2022 Transmission Annual Planning Report

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Foreword

'The energy transformation and the opportunities it brings to Queensland continue to grow'

Planning of the Queensland transmission network has never been more important. We are going through a once in a generation change as we navigate to net zero by 2050. Powerlink, as the Jurisdictional Planning Body (JPB) for Queensland, is adopting a staged, least regret path when planning the transmission network to ensure Queenslanders remain connected to reliable and cost-effective electricity into the future.

The Queensland Government's 50% Renewable Energy Target by 2030 is well within our grasp. Proponents of significant variable renewable energy (VRE) generation, storage systems as well as alternative energy projects such as hydrogen, are in detailed discussions with Powerlink's experts to connect to the transmission network.

As we've seen in recent years, interest remains high from VRE generation projects proponents aspiring to connect in an ideal location such as Queensland. Since publication of the 2021 Transmission Annual Planning Report (TAPR), Powerlink has completed four projects to connect VRE developments and construction is underway to connect a further 1,640MW of generation and battery projects. Powerlink is also progressing a significant number of connection applications which are well advanced.

Powerlink's network planning shows that the transmission network will require augmentation in the years to come to enable the transfer of large amounts of energy from intermittent renewable generators to storage facilities and then to load centres. This has been conveyed in the recently released Queensland Energy and Jobs Plan and foreshadowed in the Australian Energy Market Operator's 2022 Integrated System Plan (ISP). As the transmission network expands, Powerlink is committed to proactive engagement and to working with communities, industry and stakeholders to create and sustain long-term value for customers.

In collaboration with the Queensland Government and industry, we are delivering Australia's first tranche of Renewable Energy Zones (REZ) which will unlock up to 500MW of renewable capacity in northern Queensland by the end of 2023 and support the development of one of Australia's largest onshore wind farms in southern Queensland by early 2024. These REZ sit at the forefront of transformational change and are a sign of what can be achieved as Queensland unleashes its renewable energy potential which is the envy of the world.

Looking out over the 10-year period of the TAPR, as we leverage the changing generation mix and load behaviours of the new energy system, it is clear challenges await us. Powerlink is looking ahead to meet these challenges with a focus on innovation and the introduction of alternate technology and non-network solutions to ensure the smooth operation of the transmission network and to shape the development of cost-effective investment solutions for our customers.

We trust the information contained in this TAPR such as the energy and demand forecasts, committed generation, current transmission projects and areas of possible future transmission network investments, will help inform communities, customers and industry about Powerlink's future plans.

As we embark on the energy transformation to connect Queenslanders to a world-class energy future, our commitment remains on providing safe, reliable and cost-effective electricity to more than five million Queenslanders and 238,000 businesses who depend on our services every day.

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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 2022 TAPR outlines the key factors impacting Powerlink's transmission network development and operations. The TAPR also discusses the energy transformation and 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 mild growth for summer maximum demand, and decline in the minimum delivered demand. The forecast delivered energy from the transmission network over the 10-year outlook period remains relatively unchanged but with a slight upward trajectory mainly due to industries beginning to electrify their operations to meet their emission reduction targets.

Powerlink has worked closely with the Queensland Government in the development of the Queensland Energy and Jobs Plan (QEJP) which was released in late September 2022. This work included supporting the establishment of new Queensland Renewable Energy Zones (QREZ), as well as input on the new transmission infrastructure required to support the energy transformation which has the potential to create long-lasting benefits for Queensland communities.

The capital expenditure required to manage emerging risks related to assets reaching the end of their technical service life continues to represent a substantial program of work over the outlook period. As indicated in the QEJP, the impact and increasing momentum of the energy transformation in Queensland will result in the need for additional capital expenditure for network augmentations. As a result, the energy transformation will significantly change the requirements for transmission infrastructure in the outlook period as discussed in Powerlink's 'Actioning the Queensland Energy and Jobs Plan'. While not included in the 2022 TAPR analysis, this work is well underway and the 2023 TAPR will incorporate the QEJP in conjunction with AEMO's Integrated System Plan (ISP) to inform communities, customers and other stakeholders of Powerlink's future planning activities.

Network planning studies for the 2022 TAPR have focused on evaluating the enduring need for existing assets and the possible need for new assets to ensure network resilience in the context of increasing diversity of generation, a mild growth in demand 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 to seek stakeholder input on planning and decision-making across a range of topics. We also held an Energy Transformation Webinar in March to provide further detail on the development of Powerlink's 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 focused on driving a customer-centric culture and conduct in energy businesses to create price and service delivery improvements for the benefit of customers.

Enabling the energy transformation in Queensland

The transmission system has a critical role to play as a central platform and enabler for the energy transformation. Powerlink is playing an active role by strategically planning the transmission network, guiding and shaping the power system, as Queensland moves to a lower carbon future. This will ensure that the high voltage transmission network is capable of unlocking opportunities and benefits associated with a decarbonised energy system. This will help power economic growth, enable market efficiencies, deliver local benefits to communities and minimise costs to customers.

Potential developments associated with electrification and hydrogen electrical loads are significant, and the Queensland transmission network is expected to play a central role in enabling the decarbonisation of industry and the development of both domestic and export hydrogen markets. Energy storage and pumped hydro projects such as Borumba and Pioneer-Burdekin Pumped Hydro Energy Storage (PHES), together with firming services, will also form an integral part of the future mix of technologies in Queensland.

The continued uptake of rooftop photovoltaic (PV) systems is also significantly changing the daily load flows and the way in which transmission and generation systems are planned and operated. Decreasing minimum demand will lower the amount of synchronous generation that is online and this could further impact on voltage control, system strength and inertia. Orchestration of technologies across the different supply chain levels, including large-scale generation and storage, demand side management (DSM) and time of day shifting, customer energy and storage sources, and electric vehicle (EV) charging will all be key to optimising the utilisation and performance of the energy system.

Electricity energy and demand forecasts

The 2021/22 summer in Queensland had below average daily maximum and minimum temperatures and above average temperatures in March, which saw an overall summer peak delivered demand of 9,031MW at 7.00pm on 8 March, 62MW above the 2020/21 maximum delivered demand. Operational 'as generated' peak was recorded at this same time reaching 10,058MW. Peak native demand was recorded one hour prior at 6pm, reaching 9,326MW. After temperature correction, the 2021/22 summer maximum delivered demand was 8,876MW, 4.9% higher than that forecast in the 2021 TAPR.

The 2022 Queensland minimum delivered demand was recorded at 11.00am on 25 September 2022, when only 2,597MW was delivered from the transmission grid (refer to Figure 3.4 for load measurement definitions). Operational 'as generated' minimum demand was recorded on 11 September 2022 at 1.00pm and set a new record for Queensland of 3,469MW, passing the previous minimum record of 3,784MW set in October 2021.

Powerlink has adopted AEMO's 2022 Electricity Statement of Opportunity (ESOO) forecasts in its planning analysis for the 2022 TAPR. The forecast captures impacts of the COVID-19 pandemic, growth in rooftop PV installations, changing Queensland economic growth conditions, energy efficiency initiatives, battery storage and electric vehicles (EV), electrification and tariffs through Step Change, Slow Change and Hydrogen Export 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 Step Change scenario forecast, Queensland's delivered energy consumption is forecast to increase at an average of 0.6% per annum over the next 10 years from 47,405GWh in 2021/22 to 50,201GWh in 2031/32. The increase in energy consumption is mainly due to industries beginning to electrify their operations to meet their emission reduction targets.

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Electricity demand forecast

Based on the Step Change scenario forecast, Queensland's transmission delivered summer maximum demand is forecast to increase at an average rate of 2.0% per annum over the next 10 years, from 8,876MW (weather corrected) in 2021/22 to 10,819MW in 2031/32. Annual minimum transmission delivered demands are expected to decrease in all forecast scenarios presented in the 2022 TAPR. These AEMO 2022 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.

Developing a future network that supports the long-term needs of customers

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

Given the energy transformation, there is the potential for significant expansion of the transmission network over the next 10 years and beyond. Initiatives such as the ISP and QEJP will inform the future development of the power system and the associated transmission network topography in Queensland and the NEM. Powerlink is adopting a staged planning approach to the transmission network development that provides flexibility to meet future forecast scenarios. This approach enables assumptions to be fully tested prior to phased investment decisions.

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

- undertake ongoing active customer, stakeholder and community 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 Step Change scenario forecast, 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 loads have the potential to significantly impact the performance and adequacy of the transmission network. 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 grid section. Depending on the emergence of network limitations it may become economical to increase the power transfer capacity to alleviate constraints across this grid section. 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. 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 a sizeable portion 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.

Renewable energy and generation capacity

To date Powerlink has completed connection[1] of 21 large-scale solar and wind farm projects in Queensland, adding 3,030MW of generation capacity to the grid. In addition, approximately 32 connection applications, totalling about 11,000MW of new generation capacity, have been received and are at varying stages of progress. This includes under construction connections for approximately 1,025MW of VRE.

To ensure that any adverse system strength impact is adequately addressed, Powerlink is working closely with customers, suppliers and AEMO to model system strength model in 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 ensure there is adequate system strength in Queensland.

Grid section and zone performance

During 2021/22, the Powerlink transmission network performed reliably. Record peak transmission delivered demand was recorded for the Ross, North, Central West, Surat, South West and Moreton zones. Record minimum transmission delivered demand was recorded in the majority of zones with Ross, Wide Bay and South West zones all experiencing periods of negative transmission delivered demand.

Inverter-based resources in northern Queensland experienced approximately 462 hours of constrained operation during 2021/22. This is a reduction in the constraint times experienced over the last two years. This is due to Powerlink addressing a fault level shortfall in North Queensland and several VRE customers completing their system strength remediation works.

Consultation on network investments

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.

[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.

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Expanding New South Wales to Queensland transmission transfer capacity

The QNI 'minor' upgrade construction works are complete and inter-network testing is progressing to release additional capacity to the market in a staged approach. These tests are expected to continue until mid-2023.

Further to the 2020 ISP, the 2022 ISP identified an additional option for the Future ISP Project to further upgrade the transmission capacity between Queensland and New South Wales (NSW) (coined 'QNI Connect'), requiring Preparatory Activities for a 500kV option by 30 June 2023. This is in addition to the information provided as part of the Preparatory Activities for the 2020 ISP, being a staged 330kV double circuit line to the Queensland/NSW border.

Future ISP projects in Queensland

The 2022 ISP identified upgrades in Queensland as part of the optimal development path for the NEM. 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 security, reliability, affordability and reduced emissions.

Two projects were nominated for preparatory activities. These include:

- Darling Downs REZ Expansion (Stage 1)
- QNI Connect (500kV option).

Preparatory activities for these projects will be provided to AEMO to inform the development of the 2024 ISP by 30 June 2023.

Power system security services in central, southern and the broader Queensland regions

Powerlink issued a Request for Power System Security Services in May 2022 seeking Expressions of interest (EOI) from market participants for offers for Network Support and Control Ancillary Services (NSCAS) and system strength remediation services for an NSCAS gap in south east Queensland and fault level shortfall declared by AEMO at the Gin Gin node respectively. Submissions closed on 24 June 2022.

Discussions with proponents of non-network solutions to address the declared shortfalls are continuing as at the publication of the 2022 TAPR and Powerlink continues to work closely with non-network solution proponents and AEMO to meet the declared and long-term power system security service requirements.

Committed and commissioned projects

During 2021/22, having finalised the necessary regulatory processes for the proposed replacement of network assets, the committed projects for investment across Powerlink's network include:

- Establishment of a 3rd connection into Woree (Stage 1 Northern QREZ)
- Broadsound bus reactor
- Woree secondary systems and Static VAr Compensator (SVC) secondary systems replacement
- Cairns secondary systems replacement
- Chalumbin secondary systems replacement
- Line refit works between Townsville South and Clare South substations
- Townsville South primary plant and secondary systems replacement
- Ross 275/132kV primary plant and transformers replacement
- Strathmore transformer establishment and secondary systems replacement
- Nebo primary plant, secondary systems and transformer replacements
- Blackwater transformers replacement
- Lilyvale primary plant and transformer replacement
- Bouldercombe primary plant replacement

- Baralaba secondary systems replacement
- Palmwoods secondary systems replacement
- Tarong secondary systems replacement
- Line refit works between West Darra, Sumner and Rocklea.

Projects completed in 2021/22 include:

- Life extension works between Barron Gorge and Kamerunga substations
- Line refit works between Egans Hill and Rockhampton substations
- Bouldercombe transformer replacement
- Gin Gin Substation rebuild
- Ashgrove West Substation replacement
- Belmont secondary systems replacement.

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 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 2021 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 EOI for power system security services in central, southern and the broader Queensland regions. 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.

Engagement with customers, community and other stakeholders

Powerlink is committed to proactively engaging with customers, communities, First Nations Peoples and other stakeholders in seeking their input into Powerlink's business processes and decision-making. All engagement activities are undertaken in accordance with our Stakeholder Engagement Framework and Community Engagement Strategy, which set out the principles, objectives and outcomes Powerlink seeks to achieve in its interactions with stakeholders and the broader communities in which we operate. 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 in November 2021, it provides comparisons between baseline research undertaken in 2012 and year-on-year trends to inform engagement strategies with individual stakeholders.

Engaging with communities is an important part of providing electricity transmission services that are safe, reliable and cost-effective. Transmission network infrastructure stays in-service for up to 50 years and Powerlink is focused on building positive relationships and partnering with local communities to deliver benefits for the longer term. In 2021, a new Community Engagement Strategy was developed and implemented to support delivery of the energy transformation and ensure Powerlink was focused on driving mutually beneficial outcomes for impacted communities. We also undertook targeted community engagement research in south-western Queensland to gauge community acceptability of renewable development and transmission infrastructure. The research findings support our engagement going forward and ensure we are focused on key factors that are important to communities. We have now undertaken similar sentiment research in North and Central Queensland. As Powerlink continues to operate and maintain the existing network through to embarking on planning and building the transformational network of the future, local communities will be front and centre in our planning and decision-making.

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Powerlink recognises the importance of transparency for stakeholders, particularly when:

- undertaking transmission network planning
- developing meaningful and relevant data for publication in the TAPR portal in relation to potential future investments
- engaging in public consultation under the RIT-T process.

Powerlink will also discuss the technical information provided in the TAPR with stakeholders at a dedicated session at the Transmission Network Forum to be held in November 2022.

Focus on continuous improvement in the TAPR

As part of Powerlink's commitment to continuous improvement, the 2022 TAPR continues to focus on an integrated approach to future network development and contains detailed discussion on key areas of future expenditure.

The 2022 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 1.13.2 and 6.7)
- links to Powerlink's recently improved TAPR portal website incorporating the 2022 TAPR templates and discusses the context, methodology and principles applied for the development of the Queensland transmission network data (refer to Appendix B)
- provides new and additional information in relation to transmission lines approaching end of technical life which require potential reinvestment or consideration for retirement in the next 10 to 15 years (refer to Section 6.14).

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.
- Since publication of the 2021 TAPR, Powerlink has continued to proactively engage with customers, communities and other stakeholders, in particular seeking their input into Powerlink's network development, ongoing operations and new investment decisions.
- Given the scale and pace of the transformation of Queensland's energy system, Powerlink is implementing an integrated approach to future network planning to ensure the transmission network is developed in a reliable, secure and cost-effective manner while enabling the shift to a lower carbon future.
- Powerlink has collaborated with the Queensland Government in the development of the Queensland Energy and Jobs Plan (QEJP), including establishment of new Renewable Energy Zones, energy storage and firming requirements, and broader technical aspects associated with the energy transformation.
- The 2022 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) 2022 Integrated System Plan (ISP).
- Based on Powerlink's most recent planning review and information currently available, the 2022 TAPR also provides substantial detailed technical data (TAPR templates), available within Powerlink's TAPR portal, to further inform stakeholders and customers on potential transmission network developments within the next 10 years.

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 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, and associated templates and portal.

The 2022 TAPR includes information on 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 2022 TAPR continues to support the connection of variable renewable energy (VRE) generation to Powerlink's transmission network, enabling the transformation to a lower carbon future (refer to Section 2.3).

Powerlink's annual planning review and TAPR play an important role helping to ensure the transmission network continues to meet the needs of Queensland 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].

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 energy system over the next two decades. It establishes a whole of system plan for an efficient transformation by identifying 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 requiring regulatory consultation, and informs market participants, investors, policy decision makers and customers on a range of potential development opportunities.

The 2022 TAPR incorporates AEMO's demand and energy forecasts, consistent with those published for the 2022 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 more strategic and longer term. Further, the ISP, Network Support and Control Ancillary Service (NSCAS), Inertia and System Strength Reports (System Security Reports) 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 2022 TAPR in conjunction with AEMO's 2022 ESOO which was published in August 2022. The most recent ISP was released on 30 June 2022 and NSCAS and System Security Report and Update on 17 December 2021 and 11 May 2022 respectively.

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, stakeholders and communities 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, stakeholders and communities
- 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] For the purposes of Powerlink's 2022 TAPR, Version 186 of the NER in place from August 2022.

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 5.22.17 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. Commissioning of the Transgrid augmentations associated with the minor upgrade of the Queensland to New South Wales Interconnector (QNI) was completed in July 2022. Inter-regional system tests, in accordance with 5.7.7 of NER, have commenced to release additional power transfer capacity to the NEM. These tests are expected to continue until mid-2023.

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 lower carbon future. Moving the energy system to much greater levels of VRE generation will present new opportunities for communities and local businesses throughout the State. This shift also brings technical challenges for transmission networks, as well as other parts of the electricity supply chain.

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

Broadly these challenges include:

- System strength (refer to chapters 2, 6, 7, 8 and 10)
- Minimum demand (refer to chapters 2, 3,4 and 6)
- Marginal Loss factors (MLF) (refer to Chapter 10)
- Network congestion on the transmission network and the impact of future load developments as generation patterns change (refer to chapters 2, 6, 7, 8 and 9)
- Requirements for energy storage (refer to Chapter 2).

Powerlink has continued working with the Queensland Government to support the transformation to a new energy system underpinned by renewable energy. Powerlink has provided significant input to the QEJP and advised on key matters. This includes the establishment of additional Renewable Energy Zones (REZs), large-scale energy storage and firming requirements including Pumped Hydro Energy Storage (PHES), and a range of broader technical issues to enable the transformation of Queensland's energy system.

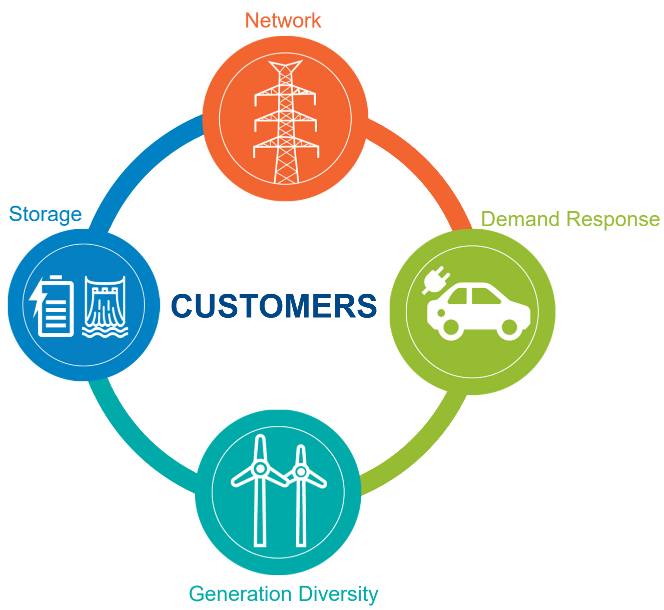
There has also been significant interest from large industrial customers looking to decarbonise their operations through electrification, and the emergence of new hydrogen-based facilities and industries. Powerlink has been supporting the Queensland Government and relevant customers in progressing these developments.

Powerlink will continue to deliver safe, reliable and cost-effective transmission services to Queenslanders while strategically planning, guiding and enabling opportunities for the development of Queensland's future energy system.

1.5.1 Balancing the energy system transformation

Powerlink has actively engaged with key stakeholders exploring new and alternate technologies, Distributed Energy Resources (DER), and opportunities for energy storage to develop strategies which identify optimal electricity supply development pathways. This will help deliver Queensland's untapped renewable energy potential as well as enable a balanced approach to the broader energy transformation with customers at the centre (refer to Figure 1.1).

Figure 1.1 Balancing the energy system transformation



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

1.6 Connecting Queenslanders to a world-class energy future

Powerlink is undertaking long-term network planning to ensure a staged and least regret development of the transmission network in the State. As well as responding safely to the ongoing impacts of the COVID-19 pandemic and unprecedented flood events, Powerlink is continuing to:

- provide guidance to enable the energy transformation, including support for the QEJP
- undertake ongoing active community, 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
- place considerable emphasis on an integrated, flexible and holistic analysis of future investment needs
- support diverse generation connections
- ensure its approach to investment decisions delivers positive outcomes for customers
- adapt to changes in customer behaviour and economic outlook
- ensure compliance with changes in legislation, regulations and operating standards
- focus on developing options that deliver safe, reliable and cost-effective transmission services.

1.7 Overview of approach to asset management

Powerlink is committed to sustainable asset management practices that consider and recognise customer and stakeholder requirements, ensuring assets are managed 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.

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.

New network developments and reinvestments are proposed to meet these legislative and NER obligations. Each of these clauses prescribes a slightly different consultation process[3].

[3] Powerlink's power system security consultations which include system strength requirements are currently undertaken through an Expression of interest (EOI) process.

The Regulatory Investment Test for Transmission (RIT-T) is the most frequent NER consultation process undertaken by Powerlink. 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:

- non-network solutions including local generation or DSM initiatives
- network augmentation
- asset replacement
- asset retirement
- network reconfiguration
- 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[4] (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.

Powerlink may also propose transmission investments that deliver a net market benefit when assessed in accordance with the RIT-T.

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 $7 million. Powerlink continues to publish information and consult with potential providers of non-network solutions for the provision of network support control and ancillary services (NSCAS)[5], 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, system strength and the potential to facilitate future storage requirements to firm intermittent renewable generation and help address minimum demand.

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4 NER Clause 5.16.3 (a)(5).
5 NER Clause 5.20.3(b).

1 Introduction

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, system strength and reactive power capability
- existing and future renewable developments including REZ
- anomalies in Powerlink's operating environment or changes in technical characteristics such as minimum demand, inertia and system strength as the power system continues to evolve.

This includes consultation with the relevant Distribution Network Service Provider (DNSP) in situations where the performance of the transmission network may impact on, or be impacted 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 such as decarbonisation through electrification and emerging industries relating to hydrogen.

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 role that transmission needs to play in the energy transformation and 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, demand based limitations and energy transformation objectives 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
- implementing non-network solutions
- reinvesting to extend the service life of assets
- replacing assets of different capacity or type
- changing the topography of the network.

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 investments and 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 1.2.

1 Introduction

Figure 1.2 Overview of Powerlink's TAPR planning process

Inputs

- Asset management policy and strategy
- Transmission Authority
- Asset Planning Criteria Framework
- Queensland Energy and Jobs Plan
- Generation, demand and energy forecasting
- AEMO Reports (ISP, NSCAS, System Strength and Inertia)
- Asset condition and performance monitoring
- New customer connection need
- Consultation and customer/ consumer/community engagement

Integrated Planning

- Analysis of asset condition, performance and related risks
- Analysis of network capability and limitations (including Distribution Network Service Provider joint planning)
- Compliance with system standards
- Analysis of market impacts
- Analysis of operational impacts and constraints
- Overall review of portfolio delivery and risks

Solution Development

- Integrated review of investment need and risks
- Development of investment options (network reconfiguration, non-network solution, network solution)
- Risk and cost benefit analysis of investment options
- Project level delivery risk assessment
- Market and regulatory consultation (e.g. Regulatory Investment Test for Transmission)

TAPR

- Customer and stakeholder engagement
- Demand and energy forecast
- Analysis of network capability and performance
- Future network developments to address network limitations, condition and performance
- Potential opportunities for non-network solutions
- Committed and commissioned network projects
- Strategic network development
- Network technical data (e.g. connection point demand forecasts, fault levels)
- TAPR templates

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 focused 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 May 2022 Powerlink published an Expression of interest (EOI), Request for power system security services in central, southern and broader Queensland regions to address the requirements of AEMO's 2021 System Security Reports: System Strength, Inertia and NSCAS published in December 2021 and Update to 2021 System Security Reports published in May 2022[6]. The Reports declared an NSCAS gap in South Queensland of up to 250MVAr to be addressed immediately and an immediate system strength shortfall of up to 90MVA at the Gin Gin fault level node to be addressed by March 2023. Submissions to the EOI closed on 24 June 2022.

Discussion with proponents to address the system strength declared shortfalls are continuing as at the publication of the 2022 TAPR and further information will be published in early 2023 once all offers have been fully evaluated and discussed in the 2023 TAPR. The EOI process is discussed further in sections 6.8 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 2021 TAPR is provided in Chapter 4.

1.8.4 Potential future projects

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 2022 ISP did not identify any actionable projects within Queensland. However, the 2022 ISP did identify several projects that may become actionable in future ISPs including potential REZ expansion to assist the development and co-ordination of generation and transmission infrastructure[7]. Projects identified as part of the optimal development path nominated in the 2022 ISP which relate to Powerlink's transmission network, include:

- Central to Southern Queensland
- Darling Downs REZ Expansion
- Gladstone Grid Reinforcement
- QNI Connect

[6] Refer to AEMO's website.

[7] Refer to the 2022 ISP Appendix 3 Renewable energy zones.

- Facilitating Power to Central Queensland
- Far North Queensland REZ Expansion.

Darling Downs REZ Expansion and QNI Connect (500kV option) have been nominated for preparatory activities by 30 June 2023[8].

Given the energy transformation, there is the potential for significant expansion of the transmission network over the next 10 years and beyond. While not included in the 2022 TAPR analysis, this work is well underway and insights are provided in Powerlink's 'Actioning the Queensland Energy and Jobs Plan'. The 2023 TAPR will incorporate the QEJP in conjunction with the ISP to inform Powerlink's planning activities.

As part of this, Powerlink is committed to early engagement and working in partnership with communities, local government and other stakeholders to deliver the new energy future. This includes working together to identify opportunities which deliver positive outcomes and long-term benefits as the energy system evolves, particularly in developing new transmission infrastructure in key parts of the State.

1.9 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 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 a 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).

1.9.1 Overview of the status of connection projects

Interest remains high from VRE generation and storage projects aspiring to connect in Queensland and Powerlink is progressing a significant number of connection applications which are well advanced (refer to Section 6.6.3). Table 1.1 provides an overview of the development of connection projects undertaken or being undertaken by Powerlink since 2018 (refer to Section 10.1).

8 Preparatory Activities reports for Central to Southern Queensland, Gladstone Grid Reinforcement and QNI connect were provided to AEMO by 30 June 2021.

Table 1.1 Overview of connection projects

Solar/Wind Projects	2022 TAPR status	
Total completed to date	21	3,030MW
Committed	2	565MW
Under construction (1)	2	1,025MW
Existing, committed and under construction		**4,620MW**
Connection Applications	32	11,000MW

Notes:

(1) Early works under construction at the time of 2022 TAPR publication.

(2) A 250MW committed pumped hydro storage project is underway at the time of 2022 TAPR publication.

(3) To date Powerlink has completed a 100MW storage project and a 50MW storage project is committed and under construction.

1.10 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 probability weighted 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.

1.11 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.

1.11.1 The reinvestment criteria framework

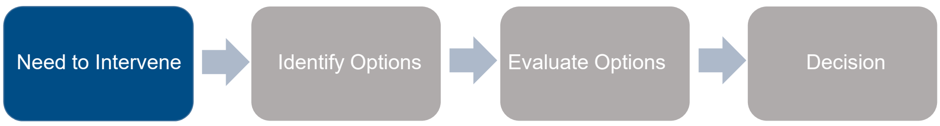
The reinvestment criteria framework defines the methodology that Powerlink uses to assess the need and timing for intervention on network assets to ensure that industry compliance obligations are met. The methodology aims to improve transparency and consistency within the asset reinvestment process, 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 1.3) 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 1.3 Asset Reinvestment Process



1.11.2 Asset reinvestment review

Powerlink is undertaking a review of its asset reinvestment approach and criteria to ensure consistency with contemporary asset management and risk-based decision frameworks and to further support the Australian Energy Regulator's (AER's) 2023-27 Revenue Determination. The review focuses on transmission line reinvestment and provides an opportunity to identify improvements which will ultimately benefit customers as the complexities and challenges of maintaining the network continue to grow.

The Asset Reinvestment Review (ARR) Working Group has been established to ensure customers and the AER are actively involved in the review and its recommendations. The aim of the review is to consider the prudency and efficiency of network reinvestment and the associated risk-based economic assessments[9].

The review deliverables include:

- a report prepared in conjunction with all ARR Working Group members that provides clear recommendations for improvements to Powerlink's asset management approach and criteria to guide successful implementation of the report's recommendations
- a 12-month post-review report to outline how the recommendations have been implemented and the resultant benefits.

9 Refer to the AER's Industry practice application note for asset replacement planning.

While the focus of the review is to further improve Powerlink's approach to asset management practices for transmission line reinvestment, where appropriate Powerlink will apply any improvement identified to other areas of asset reinvestment planning to ensure positive outcomes for customers.

1.12 External economic factors and transmission network investments

The external environment in which Powerlink operates is becoming more complex with many factors such as rising inflation, increasing interest rates, and an ongoing disruption to supply chains and materials shortages due to COVID-19 and geopolitical impacts. Cost increases occurring across labour, fuel, logistics, steel, cement, copper, aluminium, and other key commodities are affecting the supply chains across many sectors globally (refer to Section 6.4.1). While recognising these complexities, Powerlink is focused on identifying supply risks and delivering solutions to ensure customers continue to receive cost-effective and efficient services in this uncertain environment.

1.13 Stakeholder engagement

Powerlink shares targeted, timely and transparent information with its customers, communities, First Nations Peoples and other stakeholders using a range of engagement methods. Customers are defined as those who are directly connected to Powerlink's network, and electricity customers, 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 network. As an example, during 2022 Powerlink continued the approach to ongoing discussions with multiple potential non-network solution providers in relation to the progress of the EOI for the Request for power system security services in central, southern and broader Queensland regions.

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, transmission network planning and energy transformation.

1.13.1 Customer, stakeholder and community engagement

Powerlink is committed to proactively engaging with customers, communities, First Nations Peoples and other stakeholders in seeking their input into Powerlink's business processes and decision-making. All engagement activities are undertaken in accordance with our Stakeholder Engagement Framework and Community Engagement Strategy, which set out the principles, objectives and outcomes Powerlink seeks to achieve in its interactions with stakeholders and the broader communities in which we operate. 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 in November 2021, it provides comparisons between baseline research undertaken in 2012 and year-on-year trends to inform engagement strategies with individual stakeholders.

1 Introduction

Engaging with communities is an important part of providing electricity transmission services that are safe, reliable and cost-effective. Transmission network infrastructure stays in-service for up to 50 years and Powerlink is focused on building positive relationships and partnering with local communities to deliver benefits for the longer term. In 2021, a new Community Engagement Strategy was developed and implemented to support delivery of the energy transformation and ensure Powerlink was focused on driving mutually beneficial outcomes for impacted communities. We also undertook targeted community engagement research in south-western Queensland to gauge community acceptability of renewable development and transmission infrastructure. The research findings support our engagement going forward and ensure we are focused on key factors that are important to communities. We are now undertaking similar sentiment research in North and Central Queensland. As Powerlink continues to operate and maintain the existing network through to embarking on planning and building the transformational network of the future, local communities will be front and centre in our planning and decision-making.

2021/22 Community engagement activities

In 2021, Powerlink developed a Community Engagement Strategy to guide its engagement activities across the state and set the tone for how we want to proactively engage to drive a positive social licence to operate in key communities. The strategy is now embedded and driving the business focus on engaging early and often, particularly with communities where we are building new infrastructure and connecting renewable development projects. This early engagement approach includes seeking feedback and input earlier in the project development process and incorporating these insights into our planning and decision-making. To date, this approach has supported a positive social licence to operate for Powerlink in key communities.

2021/22 Stakeholder engagement activities

Since the publication of the 2021 TAPR, Powerlink has engaged with stakeholders and customers in various ways through a range of activities as outlined below.

2023-27 Revenue Proposal

The AER released its Final Decision on Powerlink's Revenue Proposal in April 2022, following an extensive two year engagement program. The engagement approach delivered a Revenue Proposal that was '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 June and October 2021, and during 2022 met in March and June. Key topics for discussion included co-designing new customer metrics, a strategic review of the Energy Charter, demand management innovation and enterprise resilience review engagement.

Asset Reinvestment Review Working Group

As part of its commitment to customer engagement, during 2022 Powerlink established an Asset Reinvestment Review (ARR) Working Group to shape and participate in a review of its asset reinvestment approach. The ARR Working Group is comprised of representatives from the AER, key customer advocates and members of Powerlink's Customer Panel. A co-designed scope for the review was developed with the ARR Working Group to guide discussions. The scope focuses on both the prudency and efficiency elements of reinvestment capital expenditure, with a focus on Powerlink's approach to transmission line refit projects. The review is still currently underway with a formal report due in early 2023.

2021 Transmission Network Forum

In November 2021, more than 200 customers attended (in person and virtually) Powerlink's annual Transmission Network Forum. The forum provided updates on the state of the network and 2021 TAPR highlights, followed by interactive breakout sessions on creating a robust Renewable Energy Zone (REZ) framework for Queensland and navigating the industry's pathway to electrification and decarbonisation. The live stream recording, presentation and 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 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.

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

1.13.2 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 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. More recently in 2022, Powerlink is in discussions with proponents of non-network solutions to assist in a short-term solution to address an NSCAS gap in southern Queensland until a longer term solution can 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 2022 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 data contained within the TAPR portal published in conjunction with the 2022 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.

Since publication of the 2021 TAPR, Powerlink has continued its collaboration with Energy Networks Australia (ENA) and the Institute for Sustainable Futures[10] 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.

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.

1.14 Focus on continuous improvement

As part of Powerlink's commitment to continuous improvement, the 2022 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 2022 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)

[10] Information available at Network Opportunity Mapping.

- 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 1.12.2 and 6.7)
- links to Powerlink's recently improved TAPR portal website incorporating the 2022 TAPR templates and discusses the context, methodology and principles applied for the development of the Queensland transmission network data (refer to Appendix B)
- provides new and additional information in relation to transmission lines approaching end of technical life which require potential reinvestment or consideration for retirement in the next 10 to 15 years (refer to Section 6.14).

1 Introduction

CHAPTER 2

The transforming energy system

2 The transforming energy system

Key highlights

- This chapter discusses opportunities and challenges arising as a result of a rapidly evolving energy system.
- Powerlink is playing an active role in the energy transformation by strategically planning the transmission network, guiding and shaping the power system, and enabling opportunities as Queensland moves to a lower carbon future.
- Powerlink has worked with the Queensland Government in the development of the Queensland Energy and Jobs Plan (QEJP), including the establishment of new Renewable Energy Zones (REZ) and providing input on the transmission implications of possible developments in the power system. Powerlink continues to inform and provide context to broader technical aspects associated with the energy transformation.
- Powerlink's long-term strategic planning considers a staged approach of low regret investments and remains focused on delivering safe, reliable and affordable services taking 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 continued growth in variable renewable energy (VRE), customer energy sources including rooftop PV systems, and broader shifts to electrification and decarbonisation within Queensland industries
  - the condition and performance of existing assets, and planning the network in such a way that it is best configured to meet current and future energy needs while maintaining the flexibility to adapt as the network evolves.

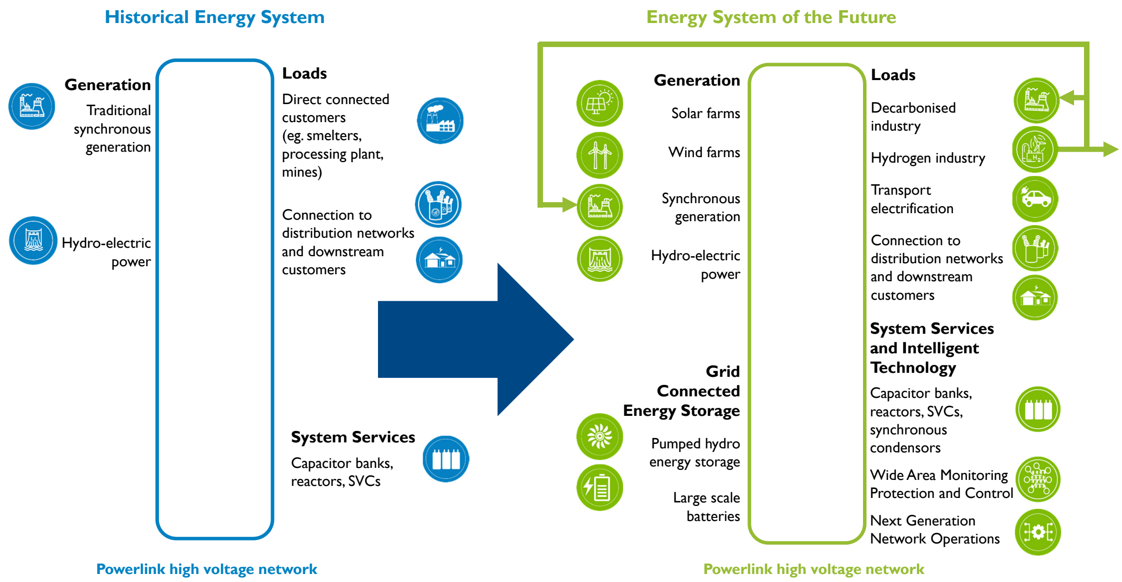
2.1 Introduction

The transformation of the energy system within Queensland to one underpinned by clean, sustainable and affordable renewable energy is well underway. The share of large-scale VRE within the State continues to increase with significant growth in grid-connected solar and wind farms. The uptake of rooftop PV systems continues to be strong. A number of corporations have committed to the decarbonisation of existing fossil fuelled operations and processes either through electrification or clean fuel substitution to leverage Queensland's abundant renewable energy resources. A new industry based on hydrogen is also emerging.

The Queensland transmission system is central to the efficient transformation to a lower carbon future. The energy system of the future will be characterised by a mix of technologies and infrastructure along the entire energy supply chain as part of the transformation to net zero emissions. It will look considerably different to the energy system in the past with large-scale renewable generation, battery energy storage systems, large-scale Pumped Hydro Energy Storage (PHES), decarbonised industrial loads, emerging green hydrogen markets, electric transportation, distributed consumer energy sources, and innovative intelligent control and orchestration all being integral components of the decarbonised energy system.

The transmission system has a critical role to play as a central platform and enabler for the energy transformation. As the Jurisdictional Planning Body (JPB) and Transmission Network Service Provider (TNSP) within Queensland, Powerlink is playing an active role in shaping the electricity system of the future through collaboration with Government and key industry groups, guiding network and non-network investment, providing technical advice, and overseeing investigation and studies for key infrastructure critical for the energy transformation.

Figure 2.1 Energy system of the future



2.2 Queensland Energy and Jobs Plan

The Queensland Government has published the Queensland Energy and Jobs Plan (QEJP), which outlines how it intends to meet the Queensland Renewable Energy Targets (existing and new targets) and more broadly achieve transformation to a lower carbon future.

Powerlink has worked closely with the Queensland Government in the development of the plan, including the establishment of Renewable Energy Zones and providing input on the transmission implications of possible developments in the power system. Powerlink continues to inform and provide context to the broader technical aspects associated with the energy transformation.

Powerlink is also been actively involved and is supporting a number of significant initiatives and collaborative works within the energy industry. These include development of AEMO's Integrated System Plan (ISP) and various Australian Energy Market Commission (AEMC) Rule changes and reviews.

2.3 Renewable Energy Zones

A Renewable Energy Zone (REZ) is a geographic area which has significant high quality renewable resources, suitable topography and available land to support the efficient connection of a number of large-scale renewable energy projects. Development of a REZ allows multiple grid-scale renewable energy developments to be connected in the one location realising economies of scale and enabling the connection of grid-connected renewable energy in a more cost-effective and coordinated manner. The development of REZs also streamlines implementation of renewable energy projects by leveraging off common infrastructure.

Queensland is an attractive location for grid-scale VRE generation as the State is rich in a diverse range of renewable resources. The establishment of REZs enables large-scale renewable generation, transmission grid, energy storage and firming, and ancillary system services to be coordinated and optimised to maximise the potential capacity of renewable energy in the most cost efficient manner possible whilst reducing investment risk and financing cost for developers.

2.3.1 QREZ

As part of the Queensland Government's COVID-19 Economic Recovery Plan, the Queensland Government has committed $145 million to establish three QREZ regions in northern, central and southern Queensland to help facilitate the energy transformation.

Powerlink has been working closely with the Queensland Government to identify strategic transmission investments that can maximise the capacity and cost efficiency for renewable energy and decarbonisation opportunities. The guiding principles for Powerlink in development of the QREZs include:

- optimising the existing capacity of the transmission network to provide scale efficient infrastructure for renewable energy development
- developing REZ in areas where shared network transmission capacity enables access to the market
- efficiently developing REZ to match regional loads to minimise losses
- seeking diversity in VRE generation sources to optimise firming services so as to ensure continued reliability and security of supply at the lowest cost to customers
- engaging with communities within the decision-making process to minimise environmental and landholder impacts, and deliver benefits for local communities.

2.3.2 QREZ Proposed Framework

The Queensland Government with input from Powerlink has proposed a framework for unlocking additional renewable generation in the State. The State Government Technical Discussion Paper presented the desired QREZ model attributes. Under the proposed model, recommendations would be provided to the Queensland Minister for Energy on investigation areas. The Minister would then provide a market and community notice to engage with industry and community on these investigation areas and test locational feasibility.

The engagement will inform Powerlink in assessing and recommending the investigation areas and REZ infrastructure to be progressed for further development. Supported by the recommendations, the Queensland Minister for Energy would then declare the REZ. At this point the QREZ framework would be applied to the nominated area and infrastructure with relevant information released in a draft REZ Management Plan (RMP). Engagement will occur on the draft RMP with the declared REZ design and parameters published in the final RMP.

The Queensland Government also released a Community Consultation Paper on QREZ identifying four proposed local benefit principles for community feedback. This framework continues to be under development incorporating feedback from consultation processes.

2.3.3 Northern QREZ

In May 2021 it was announced that the Queensland Government would direct $40 million of committed funding in transmission line infrastructure to establish the Northern QREZ, with Neoen's Kaban Wind Farm identified as the first Northern QREZ project. The transmission augmentation work involves energising one side of the existing 132kV coastal double circuit to 275kV operation. The development of the northern QREZ will increase renewable hosting capacity within the area by up to 500MW opening the region for further investment.

Powerlink has completed public consultation for the funded augmentation, with submissions to the consultation supportive of the establishment of the Northern QREZ. This REZ provides additional benefits including improving reliability of supply to the Cairns area. The establishment of the Northern QREZ through upgrading of the third circuit to 275kV operation is scheduled for completion by November 2023 (refer to Table 11.3).

2.3.4 Central QREZ

The Central QREZ has potential hydrogen and existing energy-intensive industries which are looking to decarbonise through either electrification of existing processes and/or conversion to loads powered by renewable energy.

The Central Queensland REZ covers a strong part of the network where the existing Gladstone and Callide synchronous generators are connected. This REZ is connected via a meshed 275kV network between Bouldercombe, Calliope River and Calvale 275kV substations, and was identified within the 2022 AEMO ISP as having high quality solar and wind resources.

Powerlink is currently progressing a number of connection enquiries to develop wind, solar and battery energy storage projects within this area. As outlined in the QEJP, Powerlink will progress transmission investment within Central Queensland to support renewable energy and decarbonisation in the area. This investment includes the construction of a new 275kV double circuit transmission line between Calvale and Calliope River substations which will unlock up to 1800MW of renewable hosting capacity. Powerlink will also invest in the 275kV system to the Banana area west of Calvale substation to further unlock an additional 1500MW of renewable energy hosting capacity, and the establishment of synchronous condensers in the Gladstone zone to provide system strength to support VRE development.

2.3.5 Southern QREZ

The Southern QREZ has significant potential for grid scale VRE development with a diverse mix of industries and energy sources. The REZ is close to large load centres in South East Queensland and the interconnector to New South Wales. This region has strong network and existing capacity to connect new projects, and good wind resources which will complement existing solar, storage and other generation. The MacIntyre Wind Precinct connection project is scheduled for completion by 2024 and will create renewable hosting capacity up to 2,000MW. The facility will be one of the largest on-shore wind farms in the world upon completion.

The Wambo Wind Farm is a proposed renewable development located in the Western Downs local government area. Stage 1 of the project proposes 250MW of generating capacity. The 275kV connection to the Wambo Wind Farm will allow up to 1,850MW of renewable hosting capacity in the area. Other proponents have expressed interest in the area and Powerlink is progressing a number of connection enquiries.

2.4 Energy Storage

Energy storage and firming services will form an integral part of the future mix of technologies in Queensland. These services appropriately located and sized will increase the reliability of supply from intermittent generation sources by shifting energy to manage peaks and troughs associated with weather conditions, consumer demand, and other factors.

The energy system of the future will comprise a mix of firming services ranging from PHES, grid-connected battery energy storage systems (BESS), community battery systems, residential household batteries, and dispatchable generation sources (such as gas fired or hydrogen fuelled generation). PHES are utility scale energy storage systems which deliver hydro-electric power generated through the release of water from an upper reservoir to a lower elevation reservoir, and store energy by using the same machines to pump water from the lower reservoir to the upper reservoir. These systems are generally larger in scale and provide longer duration energy storage whereas battery systems provide energy at smaller storage scales over shorter periods. Both technologies will also provide critical system security services necessary to support the transmission network as part of the energy transformation.

2.4.1 Pumped Hydro Energy Storage (PHES)

The QEJP includes the investment of two large PHES projects to enable the transformation of the energy system in a reliable and cost-effective manner for the longer term. The long lead times for the development of pumped hydro storage facilities means that work is required at the current time to ensure that Queensland has sufficient large-scale energy storage available in future.

Powerlink has been leading detailed design and business case development of the Borumba PHES facility for the Queensland Government. The Borumba site is located south west of Gympie, and was selected as the first site for detailed design and cost analysis following a state-wide assessment of potential pumped hydro locations.

The Borumba PHES facility will play a crucial role in the transformation of Queensland's energy system. Preliminary assessments indicate that the facility could be capable of generating up to 2GW of power for a period of 24 hours. The site is located in proximity to several existing transmission corridors within southern Queensland, and is strategically located to provide firming and system support services for significant renewable energy generation development in the southern QREZ.

Due to the scale of generation and storage capacity, new transmission infrastructure will be required from the facility to two substation sites in south east Queensland. Powerlink and the Queensland Government are committed to engaging early and often with the community and other key stakeholders to ensure the project delivers, not only the best outcomes for Queenslanders, but also those who live in the region. A number of information sessions have been held with the community in this region and a Stakeholder Reference Group has also been established to seek further input and feedback. The outcomes of the extensive engagement to date is helping inform the detailed analytical studies and transmission connection investigations being undertaken for the project.

The QEJP has also announced the development of a second PHES facility located within north Queensland with the preferred site in the western Pioneer Valley area with upper reservoirs located at the head of the Burdekin River catchment. This second PHES will have an energy storage capacity of 5GW over 24 hours making the facility the largest in the world. The facility is expected to be delivered over two stages, with the first stage (2500MW/60GWh) being delivered by 2032 and the second stage (2500MW/60GWh) completed by 2035. The PHES will connect to a new 500kV backbone transmission system required for large-scale transportation of renewable energy and storage across the State.

The Queensland Government has set aside $273.5 million (including $203.5 million of new funding) to advance the Borumba and Pioneer-Burdekin PHES projects. This funding will support detailed engineering and environmental investigations, community engagement and early access works, and build on the work progressed to date on the Borumba PHES project. The Government has announced the establishment of a new publically owned entity (Queensland Hydro) to progress these PHES foundational investments.

Powerlink also has also been engaged by Genex Power Limited (Genex) to undertake a range of activities relating to a 275kV electricity transmission line and associated substations for the connection of the Kidston Clean Energy Hub located in north Queensland (approximately 270km north west of Townsville). This renewable energy facility includes the construction of a 250MW/2000MWh PHES facility (K2-Hydro) currently scheduled for completion within the 2025 financial year.

In addition to the above, there are also numerous smaller capacity and shorter duration PHES projects being proposed and developed by the private sector. These proposals will also form important components of the energy transformation within Queensland.

2.4.2 Battery Energy Storage Systems (BESS)

Grid-scale battery energy storage systems supported by advanced inverter technology will play a greater role in the future transmission network providing system security services such as shorter term energy storage, frequency regulation, voltage control, virtual inertia and system strength. Grid-forming batteries can play a constructive role in increasing the hosting capability of inverter based renewable generation and supporting the secure operation of the power system.

Grid-scale batteries can also play a role as virtual transmission lines (VTLs). This offers the potential to alleviate transmission congestion and defer the need for future network augmentations. Battery services can also be used to manage the impact of network outages by reducing constraints on generation, and potentially provide other support and ancillary services for the transmission network.

Queensland's first large-scale BESS was connected to Powerlink's transmission network at Wandoan South Substation and Vena Energy have now commenced commercial operation of the facility. A number of additional large-scale grid connected BESS are in various stages of connection and construction within Queensland.

Powerlink also has implemented an innovative commercial and technical model to guide the market on network services for grid-scale battery energy storage devices. In early 2021, Powerlink published an Expression of interest (EOI) to enable the development and construction of storage solutions that benefit customers and enable the wider energy transformation. This process involved Powerlink and proponents collaboratively developing technical and commercial models to maximise the overall value of grid-scale batteries to the power system and customers.

As part of this model, Powerlink has offered BESS proponents the opportunity to construct and install BESS at beneficial locations in the network in return for network support mechanisms. In actively supporting the development of BESS, Powerlink is seeking to establish synergistic relationships with commercial operators to enable scale and scope efficiencies and achieve the objectives of both network technical requirements and commercial outcomes for investors.

CS Energy and Powerlink have partnered to implement the largest utility-scale battery in the State as part of this work to make the energy network more secure and stable, support the shift to renewables, and contribute to reducing electricity costs to customers. The 200MW/400MWh battery will be installed at Powerlink's Greenbank Substation located within the Moreton zone in south east Queensland.

Powerlink is progressing the EOI to identify additional partnerships for BESS installation within Queensland, with the preference for up to two sites located within central and north Queensland to accommodate utility scale battery systems up to 200MW/400MWh. It is envisaged the commercial and technical arrangements developed as part of this process may be made available to other new and existing grid-scale batteries, as well as other flexible resources to provide required technical and network support mechanisms.

2.4.3 Comparison of Energy Storage Systems

The energy system of the future will require a variety of storage devices ranging from large-scale pumped hydro storage, grid-scale and community battery energy storage systems, and customer energy resources (including residential battery devices). The potential hybrid adoption of battery storage capability within electric vehicles and hydrogen storage are also future potential storage mechanisms.

An indication of the relative sizes of energy storage for existing and proposed storage infrastructure projects within Queensland are shown in Figure 2.2. Pumped hydro and battery energy storage devices are also able to provide a range of transmission and system security services, including system strength, inertia, frequency and ancillary control. These services are critical for the secure operation of a lower carbon energy system.

Figure 2.2 Relative energy storage capacities of PHES and BESS

2.5 Electrical demand changes

The electrification of major industrial processes, mining operations, and transportation will be an integral component of Australia's pathway to net zero emissions. Access to a secure, cost-effective and reliable transmission network will be pivotal in enabling sectors the opportunity to electrify operations with renewable generation sources, and for Queensland to transform into a renewable hydrogen exporter.

The electrification of existing fossil fuel operation and processes presents the primary avenue for decarbonisation. It has been estimated that around 20% of the energy needs of existing Queensland industries are currently met through electricity, and that around 60% of Queensland's energy consumption has the potential for direct electrical substitution through use of existing and emerging commercialised technologies. The remaining 20% of consumption within the State comprises of energy that is expected to require further technological development for electrical substitution.

2.5.1 Decarbonisation through Electrification

The nature and concentration of energy use across the State varies considerably depending on the category of customer. There are significant mining operations within the Central West and North zones, and electrification of mining operations will impact on transmission capacity requirements to these, and within, these areas (refer to sections 9.2.1 and 9.2.2). LNG extraction and compression facilities are concentrated within the Surat and Gladstone zones, and there are significant opportunities to decarbonise these processes through electrification (refer to Section 9.2.3).

The transportation sector presents one of the largest opportunities for decarbonisation. The adoption of electric vehicles (EVs) presents the shortest term opportunity for increasing electrification and decarbonisation. The charging behaviour and patterns for EVs has the potential to either support or challenge network requirements from the grid. The management of electric vehicle (EV) charging will be important to optimising the utilisation of the existing network, particularly within the Moreton and Gold Coast zones.

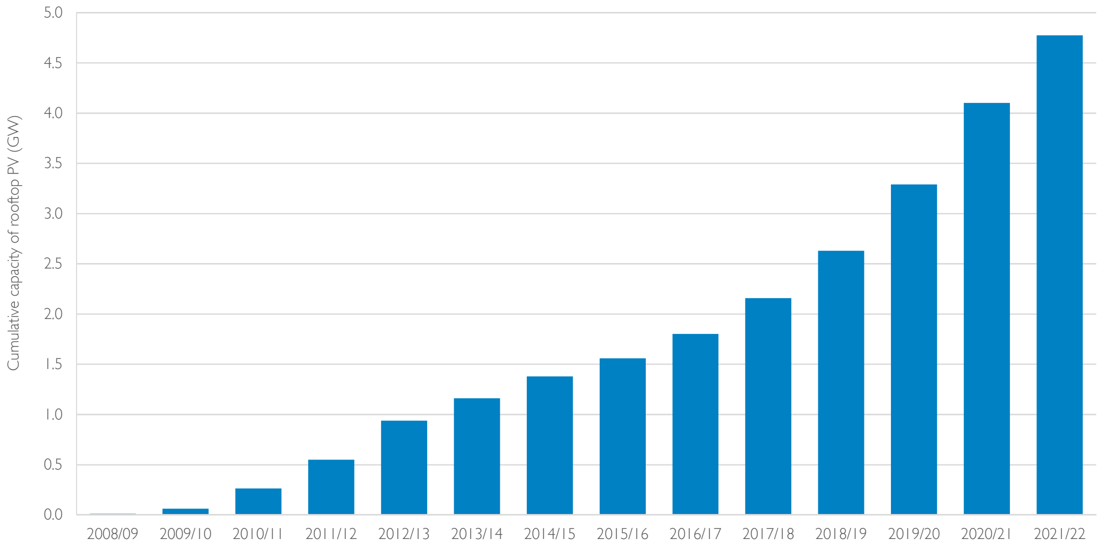
EVs have the potential for dual purpose application in terms of being both mobility and household distributed energy sources. EV battery capacities are generally larger than required for typical household daily use, and it may be possible to leverage this capacity to smooth daily demand usage patterns and rooftop PV output. Both residential battery systems and electric vehicles have the potential to optimise transmission and distribution network utilisation under appropriately designed orchestration incentives and mechanisms.

2.5.2 Rooftop PV and Distributed Energy Sources

Residential and commercial loads are generally located within built up urban and township areas, with continued uptake of rooftop PV systems and distributed energy sources having the greatest impact to demand and energy patterns in these areas.

Queensland has one of the highest penetrations of rooftop PV systems in the world. The current installation rate is approximately 700MW per annum with the average installation size within residential households increasing over time. The uptake of rooftop PV systems is expected to continue with the most recent 2022 Queensland Household Energy Survey (QHES) indicating that 26% of participants intend to purchase new or upgrade rooftop PV systems in the next three years, and 92% indicated they would replace their existing panels with similar sizes or larger if their current system failed. Around 48% of survey participants indicated they would replace their existing system with a higher capacity system if their current system failed.

Figure 2.3 Cumulative capacity increase of Queensland rooftop PV (1) (2)

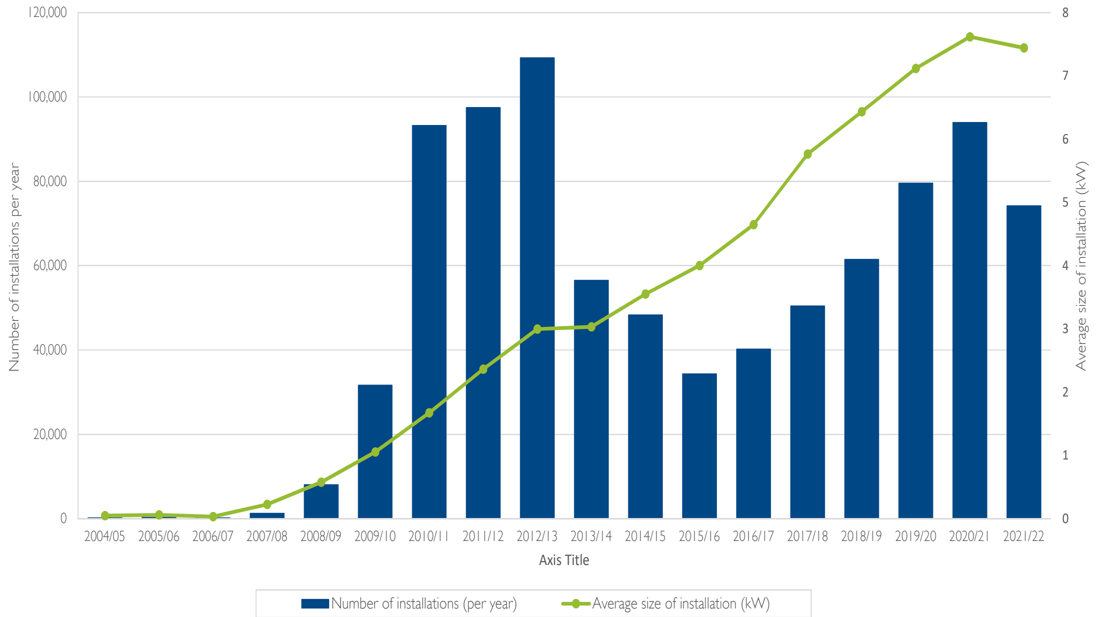


Notes:

(1) Source: Clean Energy Regulator.

(2) Note that registrations generally lag installations and hence data for FY2022 may be slightly understated.

Figure 2.4 Annual installation rates and average sizes for Queensland rooftop PV (1) (2)



Notes:

(1) Source: Clean Energy Regulator.

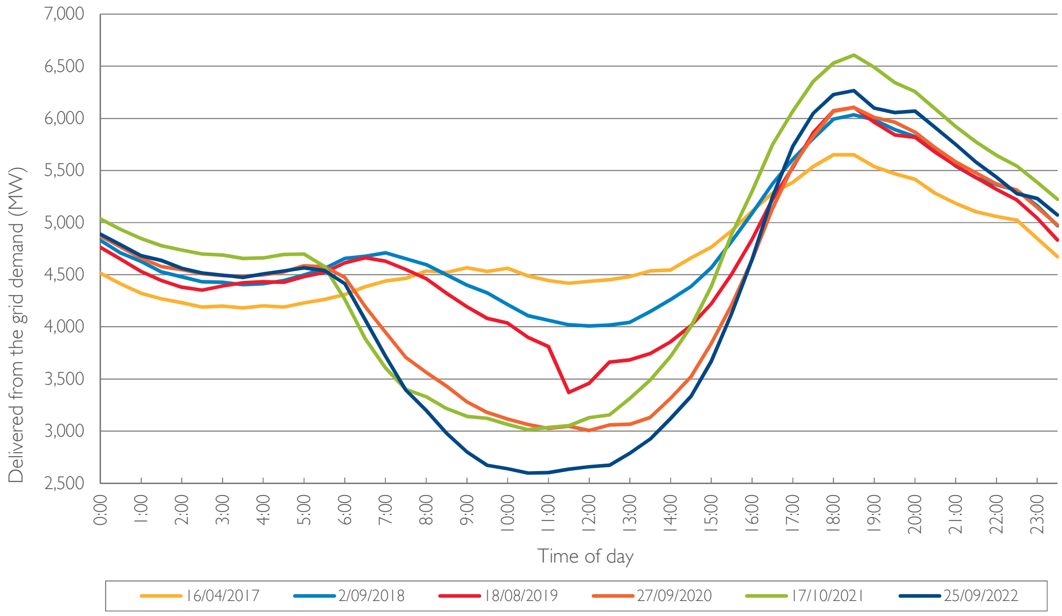
(2) Note that registrations generally lag installations and hence data for FY2022 may be slightly understated.

The installation of small scale rooftop PV systems and distribution connected solar farms has progressively changed the characteristics of daily demand required to be supplied by the Powerlink transmission network. Historically the delivered load profile has generally seen daily peaks occur during the mid afternoon or evening periods. However the cumulative effect of small scale solar renewable energy 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 in the winter and spring seasons. The term 'duck curve' was first coined by the Californian Independent System Operator to describe the effects of utility scale solar power generation on the shape of the daily net 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 2.5 depicts the change in daily load profile of the transmission delivered profile within Queensland.

Minimum demand during the day has continued to decrease with the progressive installation of rooftop PV and distribution network solar system connections. 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 large-scale generation and the transmission network. With the expected continued uptake of residential and commercial rooftop PV installations, and in the absence of significant levels of demand shifting or distributed energy storage, minimum demand levels are expected to further decrease with a continued widening between maximum and minimum demand.

Figure 2.5 Transmission delivered annual minimum demand for the Queensland region (1)(2)



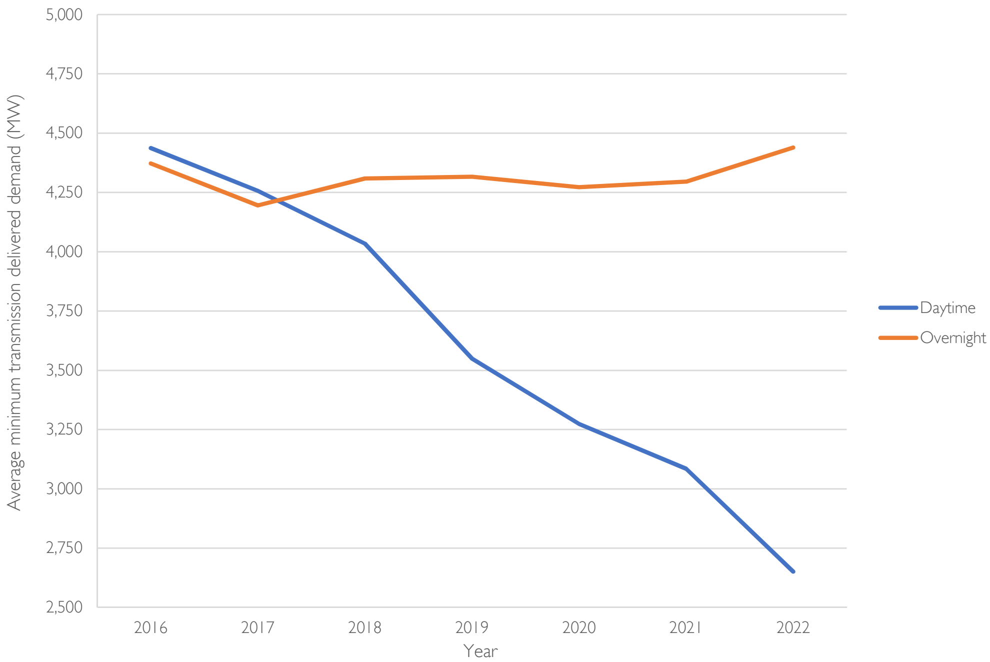
Notes:

(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) 2022 trace based on preliminary metering data up to 3 October 2022.

Continuation of this trend is likely to present challenges to the energy system. Generators are increasingly required to ramp up and down in response to daily demand variations more frequently. Decreasing minimum demand will lower the amount of synchronous generation that is able to be online and this could further impact on voltage control, stability, 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 power system security challenges, and these type of services could offer a number of benefits to the energy system including reducing the need for additional transmission network investment.

Figure 2.6 Increasing divergence between day time minimum demand and overnight demand (1)



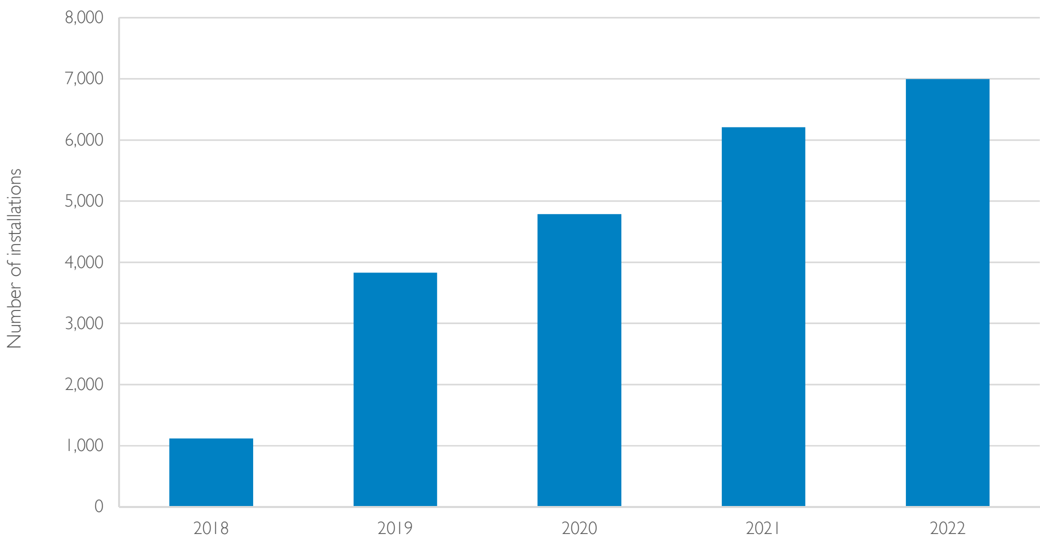
Note:

(1) Average of the five lowest demand days per calendar year for day time and overnight based on delivered from the Queensland transmission grid demand.

(2) 2022 figures based on preliminary metering data up to 3 October 2022.

Residential household batteries have the potential to help smooth daily demand profiles and improve the utilisation of the network where appropriate incentives are in place. The small-scale battery segment is continuing to build steadily in Queensland with almost 7,000 battery installations currently reported within residential households (refer Figure 2.7).

Figure 2.7 Residential battery uptake within Queensland (1)



Note:

(1) Source: Clean Energy Regulator.

Powerlink, Energy Queensland and the Queensland Government recognise the need to ensure that investments and measures to address minimum demand are complementary, and that energy storage across the supply chain (transmission, distribution and consumer level) need to operate in a coordinated manner. Orchestration of technologies across the different supply chain levels, including large-scale generation and storage, demand side management (DSM) and time of day shifting, customer energy and storage sources, and 11.00am charging will be key to optimising utilisation and performance of the energy system.

2.5.3 Emerging Hydrogen Industry

The Queensland Government is committed to working with industry to accelerate the development of hydrogen related industries, including the production and export of hydrogen and manufacturing of associated hydrogen industrial components. Queensland is well placed for the development of a range of hydrogen production and secondary supporting manufacturing industries due to the prevalence of large-scale renewable energy development, available land, and proximity to ports particularly within the Townsville, Gladstone, and Brisbane Trade Coast areas. Potential markets include both domestic hydrogen to decarbonise existing industrial processes and establishment of new hydrogen export markets.

Powerlink and the Queensland Government are supporting a range of significant hydrogen developments in Queensland. Key activities for Powerlink include:

- project development for the connection of renewable hydrogen facilities within the Brisbane Trade Coast Area
- a hydrogen electrolyser manufacturing facility within Gladstone
- large-scale production facilities for green hydrogen and ammonia within the Gladstone State Development Area (SDA).

Powerlink has experienced increasing customer interest over the past year associated with the decarbonisation of industrial processes through electrification and the emerging hydrogen industry within Queensland. Potential developments associated with electrification and hydrogen are significant, and the Queensland transmission network is expected to play a central role in enabling the decarbonisation of industry, and the development of both domestic and export hydrogen markets.

2.6 Technical Considerations

The scale and pace of changes to the transforming energy system within Queensland has been significant, and this is presenting technical challenges and new requirements for the power system.

The transmission network has historically been designed for the bulk transfer of energy from large power stations to regional load and industrial centres. However, the development of large-scale grid connected and embedded VRE sources coupled with the rapid uptake of distributed residential and commercial rooftop PV systems are changing generation profiles and power flows. The reduction of synchronous generation sources is impacting the electrical characteristics of the energy system, with challenges presenting in the areas of voltage control, stability, system strength, inertia and ramp rates.

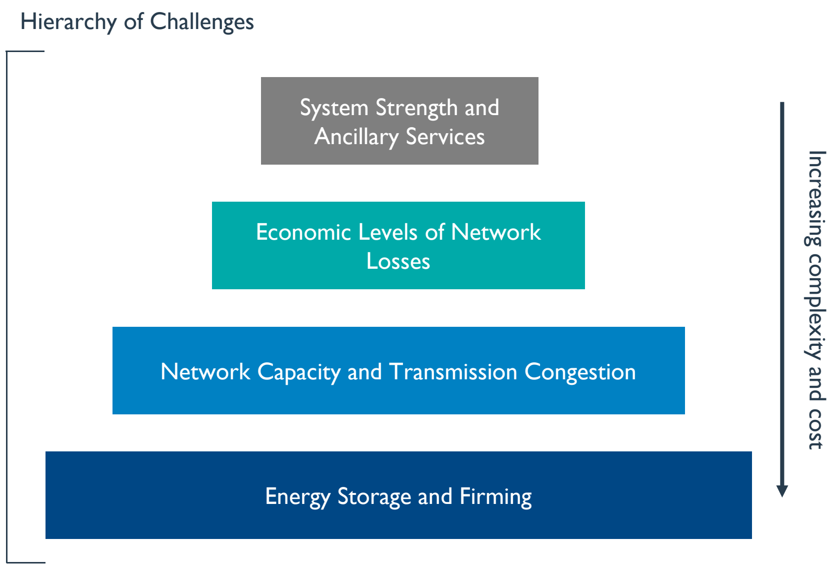
There is a general hierarchy of technical challenges in terms of complexity and cost (refer Figure 2.8). Solutions to these challenges can be multi-faceted, and in many cases require new and innovative approaches. Powerlink has been at the forefront of implementing new approaches and technologies, and guiding and shaping developments in the market to optimise performance and utilisation of the transmission system.

For example, Powerlink has worked with existing and intending renewable energy developers to optimise the control philosophy and settings of plant to improve the renewable energy hosting capacity of areas within Queensland. Powerlink's Large-Scale Battery Services EOI process has also guided the development of grid connected battery storage systems using grid-forming inverters at optimal locations within the transmission network.

Powerlink is also progressively implementing the Wide Area Monitoring Protection and Control (WAMPAC) system to maximise the utilisation of the network, and provide an additional layer of security and resilience to system disturbances and events. WAMPAC has been implemented for system protection services across the central to south Queensland grid section (refer Section 8.3), and further applications for the technology are progressing to more effectively manage the performance of the transmission network.

Powerlink has been managing design studies for the proposed large-scale Borumba PHES facility for the Queensland Government, and collaborating closely with AEMO on the 2022 ISP through technical working groups and other related activities. As outlined in the QEJP, Powerlink will progress the development of a new higher voltage and capacity transmission system (up to 500kV) from north to south Queensland to act as the backbone for efficient large-scale transportation of renewable energy and storage across the State. This new backbone system will be implemented in stages, and provide one of the cornerstones for enabling energy transformation in Queensland.

Figure 2.8 Hierarchy of technical challenges with the energy transformation



2.7 Energy transformation and engagement with our communities

New transmission infrastructure that is needed to be built as part of the transformation to a lower carbon energy system has the potential to create long-lasting benefits for Queensland communities. Powerlink will work closely with Queensland communities to deliver additional local benefits for those impacted by energy infrastructure.

Powerlink is undertaking early and authentic engagement to listen to our communities and other stakeholders and better understand their needs and priorities. Our goal is to develop co-existence arrangements with landholders and seek to provide long-term benefits for the communities in which we operate. Our Community Engagement Strategy underpins this focus on ensuring local benefits and community investment go hand in hand with delivering the new energy future.

2.8 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 customers (customers also includes consumers in Powerlink's engagement processes).

Powerlink is keeping abreast of new technological developments and collaborating with the Queensland Government, AEMO, Energy Queensland, and other market participants to enable the energy transformation. This will ensure that the high voltage transmission network is capable of unlocking opportunities and benefits associated with a decarbonised energy system to power economic growth, enable market efficiencies, deliver local benefits to communities, and minimise costs to customers.

2 The transforming energy system

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.
- Queensland set a new record maximum transmission delivered demand of 9,031MW on 8 March 2022. This maximum demand occurred at 7.00pm and was 62MW higher than the previous maximum delivered demand set in 2019.
- Queensland set a new record minimum transmission delivered demand of 2,597MW on 25 September 2022. This minimum demand occurred at 11.00am and was 409MW lower than the previous record minimum set in September 2020.
- Native plus rooftop photovoltaic (PV) energy increased by approximately 1.6% between 2020/21 and 2021/22.
- Powerlink has adopted the Australian Energy Market Operator's (AEMO) 2022 Electricity Statement of Opportunity (ESOO) forecasts in its planning analysis for the 2022 Transmission Annual Planning Report (TAPR). Powerlink is focused on working with AEMO to understand the potential impacts of emerging technologies (e.g. electric vehicles and electrification of broader industry processes) and new industries so transmission network services are developed in ways that are valued by customers.
- Powerlink has not taken account of the Queensland Government's recently announced Queensland Energy and Jobs Plan (QEJP) in the preparation of these forecasts. This will be captured in future TAPRs, including the impacts of higher renewable energy targets released in this plan[1].
- Based on AEMO's Step Change scenario forecast, Queensland's delivered maximum demand is expected to have mild growth with an average annual increase of 2.0% 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 increase over the next 10 years predominantly due to the electrification of load within a number of Queensland industries. Based on AEMO's Step Change scenario, transmission delivered energy consumption is expected to increase at an average rate of 0.6% per annum over the next 10 years.

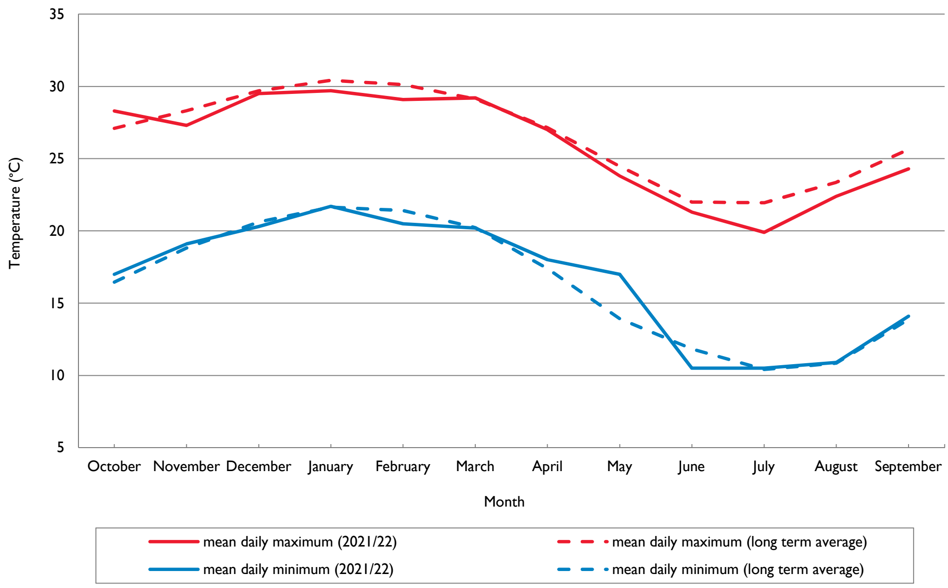
3.1 Overview

The 2021/22 summer Queensland maximum transmission delivered demand occurred at 7.00pm on 8 March 2022, when 9,031MW was delivered from the transmission grid (refer to Figure 3.4 for load measurement definitions). Operational 'as generated' peak was recorded at this same time, reaching 10,058MW. Peak native demand was recorded one hour prior at 6pm, reaching 9,326MW. After weather correction, the 2021/22 summer maximum transmission delivered demand was 8,876MW, 4.9% higher than that forecast in the 2021 ESOO Steady Progress scenario.

Figure 3.1 shows observed mean temperatures for Brisbane during 2021/22 compared with long-term averages. The comparison reveals a slightly cooler summer than average in south east Queensland, whilst daily maximum temperatures in March were slightly higher than the long-term average.

[1] Previous 50% Renewable Energy Target (QRET) by 2030 achieved two years earlier, 60% by 2030, 70% by 2032, followed by greater than 80% by 2035.

Figure 3.1 Brisbane temperature ranges over 2021/22 (1)



Note:

(1) Long-term average based on years 2000 to 2021/22.

The 2022 Queensland minimum delivered demand occurred at 11.00am on 25 September 2022, when only 2,597MW was delivered from the transmission grid (refer to Figure 3.4 for load measurement definitions). Operational 'as generated' minimum demand was recorded on 11 September 2022 at 1.00pm and set a new record for Queensland of 3,469MW, passing the previous minimum record of 3,784MW set in October 2021. At the time of minimum delivered demand directly connected loads made up about 66% of the transmission delivered demand with Distribution Network Service Provider (DNSP) customers making up the remainder. 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 2022 ESOO. Further information on the development of AEMO's 2022 ESOO is available on AEMO's website[2].

The AEMO 2022 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 (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. Powerlink has not taken account of the Queensland Government's recently announced Queensland Energy and Jobs Plan (QEJP) in the preparation of these forecasts. This will be captured in future TAPRs, including the impacts of higher renewable energy targets released in this plan.

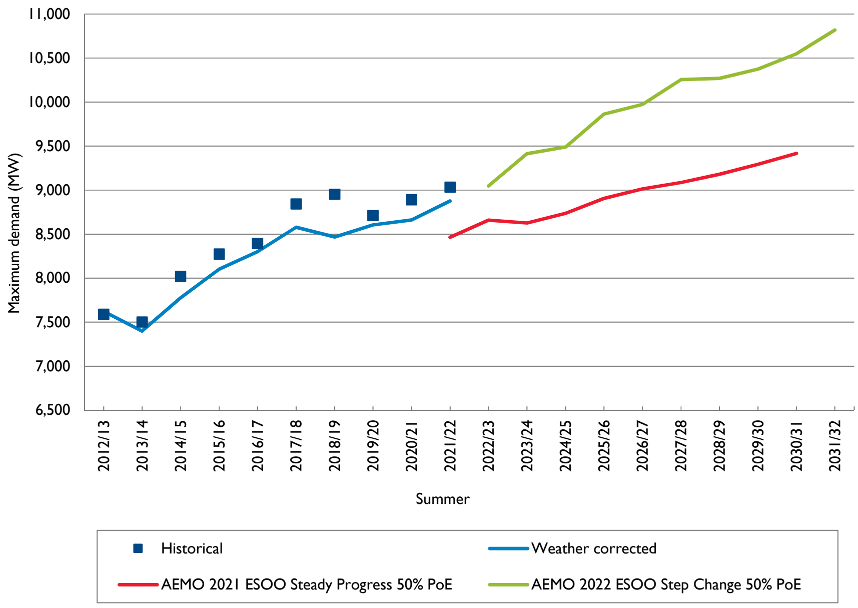
[2] AEMO, Forecasting Approach - Electricity Demand Forecasting Methodology, September 2021.

3 Energy and demand projections

At the end of June 2022, Queensland reached 4,808MW of installed rooftop PV capacity[3]. Growth in rooftop PV capacity has decreased from around 65MW per month in 2020/21 to 56MW per month in 2021/22. An impact of rooftop PV, has been to time shift both the state's minimum and maximum demands. The minimum demand now occurs during the day rather than night time. The maximum demand now occurs between 6:00pm and 7:00pm. As a result of significant capacity increases in rooftop PV and small-scale Photovoltaic non-scheduled generation (PVNSG), maximum demand is unlikely to occur in the day time, it is now expected to occur in the early evening.

Figure 3.2 shows a comparison of AEMO's 2021 ESOO delivered summer maximum demand forecast based on the Steady Progress scenario with AEMO's 2022 ESOO based on the Step Change scenario, both with 50% Probability of Exceedance (PoE).

Figure 3.2 Comparison of AEMO's 2021 ESOO Steady Progress scenario delivered demand forecast with the 2022 ESOO Step Change scenario (1) (2)



Notes:

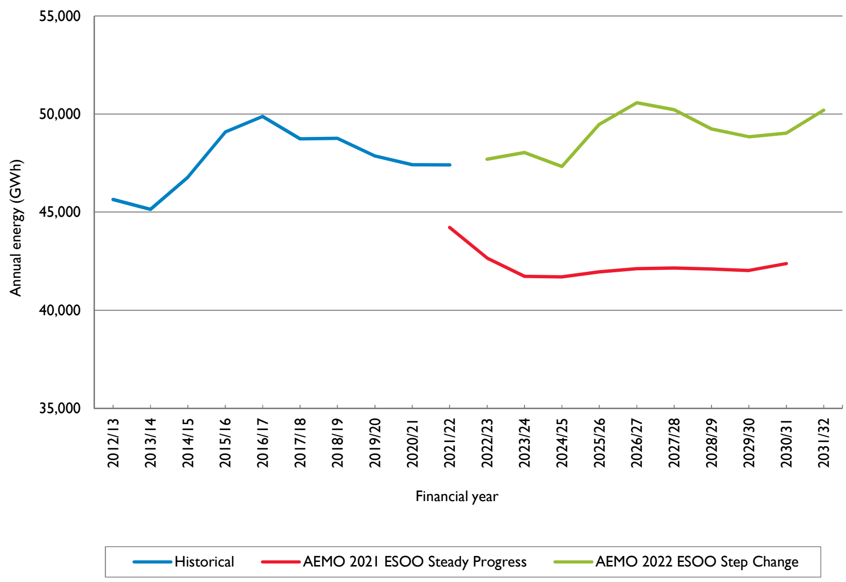
(1) AEMO's 2022 ESOO forecast has been converted from 'operational sent-out' to 'transmission delivered' for the purposes of comparison. Refer to Figure 3.4 for further details.

(2) AEMO's 2022 ESOO forecast has been adjusted for future uncommitted distribution connected renewables by Powerlink to incorporate the Queensland Government's target of 50% renewable energy by 2030.

Figure 3.3 shows a comparison of AEMO's 2021 ESOO delivered energy forecast based on the Steady Progress scenario with AEMO's 2022 ESOO Step Change scenario. Section 3.4 discusses updates included in AEMO's 2022 ESOO forecasts. The uplift in delivered energy in AEMO's 2022 Step Change scenario is from a combination of increasing consumption in both Energy Queensland's distribution network and Powerlink's directly connected customers. The increase in energy consumption is mainly due to industries beginning to electrify their operations to meet their emission reduction targets. Last years' forecast showed a flat forecast for Powerlink's direct connect customers and a declining forecast for Energy Queensland's consumption.

[3] Clean Energy Regulator, Postcode data for small-scale installations – all data, data as at 31/08/2022, September 2022. Whilst RET legislation allows a 12 month creation period for registered persons to create their certificates, updates for the first nine months of this window are generally not material.

Figure 3.3 Comparison of AEMO's 2021 ESOO Steady Progress scenario delivered energy forecast with the 2022 ESOO Step Change scenario (1)



Note:

(1) AEMO's 2022 ESOO forecast has been converted from 'operational sent-out' to 'transmission delivered' for the purposes of comparison. Refer to Figure 3.4 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 may 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 for 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.

Powerlink is proactively engaging with customers to understand their decarbonisation plans. To enable efficient planning of the network, early customer consultation is required to allow transmission network services to be developed in ways that are valued by customers.

Transmission customer forecasts

New large loads

No new large loads have connected or have committed to connect in the outlook period[4].

Possible new large loads

There are several proposals under development for large mining, metal processing, other industrial loads and the electrification of existing loads. These proposed new large loads total approximately 4,820MW. The likely distribution of these loads are defined in Table 3.1. The majority of these proposed loads have not been included in AEMO's 2022 ESOO Step Change scenario forecast. However, AEMO's Step Change scenario forecast did allow for approximately 500MW of new electrification load in the Gladstone zone (refer to sections 6.10.2 and 9.2.3). The proposed load in the Gladstone zone in Table 3.1 is inclusive of this 500MW.

Table 3.1 Possible large loads excluded from the Slow Change, Step Change and Hydrogen Export scenario forecasts

Zone	Description	Possible load
Northern	Electrification of existing mining load New industrial and mining loads	Up to 1,010MW
Central	Hydrogen facility Electrification of existing industrial load New manufacturing loads	Up to 2,360MW
South Queensland	Hydrogen facility Data centre	Up to 1,450MW

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.

4 As of 30 June 2022. Fitzroy Mine in the Northern Bowen Basin has not been included in the forecast prepared for the 2022 TAPR.

The annual minimum demand has moved from overnight to the day time since 2018 (this is described in Section 2.5.2). 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 2022 TAPR reports on the Slow Change, Step Change and Hydrogen Export scenario forecasts provided by AEMO and aligned to their 2022 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 Change, Step Change and Hydrogen Export scenarios are shown in Table 3.2. These growth rates refer to transmission delivered quantities as described in Section 3.4.1. For summer and winter maximum demand, growth rates are based on 50% PoE corrected values for 2021/22 and 2021 respectively.

Table 3.2 Average annual growth rate over next 10 years

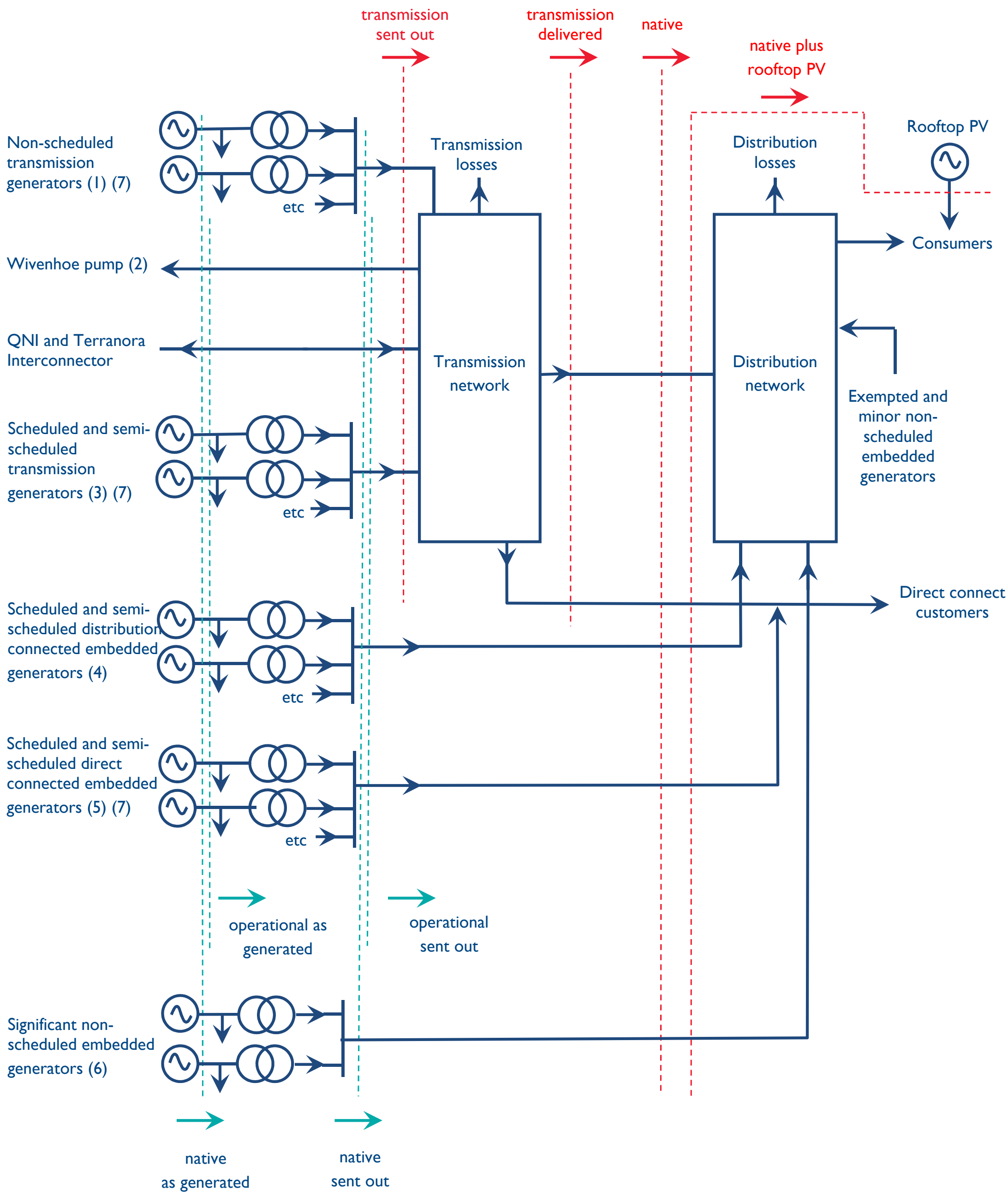
	AEMO future scenario outlooks		
	Slow Change	Step Change	Hydrogen Export
Delivered energy	-3.2%	0.6%	3.1%
Delivered summer maximum demand (50% PoE)	-0.6%	2.0%	2.9%
Delivered winter maximum demand (50% PoE)	-0.2%	2.6%	3.7%

3.4.1 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 3.4 shows the common ways demand and energy measurements are defined, with this terminology used consistently throughout the TAPR.

3 Energy and demand projections

Figure 3.4 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, Racecourse Mill, Barcaldine Solar Farm, Longreach Solar Farm, German Creek, Oaky Creek, Baking Board Solar Farm, Sunshine Coast Solar Farm 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.

3.4.2 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 3.4.

Transmission losses are the difference between transmission sent out and transmission delivered energy. Scheduled Power Station (PS) 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
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
2021/22	53,737	49,940	54,744	51,052	48,625	47,405	50,081	56,159

The transmission delivered energy forecasts are presented in Table 3.4.

Table 3.4 Forecast annual transmission delivered energy (GWh)

Financial Year	Slow Change	Step Change	Hydrogen Export
2022/23	44,692	47,707	48,619
2023/24	42,887	48,037	48,538
2024/25	42,135	47,328	46,494
2025/26	41,628	49,473	46,379
2026/27	41,340	50,578	50,537
2027/28	41,108	50,221	52,008
2028/29	41,107	49,245	52,981
2029/30	33,885 (1)	48,840	56,539
2030/31	34,193	49,033	56,787
2031/32	34,283	50,201	64,401

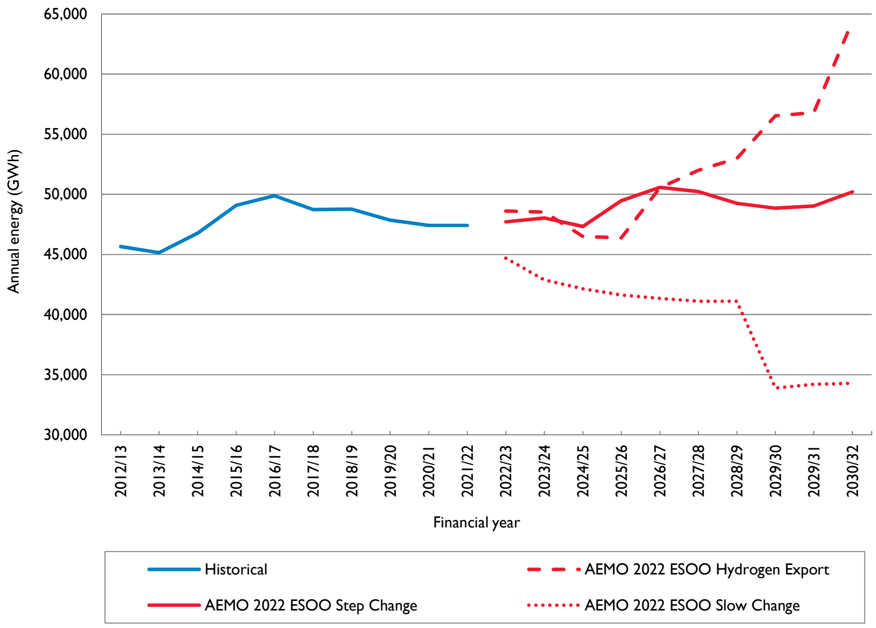
Note:

(1) AEMO assumes the shutdown of a large industrial load in the Slow Change scenario in summer 2029/30.

3 Energy and demand projections

The historical annual transmission delivered energy from Table 3.3 and the forecast transmission delivered energy for the Slow Change, Step Change and Hydrogen Export scenarios from Table 3.4 are shown in Figure 3.5.

Figure 3.5 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 Change	Step Change	Hydrogen Export
2022/23	47,992	51,006	51,918
2023/24	46,949	52,099	52,599
2024/25	46,886	53,061	53,170
2025/26	46,408	55,417	54,688
2026/27	46,268	56,821	59,851
2027/28	46,176	56,917	62,345
2028/29	46,314	56,690	63,920
2029/30	39,244 (1)	56,839	68,847
2030/31	39,274	57,683	70,880
2031/32	39,521	59,113	79,826

Note:
(1) AEMO assumes the shutdown of a large industrial load in the Slow Change scenario in summer 2029/30.

3.4.3 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
2012/13	8,278	8,208	8,448	8,427	8,113	7,597	7,638	7,911	7,911
2013/14	8,445	7,892	8,587	8,045	7,810	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
2021/22	10,058	9,503	10,126	9,624	9,332	9,031	8,876	9,323	9,323

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

Table 3.7 Forecast summer transmission delivered maximum demand (MW) (1)

Summer	Slow Change			Step Change			Hydrogen Export		
	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE
2022/23	8,372	8,699	9,105	8,710	9,047	9,466	8,820	9,163	9,590
2023/24	8,449	8,797	9,186	9,050	9,415	9,821	9,040	9,414	9,831
2024/25	8,401	8,711	9,106	9,164	9,488	9,901	9,211	9,543	9,969
2025/26	8,459	8,785	9,217	9,526	9,864	10,307	9,308	9,657	10,119
2026/27	8,511	8,808	9,231	9,669	9,972	10,400	10,046	10,352	10,800
2027/28	8,515	8,850	9,229	9,923	10,256	10,642	10,180	10,521	10,934
2028/29	8,684	9,006	9,425	9,961	10,269	10,695	10,367	10,683	11,135
2029/30 (2)	7,911	8,211	8,619	10,102	10,375	10,774	10,619	10,897	11,321
2030/31	7,944	8,253	8,655	10,281	10,549	10,953	10,893	11,175	11,630
2031/32	8,084	8,388	8,788	10,561	10,819	11,211	11,599	11,868	12,315

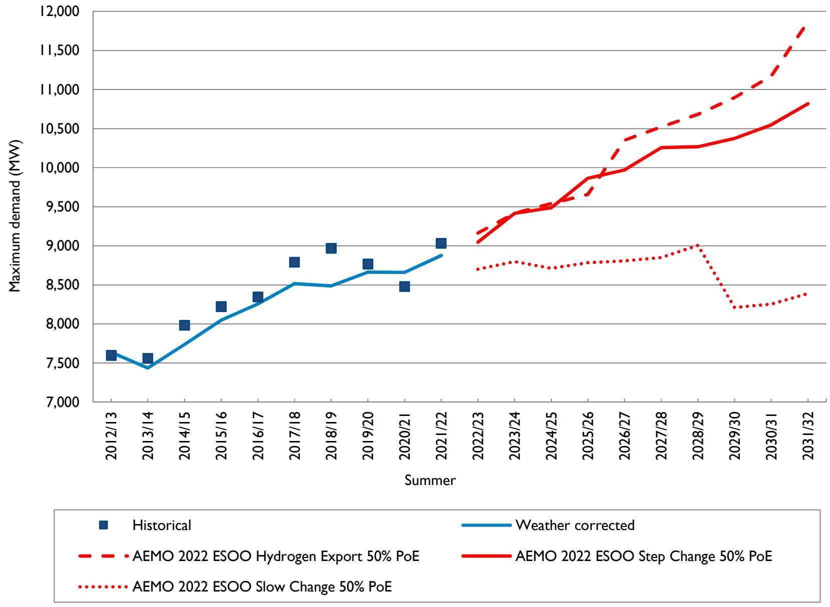
Notes:

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

(2) Shutdown of a large industrial load is assumed in the Slow Change scenario in summer 2029/30.

The summer historical transmission delivered maximum demands from Table 3.6 and the forecast 50% PoE summer transmission delivered maximum demands for the Slow Change, Step Change, and Hydrogen Export scenarios from Table 3.7 are shown in Figure 3.6.

Figure 3.6 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
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
2021/22	10,013	9,475	10,089	9,615	9,196	8,907	9,326	9,468	9,295

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

Table 3.9 Forecast summer native maximum demand (MW)

Summer	Slow Change			Step Change			Hydrogen Export		
	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE
2022/23	8,784	9,109	9,518	9,122	9,457	9,878	9,232	9,573	10,002
2023/24	8,764	9,110	9,501	9,368	9,731	10,139	9,454	9,826	10,245
2024/25	8,824	9,132	9,529	9,582	9,903	10,319	9,655	9,985	10,413
2025/26	8,832	9,155	9,590	9,954	10,289	10,735	9,927	10,274	10,739
2026/27	8,885	9,179	9,604	10,230	10,530	10,960	10,576	10,879	11,330
2027/28	8,957	9,291	9,672	10,347	10,678	11,066	10,731	11,069	11,485
2028/29	9,021	9,341	9,763	10,426	10,731	11,159	10,926	11,240	11,694
2029/30 (1)	8,259	8,557	8,967	10,579	10,850	11,251	11,207	11,482	11,908
2030/31	8,325	8,632	9,036	10,791	11,058	11,464	11,522	11,802	12,258
2031/32	8,432	8,734	9,136	11,068	11,323	11,717	12,273	12,540	12,989

Note:
(1) Shutdown of a large industrial load is assumed in the Slow Change scenario in summer 2029/30.

3.4.4 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
2013	7,131	6,761	7,273	6,921	6,780	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	7,376	7,714	7,725
2022	8,162	8,216	8,238	8,347	8,141	7,921	(1)	8,127	8,127

Note:
(1) The winter 2022 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) (1)

Winter	Slow Change			Step Change			Hydrogen Export		
	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE
2023	7,363	7,607	7,914	7,642	7,885	8,209	7,691	7,932	8,253
2024	7,351	7,596	7,908	7,811	8,056	8,379	7,781	8,028	8,353
2025	7,404	7,642	7,953	8,002	8,240	8,576	7,897	8,137	8,466
2026	7,432	7,671	7,979	8,381	8,623	8,942	8,296	8,539	8,854
2027	7,498	7,736	8,045	8,632	8,868	9,184	9,071	9,306	9,619
2028	7,559	7,801	8,118	8,707	8,936	9,255	8,958	9,184	9,503
2029	7,438	7,714	8,076	8,781	9,007	9,324	9,875	10,098	10,419
2030 (2)	6,869	7,116	7,433	8,875	9,108	9,418	11,219	11,451	11,766
2031	6,944	7,182	7,508	9,083	9,309	9,620	10,460	10,688	10,999
2032	7,007	7,250	7,563	9,321	9,543	9,854	10,386	10,615	10,925

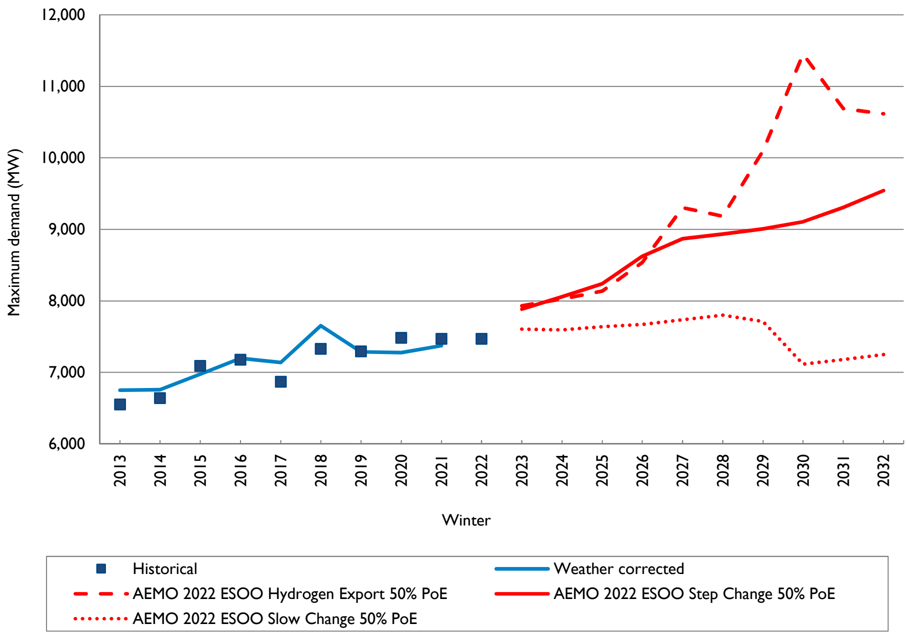
Notes:

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

(2) Shutdown of a large industrial load is assumed in the Slow Change scenario in summer 2029/30.

The winter historical transmission delivered maximum demands from Table 3.10 and the forecast 50% PoE summer transmission delivered maximum demands for the Slow Change, Step Change, and Hydrogen Export scenarios from Table 3.11 are shown in Figure 3.7.

Figure 3.7 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
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	7,699	8,324	7,948	7,663	7,468	7,754	7,754	7,830
2022	8,625	8,216	8,701	8,347	8,141	7,921	8,127	8,127	(1)

Note:

(1) The winter 2022 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 Change			Step Change			Hydrogen Export		
	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE
2023	7,645	7,897	8,196	7,925	8,176	8,491	7,973	8,223	8,535
2024	7,640	7,893	8,198	8,148	8,402	8,717	8,162	8,418	8,735
2025	7,694	7,941	8,244	8,353	8,599	8,927	8,361	8,610	8,930
2026	7,732	7,980	8,279	8,751	9,002	9,312	8,799	9,050	9,357
2027	7,801	8,046	8,347	9,028	9,272	9,580	9,607	9,850	10,155
2028	7,865	8,115	8,424	9,150	9,388	9,699	9,503	9,737	10,048
2029	7,758	8,043	8,397	9,241	9,477	9,785	10,468	10,701	11,013
2030 (1)	7,184	7,440	7,749	9,376	9,618	9,920	11,873	12,114	12,419
2031	7,260	7,506	7,823	9,600	9,835	10,137	11,183	11,420	11,723
2032	7,323	7,574	7,878	9,864	10,094	10,397	11,177	11,414	11,716

Note:
(1) Shutdown of a large industrial load is assumed in the Slow Change scenario in summer 2029/30.

3.4.5 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)

Summer	Operational as generated	Operational sent out	Native as generated	Native sent out	Transmission sent out	Transmission delivered	Native	Native plus rooftop PV
2013	4,176	3,838	4,305	3,978	3,849	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	3,869	3,480	3,958	3,701	3,043	3,014	3,671	6,804
2022 (1)	3,504	3,065	3,617	3,283	2,707	2,597	3,173	6,457

Note:
(1) 2022 minimum based on preliminary data up to 3 October 2022.

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 Change			Step Change			Hydrogen Export		
	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE
2022/23	1,854	1,994	2,143	2,167	2,308	2,475	2,125	2,267	2,437
2023/24	1,350	1,497	1,646	1,854	2,026	2,220	1,597	1,772	1,973
2024/25	1,170	1,308	1,460	1,594	1,772	1,987	1,087	1,271	1,496
2025/26	901	1,049	1,203	1,500	1,658	1,823	695	893	1,145
2026/27	640	784	957	1,253	1,413	1,600	925	1,272	1,650
2027/28	425	568	744	929	1,079	1,263	731	946	1,206
2028/29	-188	2	234	470	648	838	342	684	1,090
2029/30 (2)	-641	-494	-323	146	376	656	668	917	1,217
2030/31	-759	-606	-431	-325	-124	81	118	339	554
2031/32	-874	-728	-536	-435	-231	-17	1,050	1,275	1,501

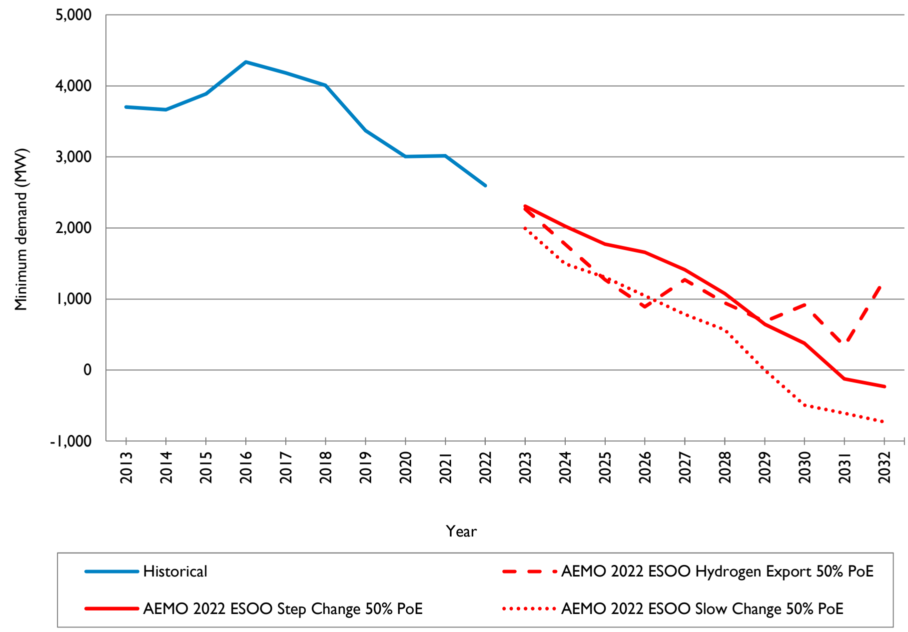
Notes:

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

(2) Shutdown of a large industrial load is assumed in the Slow Change scenario in summer 2029/30.

The annual historical transmission delivered minimum demands from Table 3.14 and the forecast 50% PoE annual transmission delivered minimum demands for the Slow Change, Step Change, and Hydrogen Export scenarios from Table 3.15 are shown in Figure 3.8.

Figure 3.8 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 Change (2)			Step Change			Hydrogen Export		
	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE	90% PoE	50% PoE	10% PoE
2022/23	2,837	2,980	3,127	3,173	3,318	3,481	3,131	3,277	3,443
2023/24	2,456	2,604	2,751	3,007	3,183	3,374	2,866	3,044	3,242
2024/25	2,250	2,390	2,540	2,784	2,966	3,177	2,597	2,785	3,006
2025/26	2,026	2,176	2,329	2,756	2,950	3,186	2,505	2,707	2,955
2026/27	1,819	1,965	2,136	2,630	2,792	2,977	2,929	3,279	3,654
2027/28	1,621	1,766	1,940	2,352	2,503	2,685	2,964	3,126	3,315
2028/29	921	1,115	1,343	2,036	2,217	2,404	2,806	3,151	3,554
2029/30 (2)	552	701	871	1,761	1,950	2,147	3,500	3,707	3,912
2030/31	445	599	773	1,604	1,806	2,010	3,304	3,528	3,741
2031/32	375	524	714	1,474	1,680	1,892	4,397	4,625	4,848

Notes:

(1) Forecasts 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.

(2) Shutdown of a large industrial load is assumed in the Slow Change scenario in summer 2029/30.

3.5 Zone forecasts

AEMO's 2022 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	1.17
Ross	1.29	1.46
North	1.16	1.12
Central West	1.10	1.20
Gladstone	1.02	1.03
Wide Bay	1.02	1.07
Surat	1.20	1.17
Bulli	1.04	1.07
South West	1.04	1.11
Moreton	1.01	1.02
Gold Coast	1.03	1.10

Tables 3.18 and 3.19 show the historical and forecast of transmission delivered energy and native energy for the Step Change 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												
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
2021/22	1,598	2,418	2,755	2,776	9,124	904	5,420	1,395	990	17,101	2,924	47,405
Forecasts												
2022/23	1,454	2,659	2,507	2,560	9,369	936	5,319	1,721	1,046	17,162	2,974	47,707
2023/24	1,494	2,655	2,592	2,661	9,395	647	5,017	1,727	1,047	17,713	3,089	48,037
2024/25	1,404	2,502	2,447	2,518	9,846	386	4,511	1,579	959	18,025	3,151	47,328
2025/26	1,475	2,600	2,567	2,777	9,900	455	4,413	1,540	1,050	19,298	3,398	49,473
2026/27	1,456	2,564	2,530	2,734	11,128	447	4,323	1,507	1,037	19,426	3,426	50,578
2027/28	1,396	2,461	2,390	2,607	11,639	407	4,186	1,458	979	19,294	3,404	50,221
2028/29	1,294	2,290	2,215	2,413	12,145	342	3,924	1,365	891	19,010	3,356	49,245
2029/30	1,206	2,145	2,059	2,248	13,001	280	3,749	1,303	809	18,731	3,309	48,840
2030/31	1,173	2,028	1,937	2,128	13,871	243	3,535	1,225	759	18,804	3,330	49,033
2031/32	1,207	2,060	1,994	2,175	13,891	267	3,473	1,200	794	19,641	3,499	50,201

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												
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
2021/22	1,618	2,900	3,212	3,515	9,124	1,164	5,626	1,395	1,454	17,149	2,924	50,081
Forecasts												
2022/23	1,486	3,303	3,065	3,342	9,369	1,240	5,595	1,721	1,682	17,229	2,974	51,006
2023/24	1,526	3,373	3,150	3,443	9,395	1,271	5,616	1,727	1,724	17,785	3,089	52,099
2024/25	1,540	3,408	3,192	3,485	9,846	1,278	5,606	1,724	1,735	18,096	3,151	53,061
2025/26	1,637	3,553	3,358	3,688	9,900	1,352	5,605	1,721	1,838	19,367	3,398	55,417
2026/27	1,643	3,561	3,364	3,688	11,128	1,353	5,606	1,722	1,835	19,495	3,426	56,821
2027/28	1,619	3,523	3,289	3,624	11,639	1,328	5,607	1,723	1,799	19,362	3,404	56,917
2028/29	1,577	3,461	3,223	3,536	12,145	1,282	5,575	1,715	1,741	19,079	3,356	56,690
2029/30	1,534	3,396	3,147	3,450	13,001	1,235	5,570	1,715	1,681	18,801	3,309	56,839
2030/31	1,525	3,379	3,124	3,426	13,871	1,216	5,565	1,714	1,658	18,875	3,330	57,683
2031/32	1,580	3,451	3,218	3,510	13,891	1,249	5,583	1,718	1,705	19,709	3,499	59,113

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 Step Change 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												
2012/13	278	297	373	546	1,219	233	13	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
2021/22	363	441	473	518	1,103	269	594	174	253	4,146	697	9,031
Forecasts												
2022/23	345	353	520	435	1,162	210	599	188	204	4,313	718	9,047
2023/24	360	366	541	476	1,169	249	610	186	239	4,484	735	9,415
2024/25	352	365	548	473	1,218	244	614	184	233	4,521	736	9,488
2025/26	371	375	576	507	1,224	259	611	182	248	4,742	769	9,864
2026/27	374	370	579	502	1,359	235	597	182	225	4,778	771	9,972
2027/28	384	398	592	544	1,413	277	614	181	265	4,813	775	10,256
2028/29	383	393	588	549	1,468	276	615	181	265	4,782	769	10,269
2029/30	389	399	593	553	1,562	282	615	181	271	4,764	766	10,375
2030/31	399	408	600	560	1,657	290	616	181	279	4,790	769	10,549
2031/32	418	426	618	579	1,662	305	620	181	294	4,925	791	10,819

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												
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
2021/22	363	516	504	591	1,103	269	708	174	254	4,143	697	9,322
Forecasts												
2022/23	345	465	562	527	1,159	237	710	187	248	4,302	715	9,457
2023/24	359	469	582	553	1,166	248	706	185	258	4,472	733	9,731
2024/25	354	477	593	563	1,221	255	721	185	264	4,532	738	9,903
2025/26	374	488	622	597	1,229	270	719	183	278	4,757	772	10,289
2026/27	378	494	629	608	1,369	273	722	184	281	4,815	777	10,530
2027/28	386	507	639	627	1,423	279	718	183	287	4,848	781	10,678
2028/29	387	503	638	633	1,485	280	721	183	288	4,835	778	10,731
2029/30	394	509	643	638	1,582	285	722	183	293	4,825	776	10,850
2030/31	405	520	653	647	1,682	295	726	184	303	4,862	781	11,058
2031/32	424	538	671	665	1,686	310	728	184	318	4,996	803	11,323

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 Step Change 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
Actuals												
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
2022	230	246	322	431	991	280	508	162	360	3,780	611	7,921
Forecasts												
2023	235	263	398	548	1,127	238	538	193	287	3,442	616	7,885
2024	240	269	405	565	1,128	246	537	191	293	3,552	630	8,056
2025	247	278	418	583	1,140	256	535	189	304	3,652	638	8,240
2026	254	289	437	618	1,185	269	544	187	319	3,852	669	8,623
2027	263	288	452	647	1,207	279	546	188	331	3,978	689	8,868
2028	258	282	443	643	1,328	273	539	185	325	3,975	685	8,936
2029	258	282	442	650	1,385	273	536	184	324	3,986	687	9,007
2030	259	282	441	648	1,448	274	538	185	326	4,015	692	9,108
2031	264	285	444	652	1,544	280	538	185	334	4,081	702	9,309
2032	271	291	448	657	1,646	289	541	185	344	4,156	715	9,543

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

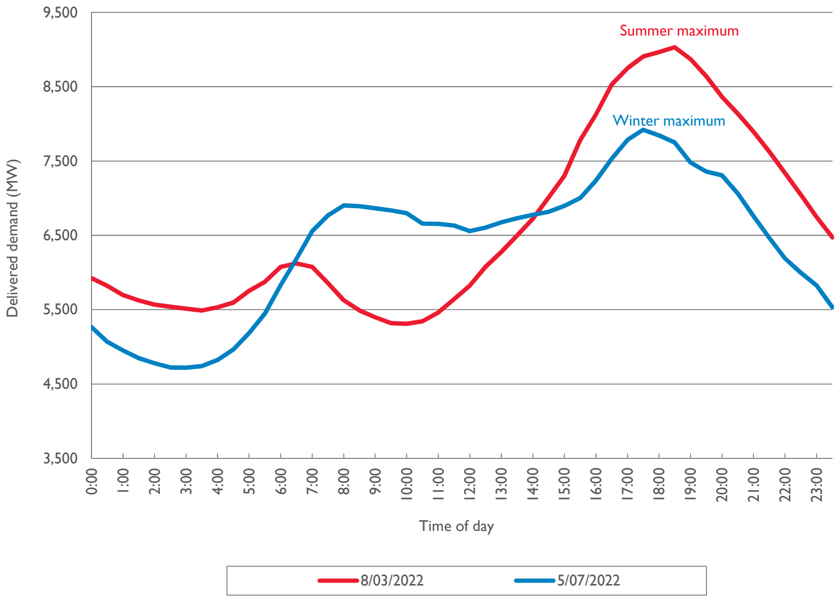
Winter	Far North	Ross	North	Central West	Gladstone	Wide Bay	Surat	Bulli	South West	Moreton	Gold Coast	Total
Actuals												
2013	195	291	374	499	1,200	195	89	17	290	3,040	579	6,769
2014	226	369	420	509	1,200	204	90	51	286	2,975	551	6,881
2015	192	334	404	518	1,249	203	208	137	288	3,281	597	7,411
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
2022	230	248	375	458	991	280	634	162	357	3,779	611	8,125
Forecasts												
2023	234	297	461	605	1,119	237	703	191	304	3,414	611	8,176
2024	240	304	471	626	1,127	246	706	191	313	3,548	630	8,402
2025	248	314	485	645	1,141	257	707	189	324	3,650	639	8,599
2026	255	326	504	681	1,188	270	716	187	340	3,864	671	9,002
2027	265	325	522	712	1,213	281	723	189	353	3,997	692	9,272
2028	261	321	515	712	1,342	277	717	187	348	4,016	692	9,388
2029	261	322	514	720	1,402	277	715	187	348	4,036	695	9,477
2030	263	324	516	721	1,471	279	721	188	351	4,081	703	9,618
2031	269	328	520	726	1,571	286	722	188	360	4,152	714	9,835
2032	277	335	525	733	1,678	295	726	189	371	4,235	728	10,094

3 Energy and demand projections

3.6 Summer and winter maximum and annual minimum daily profiles

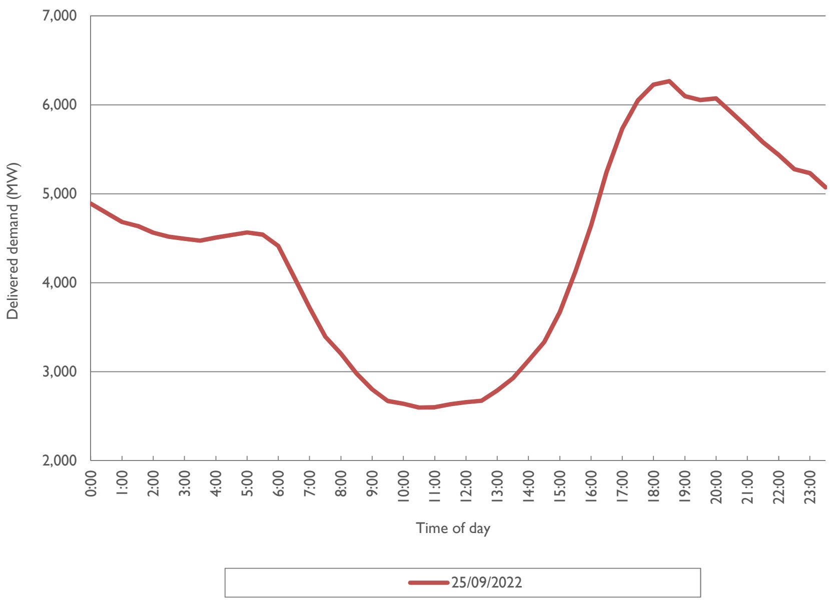
The daily load profiles (transmission delivered) for the Queensland region on the days of summer 2021/22 and winter 2022 maximum demands are shown in Figure 3.9.

Figure 3.9 Daily load profile of summer 2021/22 and winter 2022 maximum transmission delivered demand days



The 2022 annual minimum (transmission delivered) daily load profile for the Queensland region is shown in Figure 3.10.

Figure 3.10 Daily load profile of 2022 minimum transmission delivered day (1)



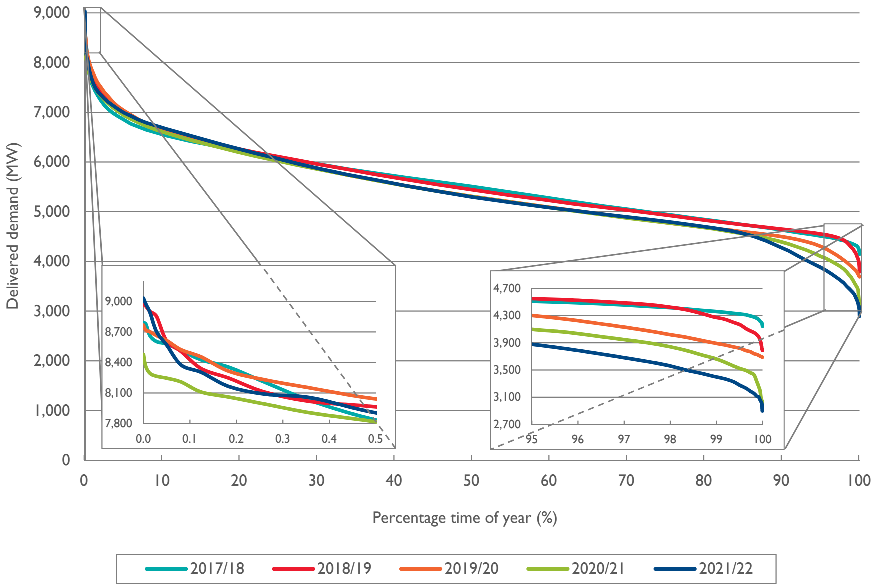
Note:

(1) Based on preliminary meter data up to 3 October 2022.

3.7 Annual load duration curves

The annual historical load duration curves for the Queensland region transmission delivered demand since 2017/18 is shown in Figure 3.11.

Figure 3.11 Historical transmission delivered load duration curves



3 Energy and demand projections

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 2021 Transmission Annual Planning Report (TAPR) include:
  - Australian Energy Market Operator (AEMO) declared an immediate need for additional reactive power absorption capability in Southern Queensland and a system strength shortfall at the Gin Gin 275kV fault level node. Powerlink is working with AEMO and market participants to address these gaps.
  - AEMO and Network Service Providers (NSP) have worked together on the development of the System Strength Impact Assessment Guidelines and Methodology following the Australian Energy Market Commission's (AEMC) Efficient management of system strength on the power system Rule change.
  - AEMO, Transgrid and Powerlink have collaborated on model development, model management and test activities to facilitate the safe and expeditious release of additional capacity on the Queensland to New South Wales interconnector (QNI).
  - 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 the Moreton zone, by Energy Queensland (EQL) load transfers – either as part of an over load management system (OLMS) or permanent transfers.
  - Potential line refit works in North Queensland and the possible retirement of 110kV lines in the Moreton zone.

4.1 Introduction

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).

Powerlink's joint planning framework with 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 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 faced by the different network owners and operators
- understand existing and forecast network limitations 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 operated and managed, and what network changes are required.

Projects where a feasible network option exists which is greater than $7 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 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 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)
- 2021 Power System Frequency Risk Review (PSFRR) (refer to Section 8.3)
- 2022 General Power System Risk Review (GPSRR)
- AEMO's 2021 System Security Reports
- Network Support and Control Ancillary Service (NSCAS)
- System Strength and Inertia requirements
- AEMO's 2022 Integrated System Plan (ISP) including joint planning and 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's System Strength Impact Assessment Guidelines and Methodology following the AEMC Efficient management of system strength on the power system Rule change
- AEMO and jurisdictional planners to support and promote collaboration and coordination of model development, model management and test activities to facilitate the safe and expeditious release of inter-network capacity
- 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 worked 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 and 2022 Powerlink provided feedback on the proposed ISP methodology and inputs, assumptions and scenarios. As requested in AEMO's 2020 ISP (published in July 2020) Powerlink also prepared Preparatory Activity reports for two intra-regional projects and for an interconnector upgrade (refer to Section 9.3). This involvement was 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, regular engagement, workshops and various formal consultations. This engagement helps underpin the inputs, assumptions and methodology for the ISP.

Methodology

More information on the 2022 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 – System strength, inertia and NSCAS reports

AEMO has identified system security needs across the NEM for the coming five-year period as the energy transformation continues at pace. Declining minimum operational demand, changing synchronous generator behaviour and rapid uptake of variable renewable energy (VRE) resources combine to present opportunities in each region for delivery of innovative and essential power system security services.

The 2021 System Security Report and 2022 Update are part of the NER framework intended to plan for the security of the power system under these changing operating conditions. The unprecedented nature and pace of change in the NEM means more shortfalls and gaps in requirements for system strength, inertia and Network Support and Control Ancillary Services (NSCAS) are anticipated during this transformational period. The identification of actual or emerging shortfalls and gaps is a natural step to facilitate the necessary services and investment to address these essential system security needs.

Process

Powerlink has worked closely with AEMO to determine the system strength, inertia and NSCAS requirements for the Queensland region. Powerlink and AEMO reviewed the Queensland fault level nodes and their minimum three phase fault levels and assessed the reactive power absorption requirements.

Methodology

AEMO applied the System Strength Requirements Methodology[1] to determine the Queensland fault level nodes and their minimum three phase fault levels for 2022. More information on the System Strength Requirements Methodology, System Strength Requirements and Fault Level Shortfalls is available on AEMO's website.

AEMO applied the Network Support and Control Ancillary Service Description and Quantity Procedure[2] to identify whether there are reactive power capability gaps.

Outcomes

AEMO published a Notice of Queensland System Strength Requirements and Gin Gin Fault Level Shortfall in May 2022. AEMO declared a fault level shortfall ranging from 33 to 90MVA over the five-year outlook. AEMO requested that services be available from 31 March 2023 (refer to sections 6.8 and 10.4).

AEMO published the System Strength, Inertia, and Network Support and Control Ancillary Services Report in December 2021. AEMO declared an immediate gap of 120 MVAr reactive power absorption in Southern Queensland, rising to 250 MVAR by 2026 (refer to sections 6.8 and 6.11.4).

4.5 General Power System Risk Review (GPSRR) and Power System Frequency Risk Review (PSFRR)

In accordance with rule 5.20A of the NER, AEMO is now required to undertake a General Power System Risk Review (GPSRR) and prepare a GPSRR report for the NEM at least annually. From 2023, the GPSRR replaces and expands on the scope of the previous biennial PSFRR. Consultation and collaboration has commenced for the 2023 GPSRR. AEMO plans to publish the 2023 GPSRR report by 31 July 2023.

The methodology and key outcomes from the 2022 PSFRR are described below. The PSFRR scope was limited to review of power system frequency risks associated with non-credible contingency events in the NEM. AEMO published the 2022 PSFRR in July 2022.

Process

In accordance with Clause 5.20A of the NER, AEMO in consultation with TNSPs is now required to prepare a GPSRR for the NEM. The purpose of the GPSRR is to review:

- A prioritised set of risks comprising contingency events and other events and conditions that could lead to cascading outages or major supply disruptions
- The current arrangements for managing the identified priority risks and options for their future management

1 System Security Market Frameworks Review, System Strength Requirements Methodology and System Strength Requirements and Shortfalls, July 2018.
2 Network Support and Control Ancillary Service Description and Quantity Procedure.

- The arrangements for management of existing protected events and consideration of any changes or revocation
- The performance of existing Emergency Frequency Control Schemes (EFCS) and the need for any modifications.

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 2022 PSFRR report recommended:

- Establishment of an Over Frequency Generation Shedding (OFGS) scheme. Studies show that if Queensland is exporting to NSW, frequency in Queensland could rise above 52Hz following loss of both QNI circuits.
- Implementation of a Special Protection Scheme (SPS) for the loss of both Columboola to Western Downs 275kV lines. The loss of both of these lines, which supply the Surat zone, is non-credible but could cause QNI to lose stability.
- Assessment of the risk and solution options to further mitigate instability for the non-credible loss of both Calvale to Halys 275kV lines following the commencement of QNI minor commissioning.

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 finalised 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. Transgrid has now commissioned these works and Powerlink is working with Transgrid and AEMO on QNI tests to facilitate the safe and expeditious release of additional capacity.

AEMO's ISP continues to investigate opportunities for expansion of interconnector capacity. In the 2022 ISP, QNI Connect (500kV option) and Darling Downs REZ Expansion as future ISP projects, have been nominated for Preparatory Activities by 30 June 2023 (refer to sections 9.3.1 and 9.3.4).

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[3]. 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.

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

Table 4.1 Joint planning activities

Activity	Frequency	
	As required	Annual
Sharing and validating information covering specific issues	Y	
Sharing updates to network data and models	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	
Sharing information for respective works plans	Y	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	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 2021 TAPR (refer to Table 4.2). 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 6.9.1
Line refit works between Ross and Alan Sheriff substations	Section 6.9.2
Goodna 110/33kV transformer load management scheme (1)	Section 6.11.4
SEQ reactive power and voltage control	Section 6.11.4
Possible retirement of Richlands to Algester 110kV lines	Section 6.11.4

Notes:

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

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.

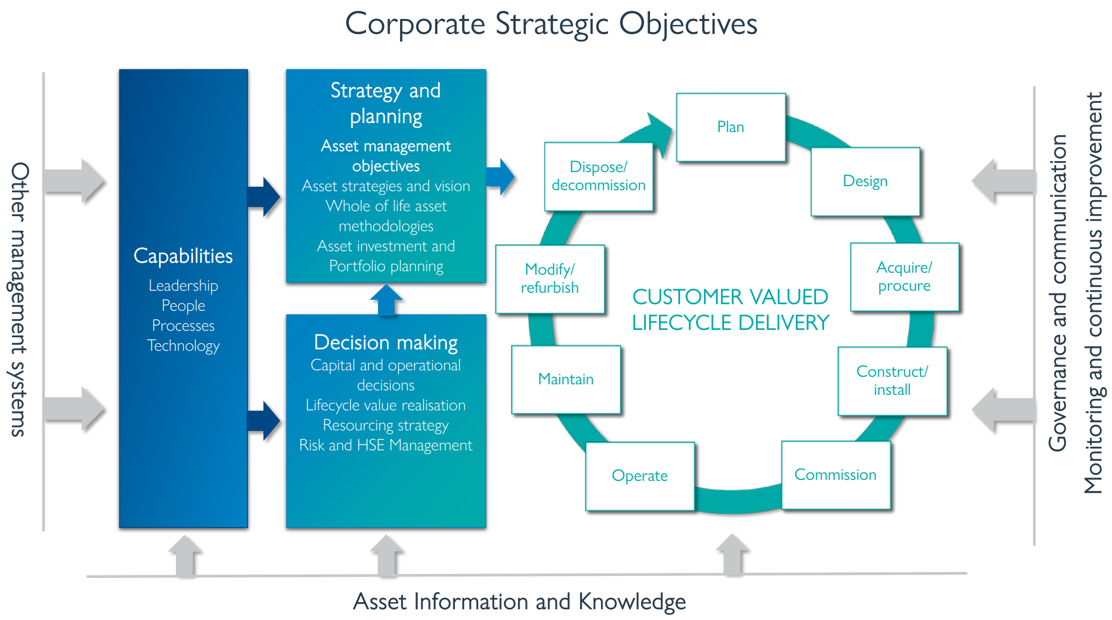
5.2 Overview of approach to asset management

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.

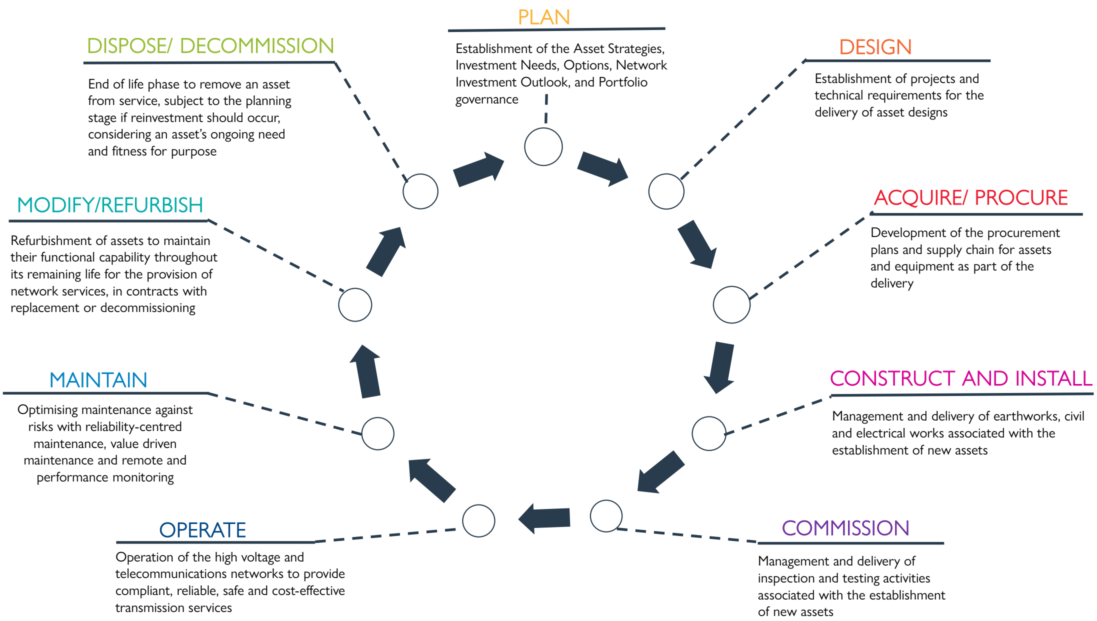
Reinvestment in assets approaching the end of their technical service life forms a substantial part of Powerlink's future network investment plans across the 10-year outlook period. Accordingly, the assessment of risk associated with the condition and performance of these assets is of particular importance. 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
- 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
- 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, technically complex and dynamic operating environment.
- The proposed future network developments discussed in the 2022 Transmission Annual Planning Report (TAPR) do not include the investment in new transmission that is needed under the energy transformation as discussed in the Queensland Energy and Jobs Plan (QEJP) released in September 2022. The work to integrate these investments with the existing network asset risks is well underway.
- 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, including the potential impacts of the energy transformation
  - the role of emerging technologies and assessing a range of technical factors and dynamic changes in Powerlink's operating environment to ensure network resilience
  - enabling opportunities for the connection of new firming generation and variable renewable energy (VRE generation) where technically and economically feasible to deliver positive benefits to customers
  - actively seeking opportunities to implement more cost-effective 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) and the QEJP.
- Powerlink has undertaken the necessary preparatory activities that informed the analysis for the 2022 ISP and QEJP.

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))
- a table summarising possible connection point proposals.

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

6.2 ISP alignment

The 2022 ISP published by AEMO in June 2022 provides an independent, strategic view of the efficient development of the NEM transmission network to 2050.

Powerlink will proactively monitor the changing outlook for the Queensland region and take into consideration the impact of emerging technologies, withdrawal of coal-fired generation and the integration of VRE and firming 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 and deliver efficient market outcomes
- investing is assets and/or non-network solutions to meet Powerlink's obligations for system strength and voltage control (refer to Section 6.8 and Chapter 10)
- non-network solutions.

Given the energy transformation, there is the potential for significant expansion of the transmission network over the next 10 years and beyond. While not included in the 2022 TAPR analysis, this work is well underway and insights are provided in Powerlink's 'Actioning the Queensland Energy and Jobs Plan'. The 2023 TAPR will incorporate the QEJP in conjunction with the ISP to inform Powerlink's planning activities.

[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.

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 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
- energy transformation, including the integration of VRE and new firming generation
- new customer access requirements including the development of Renewable Energy Zones (REZs)
- potential power system development pathways signalled in the ISP and QEJP
- 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
- 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 $7 million[2], Powerlink is required to undertake a Regulatory Investment Test for Transmission (RIT-T). The RIT-T describes the need, the credible options identified and defines the requirements for non-network alternatives.

2 The Regulatory Investment Test for Transmission (RIT-T) cost threshold increased from $6 million to $7 million from 1 January 2022 (refer to the AER's 2021 Cost Threshold Review Determination).

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, inertia and reactive power 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.
Transformer refit	Powerlink utilises a transformer reinvestment strategy called transformer refit to extend the service life of a transformer to provide cost benefits through the deferral of the timing for a future transformer replacement. Transformer refit may include replacement of components such as high voltage bushings, tap changers and instruments, addressing sources of oil leaks such as replacement of gaskets and main lid sealing, replacement of transformer oil, and addressing radiator corrosion.
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 rapidly changing environment, Powerlink is focusing on a staged, least regret and integrated approach to future network planning to ensure the transmission network is fit-for-purpose and able to meet customers' needs as the broader economy transforms to a lower carbon future. This includes assessing the enduring need for key ageing assets that are approaching the end of their technical service life and maintaining power system security. Powerlink's planning process considers alternative investment options such as network reconfiguration to manage asset condition or to address network limitations as well as non-network solutions where economic and technically feasible. Powerlink also maintains a focused 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.

The proposed future network developments discussed in the 2022 TAPR do not include or take into account the investment in new transmission that is needed under the energy transformation as discussed in the QEJP released in September 2022.

6.4.1 External economic factors and transmission network investments

The external environment in which Powerlink operates is becoming more complex. Rising inflation and interest rates, and an ongoing disruption to supply chains and materials shortages due to COVID-19 and geopolitical impacts, continue to be a challenge. These global factors, coupled with domestic factors, such as a strong demand and a tight labour market with unemployment rates around generational lows[3], are contributing to an upward pressure on prices.

The economic impact of supply constraints, coupled with the increasing inflation rate in Australia which has risen to its highest levels since the early 1990s[4], is affecting infrastructure project costs. A market sounding report by Energy Networks Australia (ENA) has observed supply chain pressures resulting in up to 40% increases in capital expenditure and at least a 5% increase in operational pressure for major projects[5]. This included cost increases occurring across labour, fuel, logistics, steel, cement, copper, aluminium, and other key commodities.

While recognising these complexities, Powerlink is focused on identifying supply risks and delivering solutions to ensure customers continue to receive cost-effective and efficient services in this uncertain environment.

6.5 Forecast network limitations

As outlined in Section 1.8.1, 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 Step Change scenario forecast discussed in Chapter 3, the maximum demand for electricity is expected to have mild growth with an average annual increase of 2% over the next 10 years.

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3 Reserve Bank of Australia – Statement on Monetary Policy (August 2022).
4 Reserve Bank of Australia – Statement on Monetary Policy (August 2022).
5 Energy Networks Australia - Market sounding report on transmission.

AEMO's Step Change scenario forecast includes 500MW of new electrification load in the Gladstone zone by 2030. This would lead to network limitations on the main transmission system into the Gladstone zone. Notwithstanding this potential new load, 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 and the QEJP.

In Powerlink's Revenue Determination 2023-27[6], 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, changing nature of load 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[7] summarises limitations identified in Powerlink's transmission network and noted in AEMO's December 2021 System Security Reports: System Strength, Inertia and NSCAS and May 2022 Update to 2021 System Security Reports.

[6] Information on Powerlink's Revenue Proposal for the regulatory period is available on Powerlink's website.
[7] 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 (2022/23)	3-year outlook (up to 2025/26)	5-year outlook (up to 2027/28)	Reference
System strength shortfall at Gin Gin	Central West	AEMO declared system strength shortfall December 2021	From 31 March 2023 (2)			Section 6.8
Reactive power absorption gap in southern Queensland	Moreton	AEMO declared gap December 2021	Immediate gap (2)			Section 6.8
Managing voltages in Queensland	Central West		2020/21 project in progress (1)			Table 11.6
	Moreton		2022/23 (2)(3)			Section 6.11.4

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 275kV bus reactor at Broadsound Substation, is commissioned in June 2023.

(2) Refer to AEMO's December 2021 System Security Reports and Update to 2021 System Security Reports and Powerlink's Expression of Interest (EOI), Request for System Security Services in central, southern and the broader Queensland regions which is currently in progress to address the declared System Strength and NSCAS requirements and discussed in sections 6.8 and 10.4.1.

The short-term solution for the reactive power requirement to meet the immediate gap in southern Queensland is being addressed through the Request for System Security Services in central, southern and the broader Queensland EOI process. Taking the outcome of the EOI into consideration, it is expected that the longer term solution will be considered as part of the RIT-T process to manage voltages in south-east Queensland currently in progress.

(3) The network risk associated with this limitation is currently being managed through a range of operational measures and is anticipated to be further supported by the outcome of Powerlink's EOI (refer to note 2) until such time as the preferred option identified in the current RIT-T is implemented and/or a non-network solution identified through the RIT-T process is implemented.

Based on AEMO's Step Change scenario forecast discussed in Chapter 3 there are no other network limitations forecast to occur in Queensland in the next five years[8].

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 (including electrification of existing industrial processes), 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. However, there were no forecast network limitations identified in Powerlink's transmission network in the 2021 TAPR which fall into this category in 2022.

Based on AEMO's Step Change scenario forecast there is approximately 500MW of additional load connected in the Gladstone zone by 2031. This load is associated with electrification of existing customer's processes. The impact of this additional load is discussed in sections 6.10.2 and 9.2.3.

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

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.

Proposals for transmission investments (which includes reinvestment and augmentations) over $7 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 taking into consideration the QEJP where appropriate, should action be 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
- 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[9].

Based on customer feedback, the 2022 TAPR portal information has been expanded to include additional information and links to relevant public documentation to further assist customers.

6.6.1 Current consultations – proposed transmission investments

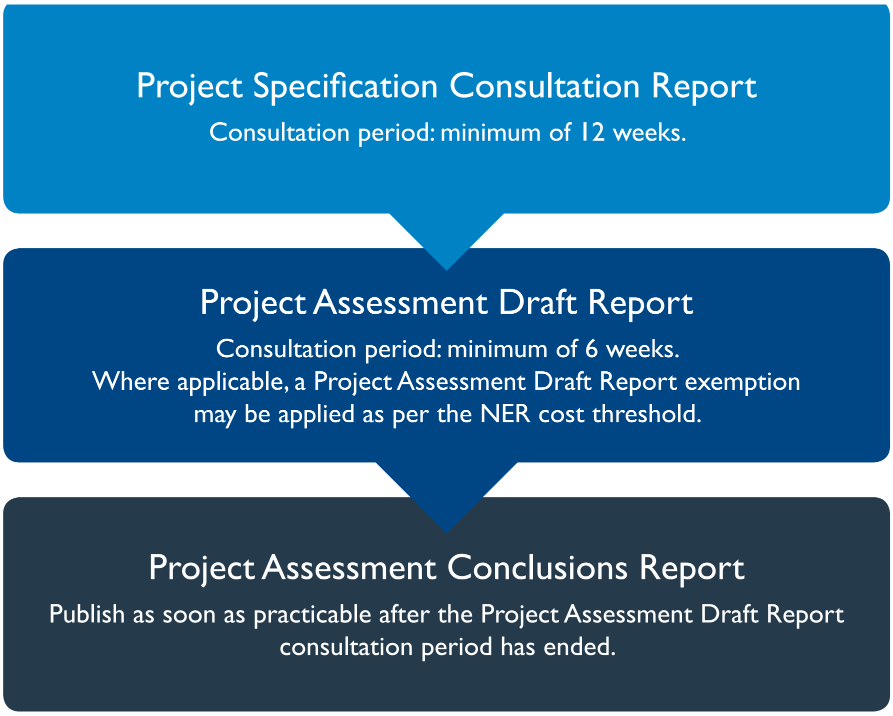
Commencing August 2010, proposals for transmission investments over $7 million addressing network limitations (augmentation works) are progressed under the provisions of Clause 5.16.4 of the NER. In September 2017 this NER requirement, to undertake a RIT-T, was extended[10] to include the proposed replacement of network assets. In July 2018 this was further extended to include proposed investments required to meet system strength and inertia shortfalls[11]. 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 over $7 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).

9 In accordance with the AER's TAPR Guidelines published in December 2018 and made available in Powerlink's TAPR portal.
10 Replacement expenditure planning arrangements Rule 2017 No. 5.
11 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 2021 TAPR are listed in Table 6.3 (refer also to Table 11.6).

Table 6.3 RIT-T consultations completed since publication of the 2021 TAPR

Consultation
Maintaining reliability of supply in the Cairns region – Stage 1
Addressing the secondary systems condition risks at Innisfail
Addressing the secondary systems condition risks at Chalumbin
Maintaining reliability of supply in the Tarong and Chinchilla local areas

RIT-T consultations currently underway are listed in Table 6.4

Table 6.4 RIT-T consultations currently underway

Consultation (1)	Reference
Managing voltages in South East Queensland	Section 6.11.4
Managing power transfer capability and reliability of supply at Redbank Plains	Section 6.11.4

Note:
(1) The consultations reflect the RIT-T status as at 30 September 2022.

Other consultations (non RIT-T) currently underway since publication of the 2021 TAPR are listed in Table 6.5.

Table 6.5 Other consultations currently underway since publication of the 2021 TAPR[12]

Consultation	Reference
Request for power system security services in central, southern and the broader Queensland region	Section 6.8

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

Notwithstanding consideration of the QEJP and power system security requirements, Powerlink's capital expenditure program of work in the 10-year outlook period will focus on investment in the transmission network to manage the risks arising from ageing assets remaining in-service. These emerging risks are discussed in Section 6.9 to 6.11. 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 investment in a network asset or limitation.

Table 6.6 Anticipated consultations in the forthcoming 12 months (to October 2023)

Consultation (1)	Reference
Addressing the secondary systems condition risks at Tangkam	Section 6.11.1
Addressing the secondary systems condition risks at Mudgeeraba	Section 6.11.5

Note:
(1) The anticipated consultations listed in Table 6.6 reflect the RIT-T status as at 30 September 2022.

Future ISP projects

The 2022 ISP did not identify any 'actionable' projects within Queensland. However, the 2022 ISP did identify several projects that are part of the optimal development path and may become actionable in future ISPs. Further to the three preparatory activities reports previously provided to AEMO[13], two additional projects were nominated for Preparatory Activities by 30 June 2023. These include:

- Darling Downs REZ Expansion
- QNI Connect (500kV option Powerlink and Transgrid).

Preparatory activity reports for these projects will be provided to AEMO by 30 June 2023 and are discussed further in Section 9.3. The commencement for consultation for these projects will be triggered by future ISPs and considered in conjunction with the QEJP[14].

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)[15] or be initiated by generators or customers.

Table 6.7 lists connection works that are anticipated to be required within the 10-year outlook period.

[12] Power System Security Consultations
[13] Preparatory Activities reports for Central to Southern Queensland, Gladstone Grid Reinforcement and QNI connect were provided to AEMO by 30 June 2021.
[14] Refer to Section 5.16A.3.
[15] 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[16]

Connection point name (1) (2)	Proposal	Zone
Clarke Creek Wind Farm	New wind farm	Central West
Bouldercombe Battery Energy Storage System (BESS)	New BESS	Central West

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 in progress (refer to Table 11.1).

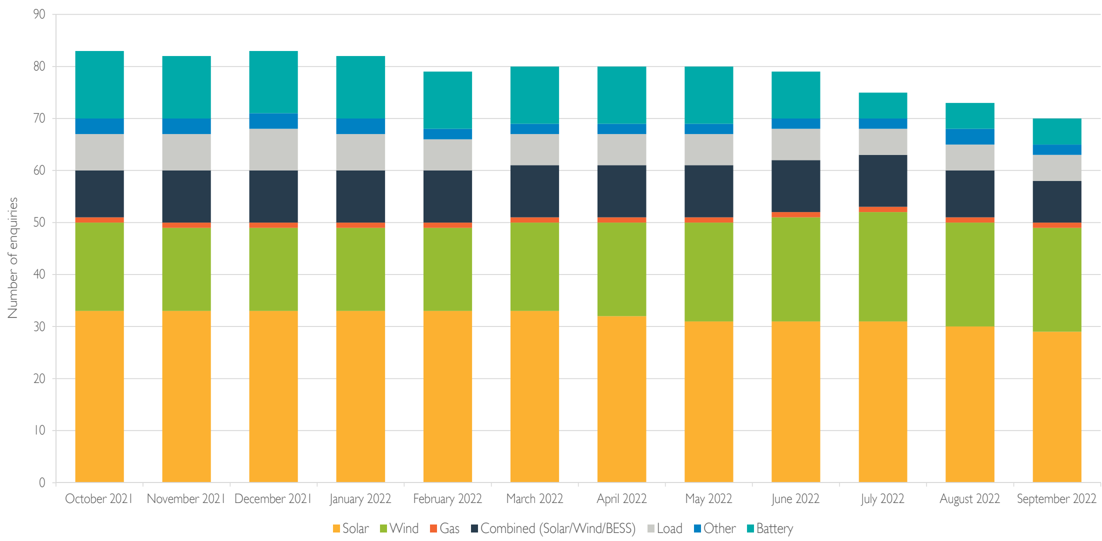
It should be noted that while not fully at the stage where the project can be classified as committed under the NER[16] at the time of publication of the 2022 TAPR, Powerlink has signed an agreement for the construction of assets for the connection of the MacIntyre Wind Precinct proposed renewable development to the transmission network in south-west Queensland[17]. More information on this project is available on Powerlink's website.

Table 6.8 summarises connection point activities[18] undertaken by Powerlink since publication of the 2021 TAPR (refer also to figures 6.2 and 6.3). Further 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	5	0	Solar, Wind, Hydro, Storage
Central	7	2	Solar, Wind, Storage
South	20	0	Solar, Wind, Storage
Total	32	2	

Figure 6.2 Customer enquiries per month since publication of the 2021 TAPR

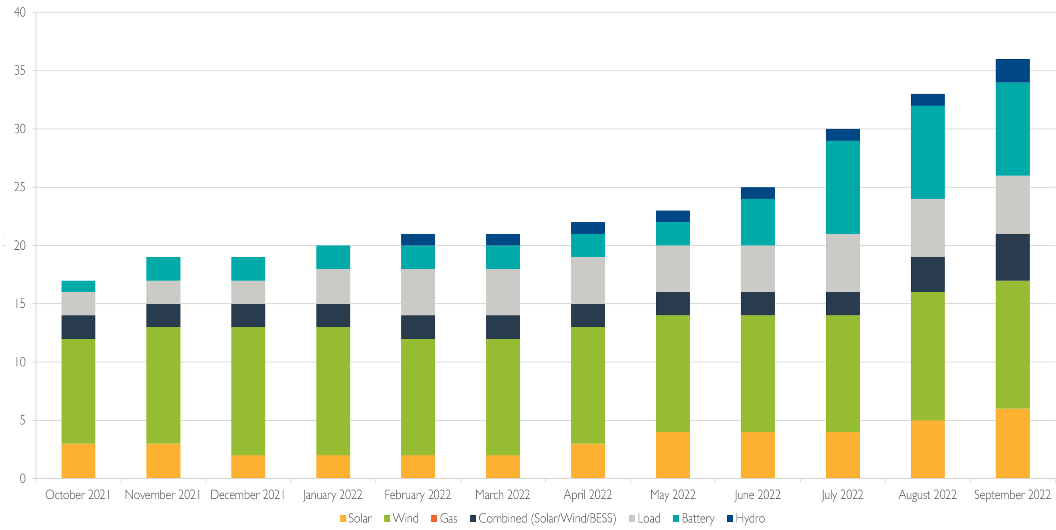


16 AEMO's definition of 'committed' from the System Strength Impact Assessment Guidelines (effective 1 July 2018) has been adopted for connection point proposals identified in the TAPR.

17 As not included in Table 6.7, the MacIntyre and Karara Wind Farms are included in the connection point activities as noted in Table 6.8.

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

Figure 6.3 Cumulative customer applications per month since publication of the 2021 TAPR



6.7 Proposed network developments

The proposed future network developments discussed in the 2022 TAPR do not include the investment in new transmission that is needed under the energy transformation as discussed in the QEJP recently released in September 2022. Notwithstanding this, Powerlink's capital expenditure program of work will also focus on the risks arising from the condition and performance of existing aged assets, as well as emerging limitations in the capability of the network as the broader economy transforms to a lower carbon future.

As the Queensland transmission network experienced considerable growth in the period from 1960 to 1980, there are now a large number of transmission assets ranging from 40 to just beyond 60 years old. It has been identified that a number of these assets are approaching the end of their technical service life and investment in some form is required within the 10-year outlook period in order to manage emerging risks related to safety, reliability and other factors.

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

- improve and further refine options under consideration
- identify other options from those originally specified, including a consideration of the broader energy transformation where appropriate, which may deliver a greater benefit to customers.

Information regarding possible investment alternatives, network limitations 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.

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.

6 Future network development

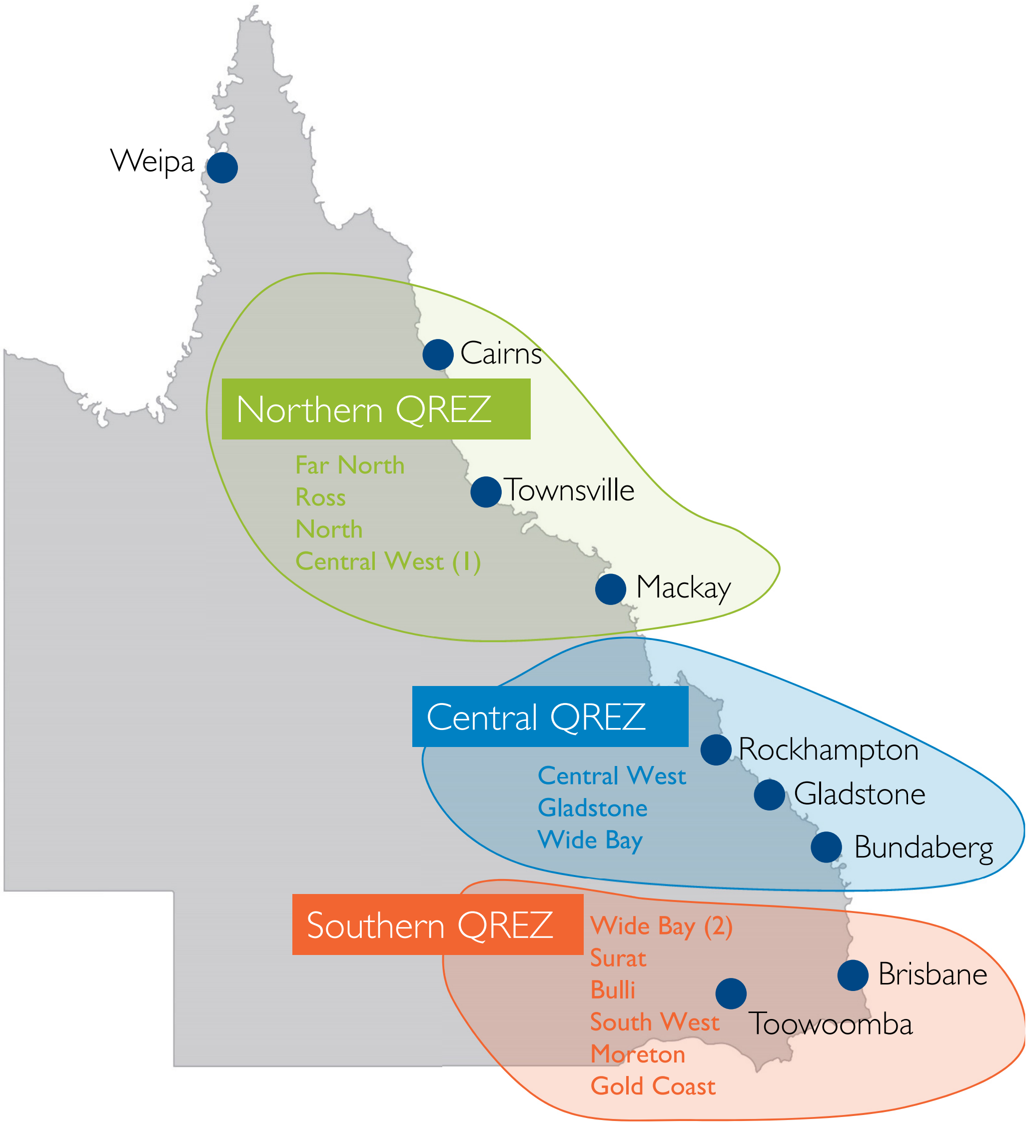
Proposed network developments discussed within this chapter identify the most likely network solution, although this has the potential to change with ongoing detailed analysis of asset condition and risks, network requirements, the dynamic impacts of energy transformation or as a result of RIT-T consultations. The indicative cost of potential projects is also updated each year to keep pace with external project cost increases that are being experienced broadly across many industries (refer to Section 6.4.1). On balance, where there may be other factors materially influencing the updated indicative cost, such as a more granular view of condition and project scope, these factors are noted in the relevant summary table included at the end of each zone discussion.

Other than the outcomes set out in the 2021 System Security Reports and May 2022 Update (refer to Section 6.8) 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 and Power System Frequency Risk Review (PSFRR). 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 2022 annual planning review.

6.7.1 Geographical context

An analysis of investment needs and potential limitations has been performed across Powerlink's standard geographic zones (refer to sections 6.9 to 6.11). Given the rapid pace of the energy transformation, to provide geographical context, the reinvestment needs and network limitations are aligned with the Queensland Renewable Energy Zones (QREZ) development areas as shown in Figure 6.4.

Figure 6.4 Queensland Renewable Energy Zones



6.7.2 Investment context, timeframes and description

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 identified needs. 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 broader economy transforms to a lower carbon future, delivering positive outcomes for customers.

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.

For clarity, possible network investments (which includes reinvestment and augmentations) have been separated into two periods.

Possible network investments within five years

This includes the financial period from 2022/23 to 2027/28 for possible near-term investments when:

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

Possible network investments within six to 10 years

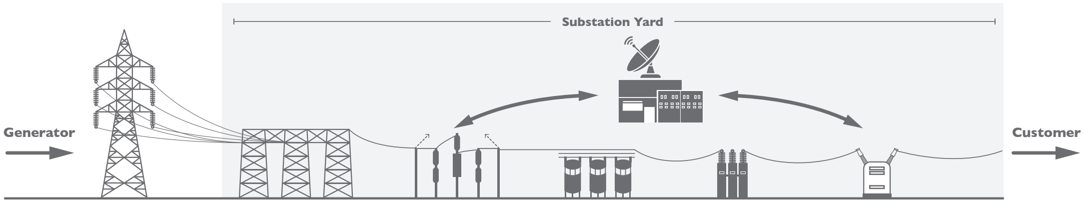
This includes the financial period from 2028/29 to 2032/33, for possible medium to long-term investments. Powerlink takes a balanced, prudent and proportionate approach to the consideration of investment needs to address the risks arising from network assets in the medium to long-term and undertakes detailed planning analysis and condition assessment closer to the possible investment date, typically within five years.

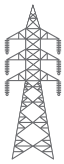
In addition, due to the current dynamic operating environment, there is less certainty regarding the needs or drivers for investments in these later years of the annual planning review period. As a result, considerations in this period have a greater potential to change when compared to near-term investments. Possible investment considerations within six to 10 years will need to be flexible in order to adapt to externally driven changes as the broader economy transforms to a lower carbon future and customer behaviours continue to 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 2021 TAPR and 2022 TAPR and TAPR Templates. Significant timing differences are noted in the analysis of the program of work within this chapter (refer to sections 6.9 to 6.11).

The functions performed by the major transmission network assets discussed in this chapter are illustrated in Figure 6.5.

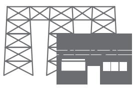
Figure 6.5 The functions of major transmission assets





Transmission line

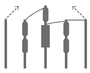
A transmission line consists of tower structures, high voltage conductors and insulators and transports bulk electricity via substations to distribution points that operate at lower voltages.



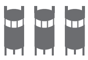
Substation

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.

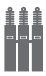
A substation that connects to transmission lines, but does not include a transformer, is known as a switching station.



- **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.



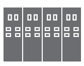
- **Static VAR Compensator (SVC)**
  A SVC is used where needed, to smooth voltage fluctuations, which may occur from time-to-time on the transmission network. This enables more power to be transferred on the transmission network and also assists in the control of voltage.



- **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.

6.8 Power system security requirements

In May 2022 Powerlink published an Expression of Interest (EOI), Request for Power System Security Services in central, southern and broader Queensland regions. The EOI requested submissions from potential solution providers to ascertain and evaluate options (both non-network and network) to meet the power system security requirements identified in the AEMO's 2021 System Security Reports: System Strength, Inertia and NSCAS and Update to 2021 System Security Reports published on 17 December 2021 and 11 May 2022 respectively.

The EOI requested potential non-network solutions to address AEMO's declared shortfalls of:

- an immediate system strength shortfall of up to 90MVA at the Gin Gin 275kV fault level node, located in the Wide Bay zone, to be addressed from 31 March 2023
- an NSCAS gap of 120MVAr, more specifically a Reliability and Security Ancillary Service (RSAS) gap[19], in southern Queensland to be addressed immediately and rising to 250MVAr by 2026.

Submissions closed on the 24 June 2022 and Powerlink is currently clarifying submission information and performing technical and economic feasibility assessments for the declared shortfalls. Further information will be published by early 2023 once all offers have been fully evaluated and discussed in the 2023 TAPR.

6.9 Northern region

The Northern region includes proposed network investments located within the Far North, Ross and North zones and broadly aligns with the Northern QREZ development area stretching between Mackay and Cairns, encompassing the northern most extent of Powerlink's transmission network. The Northern region also includes a number of candidate REZ areas in north Queensland identified in the 2022 ISP optimal development pathway (refer to Figure 9.2).

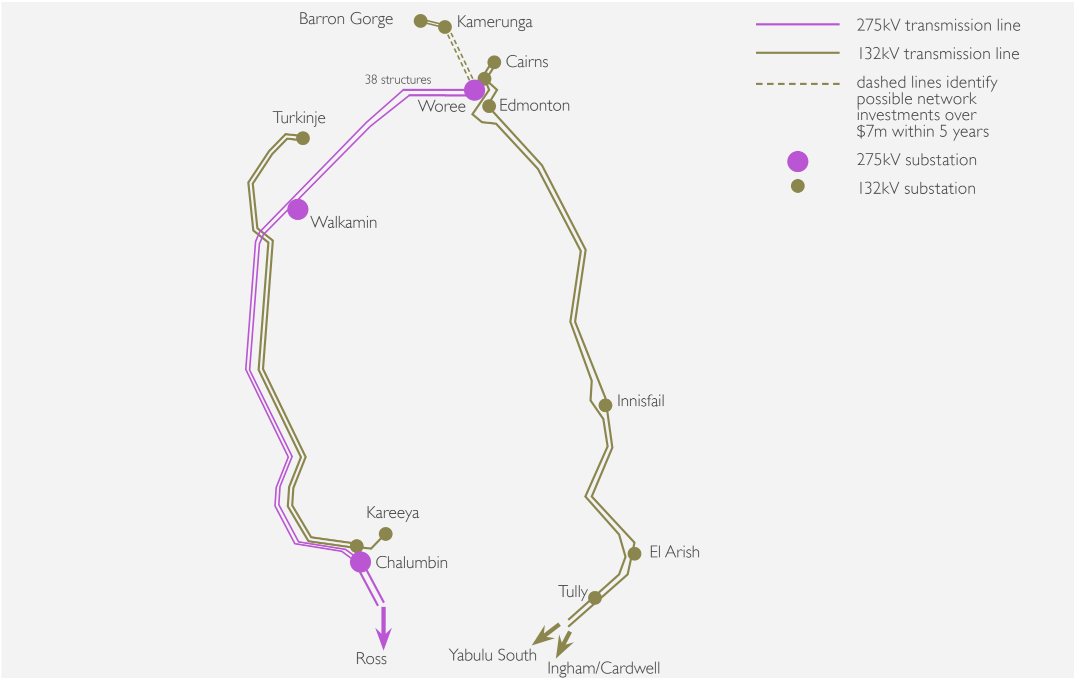
6.9.1 Far North zone

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 6.6).

19 Reliability and Security Ancillary Service (RSAS) gap.

Figure 6.6 Far North zone transmission network



Possible load driven limitations

Based on AEMO's Step Change 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.

Possible network investments within five years

Network investments (which include reinvestments and augmentations) in the 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 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 $42 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 (PS) 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[20]
- 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 PS connection in the area.

Ross to Chalumbin to Woree 275kV transmission lines

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, committed Kaban Wind Farm and Kareeya Power Station (PS). As a result of the funded augmentation consultation undertaken by Powerlink to facilitate the development of Stage 1 of the Northern QREZ, establishment of a 3rd 275kV connection into Woree Substation is expected to be completed in November 2023.

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.

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. To address the more complex and advanced condition risks of this section of the transmission line, in June 2022 Powerlink completed a RIT-T, Maintaining reliability of supply in the Cairns region Stage 1- Addressing the condition risks of the transmission towers between Davies Creek and Bayview Heights. The Project Assessment Conclusions Report (PACR) identified the preferred option for implementation, refit of the 37 towers through the selective replacement of corroded members and components, along with the painting of all 37 towers (refer to Table 11.6).

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

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. This section of the transmission line is deteriorating at a slower rate than assets assessed under Stage 1 works due to its location on the western side of the Great Dividing Range. A potential reinvestment for this section (based on the most recent condition assessment) is expected around 2029 (refer to Table 6.10).

Possible non-network solutions

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

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 investments in the Far North zone within five years

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 investment, 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.

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

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Transmission lines					
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 (1)	$42m
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 or a non-network alternative of up to 15MW at peak and up to 100MWh per day on a continuous basis to provide supply to the 22kV network at Tully	$6m(2)
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 (1)	$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	$4m
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	$4m

Notes:

(1) The envelope for non-network solutions is defined in Section 6.9.1.

(2) At the time of publication of the 2022 TAPR, Powerlink does not anticipate the most expensive credible option will reach the RIT-T cost threshold of $7m.

Possible network investments within six to 10 years

As a result of the annual planning review, Powerlink has identified that the following investments 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 2028/29 to 2032/33 (refer to Table 6.10).

Table 6.10 Possible network investments 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 Far North and Ross zones	Staged works by December 2029 (1)	New transmission line (2)	$72m
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	$6m (3)
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
275/132kV substation establishment to maintain supply to Turkinje substation	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	$39m
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	$17m
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 2021 TAPR is based upon updated information on the condition of the assets.

(2) The envelope for non-network solutions is defined in Section 6.9.1.

(3) Compared to the 2021 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 in the 10-year outlook period[21]

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 275kV Substation at Turkinje and cut into an existing 275kV Chalumbin to Woree circuit via a new 275kV DC line constructed from Turkinje. Should this option eventuate, there will be an opportunity to retire the existing 132kV transmission line from Chalumbin to Turkinje.

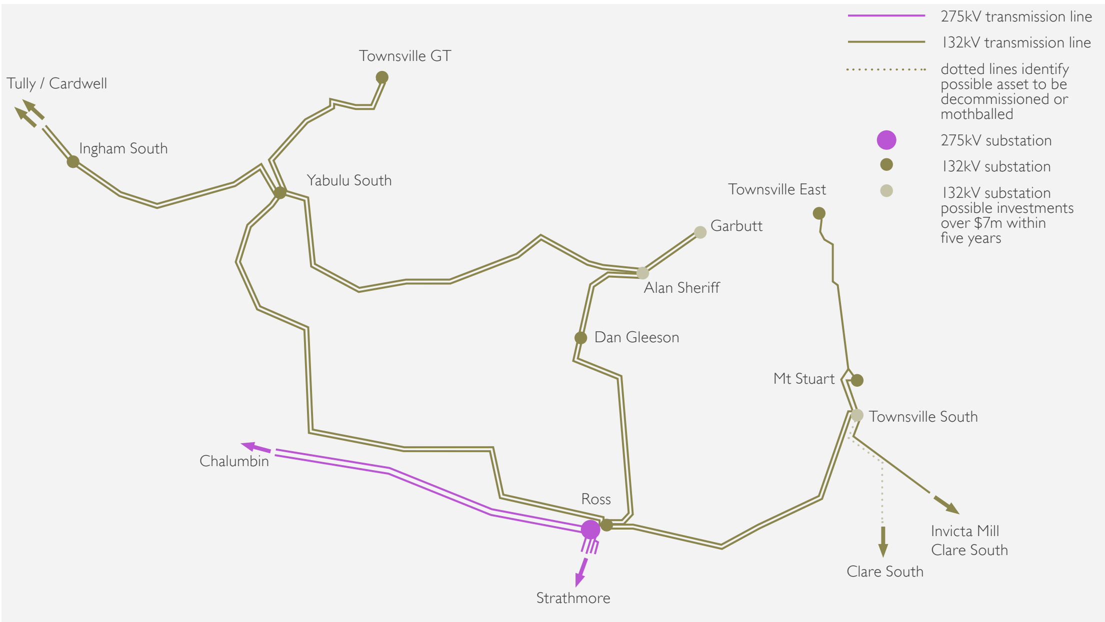
Refer Table 11.7 for confirmed asset retirements in the Far North zone and Table 6.30 for possible asset retirements beyond the 10-year outlook period.

6.9.2 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 6.7 and 6.8).

Figure 6.7 Northern Ross zone transmission network



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

Figure 6.8 Southern Ross zone transmission network

Possible load driven limitations

Based on AEMO's Step Change 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 investments within five years

Network investments (which includes reinvestment and augmentations) 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 $12 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.

Garbutt 132kV Substation

Potential consultation	Addressing the secondary systems condition risks at Garbutt
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 $10 million by June 2026

Garbutt Substation was established in the 1950s as a 132/66kV bulk supply and transformation point to the distribution network. In the early 1960s three bays were added to the substation, and in 1978 two power transformers replaced the previous units. In 2004, the substation was rebuilt in a transformer ended configuration, with the switching function established at Alan Sherriff.

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 support the 66kV network in north east Townsville of up to 110MW at peak and up to 800MWh per day.

Townsville South 132kV Substation

Potential consultation	Addressing the secondary systems condition risks at Townsville South
Project driver	Condition driven replacement to address emerging obsolescence and compliance risks on 132kV secondary systems
Project timing	June 2028
Proposed network solution	Selected replacement of secondary systems at an estimated cost of $16 million by June 2028

Townsville South is a major substation supplying the city of Townsville, the major industrial load of Sun Metals Zinc Refinery and serving as a connection point for the Mt Stuart Power Station (PS).

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 Townsville East and Townsville South (including Sun Metals) of up to 150MW at peak and up to 3000MWh per day. It would also need to facilitate the connection of Mt Stuart PS.

Possible network investments in the Ross zone within five years

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 investment, 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.

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

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Substations					
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)	$12m
Ingham South 132kV secondary systems replacement	Full replacement of 132kV secondary systems	Maintain supply reliability to the Ross zone	June 2026	Selected replacement of 132kV secondary systems (1)	$6m
Garbutt 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	$10m (3)
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	$4m
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	$16m

Notes:

(1) The envelope for non-network solutions is defined in this Section 6.9.2.

(2) The change in timing of the network solution from the 2021 TAPR is based upon updated information on the condition of the assets.

(3) Compared to the 2021 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 investments within six to 10 years

As a result of the annual planning review, Powerlink has identified that the following investments 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 2028/29 to 2032/33 (refer to Table 6.12).

Table 6.12 Possible network investments 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	December 2029 (1)	New 132kV transmission line Targeted line refit works on steel lattice structures with painting	$4m
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	December 2029 (1)	New 132kV transmission line	$8m
Line refit works on the 132kV transmission line between Dan Gleeson and Alan Sherriff substations	Line refit works on steel lattice structures	Maintain supply reliability to the Ross zone	December 2028	New 132kV transmission line	$4m
Substations					
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	$12m
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	$4m

Note:
(1) The change in timing of the network solution from the 2021 TAPR is based upon updated information on the condition of the assets.

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.

Refer to Table 6.30 for possible asset retirements beyond the 10-year outlook period.

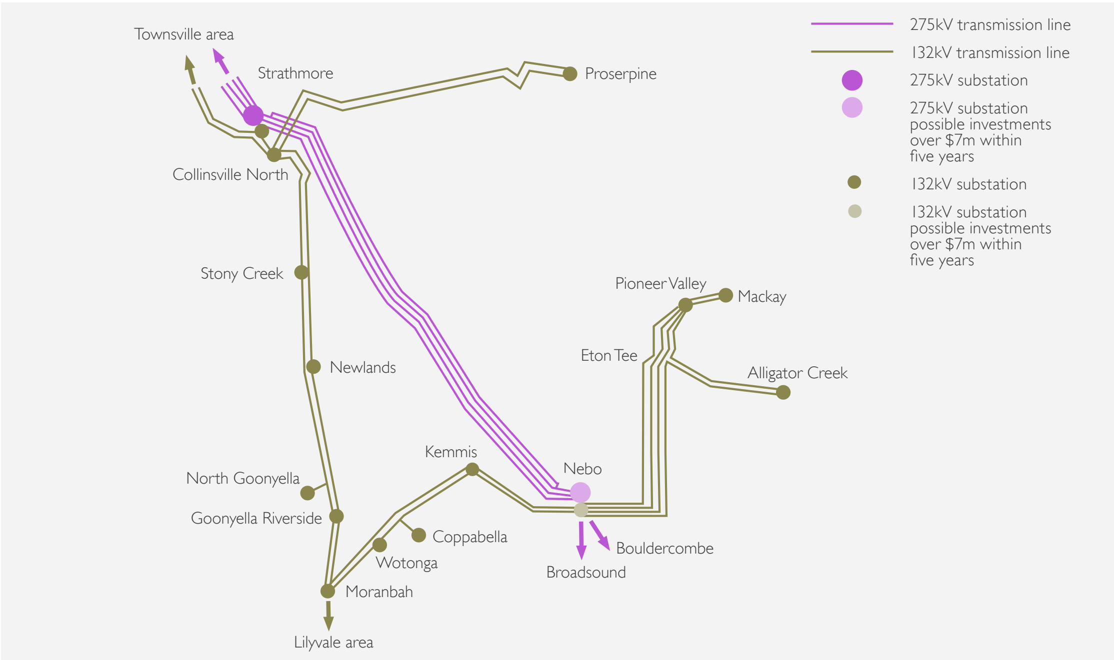
6.9.3 North zone

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 6.9).

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

Figure 6.9 North zone transmission network



Possible load driven limitations

Based on AEMO's Step Change 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 and low power transfer 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 8.6.2.

Possible network investments within five years

Network investments (which includes reinvestment and augmentations) 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 to supply Ergon Energy's distribution network and Powerlink's direct connected customers in the Northern Bowen Basin. 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.

Possible network investments in the North zone within five years

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 investment, 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.

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

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Substations					
Alligator Creek 132kV primary plant replacement	Selected replacement of 132kV primary plant	Maintain supply reliability to the North zone	June 2024	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
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
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	$6m (2)

Notes:

(1) The envelope for non-network solutions is defined in Section 6.9.3.

(2) Compared to the 2021 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 investments 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 2028/29 to 2032/33 (refer to Table 6.14).

Table 6.14 Possible network investments 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 2029 (1)	New transmission line	$33m
Substations					
Alligator Creek SVC and 132kV secondary systems replacement	Full replacement of 132kV secondary systems	Maintain supply reliability to the North zone	June 2029 (1)	Staged replacement of 132kV secondary systems	$16m
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	$5m
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	$15m
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	$6m (2)

Notes:

(1) The revised timing from the 2021 TAPR is based upon the latest condition assessment.

(2) Compared to the 2021 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. Should it proceed, the retirement 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.

Refer to Table 11.7 for assets which have been identified for retirement at the time of publication of the 2022 TAPR and Table 6.30 for possible asset retirements beyond the 10-year outlook period.

6.10 Central region

The Central region includes proposed network investments located within the Central West and Gladstone zones that broadly aligns with the Central QREZ proposed development area. It incorporates some of Powerlink's largest industrial customers and significant coal-fired generation together with considerable opportunities for the development of new industries. The transmission network in this region is pivotal to supply power to northern and southern Queensland and plays a major role in supporting industry, rail systems and mines. The Central region also includes a number of candidate REZ areas identified in the 2022 ISP optimal development pathway (refer to Section 2.3.4 and Figure 9.2).

The Central QREZ development area has high quality solar and wind resources and has long-term hydrogen potential and existing energy-intensive industries that are seeking to decarbonise through either electrification of existing processing facilities and/or conversion to loads powered by VRE generation. Together, new VRE generation, electrification of existing industries and new large loads have the potential to significantly impact the performance of the transmission network in the Central region, including power transfers reaching the secure limits of the transmission system (refer to section 9.2.3).

As discussed in Section 6.11.1, the utilisation of the transmission network in this region depends on both the generation dispatch and supply and demand balance within the Central West and Gladstone zones, and northern and southern Queensland. In addition, the significant increase in VRE generation is changing the generation mix and impacting the operation of existing coal-fired generators within the region, which, in turn, is further effecting the utilisation of existing transmission infrastructure. This has been most evident across the Central to North Queensland and Central to South Queensland grid sections (refer sections 8.6.2 and 8.6.5 respectively) and the Queensland to NSW interconnector (QNI). A change in utilisation has implications for investment in the transmission network, including the Central to South Queensland transmission link, and the Gladstone area 275kV transmission network between the generation rich nodes of Calvale, Stanwell and Calliope River substations. Several potential investments for the Central region are outlined in sections 9.3.2 and 9.3.3.

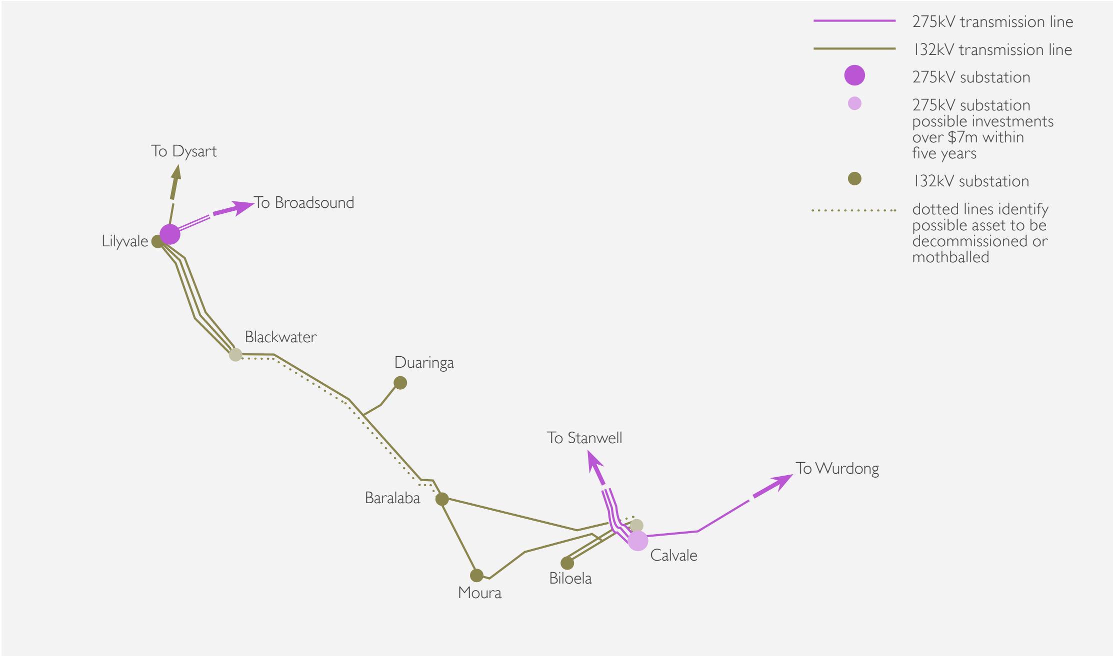
As a result, the Central region has the potential to have significantly changed requirements for transmission infrastructure in the 10-year outlook period. Given Powerlink's integrated planning approach, these requirements may result in the need for new investments that impact the proposed future network and non-network solutions identified in the geographical zones located within the region (refer to sections 6.10.1 to 6.11.1), the 'Actioning the Queensland Energy and Jobs Plan' and will be updated in subsequent TAPRs.

6.10.1 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 but will still require replacement or rebuilding in the near future (refer to Figure 6.10).

Figure 6.10 Central West 132kV transmission network



Possible load driven limitations

Based on AEMO's Step Change 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 investments within five years

Network investments (which includes reinvestment and augmentations) 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	June 2028
Proposed network solution	Selected primary plant replacement at Calvale Substation at an estimated cost of $16 million by June 2028

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 Callide C generators. Selected primary plant is anticipated to reach end of technical service life around 2028.

Possible network solutions

- Selected primary plant replacement by June 2028
- Full primary plant replacement by June 2028.

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 also a major transmission node in Central Queensland connecting power flows between northern, central and southern Queensland. It also facilitates Callide B and Callide 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 2027
Proposed network solution	Selected primary plant replacement at Broadsound Substation at an estimated cost of $16 million by December 2027

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 2027.

Possible network solutions

- Selected primary plant replacement by December 2027
- Full primary plant replacement by December 2027.

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

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 investment, 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 6.15.

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
Transmission lines					
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	Rebuild the 132kV transmission lines as a double circuit from Callide A to Moura Line refit works on the 132kV transmission line and repair all foundations	$5m
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
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
Broadsound 275kV primary plant replacement	Selected replacement of 275kV primary plant	Maintain supply reliability to the Central West zone	December 2027(1)	Full replacement of 275kV primary plant	$16m
Lilyvale 132kV secondary systems replacement	Selected replacement of 132kV secondary systems	Maintain supply to the Central West zone	June 2028 (1)	Full replacement of 132kV secondary systems	$3m
Calvale 275kV primary plant replacement	Selected replacement of 275kV primary plant	Maintain supply reliability to the Central West zone	June 2028 (1)	Full replacement of 275kV primary plant	$16m (2)

Notes:

(1) The change in timing of the network solution from the 2021 TAPR is based upon updated information on the condition of the assets.

(2) Compared to the 2021 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 investments within six to 10 years

As a result of the annual planning review, Powerlink has identified that the following investments 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 2028/29 to 2032/33 (refer to Table 6.16).

Table 6.16 Possible network investments 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 and Northern region	December 2029	Stanwell to Broadsound 2nd side stringing New 275kV transmission line between Bouldercombe and Broadsound substation	$31m
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	$14m
Nebo 132kV and 275kV secondary systems replacement	Selected replacement of 132kV and 275kV secondary systems	Maintain supply reliability to the Central West and North zones	June 2030	Full replacement of 132kV and 275kV secondary systems	$10m
Nebo SVC secondary systems replacement	Selected replacement of secondary systems	Maintain supply reliability to the Central West zone and Northern region	June 2030	Full replacement secondary systems	$6m

Possible asset retirements within the 10-year outlook period[22]

Calvale to Moura to Baralaba 132kV transmission lines

Subject to the outcome of further analysis and RIT-T consultation, a new 132kV double circuit transmission line may be constructed between Calvale and Moura substations at the end of technical service life of the existing transmission line within the 10-year outlook period. The reconfiguration allows Powerlink to mothball the existing single circuit transmission lines between Callide and Baralaba, and Baralaba and Moura substations at the end of their technical service lives and retired from service.

Baralaba to Blackwater 132kV transmission line

The 132kV inland transmission line was constructed in the mid-1960s to support the loads in the Central West area. Due to reconfiguration in the area, this transmission line is disconnected at the Baralaba substation, and may be retired from service at the end of technical service life within the 10-year outlook period.

Refer to Table 6.30 for possible asset retirements beyond the 10-year outlook period.

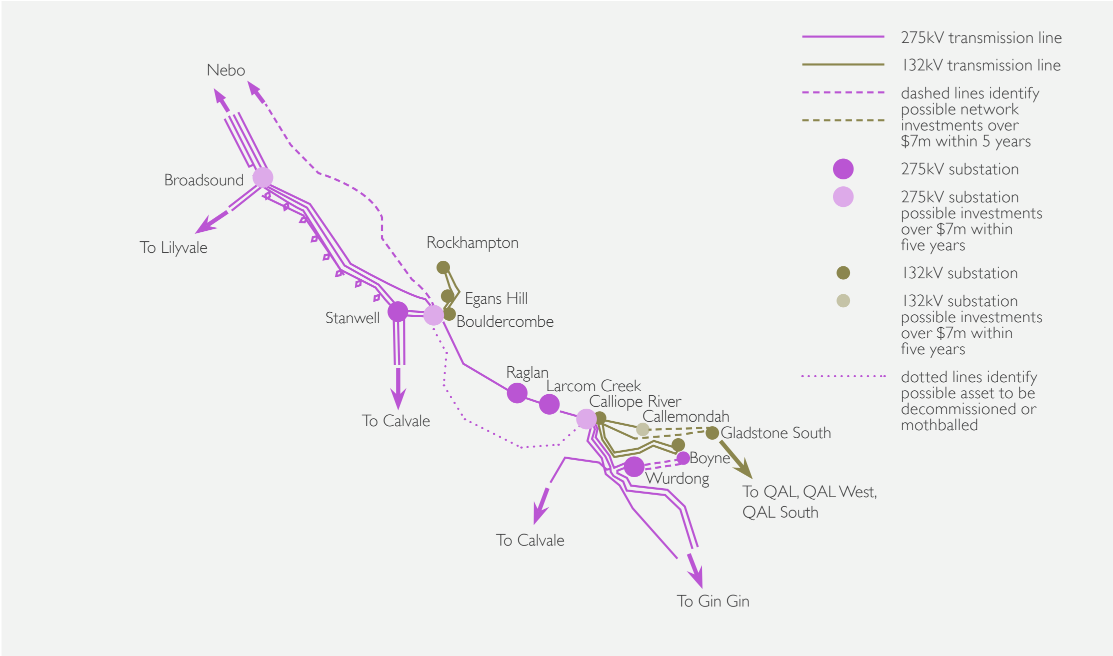
6.10.2 Gladstone zone

Existing network

The Gladstone 275kV network was initially developed in the 1970s with the Gladstone Power Station (PS) 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 6.11).

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

Figure 6.11 Gladstone transmission network



Possible load driven limitations

Based on AEMO's Step Change scenario forecast discussed in Chapter 3, there is approximately 500MW of additional load connected in the Gladstone zone by 2031. This load is associated with electrification of a component of the existing industrial processes within the area. While Powerlink has no commitment from any direct connect customers to electrify industrial process, Powerlink is in early discussions with corporations that have committed to decarbonisation of their existing fossil fuelled operations and processes. Therefore, for this TAPR, any additional capacity forecast to be required to meet this increase in load will only be considered in the context of the main 275kV network supplying the Gladstone zone. Network limitations downstream of the main transmission system cannot be assessed without specific customer identification.

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. In addition, the new electrification loads and any other new loads have the potential impose significant limitations impacting market outcomes as well as reliability of supply obligations. Possible network solutions to address these issues are outlined in Section 9.3.3.

Notwithstanding this additional electrification load and any future new loads and taking into account 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 investments within five years

Network investments (which includes reinvestment and augmentations) 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 2026
Proposed network solution	Rebuild the 275kV transmission line between Calliope River and Larcom Creek substations as double circuit high capacity transmission line turning in one circuit at an estimated cost of $35 million, by June 2026

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 between Mt Miller near Calliope River and Larcom Creek
- 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 and turn-in one circuit to Larcom Creek substation
- Rebuild the 275kV transmission line between Calliope River and Larcom Creek as double circuit transmission line construction and turn-in both circuits to Larcom Creek substation.

The proposed network solution is heavily influenced by the energy transformation. There are several drivers, yet to be committed, that can have a material impact on the transmission capability required into the Gladstone zone. A number of corporations have committed to the decarbonisation of existing fossil fuelled operations and processes either through electrification or clean fuel substitution. This will have the impact of materially changing the supply and demand balance of the Gladstone zone necessitating greater investment in transmission capability. Refitting this low capacity 275kV line or constructing a new higher capacity single circuit 275kV line is not aligned with this broader strategy.

Constructing a new high capacity 275kV double circuit line may also allow for the retirement of the more western 275kV single circuit line between Calliope River and Bouldercombe substations when this line reaches its end of technical service life or converted into a connection asset for one of several wind farm proponents in the area.

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

Potential 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 $11 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

Potential consultation	Maintaining reliability of supply to Gladstone South
Project driver	Emerging condition risks due to structural corrosion
Project timing	June 2026
Proposed network solution	Rebuild the double circuit transmission line between Callemondah and Gladstone South substations, at an estimated cost of $25 million, by June 2026

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.

In making this investment decision Powerlink will also take into account the possible decarbonisation of existing fossil fuelled operations and processes that are currently supplied from this network. This may impact the scale and configuration of the optimal network investment. These development plans will be reported in subsequent TAPRs as more certainty and commitment of these additional loads emerge.

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 investments in the Gladstone zone within five years

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 investment, 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.

Table 6.17 Possible network investments 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 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)	$11m (3)
Rebuild the 132kV transmission line between Callemondah and Gladstone South Substation	Rebuild the 132kV double circuit transmission line between Callemondah and Gladstone South Substation	Maintain supply reliability in the Gladstone zone	June 2026 (2)	Line refit works on steel lattice structures (1)	$25m (3)
Rebuild the 275kV transmission line between Calliope River and Larcom Creek Substation	Rebuild the 275kV transmission line between Calliope River and Larcom Creek as double circuit transmission line construction and turn-in one circuit to Larcom Creek Substation	Maintain supply reliability in the Gladstone zone	June 2026 (2)	Line refit works on the 275kV transmission line between Larcom Creek substation and Mt Miller near Calliope River (1)	$35m
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 6.10.2.

(2) The change in timing of the network solution from the 2021 TAPR is based upon updated information on the condition of the assets.

(3) Compared to the 2021 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 investments within six to 10 years

As a result of the annual planning review, Powerlink has identified that the following investments 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 2028/29 to 2032/33 (refer to Table 6.18).

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

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Transmission lines					
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 (2)	Line refit works on steel lattice structures Rebuild the 275kV transmission line between Raglan and Larcom Creek as a single circuit line	$42m
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)(2)	Line refit works on steel lattice structures Rebuild the 275kV transmission line between Raglan and Bouldercombe as a single circuit line	$79m
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
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
Bouldercombe 275kV secondary systems replacement	Full replacement of the 275kV secondary systems	Maintain supply reliability in the Gladstone zone	June 2032	Selected replacement of 275kV secondary systems	$25m
Calliope River 275kV secondary systems replacement	Full replacement of the 275kV secondary systems	Maintain supply reliability in the Gladstone zone	June 2032	Selected replacement of 275kV secondary systems	$28m

Notes:

(1) The change in timing of the network solution from the 2021 TAPR is based upon updated information on the condition of the assets.

(2) The required timing for this network investment will depend on the overall supply and demand balance in the Gladstone zone. This is impacted by the future operation of the Gladstone PS and the development of new loads associated with decarbonising existing industrial processes and new industries.

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

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.

Calliope River to Bouldercombe 275kV transmission single circuit line

The 275kV transmission line was constructed in 1980 to support the loads in the Gladstone area. Due to reconfiguration in the area and changed network requirements under some generation and load scenarios within the 10-year outlook period, this transmission line will be decommissioned at end of technical service life. or there may be an opportunity to convert into a connection asset for one of several wind farm proponents in the area.

Refer to Table 6.30 for possible asset retirements beyond the 10-year outlook period.

6.11 Southern region

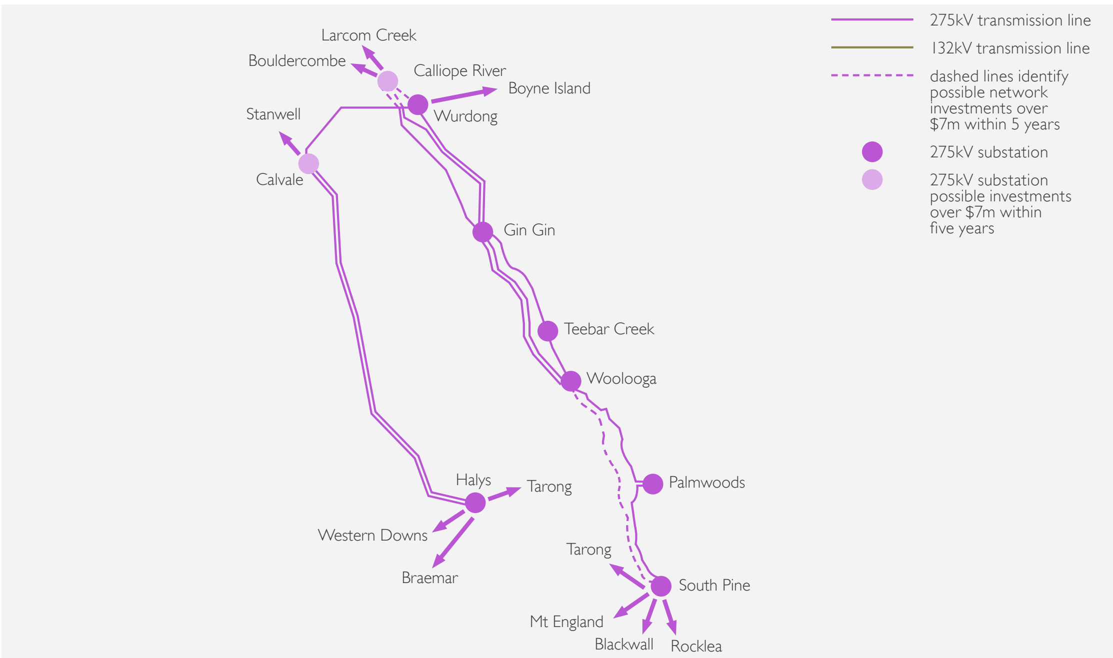
The Southern region includes proposed network investments located within the Wide Bay, South West, Surat, Bulli, Moreton and Gold Coast zones. The region broadly aligns with the Southern QREZ proposed development area. The Southern region includes a diverse range of industries and large load centres with considerable opportunity to connect renewable energy resources such as wind and solar to the transmission network. It is also located close to QNI. The Southern region also includes a number of candidate REZ areas in southern Queensland identified in the ISP (refer to Figure 9.2).

6.11.1 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 6.12). These transmission lines traverse a variety of environmental conditions and as a result exhibit different corrosion rates and risk profiles.

Figure 6.12 CQ-SQ transmission network



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

Possible load driven limitations

Based on AEMO's Step Change 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.

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. 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 may increase following the commissioning of the QNI Minor project (refer to Section 6.13).

The 2022 ISP identified a potential Central to Southern Queensland network project as a Future ISP project. The ISP modelling identified two stages to expand the transmission capacity across this CQ-SQ. The first stage involves a new mid-point switching substation on the Calvale to Halys 275kV double circuit line, to increase transfer capacity in both directions by approximately 300MW. Under the Step Change scenario forecast the timing for this incremental upgrade is 2028/29. The second stage involves a new double circuit line from Calvale to Wandoan South, to increase transfer capacity to Southern Queensland by approximately 900MW.

Possible network solutions to facilitate efficient market operation are outlined in Section 9.3.2.

Possible network investments within five years

Network reinvestments (which includes reinvestment and augmentations) in the 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	June 2026 to December 2032
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 $28 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 $79 million by December 2029. Line refit works on the 275kV transmission single circuit transmission line between Woolooga and South Pine substations at an estimated cost of $38 million by December 2028.

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 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. When this circuit is dismantled in the longer term, Wurdong would be supplied from Calliope River via a dedicated 275kV double circuit transmission line.

This strategy will be technically and economically reassessed and adjusted to align with future generation and network developments.

Strategies to address the transmission line sections with advanced corrosion in the five-year outlook will be economically assessed in consideration of longer term network needs based on future generation and network requirements. Powerlink and AEMO (through the ISP process) will continue to investigate the impact of large-scale VRE generation investment in the Queensland region on the utilisation and economic performance of the CQ-SQ grid section. 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.

The longer term network solution options to address the condition based drivers 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
- 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.

Closer to the timing of the investment decision and as part of the option analysis under the RIT-T, Powerlink will consider whether the proposed preferred option will have a material inter-network impact.

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 investments in the Wide Bay zone within five years

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 investment, 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.

Table 6.19 Possible network investments 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	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	Refit the two single circuit 275kV transmission lines	$28m
Line refit works on the 275kV transmission line between Calliope River Substation and Wurdong Tee	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 2028 (1)	Rebuild the 275kV transmission line between Woolooga and South Pine substations	$38m

Note:
(1) The revised timing from the 2021 TAPR is based upon the latest condition assessment.

Possible network investments within six to 10 years

As a result of the annual planning review, Powerlink has identified that the following investments 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 2028/29 to 2032/33 (refer to Table 6.20).

Table 6.20 Possible network investments 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 2029 (1)	Targeted refit and partial double circuit rebuild of the 275kV transmission line between Wurdong Tee and Gin Gin Substation New 275kV DCST transmission line	$79m
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	Rebuild 275kV transmission line between South Pine and Palmwoods substations	$13m
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	$42m
Substations					
Teebar Creek secondary systems replacement	Full replacement of 132kV and 275kV secondary systems	Maintain supply to the Wide Bay zone	December 2028	Selected replacement of 132kV and 275kV secondary systems	$19m
Woolooga 275kV and 132kV 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	$40m
Palmwoods 275kV and 132kV selected primary plant replacement	Selected replacement of 275kV and 132kV primary plant	Maintain supply to the Wide Bay zone	June 2030	Full replacement of 275kV and 132kV primary plant	$35m
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	$11m

Note:

(1) Compared to the 2021 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

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

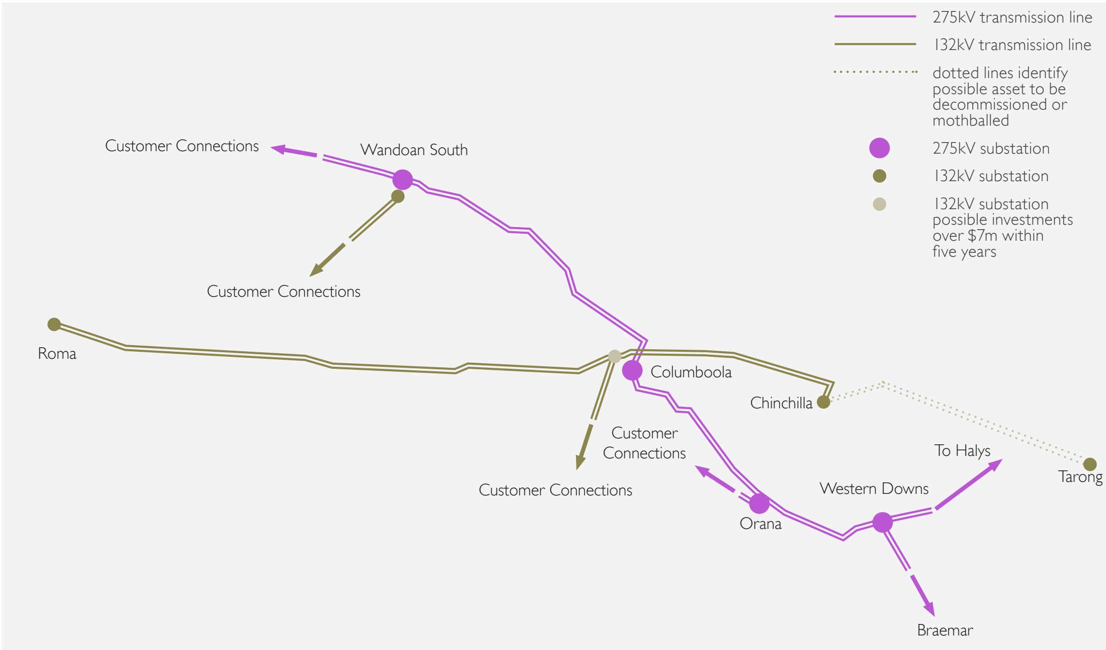
Refer to Table 6.30 for possible asset retirements beyond the 10-year outlook period.

6.11.2 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 6.13).

Figure 6.13 Surat Basin North West area transmission network



Possible load driven limitations

Based on AEMO's Step Change 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 investments within the 10-year outlook period

As assets approach their anticipated end of technical service life, the potential projects and alternatives (options) identified as a result of the annual planning review will be subject to detailed analysis to confirm alignment with future investment, 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. Powerlink has identified that the following investment is 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 2028/29 to 2032/33 (refer to Table 6.21).

Table 6.21 Possible network investments 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 systems 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

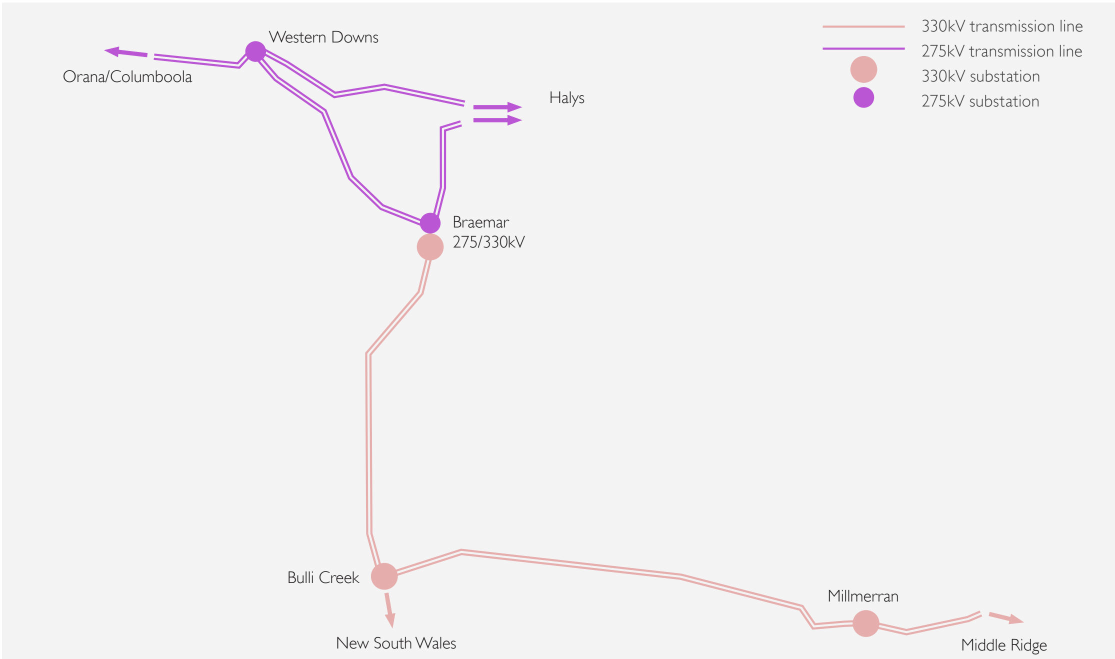
Current planning analysis has not identified any potential asset retirements in the Surat zone within the 10-year outlook period.

6.11.3 Bulli zone

Existing network

The Bulli zone is defined as the area surrounding Goondiwindi and the 330kV and 275kV network south of Kogan Creek Power Station and west of Millmerran Power Station (refer to Figure 6.14).

Figure 6.14 Bulli area transmission network



Possible load driven limitations

Based on AEMO's Step Change 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 investments in the Bulli zone within five years

As assets approach their anticipated end of technical service life, the potential projects and alternatives (options) identified as a result of the annual planning review will be subject to detailed analysis to confirm alignment with future investment, 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 6.22. Powerlink has identified that the following investment is 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 2022/23 to 2027/28 (refer to Table 6.22).

Table 6.22 Possible network investments in the Bulli zone within five years

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Substations					
Millmerran 330kV AIS secondary systems replacement	Selected replacement of 330kV secondary systems	Maintain supply reliability in the Bulli zone	December 2026	Full replacement of secondary systems	$6m

Possible network investments within six to 10 years

As a result of the annual planning review, Powerlink has identified that the following investments 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 2028/29 to 2032/33 (refer to Table 6.23).

Table 6.23 Possible network investments in the Bulli zone within six to 10 years

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Substations					
Braemar 330kV secondary systems replacement non-iPASS	Selected replacement of 330kV secondary systems	Maintain supply reliability in the Bulli zone	June 2029	Full replacement of secondary systems	$23m
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

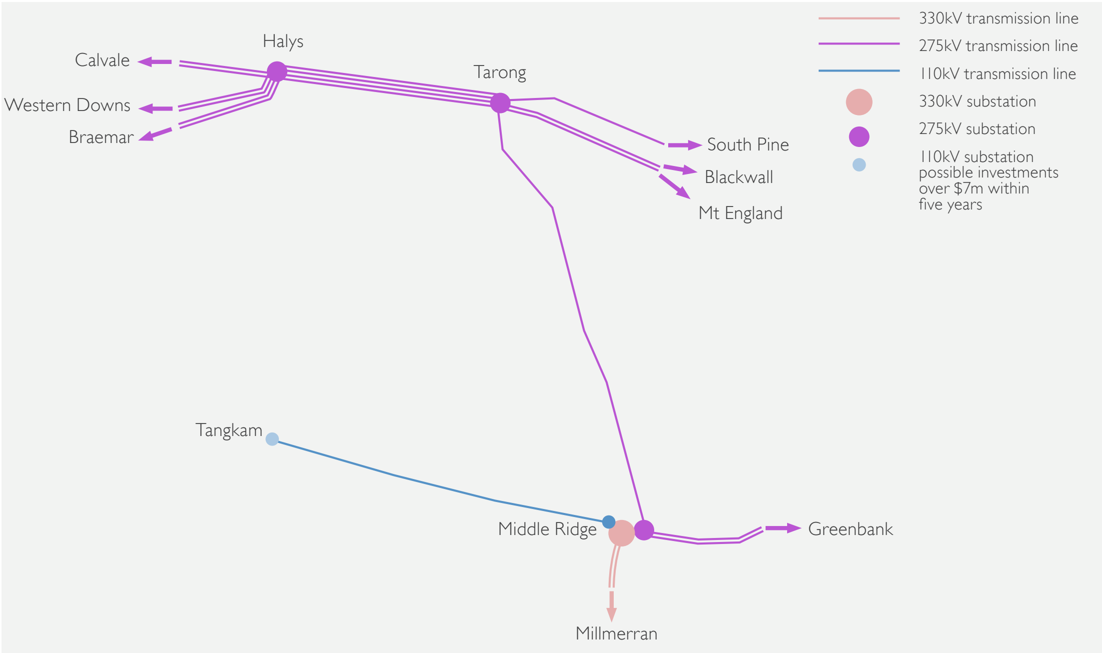
Current planning analysis has not identified any potential asset retirements in the Bulli zone within the 10-year outlook period.

6.11.4 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 6.15).

Figure 6.15 South West area 330kV and 275kV network



Possible load driven limitations

Based on AEMO's Step Change 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 investments within five years

Network investments (which includes reinvestment and augmentations) in the 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

Tangkam 110kV Substation

Anticipated consultation	Addressing the secondary systems condition risks at Tangkam
Project driver	Emerging condition and 110kV secondary systems compliance risks
Project timing	December 2024
Proposed network solution	Full replacement of the 110kV secondary systems at Tangkam Substation at an estimated cost of $15 million by June 2024

Tangkam Substation was established in 1999 as part of the Oakey Gas Turbine Power Station connection.

Possible network solutions

- Full replacement of all 110kV secondary systems in a new building by June 2024
- Full replacement of all 110kV secondary systems in the existing building by June 2024.

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

Possible non-network solutions

Powerlink would consider a non-network option that avoids the proposed replacement of the ageing and obsolete secondary systems. The non-network option would need to replicate, in part or full, the support that Tangkam Substation delivers to customers in the area on a cost-effective basis. To maintain reliability standards, a non-network local generation solution would need to inject up to 70MW at peak and up to 700MWh per day on a continuous basis to supply the 110kV network.

Possible network investments in the South West zone within five years

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 investment, 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.

Table 6.24 Possible network investments in the South West zone within five years

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Substations					
Tangkam 110kV secondary systems replacement	Full replacement of 110kV secondary systems	Maintain supply reliability in the South West zone	June 2024	Staged replacement of 110kV secondary systems (1)	$15m

Note:

(1) The envelope for non-network solutions is defined in Section 6.11.4.

Possible network investments within six to 10 years

As a result of the annual planning review, Powerlink has identified that the following investments 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 2028/29 to 2032/33 (refer to Table 6.25).

Table 6.25 Possible network investments in the South West zone within six to 10 years

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Substations					
Middle Ridge 110kV primary plant replacement	Selected replacement of selected 110kV primary plant	Maintain reliability of supply at Middle Ridge Substation	December 2028	Full replacement of 110kV primary plant	$3m
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	Full replacement of 275kV and 110kV secondary systems	$40m
Tarong 275kV and 66kV secondary systems replacement	Selected replacement of 275kV and 66kV secondary systems	Maintain supply reliability in the South West zone	June 2030	Full replacement of 275kV and 66kV secondary systems	$29m

Possible asset retirements within the 10-year outlook period [24]

Refer to Table 11.7 for confirmed asset retirements in the South West zone and Table 6.30 for possible asset retirements beyond the 10-year outlook period.

6.11.5 Moreton zone

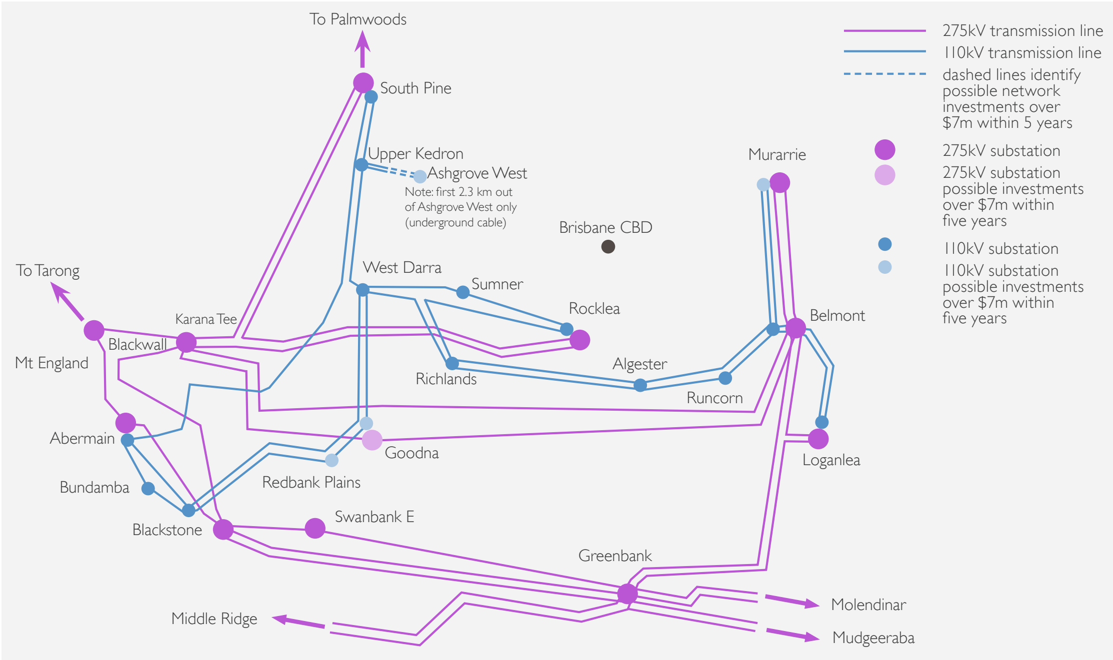
Existing network

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 6.16).

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).

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

Figure 6.16 Greater Brisbane transmission network



Possible load driven limitations

Based on AEMO's Step Change 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 meet power system performance standards 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

In December 2021 AEMO published the System Strength, Inertia, and Network Support and Control Ancillary Services Report (NSCAS). This report declared an immediate gap of 120MVAr reactive power absorption in Southern Queensland, rising to 250MVAR by 2026. Powerlink worked with AEMO in the preparation of their report and subsequent gap declaration. Prior to this Powerlink had already identified a need for additional reactive power absorption capability in Southern Queensland and commenced a RIT-T process to address this need.

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 Project Specification Consultation Report (PSCR) (with Project Assessment Draft Report (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 PADR in October 2022.

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 the declining minimum day time demand and the increasing leading power factor load characteristic are also encouraged. Where technically and economically feasible, the relevant detailed requirements will be refined with proponents through the submission process and assessed on a case by case basis against 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 investments within five years

Network investments (which includes reinvestment and augmentations) in the 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 maximum demand expected to maintain low growth over the next 10 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 $14 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 overhead, with the final 2.3km long section to Ashgrove West Substation being 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 2025
Proposed network solution	Refit and life extension of both 110/11kV transformers and replacement of all 110kV primary plant at Redbank Plains Substation at an estimated cost of $8 million by June 2025

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 two 110/11kV 25MVA transformers 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

- Refit and life extension of both 110/11kV transformers and replace selected 110kV primary plant by 2025
- Refit and life extension of both 110/11kV transformers by and replace all 110kV primary plant by June 2025
- Replacement of both 110/11kV transformers and replace selected 110kV primary plant by 2025
- Replacement of both 110/11kV transformers and full replacement of 110kV primary plant by June 2025
- Replace/life extend one 110/11kV transformer and engage non-network support by June 2025.

In accordance with the requirements of the RIT-T, Powerlink published a PSCR (with PADR exemption) in April 2022 which identified the refit and life extension of both 110/11kV transformers and replacement of all 110kV primary plant at Redbank Plains Substation by 2025 as the preferred network option. Submissions to the PSCR closed in July 2022 and Powerlink anticipates the publication of the PACR by December 2022.

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.

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	December 2026
Proposed network solution	Full replacement of the 110kV secondary systems at Ashgrove West Substation at an estimated cost of $9 million by December 2026

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 December 2026
- Staged replacement on 110kV secondary systems by December 2026.

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 $22 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 investments in the Moreton zone within five years

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 investment, 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, from around 2022/23 to 2027/28 (refer to Table 6.26).

Table 6.26 Possible network investments 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)	$14m
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
Substations					
Redbank Plains 110kV primary plant and 110/11kV transformer reinvestment	Refit and life extension of both 110/11kV transformers and replacement of selected 110kV primary plant	Maintain reliability of supply at Redbank Plains Substation	June 2025	Full replacement of 110kV primary plant, replace one 110/11kV transformer and engage non-network support (1)	$8m
South Pine 275/110kV transformer life extension	Life extension of a single 275kV/110kV transformer	Maintain supply reliability in the Moreton zone	June 2025	Retirement of a single 275kV/110kV transformer with non-network support	$2m
South-east Queensland bus reactors (2)	Install 275kV bus reactors at Woolooga, Blackstone and Belmont substations	Maintain system voltages within limits	December 2025	Install 275kV bus reactors at Woolooga, Blackstone and Greenbank substations Non-network solution yielding the same voltage control capacity (1)	$32m
Ashgrove West 110kV secondary systems replacement	Full replacement of 110kV secondary systems	Maintain supply reliability in the Moreton zone	December 2026 (3)	Staged replacement of 110kV secondary systems (1)	$9m (4)

Table 6.26 Possible network investments in the Moreton zone within five years (*continued*)

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
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 Moreton zone	June 2027	Staged replacement of 110kV secondary systems (1)	$22m

Notes:

(1) The envelope for non-network solutions is defined in Section 6.11.5.

(2) Proposed preferred option identified in the PSCR.

(3) The change in timing of the network solution from the 2021 TAPR is based upon updated information on the condition of the assets.

(4) Compared to the 2021 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 investments 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 2028/29 to 2032/33 (refer to Table 6.27).

Table 6.27 Possible network investments 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 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 the Moreton zone	December 2030	Rebuild the 275kV transmission line between Bergins Hill, Goodna and Belmont substations	$38m
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 the Moreton zone	June 2032	Rebuild the 110kV transmission line between West Darra and Upper Kedron substations	$5m
Substations					
Algester 110kV secondary systems replacements	Full replacement of 110kV secondary systems	Maintain supply reliability in the Moreton zone	December 2028	Staged replacement of 110kV secondary systems	$11m
Rocklea 110kV primary plant replacement	Full replacement of 110kV primary plant	Maintain supply reliability in the Moreton zone	December 2028	Staged replacement of 110kV primary plant	$5m

Table 6.27 Possible network investments in the Moreton zone within six to 10 years (*continued*)

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Bundamba 110kV secondary systems replacement	Full replacement of 110kV secondary systems	Maintain supply reliability in the Moreton zone	December 2028	Staged replacement of 110kV primary plant	$6m
South Pine SVC secondary systems replacement	Full replacement of SVC secondary systems	Maintain supply reliability in the Moreton zone	June 2029 (1)	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	Installation of a smaller 110/33kV transformer and non-network support	$6m
Goodna 275kV and 110kV secondary systems replacement	Full replacement of 275kV and 110kV secondary systems	Maintain supply reliability in the Moreton zone	June 2029	Staged replacement of 275kV and 110kV secondary systems (1)	$20m
West Darra 110kV secondary systems replacement	Full replacement of 110kV secondary systems	Maintain supply reliability in the Moreton zone	June 2029 (1)	Staged replacement of 110kV secondary systems	$11m
Rocklea 275/110kV transformer replacement	Replacement of one 275/110kV transformer at Rocklea	Maintain supply reliability in the Moreton zone	June 2029 (1)	Life extension of one 275/110kV transformer at Rocklea	$5m
Loganlea 275kV primary plant replacement	Full replacement of 275kV primary plant	Maintain supply reliability in the Moreton zone	June 2029 (1)	Staged replacement of 275kV primary plant	$5m
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	Staged replacement of 275kV SVC and secondary systems	$33m
Goodna 275kV and 110kV secondary systems replacement	Full replacement of secondary systems	Maintain supply reliability in the Moreton zone	June 2029	Staged replacement of 275kV and 110kV secondary systems	$20m
Mount England 275kV secondary systems and primary plant replacement	Full replacement of 275kV secondary systems and staged replacement of primary plant	Maintain supply reliability in the Moreton zone	June 2029	Staged replacement of 275kV secondary systems and primary plant	$11m
Belmont 110kV and 275kV secondary systems replacement	Full replacement of secondary systems	Maintain supply reliability in the Moreton zone	June 2029	Staged replacement of 275kV and 110kV secondary systems	$24m

Table 6.27 Possible network investments in the Moreton zone within six to 10 years (*continued*)

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
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
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 275kV and 110kV secondary systems replacement	Full replacement of 275kV and 110kV secondary systems	Maintain supply reliability in the Moreton zone	June 2030	Staged replacement of 275kV and 110kV secondary systems	$14m
Palmwoods 132kV secondary systems replacement	Full replacement of secondary systems	Maintain supply reliability in the Moreton zone	June 2030	Staged replacement of 132kV secondary systems	$21m
Loganlea 110kV secondary systems replacement non-iPASS	Full replacement of secondary systems	Maintain supply reliability in the Moreton zone	June 2031	Staged replacement of 110kV secondary systems	$22m

Note:

(1) The change in timing of the network solution from the 2021 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

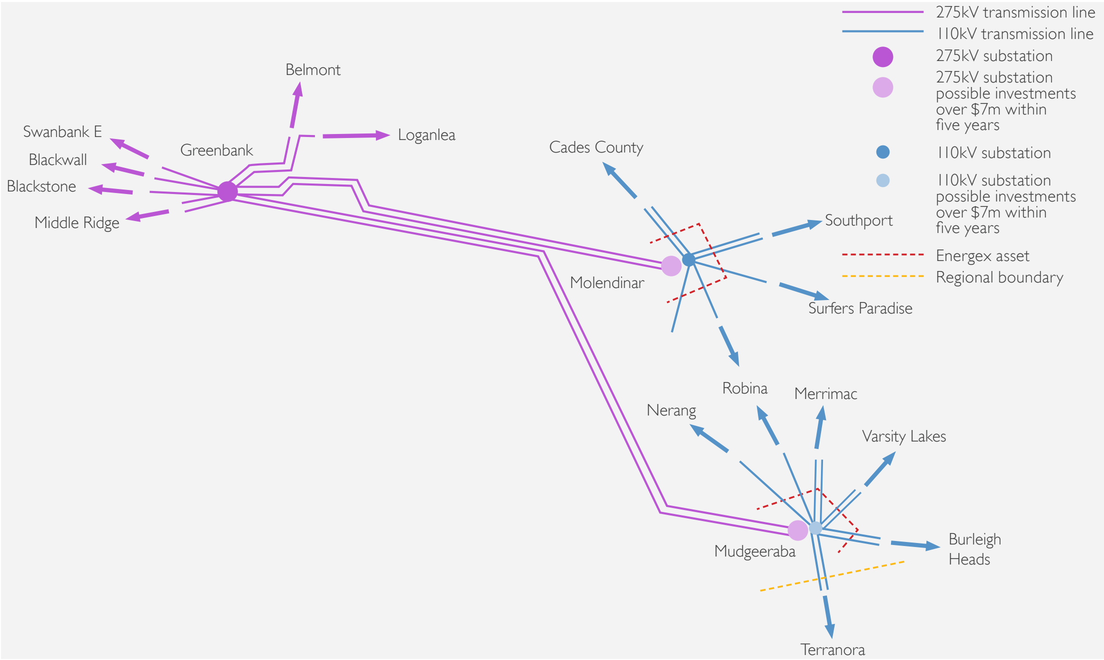
Based on the condition of one of the 110/33kV transformers at Loganlea, it is proposed to retire this transformer at the end of technical service life by June 2023. Powerlink considers that this will not impact on the ability to meet the obligations of Powerlink's reliability criteria. Further joint planning will be undertaken prior to a final decision being made.

6.11.6 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 6.17).

Figure 6.17 Gold Coast transmission network



Possible load driven limitations

Based on AEMO's Step Change 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 investments within five years

Network investments (which includes reinvestment and augmentations) in the 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 million to $53 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.

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	June 2028
Proposed network solution	Staged replacement of secondary systems at an estimated cost of $12 million by June 2028

Possible network solutions

- Staged replacement of the secondary systems components by June 2028
- Full replacement of all secondary systems by June 2028.

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	June 2028
Proposed network solution	Selected replacement of primary plant at an estimated cost of $20 million by June 2028

Possible network solutions

- Selected replacement of primary plant by June 2028
- Full replacement of all primary plant by June 2028.

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 2027
Proposed network solution	Full replacement of secondary systems at an estimated cost of $23 million by December 2027

Possible network solutions

- Staged replacement of the secondary systems components by December 2027
- Full replacement of all secondary systems by December 2027.

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 investments in the Gold Coast zone within five years

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 investment, 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, from around 2022/23 to 2027/28 (refer to Table 6.28).

Table 6.28 Possible network investments in the Gold Coast zone within five years

Potential project	High level scope	Purpose	Earliest possible commissioning date	Alternatives	Indicative cost
Substations					
Molendinar 275kV secondary systems replacement	Full replacement of 275kV secondary systems	Maintain supply reliability in the Gold Coast zone	December 2027 (2)	Selected replacement of 275kV secondary systems (1)	$23m
Mudgeeraba 110kV secondary systems replacement	Partial replacement of 110kV secondary systems	Maintain supply reliability in the Gold Coast zone	June 2028 (2)	Full replacement of 110kV secondary systems (1)	$12m
Mudgeeraba 110kV primary plant replacement	Selected replacement of 110kV equipment	Maintain supply reliability in the Gold Coast zone	June 2028 (2)	Staged replacement of 110kV primary plant in existing bays and selected 275kV equipment (1)	$21m

Notes:

(1) The envelope for non-network solutions is defined in Section 6.11.5.

(2) The change in timing of the network solution from the 2021 TAPR is based upon updated information on the condition of the assets.

Possible network investments 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 2028/29 to 2032/33. (refer to Table 6.29).

Table 6.29 Possible network investments 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
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	$53m
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	$11m

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.

6.12 Supply demand balance

The outlook for the supply demand balance for the Queensland region was published in the AEMO 2022 Electricity Statement of Opportunity (ESOO)[25]. Interested parties who require information regarding future supply demand balance should consult this document.

6.13 Existing interconnectors

The Queensland transmission network is interconnected to the NSW transmission system through the QNI transmission line and Terranora Interconnector transmission line.

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.

6.13.1 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. The PACR identified the preferred option as uprating the 330kV Liddell to Tamworth 330kV lines, installing Static VAr Compensators (SVC) at Tamworth and Dumaresq substations and static capacitor banks at Tamworth, Armidale and Dumaresq substations. These project works have now been completed by Transgrid. Inter-network testing, as required by NER 5.7.7, is now progressing to release additional capacity to the market in a staged approach. These tests are expected to continue until mid-2023.

The 2022 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.

6.14 Transmission lines approaching end of technical service life beyond the 10-year outlook period

As transmission lines approach their anticipated end of technical service life, detailed planning studies are undertaken to confirm the asset's enduring need taking into consideration asset condition and risk as well as alignment with future investment or possible network optimisation strategies. Options considered may include line refit, targeted and/or staged refit or replacement, upfront replacement or rebuild, network reconfiguration, non-network alternatives, asset de-rating or retirement.

The information contained in Table 6.30, which goes five years beyond the 10-year outlook period of the 2022 TAPR, is provided in good faith26 and is the best information available at the time of TAPR publication. Transmission equipment ratings information is available on AEMO's website and can also be accessed via the TAPR Portal.

Given the rapid speed of the energy transformation, proponents who wish to connect to Powerlink's transmission network are strongly encouraged to contact BusinessDevelopment@powerlink.com.au in the first instance.

[25] Published by AEMO in August 2022.

[26] For completeness, please refer to Powerlink's Disclaimer on page 2.

Table 6.30 Transmission Lines approaching end of technical service: 10-15 years (July 2033 – June 2038)

Region	Zone	Feeder	Voltage	General location	Anticipated end of technical service life
Northern	Far North	7225	132kV	Between Cairns and Woree substations	2032
Northern	Far North	7165	132kV	Between Chalumbin and Turkinje substations	2036
Northern	Far North	7191	132kV	Proserpine Substation	2036
Northern	Far North	7227	132kV	Between Cairns and Woree substations	2037
Northern	North	7152	132kV	Between Eton and Alligator Creek Substation	2032
Northern	North	7156	132kV	Between Ross and Townsville South substations	2034
Northern	North	8858	275kV	Between Strathmore and Ross substations	2035
Northern	North	820	275kV	Between Bouldercombe and Broadsound substations	2033
Central	North	7124	132kV	Between Moranbah and Dysart substations	2036
Central	Central West	7150	132kV	Between Lilyvale and Dysart substations	2032
Central	Central West	833	275kV	Between Broadsound and Lilyvale substations	2035
Central	Central West	7112	132kV	Between Baralaba and Moura substations	2035
Central	Central West	7109	132kV	Between Baralaba and Calvale substations	2035
Central	Central West	7159	132kV	Between Callide A and Calvale substations	2036
Central	Central West	7161	132kV	Calvale Substation	2037
Central	Central West	851	275kV	Between Calvale Substation and Callide Power Station	2037
Central	Central West	852	275kV	Between Calvale Substation and Callide Power Station	2037
Central	Gladstone	812	275kV	Between Bouldercombe and Calliope River substations	2033
Central	Gladstone	8876	275kV	Between Gladstone and Calliope River substations	2037
Central	Gladstone	8877	275kV	Between Gladstone and Calliope River substations	2032
Central	Gladstone	8878	275kV	Between Gladstone and Calliope River substations	2033
Central	Gladstone	871	275kV	Between Calvale and Wurdong substations	2037
Southern	Wide Bay	8850	275kV	Between Woolooga and Teebar Creek substations	2032
Southern	Wide Bay	810	275kV	Between Woolooga and Palmwoods substations	2036
Southern	South West	831	275kV	Between Tarong and Middle Ridge substations	2032

Table 6.30 Transmission Lines approaching end of technical service: 10-15 years (June 2033 – July 2038) (*continued*)

Region	Zone	Feeder	Voltage	General location	Anticipated end of technical service life
Southern	South West	841	275kV	Between Tarong Power Station and Tarong Substation	2033
Southern	South West	843	275kV	Between Tarong Power Station and Tarong Substation	2035
Southern	Moreton	832	275kV	Between Tarong and South Pine substations	2032
Southern	Moreton	823	275kV	Between Mt England Substation and Wivenhoe Power Station	2034
Southern	Moreton	827	275kV	Between Tarong and Blackwall substations	2035

6 Future network development

CHAPTER 7

Non-network solution opportunities

7 Non-network solution opportunities

Key highlights

- Powerlink welcomes the opportunity to utilise non-network solutions that 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, there will be an increasing need for non-network solutions to assist in managing voltages during minimum demand conditions and more generally as the energy system transforms.
- 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 Transmission Annual Planning Report (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.

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, system strength and network support and control ancillary services (NSCAS) requirements, ensuring the secure operation of the transmission network
- to provide demand management and load balancing.

7.2.1 Possible impacts of the energy transformation

Due to the energy transformation, there is the potential to have significantly changed requirements for transmission infrastructure in the 10-year outlook period. Given Powerlink's integrated planning approach, these requirements may result in the need for new investments that impact the proposed future network and non-network solutions identified in Table 7.1 and Chapter 6 and will be updated in subsequent TAPRs if this eventuates.

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 RIT-T and Power System Security consultation processes and Powerlink's Network Support Contracting Framework.

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	$42	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 6.9.1
Rebuild the 275kV transmission line between Calliope River and Larcom Creek Substation	$35m	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 2026	Section 6.10.2
Line refit works on the 275kV transmission line between Wurdong and Boyne	$11m	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 6.10.2
Rebuild the 132kV transmission line between Callemondah and Gladstone South substations	$25m	Gladstone	Up to 160MW and up to 1,820MWh per day	June 2026	Section 6.10.2
Rebuild of two of the three transmission lines between Calliope River and Wurdong tee as a double circuit by June 2026 Line refit works on the remaining single circuit 275kV transmission line between Calliope River Substation and Wurdong Tee by June 2026	$28m $6m	Wide Bay	Powerlink would consider proposals from non-network providers that can significantly contribute to reducing the load requirement in this region.	June 2026	Section 6.11.1
Line refit works on the 275kV transmission line between Woolooga and South Pine substations	$38m	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.	December 2028	Section 6.11.1

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
Replacement of the 110kV underground cable between Upper Kedron and Ashgrove West substations	$14m	Moreton	Up to 220MW at peak to Brisbane's inner north-west suburb (potentially coupled with network reconfiguration)	June 2026	Section 6.11.4
Line refit works on sections of the 275kV transmission line between Greenbank and Mudgeeraba substations	$30-53m	Gold Coast	Proposals which may significantly contribute to reducing the requirements in the southern Gold Coast and northern NSW area	December 2028	Section 6.11.5
Substations - primary plant and secondary systems					
Edmonton 132kV secondary systems replacement	$6	Far North	Up to 55MW at peak and 770MWh per day on a continuous basis to provide supply to the 22kV network at Innisfail	June 2026	Section 6.9.1
Alan Sherriff 132kV secondary systems replacement	$12m	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 6.9.2
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 2026	Section 6.9.2
Garbutt 132kV secondary systems replacement	$10m	Ross	Up to 110MW at peak and up to 800MWh per day on a continuous basis to provide supply to the 66kV network in north east Townsville	June 2026	Section 6.9.2
Townsville South 132kV secondary systems replacement	$16m	Ross	Up to 150MW at peak and up to 3000MWh per day on a continuous basis to provide supply to Townsville East and Townsville South (including Sun Metals). It would also need to facilitate the connection of Mt Stuart Power Station (PS).	June 2028	Section 6.9.2
Strathmore SVC secondary systems replacement	$6m	North	Up to 260MVArs capacitive and 80MVArs reactive dynamic voltage support at Strathmore	June 2026	Section 6.9.3

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
Calvale 275kV primary plant replacement	$16m	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	June 2028	Section 6.10.1
Broadsound 275kV primary plant replacement	$16m	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 2027	Section 6.10.1
Callemondah Substation primary plant and secondary systems replacement	$7m	Gladstone	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 6.10.2
Tangkam 110kV secondary systems replacement	$16m	South West	Up to 70MW at peak and up to 700MWh per day on a continuous basis to supply the 110kV network at Tangkam	December 2024	Section 6.11.1 Anticipated RIT-T
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 6.11.4 RIT-T in progress (1)
Ashgrove West 110kV secondary systems replacement	$9m	Moreton	Up to 220MVA at peak to Brisbane's inner north-west suburb (potentially coupled with network reconfiguration)	December 2026	Section 6.11.4

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
Murarrie 110kV secondary systems replacement	$22m	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 6.11.4
Mudgeeraba 110kV secondary systems replacement	$12m	Gold Coast	Proposals which may significantly contribute to reducing the requirements in the transmission into the southern Gold Coast and northern NSW area	June 2028	Section 6.11.5 Anticipated RIT-T
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	June 2028	Section 6.11.5
Substations - transformers					
Tully 132/22kV transformer replacement	$6m(2)	Far North	Life extension of the existing transformer or a non-network alternative of up to 15MW at peak and up to 100MWh per day on a continuous basis to provide supply to the 22kV network at Tully	June 2024	Section 6.9.1
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 2025	Section 6.11.4 RIT-T in progress

Notes:

(1) The Managing voltages in South East Queensland consultation also takes into consideration the longer term NSCAS gap requirements identified in AEMO's 2021 System Security Reports. The preferred option identified in the subsequent Project Assessment Draft Report may change from the potential project identified in Table 7.1.

(2) TAPR template data associated with emerging constraints which may require future capital expenditure, including potential projects which fall below the RIT-T cost threshold of $7m, 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).

7 Non-network solution opportunities

CHAPTER 8

Network capability and performance

8 Network capability and performance

Key highlights

- Generation commitments since the 2021 Transmission Annual Planning Report (TAPR) add 740MW to Queensland's semi-scheduled variable renewable energy (VRE) generation capacity taking the total existing and committed semi-scheduled VRE generation capacity to 4,934MW.
- Storage commitments since the 2021 TAPR include the 50MW 2 hour Bouldercombe Battery energy storage system (BESS).
- Record peak transmission delivered demand was recorded for the Ross, North, Central West, Surat, South West and Moreton zones during 2021/22.
- The transmission network has performed reliably during 2021/22, 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 3.9.

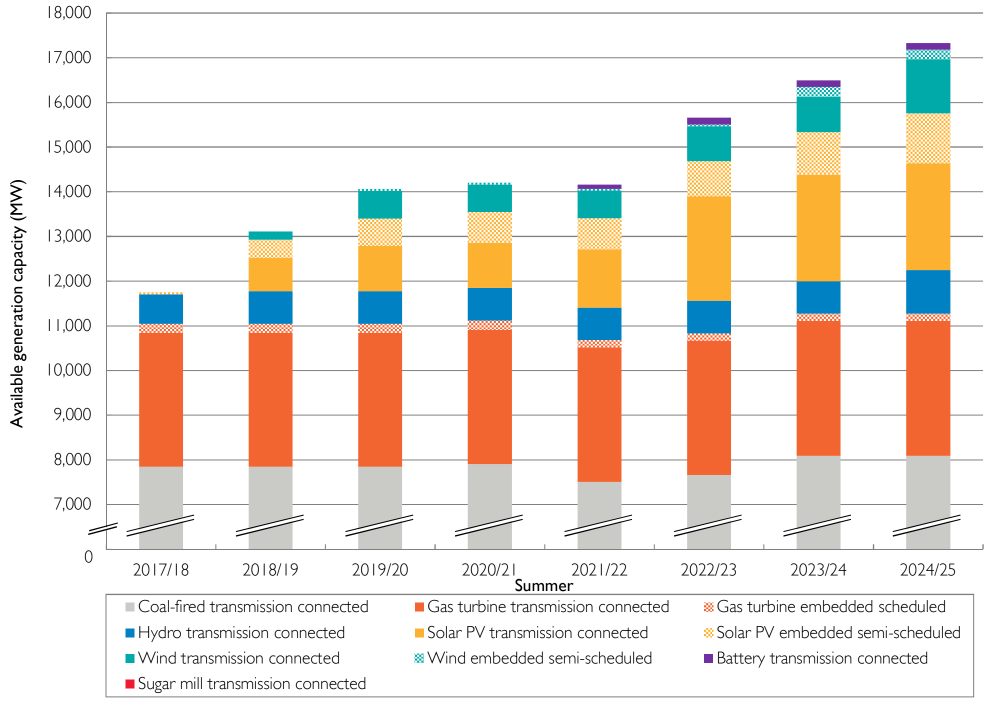
The location and pattern of generation dispatch influences power flows across most of the Queensland network. Future generation dispatch patterns and interconnector flows are uncertain in the deregulated electricity market and will vary substantially due to output of VRE generation and due to the effect 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 2021/22, commitments have added 740MW of semi-scheduled VRE capacity, taking Queensland's semi-scheduled VRE generation capacity to 4,934MW. Figure 8.1 illustrates the expected changes to available and committed large-scale generation capacity in Queensland from summer 2017/18 to summer 2024/25.

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 Bouldercombe BESS has reached committed status since the 2021 TAPR.

Semi-scheduled transmission connected Wandoan South Solar Farm and Clarke Creek Wind Farm have reached committed status since the 2021 TAPR.

Rodds Bay Solar Farm has been de-committed since the 2021 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.

8 Network capability and performance

Table 8.1 Available generation capacity – existing and committed generators connected to the Powerlink transmission network or direct connect customers

Generator	Location	Available capacity MW generated (1) Summer 2022/23	Winter 2023	Summer 2023/24	Winter 2024	Summer 2024/25	Winter 2025
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	750	730	750	730	750
Millmerran	Millmerran PS	822	852	822	852	822	852
Total coal-fired		7,659	8,171	8,089	8,171	8,089	8,171
Gas turbine							
Townsville 132kV	Townsville GT 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 gas 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 (6)	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 capacity MW generated (1)					
		Summer 2022/23	Winter 2023	Summer 2023/24	Winter 2024	Summer 2024/25	Winter 2025
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	82
Woolooga Energy Park	Woolooga	176	176	176	176	176	176
Blue Grass	Chinchilla	148	148	148	148	148	148
Columboola	Columboola	162	162	162	162	162	162
Gangarri	Wandoan South	120	120	120	120	120	120
Wandoan South	Wandoan South	125	125	125	125	125	125
Edenvale Solar Park	Orana	146	146	146	146	146	146
Western Downs Green Power Hub	Western Downs	400	400	400	400	400	400
Darling Downs	Braemar	108	108	108	108	108	108
Total solar PV		2,383	2,383	2,383	2,383	2,383	2,383
Wind (7)							
Mt Emerald	Walkamin	180	180	180	180	180	180
Kaban	Tumoulin	152	152	152	152	152	152
Clarke Creek (8)	Broadsound			440	440	440	440
Coopers Gap	Coopers Gap	440	440	440	440	440	440
Total wind		772	772	1,212	1,212	1,212	1,212
Battery (7)							
Bouldercombe 2h BESS	Bouldercombe	50	50	50	50	50	50
Wandoan South 1.5h BESS	Wandoan South	100	100	100	100	100	100
Total battery		150	150	150	150	150	150
Sugar mill							
Invicta (5)	Invicta Mill	0	34	0	34	0	34
Total sugar mill		0	34	0	34	0	34
Total all stations		**14,701**	**15,506**	**15,581**	**15,946**	**15,831**	**16,196**

Notes:

(1) Synchronous generator capacities shown are at the generator terminals and are therefore greater than Power Station (PS) 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 PS is an open-cycle, dual-fuel, gas-fired PS. The generated capacity quoted is based on gas fuel operation.

(5) Koombooloomba and Invicta are transmission connected non-scheduled generators.

(6) Wivenhoe and Kidston Pumped Hydro Storage are shown at full capacity. However, output can be limited depending on water storage levels.

(7) VRE generators and batteries are shown at maximum capacity at the point of connection. The capacities are nominal as the generator rating depends on ambient conditions.

(8) Generators undergoing commissioning are shown at full capacity from the anticipated start of commissioning activities. Actual available generating capacity will vary over the course of the commissioning program.

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.

Non-scheduled embedded Daandine was retired since the 2021 TAPR.

Semi-scheduled embedded Bullyard Solar Farm and Bundaberg Solar Farm have reached committed status since the 2021 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 capacity MW generated (1)					
		Summer 2022/23	Winter 2023	Summer 2023/24	Winter 2024	Summer 2024/25	Winter 2025
Gas turbine (1)							
Townsville 66kV	Townsville GT PS	78	82	78	82	78	82
Barcaldine	Barcaldine	32	37	32	37	32	37
Roma	Roma	54	68	54	68	54	68
Total gas turbine		164	187	164	187	164	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
Bundaberg	Gin Gin				78	78	78
Bullyard	Gin Gin				97	97	97
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	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	725	949	1,124	1,124	1,124
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		**892**	**955**	**1,329**	**1,527**	**1,504**	**1,527**

Notes:

(1) Synchronous generator capacities shown are at the generator terminals and are therefore greater than PS 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. The capacities are nominal as the generator rating depends on ambient conditions.

8.3 Network control facilities

Powerlink participated in the 2022 Power System Frequency Risk Review[2] (PSFRR), published by AEMO in July 2022. 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 has made three recommendations in relation to Queensland in this review:

- Establishment of an Over Frequency Generation Shedding (OFGS) scheme to manage over frequency if QNI separates.
- Implement a Special Protection Scheme (SPS) for the loss of both Columboola to Western Downs 275kV lines. The loss of both of these lines, which supply the Surat zone, is non-credible but could cause QNI to lose stability.
- Assessment of the risk and solution options to further mitigate instability for the non-credible loss of both Calvale to Halys 275kV lines following the commencement of QNI minor commissioning.

Powerlink enhanced the CQ-SQ SPS with a new Wide Area Monitoring, Protection and Control (WAMPAC) architecture by April 2021. The WAMPAC scheme avails approximately 600MW of northern VRE generation and up to 700MW[4] of southern Queensland 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 envelope of the CQ-SQ grid section flow. Powerlink is assessing the risks ahead of designing a second tranche of the scheme to further reduce the exposure.

AEMO has identified non-credible contingencies outside Queensland that could result in the loss of stability across QNI. AEMO plans to conduct further investigation to consider applying a protected event or installation of appropriate SPS to manage these scenarios.

AEMO has also assessed the network risk against the 2022 Draft ISP Step Change scenario forecasts. This has highlighted the potential for insufficient Under Frequency Load Shedding (UFLS) during periods of high rooftop photovoltaic (PV) output. AEMO requested that Powerlink, in collaboration with Energy Queensland, identify and implement measures to restore UFLS load. A working group has been formed and is progressing this activity.

Associated with high penetration of rooftop PV installations, Powerlink is reviewing the transient stability limits for CQ-SQ and QNI. The review includes dynamic load models that include rooftop PV behaviour. Powerlink will update this limit advice by April 2023.

Powerlink owns other network control facilities that 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, 2022 Power System Frequency Risk Review, July 2022.
[3] AEMC, Rule Determination National Electricity Amendment (Emergency Frequency Control Schemes) Rule 2017, March 2017.
[4] Includes both 250MW Wivenhoe PS units (if operating in pumping mode).

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
CQ-SQ N-2 WAMPAC scheme	Minimise risk of CQ-SQ 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 2022.

Figure 8.2 Existing HV network July 2022 – North Queensland

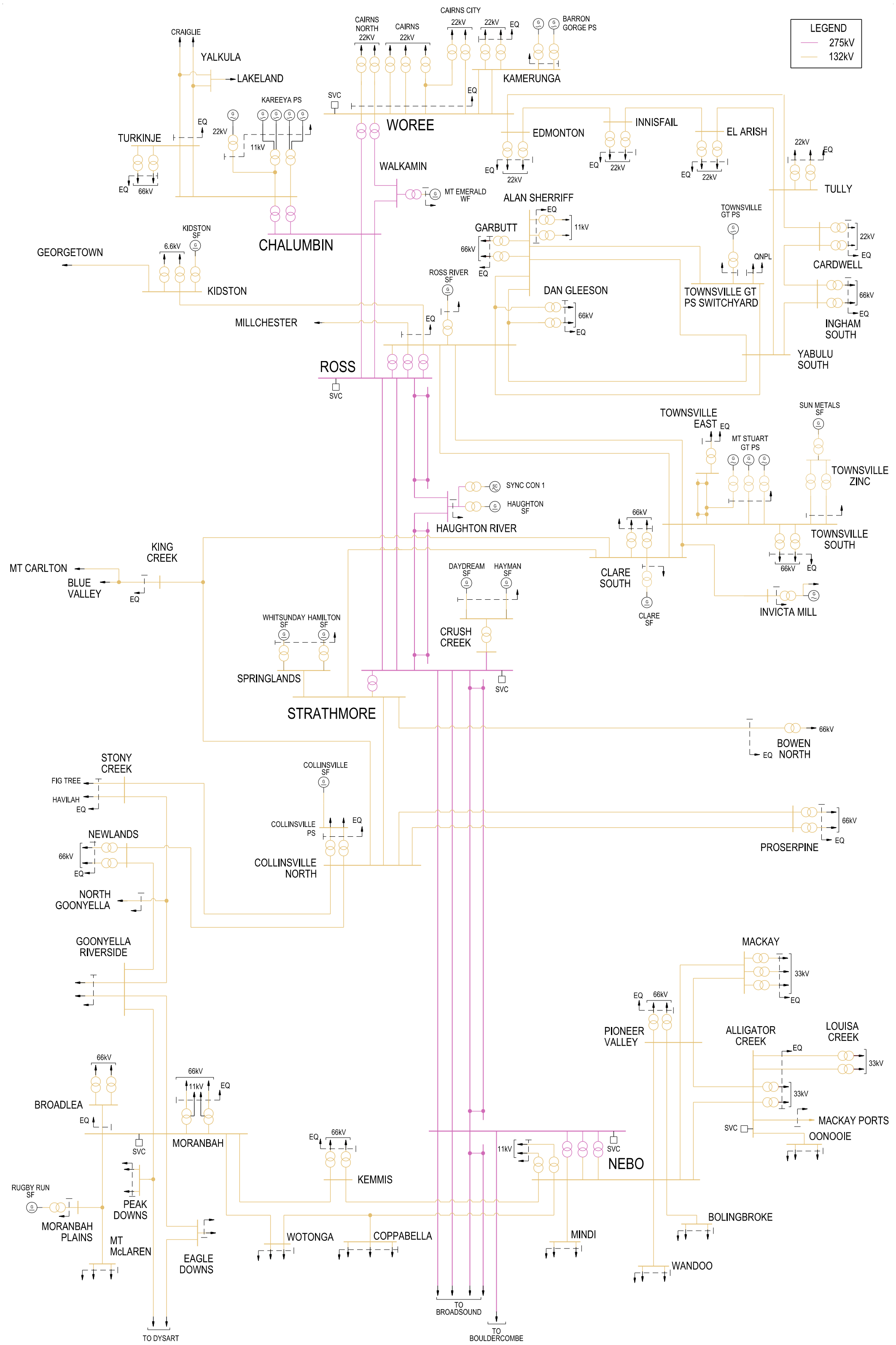


Figure 8.3 Existing HV network July 2022 – Central Queensland

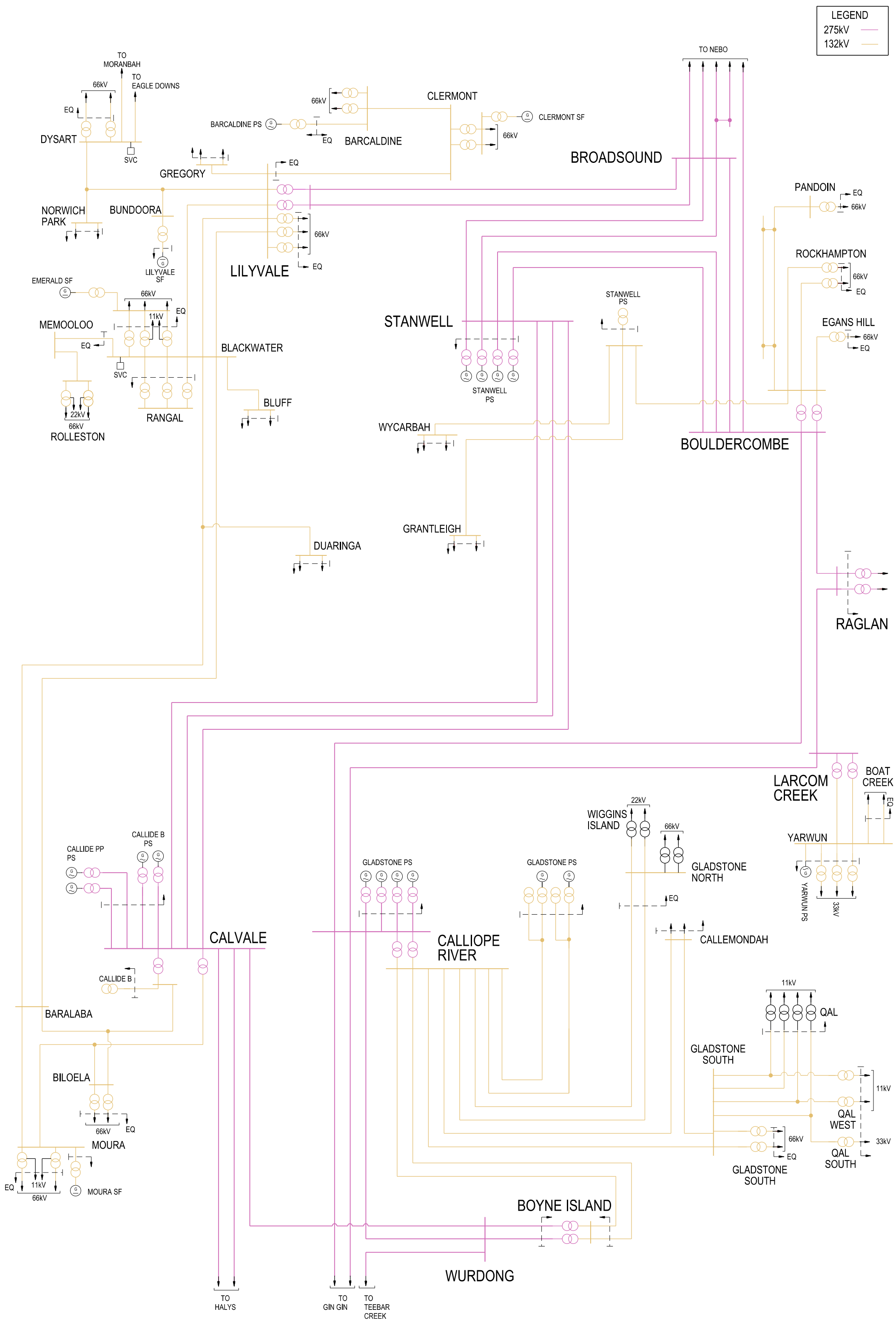


Figure 8.4 Existing HV network July 2022 - South West Queensland

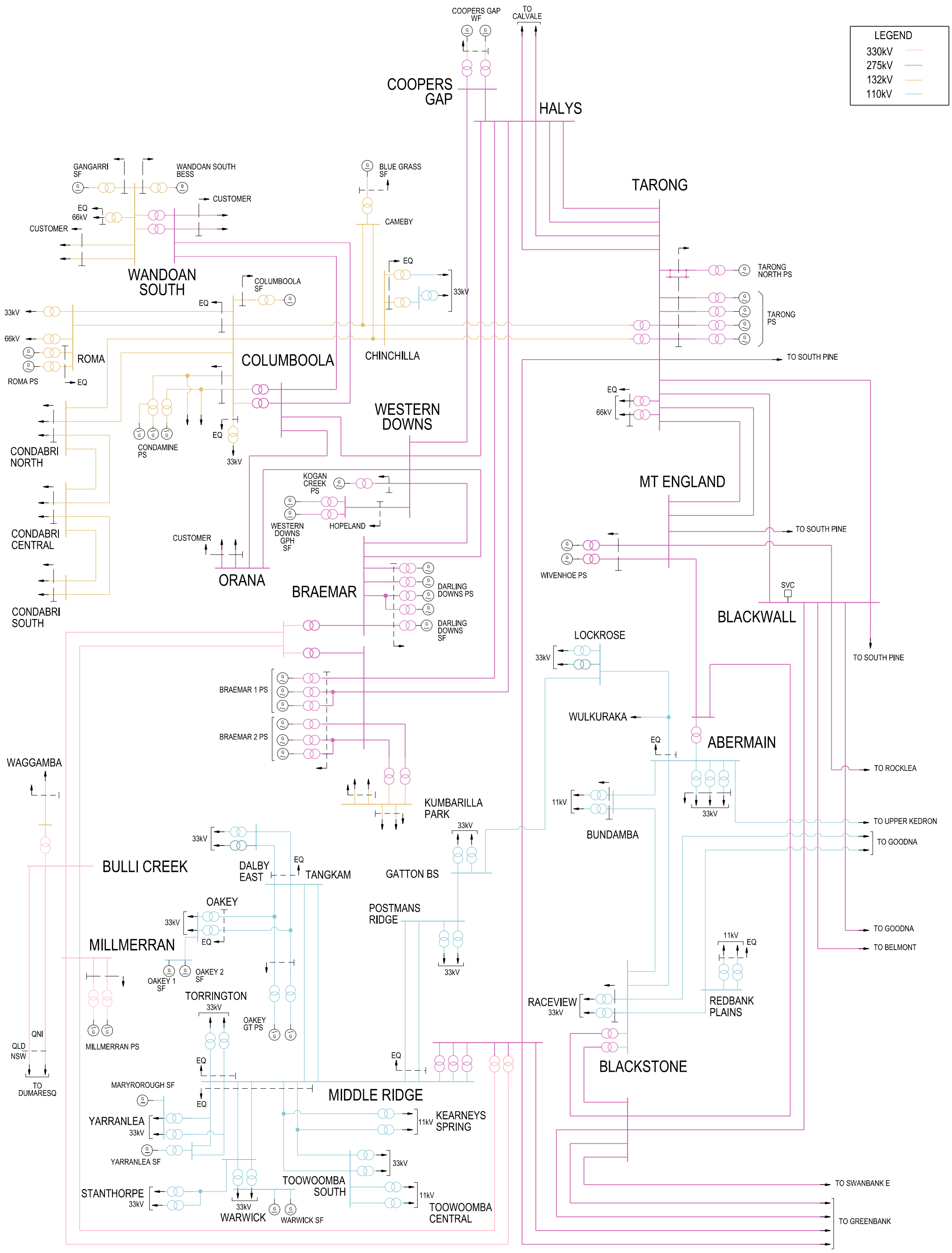
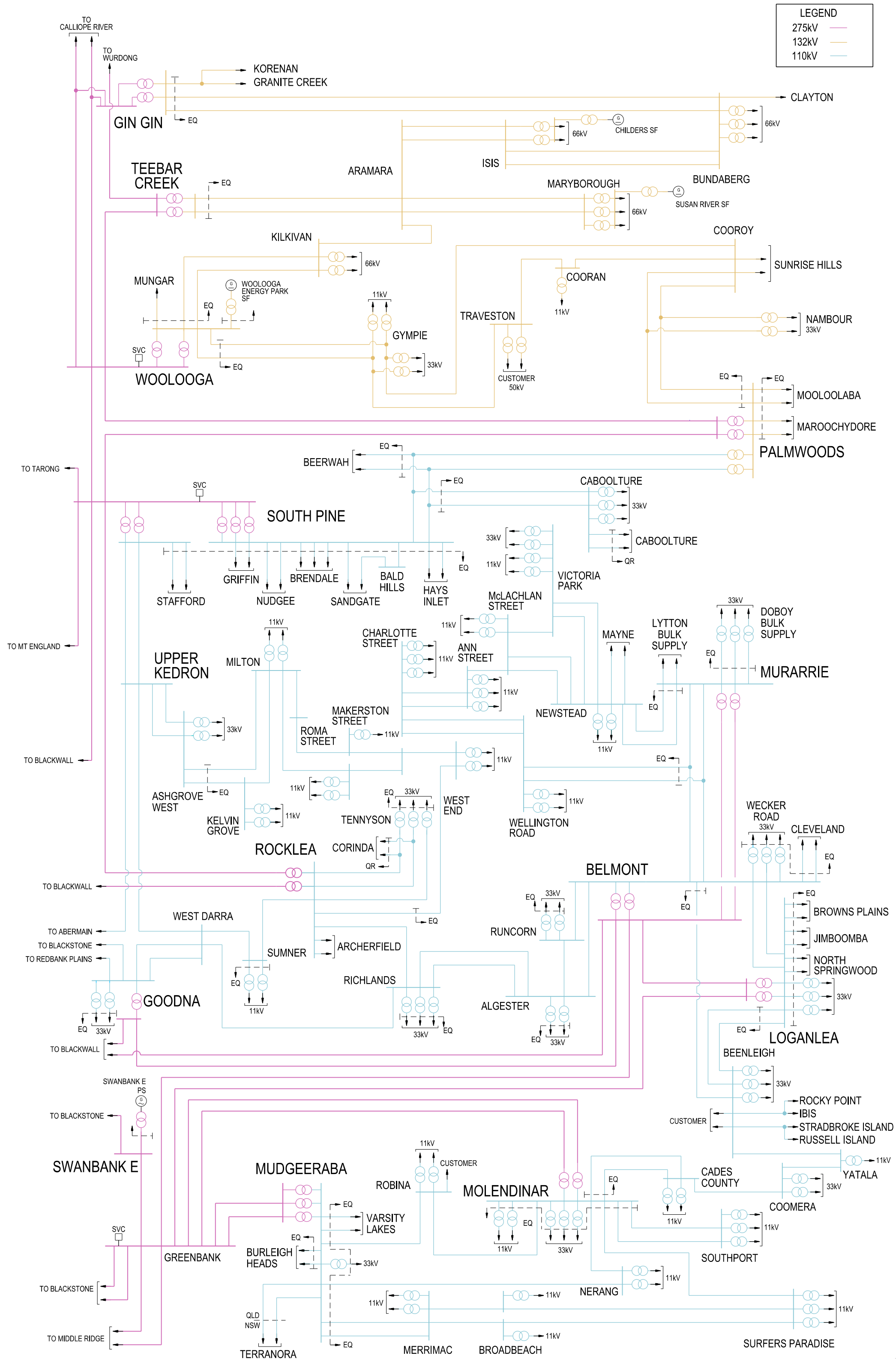


Figure 8.5 Existing HV network July 2022 - South East Queensland



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.1 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 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

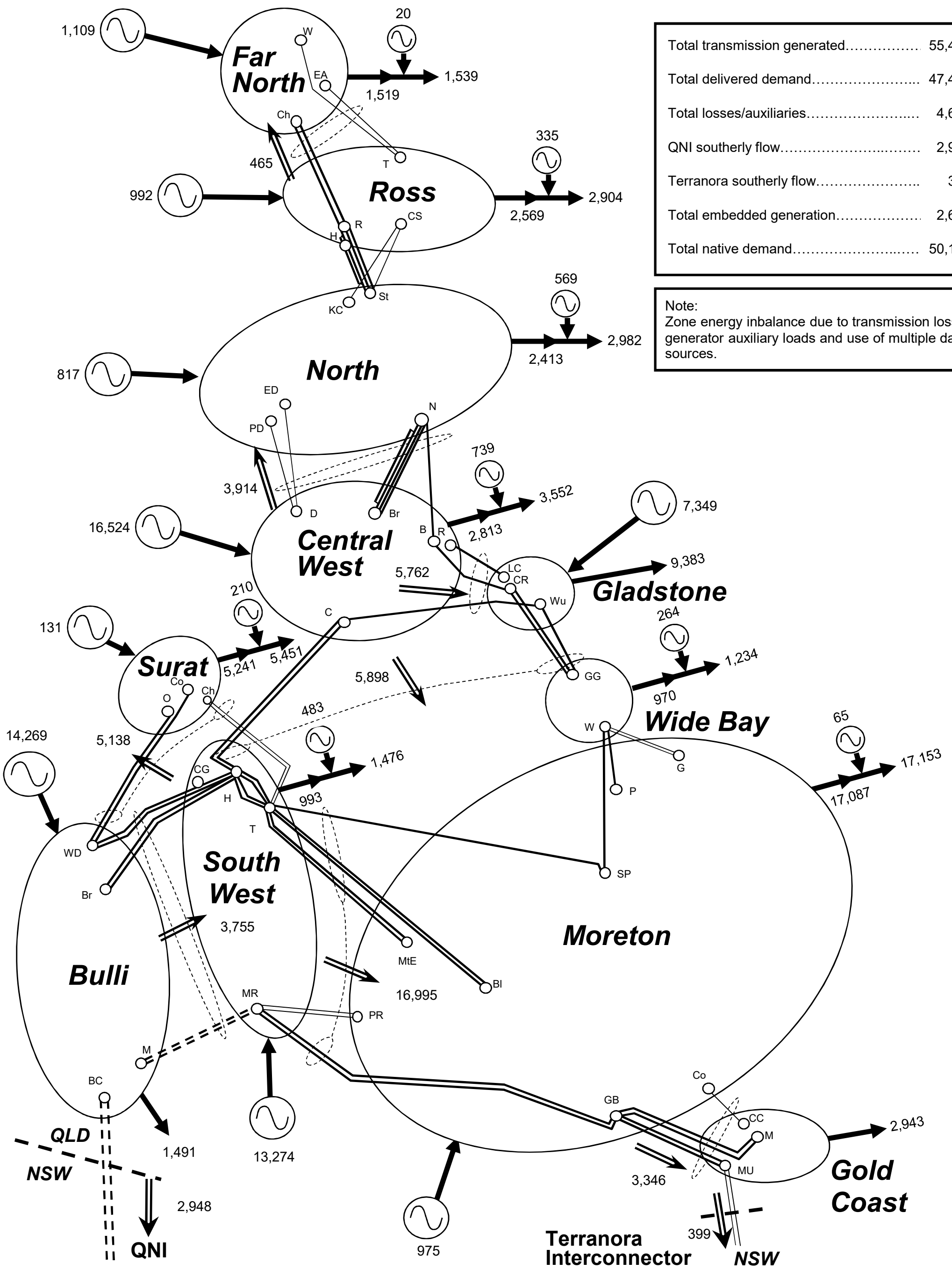
This section is a qualitative summary of system conditions with major effects on transfer capability across key grid sections of the Queensland network.

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 affected by load, generation and transfers to neighbouring zones. Figures 8.6 and 8.7 provide 2020/21 and 2021/22 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 2020/21 to 2021/22. These figures assist in the explanation of differences between 2020/21 and 2021/22 grid section transfer duration curves.

Figure 8.6 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.

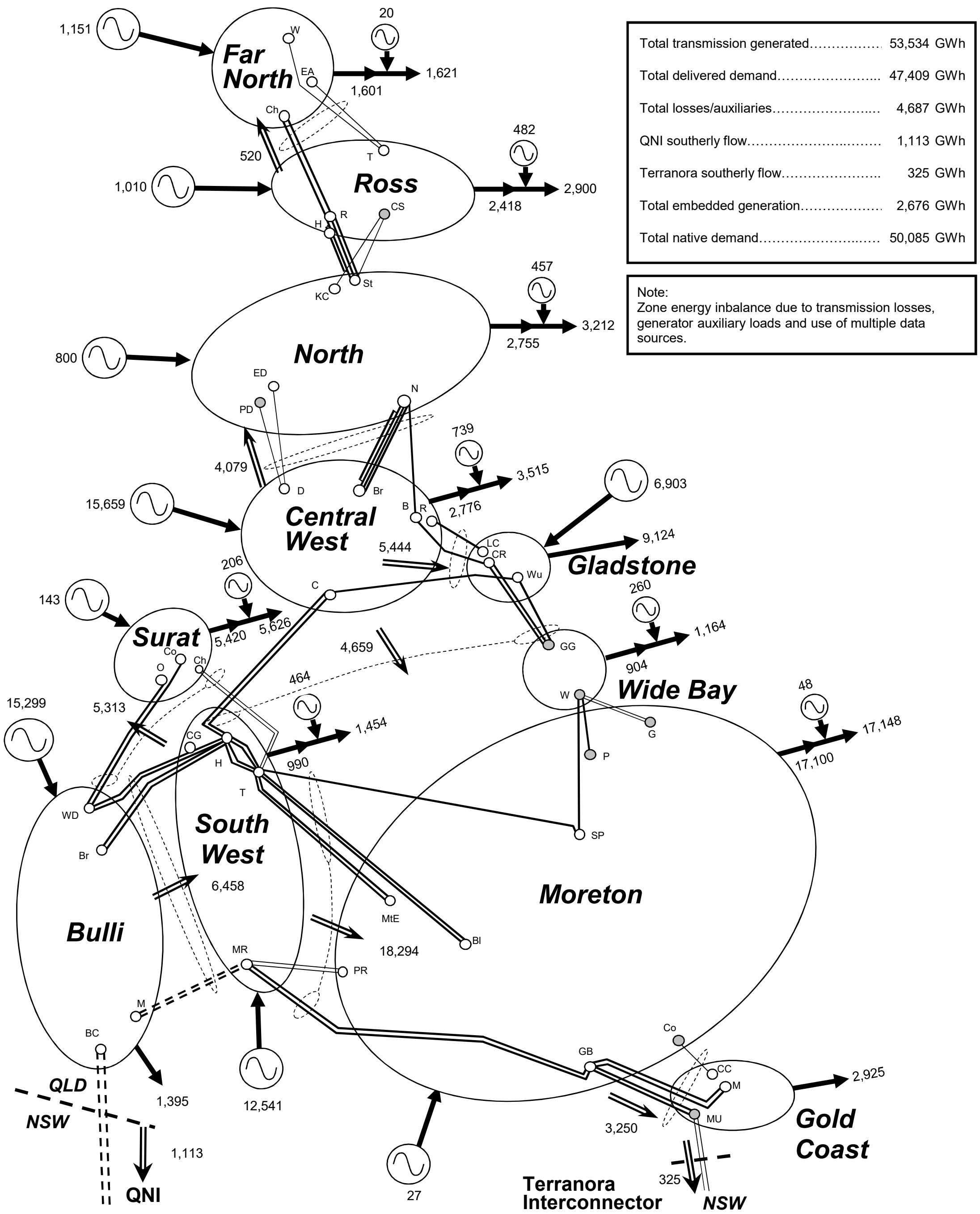
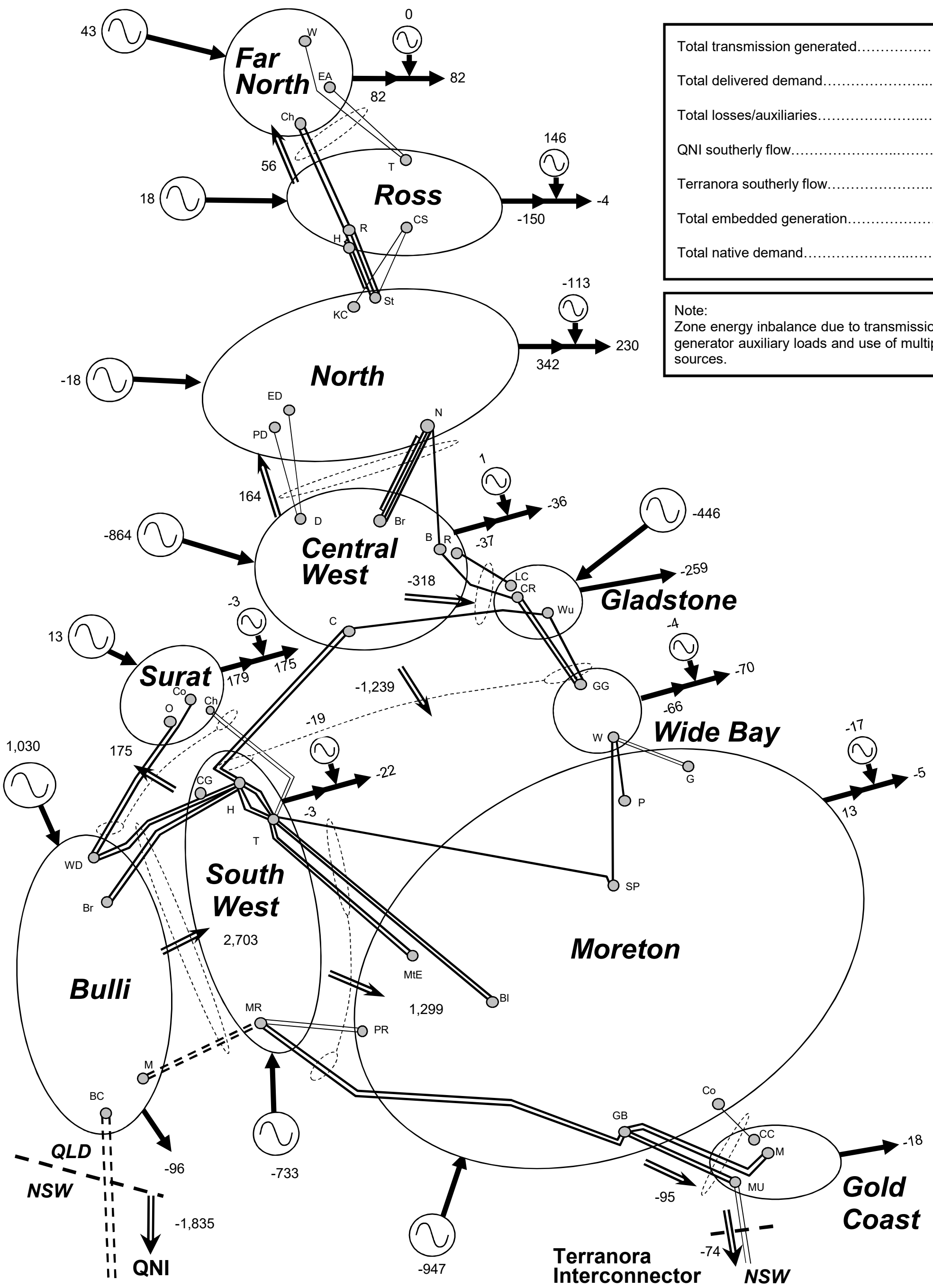


Figure 8.7 2021/22 zonal electrical energy transfers (GWh)

Figure 8.8 Change in zonal electrical energy transfers (GWh)



Total transmission generated................	-1,904 GWh
Total delivered demand........................	-13 GWh
Total losses/auxiliaries.........................	17 GWh
QNI southerly flow................................	-1,835 GWh
Terranora southerly flow.......................	-74 GWh
Total embedded generation...................	-10 GWh
Total native demand.............................	-22 GWh

Note:
Zone energy inbalance due to transmission losses, generator auxiliary loads and use of multiple data sources.

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 the Woree SVC or Mt Emerald Wind Farm.

The limit equation in Table D.1 of Appendix D shows that the following variables have a significant effect on transfer capability:

- Far North zone 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 2021/22. 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

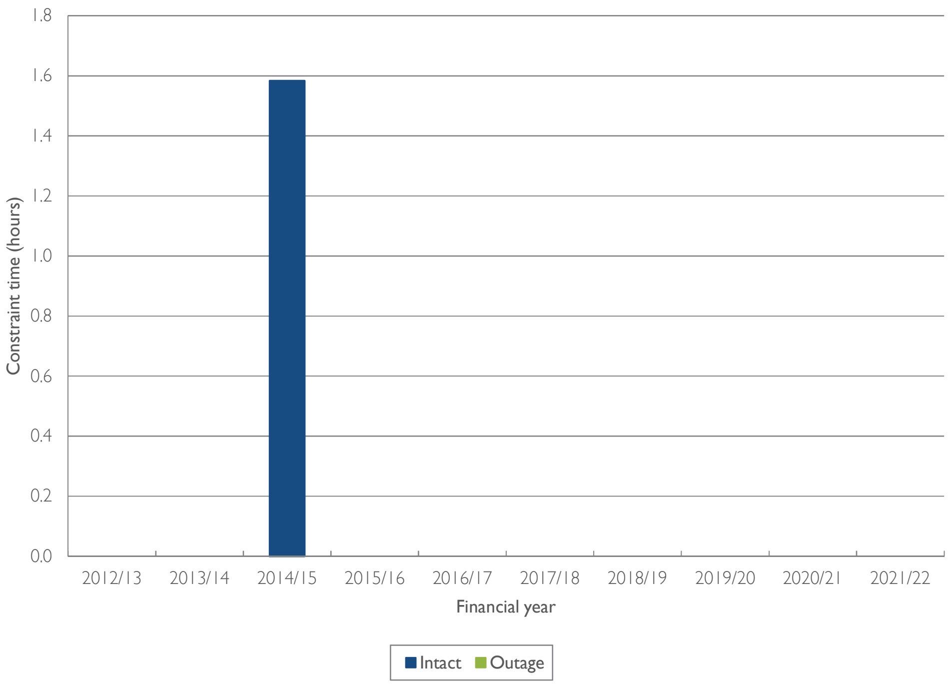
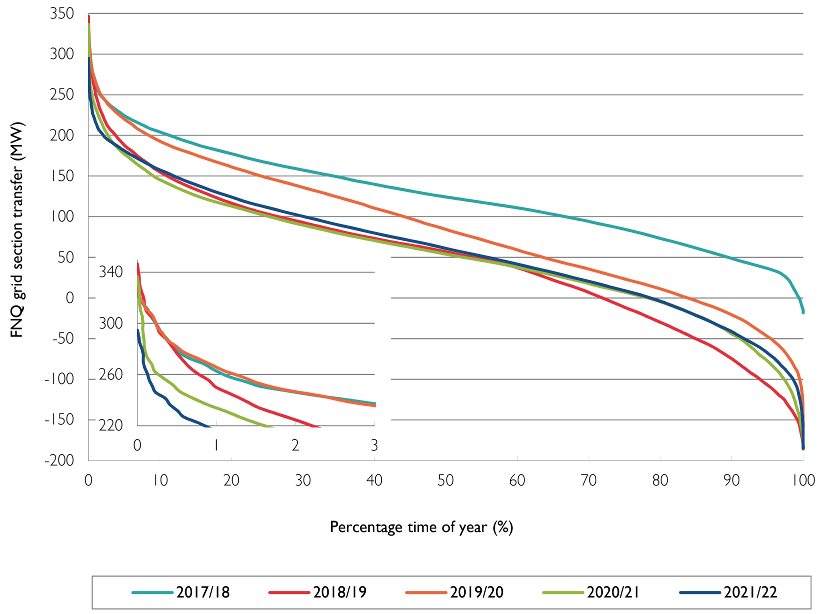


Figure 8.10 provides historical transfer duration curves showing a similar profile to 2020/21. Historically, changes in peak flow and energy delivered to the Far North zone by the transmission network have been dependant on the Far North zone load and generation from the hydro generating power stations at Barron Gorge and Kareeya. These vary depending on rainfall levels in the Far North zone. The total delivered energy of the Far North zone has increased since 2020/21. This increase has been supplied by increases in the total energy transferred across the Far North grid section and the combined hydro generating PS and Mt Emerald Wind Farm generation (refer to figures 8.6, 8.7 and 8.8).

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

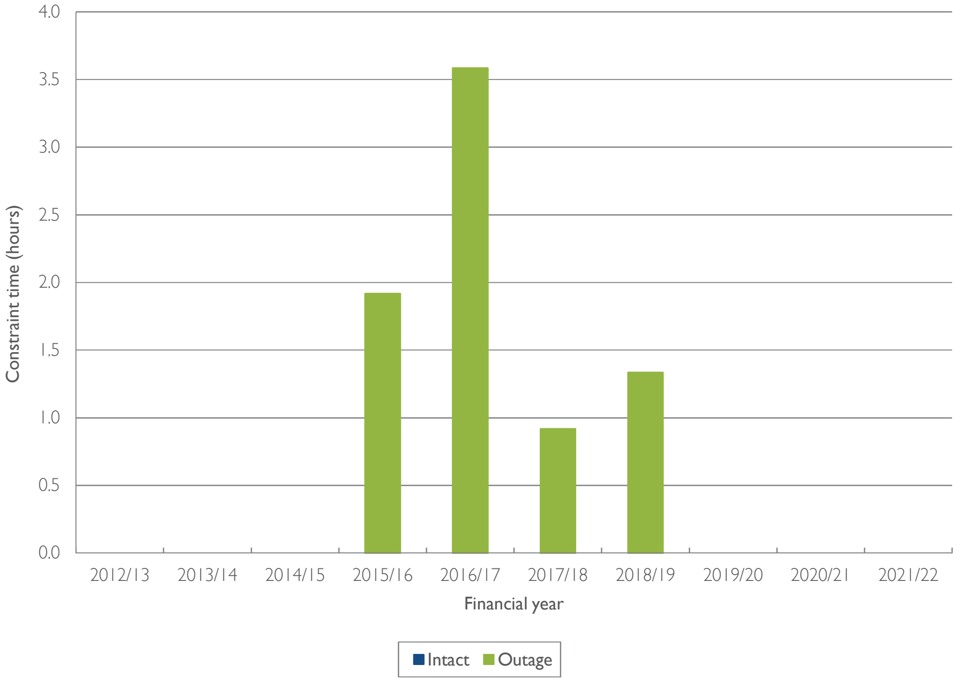
Maximum power transfer across the CQ-NQ grid section may be set by thermal ratings associated with an outage of a Stanwell to Broadsound 275kV circuit, under certain prevailing ambient conditions. Power transfers may also be constrained by voltage stability limitations associated with the contingency 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 2021/22. 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 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 over recent years. Despite reductions in total energy transfer, the peak power transfer in 2021/22 is similar to previous years. This new transfer duration shape is predominantly attributed to the addition of solar and wind farms in the Far North, Ross and North zones.

Figure 8.12 Historical CQ-NQ grid section transfer duration curves

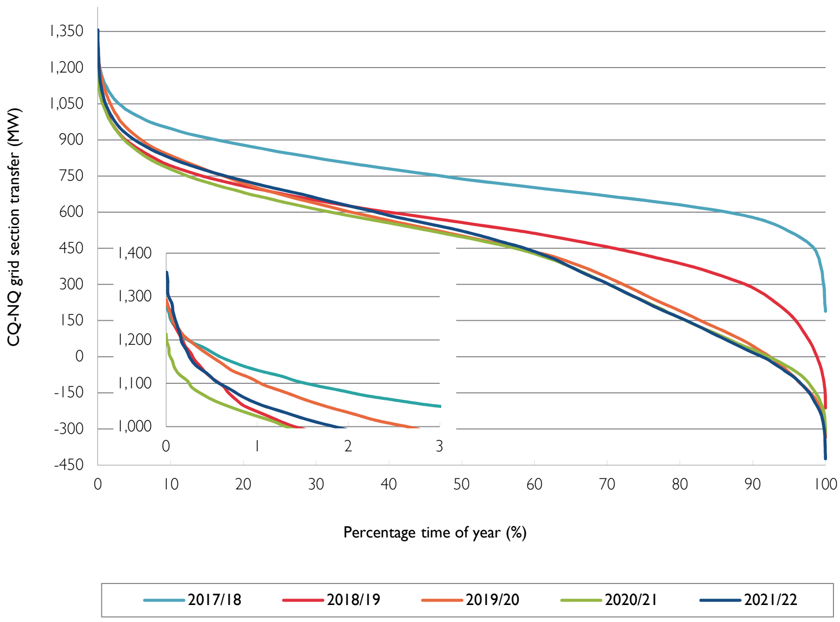
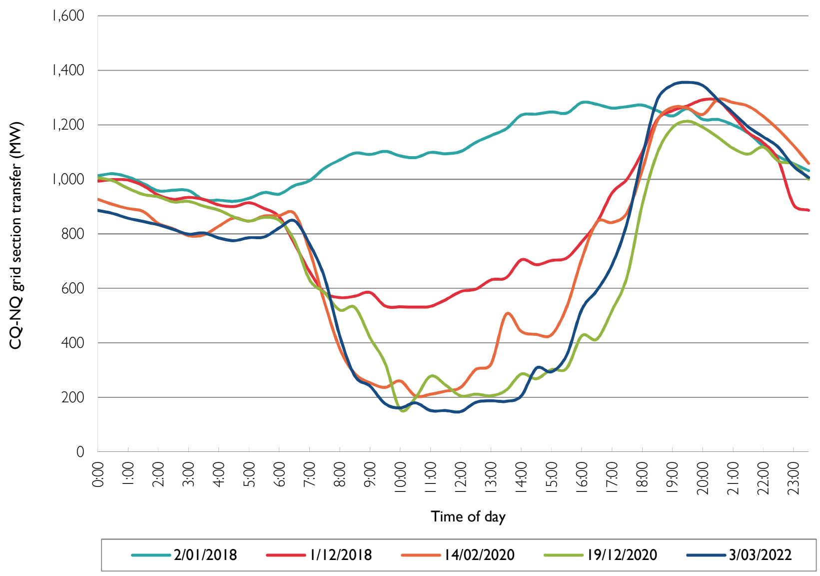


Figure 8.13 provides a different view of the altered power flows experienced over the last years for the day corresponding to the annual peak CQ-NQ transfer. This shows the impact of solar generation in creating minimum demands and network transfers in the middle of day.

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 and large-scale VRE 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)[5] recommending the establishment of a 150MVAr 300kV bus reactor at Broadsound, which is expected to be commissioned by August 2023.

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.

North Queensland (NQ) has been the focus of system strength limitations in Queensland due to the high of number of VRE plants and relatively low synchronous fault levels. Electromagnetic Transient-type (EMT) analysis has been performed to determine the system conditions that could result in unstable operation of VRE plant. The limit equations in Table D.3 of Appendix D reflect the output of this analysis. 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
- status of Haughton Synchronous Condenser.

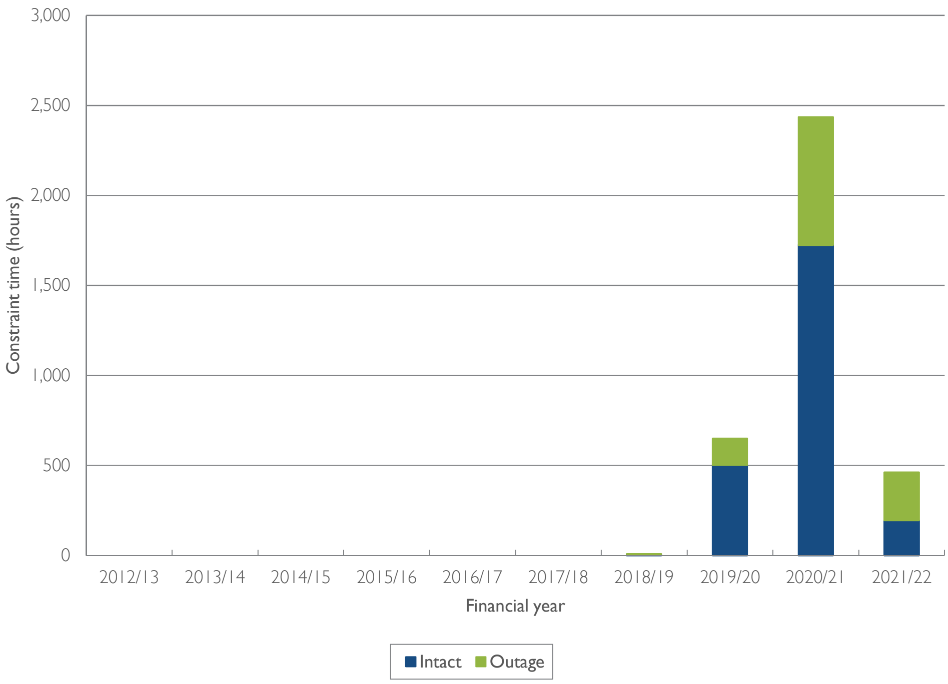
[5] Powerlink, Project Assessment Conclusions Report - Managing voltage control in Central Queensland, February 2021.

Information pertaining to the historical duration of constrained operation for inverter-based resources in NQ is summarised in Figure 8.14. During 2021/22, inverter-based resources in NQ experienced 462 hours of constrained operation, of which 195 hours occurred during intact system conditions. This is a significant reduction from 2020/21. The reduction in constrained operation is due to two primary reasons:

- retuning of inverter controls at several solar farms in north Queensland and Mt Emerald Wind Farm
- commissioning of Haughton Synchronous Condenser.

In December 2021, AEMO declared a fault level shortfall at the Gin Gin node in the Wide Bay zone. Subsequently Powerlink initiated an Expression of interest (EOI) for services to address this fault level shortfall[6]. While the shortfall was declared in the Wide Bay zone, it may be best addressed by a solution elsewhere in the state. The EOI closed at the end of June 2022 and options are being assessed. The result of this process may have further impact on the North Queensland system strength limit advice.

Figure 8.14 Historical NQ system strength constraint times (1)



Note:

(1) AEMO's Infoserver (and therefore the 2021 TAPR) includes bound constraints applying to unavailable VRE (e.g. solar farms during the night). These constraint records are now removed from the calculation. Constraint times for 2020/21 have been revised.

8.6.4 Gladstone grid section

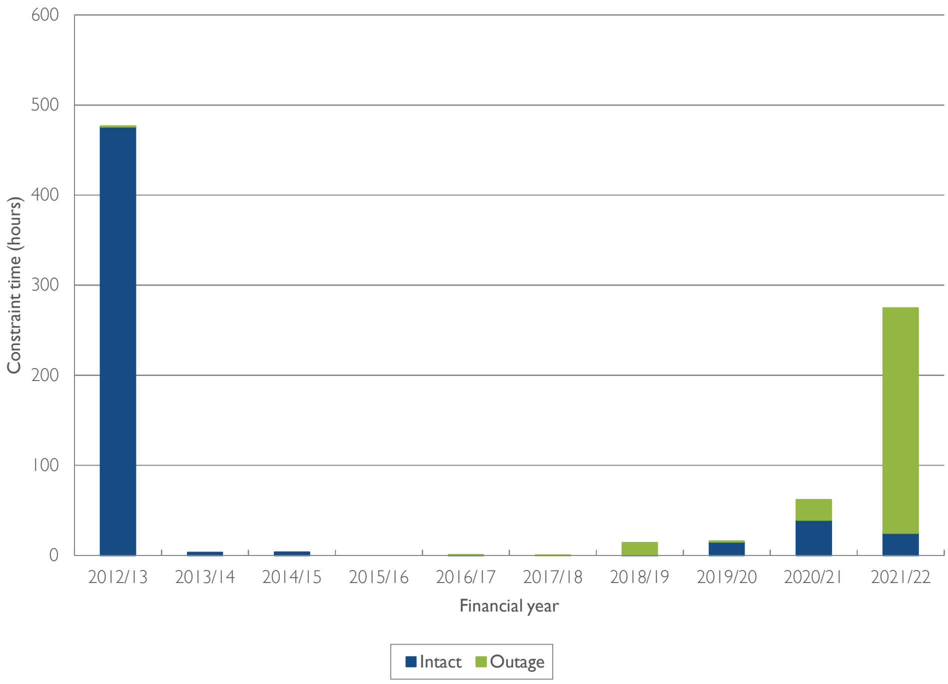
Maximum power transfer across the Gladstone grid section is set by the thermal rating of the Bouldercombe to Raglan, Larcom Creek to Calliope River, Calvale to Wurdong or the Calliope River to Wurdong 275kV circuits.

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).

[6] Powerlink, Request for power system security services in central, southern and broader Queensland regions, May 2022.

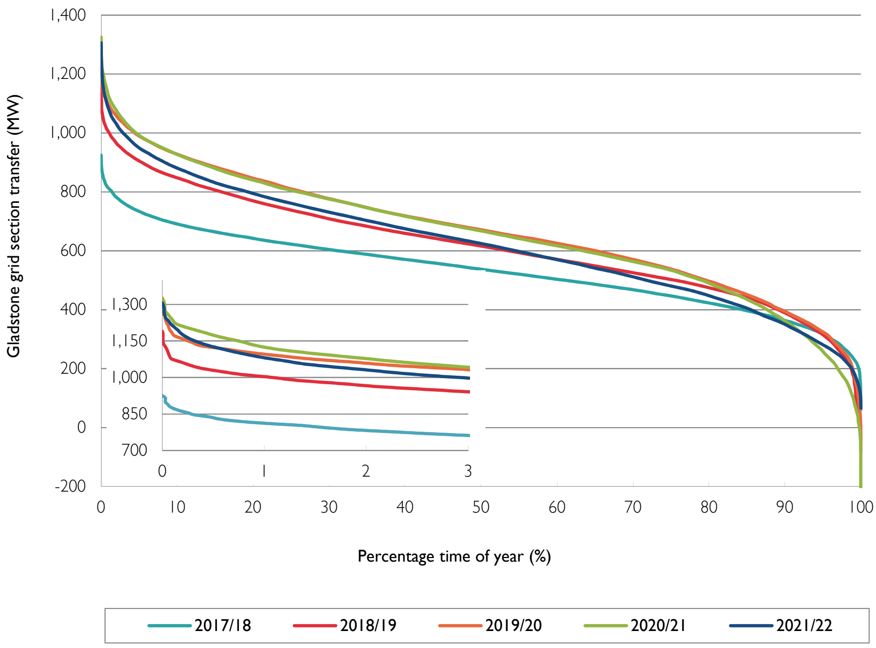
Information pertaining to the historical duration of constrained operation for the Gladstone grid section is summarised in Figure 8.15. During 2021/22, the Gladstone grid section experienced 275 hours of constrained operation, 25 hours during intact system conditions due to low Gladstone PS generation. The large increase in constrained operation was due to outages associated with planned maintenance activities on lines between Central West and Gladstone zones.

Figure 8.15 Historical Gladstone grid section constraint times



Power flows across this grid section are highly dependent on the balance of generation and demand in Gladstone and transfers to between CQ and SQ. Figure 8.16 provides historical transfer duration curves showing decreased utilisation in 2021/22 compared to 2020/21. Reduced demand in the Gladstone zone and lower transfers between CQ and SQ is responsible for this change (refer to figures 8.6, 8.7 and 8.8).

Figure 8.16 Historical Gladstone grid section transfer duration curves



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.

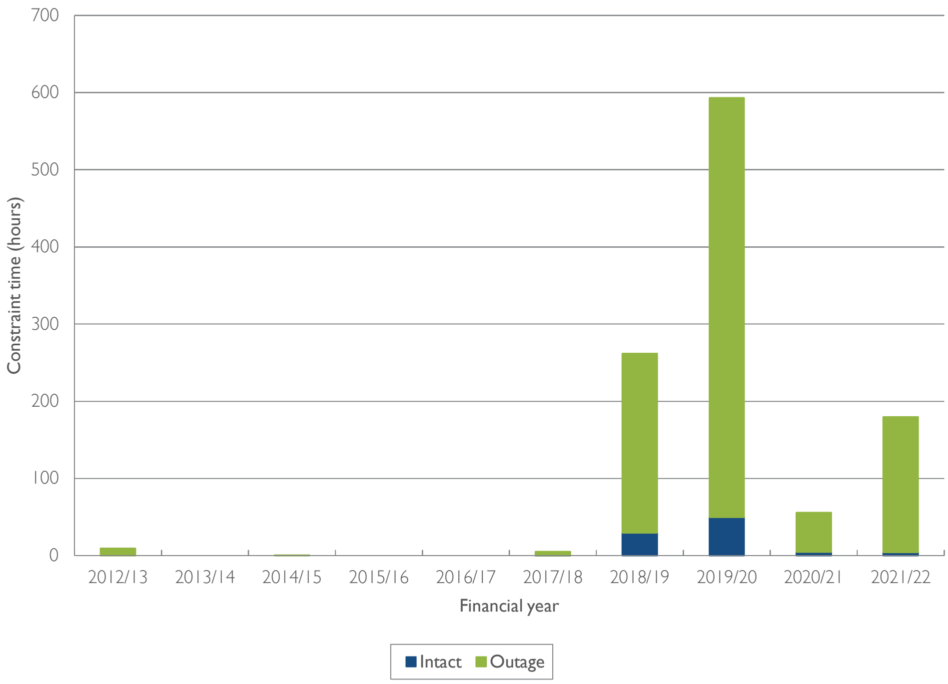
The voltage stability limit is set by insufficient reactive power reserves in the Central West and Gladstone zones following a contingency. More generating units online in these zones increase reactive power support and therefore transfer capability.

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 PS generation.

Information pertaining to the historical duration of constrained operation for the CQ-SQ grid section is summarised in Figure 8.17. During 2021/22, the CQ-SQ grid section experienced 179 hours of constrained operation. Constrained operation was due to outages associated with planned maintenance activities. Only four hours of constrained operation was during system normal conditions.

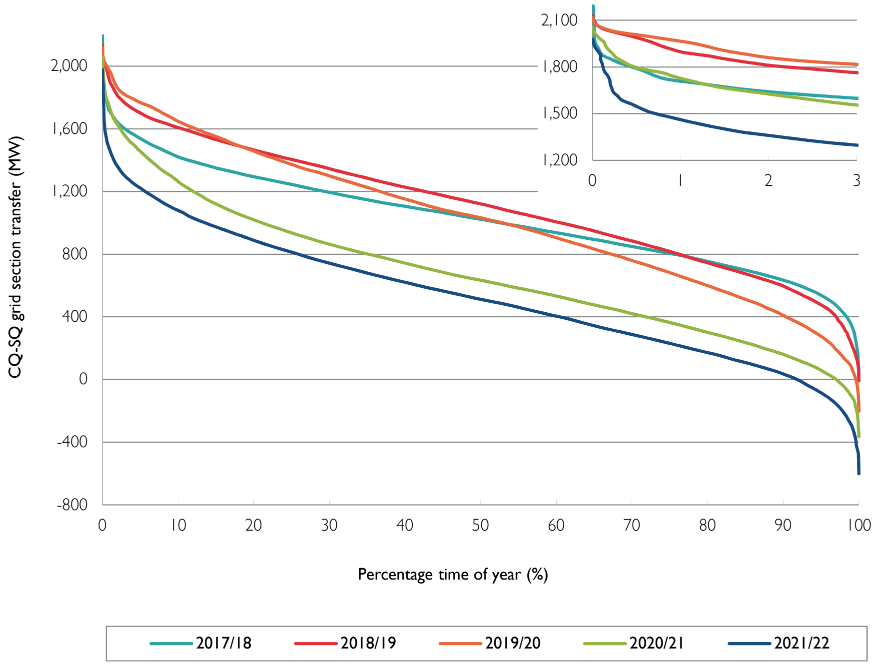
Figure 8.17 Historical CQ-SQ grid section constraint times



Associated with high penetration of rooftop PV installations in southeast Queensland, Powerlink is reviewing the transient stability limit for CQ-SQ. The review includes dynamic load models that include rooftop PV behaviour. Powerlink has committed to update this limit advice by April 2023.

Figure 8.18 provides historical transfer duration curves showing utilisation decreasing over the last two years. This decrease in transfer has been predominantly due to a significant reduction in generation in central Queensland and reduced flows over the interconnector with NSW. Over 2021/22 output from the large thermal generators in central Queensland markedly reduced (refer to figures 8.6, 8.7 and 8.8), the decrease was not as large as was observed between 2019/20 and 2020/21 but continues to break annual production lows for the area. 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.

8.6.6 Surat grid section

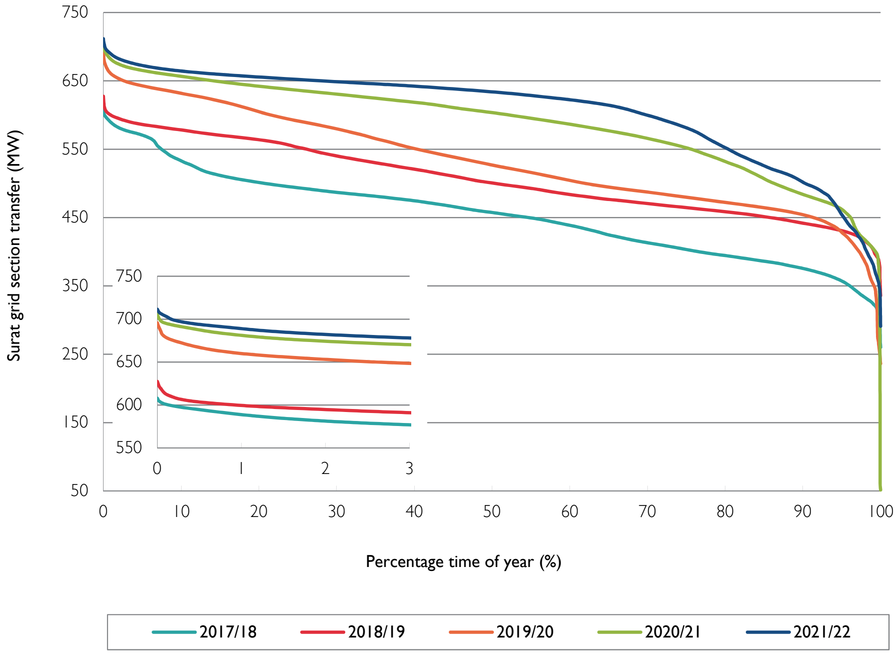
The Surat grid section was introduced in the 2014 TAPR in preparation for the establishment of the Western Downs to Columboola 275kV transmission line, Columboola to Wandoan South 275kV transmission line and Wandoan South and Columboola 275kV substations. These network developments were completed in 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[7]. 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 history of the Surat grid section.

Figure 8.19 provides the transfer duration curve since 2017/18. Grid section transfers depict the last stages of 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. All of these VRE generators are expected to be commissioned over the next year.

[7] 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.

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. The thermal rating of the Middle Ridge 330/275kV transformer sets maximum power transfer across the SWQ grid section.

The SWQ grid section did not constrain operation during 2021/22. 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

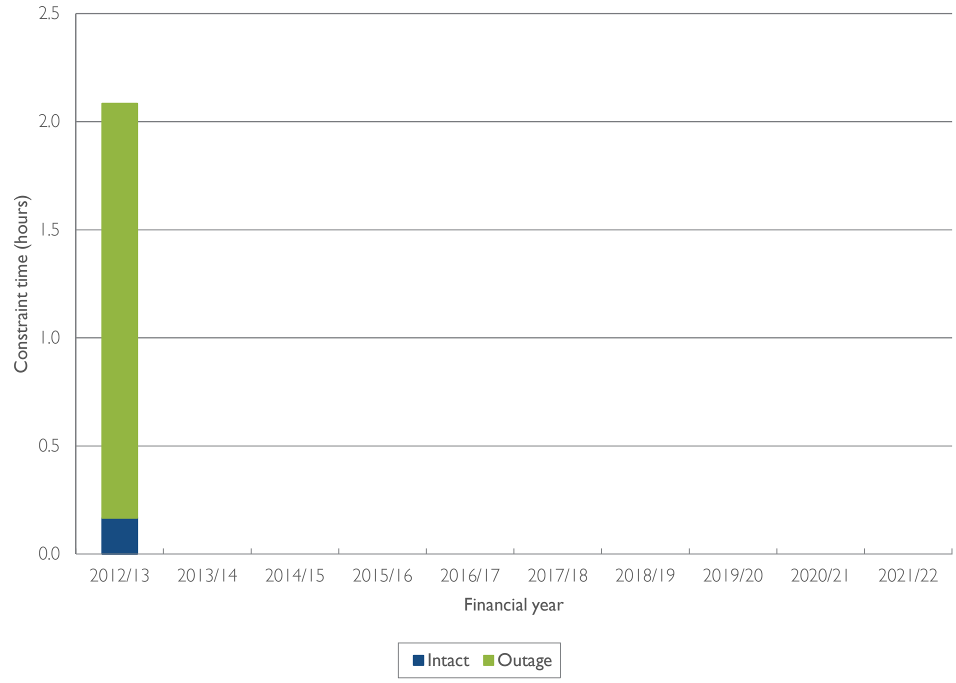
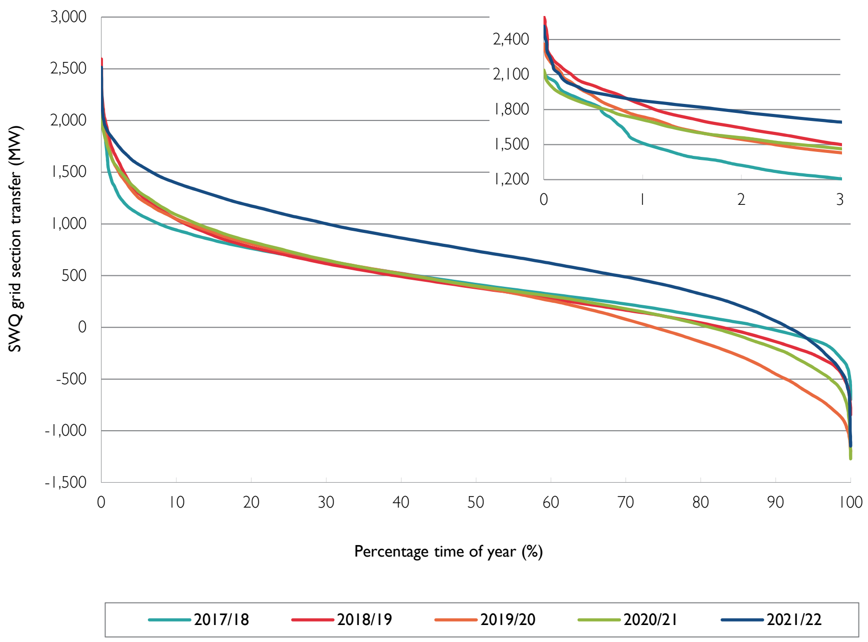


Figure 8.21 provides historical transfer duration curves showing an increase in energy transfer in 2021/22.This is predominantly due to a shift in generation from central Queensland coal to Bulli zone gas generation and reductions in interconnector flows to NSW (refer to figures 8.6, 8.7 and 8.8).

Figure 8.21 Historical SWQ grid section transfer duration curves



AEMO's 2022 Integrated System Plan[8] (ISP) required stage 1 of the Darling Downs REZ Expansion by 2028/29 in its most likely scenario. This project involves a possible upgrade to transformer capacity at Middle Ridge Substation. AEMO has requested Powerlink undertake preparatory activities for this future project by 30 June 2023.

[8] AEMO, 2022 Integrated System Plan (ISP), June 2022.

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 was constrained for 10 minutes in 2021/22. This occurred during planned maintenance work. Information pertaining to the historical duration of constrained operation for the Tarong grid section is summarised in Figure 8.22. Constraint times have been minimal over the last 10 years.

Figure 8.22 Historical Tarong grid section constraint times

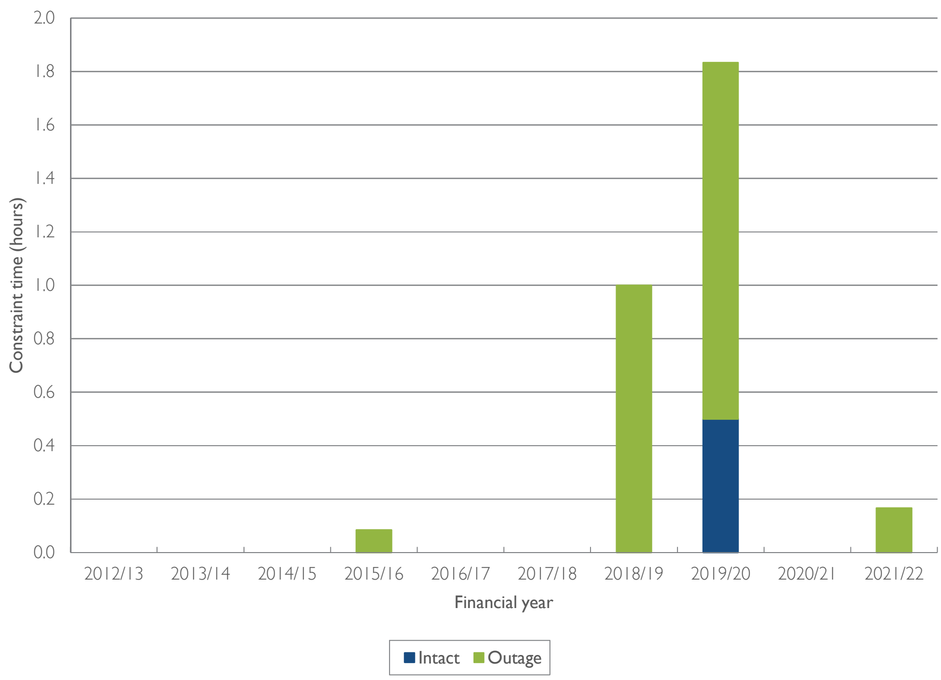
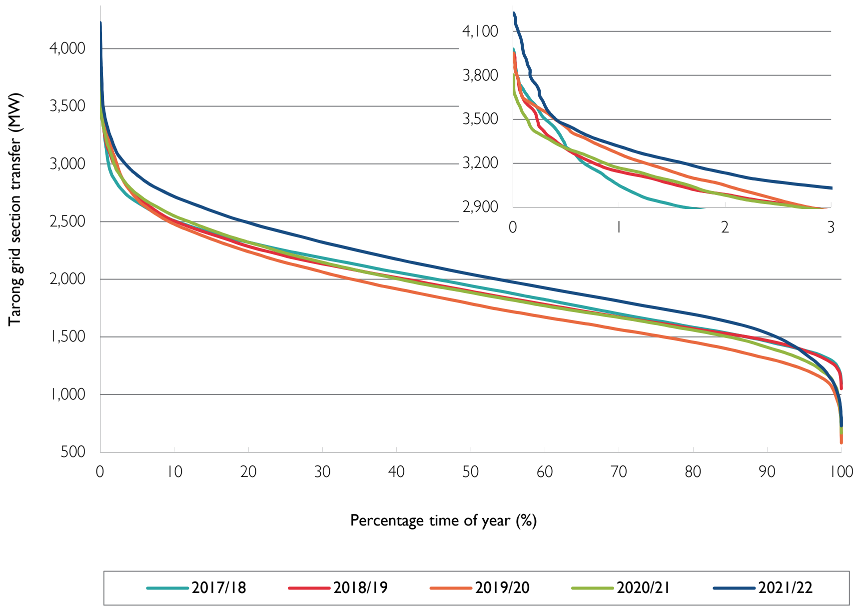


Figure 8.23 provides historical transfer duration curves showing an increase in flows in 2021/22. This is predominantly due to a reduction in net generation in the Moreton zone (refer to figures 8.6, 8.7 and 8.8). The reduction in generation is predominantly due to an unplanned outage of the Swanbank E generator between December 2021 and September 2022 and higher utilisation of Wivenhoe pumped hydro (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.

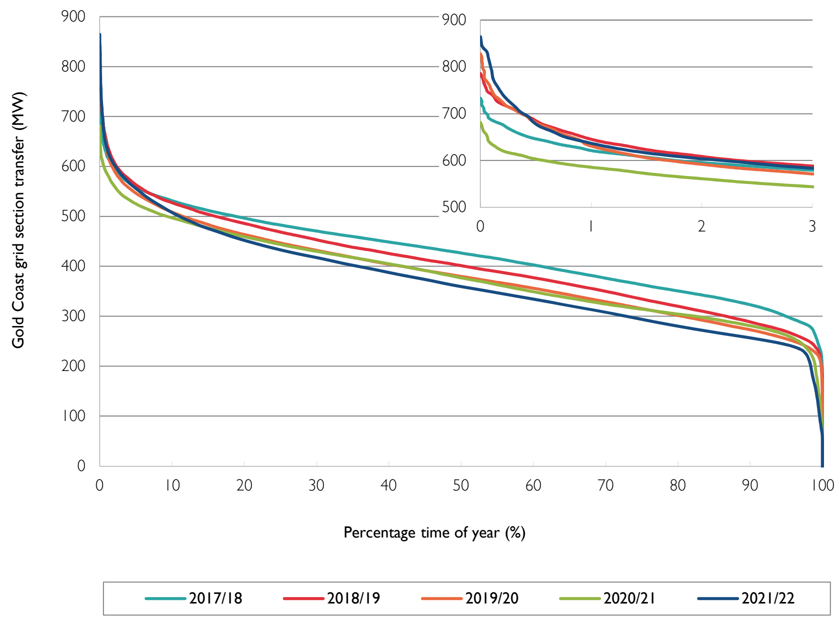
The limit equation in Table D.6 of Appendix D shows that the following variables have a significant effect on transfer capability:

- 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. There have been no constraints on the Gold Coast grid section over the last 10 years.

Figure 8.24 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 2021/22 compared to 2020/21 (refer to figures 8.6, 8.7 and 8.8).

Figure 8.24 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 2025. 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 Dumaresq and Armidale in NSW
- oscillatory stability upper limit of 1,450MW.

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 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 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 complete and inter-network testing activities, as required by NER 5.7.7, are progressing.

Associated with high penetration of rooftop PV installations, Powerlink is reviewing the transient stability limit for QNI southerly transfer. The review includes dynamic load models that include rooftop PV behaviour. Powerlink will update this limit advice by April 2023.

AEMO's 2022 Integrated System Plan[9] (ISP) considered the QNI Connect project that would increase transfer capacity between Queensland and New South Wales. The ISP identified that QNI Connect may be required as early as 2029/30 (based on the Hydrogen Superpower scenario). AEMO has requested Powerlink and Transgrid undertake preparatory activities for a 500kV QNI Connect option by 30 June 2023.

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[10]
- 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[11]) 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.

Statewide delivered energy has not materially changed from 2020/21 to 2021/22. However, there are some zones where delivered energy has increased and others where it has decreased (refer to Figure 8.8). Despite the flat state-wide delivered demand, there has been significant increases in embedded VRE generation. The Queensland region's installed rooftop PV has increased by approximately 730MW over the year, reaching approximately 4,808MW by 30 June 2022[12]. Figure 3.11 provides annual transmission delivered demand load duration curves for the Queensland region.

9 AEMO, 2022 Integrated System Plan, June 2022.
10 AEMO, List of Vulnerable Lines, effective May 2022.
11 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.
12 Clean Energy Regulator, Postcode data for small-scale installations – all data, data as at 31/08/2022, September 2022.

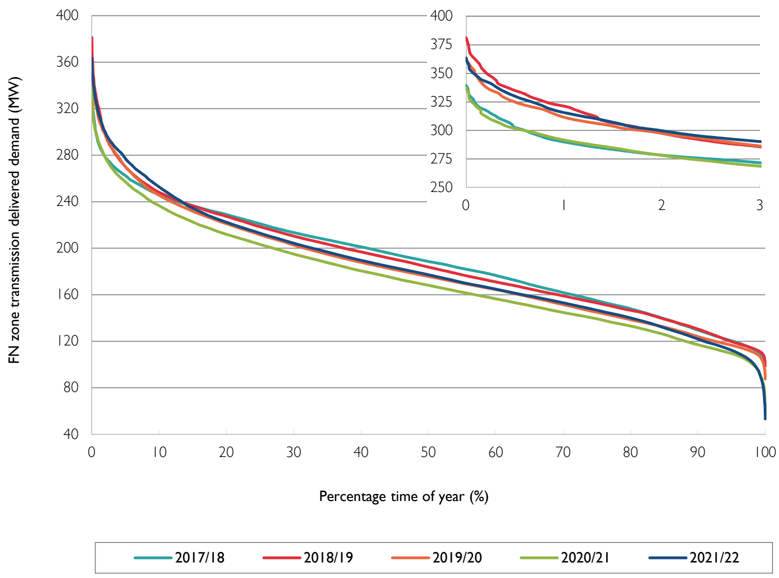
8.7.1 Far North zone

The Far North zone experienced no load loss for a single network element outage during 2021/22.

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 2021/22.

Figure 8.25 provides historical transmission delivered load duration curves for the Far North zone. Energy delivered from the transmission network increase by 5.4% between 2020/21 and 2021/22. The maximum transmission delivered demand in the zone was 363MW, 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 53MW, which is the lowest minimum demand over the last five years.

Figure 8.25 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.

There are currently no double circuits in the Far North zone in AEMO's lightning vulnerable transmission line list.

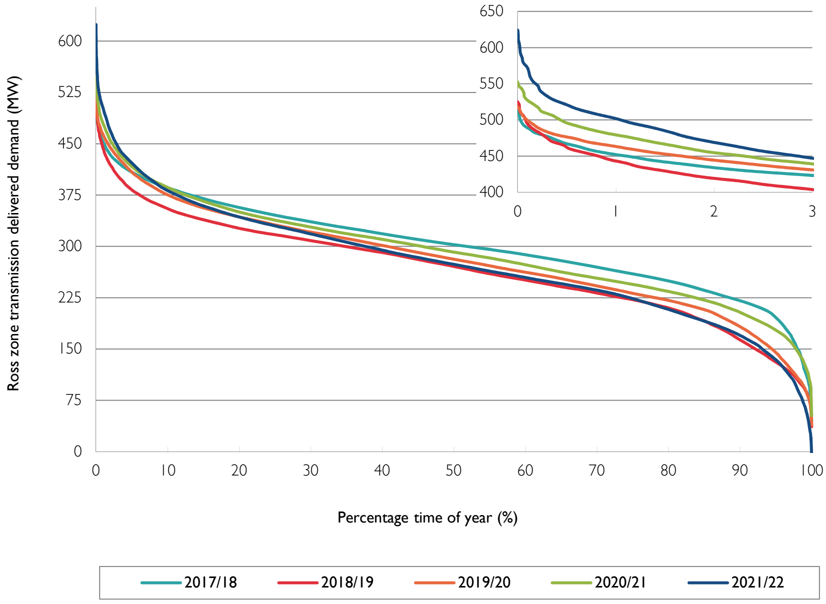
8.7.2 Ross zone

The Ross zone experienced no load loss for a single network element outage during 2021/22.

The Ross zone includes the scheduled embedded Townsville PS 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 3.4. These embedded generators provided approximately 482GWh during 2021/22.

Figure 8.26 provides historical transmission delivered load duration curves for the Ross zone. Energy delivered from the transmission network has reduced by 5.9% between 2020/21 and 2021/22. The reduction in energy delivered is predominantly due to the increase in energy from embedded generation. The peak transmission delivered demand in the zone was 624MW, which is the highest maximum demand over the last five years. The minimum transmission delivered demand in the zone was -6MW, which is the lowest demand over the last five years and the first time that the Ross zone has become a net exporter.

Figure 8.26 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.

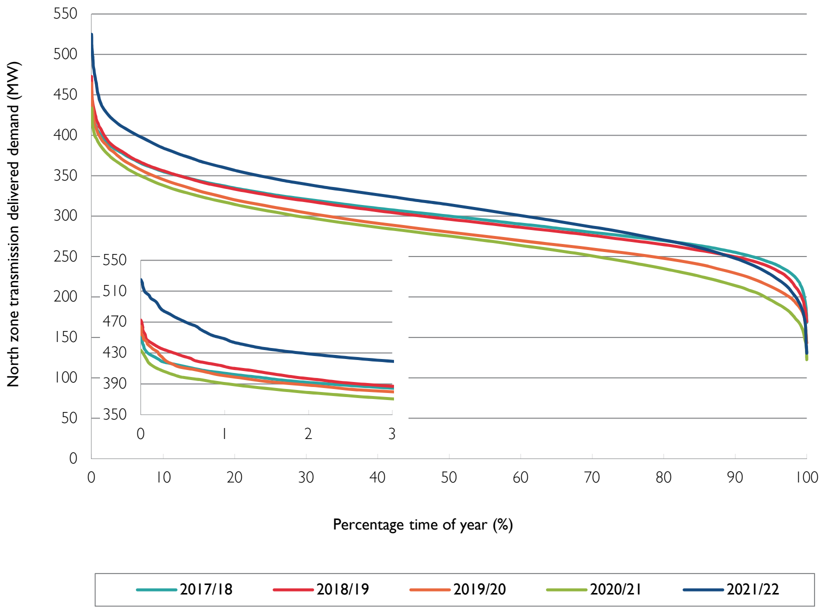
8.7.3 North zone

The North zone experienced no load loss for a single network element outage during 2021/22.

The North zone includes semi-scheduled embedded generator Collinsville Solar Farm and significant non-scheduled embedded generators Moranbah North, Moranbah and Racecourse Mill as defined in Figure 3.4. These embedded generators provided approximately 457GWh during 2021/22.

Figure 8.27 provides historical transmission delivered load duration curves for the North zone. Energy delivered from the transmission network has increased by 14.2% between 2020/21 and 2021/22, to the highest level in the last decade. The peak transmission delivered demand in the zone was 525MW, which is the highest maximum demand over the last decade. The minimum transmission delivered demand in the zone was 130MW, which is slightly higher than the lowest minimum demand in the last five years of 122MW, recorded in 2020/21.

Figure 8.27 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 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:

- Collinsville North to Proserpine 132kV double circuit transmission line, last tripped February 2018
- Collinsville North to Stoney Creek and Collinsville North to Newlands lines, last tipped November 2021.

The following double circuit has, this year, been removed from 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.

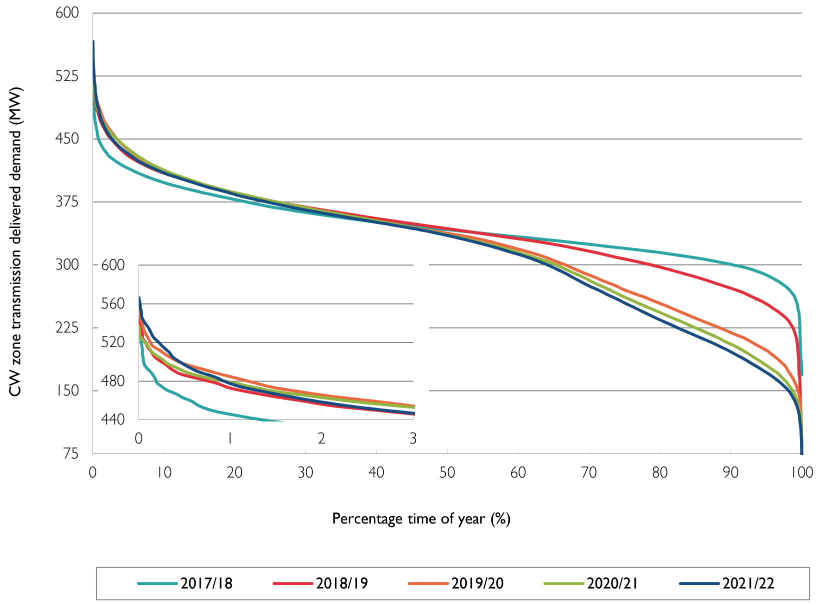
8.7.4 Central West zone

The Central West zone experienced one load loss for a single network element outage during 2021/22. The duration of the outage was less than two hours and approximately 35MWh of energy was lost. The loads impacted by this outage are supplied by a single radial connection under normal system conditions.

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 2021/22.

Figure 8.28 provides historical transmission delivered load duration curves for the Central West zone. Energy delivered from the transmission network has reduced by 1.3% between 2020/21 and 2021/22, to the lowest level in the last decade. This is a continuation of the trend seen in recent years. The peak transmission delivered demand in the zone was 566MW, which is the highest maximum demand over the last five years. The minimum transmission delivered demand in the zone was 65MW, which is slightly higher to the lowest minimum demand over the last decade, which was 64MW recorded in 2020/21.

Figure 8.28 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.

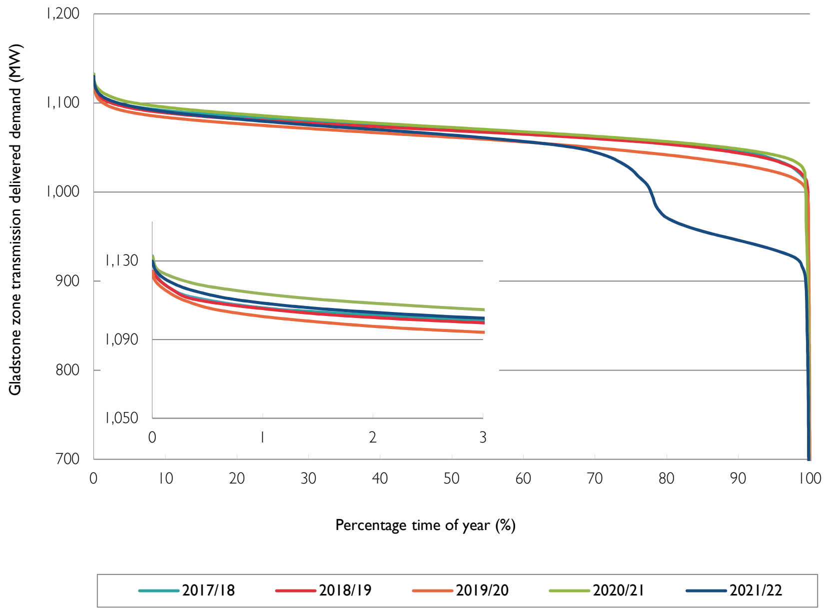
8.7.5 Gladstone zone

The Gladstone zone experienced no load loss for a single network element outage during 2021/22.

The Gladstone zone contains no scheduled, semi-scheduled or significant non-scheduled embedded generators as defined in Figure 3.4.

Figure 8.29 provides historical transmission delivered load duration curves for the Gladstone zone. The figure clearly shows a reduction in demand during 2021/22 due to unplanned outages by Boyne Smelters Limited (BSL). Energy delivered from the transmission network has reduced by 2.8% between 2020/21 and 2021/22. The peak transmission delivered demand in the zone was 1,130MW, which is close to the highest maximum demand over the last five years of 1,133MW set in 2017/18. 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 632MW.

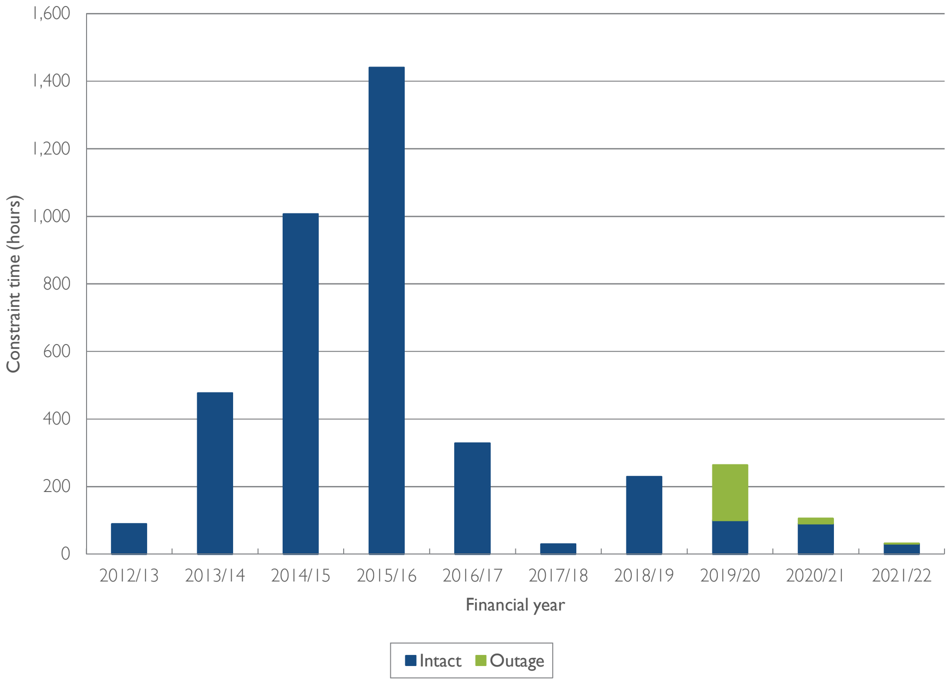
Figure 8.29 Historical Gladstone zone transmission delivered load duration curves



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 PS, 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 8.30. During 2021/22, the feeder bushing constraint experienced 32 hours of constrained operation, 1 hour during the planned outage of 275kV feeders between Calliope River and Woolooga.

Figure 8.30 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 2021/22.

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 3.4. These embedded generators provided approximately 260GWh during 2021/22.

Figure 8.31 provides historical transmission delivered load duration curves for the Wide Bay zone. Wide Bay zone is one of three 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 8.32 provides the daily load profile for the minimum transmission delivered days over the last five years.

While energy has seen significant reductions, the peak demand, which occurs at night, remains at similar levels. Energy delivered from the transmission network reduced by 6.8% between 2020/21 and 2021/22, to the lowest level in the last decade. The peak transmission delivered demand in the zone was 277MW, which is below the highest maximum demand of 316MW recorded in 2020/21. The minimum transmission delivered demand in the zone was -106MW, which is the lowest demand on record.

Figure 8.31 Historical Wide Bay zone transmission delivered load duration curves

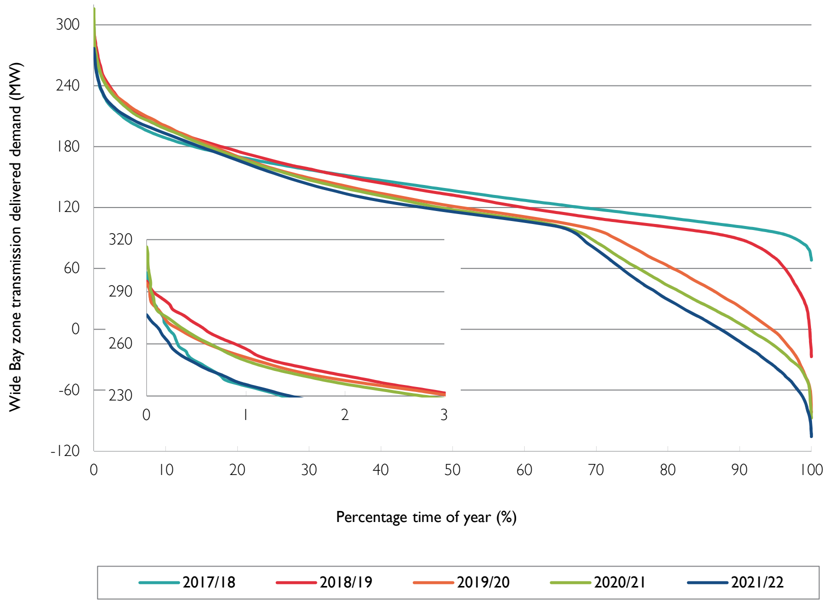
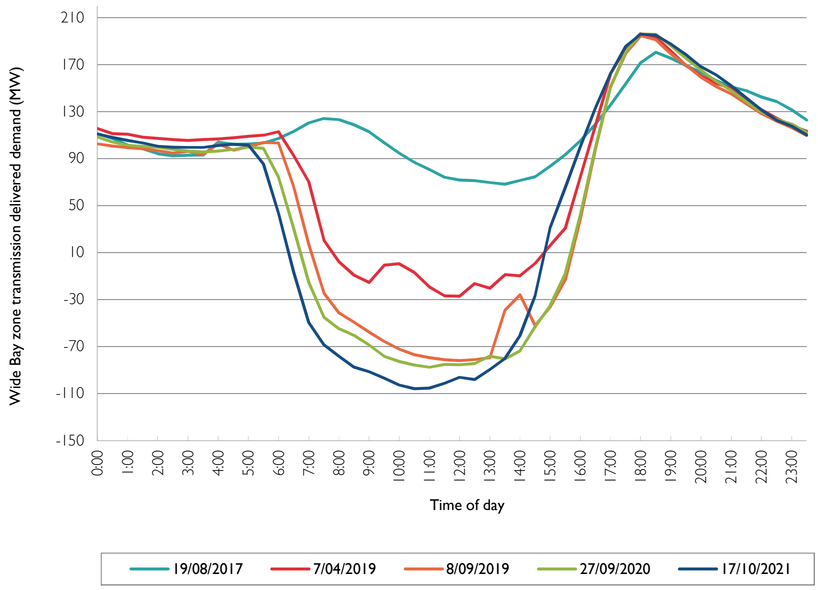


Figure 8.32 Historical Wide Bay zone minimum transmission delivered daily profile



There are currently no double circuits in the Wide Bay zone in AEMO's lightning vulnerable transmission line list.

8 Network capability and performance

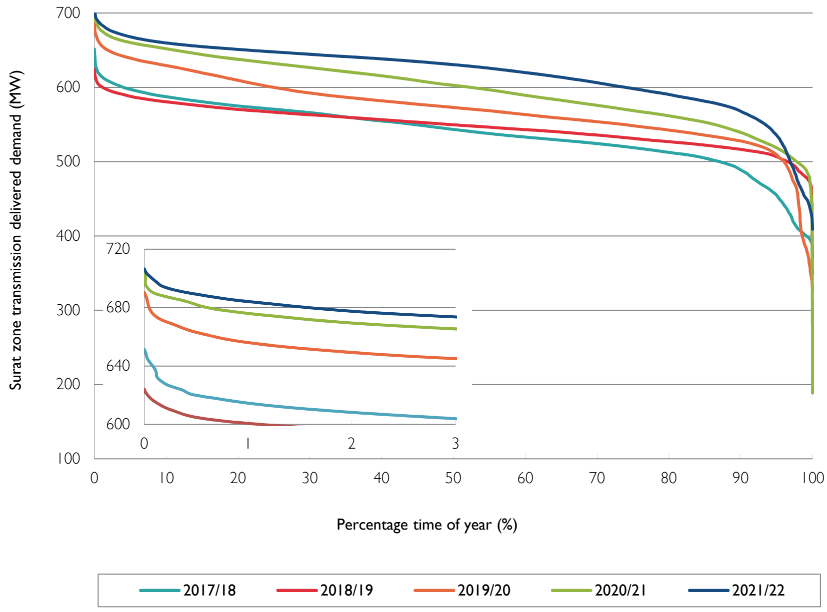
8.7.7 Surat zone

The Surat zone experienced no load loss for a single network element outage during 2021/22.

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 3.4. These embedded generators provided approximately 206GWh during 2021/22.

Figure 8.33 provides historical transmission delivered load duration curves for the Surat zone. Energy delivered from the transmission network has increased by approximately 3.4% between 2020/21 and 2021/22. The peak transmission delivered demand in the zone was 707MW, which is the highest maximum demand over the last five years but only a slightly higher than 706MW recorded in 2020/21. The minimum transmission delivered demand in the zone was 409MW. The minimum demand over the last five years of 189MW was a result of load disconnection following the Callide C unit 4 incident on 25 May 2021.

Figure 8.33 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.

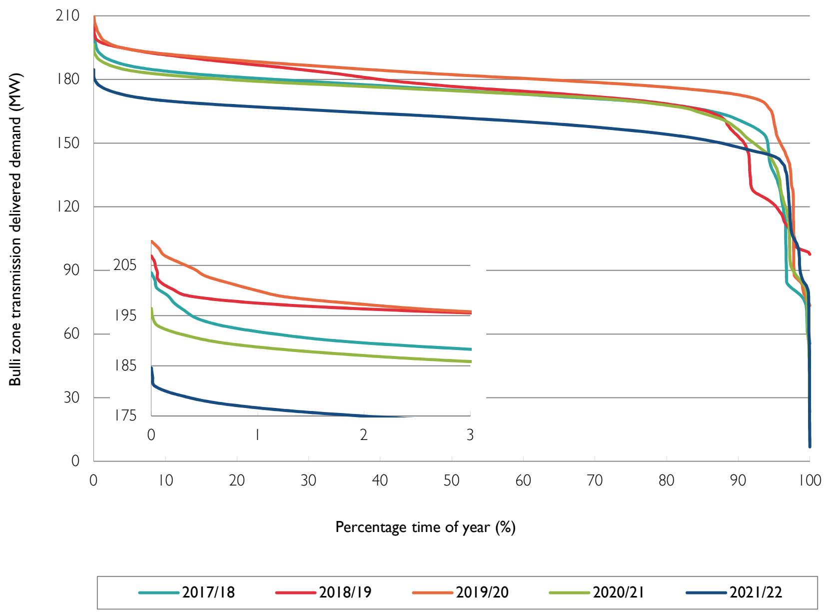
8.7.8 Bulli zone

The Bulli zone experienced no load loss for a single network element outage during 2021/22.

The Bulli zone contains no scheduled, semi-scheduled or significant non-scheduled embedded generators as defined in Figure 3.4.

Figure 8.34 provides historical transmission delivered load duration curves for the Bulli zone. Energy delivered from the transmission network has reduced by approximately 6.4% between 2020/21 and 2021/22. The peak transmission delivered demand in the zone was 185MW which is below the highest maximum demand over the last five years of 210MW set in 2019/20. The minimum transmission delivered demand in the zone was 7MW, which is the lowest demand over the last five years and was a result of an unplanned network outage.

Figure 8.34 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

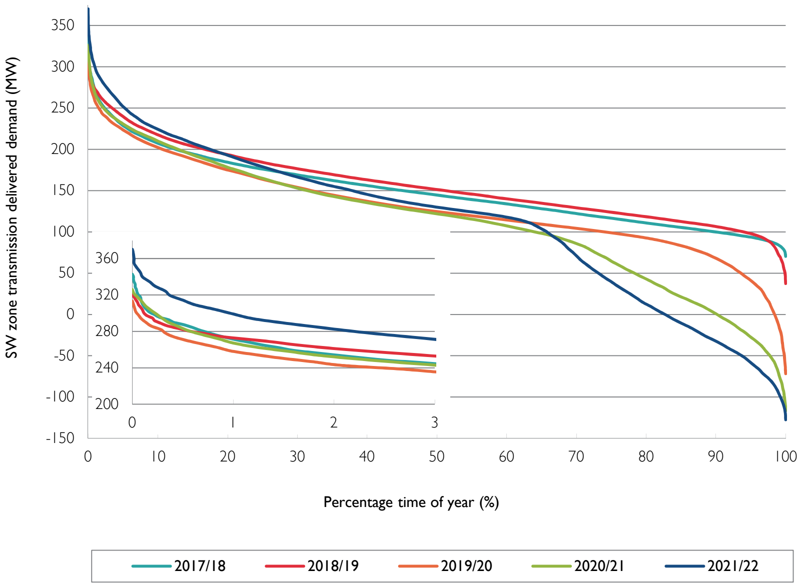
The South West zone experienced no load loss for a single network element outage during 2021/22.

The South West zone includes the semi-scheduled embedded generators Oakey 1 Solar Farm, Oakey 2 Solar Farm, Yarranlea Solar Farm, Maryrorough Solar Farm and Warwick Solar Farm as defined in Figure 3.4. These embedded generators provided approximately 464GWh during 2021/22.

Figure 8.35 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 0.3% between 2020/21 and 2021/22, to the lowest level in the last decade. The reduction in energy delivered is slightly lower than the 2020/21 figure, which was the previous record minimum. The peak transmission delivered demand in the zone was 370MW, which is the highest demand over the past five years. The minimum transmission delivered demand in the zone was -128MW, which is the lowest demand on record.

Figure 8.35 Historical South West zone transmission delivered load duration curves



The significant non-scheduled embedded Daandine PS was retired in March 2022.

There are currently no double circuits in the South West zone in AEMO's lightning vulnerable transmission line list.

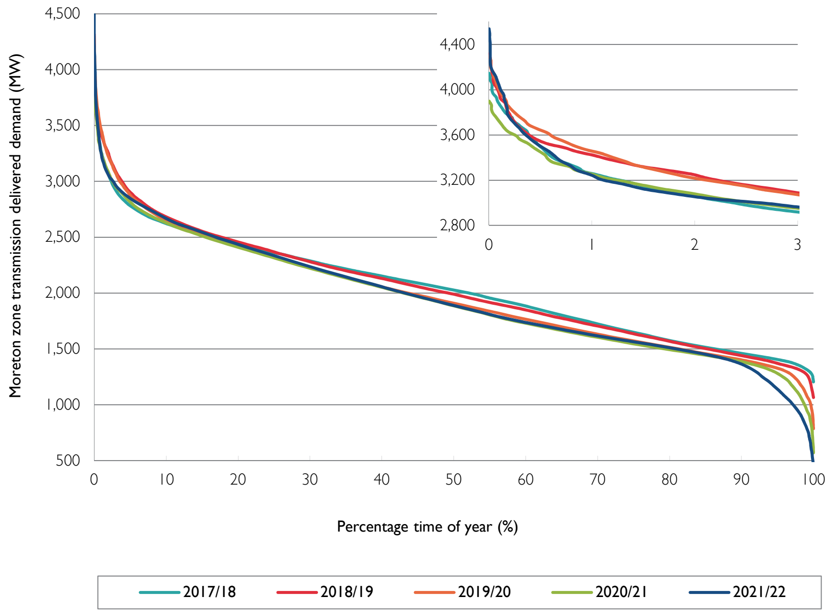
8.7.10 Moreton zone

The Moreton zone experienced no load loss for a single network element outage during 2021/22.

The Moreton zone includes the significant non-scheduled embedded generators Sunshine Coast Solar Farm, Bromelton and Rocky Point as defined in Figure 3.4. These embedded generators provided approximately 48GWh during 2021/22.

Figure 8.36 provides historical transmission delivered load duration curves for the Moreton zone. Energy delivered from the transmission network has increased by 0.1% between 2020/21 and 2021/22. This is a slight increase on the record minimum delivered energy of 17,087GWh recorded in 2020/21. The peak transmission delivered demand in the zone was 4,539MW, which is the highest maximum demand over the past five. The minimum transmission delivered demand in the zone was 451MW, which is the lowest demand on record.

Figure 8.36 Historical Moreton zone transmission delivered load duration curves

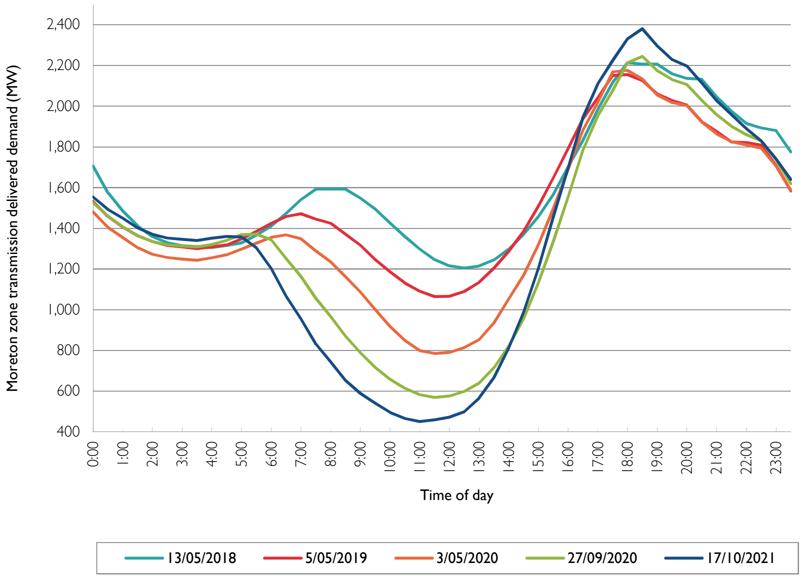


High voltages associated with these light load conditions are currently managed with existing reactive sources. However, voltage control within Powerlink's and Energex's network is forecast to become increasingly challenging for longer durations. This is discussed in Section 6.11.4. In 2021, AEMO identified an NSCAS gap of up to 250 MVAr of reactive power absorption in the southern Queensland. Due to this gap, Powerlink initiated an EOI to identify network and non-network options to address this gap[13].

Figure 8.37 provides the daily load profile for the minimum transmission delivered days for the Moreton zone over the last five years. This figure highlights the steady decrease in minimum demands but also shows the minimum demands days are shifting to later in the year, as the impact of greater rooftop PV yield outweighs the impact of higher native loads in the warmer weather. This is a trend observed across several zones with high levels of rooftop PV generation. The figure also highlights the increase gap between minimum and maximum demand on these days.

13 Powerlink, Request for power system security services in central, southern and broader Queensland regions, May 2022.

Figure 8.37 Historical Moreton zone minimum transmission delivered daily profile



There are currently no double circuits in the Moreton zone in AEMO's lightning vulnerable transmission line list.

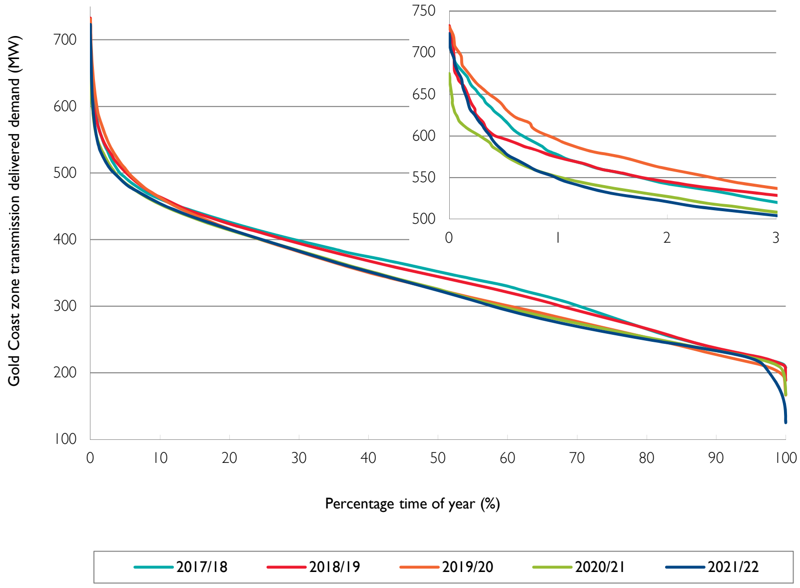
8.7.11 Gold Coast zone

The Gold Coast zone experienced no load loss for a single network element outage during 2021/22.

The Gold Coast zone contains no scheduled, semi-scheduled or significant non-scheduled embedded generators as defined in Figure 3.4.

Figure 8.38 provides historical transmission delivered load duration curves for the Gold Coast zone. Energy delivered from the transmission network has reduced by 0.6% between 2020/21 and 2021/22, to the lowest level in the last decade. The peak transmission delivered demand in the zone was 723MW, 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 125MW which is the lowest demand on record.

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

- Possible loads associated with new industrial processes, including industry based on hydrogen, and electrification of major industrial processes and mining operations, are emerging within the 10-year outlook period.
- Possible network impacts and options are provided for the Northern Bowen Basin coal mining area, North West Mineral province, Central Queensland to North Queensland (CQ-NQ) grid section and supply within South East Queensland.
- The changing generation mix also has implications for investment in the transmission network, both inter-regionally and within Queensland, across critical grid sections.
- The 2022 Integrated System Plan (ISP) and Queensland Energy and Jobs Plan (QEJP) released in September 2022 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, Central West to Gladstone grid section, Darling Downs REZ to South East Queensland and Queensland to New South Wales (NSW) Interconnector (QNI). The 2023 Transmission Annual Planning Report (TAPR) will incorporate the QEJP in conjunction with the ISP to inform Powerlink's planning activities.

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) Step Change 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.

In September 2022 the Queensland Government published the Queensland Energy and Jobs Plan (QEJP), which outlines how it intends to meet the Queensland Renewable Energy Targets, and more broadly achieve transformation to a lower carbon future. Powerlink has worked closely with the Queensland Government in the development of the QEJP, including the establishment of new Queensland Renewable Energy Zones (QREZ) development areas and providing input on the transmission implications of possible developments in the power system.

As outlined in the QEJP, Powerlink will progress the development of a new higher voltage and capacity transmission system (up to 500kV) from north to south Queensland to act as the super highway for efficient large-scale transportation of renewable energy and storage across the State. This new backbone system will be implemented in stages, and provide one of the cornerstones for enabling energy transformation in Queensland. While not captured in the 2022 TAPR given the timing of the release of the QEJP, work is well underway and insights are provided in Powerlink's 'Actioning the Queensland Energy and Jobs Plan'.

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 2022 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. Two projects were nominated for Preparatory Activities.

The 2023 TAPR will incorporate the QEJP in conjunction with the ISP to inform Powerlink's planning activities.

9.2 Possible network options to meet reliability obligations for potential new loads

The proposals for the connection of new industrial processing loads, including new industry based on hydrogen, and electrification of major industrial processes and mining operations are emerging as the broader economy transforms to a lower carbon future. These potential loads, including possible locations, are listed in Table 3.1.

The relevant resource rich areas include the Northern Bowen Basin and the North West Mineral Province (Mt Isa). There is also the potential for new technology loads and for the conversion of existing mining, industrial and manufacturing processes 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 potential new industrial processing loads, including new industry based on hydrogen, and electrification of major industrial processes and mining operations are within the existing transmission system footprint. However, the connection of the North West Mineral Province[1] to the interconnected National Electricity Market (NEM) will require transmission network extensions to reach this remote location.

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 2.5. 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 options only. 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 preferred 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 and QEJP.

Details of feasible network options are provided in sections 9.2.1 to 9.2.4, for the transmission grid sections potentially impacted by the possible new large loads in Table 3.1.

9.2.1 Northern Bowen Basin coal mining area

Based on AEMO's Step Change scenario forecast defined in Chapter 3, 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.

[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 provisional Transmission Authority.

However, there has been early discussions on electrification of existing mining processes in the Northern Bowen Basin. Electrification load gives consideration to the responses that multi-sector industries will take in line with global efforts to reduce 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.

Early discussions on electrification of existing mining processes could see load increase by up to 600MW. These loads have not reached the required development status to be included in AEMO's Step Change scenario forecast for this TAPR.

This additional load within the Northern 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 6.9).

The impacts these loads may have on the CQ-NQ grid section and possible network solutions to address these is discussed in Section 9.2.2.

Possible network solutions

Mining operations in the Northern Bowen Basin rely heavily on the existing 132kV network to deliver electricity to the area. Much of this infrastructure has limited thermal capacity. To address the potential shortfall in capacity in the transmission and distribution networks, consultation with the customers 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, VRE supply, and transmission requirements.

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 photovoltaic (PV). Given that the 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 fully address the 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 new 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
- advance the rebuild of the 132kV transmission lines that supply the Northern Bowen Basin area as higher capacity 132kV lines with associated capacitive compensation to maintain voltage control. The existing 132kV lines are forecast to reach their end of technical service in the 2040s.

9.2.2 CQ-NQ grid section transfer limit

Based on AEMO's Step Change scenario forecast outlined 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 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 11.3 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 in August 2023 (refer to Table 11.3).

As discussed in Section 9.2.1, there is the likelihood of coal mines in the Northern Bowen Basin electrifying their existing mining operations. There is also the potential load in the North West Mineral Province that may require connection to the NEM.

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 rather than rely on local generation in Mt Isa.

The Copperstring project could also enable further VRE generation in the North Queensland Clean Energy Hub to be connected to the NEM (refer to Figure 9.2) and could result in additional demand of up to 400MW to be supplied from the transmission network in North Queensland.

Therefore, the loads in Table 3.1 could result in a coincident increase in northern Queensland demand of up to 1,010MW but have not reached the required development status to be included in AEMO's Step Change 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.

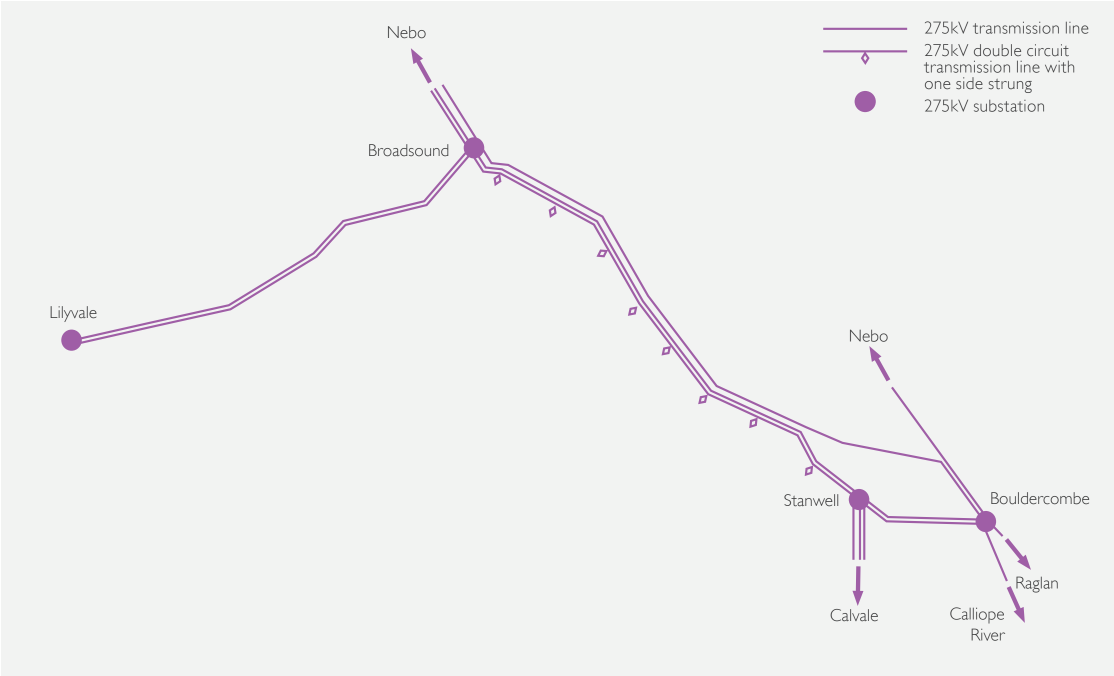
Based on current network analysis, an additional 90MW of load north of Bouldercombe will result in network congestion between Central Queensland and North Queensland that will require dispatch of additional, out-of-merit-order generation in North Queensland. As generation costs are higher in northern 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 could 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.

9 Strategic projects

Figure 9.1 Stanwell/Broadsound area transmission network



9.2.3 Gladstone grid section transfer limit

Based on AEMO's Step Change scenario forecast discussed in Chapter 3, there is approximately 500MW of additional load connected in the Gladstone zone by 2031. This load is associated with electrification of a component of the existing industrial processes within the area.

While Powerlink has no connection point commitments from any direct connect customers in the Gladstone zone at the time of the publication of 2022 TAPR, Powerlink is engaging in early discussions with customers that have committed to decarbonisation of their existing fossil fuelled operations and processes. There has also been a significant number of enquiries for the connection of new industrial processing loads in the Gladstone zone. As indicated in Table 3.1 the combined potential for additional load may be up to 2,360MW.

With reduced operation of the Gladstone Power Station (PS) as the electricity industry transforms to a lower carbon future, in combination with the electrification of existing industrial processes and/or development of new industry load, there will be a significant impact on the transmission capacity required to maintain reliability of supply in the Gladstone zone.

The additional transmission capacity required to meet this increase in load will only be considered in the context of the main 275kV network supplying the Gladstone zone. Network limitations downstream of the main transmission system would also need to be assessed based on specific customer load.

Possible network solutions

Feasible network solutions to facilitate efficient market operation and deliver reliability of supply obligations in the Gladstone zone may include:

- transmission line augmentation between Calvale and Calliope River substations and rebuild of the transmission line between Larcom Creek and Calliope River substations with a high capacity 275kV double circuit transmission line
- construction of a new high capacity 275kV double circuit transmission line between Bouldercombe, Raglan, Larcom Creek and Calliope River
- installation of a third 275/132kV transformer at Calliope River Substation.

9.2.4 Southern Queensland region

Based on AEMO's Step Change scenario forecast defined in Chapter 3, 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, Powerlink is engaging in discussions with corporations for the development of significant new loads in southern Queensland. Fortescue Future Industries (FFI), Powerlink and Economic Development Queensland (EDQ) have signed an agreement to progress a facility at Gibson Island[2] (Southern Queensland Trade Coast Area) to produce around 50,000 tonnes of renewable hydrogen per year. Connection to Powerlink's transmission network is essential to allow electricity produced by VRE generation to power the proposed hydrogen project.

This hydrogen project will add approximately 650MW to the load in SEQ and connect to Powerlink's Murarrie Substation. Network thermal limitations on the 275kV circuits between Belmont and Murarrie substations and between Blackwall and Belmont substations may occur if this new load commits.

Possible network solutions

Feasible network solutions to deliver reliability of supply to the hydrogen facility include:

- 275kV transmission line augmentation between Blackwall, Belmont and Murarrie substations
- 275kV transmission line augmentation between Belmont and Murarrie substations and installation of SmartValve[3] technology to manage thermal overload between Blackwall and Belmont substations
- Establish a 275kV substation at Nudgee and 275kV cable/s between Nudgee and Murarrie substations.

Powerlink will also consider the emerging condition based drivers as part of the planning process to ensure the most cost-effective solutions are delivered for customers. Such decisions will be undertaken using the RIT-T consultation process, where the benefits of non-network options will also be considered, including working with the proponent to identify mutually beneficial non-network options. This may include load flexibility and/or post-contingent interruptability such that investment in network can be deferred or avoided.

Powerlink is also in discussions for development of a large data storage project powered by renewable energy and battery storage[4]. The project is located adjacent to Powerlink's South Pine Substation in North Brisbane. The data centre has a capacity of up to 800MW. In addition, the developer has submitted a planning application for a 2,000MWh Battery energy storage system (BESS).

Depending on the combined operation of the load and BESS, thermal limitations may emerge on the 275kV circuits supplying the South Pine Substation.

Possible network solutions

Feasible network solutions to deliver reliability of supply to the data storage load include:

- 275kV transmission line augmentation between Tarong and South Pine substations
- 275kV or 500kV transmission line augmentation between Halys and South East Queensland (SEQ), including 275kV augmentations within SEQ.

Powerlink will also consider the emerging condition based drivers as part of the planning process to ensure the most cost-effective solutions are delivered for customers. Such decisions will be undertaken using the RIT-T consultation process, where the benefits of non-network options will also be considered, including working with the proponent to identify mutually beneficial non-network options. This may include co-ordination of the BESS to minimise the impact of the load on the network. Load flexibility and/or post-contingent interruptability may also deferred or reduce the scale of network investment required.

2 Refer to Powerlink's website.
3 SmartValve is an innovative, digital power flow control technology that unlocks network capacity by pushing power off overloaded lines or pulling power onto underutilized lines developed by SmartWires.
4 Supernode powered by renewable energy.

9.3 Alignment with AEMO's 2022 Integrated System Plan (ISP)

The 2022 ISP and its optimal development path support Australia's complex and rapid energy transformation towards net zero emissions, enabling low-cost firmed VRE and cost-effective essential transmission services to provide consumers in the NEM with safe and reliable electricity.

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 2022 ISP. The 2022 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.

Two projects were nominated for preparatory activities. These include:

- Darling Downs REZ Expansion (Stage 1)
- QNI Connect (500kV option)

Three additional projects were identified as requiring no action as AEMO will leverage the estimated project costs from previous preparatory activities. These include:

- Central to Southern Queensland reinforcement
- Gladstone Grid reinforcement
- QNI Connect (330kV option).

For each project a Preparatory Report will provide 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
- High level cost estimate.

Preparatory activity reports for the two projects above are to be provided to AEMO by 30 June 2023. This information will be used by AEMO to better inform the optimal development path for the 2024 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 (PACR) on 'Expanding NSW-Queensland transmission transfer capacity' in December 2019. The recommended QNI Minor option included 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. These project works have now been completed by Transgrid. Inter-network testing, as required by NER 5.7.7, is now progressing to release additional capacity to the market in a staged approach. These tests are expected to continue until mid-2023.

The 2020 ISP identified that the additional transmission capacity would deliver net market benefits from

- efficiently maintaining supply reliability 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 and firming services
- enhancing system resilience and optionality.

Building on the QNI Minor project, AEMO's 2020 ISP recommended that Powerlink and Transgrid complete preparatory activities for further QNI interconnector upgrades to be assessed in the 2022 ISP. For the 2022 ISP assessment, Powerlink and Transgrid proposed two 330kV options. One option (stage 1) was a single-circuit strung on a 330kV double-circuit line and the other option (stage 2) was to string the second circuit.

The 2022 ISP identified that further upgrade of the transmission capacity between Queensland and NSW (coined 'QNI Connect') is an integral part of the optimal development plan with a timing as early as 2029-30 in the Hydrogen Export scenario forecast and 2032-33 in the Step Change scenario forecast.

As the likely timing (2032-33) is beyond a practical delivery timing, AEMO has not declared QNI Connect as an actionable project. Rather AEMO has recommended that Powerlink and Transgrid carry out further preparatory activities to better inform options for the 2024 ISP. AEMO requires preparatory activities to be undertaken for a 500kV option for both NSW and Queensland scope. AEMO also requires preparatory activities for the 330kV options for the NSW scope.

Preparatory activities, as outlined in this Section, are to be completed by 30 June 2023 so that estimated costs and capacity improvements can be included in the 2024 Draft ISP.

Possible network solutions

Options to upgrade QNI capacity include both 330kV and 500kV options:

- construction of a double circuit 330kV line (one or two circuits strung) between Powerlink's Braemar Substation and Armidale South 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 and connects to intermediate substations with associated supporting plant.
- construction a double circuit 500kV line between Powerlink's Halys Substation and Transgrid's New England REZ transmission and connecting to intermediate substations with associated supporting plant.

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 section is highly dependent on generation and load in Central and North Queensland. As new generation connects in Central and North Queensland, congestion along this corridor may increase and generation may be curtailed.

Upgrading the capacity of QNI may also add to the congestion of this grid section. As outlined in Section 9.3.1, the 2022 ISP has identified a further upgrade of QNI capacity. 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 6.11.1 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 Table 6.19 and within six to 10 years in Table 6.20.

In the 2020 ISP, AEMO recommended Powerlink complete preparatory activities to increase transfer capability from CQ-SQ grid section. For the 2022 ISP, two options were selected. One option makes use of the existing transmission line with a mid-point switching station between Calvale and Halys substations. The other option includes a new double-circuit transmission line. For the 2024 ISP, since no changes are anticipated for this project, AEMO will escalate the estimated cost of the preparatory activities delivered for the 2022 ISP.

The 2022 ISP identified a staged approach to upgrade CQ-SQ as part of the optimal development path. The upgrade is critical for unlocking VRE resources in the North, Isaac, and Fitzroy REZs to deliver efficient market outcomes.

Under the Step Change scenario forecast an incremental upgrade was identified as economic by 2028-29. This involves establishing a mid-point switching station on the Calvale to Halys 275kV transmission line. By 2038-39 a more material upgrade has been identified as economic, involving the construction of a new 275kV double circuit transmission line between Calvale and Wandoan South substations.

Possible network solutions

Feasible network solutions to facilitate efficient market operation may differ in scale. These include:

- establishment of a mid-point switching substation on the 275kV double circuit between Calvale and Halys substations
- construction of a 275kV double circuit transmission line between Calvale and Wandoan South Substation
- construction of a 500kV double circuit transmission line between Central Queensland and Halys Substation
- a grid-scale battery system. A Virtual Transmission Line (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 scheme on the northern side
- A 1,500MW HVDC bi-pole overhead transmission line from Calvale and South West Queensland.

Powerlink, through the ISP process and modelling associated with the QEJP, will continue to investigate the impact of investment in large-scale VRE generation and firming generation in the Queensland region on the utilisation and economic performance of the CQ-SQ grid section. Powerlink also considers the emerging condition based drivers as part of the integrated planning process to ensure that overall the most cost-effective solutions are delivered for customers. Such decisions will be undertaken using the RIT-T consultation process, where the benefits of non-network options will also be considered.

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.

The 2022 ISP identified significant increases in VRE generation for the North, Isaac, and Fitzroy REZs (refer to Figure 9.3). With this additional generation and the retirement or reduced generation from Gladstone PS, the transmission network which supplies the Gladstone area will be constrained. As a result, forecast demand at Boyne Island, Calliope River, Larcom Creek and Raglan substations cannot be supplied. If major industrial loads are electrified, or if large hydrogen projects progress, there is a potential for a material shift in the supply-demand balance in the Gladstone area.

In the 2020 ISP, AEMO recommended Powerlink complete preparatory activities for reinforcement of Gladstone grid section. New 275kV transmission lines are proposed to increase the network transfer capability between Central West and Gladstone zones. For the 2024 ISP, since no changes are anticipated for this project, AEMO will escalate the estimated cost from the preparatory activities delivered for the 2022 ISP.

Under the Step Change scenario forecast, the 2022 ISP identified a need to materially upgrade the transmission capacity from Calvale and Bouldercombe substations into the Gladstone zone and also increase the 275/132kV transformation capacity in the Gladstone zone.

Possible network solutions

- Feasible network solutions to facilitate efficient market operation and also deliver reliability of supply obligations in the Gladstone zone 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.

Powerlink, through the ISP process and modelling associated with the QEJP, will continue to investigate the impact that investment in large-scale VRE generation and firming generation, reduced operation of the Gladstone PS and electrification of existing industrial processes and/or development of new industry load will have on the utilisation and economic performance of the Gladstone grid section. Powerlink will also consider the emerging condition based drivers as part of the integrated planning process to ensure that overall the most cost-effective solutions are delivered for customers.

9.3.4 Darling Downs REZ Expansion

The Darling Downs REZ extends from the border of NSW near Dumaresq to Columboola within the Surat zone of Queensland. The Darling Downs REZ has high network capacity and is near QNI and Brisbane. The area has abundant high quality solar and wind resources. A number of large scale and wind projects are already connected or committed within the zone (refer to Table 8.1 and Table 8.2). Furthermore, the ultimate retirement of thermal generation within this REZ will also release network capacity to allow for additional VRE connections. However, given the abundant high quality solar and wind resources in this REZ and that the energy transformation will require much more renewable generation to connect in the REZ, expansion of the Darling Downs REZ will be required.

The Darling Downs REZ connects to South East Queensland (SEQ) across two transmission corridors; a northern corridor that consists of five 275kV transmission circuits from the Tarong Substation to SEQ and a southern corridor that consists of two 330kV transformer ended (330/275kV) circuits between Millmerran and Middle Ridge substations.

The 2022 ISP analysis found that under high demand conditions, this southern corridor can only facilitate 1,300MW into SEQ from generation connected around the Bulli Creek area. This is due to a 300/275kV transformer limitation at the Middle Ridge Substation. Therefore, VRE generation will need to connect around the Halys area to increase the overall VRE hosting capacity of the Darling Downs REZ.

Notwithstanding connection of VRE generation to the more northern regions of the REZ, the 2022 ISP identifies that the Middle Ridge transformer rating is a limitation to the development of the Darling Downs REZ. The 2022 ISP identified the earliest timing for this expansion as 2025-26 in the Hydrogen Export scenario forecast and 2028-29 in the Step Change scenario forecast. The timing of these upgrades will also be influenced by generation retirements and any QNI upgrades. AEMO has identified expansion of the Darling Downs REZ for preparatory activities.

Possible network solutions

- Feasible network solutions to expand the capacity of the Darling Downs REZ include:
- Replacement of the existing 1,300MVA 330/275kV transformer at Middle Ridge with 1,500MVA 330/275kV transformer
- Replacement of both 330/275kV transformers at Middle Ridge with 330/275kV 1500MVA phase-shifting transformers
- Replacement of the existing 1,300MVA 330/275kV transformer at Middle Ridge with 1,500MVA 330/275kV transformer and installation of 1,500MVA 330kV phase-shifting transformers at Tummaville Substation[5]
- Implementation of a Special Protection scheme (SPS) involving pairing a large-scale BESS and generation runback within REZ
- 500kV double-circuit network expansion from of Halys Substation to SEQ.

Powerlink, through the ISP process and modelling associated with the QEJP, will continue to investigate the impact that investment in large-scale VRE generation and reduced operation of the thermal generation in the Darling Downs REZ area has on the utilisation and economic performance of the transmission between the Darling Downs REZ and SEQ. Powerlink will also consider the emerging condition based drivers as part of the integrated planning process to ensure that overall the most cost-effective solutions are delivered for customers.

9.3.5 ISP Renewable Energy Zones

As the NEM transforms away from synchronous generation 44GW and 141GW of VRE is forecast to be installed by 2030 and 2050 respectively under AEMO's Step Change scenario forecast in the 2022 ISP. This is allowing for strong growth in Distributed Energy Resources (DER).

In Queensland, under AEMO's 2022 ISP Step Change scenario forecast, approximately 48GW of new utility-scale wind and solar VRE is projected to be required by 2050 to assist in replacing retiring generation. Figure 9.2, sourced from the 2022 ISP, shows the REZ definitions for the Queensland region. Figure 9.3, also sourced from the 2022 ISP, shows the utility-scale VRE projected for each REZ in Queensland for the Step Change scenario forecast.

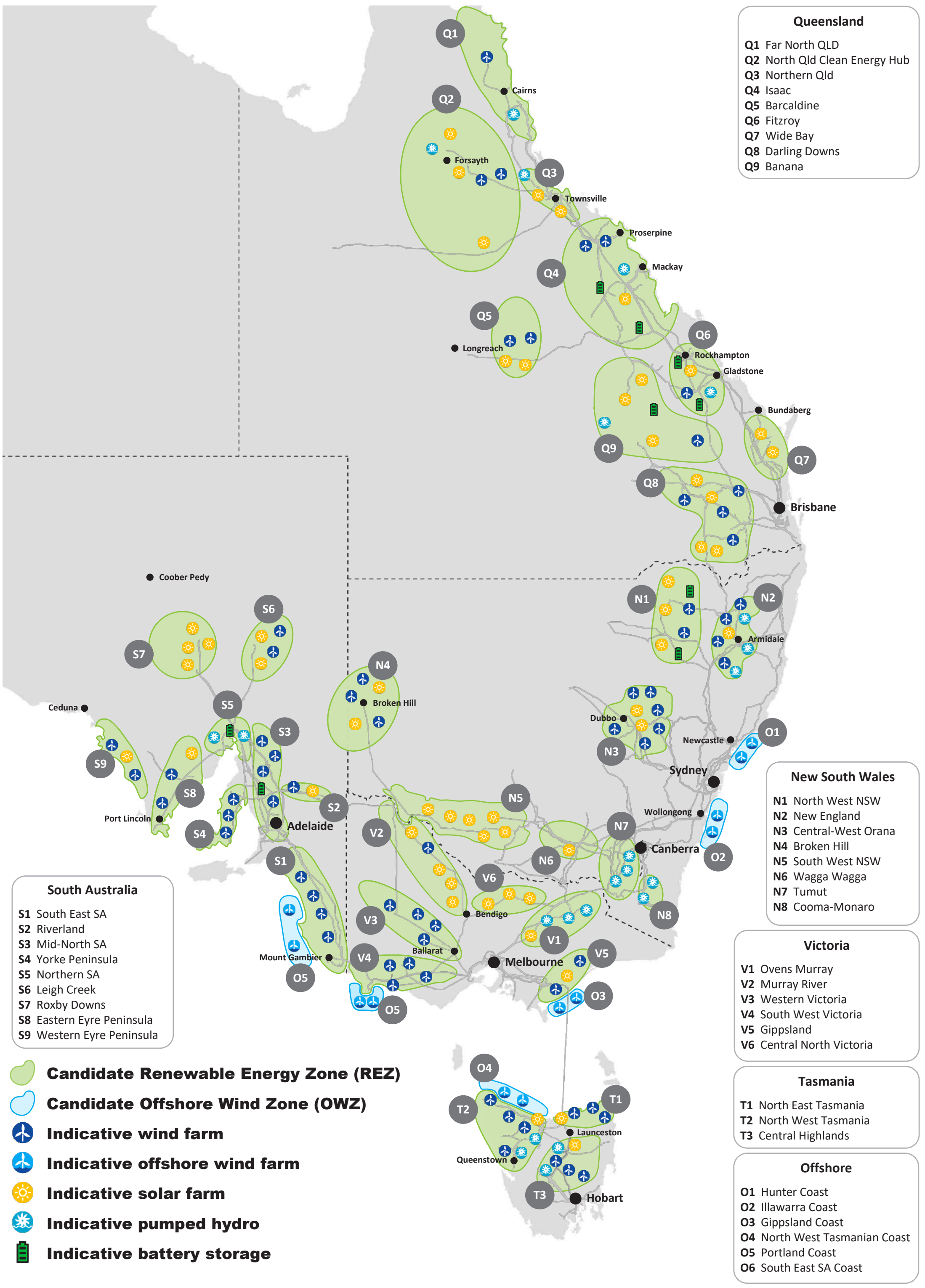
The 2022 ISP modelling shows, under the Step Change scenario:

- All REZs (to different degrees) in Queensland contribute the Queensland developing 48GW of utility-scale VRE by 2050
- Materially, VRE developments are mostly split between the Fitzroy and Darling Downs REZs, with large developments also occurring in the Banana REZ after 2040
- Darling Downs REZ sees the largest amount of projected new VRE capacity, with immediate developments taking advantage of the spare network capacity, and with 4,000MW of new VRE by 2033, and 10,000MW by 2042.
- There is an increase in VRE in the Fitzroy REZ, with over 3,000MW new VRE capacity installed by 2031. By 2040 this has increased to over 10,000MW.
- The Banana REZ is projected to see developments later in the scenario, with 9,500MW new VRE capacity by 2050.

In recognition of the potential value of REZ developments across Queensland and the three Queensland Renewable Energy Zones (QREZ) in the north, central and southern regions[6] that overlay the ISP REZ, the Queensland Government announced $145 million for REZ support (refer to Section 2.3.1). Powerlink will continue to work with Government, AEMO, stakeholders and customers to drive the most efficient and cost-effective outcomes from this process.

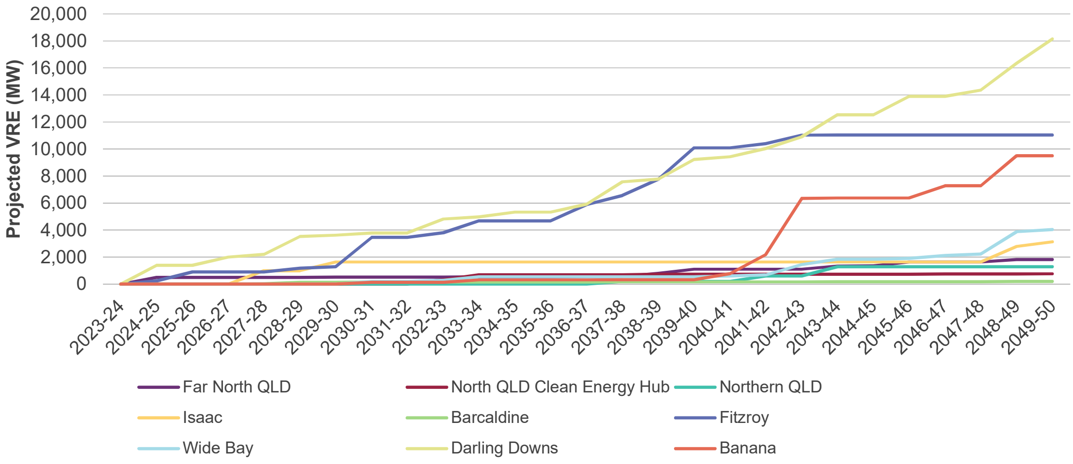
5 MacIntyre Wind Precinct project
6 Refer to Figure 6.4.

Figure 9.2 2022 ISP Renewable Energy zones



Source: AEMO

Figure 9.3 Queensland utility-scale VRE development in REZs for the Step Change scenario



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 (wind and solar PV) 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 power systems analysis using Electromagnetic Transient-Type (EMT-type) modelling for Queensland.
- Through active collaboration with solar and wind farm proponents and associated equipment manufacturers, Powerlink is implementing innovative cost-effective technical solutions to maximise the VRE hosting capacity of the Queensland transmission network and reduce the connection costs of proponents.
- Powerlink is working closely with the Queensland Government on the establishment of new Queensland Renewable Energy Zones (QREZ) development areas.

10.1 Introduction

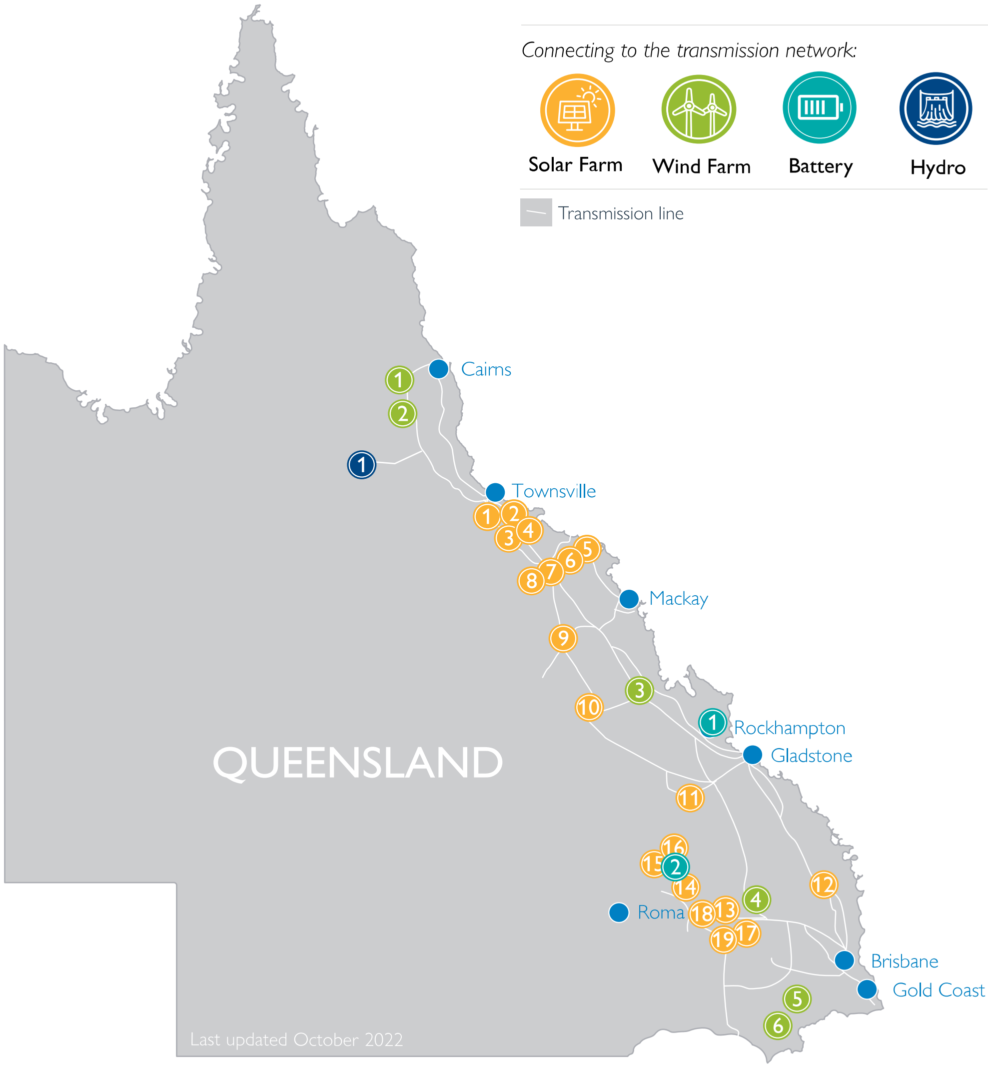
Queensland is rich in a diverse range of renewable resources – solar, wind, geothermal, biomass and hydro. This makes Queensland an attractive location for large-scale VRE generation development projects. During 2021/22, 740MW of semi-scheduled VRE generation capacity has been committed in the Queensland region, taking the total to 4,935MW 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 22 (21 VRE + 1 BESS) large-scale solar, wind farm and Battery energy storage system (BESS) projects in Queensland, adding 3,130MW of generation capacity to the grid. A significant number of formal connection applications, totalling about 11,000MW of new generation capacity, have been received and are at varying stages of progress.

To date, 3,595MW of VRE generation have connected or committed with Powerlink. Approximately 1,340MW of embedded semi-scheduled renewable energy projects exist or are committed to Energy Queensland's network. In addition to the large-scale VRE generation development projects, rooftop photovoltaic (PV) in Queensland exceeded 4,808MW in July 2022.

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 Under construction and existing connection projects since 2018



10 Renewable energy

Table 10.1 Under construction and existing connection projects since 2018

Map ID	Generator	Location	Available capacity MW generated (1)
Hydro-electric (1)			
1	Kidston Pumped Hydro Storage	Kidston	250
Solar PV (2)			
1	Ross River	Ross	116
2	Sun Metals	Townsville Zinc	121
3	Haughton	Haughton River	100
4	Clare	Clare South	100
5	Whitsunday	Strathmore	57
6	Hamilton	Strathmore	57
7	Daydream	Strathmore	150
8	Hayman	Strathmore	50
9	Rugby Run	Moranbah	65
10	Lilyvale	Lilyvale	100
11	Moura	Moura	82
12	Woolooga Energy Park	Woolooga	176
13	Blue Grass	Chinchilla	148
14	Columboola	Columboola	162
15	Gangarri	Wandoan South	120
16	Wandoan South	Wandoan South	125
17	Edenvale Solar Park	Orana	146
18	Western Downs Green Power Hub	Western Downs	400
19	Darling Downs	Braemar	108
Wind (2)			
1	Mt Emerald	Walkamin	180
2	Kaban (3)	Tumoulin	152
3	Clarke Creek (3)	Broadsound	440
4	Coopers Gap	Coopers Gap	440
5	MacIntyre (3)	Tummaville	922
6	Karara (3)	MacIntyre Intermediate Switching Station	103
Battery (2)			
1	Bouldercombe 2h BESS (3)	Bouldercombe	50
2	Wandoan South 1.5h BESS	Wandoan South	100

Notes:

(1) Shown at full capacity. However, output can be limited depending on water storage levels.

(2) VRE generators and batteries shown at maximum capacity at the point of connection. The capacities are nominal as the generator rating depends on ambient conditions.

(3) Generators undergoing construction are shown at future maximum expected capacity at the point of connection. Actual available generating capacity will vary over the course of the commissioning program.

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 Australian Energy Market Commission's (AEMC) investigation into System Strength Frameworks
- how Powerlink has and continues to meet the system strength challenges
- the fault level shortfall declared by Australian Energy Market Operator (AEMO) in December 2021 and updated in May 2022 and how Powerlink is addressing this shortfall
- the current system strength environment and the opportunities for future investment in VRE generation.

10.2 Current management of system strength and National Electricity Rules (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 the location of fault level nodes 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 10.2). 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.

1 Obligation on the connecting generator to 'do no harm' came into effect 17 November 2017 with AEMO publishing the 'System Strength Impact Assessment Guidelines' in 2018

2 Displacement may occur for periods when it is not economic for a synchronous generator to operate, and is distinct from

In May 2022[3] AEMO published an update to the system strength and inertia assessments for the NEM. In Queensland, the previous inertia shortfall[4] was removed due to improved outlook for available fast frequency control ancillary services (FCAS), but a potential future shortfall remains a possibility as the market changes. However, for system strength AEMO declared a fault level shortfall, under Clause 5.20C.2(c) of the NER, at the Gin Gin 275kV node. Powerlink's response to this declared fault level shortfall 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.

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.

AEMO has published the System Strength Requirements Methodology (SSRM), and is consulting on the System Strength Impact Assessment Guidelines (SSIAG) and the Power System Stability Guidelines (PSSG) in accordance with clauses 5.20.6, 4.6.6, 4.3.4 and the Rules consultation procedures in rule 8.9 of the NER to operationalise the AEMC Rule change. The NER requires AEMO to publish the final SSIAG by 30 November 2022. Powerlink is working very closely with AEMO on this important change.

retirement which is permanent removal from the market.

3 AEMO published an update to the December 2021 System Security Reports in May 2022. The update accounted for the identification of the Step Change scenario as the most likely of the development scenarios for AEMO's 2022 Integrated System Plan (ISP).

4 AEMO published the initial system strength and inertia assessments for the NEM in December 2021 based on the Progressive Change scenario.

Key dates in the implementation of this new system strength Rule change include:

- By 30 November 2022, TNSPs must update their pricing methodologies to include the new requirements to provide the minimum level of system strength together with the efficient level of system strength to host the forecast of VRE generation and submit it to the Australian Energy Regulator (AER) for approval. The AER must publish its final decision on the proposed amended pricing methodology by 31 January 2023.
- By 1 December 2022, AEMO is to publish its first system strength report that defines the binding system strength requirements for TNSP's (that are System Strength Service Providers) for three years' time (December 2025). The fault level shortfall framework described in Section 10.2 is retained for a period of three years.
- From 15 March 2023, the new access standards commence and system strength mitigation requirement commences, replacing the existing 'do no harm' obligations, such that parties pay the system strength charge or self-remediate. TNSPs are also required to publish transmission prices that include the system strength charge.
- An applicant who submits a connection enquiry by 15 March 2023 will come under the new system strength mitigation requirement and access standard arrangements.
- An applicant who submits an application to connect by 15 March 2023, but has not received an offer to connect, will come under the existing arrangements, unless the applicant requests the NSP to process them under the new framework.
- From 1 July 2023 the system strength charges come into effect.

10.3 Understanding system strength is essential to meet future challenges

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 allows Powerlink to quickly process generator connections and is a comprehensive model with the inverter-based plants modelled at the controller level and with simulation time steps in micro-seconds.

Powerlink undertakes a Full Impact Assessment (FIA) using system-wide EMT–type model for all VRE generation applying to connect to the Powerlink network regardless of the size of the proposed plant. This is because only an EMT-type analysis can provide information on the impact of potentially unstable interactions with other generators at this stage. Powerlink is exploring a novel method using small signal analysis to understand the impact of potentially unstable interactions with other generators. 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[5] 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.

5 AEMO, Power System Model Guidelines, July 2018.

10.3.1 Increasing renewable energy hosting capacity

Powerlink continues to work closely with AEMO, developers and inverter manufacturers to maximise the VRE generation hosting capacity of the Queensland transmission network.

Powerlink has redesigned and commissioned changes to the voltage controller at nine Static VAr Compensators (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 innovative solution has substantially reduced the proponent's connection costs compared to the much higher priced system strength remediation that would otherwise have been required.

The changing 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.

Powerlink has also worked with developers and equipment manufacturers to explore and implement changes to controller settings and plant voltage control strategies. 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. These changes have addressed controller interactions that would otherwise limit the VRE hosting capacity and significantly increase system strength remediation costs to developers. Powerlink is now requesting that this same voltage control strategy be adopted as a proactive measure for new proponents connecting in South Queensland in order to minimise the cost of connections.

Further to these initiatives, that have now influenced the approach by other TNSPs and AEMO, Powerlink is exploring the role that 'grid forming' inverter technology can play in supplying the synthetic inertia and in the portfolio of solutions available to System Strength Service Providers (SSSP) in meeting the efficient level of system strength under the new Rule discussed in Section 10.2.

Initially Powerlink has received funding from Australian Renewable Energy Agency (ARENA) to investigate technical, commercial and regulatory solutions to address system strength challenges. There were several stages to this project[6]. The final stage focused on building an understanding of the role grid forming inverter (GFI) technology with battery (referred to as 'grid forming battery') can play in contributing to system strength. Powerlink modelled a 'grid forming' battery solution from a manufacturer in system-wide EMT-type analysis. The analysis demonstrated that the 'grid forming' battery could increase the system strength and help support the operation of VRE generation in a similar manner to synchronous condensers.

The analysis demonstrated that advanced inverter controls can facilitate a higher penetration of inverter-based renewable generation (e.g. wind and solar) without compromising grid stability. ARENA published the Powerlink report on the outcome of this assessment in April 2021[7].

10.4 Declaration of fault level shortfall at Gin Gin node

In December 2021 AEMO published the 2021 System Security Reports. System strength and inertia assessments for this report were based on the Progressive Change scenario. For the Queensland region, AEMO identified a fault level shortfall at the Gin Gin 275kV fault level node and an inertia shortfall.

In May 2022, the system strength and inertia assessment for the NEM was updated to reflect the identification of the Step Change scenario as the most likely of the development scenarios for AEMO's 2022 Integrated System Plan (ISP). The update removed the previous inertia shortfall due to improved outlook for available fast frequency control ancillary services (FCAS), but a potential future shortfall remains a possibility as the market conditions change. However, for system strength AEMO reaffirmed a fault level shortfall, under Clause 5.20C.2(c) of the NER, at the Gin Gin 275kV fault level node.

The minimum three phase fault levels, from AEMO, for the Queensland fault level nodes are shown in Table 10.2.

6 Powerlink, Managing System Strength During the Transition to Renewables, May 2020.
7 PSCAD Assessment of the Effectiveness of Grid Forming Batteries.

Table 10.2 Three phase fault levels for Queensland fault level nodes

Fault level node	2021 minimum fault level (MVA) (post-contingency)
Ross 275kV	1,175
Lilyvale 132kV	1,150
Gin Gin 275kV	2,250
Western Downs 275kV	2,550
Greenbank 275kV	3,750

The declared fault level shortfall is a result of AEMO's market model forecasting lower synchronous generator dispatches in Central Queensland compared to dispatches that define the current minimum fault level requirements in Table 10.2. The forecast synchronous generator dispatches are from AEMO's 2022 ISP Step Change scenario. The shortfall ranges from 33MVAr to 90MVAr and will exist for the full five year outlook at the Gin Gin 275kV fault level node.

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. Powerlink must use reasonable endeavours to make the system strength services available by the date of 31 March 2023, as specified by AEMO in the notice issued under clause 5.20C.2(c) of the NER.

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 the Gin Gin 275kV fault level node (refer to Section 6.8).

In this instance the declared fault level shortfall is at the Gin Gin 275kV fault level node. However, consideration of the declared shortfall location in isolation may not capture technical components of the system strength shortfall or indicate from where the particular problem is most efficiently addressed. Both of these can only be informed through system-wide EMT-type analysis and in the context of the location and technical nature of any proposed solutions. That is, options which address the technical power system performance issues elsewhere in Central and North Queensland may reduce or remove the fault level shortfall at the Gin Gin 275kV fault level node.

Submissions for the EOI closed on 24 June 2022 and Powerlink is currently reviewing and evaluating proposals and submissions to address the identified shortfall and to meet regulatory obligations. Submissions were received from seven proponents with nine proposed solutions. These included operation of existing generators, gas turbine synchronous condenser conversions, BESS and Pumped Hydro Energy Storage (PHES).

Powerlink is currently clarifying submission information and performing technical and economic feasibility assessments for system security shortfall. Following detailed assessment of the selected solutions, Powerlink will negotiate contract terms, engage with AEMO and seek approval to execute the contract/s to meet the required timeframes and requirements.

The agreed system strength response to the declared shortfall at the Gin Gin 275kV fault level node is planned to be published in March 2023.

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.

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 focused on delivering a timely and transparent connection process to connecting generators including coordination of the physical connection works, GPS and system strength.

10.6 Developing Renewable Energy Zones (REZ)

Queensland Energy and Jobs Plan (QEJP) modelling indicates that 25GW of renewable generation is required by 2035. Looking beyond 2035, it is likely that Queensland will need even more renewable generation, when taking account of additional electricity demand created by new industries and electrification of existing industries such as mining and electric vehicle (EV) uptake. AEMO's 2022 ISP Step Change scenario suggests Queensland will require 48GW of renewable generation by 2050.

To facilitate this level of renewable energy connection, Powerlink is working with the Queensland Government on the establishment of new Queensland Renewable Energy Zones (QREZ) development areas. Development of a REZ allows multiple grid-scale renewable energy developments to be connected in a geographic location to realise economies of scale in REZ infrastructure and enable renewable connections in a more cost-effective and coordinated manner. An uncoordinated approach, where developers act independently, is unlikely to support scale-efficient and least-cost generation developments sufficient to meet Queensland's needs.

The coordination availed by REZ developments will facilitate a better forecast of the specific location, mix, timing and type of renewable energy connections. This will also assist Powerlink plan and implement cost-effective solutions to provide the necessary efficient levels of system strength. REZs will also be coordinated with broader investments in the interconnected transmission system, energy storage and other firming services. Therefore, REZs allows Powerlink to optimise where renewable energy is connected and integrated within the existing system to achieve renewable targets at least overall cost to customers.

Section 2.3 provides details of initial REZ development plans in Northern, Central and Southern Queensland. The combined hosting capacity of these initial plans is approximately 7GW. Therefore, considerably more needs to occur to have 25GW of renewable energy generation connected by 2035. In response, Powerlink is working on developing further REZs. The REZ development approach will facilitate efficient network connection and speed to market for Powerlink's generation proponents.

These next renewable energy plans are in development with the Queensland Government and take into account modelling outcomes from the 2022 ISP, Queensland Energy and Jobs Plan, resource mapping and market intelligence from existing and future proponents. Powerlink considers that broadly this offers the most efficient and cost-effective delivery mechanism for the grid-scale renewable energy developments required. Notwithstanding, individual connections to existing transmission infrastructure will remain an option. Powerlink encourages potential proponents to engage with Powerlink early in development planning process such that the best outcome for all parties can be achieved.

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.

To maximise the output from VRE generators under planned outages, Powerlink is developing a Wide Area Monitoring, Protection and Control System (WAMPAC) based Special Protection Scheme (SPS). This scheme will monitor the status of major transmission lines in North and Central Queensland in real time and send a trip command to pre-selected VRE generators. The scheme will also allow VRE generators in North and Central Queensland to operate at much higher output reducing generator constraints.

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 semi-scheduled 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 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 for more detail on potential future network development as well as emerging constraints.

MLFs have also emerged as an important consideration for new generator entrants, 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. However, this same situation may emerge in NQ as more large-scale wind farms connect to the transmission network.

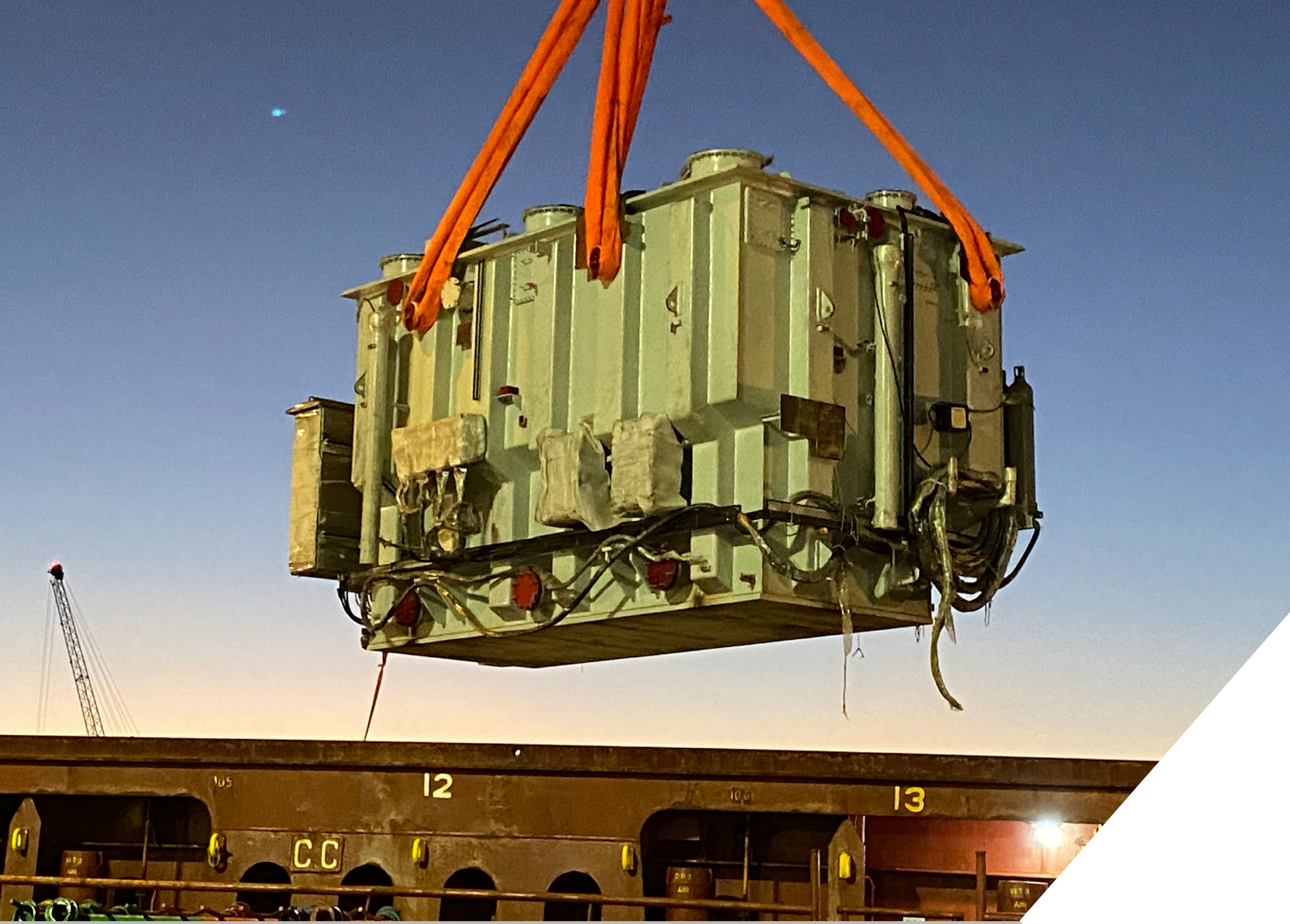
MLF reductions across NQ provide an opportunity for additional loads (or storage) to locate in NQ.

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 2021/22, Powerlink's delivery efforts have continued to be predominantly directed towards reinvestment in transmission lines and substations across Powerlink's network.
- Powerlink's investment program is focused 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.
- Major projects completed since publication of the 2021 Transmission Annual Planning Report (TAPR), such as the line refit works on the 132kV transmission line between Egans Hill and Rockhampton substations, Mackay Substation replacement, Gin Gin Substation rebuild and Ashgrove West Substation replacement, continue to ensure the safe and reliable supply of electricity to townships, local communities, industry and businesses across Queensland.
- Powerlink continues to support the development of all types of energy projects requiring connection to the transmission network in Queensland, with connection works for 1,640MW of variable renewable energy (VRE) generation developments and a Battery energy storage system (BESS) underway at the time of 2022 TAPR publication.
- During 2021/22, Powerlink has completed four projects to connect new VRE developments which are expected to add 528MW 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 2021 TAPR was published.

Table 11.1 lists connection works commissioned since Powerlink's 2021 TAPR was published.

Table 11.2 lists new transmission connection works for generating systems which are committed and under construction at October 2022. 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 2022.

Table 11.4 lists network reinvestments commissioned since Powerlink's 2021 TAPR was published.

Table 11.5 lists network reinvestments which are committed at October 2022.

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 2022.

Table 11.7 lists asset retirement works at October 2022.

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 2021

Project (1)	Purpose	Zone	Date commissioned
Kaban Green Power Hub	New Wind Farm	Far North	Quarter 3 2022
Moura Solar Farm	New Solar Farm	Central West	Quarter 4 2021
Bluegrass Solar Farm	New Solar Farm	Surat	Quarter 3 2022
Edenvale Solar Farm	New Solar Farm	Surat	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 11.2 Committed and under construction connection works at October 2022

Project (1)	Purpose	Zone	Proposed commissioning date
Kidston Pumped Storage Hydro	New pumped hydro energy storage	Ross	Quarter 2 2024
Clarke Creek Wind Farm	New Wind Farm	Central West	Quarter 3 2023
Bouldercombe BESS	New BESS	Gladstone	Quarter 2 2023
Wandoan Solar Farm	New Solar Farm	Surat	Quarter 4 2022

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) At the time of publication of the 2022 TAPR, Powerlink has signed an agreement for the construction of assets for the connection of the MacIntyre Wind Precinct proposed renewable development to the transmission network in south-west Queensland. Refer to Section 6.6.3.

Table 11.3 Committed network developments at October 2022

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
Broadsound 275kV bus reactor	Maintain voltages in the Central West zone	Central West	August 2023

Table 11.4 Commissioned network reinvestments since October 2021

Project	Purpose	Zone	Date commissioned
Life extension works on the 132kV transmission line between Barron Gorge and Kamerunga substations	Maintain supply reliability in the Far North zone	Far North	December 2021
Mackay Substation replacement	Maintain supply reliability in the North zone	North	November 2021
Bouldercombe transformer replacement	Maintain supply reliability in the Central West zone (3)	Central West	September 2021
Moura Substation replacement	Maintain supply reliability in the Central West zone (1)	Central West	December 2021
Line refit works on the 132kV transmission line between Egans Hill and Rockhampton substations	Maintain supply reliability in the Central West zone (2)	Central West	March 2022
Calliope River 275kV tower refit	Maintain supply reliability in the Gladstone zone	Gladstone	November 2021
Gin Gin Substation rebuild	Maintain supply reliability in the Wide Bay zone (4)	Wide Bay	November 2021
Ashgrove West Substation replacement	Maintain supply reliability in the Moreton zone (2)(3)(4)	Moreton	July 2021
Belmont 275kV secondary systems replacement	Maintain supply reliability in the Moreton zone (2)	Moreton	February 2022

Notes:

(1) Major works were completed in October 2017. Minor works were coordinated with Energy Queensland (Energex and Ergon Energy are part of the Energy Queensland Group) and have now been completed.

(2) Projects impacted by restrictions related to COVID-19.

(3) Formal notification of project commissioning coincided with the publication of the 2021 TAPR.

(4) Project identified under the RIT-T transitional arrangements in place for committed projects between 18 September 2017 and 30 January 2018.

Table 11.5 Committed network reinvestments at October 2022

Project	Purpose	Zone	Proposed commissioning date
Woree SVC secondary systems replacement	Maintain supply reliability in the Far North zone	Far North	December 2023
Woree secondary systems replacement	Maintain supply reliability in the Far North zone	Far North	October 2024
Chalumbin secondary systems replacement	Maintain supply reliability in the Far North zone	Far North	October 2025
Cairns secondary systems replacement	Maintain supply reliability in the Far North zone	Far North	December 2027
Garbutt configuration change	Maintain supply reliability in the Ross zone	Ross	May 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 275/132kV transformers life extension	Maintain supply reliability in the Ross zone	Ross	October 2025
Ross 275kV primary plant replacement	Maintain supply reliability in the Ross zone	Ross	November 2025
Ross 132kV primary plant replacement	Maintain supply reliability in the Ross zone	Ross	November 2025
Line refit works on the 132kV transmission line between Eton tee and Alligator Creek substations	Maintain supply reliability in the North zone (1)	North	June 2023
Strathmore 132kV secondary systems replacement	Maintain supply reliability in the North zone	North	December 2023
Strathmore 275/132kV transformer establishment	Maintain supply reliability in the North zone	North	December 2023
Nebo primary plant and secondary systems replacement	Maintain supply reliability in the North zone (2)	North	June 2024
Nebo 132/11kV transformer replacements	Maintain supply reliability in the North zone	North	June 2024
Kemmis secondary systems replacement	Maintain supply reliability in the North zone	North	October 2024
Newlands 132kV primary plant replacement	Maintain supply reliability in the North zone	North	January 2026
Baralaba secondary systems replacement	Maintain supply reliability in the Central West zone	Central West	January 2023
Dysart 132/66kV transformers replacement	Maintain supply reliability in the Central West zone (1)	Central West	June 2023

Table 11.5 Committed network reinvestments at October 2022 (*continued*)

Project	Purpose	Zone	Proposed commissioning date
Bouldercombe primary plant replacement	Maintain supply reliability in the Central West zone	Central West	June 2023
Calvale and Callide B secondary systems replacement	Maintain supply reliability in the Central West zone (1)(2)(3)	Central West	December 2023
Blackwater 66kV CT and VT replacement	Maintain supply reliability in the Central West zone	Central West	December 2023
Blackwater 132/66kV transformers replacement	Maintain supply reliability in the Central West zone	Central West	December 2024
Lilyvale 132/66kV transformers replacement	Maintain supply reliability in the Central West zone (2)	Central West	October 2025
Lilyvale 275kV and 132kV primary plant replacement	Maintain supply reliability in the Central West zone (2)	Central West	November 2026
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
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	November 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	March 2023
Tarong secondary systems replacement	Maintain supply reliability in the South West zone (1)(2)	South West	December 2022
Abermain 110kV secondary systems replacement	Maintain supply reliability in the Moreton zone(2)	Moreton	September 2023
Palmwoods 275kV secondary systems replacement	Maintain supply reliability in the Moreton zone (2)	Moreton	December 2022
Line refit works on the 110kV transmission lines between South Pine and Upper Kedron	Maintain supply reliability in the Moreton zone	Moreton	July 2023
Line refit works on the 110kV transmission lines between West Darra and Sumner	Maintain supply reliability in the Moreton zone	Moreton	August 2023
Line refit works on the 110kV transmission lines between Rocklea and Sumner	Maintain supply reliability in the Moreton zone	Moreton	September 2023
Mt England 275kV secondary systems replacement	Maintain supply reliability in the Moreton zone	Moreton	August 2024

Table 11.5 Committed network reinvestments at October 2022 (***continued***)

Project	Purpose	Zone	Proposed commissioning date
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) Projects impacted by restrictions related to COVID-19. A number of projects have also been deferred 12+ months.

(3) The majority of Powerlink's staged works are anticipated for completion by summer 2023. Remaining works associated with generation connection will be coordinated with the customer.

Table 11.6 Uncommitted network investments at October 2022

Project	Purpose	Zone	Proposed commissioning date
Line refit works on the 275kV transmission lines between Chalumbin and Woree substations (section between Davies Creek and Bayview Heights)	Maintain supply reliability to the Far North and Ross zones (1)	Far North	July 2025
Kamerunga 132kV Substation replacement	Maintain supply reliability in the Far North zone (1)(2)	Far North	December 2027
Innisfail secondary systems replacement	Maintain supply reliability in the Far North zone (1)	Far North	June 2028
Chinchilla 132kV Substation replacement	Maintain supply reliability in the South West zone (1)	South West	December 2025
Tarong 275/66kV transformers and selected primary plant replacement	Maintain supply reliability in the South West zone (1)	South West	December 2025
Redbank Plains 110/11kV transformers and selected primary plant replacement	Maintain supply reliability in the Moreton zone (1)	Moreton	October 2025

Notes:

(1) Capital expenditure in relation to network asset replacement.

(2) RIT-T has been completed. During detailed design and delivery planning it was identified that the staging required to deliver the works were not feasible and alternative options are being investigated. Further information will be available in the 2023 TAPR.

Table 11.7 Asset retirement works at October 2022 (1)

Project	Purpose	Zone	Proposed retirement date
Cairns 132/22kV Transformer 4 retirement	Removal of asset at the end of technical life in the Far North zone	Far North	December 2027
132kV transmission line retirement between Townsville South and Clare South substations	Removal of assets at the end of technical life in the Ross zone	Ross	June 2028
Tarong 275/132kV transformers retirement	Removal of assets at the end of technical life in the South West zone	South West	June 2024
Belmont 275/110kV Transformer 2 decommissioning	Removal of asset at the end of technical life in the Moreton zone	Moreton	March 2023
Belmont 275/110kV Transformer 3 decommissioning	Removal of asset at the end of technical life in the Moreton zone	Moreton	December 2023
Mudgeeraba 275/110kV Transformer 3 retirement	Removal of asset at the end of technical life in the Gold Coast zone	Gold Coast	June 2025

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 2022

11 Current, recently commissioned and committed network developments

Appendices

Appendix A Forecast of connection point maximum demands

Appendix A addresses National Electricity Rules (NER) (Clause 5.12.2(c)(I)[1] which 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, and externally sourced Distributed Energy Resource (DER) forecast from an external consultant. The economic forecasts from Deloitte Access Economics are also utilised.

The methodology used to develop the system demand forecast, is as follows:

Ergon

- A six-region based forecast model within the Ergon network, with the aggregation of regions to provide a system peak 50% PoE. Each regional forecast uses a semi-parametric model to determine the relationship between demand and Gross State Product (GSP), population growth, temperature, lags of temperature, other weather variables and holiday periods. A Monte-Carlo process is used across the 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 and population forecast
- Looking at n number of half hourly simulated demand traces a max of each of the simulated traces is used to capture a distribution of n max demand occurrences for each summer season going into the future. This include calculating of the respective POE 50 and POE 10 for the distribution of maximum demand for each season used for the forecast values of maximum demand. A stochastic correlated term is applied to the simulated demands to capture the unexplained variance in the model fits. 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.
- Further details of the methodology can be referenced in Rob J Hyndman, Shu Fan (2010) IEEE Transactions on Power Systems 25(2), 1142-1153 (latest Version, with further development is 2015).

[1] Where applicable, Clauses 5.12.2(c)(iii) and (iv) are discussed in Chapter 2.

Energex

- Uses a multiple regression equation for the relationship between demand and Gross State Product (GSP), square of weighted maximum temperature, weighted minimum temperature, coincident time relative humidity index, structural break, three continuous hot days, weekends, Fridays and the Christmas period. 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. The summer regression uses data from November to March, with the temperature data excluding days where the weighted temperatures are below set levels (i.e; the weighted daily mean temperatures < 22.0°C and the weighted daily maximum temperature < 28.5°C).
- A Monte-Carlo process is used to simulate a distribution of summer maximum demands using the latest 22 years of summer weighted temperatures and an independent ten-year GSP forecast.
- 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 electric vehicles (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 2022 based on the latest information. The 50% PoE and 10% PoE maximum demand forecasts sent to Powerlink in July 2022 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 126MW of block loads for Ergon, and 463 MW for Energex. However, only the block loads which have a significant influence on the zone substation's peak demand are incorporated, for Ergon this is 83MW and for Energex 232MW.

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 (3.8% per annum (simple average growth with COVID-19 adjusted for the 2022 ~ 2032 financial years)).
- Queensland population – 1.9% per annum (simple average growth with COVID-19 adjusted for the 2022 ~ 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 (3.0% per annum (simple average growth with COVID-19 adjusted for the 2022 ~ 2032 financial years)).
- Queensland population – Actual 0.9% in 2021, and 1.4% annum (simple average growth with COVID-19 adjusted for the 2022 ~ 2032 financial years).
- Weather – follow the recent 10-year trend.

Ergon Energy's 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 2022 ~ 2032 financial years).
- Queensland population – 1.0% per annum (simple average growth with COVID-19 adjusted for the 2022 ~ 2032 financial years).
- 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 National Institute of Economic and Industry Research (NIEIR) in their System Maximum Demand Forecasts.

Energex high growth scenario assumptions for maximum demand
- GSP – The 'high' case of GSP growth (3.8% per annum (simple average growth with COVID-19 adjusted for the 2022 ~ 2032 financial years).
- Queensland population – 1.9% per annum (simple average growth with COVID-19 adjusted for the 2022 ~ 2032 financial years).
- Rooftop PV – It is expected that the uptake of rooftop PV will continue to grow where it is forecasted that under a high technology penetration scenario, panel capacity may reach 8,771MW by 2032.
- Battery storage – Peak time (negative) contribution may reach 154MW by 2032 (behind the meter).
- EV – Price parity with the ICE type vehicles achieved earlier (whereby > 50% car sales are EV), 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 1,112MW by 2032.
- Weather – follow the recent 10-year trend.

Energex medium growth scenario assumptions for maximum demand
- GSP – The medium case of GSP growth (3.0% per annum (simple average growth with COVID-19 adjusted for the 2022 ~ 2032 financial years)).
- Queensland population – Actual 0.9% in 2021, and 1.4% annum (simple average growth with COVID-19 adjusted for the 2022 ~ 2032 financial years).
- Rooftop Solar PV – It is expected that the uptake of rooftop PV will continue to grow where it is forecasted that under a medium technology penetration scenario, panel capacity may reach 7,729MW by 2032.
- Battery storage – Peak time (negative) contribution will have a slow start of around 9MW in 2023 but may reach 80MW by 2032 (behind the meter).
- EV – Stagnant in the short-term, boom in the long-term. Peak time contribution will only amount to 2 MW in 2023 but will reach 452MW 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 2022 ~ 2032 financial years).
- Queensland population – 1.0% per annum (simple average growth with COVID-19 adjusted for the 2022 ~ 2032 financial years).
- Rooftop Solar PV – It is expected that the uptake of rooftop PV will continue to grow where it is forecasted that under a slow technology penetration scenario, panel capacity may reach 6,593MW by 2032.
- Battery storage – Peak time (negative) contribution may reach a high at 27MW in 2032 (behind the meter).
- EV – Price parity with the ICE type vehicles is achieved much later (whereby > 50% car sales are EV), 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 17MW in 2032.
- Weather – follow the recent 10-year trend.

A.3 Significant changes to the connection point maximum demand forecasts

Major differences between the 2022 forecast and the 2021 forecast can generally be attributed to natural variation in peaks below the connection point level, which 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 DER has increased for the 2022 forecast when compared to the 2021 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 2022 and 2021 forecasts are:

Connection Point	Change in growth rate
Turkinje 132kV	2.31% pa
Middle Ridge 110kV	1.36% pa
Woolooga 132kV	1.34% pa
Cairns 22kV	1.33% pa
Ingham 66kV	1.22% pa

Energex connection points with the greatest difference in growth between the 2022 and 2021 forecasts are:

Connection Point	Change in growth rate
Redbank Plains 11kV	2.58% pa

A.4 Significant differences to actual observations

The 2021/22 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 2021 forecast values for 2021/22 and what was observed.

Ergon connection points with the greater than 10% absolute difference between the peak 2021/22 and corresponding base 2021 forecast for 2021/22 are:

Connection Point	2021/22 forecast peak	2021/22 actual peak	Difference
Blackwater	105	139	32%
Ross	44	52	18%
Kamerunga	56	65	16%
Egans Hill	54	62	15%
Rockhampton	98	110	13%
Cairns	53	60	12%
Alligator Creek	28	31	11%
Turkinje	22	24	11%
Townsville South	107	93	-13%
Bulli Creek	22	19	-14%
Garbutt	112	96	-14%
Townsville East	48	41	-15%
Oakey	23	19	-17%
Tangkam	40	33	-17%

Energex connection points with the greater than 10% absolute difference between the peak 2021/22 and corresponding base 2021 forecast for 2021/22 are:

Connection Point	2021/22 forecast peak	2021/22 actual peak	Difference
Abermain 110kV	76	66	-13%
Abermain 33kV	115	101	-12%
Ashgrove West	120	106	-12%
Redbank Plans	31	28	-10%

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 providers3. 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 focused 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 (TGCP)) and TGTLXXX (TAPR Guideline Transmission Line (TGTL)).

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 rooftop 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 rooftop 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 the 11 geographical zones and eight grid sections referenced in this Transmission Annual Planning Report (TAPR) (as shown in figures 8.6 – 8.8).

Tables C.1 and C.2 provide detailed definitions of zone and grid sections.

Table C.3 provides details of the name and type of generation connected to the transmission system is each zone.

Figure C.1 provides illustrations of the 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) 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)

Note:

(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.

Table C.3 Zone generation details

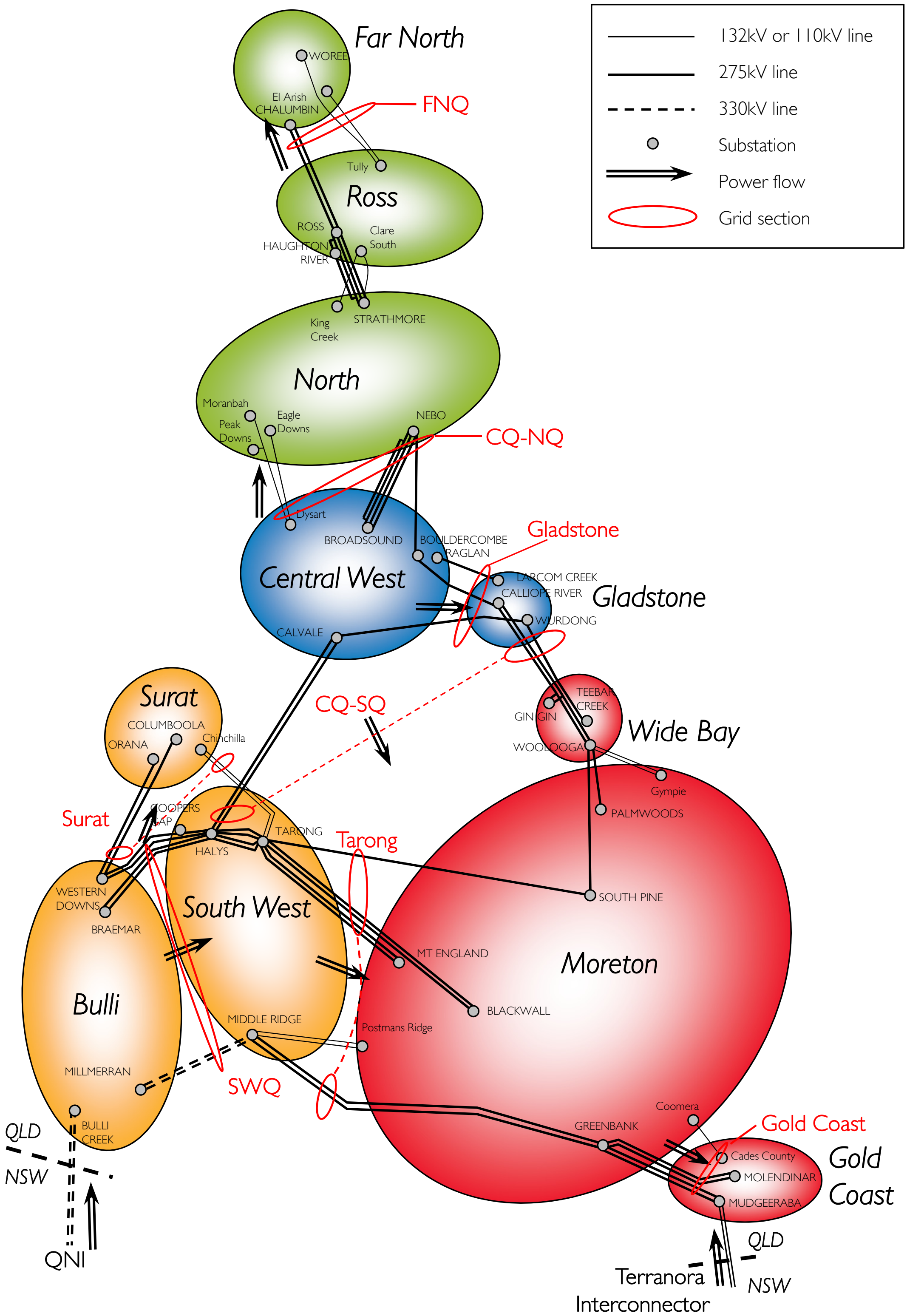
Zone	Generator	Coal-fired	Gas turbine	Hydro-electric	Solar PV	Wind	Battery	Sugar mill
Far North	Barron Gorge			•				
	Kareeya			•				
	Koombooloomba			•				
	Mt Emerald					•		
	Kaban (I)					•		
Ross	Townsville		•					
	Mt Stuart		•					
	Kidston (I)			•				
	Kidston				•			
	Clare				•			
	Haughton				•			
	Ross River				•			
	Sun Metals				•			
	Invicta							•
North	Daydream				•			
	Hamilton				•			
	Hayman				•			
	Whitsunday				•			
	Rugby Run				•			
	Clarke Creek (I)					•		
Central West	Callide B	•						
	Callide PP	•						
	Stanwell	•						
	Lilyvale				•			
	Moura (I)				•			
	Bouldercombe (I)						•	
Gladstone	Gladstone	•						
	Yarwun		•					
Wide Bay	Woolooga Energy Park				•			
Moreton	Swanbank E		•					
	Wivenhoe			•				

Table C.3 Zone generation details (*continued*)

Zone	Generator	Coal-fired	Gas turbine	Hydro-electric	Solar PV	Wind	Battery	Sugar mill
South West	Tarong	•						
	Tarong North	•						
	Oakey		•					
	Coopers Gap					•		
Bulli	Kogan Creek	•						
	Millmerran	•						
	Braemar 1		•					
	Braemar 2		•					
	Darling Downs		•					
	Darling Downs				•			
	Western Downs Green Power Hub				•			
Surat	Condamine		•					
	Columboola				•			
	Gangarri				•			
	Blue Grass				•			
	Edenvale (1)				•			
	Wandoan South (1)				•			
	Wandoan South						•	

Note:
(1) Committed generation that is yet to begin production.

Figure C.1 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	
	Equation 1	Equation 2
	Woree SVC	Mt Emerald Wind Farm
Constant term (intercept)	574	568
Number of Barron Gorge units on line [0 to 2]	21	-
Total MW generation at Barron Gorge	-0.83	-025
Total MW generation at Mt Emerald Wind Farm	-0.59	-0.96
Total MW generation at Kareeya Power Station	-0.51	-0.62
Total MW generation in Ross zone (1)	-	0.09
Total nominal MVAr of 132kV shunt capacitors on line within nominated Cairns area locations (2)	0.52	0.68
Total nominal MVAr of 275kV shunt reactors on line within nominated Cairns area locations (3)	-	-1.45
Total nominal MVAr of 132kV shunt reactors on line within nominated Chalumbin area locations (4)	-0.35	-0.45
Total nominal MVAr of 275kV shunt reactors on line within nominated Chalumbin area locations (5)	-0.42	-0.36
AEMO Constraint ID	**Q^NIL_FNQ_WRSVC**	**Q^NIL_FNQ_MEWF**

Notes:

(1) Ross generation term refers to summated active power generation at Mt Stuart, Townsville, Ross River Solar Farm, Sun Metals Solar Farm, Kidston Solar Farm, Hughenden Solar Farm, Clare Solar Farm, Haughton Solar Farm and Invicta Mill.

(2) The shunt capacitor bank locations, nominal sizes and quantities for the Cairns 132kV 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 275kV area comprise the following::
Woree 275kV 2 x 20.17MVAr

(4) The shunt capacitor bank location, nominal size and quantities for the Chalumbin 132kV and below area comprise the following:
Chalumbin tertiary 1 x 20.2MVAr

(5) The shunt reactor location, nominal sizes and quantities for the Chalumbin 275kV area comprise the following:
Chalumbin 275kV 2 x 29.4MVAr, 1 x 30MVAr

Table D.2 Central to North Queensland grid section voltage stability equations

Measured variable	Coefficient	
	Equation 1	Equation 2
	Feeder contingency	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 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 (%)	
Number of Gladstone units online	Number of Stanwell units online	Number of Callide units online (1)	Number of CQ units online (2)	Number of Kareeya units online	NQ Load	Ross + FNQ Load	Haughton Synchronous Condensor Status	Haughton SF	Other NQ Plants
≥ 2	≥ 2	≥ 1	≥ 7	≥ 2	> 350	> 150	N/A	100	100
≥ 2	≥ 2	≥ 1	≥ 7	≥ 2	> 250	> 100	OFF	0	100
≥ 2	≥ 2	≥ 1	≥ 7	≥ 2	> 250	> 100	ON	100	100
≥ 2	≥ 2	≥ 1	≥ 7	≥ 0	> 350	> 150	OFF	50	100
≥ 2	≥ 2	≥ 1	≥ 7	≥ 0	> 350	> 150	ON	100	100
≥ 3	≥ 3	≥ 0	≥ 7	≥ 2	> 450	> 250	N/A	100	100
≥ 2	≥ 3	≥ 0	≥ 6	≥ 2	> 450	> 250	N/A	80	80
≥ 2	≥ 3	≥ 2	≥ 8	≥ 0	> 450	> 250	N/A	100	100
AEMO Constraint ID								Q_NIL_STRGTH_HAUSF	Various (3)

Notes:

(1) Refers to the total number of Callide B and Callide C units online.

(2) Refers to the number of Gladstone, Stanwell and Callide units online.

(3) Q_NIL_STRGTH_CLRSF, Q_NIL_STRGTH_COLSF, Q_NIL_STRGTH_DAYSF, Q_NIL_STRGTH_HAMSF, Q_NIL_STRGTH_HAYSF, Q_NIL_STRGTH_KIDSF, Q_NIL_STRGTH_MEWF, Q_NIL_STRGTH_RGBRSF, Q_NIL_STRGTH_RRUGSF, Q_NIL_STRGTH_SMSF, Q_NIL_STRGTH_WHTSF.

System normal equations are implemented for all other north Queensland semi-scheduled generators (Mt Emerald Wind Farm, Ross River Solar Farm, Kidston Solar Farm, Clare Solar Farm, Sun Metals 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 one condition of Table D.3 where operation is constrained to 80%. Conditions resulting in lower synchronous unit capacity are 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, Columboola Solar Farm, Blue Grass Solar Farm, Western Downs Green Power Hub, Edenvale Solar Farm, Gangarri Solar Farm, Wandoan South Battery Energy Storage System, Woolooga Energy Park 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, Condamine, Roma, Kogan Creek, Braemar 1, Braemar 2, Darling Downs, Darling Downs Solar Farm, Western Downs Green Power Hub, Columboola Solar Farm, Gangarri Solar Farm, Wandoan South Battery Energy Storage System, Oakey, Oakey 1 Solar Farm, Oakey 2 Solar Farm, Yarranlea Solar Farm, Maryborough Solar Farm, Warwick Solar Farm, Blue Grass Solar Farm, Edenvale Solar Farm, Coopers Gap Wind Farm, Millmerran, and Queensland New South Wales Interconnector (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 $= \dfrac{\text{Moreton zone active demand}}{\text{Gold Coast zone active demand}} \times 100.$

(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 2022/23, 2023/24 and 2024/25.

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 the more significant embedded non-scheduled generators) on the committed network development as forecast at the end of each calendar year. The tables also show the design rating of the Powerlink substation at each location. No assessment has been provided 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 '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 sub-transient machine 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 Inertia 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 (FIA) using Electromagnetic Transient-type (EMT-type) modelling techniques. See section 10.3 for full details.

Table E.1 Indicative short circuit currents – northern Queensland

Substation	Voltage (kV)	Substation Design Rating (kA)	Indicative minimum system normal fault level (kA)	Indicative minimum post-contingent fault level (kA)	Indicative maximum short circuit currents					
					2022/23		2023/24		2024/25	
					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	13.6	13.8	13.3	13.7	13.6	13.9
Alligator Creek	132	31.5	3.2	1.9	4.4	5.8	4.4	5.8	4.5	5.9
Aurumfield	275	40.0	1.3	0.8	-	-	-	-	3.7	4.7
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	3.0	3.2	3.0	3.2	3.0	3.2
Cairns (2T)	132	31.5	2.9	0.7	6.2	8.2	6.5	8.6	6.8	8.9
Cairns (3T)	132	31.5	2.9	0.7	6.2	8.1	6.5	8.5	6.8	8.9
Cairns (4T)	132	31.5	2.9	0.7	6.2	8.2	6.5	8.6	6.8	9.0
Cardwell	132	31.5	1.9	1.0	3.1	3.3	3.3	3.6	3.3	3.6
Chalumbin	275	31.5	1.8	0.7	4.5	4.9	4.8	5.2	5.3	5.6
Chalumbin	132	31.5	3.3	1.6	6.8	7.9	7.1	8.2	7.4	8.5
Clare South	132	31.5	3.3	2.8	8.1	8.2	6.6	6.8	6.6	6.9
Collinsville North	132	31.5	4.4	2.1	11.2	12.0	11.1	12.0	11.5	12.2
Coppabella	132	31.5	2.2	1.5	3.0	3.4	3.0	3.4	3.1	3.4
Crush Creek	275	40.0	3.5	3.1	9.9	11.3	10.0	11.4	10.7	11.9
Dan Gleeson (1T)	132	31.5	4.1	3.8	12.8	13.2	12.7	13.1	13.0	13.3
Dan Gleeson (2T)	132	31.5	4.1	3.8	12.8	13.3	12.7	13.2	13.0	13.4
Edmonton	132	31.5	1.3	0.4	5.6	6.8	5.9	7.1	6.1	7.3
Eagle Downs	132	31.5	3.0	1.5	4.6	4.4	4.6	4.5	4.6	4.5
El Arish	132	31.5	2.0	0.9	3.3	4.1	3.7	4.5	3.8	4.6
Garbutt	132	31.5	3.8	1.8	11.1	11.0	10.9	10.9	11.2	11.0
Greenland	132	31.5	3.5	2.1	-	-	5.5	5.0	5.6	5.0
Goonyella Riverside	132	31.5	3.5	1.5	6.0	5.5	6.0	5.5	6.1	5.5
Guybal Munjan	275	40.0	2.2	1.1	-	-	-	-	6.6	5.3
Haughton River	275	40.0	2.7	2.1	7.8	8.1	7.9	8.2	8.4	8.6
Ingham South	132	31.5	1.9	1.0	3.3	3.4	3.4	3.6	3.5	3.6
Innisfail	132	31.5	1.8	1.2	3.0	3.6	3.2	3.9	3.3	3.9
Invicta	132	19.3	2.5	2.4	5.3	4.8	5.2	4.8	5.2	4.8
Kamerunga	132	31.5	2.4	1.4	4.6	5.5	5.8	7.0	6.0	7.2
Kareeya	132	40.0	3.0	1.5	5.8	6.5	6.0	6.6	6.2	6.9
Kemmis	132	31.5	3.9	1.6	6.0	6.6	6.1	6.6	6.2	6.6
King Creek	132	31.5	2.8	2.0	5.4	4.4	5.3	4.3	5.3	4.4
Lake Ross	132	31.5	4.7	4.3	17.8	19.9	17.5	19.6	18.1	20.1
Mackay	132	31.5	3.5	2.9	5.0	6.0	5.0	6.0	5.1	6.1
Mackay Ports	132	31.5	2.6	1.6	3.4	4.1	3.4	4.1	3.5	4.1
Mindi	132	31.5	3.3	3.1	4.8	3.7	4.8	3.7	4.9	3.7

Table E.1 Indicative short circuit currents – northern Queensland (*continued*)

Substation	Voltage (kV)	Substation Design Rating (kA)	Indicative minimum system normal fault level (kA)	Indicative minimum post-contingent fault level (kA)	Indicative maximum short circuit currents					
					2022/23		2023/24		2024/25	
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)
Moranbah	132	31.5	4.1	3.3	7.9	9.4	7.9	9.4	8.1	9.4
Moranbah Plains	132	31.5	2.7	2.3	4.4	4.8	4.4	4.8	4.4	4.0
Moranbah South	132	31.5	3.3	2.8	5.7	5.2	5.7	5.2	5.8	5.2
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	10.7	11.0	11.9	11.9
Nebo	132	31.5	7.3	6.4	13.4	15.4	13.4	15.5	14.2	16.2
Newlands	132	25.0	2.5	1.2	3.6	4.0	3.6	4.0	3.6	4.0
North Goonyella	132	31.5	2.9	1.4	4.5	3.7	4.5	3.7	4.6	3.8
Oonooie	132	31.5	2.4	1.5	3.1	3.6	3.1	3.6	3.1	3.7
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	6.6	7.5
Proserpine	132	31.5	2.0	1.3	3.5	4.0	3.5	4.0	3.5	4.1
Ross	275	40.0	2.8	2.5	9.0	10.0	9.2	10.5	10.2	11.3
Ross	132	40.0	4.7	4.3	18.4	20.7	18.0	20.3	18.8	21.0
Springlands	132	31.5	4.7	2.2	12.4	14.1	12.3	14.1	12.7	14.4
Stony Creek	132	31.5	2.5	1.1	3.8	3.7	3.8	3.7	3.8	3.7
Strathmore	275	40.0	3.6	3.1	10.0	11.4	10.1	11.5	10.8	12.1
Strathmore	132	40.0	4.8	2.2	12.8	15.0	12.7	15.0	13.1	15.4
Townsville East	132	31.5	3.9	1.5	12.9	12.5	12.7	12.4	12.9	12.6
Townsville South	132	31.5	4.2	3.9	17.5	21.1	17.0	20.5	17.4	20.9
Townsville GT PS	132	31.5	3.6	2.4	10.7	11.2	9.9	10.6	10.1	10.7
Tully	132	31.5	2.3	1.9	4.1	4.2	4.8	5.7	4.9	5.8
Tully South	275	40.0	1.7	1.4	-	-	3.7	4.0	3.9	4.1
Tumoulin	275	40.0	1.8	1.1	3.9	4.5	4.2	4.9	4.5	5.2
Turkinje	132	31.5	1.8	1.1	2.7	3.1	2.8	3.1	2.8	3.2
Walkamin	275	40.0	1.5	0.7	3.6	4.3	4.0	4.6	4.3	4.9
Wandoo	132	31.5	3.3	3.1	4.5	3.3	4.5	3.3	4.6	3.3
Woree (1T)	275	40.0	1.4	0.7	3.6	4.4	4.3	5.1	4.6	5.4
Woree (2T)	275	40.0	1.4	0.7	3.5	4.3	-	-	-	-
Woree	132	40.0	2.9	1.6	6.4	8.8	6.8	9.2	7.1	9.7
Wotonga	132	31.5	3.6	1.7	6.2	7.2	6.2	7.0	6.3	7.1
Yabulu South	132	40.0	4.0	3.7	12.9	12.2	11.0	11.0	11.3	11.1

Table E.2 Indicative short circuit currents – central Queensland

Substation	Voltage (kV)	Substation Design Rating (kA)	Indicative minimum system normal fault level (kA)	Indicative minimum post-contingent fault level (kA)	Indicative maximum short circuit currents 2022/23		2023/24		2024/25	
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)
Baralaba	132	31.5	3.9	2.5	4.3	3.7	4.4	3.8	4.4	3.8
Biloela	132	31.5	3.7	1.1	7.9	8.2	8.1	8.3	8.1	8.3
Blackwater	132	31.5	4.4	3.9	5.8	7.0	5.9	7.0	5.9	7.1
Bluff	132	31.5	2.8	2.6	3.5	4.3	3.5	4.2	3.5	4.2
Bouldercombe	275	40.0	10.8	9.3	19.8	19.4	20.5	19.9	21.6	20.5
Bouldercombe	132	40.0	9.1	4.8	14.5	16.7	14.7	16.9	14.8	17.1
Broadsound	275	40.0	6.3	5.1	12.1	9.3	12.4	9.4	15.3	16.2
Bundoora	132	31.5	5.5	4.7	9.1	8.8	9.2	9.0	9.4	9.2
Callemondah	132	31.5	17.2	6.7	22.0	24.6	22.1	24.7	22.2	24.8
Calliope River	275	40.0	12.2	10.5	20.8	23.7	21.1	24.3	21.4	24.6
Calliope River	132	40.0	19.0	15.6	24.6	29.7	24.8	29.9	25.0	30.1
Calvale	275	40.0	11.5	8.7	20.7	21.9	23.8	26.2	24.1	26.4
Calvale (1T)	132	40.0	5.6	1.0	8.7	9.5	8.9	9.8	8.9	9.8
Calvale (2T)	132	40.0	5.8	1.2	8.4	9.2	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	2.8
Dysart	132	25.0	3.2	1.9	4.8	5.3	4.8	5.4	4.8	5.4
Egans Hill	132	31.5	5.7	3.7	8.3	8.2	8.4	8.2	8.4	8.2
Gladstone PS	275	40.0	11.7	10.0	19.3	21.6	19.6	22.0	19.9	22.3
Gladstone PS	132	40.0	17.2	13.7	21.7	24.9	21.8	25.1	21.9	25.1
Gladstone South	132	40.0	12.8	9.6	16.2	17.2	16.2	17.3	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	10.0	11.2	10.2	11.4	10.5	11.8
Larcom Creek	275	40.0	9.5	3.3	15.4	15.2	15.6	16.6	15.8	16.7
Larcom Creek	132	40.0	7.7	4.0	12.3	13.8	12.3	14.0	12.4	14.0
Lilyvale	275	40.0	3.7	2.8	6.2	6.0	6.2	6.1	6.7	6.6
Lilyvale	132	31.5	6.2	5.1	10.6	12.2	10.7	12.4	11.1	13.0
Moura	132	31.5	3.2	1.7	4.3	5.3	4.4	5.4	4.4	5.4
Norwich Park	132	31.5	2.7	2.6	3.7	2.7	3.7	2.7	3.7	2.7
Pandoin	132	31.5	4.8	3.3	6.9	6.1	7.0	6.1	7.0	6.1
Raglan	275	40.0	7.9	4.4	11.8	10.4	12.0	10.7	12.2	10.8
Rockhampton (1T)	132	40.0	4.7	1.2	6.4	6.3	6.5	6.4	6.5	6.4
Rockhampton (5T)	132	40.0	4.5	1.3	6.2	6.1	6.3	6.2	6.3	6.2

Table E.2 Indicative short circuit currents – central Queensland (*continued*)

Substation	Voltage (kV)	Substation Design Rating (kA)	Indicative minimum system normal fault level (kA)	Indicative minimum post-contingent fault level (kA)	Indicative maximum short circuit currents 2022/23 3 phase (kA)	2022/23 L – G (kA)	2023/24 3 phase (kA)	2023/24 L – G (kA)	2024/25 3 phase (kA)	2024/25 L – G (kA)
Rocklands	132	31.5	5.6	3.6	7.7	6.6	7.8	6.6	7.8	6.6
Stanwell	275	31.5	11.6	9.6	22.3	24.0	23.3	24.8	24.6	25.8
Stanwell	132	31.5	4.5	3.2	5.9	6.4	6.0	6.4	6.0	6.4
Wurdong	275	31.5	10.7	6.7	16.5	16.5	16.8	16.8	17.0	16.9
Wycarbah	132	40.0	3.6	2.7	4.5	5.4	4.6	5.3	4.6	5.3
Yarwun	132	40.0	7.5	4.4	12.9	14.8	12.9	14.9	12.9	14.9

Table E.3 Indicative short circuit currents – southern Queensland

Substation	Voltage (kV)	Substation Design Rating (kA)	Indicative minimum system normal fault level (kA)	Indicative minimum post-contingent fault level (kA)	Indicative maximum short circuit currents 2022/23 3 phase (kA)	2022/23 L – G (kA)	2023/24 3 phase (kA)	2023/24 L – G (kA)	2024/25 3 phase (kA)	2024/25 L – G (kA)
Abermain	275	40.0	8.3	6.5	18.3	18.8	18.4	18.8	18.5	18.9
Abermain	110	40.0	13.1	10.4	21.5	24.5	21.6	24.5	21.6	24.6
Algester	110	31.5	13.2	11.8	21.1	20.9	21.2	20.9	21.2	20.9
Ashgrove West	110	31.5	12.4	9.4	19.2	20.1	19.2	19.6	19.2	19.6
Belmont	275	40.0	8.1	7.4	17.0	17.9	17.1	17.9	17.2	17.9
Belmont	110	40.0	16.0	15.0	27.8	34.5	27.9	34.4	28.0	34.5
Blackstone	275	40.0	8.9	8.1	21.4	23.4	21.5	23.6	21.6	23.6
Blackstone	110	40.0	14.8	13.6	25.5	27.9	25.6	28.0	25.6	28.1
Blackwall	275	40.0	9.5	8.6	22.7	24.3	22.8	24.4	22.9	24.5
Blythdale	132	40.0	3.2	2.3	4.3	5.3	4.3	5.4	4.3	5.4
Braemar	330	50.0	7.2	5.9	24.3	26.4	24.8	26.8	24.8	26.8
Braemar (West)	275	40.0	8.1	4.7	28.8	31.7	29.7	32.6	29.7	32.6
Braemar (East)	275	40.0	8.3	5.4	27.5	31.8	27.9	32.2	27.9	32.2
Bulli Creek	330	50.0	7.1	3.4	18.6	14.9	18.9	15.0	18.9	15.0
Bulli Creek	132	40.0	3.0	3.0	3.8	4.3	3.8	4.4	3.8	4.4
Bundamba	110	31.5	11.2	7.7	17.3	16.6	17.3	16.6	17.3	16.7
Cameby	132	31.5	5.2	4.2	11.0	9.7	11.1	9.7	11.1	9.7
Chinchilla	132	25.0	5.4	3.8	8.7	10.1	8.7	10.1	8.7	10.1
Clifford Creek	132	31.5	4.1	3.4	6.0	5.4	6.0	5.4	6.0	5.4
Columboola	275	40.0	5.6	4.3	14.2	13.4	14.5	13.6	14.5	13.6
Columboola	132	40.0	7.8	5.0	18.2	21.2	18.7	21.8	18.7	21.8
Condabri North	132	31.5	6.9	5.5	14.5	13.3	14.8	13.5	14.8	13.5
Condabri Central	132	31.5	5.4	4.5	9.5	7.0	9.6	7.0	9.6	7.0
Condabri South	132	31.5	4.4	3.7	6.8	4.6	6.9	4.6	6.9	4.6
Coopers Gap	275	40.0	8.3	3.2	18.0	17.8	18.2	18.0	18.3	18.0
Dinoun South	132	31.5	4.6	3.6	6.9	7.1	6.9	7.1	6.9	7.1
Eurombah (IT)	275	40.0	2.8	1.2	4.7	4.9	4.7	4.9	4.7	4.9
Eurombah	132	40.0	4.7	3.5	7.3	8.9	7.4	8.9	7.4	9.0
Fairview	132	31.5	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	6.9	5.5	6.9	5.5	6.9
Gin Gin	275	40.0	6.5	4.4	9.3	8.8	9.4	8.8	9.8	9.2
Gin Gin	132	40.0	8.0	6.0	12.2	13.1	12.2	13.1	13.0	14.1

Table E.3 Indicative short circuit currents – southern Queensland (*continued*)

Substation	Voltage (kV)	Substation Design Rating (kA)	Indicative minimum system normal fault level (kA)	Indicative minimum post-contingent fault level (kA)	Indicative maximum short circuit currents 2022/23 3 phase (kA)	2022/23 L – G (kA)	2023/24 3 phase (kA)	2023/24 L – G (kA)	2024/25 3 phase (kA)	2024/25 L – G (kA)
Goodna	275	40.0	8.0	5.6	16.3	16.1	16.4	16.1	16.5	16.1
Goodna	110	40.0	14.9	13.1	25.5	27.5	25.6	27.6	25.6	27.6
Greenbank	275	50.0	8.7	8.0	20.6	22.6	20.8	22.7	20.8	22.8
Hayls	275	50.0	12.1	10.4	33.3	28.6	34.0	29.2	34.0	29.3
Kumbarilla Park (2T)	275	40.0	6.8	1.7	16.9	16.2	17.1	16.4	17.1	16.4
Kumbarilla Park	132	40.0	8.4	5.6	13.2	15.3	13.3	15.3	13.3	15.3
Loganlea	275	40.0	7.5	6.2	15.0	15.4	15.1	15.5	15.1	15.5
Loganlea	110	40.0	13.6	12.2	22.7	27.3	22.8	27.3	22.9	27.4
Middle Ridge (4T)	330	50.0	5.9	3.2	12.8	12.3	12.9	12.4	12.9	12.4
Middle Ridge (5T)	330	50.0	6.0	3.2	13.2	12.8	13.3	12.8	13.3	12.9
Middle Ridge	275	31.5	7.8	6.9	18.4	18.4	18.5	18.6	18.5	18.6
Middle Ridge	110	31.5	10.8	8.9	21.5	25.3	21.6	25.4	21.6	25.5
Millmerran	330	40.0	6.5	6.1	18.7	19.9	18.8	20.1	18.8	20.1
Molendinar (1T)	275	40.0	5.1	2.1	8.3	8.1	8.3	8.1	8.3	8.1
Molendinar (2T)	275	40.0	5.1	2.1	8.2	8.1	8.3	8.1	8.3	8.1
Molendinar	110	40.0	12.4	10.8	19.3	24.5	19.4	24.5	19.4	24.5
Mt England	275	31.5	9.4	8.5	23.0	23.1	23.2	23.2	23.2	23.3
Mudgeeraba	275	40.0	5.6	4.5	9.3	8.6	9.3	8.6	9.3	8.6
Mudgeeraba	110	40.0	11.8	10.9	17.4	21.1	17.4	21.1	17.5	21.1
Murarrie (1T)	275	40.0	7.0	2.3	13.2	13.2	13.3	13.2	13.3	13.2
Murarrie (2T)	275	40.0	7.0	2.3	13.2	13.3	13.3	13.3	13.3	13.4
Murarrie	110	40.0	14.2	13.1	23.8	28.9	23.9	28.8	23.9	28.8
Oakey GT	110	31.5	4.9	3.5	11.3	12.4	11.3	12.4	11.3	12.4
Oakey	110	31.5	4.6	1.3	10.1	10.0	10.2	10.1	10.2	10.1
Orana	275	40.0	6.3	3.3	16.5	16.5	17.0	16.5	17.0	16.6
Palmwoods	275	31.5	5.7	3.5	8.8	9.2	8.8	9.2	8.9	9.2
Palmwoods	132	31.5	8.0	6.1	13.4	16.1	13.4	16.2	13.5	16.2
Palmwoods (8T)	110	31.5	5.7	2.6	7.3	7.6	7.3	7.6	7.3	7.6
Redbank Plains	110	31.5	13.2	9.7	21.4	20.7	21.5	20.7	21.5	20.7
Richlands	110	31.5	13.5	11.2	21.9	22.6	22.0	22.6	22.0	22.6
Rocklea (1T)	275	31.5	7.1	2.3	13.3	12.3	13.4	12.4	13.4	12.4

Table E.3 Indicative short circuit currents – southern Queensland (***continued***)

Substation	Voltage (kV)	Substation Design Rating (kA)	Indicative minimum system normal fault level (kA)	Indicative minimum post-contingent fault level (kA)	Indicative maximum short circuit currents 2022/23		2023/24		2024/25	
					3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)	3 phase (kA)	L – G (kA)
Rocklea (2T)	275	31.5	5.5	2.3	8.8	8.4	8.8	8.5	8.9	8.5
Rocklea	110	31.5	14.9	13.1	25.1	28.8	25.1	28.7	25.2	28.8
Runcorn	110	31.5	12.2	8.7	18.8	19.2	18.9	19.2	18.9	19.3
South Pine	275	40.0	9.1	8.4	19.1	21.6	19.3	21.7	19.3	21.8
South Pine (West)	110	40.0	13.1	10.3	20.5	23.7	20.6	23.7	20.6	23.7
South Pine (East)	110	40.0	13.8	11.8	21.7	27.8	21.8	27.9	21.9	28.0
Sumner	110	31.5	13.0	9.2	20.7	20.3	20.8	19.6	20.8	19.7
Swanbank E	275	40.0	8.8	7.4	21.0	22.8	21.2	23.1	21.3	23.1
Tangkam	110	31.5	5.7	3.9	13.4	12.4	13.5	12.4	13.5	12.4
Tarong	275	40.0	12.6	10.7	34.7	36.3	35.4	37.7	35.5	37.7
Tarong (1T)	132	40.0	4.5	1.1	5.8	6.1	5.8	6.1	5.8	6.1
Tarong	66	40.0	11.5	6.7	15.5	16.6	15.5	16.6	15.5	16.6
Teebar Creek	275	40.0	5.1	2.4	7.6	7.2	7.6	7.2	7.7	7.3
Teebar Creek	132	40.0	7.4	4.5	11.0	11.8	11.0	11.8	11.2	11.9
Tennyson	110	31.5	10.7	9.8	16.3	16.4	16.3	16.4	16.3	16.4
Upper Kedron	110	40.0	13.4	11.6	21.3	18.8	21.4	18.6	21.4	18.6
Wandoan South	275	40.0	4.0	3.1	8.3	9.4	8.4	9.5	8.4	9.5
Wandoan South	132	40.0	5.7	4.4	10.3	13.2	10.4	13.3	10.4	13.3
West Darra	110	31.5	14.8	13.6	25.0	23.8	25.0	23.7	25.1	23.7
Western Downs	275	40.0	7.9	5.4	27.9	29.4	29.4	33.8	29.4	33.8
Woolooga	275	40.0	6.7	5.7	10.7	12.2	10.7	12.2	10.9	12.4
Woolooga	132	40.0	9.3	7.4	15.1	18.5	15.1	18.5	15.3	18.7
Yuleba North	275	40.0	3.5	2.8	6.5	7.1	6.6	7.2	6.6	7.2
Yuleba North	132	40.0	5.2	4.0	8.3	10.0	8.3	10.1	8.3	10.1

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
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
ENA	Energy Networks Australia
EMT-type	Eletromagnetic Transient-type
EOI	Expresession of interest
ESOO	Electricity Statement of Opportunity
EV	Electric vehicle
FIA	Full Impact Assessment
FNQ	Far North Queensland
IAM	Institute of Asset Management

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 Factors
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
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
PoE	Probability of Exceedance
PS	Power Station
PSCR	Project Specification Consultation Report
PSFRR	Power System Frequency Risk Review
PV	Photovoltaic

Appendix G - Glossary (*continued*)

PVNSG	Photovoltaic non-scheduled generation
QAL	Queensland Alumina Limited
QER	Queensland Energy Regulator
QHES	Queensland Household Energy Survey
QNI	Queensland to 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
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	Terawatt hour
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

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