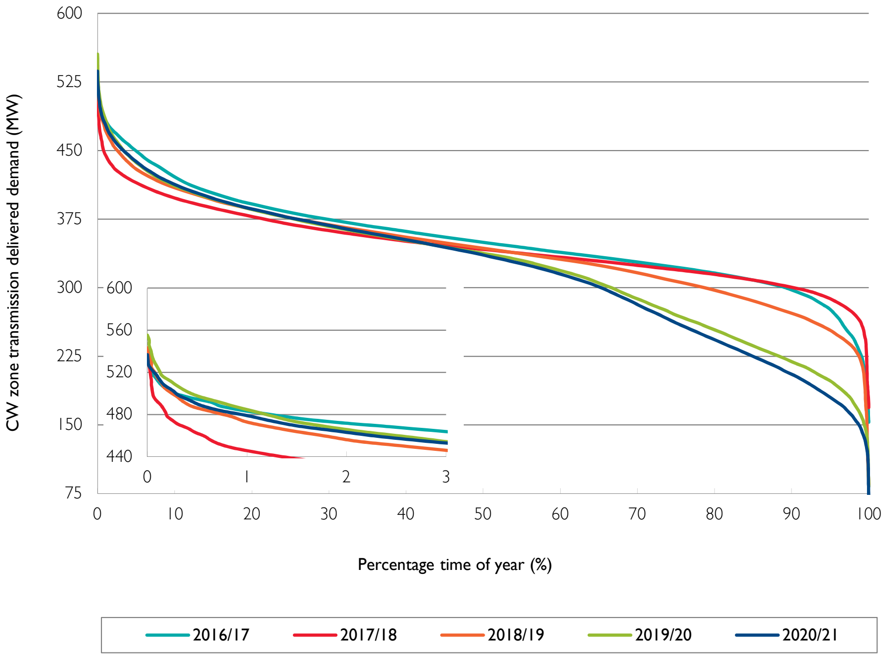
8.7.4 Central West zone

The Central West zone experienced no load loss for a single network element outage during 2020/21.

The Central West zone includes the scheduled embedded Barcaldine generator, semi-scheduled embedded generators Clermont Solar Farm, Emerald Solar Farm and Middlemount Solar Farm and significant non-scheduled embedded generators Barcaldine Solar Farm, Longreach Solar Farm, German Creek and Oaky Creek as defined in Figure 3.5. These embedded generators provided approximately 739GWh during 2020/21.

Figure 8.29 provides historical transmission delivered load duration curves for the Central West zone. Energy delivered from the transmission network has reduced by 1.6% between 2019/20 and 2020/21, to the lowest level in the last decade. The peak transmission delivered demand in the zone was 537MW, which is below the highest maximum demand over the last five years of 555MW set in 2019/20. The minimum transmission delivered demand in the zone was 366MW, which is the lowest minimum demand over the last five years.

Figure 8.29 Historical Central West zone transmission delivered load duration curves



EDL has advised AEMO of its intention to retire Oaky Creek non-scheduled embedded generators in 2025.

There are currently no double circuits in the Central West zone in AEMO's lightning vulnerable transmission line list.

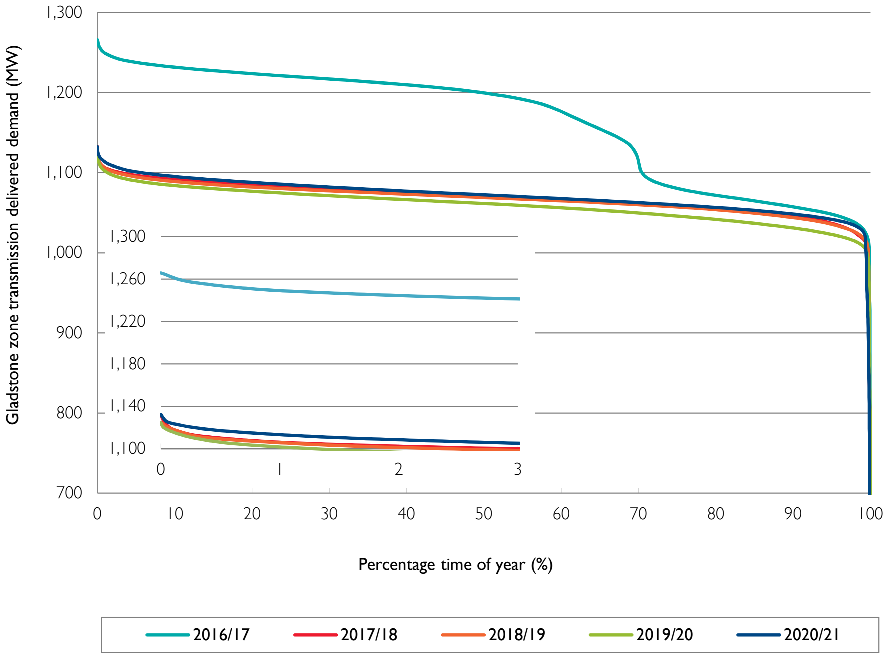
8.7.5 Gladstone zone

The Gladstone zone experienced no load loss for a single network element outage during 2020/21.

The Gladstone zone contains no scheduled, semi-scheduled or significant non-scheduled embedded generators as defined in Figure 3.5.

Figure 8.30 provides historical transmission delivered load duration curves for the Gladstone zone. The figure clearly shows a reduction in demand between 2015/16 and 2016/17 due to changed operation by Boyne Smelters Limited (BSL). Energy delivered from the transmission network has increased by 0.9% between 2019/20 and 2020/21. The peak transmission delivered demand in the zone was 1,132MW, which is below the highest maximum demand over the last five years of 1,266MW set in 2016/17. Minimum demand coincides with small periods when one or more smelter potlines are out of service. The minimum transmission delivered demand in the zone was 366MW, which is the lowest minimum demand over the last five years.

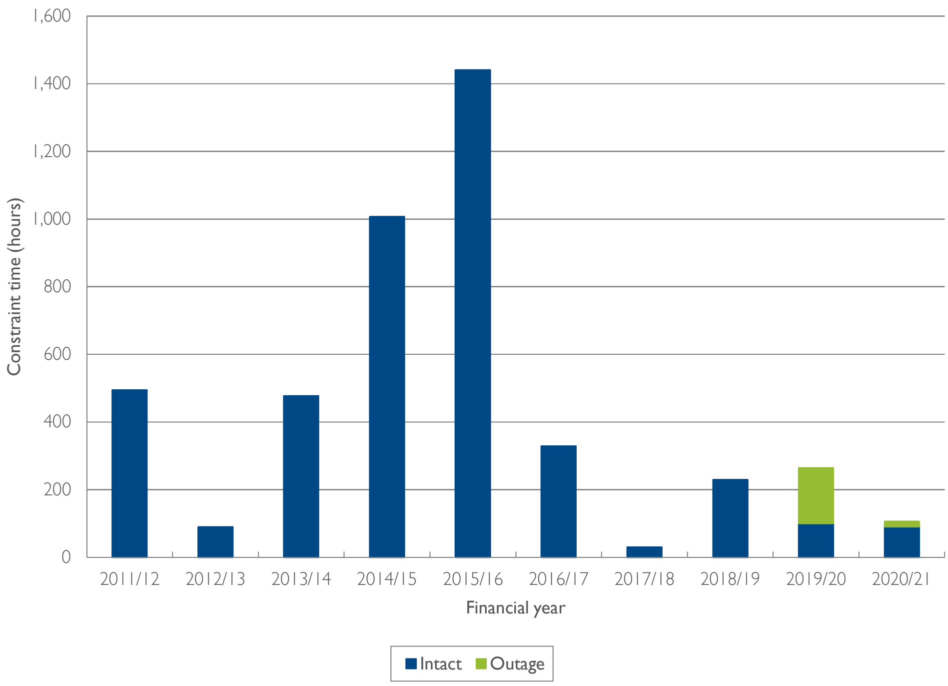
Figure 8.30 Historical Gladstone zone transmission delivered load duration curves



Constraints occur within the Gladstone zone under intact network conditions. These constraints are associated with maintaining power flows within the continuous current rating of a 132kV feeder bushing within BSL's substation. The constraint limits generation from Gladstone Power Station, mainly from the units connected at 132kV. AEMO identifies the system normal constraint by constraint identifier Q>NIL_BI_FB. This constraint was implemented in AEMO's market system from September 2011.

Information pertaining to the historical duration of constrained operation due to this constraint is summarised in Figure 8.31. During 2020/21, the feeder bushing constraint experienced 106 hours of constrained operation, 15 hours during planned outage of 275kV feeders between Calliope River and Woolooga.

Figure 8.31 Historical Boyne Island feeder bushing constraint times



There are currently no double circuits in the Gladstone zone in AEMO's lightning vulnerable transmission line list.

8.7.6 Wide Bay zone

The Wide Bay zone experienced no load loss for a single network element outage during 2020/21.

The Wide Bay zone includes the semi-scheduled embedded generators Childers Solar Farm and Susan River Solar Farm, and significant non-scheduled embedded generator Isis Central Sugar Mill as defined in Figure 3.5. These embedded generators provided approximately 264GWh during 2020/21.

Figure 8.32 provides historical transmission delivered load duration curves for the Wide Bay zone. Wide Bay zone is one of two zones in Queensland where the delivered demand reaches negative values, meaning that the embedded generation exceeds the native load, the transmission network supplying the zone is often operated at zero and near zero loading, and the embedded generation makes use of the transmission network to feed loads in other zones. Figure 8.33 provides the daily load profile for the minimum transmission delivered days over the last five years.

Whilst energy has seen significant reductions, the peak demand, which occurs at night, remains at similar levels. Energy delivered from the transmission network reduced by 5.9% between 2019/20 and 2020/21, to the lowest level in the last decade. The peak transmission delivered demand in the zone was 316MW, which is the highest maximum demand. The minimum transmission delivered demand in the zone was -88MW, which is the lowest demand on record.

Figure 8.32 Historical Wide Bay zone transmission delivered load duration curves

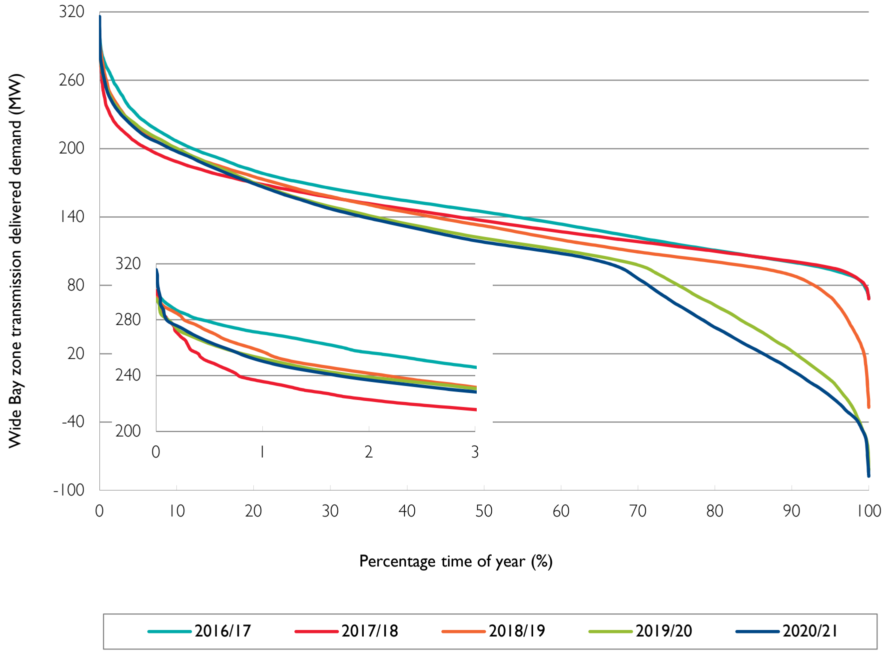
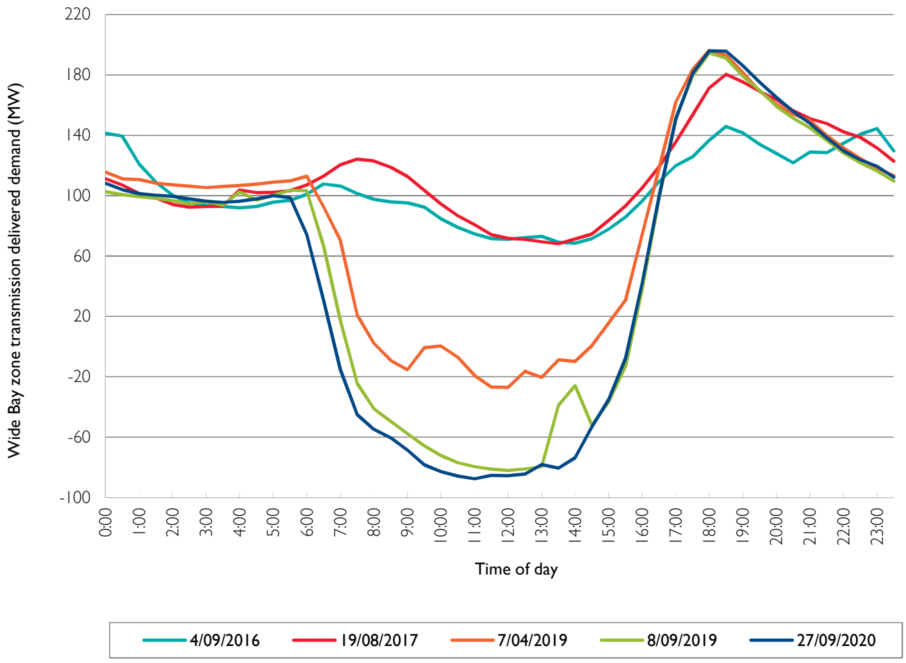


Figure 8.33 Historical Wide Bay zone minimum transmission delivered daily profile



There are currently no double circuits in the Wide Bay zone in AEMO's lightning vulnerable transmission line list.

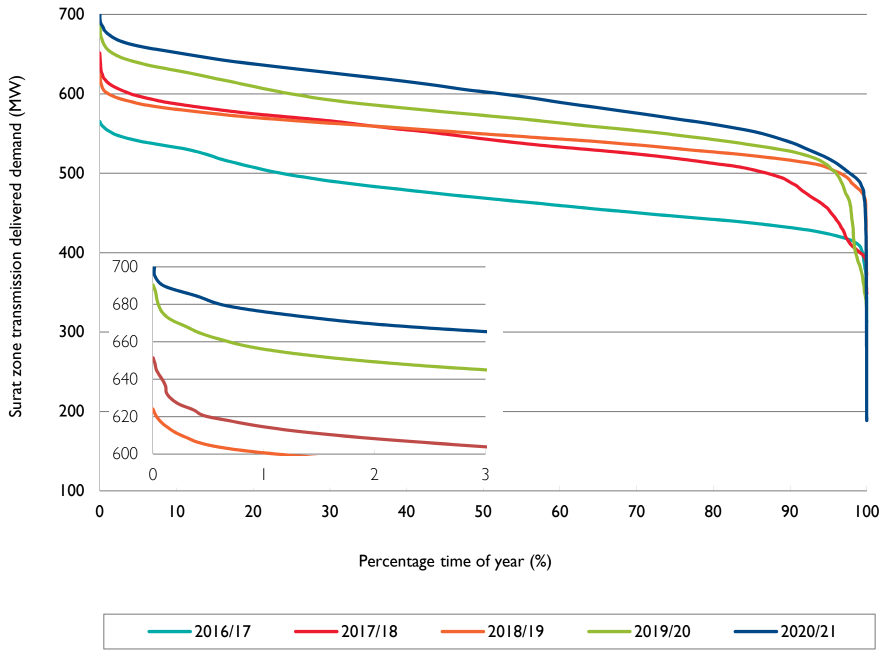
8.7.7 Surat zone

The Surat zone experienced no load loss for a single network element outage during 2020/21.

The Surat zone includes the scheduled embedded Roma and direct connected embedded Condamine generators and significant non-scheduled embedded generator Baking Board Solar Farm as defined in Figure 3.5. These embedded generators provided approximately 210GWh during 2020/21.

Figure 8.34 provides historical transmission delivered load duration curves for the Surat zone. Energy delivered from the transmission network has increased by approximately 4.3% between 2019/20 and 2020/21. The peak transmission delivered demand in the zone was 706MW, which is the highest maximum demand over the last five years. The CSG load in the zone has now reached expected demand levels. The minimum transmission delivered demand in the zone was 189MW, which is the lowest demand over the last five years as a result of load disconnection following the Callide C unit 4 incident on 25 May 2021.

Figure 8.34 Historical Surat zone transmission delivered load duration curves



As a result of double circuit outages associated with lightning strikes, AEMO includes the following double circuits in the Surat zone in the vulnerable list:

- Tarong to Chinchilla 132kV double circuit transmission line, last tripped October 2020
- Condabri North to Condabri Central 132kV double circuit transmission line, last tripped January 2020.

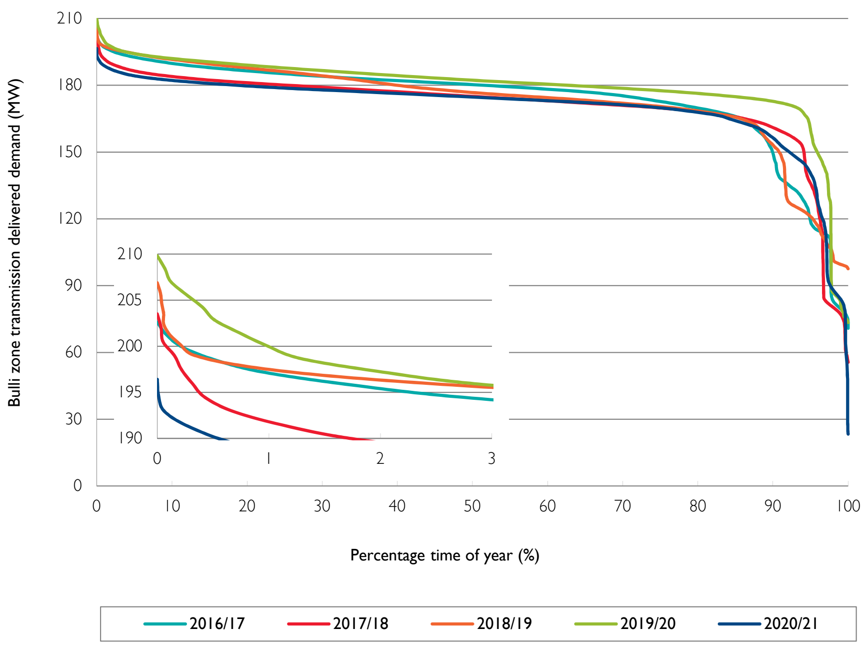
8.7.8 Bulli zone

The Bulli zone experienced no load loss for a single network element outage during 2020/21.

The Bulli zone contains no scheduled, semi-scheduled or significant non-scheduled embedded generators as defined in Figure 3.5.

Figure 8.35 provides historical transmission delivered load duration curves for the Bulli zone. Energy delivered from the transmission network has reduced by approximately 5.6% between 2019/20 and 2020/21. The peak transmission delivered demand in the zone was 196MW which is below the highest maximum demand over the last five years of 210MW set in 2019/20. The CSG load in the zone has now reached expected demand levels. The minimum transmission delivered demand in the zone was 23MW, which is the lowest demand over the last five years as a result of a load disconnection event.

Figure 8.35 Historical Bulli zone transmission delivered load duration curves



There are currently no double circuits in the Bulli zone in AEMO's lightning vulnerable transmission line list.

8.7.9 South West zone

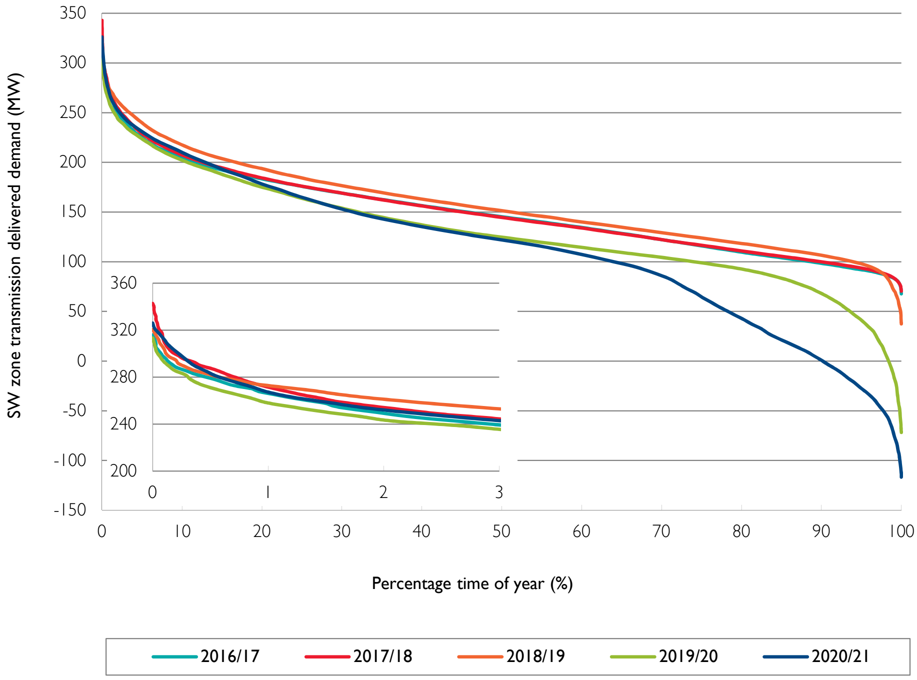
The South West zone experienced no load loss for a single network element outage during 2020/21.

The South West zone includes the semi-scheduled embedded generators Oakey 1 Solar Farm, Oakey 2 Solar Farm, Yarranlea Solar Farm, Maryrorough Solar Farm, Warwick Solar Farm and significant non-scheduled embedded generator Daandine Power Station as defined in Figure 3.5. These embedded generators provided approximately 483GWh during 2019/20.

Figure 8.36 provides historical transmission delivered load duration curves for the South West zone. The South West zone is one of two zones in Queensland where the delivered demand reaches negative values, meaning that the embedded generation exceeds the native load, the transmission network supplying the zone is often operated at zero and near zero loading, and the embedded generation makes use of the transmission network to supply loads in other zones.

Energy delivered from the transmission network has reduced by 12.9% between 2019/20 and 2020/21, to the lowest level in the last decade. The reduction in energy delivered is due to the increase in energy from embedded generation. The peak transmission delivered demand in the zone was 326MW, which is below the highest maximum demand over the past five years of 343MW set in 2017/18. The minimum transmission delivered demand in the zone was -117MW, which is the lowest demand on record.

Figure 8.36 Historical South West zone transmission delivered load duration curves



Energy Infrastructure Investments (EII) has advised AEMO of its intention to retire Daandine Power Station in June 2022.

There are currently no double circuits in the South West zone in AEMO's lightning vulnerable transmission line list.

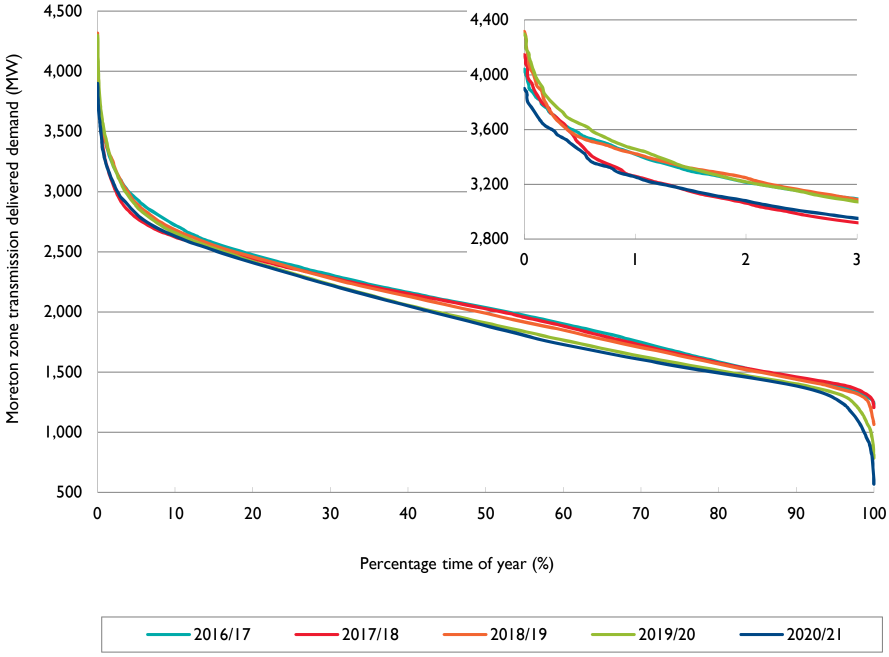
8.7.10 Moreton zone

The Moreton zone experienced no load loss for a single network element outage during 2020/21.

The Moreton zone includes the significant non-scheduled embedded generators Sunshine Coast Solar Farm, Bromelton and Rocky Point as defined in Figure 3.5. These embedded generators provided approximately 65GWh during 2020/21.

Figure 8.37 provides historical transmission delivered load duration curves for the Moreton zone. Energy delivered from the transmission network has reduced by 1.8% between 2019/20 and 2020/21, to the lowest level in the last decade. The peak transmission delivered demand in the zone was 3,899W, which is below the highest maximum demand over the past five years of 4,316MW set in 2018/19. The minimum transmission delivered demand in the zone was 570MW which is the lowest demand on record.

Figure 8.37 Historical Moreton zone transmission delivered load duration curves



High voltages associated with these light load conditions are currently managed with existing reactive sources. However, voltage control within Powerlink's and Energex's network is forecast to become increasingly challenging for longer durations. This is discussed in Section 6.7.10.

There are currently no double circuits in the Moreton zone in AEMO's lightning vulnerable transmission line list.

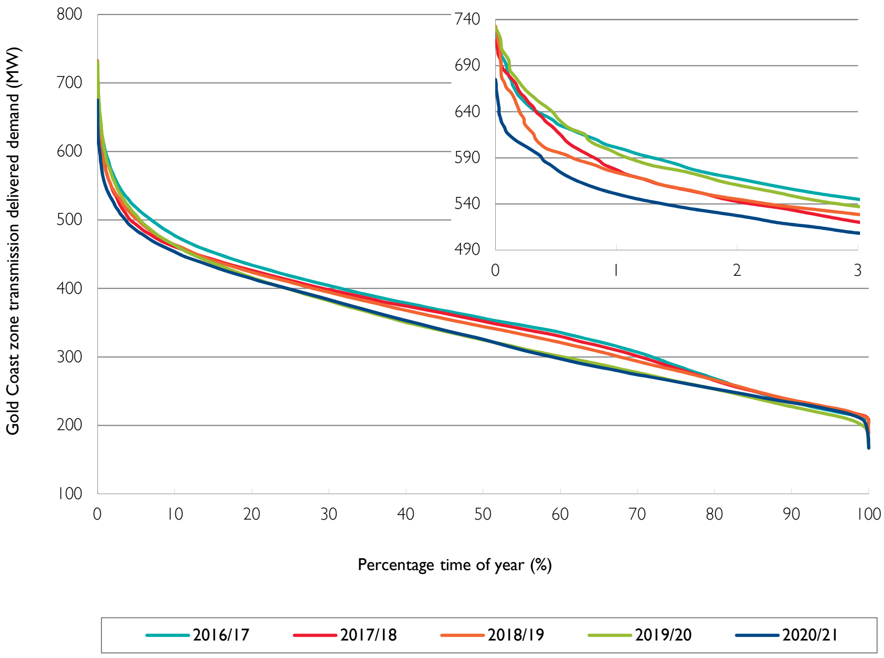
8.7.11 Gold Coast zone

The Gold Coast zone experienced no load loss for a single network element outage during 2020/21.

The Gold Coast zone contains no scheduled, semi-scheduled or significant non-scheduled embedded generators as defined in Figure 3.5.

Figure 8.38 provides historical transmission delivered load duration curves for the Gold Coast zone. Energy delivered from the transmission network has reduced by 0.9% between 2019/20 and 2020/21, to the lowest level in the last decade. The peak transmission delivered demand in the zone was 675MW, which is below the highest maximum demand over the last five years of 732MW set in 2018/19. The minimum transmission delivered demand in the zone was 167MW which equals the lowest demand on record set in 2019/2020.

Figure 8.38 Historical Gold Coast zone transmission delivered load duration curves



There are currently no double circuits in the Gold Coast zone in AEMO's lightning vulnerable transmission line list.

8 Network capability and performance

CHAPTER 9

Strategic projects

9 Strategic projects

Key highlights

- Plausible new loads within the resource rich areas of Queensland or at the associated coastal port facilities may cause network limitations to emerge within the 10-year outlook period. Possible network options are provided for Bowen Basin coal mining area, Bowen Industrial Estate, Galilee Basin coal mining area, North West Mineral province, Central Queensland to North Queensland (CQ-NQ) grid section and the Surat Basin north west area.
- The changing generation mix also has implications for investment in the transmission network, both inter-regionally and within Queensland, across critical grid sections. The 2020 Integrated System Plan (ISP) and recent Queensland Government announcements identify the development of Renewable Energy Zones (REZs) that could impact the utilisation and adequacy of the Gladstone and Central Queensland to South Queensland (CQ-SQ) grid sections and Queensland to New South Wales (NSW) Interconnector (QNI).
- Potential in Queensland for the future electrification of mining and conversion of gas loads to electric.

9.1 Introduction

Chapter 3 provides details of several proposals for large mining, metal processing and other industrial loads whose development status is not yet at the stage that they have been included (either wholly or in part) in the Australian Energy Market Operator's (AEMO) Steady Progress scenario forecast. These load developments are listed in Table 3.1. The possible impact these uncertain loads may have on the performance and adequacy of the transmission system is discussed in Section 9.2.

This chapter also provides details of AEMO's ISP. The ISP identifies the optimal development path over a planning horizon of at least 20 years for the strategic and long-term development of the national transmission system. The ISP establishes a whole of system plan that integrates generation and transmission network developments. The ISP identifies actionable and future projects, and informs market participants, investors, policy decision makers and consumers on a range of development opportunities.

The 2020 ISP did not identify any actionable projects within Queensland. However, it did identify several projects that are part of the optimal development path and may become actionable in future ISPs. Three such projects were nominated for Preparatory Activities. These include:

- QNI Medium and Large interconnector upgrades
- Central to Southern Queensland reinforcement
- Gladstone Grid reinforcement.

Preparatory activity reports for these projects were provided to AEMO on 30 June 2021 and are discussed further in Section 9.3.

9.2 Possible network options to meet reliability obligations for potential new loads

The proposals for new large mining, metal processing and other industrial loads including hydrogen, listed in Table 3.1 are within the resource rich areas of Queensland or at associated coastal port facilities. The relevant resource rich areas include the Bowen, Galilee and Surat Basins and the North West Mineral Province (Mt Isa). There is also the potential conversion of existing mining, industrial and manufacturing from gas and/or diesel to electricity. Together, these loads have the potential to significantly impact the performance of the transmission network supplying these areas, including power transfers reaching the secure limits of the transmission system.

The new load developments in the Bowen and Surat basins and associated coastal port facilities are within the existing transmission system footprint. However, the connection of new loads in the Galilee Basin and the connection of existing loads in the North West Mineral Province[1] to the interconnected National Electricity Market (NEM) will require transmission network extensions to these remote locations.

[1] CopperString 2.0 is being developed by CuString Pty Ltd, a private Townsville based company with a long history in the energy supply industry in North Queensland. Copperstring has now been granted a Transmission Authority.

The commitment of some or all of these loads may cause power transfers to exceed the capability of the network. This could be due to plant ratings, voltage stability and/or transient stability. However, all of these loads will have a positive impact on the minimum load issues discussed in Section 2.6. This is particularly the case since the load profile for these mining, metal processing and industrial loads are typically relatively flat.

Powerlink has analysed the impact of these new loads on power transfers and assessed the adequacy of the network capability to meet the required needs. Where the capability of the prescribed network is forecast to be exceeded, network developments that could be required to meet those needs have been identified. Options to address the network limitations can also include demand side management (DSM) and generation non-network solutions.

This section focuses on the most likely network development option. As the proposed loads become committed, detailed planning analyses will inform and optimise the project scopes and cost estimates. The Regulatory Investment Test for Transmission (RIT-T) will consult and finally recommend the credible option (which may include a non-network option or component) that maximises the present value of the net economic benefit to all those who produce, consume and transport electricity in the market.

The emergence and magnitude of network limitations resulting from the commitment of these loads will also depend on the location, type and capacity of new or withdrawn generation. For the purpose of this assessment the existing and committed generation in tables 8.1 and 8.2 has been taken into account when discussing the possible network limitations. However, where current interest in connecting further variable renewable energy (VRE) generation has occurred, that has the potential to materially impact the magnitude of the emerging limitation, this is also discussed in the following sections. Powerlink will consider these potential limitations holistically with any emerging condition based drivers as part of the longer term planning process and in conjunction with the ISP.

Details of feasible network options are provided in sections 9.2.1 to 9.2.5, for the transmission grid sections potentially impacted by the possible new large loads in Table 3.1.

9.2.1 Bowen Basin coal mining area

Based on AEMO's Steady Progress scenario forecast defined in Chapter 3, the committed network described in Chapter 11, and the committed generation listed in tables 8.1 and 8.2, network limitations are not forecast to exceed network reliability requirements established under Powerlink's planning standard.

However, there has been a proposal for the development of coal seam gas (CSG) processing load and/or new mining load of up to 80MW (refer to Table 3.1) in the Bowen Basin. These loads have not reached the required development status to be included in AEMO's Steady Progress scenario forecast for this Transmission Annual Planning Report (TAPR).

The new loads within the Bowen Basin area would result in voltage and thermal limitations on the 132kV transmission system upstream of their connection points. Critical contingencies include an outage of a 132kV transmission line between Nebo and Moranbah substations, or the 132kV transmission line between Lilyvale and Dysart substations (refer to Figure 6.6).

The impacts these loads may have on the CQ-NQ grid section and possible network solutions to address these is discussed in Section 9.2.4.

AEMO's Steady Progress scenario forecast does allow for increasing additional electrification load from 2025/26. The total load across the multi-sector industries increases from approximately 50MW in 2025/26 to 500MW in 2031/32. This additional electrification load gives consideration to the responses that multi-sector industries will take in line with global efforts to reduce carbon emissions. Whilst the location of this additional load is uncertain there is a likelihood that a significant contribution will come from mining companies aiming to minimise carbon emissions. To achieve this, mines will need to replace diesel fuel within their operations through the introduction of a modern electrified mining fleet or the substitution of diesel fuel with hydrogen. This may lead to significant increases in electrical demand and also require significant supplies of renewable electricity.

Possible network solutions

Feasible network solutions to address the limitations are dependent on the magnitude and location of load. The location, type and capacity of future VRE generation connections in North Queensland (NQ) may also impact on the emergence and severity of network limitations. The type of VRE generation interest in this area is predominately large-scale solar photo voltaic (PV). Given that the CSG and coal mine load profile would be expected to be relatively flat, it is unlikely that the day time PV generation profile will be able to successfully address all emerging limitations.

Depending on the magnitude and location of load, possible network options may include one or more of the following:

- 132kV phase shifting transformers to improve the sharing of power flow in the Bowen Basin within the capability of the existing transmission assets
- construction of 132kV transmission lines between the Nebo, Broadlea and Peak Downs areas
- construction of 132kV transmission line between Moranbah and a future substation north of Moranbah.

Notwithstanding these potential new loads, the electrification of mines and/or the generation and use of hydrogen on site will significantly increase the demand for electricity in the Bowen Basin. Mining in the Bowen Basin relies heavily on the existing 132kV network to deliver power to the region. Much of this infrastructure has limited thermal capacity. To address the potential shortfall in capacity in the transmission and distribution networks, consultation with the miners in the Bowen Basin is required to assess the likely decarbonisation pathways under consideration (electrification or hydrogen), in order to forecast the potential energy demand, renewable energy supply, and transmission requirements. It would not be unexpected that the Bowen Basin 132kV network would need to be replaced or overlayed with a high capacity 275kV network.

9.2.2 Bowen Industrial Estate

Based on AEMO's Steady Progress scenario forecast defined in Chapter 3, no additional capacity is forecast to be required as a result of network limitations within the 10-year outlook period of this TAPR.

However, electricity demand in the Abbot Point State Development Area (SDA) is associated with infrastructure for new and expanded mining export and value adding facilities. Located approximately 20km west of Bowen, Abbot Point forms a key part of the infrastructure that will be necessary to support the development of coal exports from the northern part of the Galilee Basin. The Carmichael Coal and Rail project requires expansion of the Abbot Point port facility. This expansion would add a further 100MW of demand (refer to Table 3.1) but has not reached the required development status to be included in AEMO's Steady Progress scenario forecast.

The Abbot Point area is supplied at 66kV from Bowen North Substation. Bowen North Substation was established in 2010 with a single 132/66kV transformer and supplied from a double circuit 132kV transmission line from Strathmore Substation but with only a single transmission line connected. During outages of the single 132kV supply to Bowen North, the load is supplied via the Ergon Energy 66kV network from Proserpine, some 60km to the south. An outage of the 132kV single connection will cause voltage and thermal limitations impacting network reliability.

Possible network solutions

A feasible network solution to address the limitations comprises:

- installation of a second 132/66kV transformer at Bowen North Substation and connection of the second Strathmore to Bowen North 132kV transmission line.

9.2.3 Galilee Basin coal mining area

The Galilee Basin, 320km to 450km west of Mackay and Rockhampton, is the last remaining major coal province yet to be developed in Queensland. It is also an emerging asset with many significant energy related proposals including multiple coal mines, underground coal gasification, and oil and gas exploration.

Mining proponents in the Galilee Basin that have proposed to develop several large-scale coal mines include:

- Carmichael Coal and Rail Project (Bravus)
- Alpha Coal Project (joint venture GVK and Hancock Prospecting Pty Ltd)
- Kevin's Corner Mine (joint venture GVK and Hancock Prospecting Pty Ltd) and
- China First Project (Waratah Coal).

None of these loads have reached the required development status to be included in AEMO's Steady Progress scenario forecast for this TAPR. After considering the current development activities within the Galilee Basin, loads up to 400MW are possible (refer to Table 3.1). If new coal mining projects eventuate, voltage and thermal limitations on the transmission system upstream of their connection points may occur.

Depending on the number, location and size of coal mines that develop in the Galilee Basin it may not be technically or economically feasible to supply this entire load from a single point of connection to the Powerlink network.

The Carmichael Coal and Rail project is the most advanced of the proposed new mine developments and early construction works on the rail corridor have already commenced[2]. This project could demand up to 200MW of supply from the transmission network from a connection to Powerlink's Strathmore Substation near Collinsville. The Queensland Department of State Development notes that, as at 1 October 2020, both of the outstanding environmental approvals have now been met and all but one of the other key milestones have also been met[3].

New coal mines that develop in the southern part of the Galilee Basin may connect to Lilyvale Substation via approximately 200km of transmission line extension.

Whether these new coal mines connect at Lilyvale and/or Strathmore Substation, the new load will impact the performance and adequacy of the CQ-NQ grid section. Possible network solutions to the resultant CQ-NQ limitations are discussed in Section 9.2.4.

In addition to these limitations on the CQ-NQ transmission system, new coal mine loads that connect to the Lilyvale Substation may cause thermal and voltage limitations to emerge during an outage of a 275kV transmission line between Broadsound and Lilyvale substations.

Possible network solutions

For supply to the Galilee Basin from Lilyvale Substation, feasible network solutions to address the limitations are dependent on the magnitude of load and may include one or both of the following options:

- installation of capacitor bank/s at Lilyvale Substation
- third 275kV transmission line between Broadsound and Lilyvale substations.

The location, type and capacity of future VRE generation connections in Lilyvale, Blackwater and Bowen Basin areas may impact on the emergence and severity of this network limitation. The type of VRE generation interest in this area is predominately large-scale solar PV. Given that the coal mining load profile would be relatively flat, it is unlikely that the day time PV generation will be able to successfully address all emerging limitations.

2 Bravus Mining & Resources, Bravus.
3 Adani Outstanding Approvals Milestones Reached, Queensland Government.

9.2.4 CQ-NQ grid section transfer limit

Based on AEMO's Steady Progress scenario forecast outlined in Chapter 3 and the committed generation listed in tables 8.1 and 8.2, network limitations impacting reliability are not forecast to occur within the 10-year outlook of this TAPR. However, midday power transfer levels are reversing from northern to southern transfers. The incidence of light loading on the transmission system is forecast to increase as additional VRE generators are fully commissioned in NQ. Voltage control is therefore becoming increasingly challenging and leading to high voltage violations. As outlined in Section 11.1 Powerlink has completed a RIT-T recommending the installation of a 275kV shunt reactor at the Broadsound Substation. This reactor is planned to be commissioned by June 2023.

As discussed in sections 9.2.1, 9.2.2 and 9.2.3 there have been proposals for large coal mine developments in the Galilee Basin, development of CSG processing and electrification-related load in the Bowen Basin and associated port expansions. There is also the potential load in the North West Mineral Province.

The North West Mineral Province transmission project (Copperstring) proposes to connect Mt Isa and the North West Minerals Province to the NEM at a new substation south of Powerlink's existing Ross Substation. One of the key benefits of the Copperstring project is to allow the North West Minerals Province to access cheaper electricity from the NEM and not rely on more expensive local generation in Mt Isa. The project could also enable further renewable generation to be connected.

As a result, the Copperstring project could result in additional demand of up to 350MW to be supplied from the transmission network in North Queensland. In addition, there is up to 100MW of demand that is currently not connected to the Mt Isa grid and supplied from standalone power stations that could rapidly connect once Mt Isa is connected to the NEM.

Therefore, the loads in Table 3.1 could result in a coincident increase in northern Queensland demand of up to 930MW but have not reached the required development status to be included in AEMO's Steady Progress scenario forecast of this TAPR.

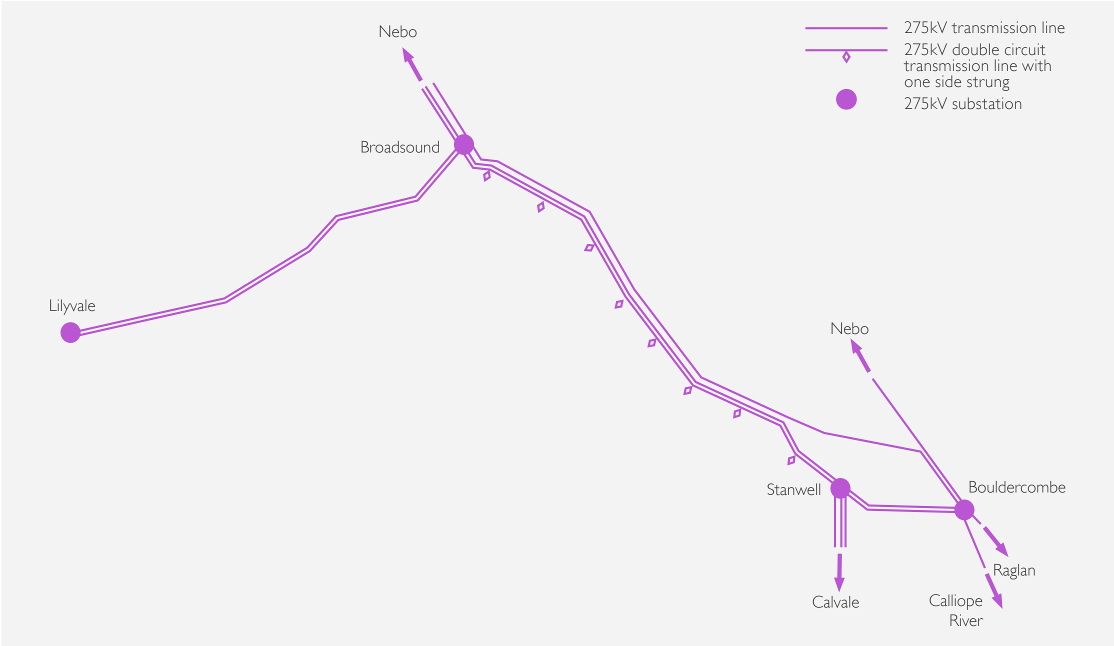
Network limitations on the CQ-NQ grid section may occur if a portion of these new loads commit. Power transfer capability into northern Queensland is limited by thermal ratings and voltage stability. Thermal limitations may occur on the Bouldercombe to Broadsound 275kV line following a critical contingency of a Stanwell to Broadsound 275kV transmission line. Voltage stability limitations may occur following the trip of the Townsville gas turbine or 275kV transmission line supplying northern Queensland.

Based on current network analysis an additional 90MW of load north of Bouldercombe will result in network congestion between Central Queensland and North Queensland that will require dispatch of additional, out-of-merit-order generation in North Queensland. As generation costs are higher in northern Queensland, due to reliance on liquid fuels, it may be economic to advance the timing of augmentation to deliver positive net market benefits. The additional load in northern Queensland that would justify the network augmentation in preference to continued network support could be as low as 250MW.

Possible network solutions

In 2002, Powerlink constructed a 275kV double circuit transmission line from Stanwell to Broadsound with one circuit strung (refer to Figure 9.1). A feasible network solution to increase the power transfer capability to northern Queensland is to string the second side of this transmission line.

Figure 9.1 Stanwell/Broadsound area transmission network



9.2.5 Surat Basin north west area

Based on AEMO's Steady Progress scenario forecast defined in Chapter 3, network limitations impacting reliability are not forecast to occur within the next five years of this TAPR.

However, there have been several proposals for additional CSG upstream processing facilities and new coal mining load in the Surat Basin north west area. These loads have not reached the required development status to be included in AEMO's Steady Progress scenario forecast for this TAPR. The loads could be up to 300MW (refer to Table 3.1) and cause voltage limitations impacting network reliability on the transmission system upstream of their connection points.

Depending on the location and size of additional load, voltage stability limitations may occur following outages of the 275kV transmission lines between Western Downs and Columboola, and between Columboola and Wandoan South substations (refer to Figure 9.2).

Possible network solutions

Due to the nature of the voltage stability limitation, the size and location of load and the range of contingencies over which the instability may occur, it may not be possible to address this issue by installing a single Static VAr Compensator (SVC) at one location.

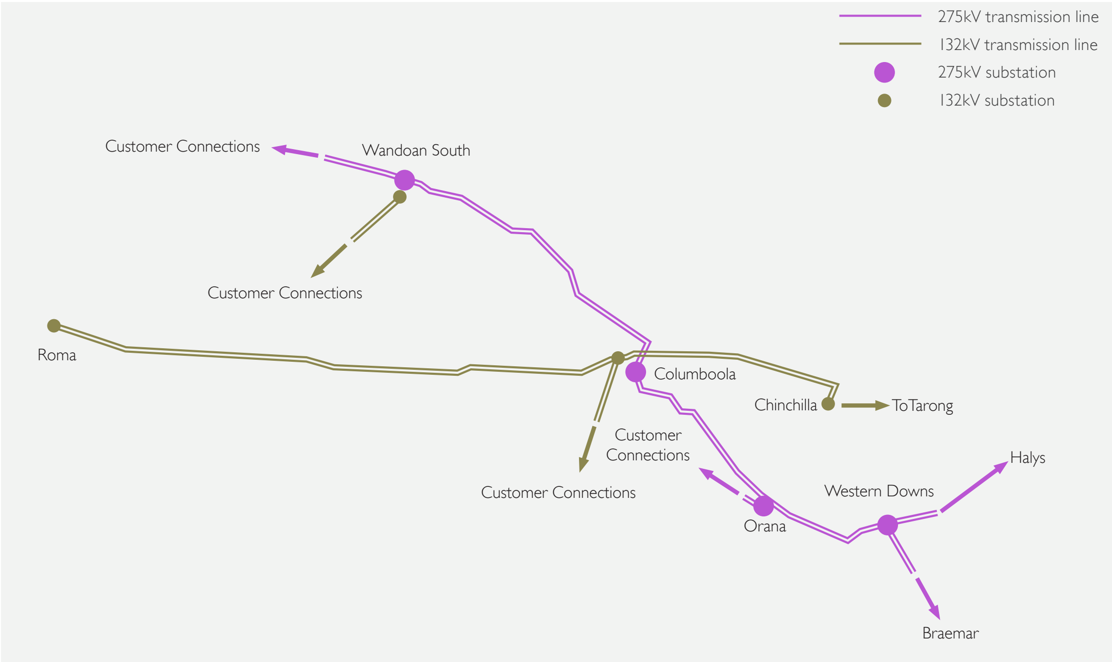
The location, type and capacity of future VRE generation connections in the Surat Basin north west area may also impact on the emergence and severity of these voltage limitations. The type of VRE generation interest in this area is large-scale solar PV. Given that the CSG upstream processing facilities and new coal mining load has a predominately flat load profile it is unlikely that the day time PV generation profile will be able to successfully address all emerging voltage limitations. However, voltage limitations may be ameliorated by these renewable plants, particularly if they are designed to provide voltage support 24 hours a day.

To address the voltage stability limitation the following network options are viable:

- SVCs, Static Synchronous Compensators (STATCOM) or Synchronous Condensers (SynCon) at both Columboola and Wandoan South substations
- additional transmission lines between Western Downs, Columboola and Wandoan South substations to increase fault level and transmission strength or
- a combination of the above options.

9 Strategic projects

Figure 9.2 Surat Basin north west area transmission network



9.3 Alignment with AEMO's Integrated System Plan

The installation of large-scale VRE generation is changing the mix of generation and impacting the utilisation of existing transmission infrastructure. This has been most evident across the Central to NQ and Central to South Queensland grid sections (refer sections 8.6.2 and 8.6.5 respectively) and the Queensland to NSW interconnector (QNI). This has implications for investment in the transmission network both inter-regional and within Queensland.

These impacts have been investigated in AEMO's 2020 ISP. The 2020 ISP identified that to deliver low-cost, secure and reliable energy, investments in transmission are needed. Although no 'actionable' projects were identified for Queensland, several Queensland projects were identified as part of the optimal development path that may become 'actionable' in future ISPs. These projects will be vital to achieving lower cost solutions that meet energy security and reliability, affordability and reduced emissions. Three such projects were nominated for Preparatory Activities. These projects include:

- QNI Medium and Large interconnector upgrades
- Central to Southern Queensland transmission link
- Gladstone grid reinforcement.

For each project a Preparatory Report summarised the following information:

- Project scope and single line diagrams
- Electrical network parameters
- Ratings of network equipment
- Power transfer limits for the existing network and following the augmentation project[4]
- Corridor and route selection
- Project schedule and staging, and
- High level cost estimate.

[4] Power transfer limits were defined as multi-term equations with independent variables observable within AEMO's market modelling software.

Preparatory activities for these projects were provided by 30 June 2021. Links to these Preparatory Reports are footnoted[5]. This information will be used by AEMO to better inform the optimal development path for the 2022 ISP.

9.3.1 Queensland to NSW Interconnector (QNI)

Increasing the capacity of interconnection between NEM regions is essential in order to take advantage of the geographic diversity of renewable resources so regions can export power when there is local generation surplus, and import power when needed to meet demand. Appropriate intra-regional transmission capacity is required to support these objectives.

Powerlink and TransGrid finalised a Project Assessment Conclusion Report on 'Expanding NSW-Queensland transmission transfer capacity' in December 2019. The recommended QNI Minor option (uprating the 330kV Liddell to Tamworth 330kV lines, and installing SVCs at Tamworth and Dumaresq substations and static capacitor banks at Tamworth, Armidale and Dumaresq substations) is now under construction.

The 2020 ISP identified that a further staged upgrade to the transmission capacity between Queensland and NSW (QNI Medium and QNI Large) was an integral part of the optimal development plan. The 2020 ISP identified that the additional transmission capacity would deliver net market benefits from:

- efficiently maintaining supply reliability in NSW following the closure of further generation and the decline in ageing generator reliability
- facilitating efficient development and dispatch of generation in areas with high quality renewable resources through improved network capacity and access to demand centres
- enabling more efficient sharing of resources between NEM regions
- enhancing system resilience and optionality.

These development options can also be coordinated with REZ developments and can be staged by geography, operating voltage and number of circuits to maximise net economic benefits. Powerlink and TransGrid agreed a lower capacity[6] 330kV transmission line to Armidale South Substation would be more likely to form part of the ISP optimal development path. Therefore, the option developed for the preparatory activities was a staged 330kV double circuit line. Each stage is a 330kV line - the first forecast for completion by 2032-33 and the second by 2035-36.

Preparatory activities, as outlined above, were completed by 30 June 2021 so that costs and capacity improvements could be included in the 2022 ISP.

Possible network solutions

The QNI Medium upgrade project proposed by the preparatory activities includes a single 330kV circuit between Braemar Substation and NSW border via a similar alignment to the existing QNI. The proposed route traverses the Central West Orana (within AEMO's North West NSW) and Darling Downs REZs.

Specifically, QNI Medium includes:

- a new 330kV double-circuit line (one circuit strung) from Armidale South to Braemar substations along similar alignment to the existing QNI including connecting to intermediate substations with associated supporting plant.

This augmentation can be expanded with a second stage to form the QNI Large upgrade.

QNI Large comprises a second 330kV circuit (second circuit strung) from Armidale South to Braemar substations connecting to intermediate substations and with associated supporting plant.

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5 Preparatory Activities QNI Medium and Large.
Preparatory Activities CQSQ Transmission Link.
Preparatory Activities Gladstone Grid Reinforcement.

6 Appendix A3.5.1 of the 2020 ISP describes the future ISP project associated with the QNI Medium project as 'single 500kV circuit between NSW and Queensland strung on a double circuit tower via western part of the existing QNI…' and the Large project 'second 500kV circuit…'.

AEMO also flagged in the 2020 ISP that it will work with Powerlink and TransGrid to explore further options in relation to virtual transmission lines (VTLs). The 2020 ISP outlined that VTLs, coupled with suitable wide area protection systems, could provide a technically feasible solution to increase the capacity of QNI. A VTL could comprise of grid-scale batteries on both sides of a QNI (for bidirectional limit increases), or a grid-scale battery on one side and braking resistor or generator tripping on the other side (for unidirectional limit increases).

9.3.2 CQ-SQ grid section reinforcement

In order for power from new and existing NQ and CQ VRE generating systems to make its way to southern Queensland and the southern states, it must be transferred through the CQ-SQ grid section. The utilisation of the CQ-SQ grid sections is therefore expected to increase (refer to Section 8.6.5) and may lead to levels of congestion depending on the response of the central and northern Queensland generators to the energy market. In addition, the utilisation may also increase following the commissioning of the QNI Minor project (refer to Section 6.9.1).

As outlined in Section 9.3.1, the 2020 ISP has identified a further upgrade of QNI capacity from 2032-33. The utilisation and adequacy of the CQ-SQ grid section is closely linked to the required efficient capacity of interconnection with NSW.

As outlined in Section 6.7.6 there are emerging condition and compliance risks related to structural corrosion on significant sections of the coastal CQ-SQ 275kV network between Calliope River and South Pine substations. Strategies to address the transmission line sections with advanced corrosion in the five year outlook are described in Section 6.7.6.

In parallel, Powerlink and AEMO (through the ISP process) continue to investigate the impact of large-scale VRE generation investment in the Queensland region on the utilisation and economic performance of intra-regional grid sections, and in particular the CQ-SQ grid section. The 2020 ISP identified the need for a material upgrade of CQ-SQ as part of the optimal development path. The 2020 ISP identified the early 2030s as the project timing. The upgrade is critical for unlocking renewable resources in the North, Isaac, and Fitzroy REZs for efficient market outcomes.

Powerlink will consider the emerging and forecast constraints holistically with the emerging condition based drivers as part of the planning process. Such decisions will be undertaken using the RIT-T consultation process, where the benefits of non-network options will also be considered.

Possible network solutions

Feasible network solutions to facilitate efficient market operation may differ in scale. The 2020 ISP identified the need for a material upgrade. The proposed project by AEMO included a new 275kV double circuit transmission line between Calvale and Wandoan South substations.

Additional network options that deliver a range of capacity improvements will also be considered in the 2022 ISP. These include:

- establishing a mid-point switching substation on the 275kV double circuit between Calvale and Halys substations
- a grid-scale battery system. A VTL option could comprise of grid-scale batteries on both sides of CQ-SQ, or a grid-scale battery on the south side and a braking resistor or generator tripping on the northern side
- A 1,500MW HVDC bi-pole overhead transmission line from Calvale and South West Queensland.

9.3.3 Gladstone grid section reinforcement

The 275kV network forms a triangle between the generation rich nodes of Calvale, Stanwell and Calliope River substations. This triangle delivers power to the major 275/132kV injection points of Calvale, Bouldercombe (Rockhampton), Calliope River (Gladstone) and Boyne Island substations.

Since there is a surplus of generation within this area, this network is also pivotal to supply power to northern and southern Queensland. As such, the utilisation of this 275kV network depends not only on the generation dispatch and supply and demand balance within the Central West and Gladstone zones, but also in northern and southern Queensland.

Based on AEMO's Steady Progress scenario forecast defined in Chapter 3 and the existing and committed generation listed in tables 8.1 and 8.2, network limitations impacting reliability are not forecast to occur within the 10-year outlook period of this TAPR.

However, the committed VRE generation in tables 8.1 and 8.2 in NQ is expected to increase the utilisation of this grid as generation in the Gladstone zone or southern Queensland is displaced. While not impacting reliability of supply, the committed VRE generation in NQ has the potential to cause congestion depending on how the thermal generating units in CQ bid to meet the NEM demand.

In addition, new loads in the resource rich areas of the Bowen Basin, Galilee Basin, North West Mineral Province and Surat Basin has the potential to further significantly increase the utilisation of this grid section. This may lead to significant limitations impacting efficient market outcomes.

Furthermore, the 2020 ISP has identified significant increases in VRE generation for the North, Isaac, and Fitzroy REZ (refer to Figure 9.5). With this generation the thermal capacity of the network between Bouldercombe, Raglan, Larcom Creek, and Calliope River will be reached. Upgrading this grid section is therefore critical for unlocking these renewable resources in these REZ as part of the optimal development path. The 2020 ISP identified the 2030s as the project timing. The timing could be brought forward with retirement of Gladstone generation[7].

Possible network solutions

Depending on the emergence of network limitations within the 275kV network it may become economically viable to increase its power transfer capacity to alleviate constraints. Feasible network solutions to facilitate efficient market operation may include:

- transmission line augmentation between Calvale and Calliope River substations and rebuild between Larcom Creek and Calliope River substations with a high capacity 275kV double circuit transmission line
- new high capacity 275kV double circuit transmission line between Bouldercombe, Raglan, Larcom Creek and Calliope River
- third Calliope River 275/132kV transformer.

9.3.4 ISP Renewable Energy Zones

As the NEM transforms away from synchronous generation and towards VRE, an additional 34GW to 47GW of new VRE needs to be installed depending on the ISP scenario. This is allowing for strong growth in DER and the large-scale VRE that is already installed or expected to be operational. In Queensland, under AEMO's 2020 ISP Central scenario, approximately 11GW of large-scale VRE still needs to be installed by the early 2040s.

A number of REZ development opportunities for the Queensland region have been identified in the ISP's optimal development path. Under the Central scenario, additional VRE generation is planted in five out of eight candidate REZs; North Queensland (FNQ), Isaac, Fitzroy, Wide Bay and Darling Downs (refer to Figure 9.3).

These REZs are developed in phases. Initially VRE developments are planted to help meet Queensland's Renewable Energy Target (QRET). The additional VRE is planted where there is relatively good access to existing network capacity and system strength. The 2020 ISP identified wind and solar generation in the Darling Downs and Fitzroy REZ using this existing transmission capacity.

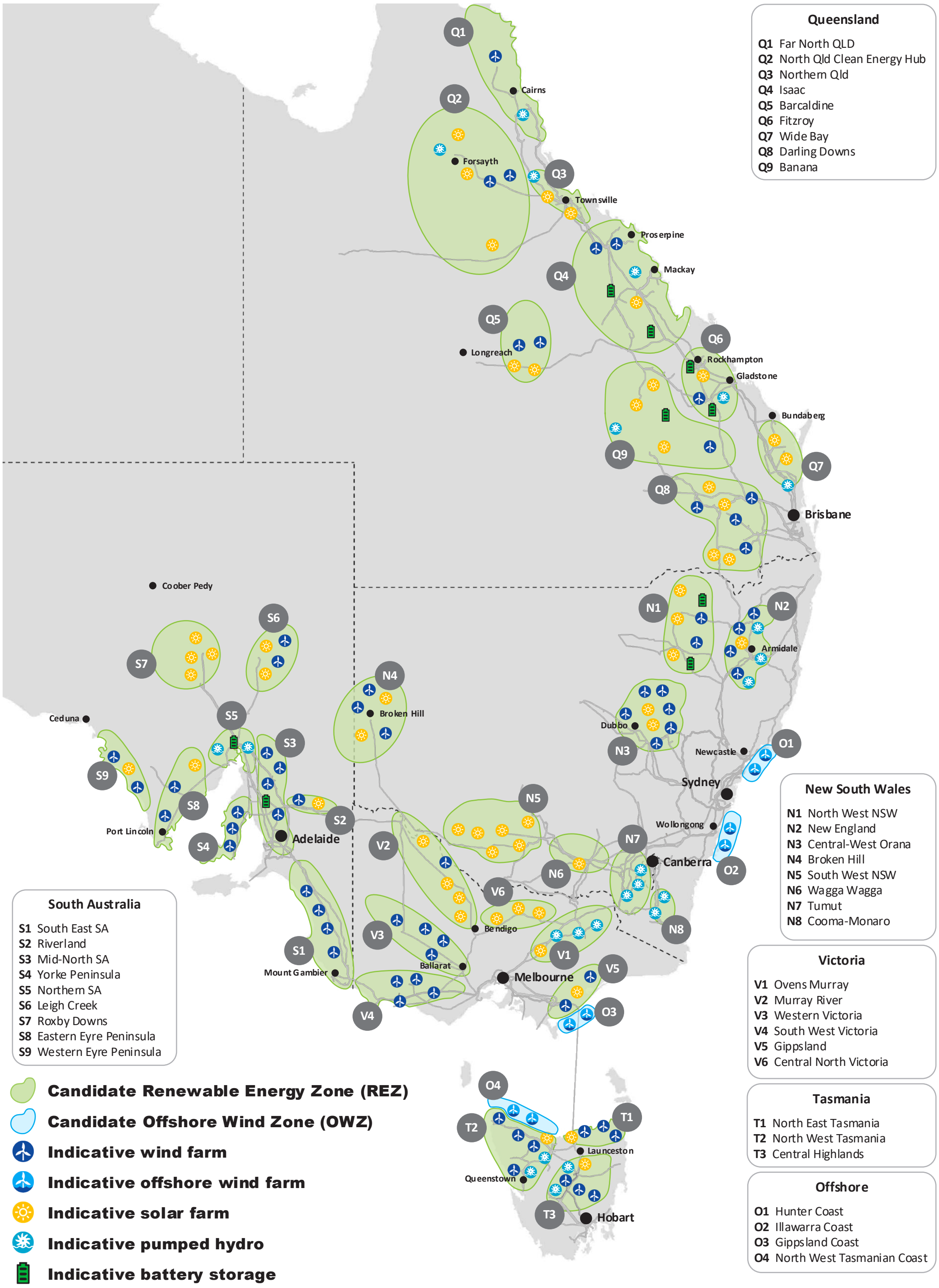
Finally VRE developments are associated with future ISP projects. Larger VRE development in the Fitzroy REZ (wind and solar) and Isaac REZ (wind) are supported by future ISP projects which include the Gladstone and Central to Southern Queensland grid section reinforcements and expansions of QNI (refer to sections 9.3.1, 9.3.2 and 9.3.3). Renewable developments in the FNQ REZ also require 275kV upgrades within this REZ.

In recognition of the potential value of REZ developments across Queensland (the three REZ in north, central and southern zones that overlay the REZ identified in the ISP), the Queensland Government announced $145 million for REZ support (refer to Chapter 2). Powerlink will continue to work with Government, AEMO, stakeholders and customers to drive the most efficient and cost effective outcomes from this process.

[7] The potential closure of a large industrial load in the Gladstone zone also influences the required size and timing of this project.

9 Strategic projects

Figure 9.3 2020 ISP Renewable Energy zone candidates in Queensland



Source: AEMO

CHAPTER 10

Renewable energy

10 Renewable energy

Key highlights

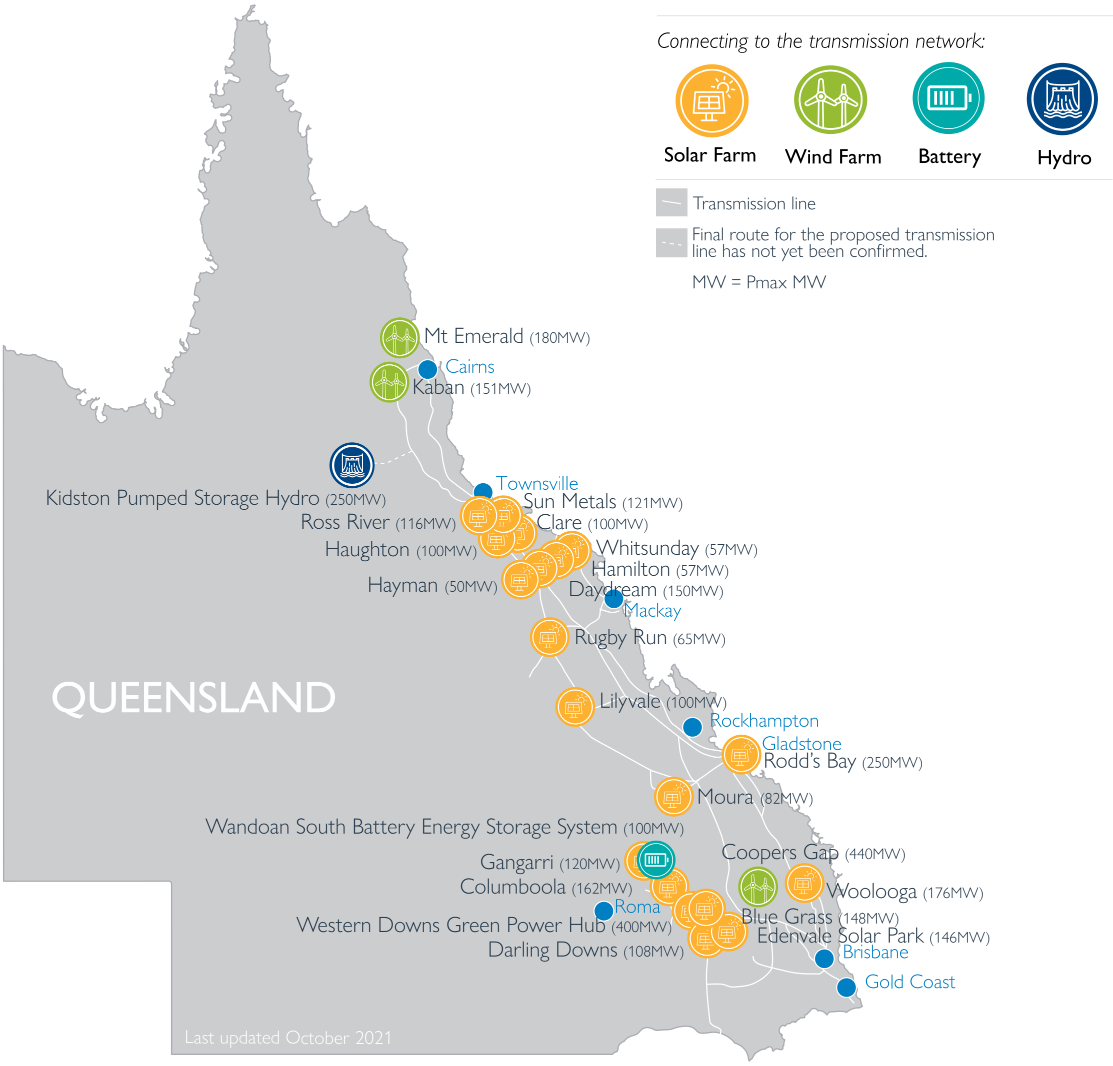
- This chapter explores the potential for the connection of variable renewable energy (VRE) generation to Powerlink's transmission network.
- Powerlink has a central role in enabling the connection of VRE in Queensland.
- System strength has been a focus for VRE generators and Powerlink, including development of the Electromagnetic Transient Type (EMT-type) model for Queensland.
- Through active collaboration with solar and wind farm proponents and associated equipment manufacturers, Powerlink has implemented innovative cost-effective technical solutions in relation to the declared fault level shortfall at Ross node.
- Powerlink is actively engaging in the Australian Energy Market Commission's (AEMC) System Strength Frameworks Review to improve outcomes for connecting parties.

10.1 Introduction

Queensland is rich in a diverse range of renewable resources – solar, wind, geothermal, biomass and hydro. This makes Queensland an attractive location for large-scale VRE generation development projects. During 2020/21, 470MW of semi-scheduled VRE generation capacity was committed in the Queensland region, taking the total to 4,444MW that is connected, or committed to connect, to the Queensland transmission and distribution networks (refer to Section 8.2). To date Powerlink has completed connection of 13 large-scale solar and wind farm projects in Queensland, adding 1,644MW of generation capacity to the grid. Approximately 30 connection applications, totalling about 6,400MW of new generation capacity, have been received and are at varying stages of progress. This includes committed connections for a further 1,635MW of VRE. In addition to the large-scale VRE generation development projects, rooftop photovoltaic (PV) in Queensland exceeded 4,074MW in July 2021.

Figure 10.1 shows the location and type of generators connected and committed to connect to Powerlink's network. Department of Energy and Public Works (DEPW) also provides mapping information on proposed (future) VRE projects, together with existing generation facilities (and other information) on its website. For the latest information on proposed VRE projects and locations in Queensland, please refer to the DEPW website.

Figure 10.1 Committed and existing connection projects since 2018



Utility scale and rooftop connections of VRE generation, both in Queensland and the rest of the National Electricity Market (NEM), has brought with it a number of challenges to which Powerlink is responding. One of the main contributors to this challenging environment is system strength. The distributed nature of VRE generation is also changing the way the transmission network is operated, including changes to flow patterns and network utilisation.

This chapter provides information on:

- the current system strength obligations placed on Powerlink and connecting proponents of large-scale inverter-based plant under the National Electricity Rules (NER)
- the recommendations from the AEMC's investigation into System Strength Frameworks
- how Powerlink has and continues to meet the system strength challenges
- the fault level shortfall declared by AEMO in April 2020 and how Powerlink addressed this shortfall
- the current system strength environment and the opportunities for future investment in VRE generation.

10.2 Current management of system strength and NER obligations

On 1 July 2018, the AEMC rule for 'Managing Power System Fault Levels' came into effect.

Under the Rule

- AEMO develops a system strength requirements methodology guideline and determines where the fault level nodes are in each region, plus the minimum three phase fault levels and any projected fault level shortfalls at those fault level nodes.
- Transmission Network Service Providers (TNSPs) or jurisdictional planning bodies, as the System Strength Service Providers for each region, are responsible for procuring system strength services to meet a fault level shortfall declared by AEMO. These services must be made available by a date nominated by AEMO which is at least 12 months from the declaration of the shortfall, unless an earlier date is agreed with the System Strength Service Provider.
- Network Service Providers (NSPs) undertake system strength impact assessments to determine whether a proposed new or altered generation or market network service facility connection to their network will result in an adverse system strength impact.
- Applicants pay for system strength connection works undertaken by a NSP to address an adverse system strength impact caused by their proposed connection to the NSP's network or propose a system strength remediation scheme[1] .

Consistent with this methodology, Powerlink worked with AEMO to determine the required minimum fault level at key 'fault level nodes' within the Powerlink network (refer to Table 10.1). The minimum fault level is used to assess that the system can be operated safely and securely. The initial assessment was completed in mid-2018.

The guidelines require the minimum fault level to be reassessed no more than once in every 12 month period to determine whether a fault level shortfall exists or is likely to exist in the future. This assessment considers the displacement[2] of existing synchronous plant in Queensland.

In early 2020, Powerlink and AEMO reviewed the minimum fault level requirements within the Powerlink network. As a result of this review, AEMO published (9 April 2020) a report 'Notice of Queensland System Strength Requirements and Ross Fault Level Shortfall' to the NEM under Clause 5.20C.2(c) of the NER. Powerlink's response to this declared fault level short fall is discussed in Section 10.4.

10.2.1 System Strength Frameworks Review

On 21 October 2021 the AEMC published its final Rule determination on the Efficient Management of System Strength on the power system. The previous framework (refer Section 10.2 above) has been shown in practice to be reactive and slow to provide system strength, resulting in a lack of this essential system service. Shortfalls of this essential service in recent years have resulted in delays in the connection of new inverter-based renewable (IBR) generators, as there has been insufficient system strength to allow them to connect securely.

The AEMC concluded that these delays, and the resultant uncertainty they create, impose costs on connecting new generation. These costs are ultimately passed through to customers. A lack of system strength in the system has also meant that lower-cost, lower emissions, renewable generators are being constrained off, again increasing costs to customers.

The energy mix is rapidly transforming and solutions to the system strength issues require sufficient time to be delivered. The AEMC concluded that the short-term reactive approach to deliver a theoretical minimum system strength level is not workable and does not sufficiently enable planning for the long-term management of issues.

[1] Obligation on the connecting generator to 'do no harm' came into effect 17 November 2017 with AEMO publishing the 'Interim System Strength Impact Assessment Guidelines'.

[2] Displacement may occur for periods when it is not economic for a synchronous generator to operate, and is distinct from retirement which is permanent removal from the market.

Powerlink worked closely with the AEMC and through Energy Network Australia (ENA) in the development of this important Rule change. The result is that the AEMC's final rule determination has increased the emphasis on medium to long-term planning for system strength needs. The rule specifies three main elements:

- Supply side: System strength will be supplied through a Transmission Network Service Provider (TNSP) led procurement service. TNSPs, would be responsible for providing efficient levels of system strength on a forward looking basis over a given timeframe. Planning for the standard is rolled into the existing Transmission Annual Planning Report (TAPR) and Regulatory Investment Test for Transmission (RIT-T) processes.
- Coordination: Connecting parties with IBR generators would have the choice between paying to use the system strength provided by the TNSP or providing their own system strength by remediating their impact. This mechanism would mean that while customers would bear some of the initial cost of providing system strength services, over time this cost will be recovered from connecting parties, with minimal stranded asset risk borne by consumers.
- Demand side: New access standards, to ensure that connecting parties with IBR generators would only use the efficient volumes of this valuable common pool resource. The new access standards also underpin the coordination measures, by allowing generators to undertake actions to reduce the amount of system strength they require. IBR generators must meet two new requirements; a minimum short circuit ratio (SCR) and a phase shift capability.

10.3 Developing an understanding of the system strength challenges

Powerlink continues to better understand the system strength challenges and has worked closely with AEMO, Australian Renewable Energy Agency (ARENA) and inverter manufacturers to maximise the VRE generation hosting capacity of the Queensland transmission network.

Fundamental to the understanding of system strength challenges has been the development of a system-wide EMT-type model. This has allowed the study of system strength and its impact on the stability and performance of the power system.

Powerlink has developed an EMT-type model that extends from Far North Queensland (FNQ) to the Hunter Valley in New South Wales (NSW). It includes plant specific models for all VRE and synchronous generators (including voltage control systems) and transmission connected dynamic voltage control plant (Static VAr Compensators and Statcoms). This is the most detailed modelling possible with the inverter-based plants modelled at the controller level and with simulation time steps in micro-seconds.

In 2018, AEMO's System Strength Impact Assessment Guidelines introduced a Preliminary Impact Assessment (PIA) screening based on the calculation of available fault level (AFL)[3]. This methodology was developed based on the best available knowledge of system strength at that time. Powerlink has now established that the dominant limitation to hosting capacity is the potential for multiple generators, and other transmission connected dynamic plant, to interact in an unstable manner. These dynamic plant control interactions manifest as an unstable or undamped oscillation in the power system voltage. The frequency of the oscillation is dependent on the participating plants, but is broadly characterised as between 8Hz and 15Hz. The PIA fault level screening methodology does not provide any insights to this limitation.

As a result, Powerlink now undertakes a Full Impact Assessment (FIA) for all VRE generation applying to connect to the Powerlink network regardless of the size of the proposed plant and available fault level indicated from the PIA. This is because only an FIA can provide information on the impact of potentially unstable interactions with other generators.

[3] AEMO, System Strength Assessment Guidelines, July 2018

The FIA is carried out as part of the connection process as per AEMO's System Strength Impact Assessment Guidelines. This is to ensure that any adverse system strength impact is adequately identified and addressed as part of the connection application either via a system strength remediation scheme or through system strength connection works.

It is vital that proponents provide high-quality EMT-type models as per AEMO's Power System Model Guidelines[4] for the FIA process. One of the most common delays to project assessments is the need to request changes to proponent models. Generation must meet the NER Generator Performance Standards (GPS), and generation proponents are required to demonstrate that their proposed generation technology is able to meet these standards during the connection process.

AEMO's System Strength Impact Assessment Guidelines provides additional details regarding the assessment process and methodology, while AEMO's Power System Model Guidelines provides additional information regarding modelling requirements.

10.3.1 Australian Renewable Energy Agency (ARENA) Project

Powerlink received funding from ARENA to investigate technical, commercial and regulatory solutions to address system strength challenges. The study looked at addressing system strength challenges by exploring the merits of several technical solutions, as well as business and regulatory models to facilitate lower cost solutions and remove commercial barriers. The study is occurred over a number of stages.

For stage 1 Powerlink partnered with GHD to prepare an initial report on system strength. The purpose of the report was to promote better understanding on how system strength can impact investment in generation and transmission network assets. The report targets a broad audience to establish a base level of understanding between all stakeholders involved in the power system and serve as a basis for informing the ongoing development of regulatory frameworks. Solar farm operators Pacific Hydro and Sun Metals also supported the report's development. The 'Managing System Strength during the Transition to Renewables' report was published in May 2020 (refer to Powerlink's website[5]).

Subsequent stages of this project built on these foundations. Powerlink published a stage 2 report, 'PSCAD Assessment of the effectiveness of a centralised synchronous condenser approach' in October 2020 which demonstrated the potential benefits of connecting proponents sharing a scale-efficient synchronous condenser to meet their individual system strength remediation obligations. The technical viability was demonstrated in a system-wide EMT-type case study, which compared distributed, project specific, synchronous condenser installations to a centralised shared scale-efficient synchronous condenser solution.

Further stages focussed on building understanding of the role grid forming inverter technology with battery (referred to as 'grid forming battery') can play in contributing to system strength. The aim was to determine whether advanced inverter controls can facilitate a higher penetration of inverter-based renewable generation (e.g. wind and solar) without compromising grid stability.

Initially Powerlink invited inverter manufacturers to test the ability of their product(s) to mitigate system strength challenges. Powerlink provided a simulation test case and defined a range of system and plant conditions and disturbances under which the plant was to be tested for plant stability. For most of the grid forming batteries investigated stable operation was simulated down to low Short Circuit Ratios (SCR).

4 AEMO, Power System Model Guidelines, July 2018.
5 Powerlink, Managing System Strength During the Transition to Renewables, May 2020.

For the final step, Powerlink (in consultation with ARENA and AEMO) selected a promising grid forming battery solution, based on the initial preliminary assessment, and completed a rigorous system-wide EMT-type analysis. The analysis demonstrated that grid forming batteries can increase the system strength and help to support the operation of inverter connected renewables, in a similar manner as synchronous condensers. The provision of this service also has minimal impact on the battery's commercial services. In the study Powerlink demonstrated that a grid forming battery of similar MVA capacity as the synchronous condenser (identified in the previous study) could be used to support the stable operation of an otherwise unstable IBR generator, and this supporting function was only dependent on the battery being online, with no need for it to be operated in a particular fashion. In addition, the modelling showed that the grid forming battery could provide the same damping capability as the synchronous condenser with only half the MVA capacity after implementing site specific tuning.

ARENA published the Powerlink report on the outcome of this assessment in April 2021[6].

10.3.2 Retuning of transmission connected Static VAr Compensators (SVCs)

Powerlink has redesigned and commissioned changes to the voltage controller at nine SVCs in North and Central Queensland (CQ). At two transmission connected SVCs in North Queensland the control systems were modified by adjusting gain and phase parameters to allow more VRE generation to be supported. This has reduced proponent's connection costs that would have otherwise been required to provide system strength remediation.

The change to network conditions also required Powerlink to reduce the gain control of seven other SVCs in the region so they could continue to operate as designed.

10.3.3 Inverter level retuning of VRE plant

In late-2019 Powerlink developed a methodology to assess the damping provided by a VRE generator at different oscillation frequencies using an EMT-type model that could be shared with inverter manufactures but still preserve the confidentiality of their propriety information.

This work allowed Powerlink to partner with an inverter manufacturer to investigate changes to the plant voltage control strategy. The outcome of this work recommended that the bandwidth of the voltage control system be higher to counter the 8Hz to 15Hz control interactions that have been observed in Powerlink's network. Powerlink tested this revised control strategy in the state-wide EMT-type model and confirmed its effectiveness.

This approach, initiated by Powerlink in partnership with an inverter manufacturer, has been adopted in the North West Victoria area where five fully commissioned plants were being heavily constrained due to control interactions identified post their commissioning. Powerlink has also leveraging off this development to help address the declared fault level shortfall in north Queensland (refer to Section 10.4.1).

10.4 Declaration of fault level shortfall at Ross node

During early 2020, Powerlink and AEMO reviewed the minimum fault level requirements within the Powerlink network. As a result of this review, AEMO published (9 April 2020) a report 'Notice of Queensland System Strength Requirements and Ross Fault Level Shortfall' to the NEM under Clause 5.20C.2(c) of the NER.

The report identified that the fault level nodes for Queensland remain the same as those determined in mid-2018, except for the replacement of the Nebo 275kV node with the Ross 275kV node. The Ross 275kV node is now considered to be a better representation for system strength conditions in north Queensland compared to the Nebo 275kV node.

6 PSCAD Assessment of the Effectiveness of Grid Forming Batteries.

The minimum three phase fault levels from AEMO were also determined for all of the Queensland fault level nodes. Powerlink and AEMO carried out detailed EMT-type analysis to determine these system strength requirements for the Queensland region. Using the outcomes from these studies (for example, minimum required synchronous generator combinations), Powerlink and AEMO calculated a new minimum post-contingency three phase fault level of 1,300MVA at the Ross 275kV fault level node. The updated minimum three phase fault levels, from AEMO, for the Queensland fault level nodes are shown in Table 10.1.

Table 10.1 Three phase fault levels for Queensland fault level nodes

Fault level node	2020 minimum fault level (MVA) (post-contingency)
Ross 275kV	1,300
Lilyvale 132kV	1,150
Gin Gin 275kV	2,250
Western Downs 275kV	2,550
Greenbank 275kV	3,750

Based on the minimum fault level review and assessment of the projected fault levels based on dispatch outcomes from the Draft 2020 Integrated System Plan (ISP) Central scenario market modelling results, AEMO declared an immediate fault level shortfall of 90MVA at the Ross 275kV fault level node. AEMO projected that, if not addressed, this fault level shortfall will continue beyond 2024-25.

As outlined in Section 10.2, Powerlink has the responsibility to address the fault level shortfall in the Queensland region. Powerlink must also address these technical issues as efficiently as possible. In accordance with clause 5.20C.2(c) of the NER, AEMO specified 31 August 2021 as the date by which Powerlink should ensure that the necessary system strength services to address the fault level shortfall are available.

10.4.1 Actions undertaken to address the fault level shortfall

Immediately following the fault level shortfall declaration, Powerlink commenced an expression of interest (EOI) process seeking both short and long-term non-network solutions to the fault level shortfall at Ross (refer to Section 6.7.1).

In the short-term, Powerlink with AEMO's approval, entered into an agreement with CleanCo Queensland to provide system strength services through utilising its hydro generation assets in FNQ. These short-term support services were in place until 31 December 2020. Whilst not fully meeting the fault level shortfall, with associated system strength constraint advice, these support services reduced the impact and constraints on North Queensland VRE generation. This partial short-term solution allowed Powerlink to focus on assessing the most efficient long-term solutions to address the fault level shortfall.

Offers received as part of the EOI process included inverter tuning to reduce the interactions currently occurring between renewable generation and other control systems (refer to Section 10.3.3). This involved modifying the tuning of the inverters at Daydream, Hamilton, Hayman and Whitsunday Solar Farms connected to Powerlink's Strathmore Substation. Powerlink's modelling confirmed that this inverter retuning assisted with the day time solution. On this basis, Powerlink entered into an agreement to retune these four plants.

In addition, Powerlink also worked with Mt Emerald Wind Farm and the turbine equipment manufacturer on control setting changes. Powerlink's modelling confirmed that these changes could significantly reduce the overall system strength requirement at Ross and dove-tail with the solar farm tuning above to provide a complete solution to the system strength shortfall. All changes were finalised and commissioned by April 2021.

AEMO's due diligence following the retuning at the Daydream, Hamilton, Hayman and Whitsunday solar farms and update of the control settings at Mt Emerald Wind Farm concluded that the system strength requirements at the Ross node have changed since the 2020 Notice was issued. On 28 June 2021 AEMO announced the post-contingency minimum fault level requirement at the Ross node is now assessed as 1,175MVA and they no longer consider there to be a fault level shortfall at Ross. Based on this assessment, Powerlink's regional System Strength Service Provider obligations have now been fulfilled in relation to the Notice issued in April 2020 under the NER[7].

Through active collaboration with solar and wind farm proponents and associated equipment manufacturers, Powerlink has delivered a positive outcome to customers by implementing innovative cost-effective technical solutions which removed the need for long-term investment (network or non-network).

10.5 Transmission connection and planning arrangements

In May 2017, the AEMC published the Final Determination on the Transmission Connections and Planning Arrangements Rule change request. The Rule set out significant changes to the arrangements by which parties connect to the transmission network, as well as changes to enhance how transmission network businesses plan their networks.

From July 2018 new categories of connection assets were defined, namely Identified User Shared Assets (IUSA) and Dedicated Connection Assets (DCA). All new DCA services, including design, construction, ownership and operation and maintenance are non-regulated services. IUSA assets with capital costs less than $10 million are negotiated services that can only be provided by Powerlink. IUSA assets with capital costs above $10 million are non-regulated services. Powerlink remains accountable for operation of all IUSAs and any above $10 million must enter into a Network Operating Agreement to provide operations and maintenance services.

In July 2021 the AEMC finalised a rule to facilitate more efficient investment in, and use of, transmission assets built to connect generation to the 'shared' network. The finalised rule establishes a new framework for 'designated network assets' (DNAs). The new arrangements replace the current arrangements for 'large dedicated connection assets' (DCAs).

A DNA is a radial transmission extension greater than 30km in length. DCAs remain for connections less than 30km unless a proponent voluntarily chose to opt into the DNA framework. DNAs will not be subject to the open access regime that applies elsewhere on the transmission network. Instead, a DNA owner, i.e. the party that made the investment and funded the asset, is responsible for administering third-party access to its DNA. For this reason DNAs only apply to radial configurations.

A DNA is not a connection asset, but rather transmission network. It differs to the shared transmission network as the design, construction and ownership of the DNA are non-regulated services. As for IUSAs, Powerlink remains accountable for operation and maintenance of all DNAs. A special access framework for DNAs is set out in the NER Chapter 5.

As DNAs will form part of the transmission network, operated by a TNSP, the point where an individual proponent connects to a DNA will be a transmission network connection point (TNCP). This allows for the application of existing arrangements for settlement, metering, calculation of loss factors, transmission use of system charges, system strength and performance standards, with only minor modifications.

Powerlink is focussed on delivering a timely and transparent connection process to connecting generators including coordination of the physical connection works, GPS and system strength.

7 NER Clause 5.20C.2.

10.6 Indicative available network capacity – Generation Capacity Guide (GCG)

Powerlink provides a significant amount of information for parties seeking connection to the transmission network in Queensland, including the GCG. This guide is designed to provide proponents with an understanding of the current situation in Queensland with regard to system strength and to outline what it means for project planning. Proponents are encouraged to utilise this information to make informed proposals, however we encourage early engagement with Powerlink's Business Development team.

The GCG is published on Powerlink's website separate to the TAPR to facilitate updates to the GCG as required to make available the most up to date data for VRE developers. The GCG also includes thermal capacity and congestion information for customers seeking to connect to Powerlink's transmission network.

Under the NEM's open access regime, it is possible for generation to be connected to a connection point in excess of the network's capacity, or for the aggregate generation within a zone to exceed the capacity of the main transmission system. Where this occurs, the dispatch of generation may need to be constrained. This congestion is managed by AEMO in accordance with the procedures and mechanisms of the NEM. It is the responsibility of each generator proponent to assess and consider the consequences of potential congestion, both immediate and into the future.

As outlined in Section 10.4, AEMO declared a fault level shortfall in NQ. While this shortfall indicates the challenges faced for inverter-based connections in this part of the network, it does not mean that new connections are not possible. However, the underlying system strength is limited throughout the state and there are still a large number of enquiries and applications under consideration. As such, all proponents should consider the strong possibility that system strength support will be required no matter where the project will be located. This support may be provided by a synchronous condenser. However, retuning of the plant's control systems and other technology solutions could be equally effective.

To determine if system strength remediation is required a system-wide EMT-type assessment for a project-specific inverter-based plant must be undertaken. If this assessment identifies an adverse system strength impact then there is an obligation on the VRE proponent to provide system strength remediation. Powerlink will work with the proponent to explore the most cost-effective solution. This may include a shared system strength service.

10.7 System strength during network outages

Throughout the year, it is necessary to remove plant in the transmission network from service. In the majority of circumstances planned outages are necessary to maintain or replace equipment. It may also be necessary to remove plant from service unexpectedly. During these planned and unplanned outages, Powerlink and AEMO must ensure that the system continues to be operated in a secure state.

Network outages may lead to reductions in system strength. While this may be a localised issue, outages on key 275kV corridors, as well as some 275/132kV transformers, may impact the system strength of a number of VRE generators. To address this, Powerlink is working with AEMO to develop constraint equations to be implemented in the National Energy Market Dispatch Engine (NEMDE). The purpose of these equations is to maximise the dispatch of VRE generators in the Queensland system within the available system strength.

10.8 Transmission congestion and Marginal Loss Factors (MLF)

The location and pattern of generation dispatch influences power flows across most of the Queensland system. Power flows can also vary substantially with planned or unplanned outages of transmission network elements. Power flows may also be higher at times of local area or zone maximum demand or generation, and/or when embedded generation output is lower.

Maximum power transfer capability may be set by transient stability, voltage stability, thermal plant ratings (transformer and conductor ratings) or protection relay load limits. System strength may also be a constraint that limits the output from large-scale inverter-based generation in an area of the network.

Where constraints occur on the network, AEMO will constrain generation based on the market system rules within NEMDE to maintain system security.

Rapid changes in demand and generation patterns will likely result in transmission constraints emerging over time. Forecasting these constraints is not straightforward as they depend on generation development and bidding patterns in the market. For example, with the existing and committed inverter-based renewable generation in NQ, the utilisation of the Central West to Gladstone and Central to South Queensland grid sections are expected to further increase over time.

Powerlink monitors the potential for congestion to occur and assesses the need for network investments using the Australian Energy Regulator (AER)'s RIT-T. Where found to be economic, Powerlink will augment the network to ensure the electricity market operates efficiently and at the lowest overall long run cost to consumers.

Generator proponents are encouraged to refer to Chapter 6 of Powerlink's TAPR for more detail on potential future network development as well as emerging constraints.

MLFs have also emerged as an important consideration for new entrant generators, especially for PV generators in NQ. MLFs adjust the spot price to account for the marginal impact of losses from additional generation. They are calculated as a volume-weighted average for the full year and are determined based on historical generation and demand profiles adjusted for known forward commitments.

In NQ the local supply and demand balance is significant due to the long distances of the transmission system from North to South Queensland. The coincident generation from PVs has resulted in large drops in the MLFs for PV generators in NQ over recent years. The situation is not as significant for wind generators in NQ as a large amount of the wind export is not coincident with the PV output and hence does not coincide with the large demand and supply imbalance in the region.

MLF reductions across NQ provide an opportunity for additional loads (or storage) to locate in NQ.

10.9 Further information

Powerlink will continue to work with market participants and interested parties across the renewables sector to better understand the potential for VRE generation, and to identify opportunities and emerging limitations as they occur. The NER (Clause 5.3) prescribes procedures and processes that NSPs must apply when dealing with connection enquiries. Should an interested party wish to utilise the connection framework referred to in Section 10.5, it will be necessary to submit a new connection enquiry.

Figure 10.2 Overview of Powerlink's existing network connection process

Proponents who wish to connect to Powerlink's transmission network are encouraged to contact BusinessDevelopment@powerlink.com.au. For further information on Powerlink's network connection process please refer to Powerlink's website.

CHAPTER 11

Current, recently commissioned and committed network developments

11 Current, recently commissioned and committed network developments

Key highlights

- During 2020/21, Powerlink's efforts have continued to be predominantly directed towards reinvestment in transmission lines and substations across Powerlink's network.
- Powerlink's investment program is focussed on reducing the identified risks arising from assets reaching the end of technical service life and maintaining network resilience while continuing to deliver safe, reliable and cost efficient transmission services to our customers.
- A major project for Powerlink completed since publication of the 2020 Transmission Annual Planning Report (TAPR) has been the Callide A / Calvale 132kV transmission reinvestment which is critical to transporting power to the Central West area.
- Powerlink continues to support the development of all types of energy projects requiring connection to the transmission network in Queensland, with several connection works for variable renewable energy (VRE) generation completed during 2020/21.
- During 2020/21, Powerlink has completed five projects to connect new VRE and battery energy storage system (BESS) developments which are expected to add 958MW of potential generation capacity to the grid[1].

11.1 Transmission network

Powerlink Queensland's network traverses 1,700km from north of Cairns to the New South Wales (NSW) border. The Queensland transmission network comprises transmission lines constructed and operated at 330kV, 275kV, 132kV and 110kV. The 275kV transmission network connects Cairns in the north to Mudgeeraba in the south, with 110kV and 132kV systems providing transmission in local zones and providing support to the 275kV network. A 330kV network connects the New South Wales (NSW) transmission network to Powerlink's 275kV network at Braemar and Middle Ridge substations.

A geographic representation of Powerlink's transmission network is shown in Figure 11.1.

There have been no transmission network developments commissioned (augmentation works) or network assets retired[2] since Powerlink's 2020 TAPR was published.

Table 11.1 lists new connection works commissioned since Powerlink's 2020 TAPR was published.

Table 11.2 lists new transmission connection works for generating systems which are committed and under construction at October 2021. These connection projects resulted from agreement reached with relevant connected customers, generators or Distribution Network Service Providers (DNSPs) as applicable.

Table 11.3 list network developments which are committed at October 2021.

Table 11.4 lists network reinvestments commissioned since Powerlink's 2020 TAPR was published.

Table 11.5 lists network reinvestments which are committed at October 2021.

Table 11.6 lists network investments which have undergone the Regulatory Investment Test for Transmission (RIT-T) or similar process and are not fully committed at October 2021.

Table 11.7 lists asset retirement works at October 2021.

1 Refer to Table 11.1.
2 Operational works, such as asset retirements, do not form part of Powerlink's capital expenditure budget.

Table 11.1 Commissioned connection works since October 2020

Project (1)	Purpose	Zone	Date commissioned
Woolooga Energy Park Solar Farm	New solar farm (2)	Wide Bay	Quarter 3 2021
Gangarri Solar Farm	New solar farm	Surat	Quarter 4 2020
Columboola Solar Farm	New solar farm (2)	Surat	Quarter 2 2021
Wandoan South Battery	New Battery Energy Storage System (BESS)	Surat	Quarter 2 2021
Western Downs Green Power Hub Solar Farm	New solar farm (2)	Bulli	Quarter 3 2021

Notes:

(1) When Powerlink constructs a new line or substation as a non-regulated customer connection (e.g. generator, renewable generator, mine or industrial development), the costs of acquiring easements, constructing and operating the transmission line and/or are paid for by the company making the connection request.

(2) Powerlink's scope of works for this project has been completed. Remaining works associated with generation connection are being coordinated with the customer.

Table 11.2 Committed and under construction connection works at October 2021

Project (1)	Purpose	Zone	Proposed commissioning date
Kaban Green Power Hub	New wind farm	Far North	Quarter 3 2022
Kidston Pumped Storage Hydro	New pumped hydro energy storage	Far North	Quarter 1 2024
Moura Solar Farm	New solar farm	Central West	Quarter 4 2021
Bluegrass Solar Farm	New solar farm	Surat	Quarter 4 2021
Edenvale Solar Farm	New solar farm	Bulli	Quarter 3 2022

Note:

(1) When Powerlink constructs a new line or substation as a non-regulated customer connection (e.g. generator, renewable generator, mine or industrial development), the costs of acquiring easements, constructing and operating the transmission line and/or are paid for by the company making the connection request.

Table 11.3 Committed network developments at October 2021

Project	Purpose	Zone	Proposed commissioning date
Establishment of a 3rd 275kV connection into Woree	Enable development of the Northern Queensland Renewable Energy Zone and increase supply reliability in the Far North zone	Far North	November 2023

Table 11.4 Commissioned network reinvestments since October 2020

Project	Purpose	Zone	Date commissioned
Dan Gleeson 132kV secondary systems replacement	Maintain supply reliability in the Ross zone	Ross	August 2020 (1)
Ingham South 132/66kV transformers replacement	Maintain supply reliability in the Ross zone	Ross	August 2021
Kemmis 132/66kV transformer replacement	Maintain supply reliability in the North zone	North	December 2020
Callide A / Calvale 132kV transmission reinvestment	Maintain supply reliability in the Central West zone (2)(3)	Central West	July 2021

Notes:

(1) Formal notification of project commissioning coincided with the publication of the 2020 TAPR.

(2) Project identified under the RIT-T transitional arrangements in place for committed projects between 18 September 2017 and 30 January 2018.

(3) Approved works for this project were re-scoped as part of the Central West Queensland Strategy, previously named Callide A Substation replacement.

Table 11.5 Committed network reinvestments at October 2021

Project	Purpose	Zone	Proposed commissioning date
Woree secondary systems replacement	Maintain supply reliability in the Far North zone	Far North	October 2023
Woree SVC secondary systems replacement	Maintain supply reliability in the Far North zone	Far North	December 2023
Line refit works on the 132kV transmission line between Townsville South and Clare South substations	Maintain supply reliability in the Ross zone	Ross	November 2023
Townsville South 132kV primary plant replacement	Maintain supply reliability in the Ross zone	Ross	October 2025
Townsville South secondary systems replacement Stage 1	Maintain supply reliability in the Ross zone	Ross	October 2025
Ross 275kV primary plant replacement	Maintain supply reliability in the Ross zone	Ross	November 2024
Ross 132kV primary plant replacement	Maintain supply reliability in the Ross zone	Ross	December 2025
Line refit works on the 132kV transmission line between Eton tee and Alligator Creek Substation	Maintain supply reliability in the North zone (1)	North	June 2023
Mackay Substation replacement	Maintain supply reliability in the North zone (5)	North	November 2021
Strathmore 132kV secondary systems replacement	Maintain supply reliability in the North zone	North	November 2021
Strathmore 275/132kV transformer establishment	Maintain supply reliability in the North zone	North	May 2023
Nebo primary plant and secondary systems replacement	Maintain supply reliability in the North zone (5)	North	June 2024
Kemmis 132kV secondary systems replacement	Maintain supply reliability in the North zone	North	October 2024
Newlands primary plant replacement	Maintain supply reliability in the North zone	North	January 2026
Line refit works on the 132kV transmission line between Egans Hill and Rockhampton Substation	Maintain supply reliability in the Central West zone (5)	Central West	November 2021
Lilyvale 132/66kV transformers replacement	Maintain supply reliability in the Central West zone (5)	Central West	September 2024
Calvale and Callide B secondary systems replacement	Maintain supply reliability in the Central West zone (1) (3)(4)	Central West	December 2023
Moura Substation replacement	Maintain supply reliability in the Central West zone (2)	Central West	December 2021
Bouldercombe transformer replacement	Maintain supply reliability in the Central West zone	Central West	December 2021

Table 11.5 Committed network reinvestments at October 2021 (*continued*)

Project	Purpose	Zone	Proposed commissioning date
Blackwater 66kV CT & VT replacement	Maintain supply reliability in the Central West zone	Central West	December 2023
Blackwater 132kV transformers replacement	Maintain supply reliability in the Central West zone	Central West	December 2024
Dysart transformer replacement	Maintain supply reliability in the Central West zone (1)	Central West	June 2022
Lilyvale 275kV and 132kV primary plant replacement	Maintain supply reliability in the Central West zone (4)	Central West	November 2026
Bouldercombe primary plant replacement	Maintain supply reliability in the Central West zone	Central West	June 2023
Baralaba secondary systems replacement	Maintain supply reliability in the Central West zone	Central West	January 2023
Wurdong secondary systems replacement	Maintain supply reliability in the Gladstone zone	Gladstone	December 2023
Boyne Island secondary systems replacement	Maintain supply reliability in the Gladstone zone	Gladstone	December 2023
Calliope River 275kV tower refit	Maintain supply reliability in the Gladstone zone	Gladstone	November 2021
Gladstone South secondary systems replacement	Maintain supply reliability in the Gladstone zone	Gladstone	May 2026
Egans Hill secondary systems replacement	Maintain supply reliability in the Gladstone zone	Gladstone	September 2024
QAL West secondary systems replacement	Maintain supply reliability in the Gladstone zone	Gladstone	May 2026
Line refit works on 275kV transmission line between Woolooga and Palmwoods	Maintain supply reliability in the Wide Bay zone (1)	Wide Bay	November 2021
Gin Gin Substation rebuild	Maintain supply reliability in the Wide Bay zone (1)	Wide Bay	March 2022
Tarong secondary systems replacement	Maintain supply reliability in the South West zone (1) (4)	South West	December 2022
Ashgrove West Substation replacement	Maintain supply reliability in the Moreton zone (1)(4)	Moreton	June 2022
Belmont 275kV secondary systems replacement	Maintain supply reliability in the Moreton zone (4)	Moreton	November 2021
Abermain 110kV secondary systems replacement	Maintain supply reliability in the Moreton zone(4)	Moreton	May 2022
Palmwoods 275kV secondary systems replacement	Maintain supply reliability in the Moreton zone (4)	Moreton	October 2022
Line refit works on the 110kV transmission lines between South Pine and Upper Kedron	Maintain supply reliability in the Moreton zone	Moreton	July 2022

Table 11.5 Committed network reinvestments at October 2021 (*continued*)

Project	Purpose	Zone	Proposed commissioning date
Line refit works on the 110kV transmission lines between West Darra and Sumner	Maintain supply reliability in the Moreton zone	Moreton	February 2023
Line refit works on the 110kV transmission lines between Rocklea and Sumner	Maintain supply reliability in the Moreton zone	Moreton	March 2023
Swanbank E Secondary Systems Replacement	Maintain supply reliability in the Moreton zone	Moreton	July 2022
Mudgeeraba 275kV secondary systems replacement	Maintain supply reliability in the Gold Coast zone	Gold Coast	December 2024

Notes:

(1) Project identified under the RIT-T transitional arrangements in place for committed projects between 18 September 2017 and 30 January 2018.

(2) Major works were completed in October 2017. Minor works scheduling is being coordinated with Ergon Energy (Energex and Ergon Energy are part of the Energy Queensland Group).

(3) The majority of Powerlink's staged works are anticipated for completion by summer 2020/21. Remaining works associated with generation connection will be coordinated with the customer.

(4) Projects impacted by restrictions related to COVID-19. A number of projects have also been deferred 12+ months.

Table 11.6 Uncommitted network investments at October 2021

Project	Purpose	Zone	Proposed commissioning date
Cairns secondary systems replacement	Maintain supply reliability in the Far North zone (1)	Far North	December 2024
Kamerunga 132kV Substation replacement	Maintain supply reliability in the Far North zone (1)	Far North	December 2026
Broadsound 275kV bus reactor	Maintain voltages in the Central West zone (2)	Central West	June 2023
Mt England 275kV secondary systems replacement	Maintain supply reliability in the Moreton zone (1)	Moreton	October 2023

Notes:

(1) Capital expenditure in relation to network asset replacement.

(2) Capital expenditure in relation to the establishment of new network assets (augmentation).

Table 11.7 Asset retirement works at October 2021 (1)

Project	Purpose	Zone	Proposed retirement date
132kV transmission line retirement between Townsville South and Clare South substations	Removal of assets at the end of technical life in the North zone	North	June 2023
Belmont 275/110kV Transformer 2 decommissioning	Removal of asset at the end of technical life in the Moreton zone	Moreton	July 2022
Belmont 275/110kV Transformer 3 decommissioning	Removal of asset at the end of technical life in the Moreton zone	Moreton	February 2022
Mudgeeraba 275/110kV Transformer 3 retirement	Removal of asset at the end of technical life in the Gold Coast zone	Gold Coast	June 2022

Note:

(1) Operational works, such as asset retirements, do not form part of Powerlink's capital expenditure budget.

Figure 11.1 Existing Powerlink Queensland transmission network October 2021

Appendices

Appendices

Appendix A Forecast of connection point maximum demands

National Electricity Rules (NER) (Clause 5.12.2(c)(1)[1] requires the Transmission Annual Planning Report (TAPR) to provide 'the forecast loads submitted by a Distribution Network Service Provider (DNSP) in accordance with Clause 5.11.1 or as modified in accordance with Clause 5.11.1(d)'. This requirement is discussed below and includes a description of:

- the forecasting methodology, sources of input information and assumptions applied (Clause 5.12.2(c)(i)) (refer to Section A.1)
- a description of high, most likely and low growth scenarios (refer to Section A.2)
- an analysis and explanation of any aspects of forecast loads provided in the TAPR that have changed significantly from forecasts provided in the TAPR from the previous year (refer to Section A.3).
- an analysis and explanation of any aspects of forecast loads provided in the TAPR from the previous year which are significantly different from the actual outcome (refer to Section A.4).

A.1 Forecasting methodology used by Ergon Energy and Energex (part of the Energy Queensland Group) for maximum demand

Ergon Energy and Energex review and update the 10-year 50% probability of exceedance (PoE) and 10% PoE system summer maximum demand forecasts after each summer season. Each new forecast is used to identify emerging network limitations in the sub-transmission and distribution networks. For consistency, the Ergon Energy and Energex forecast system level maximum demand is reconciled with the bottom-up substation maximum demand forecast after allowances for network losses and diversity of maximum demands.

Distribution forecasts are developed using data from Australian Bureau of Statistics (ABS), the Queensland Government, the Australian Energy Market Operator (AEMO), internally sourced rooftop photovoltaic (PV) connections and historical maximum demand data. Forecasts from the National Institute of Economic and Industry Research (NIEIR) and Deloitte Access Economics are also utilised.

The methodology used to develop the system demand forecast as recommended by consultants ACIL Tasman, is as follows:

Ergon

- Develop a six region based forecast within the Ergon network, with the aggregation at the distribution system peak time to provide a system peak 50% PoE. Each regional forecast uses a multiple regression equation to determine the relationship between demand and Gross State Product (GSP), maximum temperature, minimum temperature, total electricity price, a structural break, three continuous hot days, weekends, Fridays and the Christmas period. The summer regression uses data from November to March with days which fall below 28.5°C excluded from the analysis.
- A Monte-Carlo process is used across the South East Queensland (SEQ) and regional models to simulate a distribution of summer maximum demands using the latest 10 years of summer temperatures and an independent 10-year gross GSP forecast.
- Using the 10 top summer maximum demands from the simulation, produce a probability distribution of maximum demands to identify the 50% PoE and 10% PoE maximum demands.
- A stochastic term is applied to the simulated demands based on a random normal distribution of the multiple regression standard error. This process attempts to define the maximum demand rather than the regression average demand.
- Modify the calculated system maximum demand forecasts by the reduction achieved through the application of demand management initiatives. An adjustment is also made in the forecast for the expected impact of rooftop PV, battery storage and electric vehicles (EV) based on the maximum demand daily load profile and anticipated usage patterns.

[1] Where applicable, Clauses 5.12.2(c)(iii) and (iv) are discussed in Chapter 3.

Energex

- Uses a multiple regression equation for the relationship between demand and GSP, square of weighted maximum temperature, weighted minimum temperature, total electricity price, structural break, three continuous hot days, weekends, Fridays and the Christmas period. The summer regression uses data from November to March, with the temperature data excluding days where the weather station's temperatures are below set levels (for example, Amberley mean temperatures <22.7°C and daily maximum temperature <30°C). Three weather stations are incorporated into the model via a weighting system to capture the influence of the sea breeze on peak demand. Statistical testing is applied to the model before its application to ensure that there is minimal bias in the model.
- A Monte-Carlo process is used to simulate a distribution of summer maximum demands using the latest 10 years of summer temperatures and an independent 10-year GSP forecast.
- Using the 10 top summer maximum demands, produce a probability distribution of maximum demands to identify the 50% PoE and 10% PoE maximum demands.
- A stochastic term is applied to the simulated demands based on a random distribution of the multiple regression standard error. This process attempts to define the maximum demand rather than the regression average demand.
- Modify the calculated system maximum demand forecasts by the reduction achieved through the application of demand management initiatives. An adjustment is also made in the forecast for rooftop PV, battery storage and the expected impact of EV based on the maximum demand daily load profile and anticipated usage patterns.

A.2 Description of Ergon Energy's and Energex's high, medium and low growth scenarios for maximum demand

The scenarios developed for the high, medium and low case maximum demand forecasts were prepared in June 2021 based on the latest information. The 50% PoE and 10% PoE maximum demand forecasts sent to Powerlink in July 2021 are based on these assumptions.

Block Loads

There are many block loads scheduled over the next 11 years. For the majority, the block loads are incorporated at the relevant level of the network e.g. zone substation. Only a small number are considered large enough to justify accounting for them at the system level models. Ergon does not currently incorporate any block loads in the system level models. Energex has between 20MW and 50MW of block loads incorporated in the system model over the forecast horizon.

At the zone substation level, Energy Queensland is currently tracking around 40MW of block loads for Ergon, and 70MW for Energex. However, only the block loads which have a significant influence on the zone substation's peak demand are incorporated.

Summary of the Ergon Energy model

The system demand model for regional Queensland incorporates economic, temperature and customer behavioural parameters in a multiple regression as follows:

- Aggregation of six regional forecasts to provide a system peak 50PoE at network peak coincidence.
- Demand MW = function of (weekend, public holidays, regional maximum temperature, Queensland GSP, structural break, demand management terms, and a constant).
- The demand management term captures historical movements of customer responses to the combination of PV uptake, tariff price changes and customer appliance efficiencies.

Ergon Energy's high growth scenario assumptions for maximum demand

- GSP – the high case of GSP growth (3.6% per annum (simple average growth with COVID-19 adjusted for the 2021 ~ 2032 financial years)).
- Queensland population – 1.8% per annum (simple average growth with COVID-19 adjusted for the 2021 ~ 2032 financial years).
- Weather – follow the recent trend of 10 years.

Ergon Energy's medium growth scenario assumptions for maximum demand

- GSP – the 'medium' case of GSP growth (2.8% per annum (simple average growth with COVID-19 adjusted for the 2021 ~ 2032 financial years)).
- Queensland population – Grew 1.6% (actual) in 2019, and is expected to slow down to 0.7% in 2020 (partially affected by the COVID-19 pandemic), before bouncing back to 1.3% in 2022, and gradually stabilising at around 1.4% by 2032 (based on the Deloitte's April 2021 forecasts).
- Weather – follow the recent 10-year trend.

Ergon Energy's low growth scenario assumptions for maximum demand

- GSP – the 'low' growth case of GSP growth (2.1% per annum (simple average growth with COVID-19 adjusted for the 2021 ~ 2032 financial years)).
- Queensland population – The same start value as the base case in 2020, weak GDP growth plus loss in productivity may slow population growth to 1.0% by 2032.
- Weather – follow the recent 10-year trend.

Summary of the Energex model

The latest system demand model for the South-East Queensland region incorporates economic, temperature and customer behavioural parameters in a multiple regression as follows:

- Demand MW = function of (weekend, Christmas, Friday, square of weighted maximum temperature, weighted minimum temperature, humidity index, total price, Queensland GSP, structural break, three continuous hot days, and a constant).
- In particular, the total price component incorporated into the latest model aims to capture the response of customers to the changing price of electricity. The impact of price is based on the medium scenarios for the Queensland residential price index forecast prepared by NIEIR in their System Maximum Demand Forecasts.

Energex high growth scenario assumptions for maximum demand

- GSP – The "high" case of GSP growth (3.6% per annum (simple average growth with COVID-19 adjusted for the 2021 ~ 2032 financial years)).
- Total real electricity price – Affects MW demand negatively, so the "low" case of annual price changes is assumed to be 1% lower than the base case (compounded and Consumer Price Index (CPI) adjusted).
- Queensland population – 1.8% per annum (simple average growth with COVID-19 adjusted for the 2021 ~ 2032 financial years).
- Rooftop PV – Lack of incentives for customers who lost the Feed-in tariff (FIT) tariffs, plus slow falls in battery prices which discourage PV installations. Panel capacity may reach 5,531MW by 2031 (systems <5MVA).
- Battery storage – Prices fall slowly, battery safety remains an issue, and kW demand based network tariff is not introduced. Peak time (negative) contribution may reach 31MW by 2032.
- EV – Significant fall in EV prices, accessible and fast charging stations, enhanced features, a variety of types, plus escalated petrol prices. The peak time contribution (without diversity ratio adjusted) may reach 339MW by 2032.
- Weather – follow the recent 10-year trend.

Energex medium growth scenario assumptions for maximum demand

- GSP – The medium case of GSP growth (2.8% per annum (simple average growth with COVID-19 adjusted for the 2021 ~ 2032 financial years)).
- Total real electricity price – The medium case of annual price change of 0.6%.
- Queensland population – Grew 1.6% (actual) in 2019, and is expected to slow down to 0.7% in 2020 (partially affected by the COVID-19 pandemic), before bouncing back to 1.3% in 2022, and gradually stabilising at around 1.4% by 2032 (based on the Deloitte's April 2021 forecasts).
- Rooftop PV – Panel capacity may reach 4,764MW by 2031 (systems <5MVA).
- Battery storage – Peak time (negative) contribution will have a slow start of around 4MW in 2021, but may reach 35MW by 2032.
- EV – Stagnant in the short-term, boom in the long-term. Peak time contribution will only amount to 1.0MW in 2020, but will reach 189MW by 2032. Note however, EV will also have a significant impact on GWh energy sales.
- Weather – follow the recent 10-year trend.

Energex low growth scenario assumptions for maximum demand

- GSP – The 'low' case GSP growth (2.1% per annum (simple average growth with COVID-19 adjusted for the 2021 ~ 2032 financial years)).
- Total real electricity price – The 'high' case of annual price changes is assumed to be 1% higher than the base case (compounded and CPI adjusted) values.
- Queensland population – The same start value as the base case in 2020, weak GDP growth plus loss in productivity may slow population growth to 1.0% by 2032.
- Solar PV – Strong incentives for customers who lost the FIT tariffs, plus fast falls in battery prices encourage more PV installations. Panel capacity may reach 4,280MW by 2031 (systems <5MVA).
- Battery storage – Prices fall quickly, no battery safety issues, and kW demand based network tariff is introduced. Peak time (negative) contribution may reach a high at 103MW in 2032.
- EV – Slow fall in EV prices, hard to find charging stations, charging time remaining long, still having basic features, less type sections, plus cheap petrol prices. The peak time contribution (without diversity ratio adjusted) may settle at 103MW in 2032.
- Weather – follow the recent 10-year trend.

A.3 Significant changes to the connection point maximum demand forecasts

Major differences between the 2021 forecast and the 2020 forecast can generally be attributed to natural variation in peaks below the connection point level. These natural variations can result in displaying an associated variation in year on year changes at the connection point level, and with changes in the growth in the lower levels of the network rather than from any network configuration changes or significant block loads. The forecast uptake of Distributed Energy Resources (DER) has increased for the 2021 forecast when compared to the 2020 forecast. Changes in proposed block loads also account for differences. These, combined with yearly load variations affecting the start values are the major cause of the differences observed between the two forecasts.

Ergon connection points with the greatest difference in growth between the 2021 and 2020 forecasts are:

Connection Point	Change in growth rate
Blackwater 132kV	7.2% pa
Dysart 66kV	5.3% pa
Turkinje 132kV	3.6% pa
Moranbah 66kV and 11kV	-1.3% pa
Moranbah 132kV	-3.2% pa

Energex connection points with the greatest difference in growth between the 2021 and 2020 forecasts are:

Connection Point	Change in growth rate
Redbank Plains 11kV	2.0% pa

A.4 Significant differences to actual observations

The 2020/21 summer was relatively mild across large parts of Queensland when compared to recent seasons. This, combined with ongoing COVID impacts, natural variations in the peaks, load transfers and changes to proposed block loads translated to substantial differences between the 2020 forecast values for 2020/21 and what was observed.

Ergon connection points with greater than 10% absolute difference between the peak 2020/21 and corresponding base 2020 forecast for 2020/21 are:

Connection Point	2020/21 forecast peak	2020/21 actual peak	Difference
Oakey	19.2	24.8	29.6%
Cairns City	43.4	50.1	15.5%
Columboola	73.2	84.4	15.3%
Tangkam	33.1	37.0	11.7%
Cairns	64.7	57.7	-10.9%
Blackwater 132kV	28.6	25.1	-12.1%
Kamerunga	63.9	55.4	-13.2%
Gladstone South	55.4	46.5	-16.1%
Cardwell	5.4	4.1	-24.2%
Alligator Creek 33kV	42.4	27.4	-35.5%

Energex connection points with greater than 10% absolute difference between the peak 2020/21 and corresponding base 2020 forecast for 2020/21 are:

Connection Point	2020/21 forecast peak	2020/21 actual peak	Difference
Ashgrove West 110kV	117.4	104.7	-10.8%
Middle Ridge (Postmans Ridge and Gatton)	108.0	96.0	-11.1%
Mudgeeraba 110kV	363.0	322.7	-11.1%
Tennyson	177.6	157.5	-11.3%
South Pine	963.3	845.1	-12.3%
Wecker Road	131.2	115.0	-12.4%
Ashgrove West 33kV	75.4	63.4	-15.9%
Mudgeeraba 33kV	24.3	19.6	-19.3%
Rocklea	166.8	133.6	-19.9%
Murarrie	534.5	389.5	-27.1%
Woolooga	296.6	200.3	-32.5%

A.5 Customer forecasts of connection point maximum demands

Tables A.1 to A.18 which are available on Powerlink's website, show 10-year forecasts of native summer and winter demand at connection point peak, for high, medium and low growth scenarios (refer to Appendix A.2). These forecasts have been supplied by Powerlink customers.

The connection point reactive power (MVAr) forecast includes the effect of customer's downstream capacitive compensation.

Groupings (sums of non-coincident forecasts) of some connection points are used to protect the confidentiality of specific customer loads.

In tables A.1 to A.18 the zones in which connection points are located are abbreviated as follows:

FN	Far North zone
R	Ross zone
N	North zone
CW	Central West zone
G	Gladstone zone
WB	Wide Bay zone
S	Surat zone
B	Bulli zone
SW	South West zone
M	Moreton zone
GC	Gold Coast zone

Appendix B TAPR templates

In accordance with Clause 5.14B.1(a) of the National Electricity Rules (NER), the Australian Energy Regulator's (AER) Transmission Annual Planning Report (TAPR) Guidelines[1] set out the required format of TAPRs, in particular the provision of TAPR templates to complement the TAPR document. The purpose of the TAPR templates is to provide a set of consistent data across the National Electricity Market (NEM) to assist stakeholders to make informed decisions.

Readers should note the data provided is not intended to be relied upon explicitly for the evaluation of investment decisions. Interested parties are encouraged to contact Powerlink in the first instance.

The TAPR template data may be directly accessed on Powerlink's TAPR portal[2]. Alternatively please contact NetworkAssessments@powerlink.com.au for assistance.

Context

While care is taken in the preparation of TAPR templates, data is provided in good faith. Powerlink Queensland accepts no responsibility or liability for any loss or damage that may be incurred by persons acting in reliance on this information or assumptions drawn from it.

The proposed preferred investment and associated data is indicative, has the potential to change and will be economically assessed under the RIT-T consultation process as/if required at the appropriate time. TAPR templates may be updated at the time of RIT-T commencement to reflect the most recent data and to better inform non-network providers[3]. Changes may also be driven by the external environment, advances in technology, non-network solutions and outcomes of other RIT T consultations which have the potential to shape the way in which the transmission network develops.

There is likely to be more certainty in the need to reinvest in key areas of the transmission network which have been identified in the TAPR in the near-term, as assets approach their anticipated end of technical service life. However, the potential preferred investments (and alternative options) identified in the TAPR templates undergo detailed planning to confirm alignment with future reinvestment, optimisation and delivery strategies. This near-term analysis provides Powerlink with an additional opportunity to deliver greater benefits to customers through improving and further refining options. In the medium to long-term, there is less certainty regarding the needs or drivers for reinvestments. As a result, considerations in the latter period of the annual planning review require more flexibility and have a greater potential to change in order to adapt to the external environment as the NEM evolves and customer behaviour changes.

Where an investment is primarily focussed on addressing asset condition issues, Powerlink has not attempted to quantify the impact on the market e.g. where there are market constraints arising from reconfiguration of the network around the investment and Powerlink considers that generation operating within the market can address this constraint.

Groupings of some connection points are used to protect the confidentiality of specific customer loads.

Methodology/principles applied

The AER's TAPR Guidelines incorporate text to define or explain the different data fields in the template. Powerlink has used these definitions in the preparation of the data within the templates. Further to the AER's data field definitions, Powerlink provides details on the methodology used to forecast the daily demand profiles. Table B.1 also provides further context for some specific data fields.

The data fields are denoted by their respective AER Rule designation, TGCPXXX (TAPR Guideline Connection Point) and TGTLXXX (TAPR Guideline Transmission Line).

1 First published in December 2018.
2 Refer to the TAPR portal.
3 Separate to the publication of the TAPR document which occurs annually.

Development of daily demand profiles

Forecasts of the daily demand profiles for the days of annual maximum and minimum demands over the next 10 years were developed using an in-house tool. These daily demand profiles are an estimate and should only be used as a guide. The 10-year forecasts of daily demand profiles that have been developed for the TAPR templates include:

- 50% probability of exceedance (PoE) maximum demand, MVA (TGCP008)
- Where the MW transfer through the asset with emerging limitations reverses in direction, the MVA is denoted a negative value
- Minimum demand, MVA (TGCP008)
- Where the MW transfer through the asset with emerging limitations reverses in direction, the MVA is denoted a negative value
- 50% PoE Maximum demand, MW (TGCP010)
- Minimum demand, MW (TGCP011).

Powerlink's in-house load profiling tool, incorporates a base year (1 October 2019 to 1 October 2020) of historical demand and weather data (temperature and solar irradiance) for all loads supplied from the Queensland transmission network. The tool then adds at the connection point level the impacts of future forecasts of roof-top photovoltaic (PV), distribution connected PV solar farms, battery storage, electric vehicles (EV) and load growth.

The maximum demand of every connection point within the base year has been scaled to the medium growth 50% PoE maximum demand connection point forecasts, as supplied by Powerlink's customers post-winter 2020 (the previous revision of those listed in Appendix A).

As Powerlink does not receive a minimum demand connection point forecast from its customers, the minimum demand is not scaled. The minimum demand is determined by the base year's half hour demands and the impacts of roof-top PV, distribution connected PV solar farms, battery storage and EV.

The maximum demand forecast on the minimum demand day (TGCP009) and the forecast daily demand profile on the minimum demand day (TGCP011) were determined from the minimum (annual) daily demand profiles.

Table B.1 Further definitions for specific data fields

Data field	Definition
TGCP013 and TGTL008 Maximum load at risk per year	Forecast maximum load at risk is the raw data and does not reflect the requirements of Powerlink's jurisdictional planning standard used to calculate non-network solution requirements. Please refer to Chapters 6 and 7 for information.
TGCP016 and TGTL011 Preferred investment - capital cost	The timing reflected for the estimated capital cost is the year of proposed project commissioning. RIT-Ts to identify the preferred option for implementation would typically commence three to five years prior to this date, relative to the complexity of the identified need, option analysis required and consideration of the necessary delivery timeframes to enable the identified need to be met. To assist non-network providers, RIT-Ts in the nearer term are identified in Table 6.6.
TGCP017 and TGTL012 Preferred investment - Annual operating cost	Powerlink has applied a standard 2% of the preferred investment capital cost to calculate indicative annual operating costs.
TGCP024 Historical connection point rating	Includes the summer and winter ratings for the past three years at the connection point. The historical connection point rating is based on the most limiting network component on Powerlink's network, in transferring power to a connection point. However lower downstream distribution connection point ratings could be more limiting than the connection point ratings on Powerlink's network.
TGCP026 Unplanned outages	Unplanned outage data relates to Powerlink's transmission network assets only. Forced and faulted outages are included in the data provided. Information provided is based on calendar years from January 2018 to December 2020.
TGPC028 and TGTL019 Annual economic cost of constraint	The annual economic cost of the constraint is the direct product of the annual expected unserved energy and the Value of Customer Reliability (VCR) related to the investment. It does not consider cost of safety risk or market impacts such as changes in the wholesale electricity cost or network losses.
TGTL005 Forecast 10-year asset rating	Asset rating is based on an enduring need for the asset's functionality and is assumed to be constant for the 10-year outlook period.
TGTL017 Historical line load trace	Due to the meshed nature of the transmission network and associated power transfers, the identification of load switching would be labour intensive and the results inconclusive. Therefore the data provided does not highlight load switching events.

Appendix C Zone and grid section definitions

This appendix provides definitions of illustrations of the 11 geographical zones and eight grid sections referenced in this Transmission Annual Planning Report (TAPR).

Tables C.1 and C.2 provide detailed definitions of zone and grid sections.

Figures C.1 and C.2 provide illustrations of the zone generation, zone load and grid section definitions.

Table C.1 Zone definitions

Zone	Area covered
Far North	North of Tully, including Chalumbin
Ross	North of King Creek and Bowen North, excluding the Far North zone
North	North of Broadsound and Dysart, excluding the Far North and Ross zones
Central West	South of Nebo, Peak Downs and Mt McLaren, and north of Gin Gin, but excluding the Gladstone zone
Gladstone	South of Raglan, north of Gin Gin and east of Calvale
Wide Bay	Gin Gin, Teebar Creek and Woolooga 275kV substation loads, excluding Gympie
Surat	West of Western Downs and south of Moura, excluding the Bulli zone
Bulli	Goondiwindi (Waggamba) load and the 275/330kV network south of Kogan Creek and west of Millmerran
South West	Tarong and Middle Ridge load areas west of Postmans Ridge, excluding the Bulli zone
Moreton	South of Woolooga and east of Middle Ridge, but excluding the Gold Coast zone
Gold Coast	East of Greenbank, south of Coomera to the Queensland/New South Wales border

Table C.2 Grid section definitions

Grid section (1)	Definition
FNQ	Ross into Chalumbin 275kV (2 circuits) Tully into Woree 132kV (1 circuit) Tully into El Arish 132kV (1 circuit)
CQ-NQ	Bouldercombe into Nebo 275kV (1 circuit) Broadsound into Nebo 275kV (3 circuits) Dysart to Peak Downs/Moranbah 132kV (1 circuit) Dysart to Eagle Downs 132kV (1 circuit)
Gladstone	Bouldercombe into Calliope River 275kV (1 circuit) Raglan into Larcom Creek 275kV (1 circuit) Calvale into Wurdong 275kV (1 circuit)
CQ-SQ	Wurdong to Teebar Creek 275kV (1 circuit) (2) Calliope River to Gin Gin/Woolooga 275kV (2 circuits) Calvale into Halys 275kV (2 circuits)
Surat	Western Downs to Columboola 275kV (1 circuit) Western Downs to Orana 275kV (1 circuit) Tarong into Chinchilla 132kV (2 circuits)
SWQ	Western Downs to Halys 275kV (1 circuit) Western Downs to Coopers Gap 275kV (1 circuit) Braemar (East) to Halys 275kV (2 circuits) Millmerran to Middle Ridge 330kV (2 circuits)
Tarong	Tarong to South Pine 275kV (1 circuit) Tarong to Mt England 275kV (2 circuits) Tarong to Blackwall 275kV (2 circuits) Middle Ridge to Greenbank 275kV (2 circuits)
Gold Coast	Greenbank into Mudgeeraba 275kV (2 circuits) Greenbank into Molendinar 275kV (2 circuits) Coomera into Cades County 110kV (1 circuit)

Notes:

(1) The grid sections defined are as illustrated in Figure C.2. X into Y – the MW flow between X and Y measured at the Y end; X to Y – the MW flow between X and Y measured at the X end.

(2) CQ-SQ cutset redefined following Rodds Bay Solar Farm connection in winter 2023. Wurdong to Teebar Creek 275kV becomes Rodds Bay to Teebar Creek 275kV.

Figure C.1 Zone generation and zone load legend

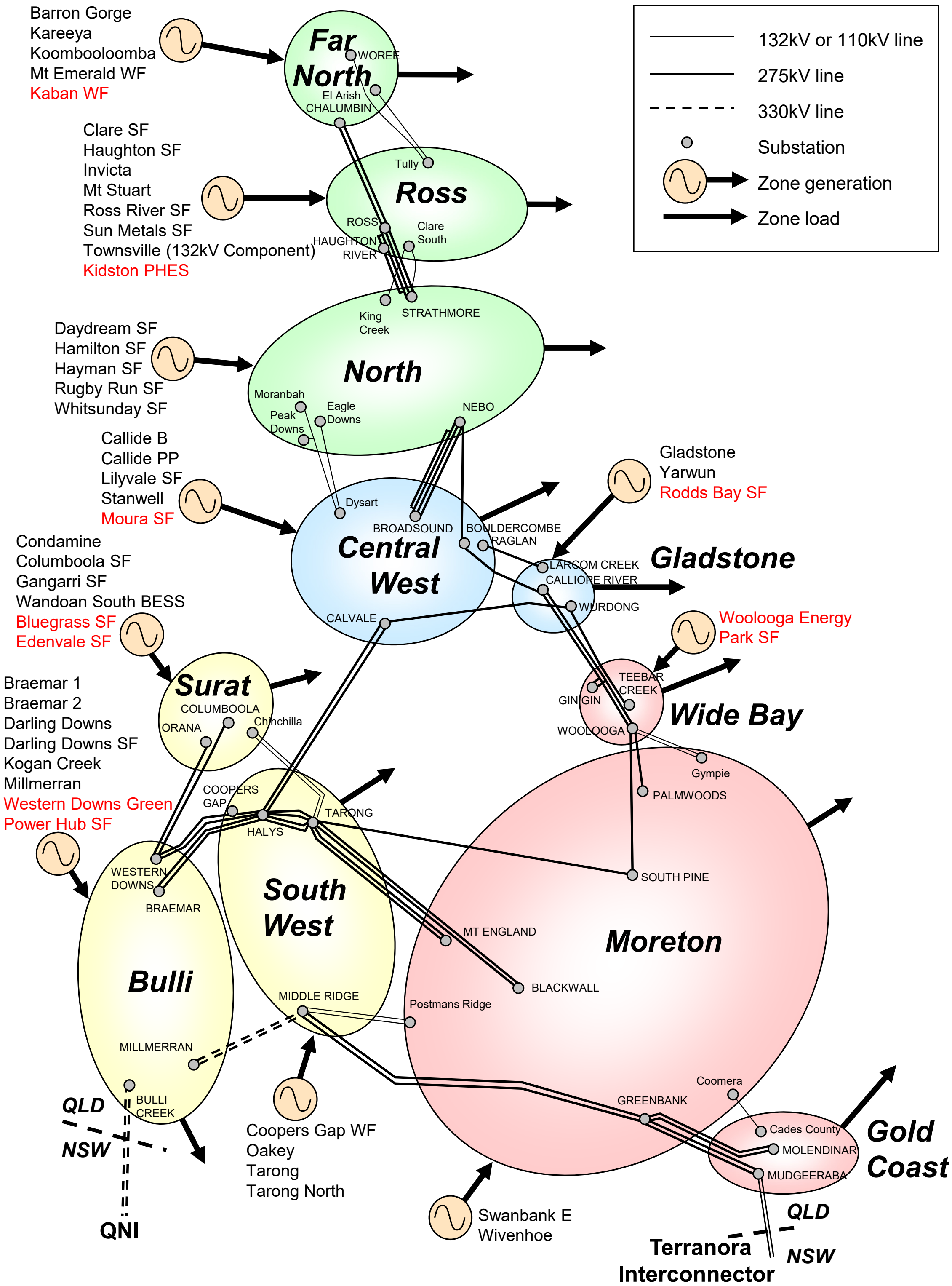
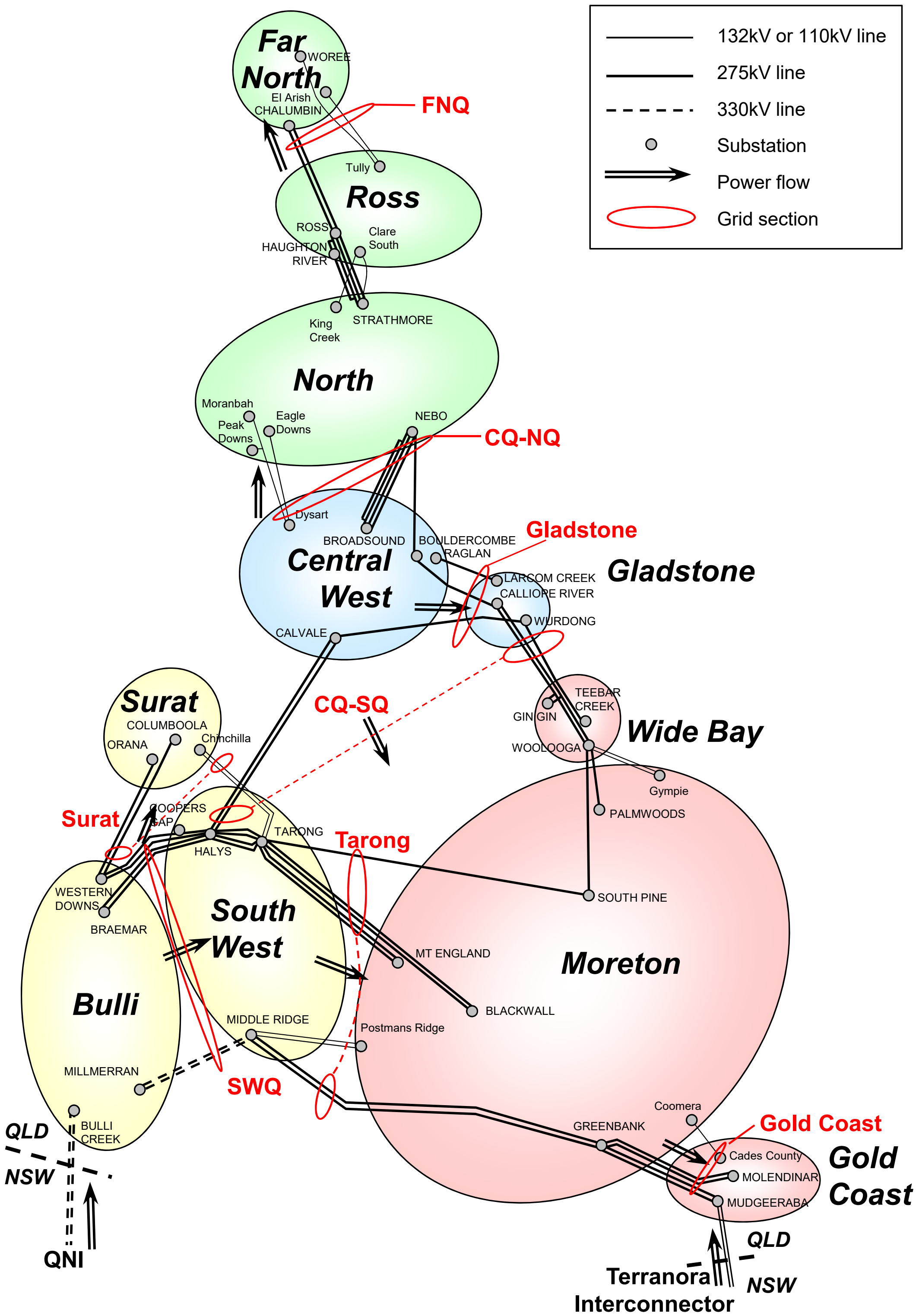


Figure C.2 Grid section legend



Appendix D Limit equations

This appendix lists the Queensland intra-regional limit equations, derived by Powerlink, valid at the time of publication. The Australian Energy Market Operator (AEMO) defines other limit equations for the Queensland Region in its market dispatch systems.

It should be noted that these equations are continually under review to take into account changing market and network conditions.

Please contact Powerlink to confirm the latest form of the relevant limit equation if required.

Table D.1 Far North Queensland (FNQ) grid section voltage stability equation

Measured variable	Coefficient (1)	
	Equation 1	Equation 2
	Ross - Chalumbin + Mt Emerald Wind Farm	Ross - Woree
Constant term (intercept)	443	455
Total MW generation at Barron Gorge	-	0.05
Total MW generation at Mt Emerald Wind Farm	-1.06	-0.42
Total MW generation at Kareeya Power Station	-0.05	-0.35
Total nominal MVAr shunt capacitors on line within nominated Cairns area locations (2)	0.08	0.07
Total nominal MVAr shunt reactors on line within nominated Cairns area locations (3)	-0.08	-0.07
Total nominal MVAr shunt capacitors on line within nominated Chalumbin area locations (4)	0.28	0.45
Total nominal MVAr shunt reactors on line within nominated Chalumbin area locations (5)	-0.28	-0.45
AEMO Constraint ID	Q^NIL_FNQ_858MEWF	Q^NIL_FNQ_8966

Notes:

(1) Equations are valid during the current FNQ reconfiguration, comprising energisation of the Ross to Woree (via Yabulu South and Tully) circuit at 275kV (previously operated at 132kV) and outage of Ross to Chalumbin and Chalumbin to Woree 275kV circuits.

(2) The shunt capacitor bank locations, nominal sizes and quantities for the Cairns area comprise the following:

Innisfail 132kV	1 x 10MVAr
Edmonton 132kV	1 x 13MVAr
Woree 132kV	2 x 54MVAr

(3) The shunt reactor location, nominal sizes and quantities for the Cairns area comprise the following:

Woree 275kV	2 x 20.17MVAr

(4) The shunt capacitor bank location, nominal size and quantities for the Chalumbin area comprise the following:

Chalumbin 132kV	1 x 50MVAr

(5) The shunt reactor locations, nominal sizes and quantities for the Chalumbin area comprise the following:

Chalumbin 275kV	2 x 29MVAr, 1 x 30MVAr
Chalumbin tertiary	1 x 20.2MVAr

Table D.2 Central to North Queensland grid section voltage stability equations

Measured variable	Coefficient Equation 1 Feeder contingency	 Equation 2 Townsville contingency (1)
Constant term (intercept)	1,500	1,650
Total MW generation at Barron Gorge, Kareeya and Koombooloomba	0.321	–
Total MW generation at Townsville	0.172	-1.000
Total MW generation at Mt Stuart	-0.092	-0.136
Number of Mt Stuart units on line [0 to 3]	22.447	14.513
Total MW generation at Mackay	-0.700	-0.478
Total MW northern VRE (2)	-1.00	-1.00
Total nominal MVAr shunt capacitors on line within nominated Ross area locations (3)	0.453	0.440
Total nominal MVAr shunt reactors on line within nominated Ross area locations (4)	-0.453	-0.440
Total nominal MVAr shunt capacitors on line within nominated Strathmore area locations (5)	0.388	0.431
Total nominal MVAr shunt reactors on line within nominated Strathmore area locations (6)	-0.388	-0.431
Total nominal MVAr shunt capacitors on line within nominated Nebo area locations (7)	0.296	0.470
Total nominal MVAr shunt reactors on line within nominated Nebo area locations (8)	-0.296	-0.470
Total nominal MVAr shunt capacitors available to the Nebo Q optimiser (9)	0.296	0.470
Total nominal MVAr shunt capacitors on line not available to the Nebo Q optimiser (9)	0.296	0.470
AEMO Constraint ID	Q^NIL_CN_FDR	Q^NIL_CN_GT

Notes:

(1) This limit is applicable only if Townsville Power Station is generating.

(2) Northern VRE include:
Mt Emerald Wind Farm, Ross River Solar Farm, Sun Metals Solar Farm, Haughton Solar Farm, Clare Solar Farm, Kidston Solar Farm, Kennedy Energy Park, Collinsville Solar Farm, Whitsunday Solar Farm, Hamilton Solar Farm, Hayman Solar Farm, Daydream Solar Farm, Rugby Run Solar Farm

(3) The shunt capacitor bank locations, nominal sizes and quantities for the Ross area comprise the following:
Ross 132kV 1 x 50MVAr
Townsville South 132kV 2 x 50MVAr
Dan Gleeson 66kV 2 x 24MVAr
Garbutt 66kV 2 x 15MVAr

(4) The shunt reactor bank locations, nominal sizes and quantities for the Ross area comprise the following:
Ross 275kV 2 x 84MVAr, 2 x 29.4MVAr

(5) The shunt capacitor bank locations, nominal sizes and quantities for the Strathmore area comprise the following:
Newlands 132kV 1 x 25MVAr
Clare South 132kV 1 x 20MVAr
Collinsville North 132kV 1 x 20MVAr

(6) The shunt reactor bank locations, nominal sizes and quantities for the Strathmore area comprise the following:
Strathmore 275kV 1 x 84MVAr

(7) The shunt capacitor bank locations, nominal sizes and quantities for the Nebo area comprise the following:
Moranbah 132kV 1 x 52MVAr
Pioneer Valley 132kV 1 x 30MVAr
Kemmis 132kV 1 x 30MVAr
Dysart 132kV 2 x 25MVAr
Alligator Creek 132kV 1 x 20MVAr
Mackay 33kV 2 x 15MVAr

(8) The shunt reactor bank locations, nominal sizes and quantities for the Nebo area comprise the following:
Nebo 275kV 1 x 84MVAr, 1 x 30MVAr, 1 x 20.2MVAr

(9) The shunt capacitor banks nominal sizes and quantities for which may be available to the Nebo Q optimiser comprise the following:
Nebo 275kV 2 x 120MVAr

The following Table describes limit equations for the inverter based resources (IBR) in north Queensland. The Boolean AND operation is applied to the system conditions across a row, if the expression yields a True value then the maximum capacity quoted for the farm in question becomes an argument to a MAX function, if False then zero (0) becomes the argument to the MAX function. The maximum capacity is the result of the MAX function.

Table D.3 NQ system strength equations

System Conditions								Maximum Capacity (%)			
Time of day (Day or Night) (1)	Number of Gladstone units online	Number of Stanwell units online	Number of Callide units online (2)	Number of CQ units online (3)	Number of Kareeya units online	NQ Load	Ross + FNQ Load	Mt Emerald WF	Sun Metals SF	Haughton SF	Other NQ Plants
D/N	≥ 2	≥ 2	≥ 1	≥ 7	≥ 2	> 350	> 150	100	100	100	100
D/N	≥ 2	≥ 2	≥ 1	≥ 7	≥ 0	> 350	> 150	100	100	50	100
D/N	≥ 3	≥ 3	≥ 0	≥ 7	≥ 2	> 450	> 250	100	100	100	100
D/N	≥ 2	≥ 3	≥ 0	≥ 6	≥ 2	> 450	> 250	80	80	80	80
D/N	≥ 2	≥ 3	≥ 2	≥ 8	≥ 0	> 450	> 250	100	100	100	100
D/N	≥ 2	≥ 2	≥ 1	≥ 7	≥ 2			0	0	0	100
D/N	≥ 2	≥ 2	≥ 1	≥ 7	≥ 0			0	0	0	100
AEMO Constraint ID								Q_NIL_STRGTH_MEWF	Q_NIL_STRGTH_SMSF	Q_NIL_STRGTH_HAUSF	Various (4)

Notes:

(1) 'Night' conditions refer to the total solar horizontal irradiance at Sun Metals, Haughton, Clare and Ross River < 4 and there are no inverters online at Sun Metals and Haughton.

(2) Refers to the total number of Callide B and Callide C units online.

(3) Refers to the number of Gladstone, Stanwell and Callide units online.

(4) Q_NIL_STRGTH_CLRSF, Q_NIL_STRGTH_COLSF, Q_NIL_STRTH_DAYSF, Q_NIL_STRTH_HAMSF, Q_NIL_STRTH_KIDSF, Q_NIL_STRGTH_RGBSF, Q_NIL_STRGTH_RRSF, Q_NIL_STRGTH_WHTSF.

System normal equations are implemented for all other north Queensland semi-scheduled generators (Ross River Solar Farm, Kidston Solar Farm, Clare Solar Farm, Whitsunday Solar Farm, Hamilton Solar Farm, Daydream Solar Farm, Hayman Solar Farm, Collinsville Solar Farm and Rugby Run Solar Farm) to ensure system security is maintained during abnormally low synchronous generator dispatches. These equations allow unconstrained operation for all but two conditions of Table D.3 where operation is constrained to 80%. Conditions resulting in lower synchronous unit capacity is constrained to 0.

Table D.4 Central to South Queensland grid section voltage stability equations

Measured variable	Coefficient
Constant term (intercept)	1,015
Total MW generation at Gladstone 275kV and 132kV	0.1407
Number of Gladstone 275kV units on line [2 to 4]	57.5992
Number of Gladstone 132kV units on line [1 to 2]	89.2898
Total MW generation at Callide B and Callide C	0.0901
Number of Callide B units on line [0 to 2]	29.8537
Number of Callide C units on line [0 to 2]	63.4098
Total MW generation in southern Queensland (1)	-0.0650
Number of 90MVAr capacitor banks available at Boyne Island [0 to 2]	51.1534
Number of 50MVAr capacitor banks available at Boyne Island [0 to 1]	25.5767
Number of 120MVAr capacitor banks available at Wurdong [0 to 3]	52.2609
Number of 50MVAr capacitor banks available at Gin Gin [0 to 1]	31.5525
Number of 120MVAr capacitor banks available at Woolooga [0 to 1]	47.7050
Number of 50MVAr capacitor banks available at Woolooga [0 to 2]	22.9875
Number of 120MVAr capacitor banks available at Palmwoods [0 to 1]	30.7759
Number of 50MVAr capacitor banks available at Palmwoods [0 to 4]	14.2253
Number of 120MVAr capacitor banks available at South Pine [0 to 4]	9.0315
Number of 50MVAr capacitor banks available at South Pine [0 to 4]	3.2522
Equation lower limit	1,550
Equation upper limit	2,100 (2)
AEMO Constraint ID	Q^^NIL_CS, Q::NIL_CS

Notes:

(1) Southern Queensland generation term refers to summated active power generation at Swanbank E, Wivenhoe, Tarong, Tarong North, Condamine, Roma, Kogan Creek, Braemar 1, Braemar 2, Darling Downs, Darling Downs Solar Farm, Oakey, Oakey 1 Solar Farm, Oakey 2 Solar Farm, Yarranlea Solar Farm, Maryrorough Solar Farm, Warwick Solar Farm, Coopers Gap Wind Farm, Millmerran, Susan River Solar Farm, Childers Solar Farm and Terranora Interconnector and Queensland New South Wales Interconnnector (QNI) transfers (positive transfer denotes northerly flow).

(2) The upper limit is due to a transient stability limitation between central and southern Queensland areas.

Table D.5 Tarong grid section voltage stability equations

Measured variable	Coefficient	
	Equation 1	Equation 2
	Calvale-Halys contingency	Tarong-Blackwall contingency
Constant term (intercept) (1)	740	1,124
Total MW generation at Callide B and Callide C	0.0346	0.0797
Total MW generation at Gladstone 275kV and 132kV	0.0134	–
Total MW in Surat, Bulli and South West and QNI transfer (2)	0.8625	0.7945
Surat/Braemar demand	-0.8625	-0.7945
Total MW generation at Wivenhoe and Swanbank E	-0.0517	-0.0687
Active power transfer (MW) across Terranora Interconnector (2)	-0.0808	-0.1287
Number of 200MVAr capacitor banks available (3)	7.6683	16.7396
Number of 120MVAr capacitor banks available (4)	4.6010	10.0438
Number of 50MVAr capacitor banks available (5)	1.9171	4.1849
Reactive to active demand percentage (6) (7)	-2.9964	-5.7927
Equation lower limit	3,200	3,200
AEMO Constraint ID	Q^^NIL_TR_CLHA	Q^^NIL_TR_TRBK

Notes:

(1) Equations 1 and 2 are offset by -100MW and -150MW respectively when the Middle Ridge to Abermain 110kV loop is run closed.

(2) Surat, Bulli and South West generation term refers to summated active power generation at generation at Tarong, Tarong North, Roma, Condamine, Kogan Creek, Braemar 1, Braemar 2, Darling Downs, Darling Downs Solar Farm, Coopers Gap Wind Farm, Oakey, Oakey 1 Solar Farm, Oakey 2 Solar Farm, Yarranlea Solar Farm, Maryrorough Solar Farm, Warwick Solar Farm, Millmerran and QNI transfers (positive transfer denotes northerly flow).

(3) There are currently 4 capacitor banks of nominal size 200MVAr which may be available within this area.

(4) There are currently 18 capacitor banks of nominal size 120MVAr which may be available within this area.

(5) There are currently 38 capacitor banks of nominal size 50MVAr which may be available within this area.

(6) Reactive to active demand percentage $= \dfrac{\text{Zone reactive demand}}{\text{Zone active demand}} \times 100$

Zone reactive demand (MVAr) = Reactive power transfers into the 110kV measured at the 132/110kV transformers at Palmwoods and 275/110kV transformers inclusive of south of South Pine and east of Abermain + reactive power generation from 50MVAr shunt capacitor banks within this zone + reactive power transfer across Terranora Interconnector.

Zone active demand (MW) = Active power transfers into the 110kV measured at the 132/110kV transformers at Palmwoods and the 275/110kV transformers inclusive of south of South Pine and east of Abermain + active power transfer on Terranora Interconnector.

(7) The reactive to active demand percentage is bounded between 10 and 35.

Table D.6 Gold Coast grid section voltage stability equation

Measured variable	Coefficient
Constant term (intercept)	1,351
Moreton to Gold Coast demand ratio (1) (2)	-137.50
Number of Wivenhoe units on line [0 to 2]	17.7695
Number of Swanbank E units on line [0 to 1]	-20.0000
Active power transfer (MW) across Terranora Interconnector (3)	-0.9029
Reactive power transfer (MVAr) across Terranora Interconnector (3)	0.1126
Number of 200MVAr capacitor banks available (4)	14.3339
Number of 120MVAr capacitor banks available (5)	10.3989
Number of 50MVAr capacitor banks available (6)	4.9412
AEMO Constraint ID	Q^NIL_GC

Notes:

(1) Moreton to Gold Coast demand ratio $= \frac{\text{Moreton zone active demand}}{\text{Gold Coast zone active demand}} \times 100$

(2) The Moreton to Gold Coast demand ratio is bounded between 4.7 and 6.0.

(3) Positive transfer denotes northerly flow.

(4) There are currently 4 capacitor banks of nominal size 200MVAr which may be available within this area.

(5) There are currently 16 capacitor banks of nominal size 120MVAr which may be available within this area.

(6) There are currently 34 capacitor banks of nominal size 50MVAr which may be available within this area.

Appendix E Indicative short circuit currents

Tables E.1 to E.3 show indicative maximum and minimum short circuit currents at Powerlink Queensland's substations.

Indicative maximum short circuit currents

Tables E.1 to E.3 show indicative maximum symmetrical three phase and single phase to ground short circuit currents in Powerlink's transmission network for summer 2021/22, 2022/23 and 2023/24 respectively.

These results include the short circuit contribution of some of the more significant embedded non-scheduled generators, however smaller embedded non-scheduled generators may have been excluded. As a result, short circuit currents may be higher than shown at some locations. Therefore, this information should be considered as an indicative guide to short circuit currents at each location and interested parties should consult Powerlink and/or the relevant Distribution Network Service Provider (DNSP) for more detailed information.

The maximum short circuit currents were calculated:

- using a system model, in which generators were represented as a voltage source of 110% of nominal voltage behind sub-transient reactance, and
- with all model shunt elements removed.

The short circuit currents shown in tables E.1 to E.3 are based on generation shown in tables 8.1 and 8.2 (together with any of the more significant embedded non-scheduled generators) and on the committed network development as at the end of each calendar year. The tables also show the rating of the lowest rated Powerlink owned plant at each location. No assessment has been made of the short circuit currents within networks owned by DNSPs or directly connected customers, nor has an assessment been made of the ability of their plant to withstand and/or interrupt the short circuit current.

The maximum short circuit currents presented in this appendix are based on all generating units online and an 'intact' network, that is, all network elements are assumed to be in service. This assumption can result in short circuit currents appearing to be above plant rating at some locations. Where this is found, detailed assessments are made to determine if the contribution to the total short circuit current that flows through the plant exceeds its rating. If so, the network may be split to create a 'normally-open' point as an operational measure to ensure that short circuit currents remain within the plant rating, until longer term solutions can be justified.

Indicative minimum short circuit currents

Minimum short circuit currents are used to inform the capacity of the system to accommodate fluctuating loads and power electronic connected systems (including non-synchronous generators and static VAr compensators (SVC)). Minimum short circuit currents are also important in ensuring power quality and system stability standards are met and for ensuring the proper operation of protection systems.

Tables E.1 to E.3 show indicative minimum system normal and post-contingent symmetrical three phase short circuit currents at Powerlink's substations. These were calculated by taking the existing intact network and setting the synchronous generator dispatch to align with AEMO's assumptions for minimum three phase fault level. The short circuit current is calculated, using the subtransient generator impedances, with the system intact and with individual outages of each significant network element. The minimum short circuit current which results from these outages is reported.

The short circuit currents are calculated using the same methodology as the 2020 System Strength and Interia Report published by AEMO in December 2020. However, small variations may exist between these two datasets due to variations in input data and modelling assumptions.

These minimum short circuit currents are indicative only. The system strength available to new non-synchronous generators can only be assessed by a Full Impact Assessment using EMT-type modelling techniques. See Section 10.3 for full details.

Table E.1 Indicative short circuit currents – northern Queensland – 2021/22 to 2023/24

Substation	Voltage (kV)	Plant Rating (lowest kA)	Indicative minimum system normal fault level (kA)	Indicative minimum post-contingent fault level (kA)	Indicative maximum short circuit currents					
					2021/22		2022/23		2023/24	
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)
Alan Sherriff	132	40.0	4.1	3.8	13.7	13.9	13.6	13.8	13.6	13.8
Alligator Creek	132	25.0	3.2	1.9	4.4	5.8	4.4	5.8	4.4	5.8
Bolingbroke	132	40.0	2.0	1.9	2.5	1.9	2.5	1.9	2.5	1.9
Bowen North	132	40.0	2.5	1.6	2.8	3.1	2.8	3.0	2.9	3.2
Cairns (2T)	132	25.0	2.9	0.7	5.9	7.9	6.0	7.9	6.2	8.1
Cairns (3T)	132	25.0	2.9	0.7	5.9	7.9	6.0	7.9	6.2	8.1
Cairns (4T)	132	25.0	2.9	0.7	5.9	7.9	-	-	-	-
Cardwell	132	19.3	1.9	1.0	3.1	3.3	3.1	3.3	3.1	3.3
Chalumbin	275	31.5	1.8	0.7	4.2	4.4	4.3	4.5	4.6	4.9
Chalumbin	132	31.5	3.3	1.6	6.6	7.6	6.6	7.6	6.8	8.0
Clare South	132	40.0	3.3	2.8	8.0	8.1	7.9	8.0	6.6	6.8
Collinsville North	132	31.5	4.4	2.1	9.1	10.1	9.1	10.0	11.1	11.9
Coppabella	132	31.5	2.2	1.5	3.0	3.4	3.0	3.4	3.0	3.4
Crush Creek	275	40.0	3.5	3.1	9.7	10.9	9.7	10.8	9.9	11.2
Dan Gleeson (1T)	132	31.5	4.1	3.8	12.9	13.3	12.9	13.2	12.8	13.2
Dan Gleeson (2T)	132	40.0	4.1	3.8	12.9	13.4	12.9	13.3	12.8	13.3
Edmonton	132	40.0	1.3	0.4	5.4	6.6	5.4	6.6	5.6	6.8
Eagle Downs	132	40.0	3.0	1.5	4.6	4.4	4.5	4.4	4.6	4.4
El Arish	132	40.0	2.0	0.9	3.3	4.0	3.3	4.0	3.3	4.1
Garbutt	132	40.0	3.8	1.8	11.2	11.0	11.1	11.0	11.1	10.9
Goonyella Riverside	132	40.0	3.5	1.5	5.9	5.4	5.9	5.4	6.0	5.4
Haughton River	275	40.0	2.7	2.1	7.7	8.0	7.7	8.0	7.8	8.1
Ingham South	132	31.5	1.9	1.0	3.3	3.4	3.3	3.4	3.3	3.4
Innisfail	132	40.0	1.8	1.2	3.0	3.6	3.0	3.6	3.0	3.6
Invicta	132	19.3	2.5	2.4	5.3	4.8	5.3	4.8	5.2	4.8
Kamerunga	132	15.3	2.4	1.4	4.5	5.4	4.6	5.4	4.7	5.5
Kareeya	132	40.0	3.0	1.5	5.6	6.3	5.7	6.3	5.8	6.5
Kemmis	132	31.5	3.9	1.6	6.1	6.6	6.0	6.6	6.0	6.6
King Creek	132	40.0	2.8	2.0	5.1	4.2	5.1	4.2	5.3	4.3
Lake Ross	132	31.5	4.7	4.3	18.0	20.0	17.8	19.9	17.8	19.8
Mackay	132	10.9	3.5	2.9	5.0	6.0	5.0	6.0	5.0	6.0
Mackay Ports	132	40.0	2.6	1.6	3.4	4.1	3.4	4.1	3.4	4.1

Table E.1 Indicative short circuit currents – northern Queensland – 2021/22 to 2023/24 ***(continued)***

Substation	Voltage (kV)	Plant Rating (lowest kA)	Indicative minimum system normal fault level (kA)	Indicative minimum post-contingent fault level (kA)	Indicative maximum short circuit currents 2021/22 3 phase (kA)	2021/22 L – G (kA)	2022/23 3 phase (kA)	2022/23 L – G (kA)	2023/24 3 phase (kA)	2023/24 L – G (kA)
Mindi	132	40.0	3.3	3.1	4.8	3.7	4.8	3.7	4.8	3.7
Moranbah	132	10.9	4.1	3.3	7.9	9.3	7.9	9.2	7.9	9.3
Moranbah Plains	132	40.0	2.7	2.3	4.4	4.0	4.4	4.0	4.4	4.0
Moranbah South	132	31.5	3.3	2.8	5.7	5.2	5.7	5.2	5.7	5.2
Mt Fox	275	40.0	-	-	-	-	-	-	5.3	4.0
Mt Mclaren	132	31.5	1.6	1.4	2.1	2.3	2.1	2.3	2.1	2.3
Nebo	275	31.5	4.7	4.1	10.6	10.9	10.6	10.8	10.6	10.8
Nebo	132	25.0	7.3	6.4	13.4	15.5	13.4	15.4	13.4	15.4
Newlands	132	25.0	2.5	1.2	3.5	4.0	3.5	3.9	3.6	4.0
North Goonyella	132	20.0	2.9	1.4	4.5	3.7	4.4	3.7	4.5	3.7
Oonooie	132	31.5	2.4	1.5	3.1	3.6	3.1	3.6	3.1	3.6
Peak Downs	132	31.5	2.9	2.2	4.2	3.7	4.2	3.7	4.2	3.7
Pioneer Valley	132	31.5	4.2	3.6	6.5	7.4	6.5	7.4	6.5	7.4
Proserpine	132	40.0	2.0	1.3	3.3	3.8	3.3	3.8	3.5	4.0
Ross	275	31.5	2.8	2.5	8.9	10.0	8.9	9.9	9.1	10.1
Ross	132	31.5	4.7	4.3	18.6	20.8	18.4	20.7	18.4	20.6
Springlands	132	31.5	4.7	2.2	9.8	11.0	9.8	10.9	12.2	14.0
Stony Creek	132	40.0	2.5	1.1	3.7	3.6	3.7	3.6	3.8	3.7
Strathmore	275	31.5	3.6	3.1	9.8	11.0	9.8	11.0	10.0	11.4
Strathmore	132	40.0	4.8	2.2	10.0	11.5	10.0	11.4	12.6	14.9
Townsville East	132	40.0	3.9	1.5	13.2	12.7	13.1	12.6	12.9	12.4
Townsville South	132	20.0	4.2	3.9	18.0	21.6	17.7	21.3	17.3	20.8
Townsville GT PS	132	31.5	3.6	2.4	10.8	11.3	10.7	11.2	10.7	11.2
Tully	132	31.5	2.3	1.9	4.1	4.2	4.1	4.2	4.1	4.3
Tumoulin	275	40.0	-	-	-	-	-	-	3.8	4.5
Turkinje	132	20.0	1.8	1.1	2.7	3.1	2.7	3.1	2.7	3.1
Walkamin	275	40.0	1.5	0.7	3.2	3.7	3.3	3.8	3.4	4.0
Wandoo	132	31.5	3.3	3.1	4.5	3.3	4.5	3.3	4.5	3.3
Woree (1T)	275	40.0	1.4	0.7	2.8	3.3	2.8	3.3	3.0	3.4
Woree (2T)	275	40.0	1.4	0.7	2.9	3.4	2.9	3.4	3.0	3.5
Woree	132	40.0	2.9	1.6	6.1	8.4	6.2	8.5	6.4	8.8
Wotonga	132	40.0	3.6	1.7	6.2	7.1	6.1	7.1	6.2	7.1
Yabulu South	132	40.0	4.0	3.7	13.0	12.2	12.9	12.2	12.9	12.2

Table E.2 Indicative short circuit currents – CQ – 2021/22 to 2023/24

Substation	Voltage (kV)	Plant Rating (lowest kA)	Indicative minimum system normal fault level (kA)	Indicative minimum post-contingent fault level (kA)	Indicative maximum short circuit currents					
					2021/22		2022/23		2023/24	
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)
Baralaba	132	15.3	3.9	2.5	4.2	3.6	4.4	3.7	4.4	3.7
Biloela	132	20.0	3.7	1.1	7.8	8.1	8.1	8.3	8.1	8.3
Blackwater	132	31.5	4.4	3.9	5.9	7.0	5.8	7.0	5.8	7.0
Bluff	132	40.0	2.8	2.6	3.5	4.3	3.5	4.3	3.5	4.3
Bouldercombe	275	31.5	10.8	9.3	20.3	19.7	20.3	19.6	20.4	19.7
Bouldercombe	132	21.8	9.1	4.8	14.3	16.7	14.3	16.6	14.3	16.6
Bororen	275	40.0	-	-	-	-	-	-	8.9	9.5
Broadsound	275	31.5	6.3	5.1	12.3	9.3	12.2	9.2	12.3	9.2
Bundoora	132	31.5	5.5	4.7	9.2	8.9	9.1	8.8	9.1	8.8
Callemondah	132	31.5	17.2	6.7	22.1	24.7	22.0	24.6	22.3	24.8
Calliope River	275	40.0	12.2	10.5	20.8	23.7	20.9	23.8	21.4	24.4
Calliope River	132	40.0	19.0	15.6	24.7	29.8	24.7	29.8	25.0	30.1
Calvale	275	31.5	11.5	8.7	23.5	26.0	23.7	26.0	23.7	26.1
Calvale (1T)	132	31.5	5.6	1.0	8.7	9.6	8.9	9.7	8.9	9.7
Calvale (2T)	132	40.0	5.8	1.2	8.4	9.3	8.6	9.4	8.6	9.4
Duaringa	132	40.0	1.9	1.7	2.3	2.9	2.3	2.9	2.3	2.9
Dysart	132	10.9	3.2	1.9	4.8	5.4	4.8	5.3	4.8	5.3
Egans Hill	132	25.0	5.7	3.7	8.3	8.2	8.2	8.1	8.3	8.1
Gladstone PS	275	40.0	11.7	10.0	19.4	21.6	19.5	21.7	19.9	22.1
Gladstone PS	132	40.0	17.2	13.7	21.8	25.0	21.7	25.0	21.9	25.1
Gladstone South	132	40.0	12.8	9.6	16.2	17.3	16.2	17.2	16.3	17.3
Grantleigh	132	31.5	2.2	1.8	2.7	2.8	2.7	2.8	2.7	2.8
Gregory	132	31.5	6.0	5.0	10.2	11.3	10.1	11.2	10.1	11.2
Larcom Creek	275	40.0	9.5	3.3	15.4	15.3	15.5	15.3	15.7	15.5
Larcom Creek	132	40.0	7.7	4.0	12.3	13.8	12.3	13.8	12.3	13.8
Lilyvale	275	31.5	3.7	2.8	6.2	6.0	6.2	6.0	6.2	6.0
Lilyvale	132	25.0	6.2	5.1	10.7	12.3	10.6	12.2	10.6	12.2
Moura	132	40.0	3.2	1.7	3.9	4.2	4.4	4.6	4.4	4.6
Norwich Park	132	31.5	2.7	2.6	3.7	2.7	3.7	2.7	3.7	2.7
Pandoin	132	40.0	4.8	3.3	6.9	6.0	6.9	6.1	6.9	6.1
Raglan	275	40.0	7.9	4.4	11.9	10.4	11.9	10.4	12.0	10.4
Rockhampton (1T)	132	40.0	4.7	1.2	6.4	6.3	6.4	6.3	6.4	6.3

Table E.2 Indicative short circuit currents – CQ – 2021/22 to 2023/24 (*continued*)

Substation	Voltage (kV)	Plant Rating (lowest kA)	Indicative minimum system normal fault level (kA)	Indicative minimum post-contingent fault level (kA)	Indicative maximum short circuit currents					
					2021/22		2022/23		2023/24	
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)
Rockhampton (5T)	132	40.0	4.5	1.3	6.2	6.1	6.2	6.1	6.2	6.1
Rocklands	132	31.5	5.6	3.6	7.7	6.6	7.7	6.5	7.7	6.5
Stanwell	275	31.5	11.6	9.6	23.0	24.6	23.0	24.6	23.1	24.7
Stanwell	132	31.5	4.5	3.2	5.9	6.4	5.9	6.4	5.9	6.4
Wurdong	275	31.5	10.7	6.7	16.6	16.5	16.7	16.6	17.3	17.7
Wycarbah	132	40.0	3.6	2.7	4.5	5.4	4.5	5.4	4.5	5.4
Yarwun	132	40.0	7.5	4.4	12.9	14.9	12.9	14.8	12.9	14.9

Table E.3 Indicative short circuit currents – southern Queensland – 2021/22 to 2023/24

Substation	Voltage (kV)	Plant Rating (lowest kA)	Indicative minimum system normal fault level (kA)	Indicative minimum post-contingent fault level (kA)	Indicative maximum short circuit currents					
					2021/22		2022/23		2023/24	
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)
Abermain	275	40.0	8.3	6.5	18.2	18.7	18.3	18.7	18.3	18.7
Abermain	110	31.5	13.1	10.4	21.5	24.5	21.4	24.4	21.4	24.4
Algester	110	40.0	13.2	11.8	21.1	20.9	21.0	20.8	21.0	20.8
Ashgrove West	110	26.3	12.4	9.4	19.1	20.1	19.1	20.0	19.1	20.0
Belmont	275	31.5	8.1	7.4	16.9	17.8	17.0	17.8	17.0	17.8
Belmont	110	37.4	16.0	15.0	27.8	34.4	27.7	34.3	27.7	34.3
Blackstone	275	40.0	8.9	8.1	21.2	23.3	21.3	23.3	21.3	23.4
Blackstone	110	40.0	14.8	13.6	25.4	27.9	25.4	27.8	25.4	27.8
Blackwall	275	37.0	9.5	8.6	22.5	24.2	22.6	24.2	22.6	24.2
Blythdale	132	40.0	3.2	2.3	4.3	5.3	4.3	5.3	4.3	5.3
Braemar	330	50.0	7.2	5.9	24.2	26.2	24.3	26.3	24.3	26.3
Braemar (East)	275	40.0	8.3	5.4	27.4	31.6	27.4	31.7	27.4	31.7
Braemar (West)	275	40.0	8.1	4.7	28.5	31.3	28.7	31.5	28.7	31.5
Bulli Creek	330	50.0	7.1	3.4	18.6	14.6	18.6	14.8	18.6	14.8
Bulli Creek	132	40.0	3.0	3.0	3.8	4.3	3.8	4.3	3.8	4.3
Bundamba	110	40.0	11.2	7.7	17.3	16.6	17.2	16.5	17.2	16.5
Cameby	132	40.0	-	-	10.1	8.6	10.8	9.6	10.8	9.6
Chinchilla	132	25.0	5.4	3.8	8.2	8.1	8.5	10.0	8.5	10.0
Clifford Creek	132	40.0	4.1	3.4	5.9	5.3	5.9	5.3	5.9	5.3
Columboola	275	40.0	5.6	4.3	13.6	12.8	13.8	13.0	13.8	13.0
Columboola	132	25.0	7.8	5.0	17.6	20.6	18.1	21.0	18.1	21.0
Condabri North	132	40.0	6.9	5.5	14.0	13.0	14.4	13.2	14.3	13.2
Condabri Central	132	40.0	5.4	4.5	9.3	6.9	9.5	7.0	9.5	7.0
Condabri South	132	40.0	4.4	3.7	6.7	4.5	6.8	4.6	6.8	4.6
Coopers Gap	275	40.0	8.3	3.2	17.8	17.6	18.0	17.7	18.0	17.7
Dinoun South	132	40.0	4.6	3.6	6.7	7.0	6.7	7.0	6.7	7.0
Eurombah (1T)	275	40.0	2.8	1.2	4.6	4.7	4.6	4.7	4.6	4.7
Eurombah (2T)	275	40.0	2.8	1.2	4.6	4.7	4.6	4.7	4.6	4.7
Eurombah	132	40.0	4.7	3.5	7.2	8.7	7.2	8.7	7.2	8.7
Fairview	132	40.0	3.0	2.5	4.1	5.2	4.1	5.2	4.1	5.2
Fairview South	132	40.0	3.8	2.9	5.4	6.8	5.4	6.8	5.4	6.8
Gin Gin	275	14.5	6.5	4.4	9.1	8.5	9.3	8.6	9.3	8.7

Table E.3 Indicative short circuit currents – southern Queensland – 2021/22 to 2023/24 (*continued*)

Substation	Voltage (kV)	Plant Rating (lowest kA)	Indicative minimum system normal fault level (kA)	Indicative minimum post-contingent fault level (kA)	Indicative maximum short circuit currents					
					2021/22		2022/23		2023/24	
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)
Gin Gin	132	20.0	8.0	6.0	11.9	12.9	12.0	13.0	12.1	13.0
Goodna	275	40.0	8.0	5.6	16.3	16.0	16.3	16.0	16.3	16.0
Goodna	110	40.0	14.9	13.1	25.4	27.5	25.4	27.4	25.4	27.4
Greenbank	275	40.0	8.7	8.0	20.5	22.5	20.6	22.5	20.6	22.5
Halys	275	50.0	12.1	10.4	33.0	28.4	33.3	28.4	33.3	28.4
Kumbarilla Park (1T)	275	40.0	6.8	1.7	16.9	16.2	16.9	16.2	16.9	16.2
Kumbarilla Park (2T)	275	40.0	6.8	1.7	16.9	16.2	16.9	16.2	16.9	16.2
Kumbarilla Park	132	40.0	8.4	5.6	13.2	15.3	13.2	15.2	13.2	15.2
Loganlea	275	40.0	7.5	6.2	15.0	15.4	15.0	15.4	15.0	15.4
Loganlea	110	25.0	13.6	12.2	22.7	27.3	22.7	27.1	22.7	27.1
Middle Ridge (4T)	330	50.0	5.9	3.2	12.8	12.4	12.8	12.3	12.8	12.3
Middle Ridge (5T)	330	50.0	6.0	3.2	13.2	12.8	13.1	12.7	13.1	12.7
Middle Ridge	275	31.5	7.8	6.9	18.4	18.5	18.4	18.4	18.4	18.4
Middle Ridge	110	18.3	10.8	8.9	21.7	25.6	21.4	25.3	21.4	25.3
Millmerran	330	40.0	6.5	6.1	18.6	19.9	18.6	19.9	18.6	19.9
Molendinar (1T)	275	40.0	5.1	2.1	8.3	8.1	8.2	8.0	8.2	8.0
Molendinar (2T)	275	40.0	5.1	2.1	8.3	8.1	8.2	8.0	8.2	8.0
Molendinar	110	40.0	12.4	10.8	20.1	25.3	19.2	24.3	19.2	24.3
Mt England	275	31.5	9.4	8.5	22.8	23.0	22.9	23.0	22.9	23.0
Mudgeeraba	275	31.5	5.6	4.5	9.5	9.4	9.3	8.5	9.3	8.5
Mudgeeraba	110	25.0	11.8	10.9	18.8	22.9	17.3	21.0	17.3	21.0
Murarrie (1T)	275	40.0	7.0	2.3	13.2	13.2	13.2	13.2	13.2	13.2
Murarrie (2T)	275	40.0	7.0	2.3	13.2	13.3	13.2	13.3	13.2	13.3
Murarrie	110	40.0	14.2	13.1	23.8	28.8	23.7	28.8	23.7	28.8
Oakey Gt	110	31.5	4.9	3.5	11.4	12.5	11.3	12.4	11.3	12.4
Oakey	110	40.0	4.6	1.3	10.2	10.1	10.1	10.0	10.1	10.0
Orana	275	40.0	6.3	3.3	15.9	14.6	16.3	16.4	16.3	16.4
Palmwoods	275	31.5	5.7	3.5	8.5	9.0	8.7	9.0	8.7	9.0
Palmwoods	132	21.9	8.0	6.1	13.0	15.8	13.2	15.9	13.2	15.9
Palmwoods (7T)	110	40.0	5.7	2.6	7.2	7.6	7.2	7.5	7.2	7.5

Table E.3 Indicative short circuit currents – southern Queensland – 2021/22 to 2023/24 (*continued*)

Substation	Voltage (kV)	Plant Rating (lowest kA)	Indicative minimum system normal fault level (kA)	Indicative minimum post-contingent fault level (kA)	Indicative maximum short circuit currents					
					2021/22		2022/23		2023/24	
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)
Palmwoods (8T)	110	40.0	5.7	2.6	7.2	7.6	7.2	7.5	7.2	7.5
Redbank Plains	110	31.5	13.2	9.7	21.4	20.7	21.3	20.6	21.3	20.6
Richlands	110	40.0	13.5	11.2	21.9	22.6	21.8	22.5	21.8	22.5
Rocklea (1T)	275	31.5	7.1	2.3	13.2	12.3	13.2	12.3	13.3	12.3
Rocklea (2T)	275	31.5	5.5	2.3	8.8	8.4	8.8	8.4	8.8	8.4
Rocklea	110	31.5	14.9	13.1	25.0	28.7	24.9	28.6	24.9	28.7
Runcorn	110	40.0	12.2	8.7	18.8	19.2	18.8	19.1	18.8	19.1
South Pine	275	31.5	9.1	8.4	18.8	21.3	19.0	21.5	19.0	21.5
South Pine (West)	110	40.0	13.1	10.3	20.5	23.6	20.4	23.5	20.4	23.5
South Pine (East)	110	40.0	13.8	11.8	21.6	27.6	21.6	27.6	21.6	27.7
Sumner	110	40.0	13.0	9.2	20.7	20.3	20.6	20.2	20.6	20.2
Swanbank E	275	40.0	8.8	7.4	20.8	22.7	21.0	22.9	21.0	22.9
Tangkam	110	31.5	5.7	3.9	13.5	12.5	13.4	12.3	13.4	12.3
Tarong	275	31.5	12.6	10.7	34.3	36.0	34.6	36.2	34.7	36.2
Tarong (1T)	132	25.0	4.5	1.1	5.8	6.0	5.8	6.0	5.8	6.0
Tarong (4T)	132	31.5	4.5	1.1	5.8	6.0	5.8	6.0	5.8	6.0
Tarong	66	40.0	11.5	6.7	15.1	16.2	15.4	16.5	15.4	16.5
Teebar Creek	275	40.0	5.1	2.4	7.2	6.9	7.4	7.1	7.5	7.2
Teebar Creek	132	40.0	7.4	4.5	10.4	11.3	10.8	11.5	10.9	11.6
Tennyson	110	40.0	10.7	9.8	16.3	16.4	16.2	16.3	16.2	16.3
Upper Kedron	110	40.0	13.4	11.6	21.2	18.8	21.2	18.7	21.2	18.7
Wandoan South	275	40.0	4.0	3.1	7.9	8.6	7.9	8.5	7.9	8.5
Wandoan South	132	40.0	5.7	4.4	10.1	13.0	10.0	12.8	10.0	12.8
West Darra	110	40.0	14.8	13.6	24.9	23.8	24.8	23.7	24.9	23.7
Western Downs	275	40.0	7.9	5.4	27.3	28.5	27.6	29.2	27.7	29.2
Woolooga	275	31.5	6.7	5.7	9.8	11.1	10.5	11.5	10.5	11.6
Woolooga	132	25.0	9.3	7.4	13.2	15.5	14.5	16.6	14.6	16.7
Yuleba North	275	40.0	3.5	2.8	6.3	6.8	6.3	6.8	6.3	6.8
Yuleba North	132	40.0	5.2	4.0	8.1	9.8	8.1	9.8	8.1	9.8

Appendix F Glossary

ABS	Australian Bureau of Statistics
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ARENA	Australian Renewable Energy Agency
BSL	Boyne Smelters Limited
BESS	Battery energy storage system
CAA	Connection and Access Agreement
CBD	Central Business District
COVID-19	Coronavirus disease 2019
CPI	Consumer Price Index
CQ	Central Queensland
CQ-SQ	Central Queensland to South Queensland
CQ-NQ	Central Queensland to North Queensland
CSG	Coal seam gas
DCA	Dedicated Connection Assets
DEPW	Department of Energy and Public Works
DER	Disbributed Energy Resources
DNSP	Distribution Network Service Provider
DSM	Demand side management
EFCS	Emergency Frequency Control Schemes
EII	Energy Infrastructure Investments
ENA	Energy Networks Australia
EMT-type	Eletromagnetic Transient-type
EOI	Expresession of interest
ESOO	Electricity Statement of Opportunity
EV	Electric vehicles
FIA	Full Impact Assessment
FIT	Feed-in tariff
FNQ	Far North Queensland
GCG	Generation Capacity Guide
IAM	Institute of Asset Management
IEP	Integrated Electricity Pathways
ISP	Integrated System Plan
IUSA	Identified User Shared Assets
JPB	Jurisdictional Planning Body
kA	Kiloampere
kV	Kilovolts
LTTW	Lightning Trip Time Window
MLF	Marginal Loss Factor
MVA	Megavolt Ampere
MVAr	Megavolt Ampere reactive
MW	Megawatt
MWh	Megawatt hour
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NER	National Electricity Rules
NNESR	Non-network Engagement Stakeholder Register
NIEIR	National Institute of Economic and Industry Research
NSP	Network Service Provider
NSCAS	Nework Support and Control Ancillary Service
NSW	New South Wales
NQ	North Queensland
OFGS	Over Frequency Generation Shedding
PACR	Project Assessment Conclusion Report
PADR	Project Assessment Draft Report
PHES	Pumped Hydro Energy Storage
PIA	Preliminary impact assessment
PoE	Probability of Exceedance
PS	Power Station
PSCR	Project Specification Consultation Report

Appendix G - Glossary **(continued)**

PSFRR	Power System Frequency Risk Review
PV	Photovoltaic
PVNSG	Photovoltaic non-scheduled generation
QAL	Queensland Alumina Limited
QER	Queensland Energy Regulator
QHES	Queensland Household Energy Survey
QNI	Queensland/New South Wales Interconnector
QRET	Queensland Renewable Energy Target
QREZ	Queensland Renewable Energy Zone
REZ	Renewable Energy Zone
RIT-D	Regulatory Investment Test for Distribution
RIT-T	Regulatory Investment Test for Transmission
SCR	Short Circuit Ratio
SDA	State Development Area
SEQ	South East Queensland
SPS	Special Protection Scheme
STATCOM	Static Synchronous Compensator
SVC	Static VAr Compensator
SWQ	South West Queensland
SynCon	Synchronous Condensor
TAPR	Transmission Annual Planning Report
TGCP	TAPR Guideline Connection Point
TGTL	TAPR Guideline Transmission Line
TNSP	Transmission Network Service Provider
Twh	Tera watt hours
UFLS	Under Frequency Load Shed
UVLS	Under Voltage Load Shed
VCR	Value of Customer Reliability
VRE	Variable renewable energy
VTL	Virtual transmission line
WAMPAC	Wide area monitoring protection and control

Contact us

Registered office	33 Harold St Virginia Queensland 4014 Australia ABN 82 078 849 233
Postal address	PO Box 1193 Virginia Queensland 4014 Australia
Telephone	+61 7 3860 2111 (during business hours)
Email	pqenquiries@powerlink.com.au
Website	www.powerlink.com.au
Social media	