TransGrid

NEW SOUTH WALES TRANSMISSION ANNUAL PLANNING REPORT

2020

VERSION 1

Front Cover: Mittagong, Southern Highlands, NSW, from the Jellore Lookout at dusk.

Purpose of the Transmission Annual Planning Report

The National Electricity Rules (NER) require TransGrid to conduct an annual planning review and publish the results by 30 June each year. The purpose of the review is to identify an optimum level of transmission investment which will enable TransGrid to deliver value for customers at an efficient cost.

The Transmission Annual Planning Report (TAPR) involves joint planning with each of the distribution network service providers in New South Wales (NSW) (Ausgrid, Endeavour Energy, and Essential Energy) and the Australian Capital Territory (ACT) (Evoenergy) as well as with Powerlink in Queensland, AusNet Services in Victoria, ElectraNet in South Australia and the Australian Energy Market Operator (AEMO). The objective of joint planning is to work together to develop the power system in the most efficient way for the benefit of customers.

The annual planning review takes into account the most recent forecasts of generation planting and retirement, state and local demand and condition and ratings of existing network assets. These inputs are used to identify and analyse present and emerging network constraints and asset renewal requirements.

In particular, our review:

- Identifies emerging constraints within the network and possible options to alleviate them;
- Assesses assets identified as reaching the end of their serviceable lives, confirms the ongoing requirements for the asset and considers options to address this; and
- Provides information to interested parties so that they may propose options to meet those needs, including non-network services.

Identified needs and opportunities, irrespective of the trigger for the need, are optimised within our network investment process. This is designed to respond to the changing needs of stakeholders and ensure the efficient delivery of our capital program.

As the Jurisdictional Planning Body for NSW, we provide input to AEMO's Electricity Statement of Opportunities (ESOO) and Integrated System Plan (ISP), which incorporates the National Transmission Network Development Plan (NTNDP). Broadly, the ESOO considers the adequacy of generation while the ISP facilitates the efficient development and connection of new generation across the National Electricity Market (NEM). These reports serve as inputs to the TAPR, and we report on relevant matters arising from these publications.

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Foreword

Electricity is central to almost every part of our lives. It lights, heats and cools our homes and workplaces. It powers mass communication and the devices we use for work, education and entertainment. It underpins our connection with one another and our mobility by powering trains, light rail, high-rise lifts and increasingly – over time – our commercial, mass transit, freight and private vehicles. It drives the output of traditional industries, manufacturing and 21st century digital enterprise which is transforming production, productivity and society.

Our demand for energy is growing and will continue to grow as we convert to an entirely new fleet of electric vehicles and hybrids over the decades ahead, and as our cities grow along with higher population.

It's not just our society's demand for electricity however, which is shaping the sector. We are also transitioning steadily away from 20th century sources of electricity - coal-fired generation - to a higher reliance on clean, low cost renewable generation including solar and wind. With the last coal-fired generator in NSW scheduled to cease operation in 2042, our challenge is defined over the next two decades. All existing coal-fired generation in this State must be replaced by firmed renewables, and even more generation capacity must be added to account for the inevitable growth to come from our society's increased population and other demand drivers.

In the last century, our electricity system was designed and developed around its main fuel source, coal. Our power stations were built consequently close to where the coal was mined – predominantly in eastern, regional NSW, and the high voltage transmission network linked these coal-fired generators with population centres including the State's major cities of Sydney, Newcastle and Wollongong, along the coast.

This century, the new sources of electricity generation – the greatest volumes and most cost-effective locations for wind and solar – are most often found further inland in NSW than the coal of last century. This necessitates new planning and investment in regional transmission lines which will connect large-scale renewable generation with population centres and industry.

The transmission network is the backbone of the power system. It provides the capacity to transport large volumes of electricity cost-efficiently at high-voltages from large generators to regions where it is used. The transmission network manages the stability of the power system, balancing supply and demand, and works to maintain system strength and inertia. It is also the platform on which the competitive wholesale electricity market operates, facilitating competition between generators and putting downward pressure on wholesale prices, which in turn delivers lower cost and value to electricity customers.

TransGrid is leading the transition of the State's electricity system to a greater reliance on low cost renewables. We are also working to increase system stability and competition within the wholesale electricity market by delivering projects for the National Electricity Market like the upgrade to the Queensland NSW Interconnector, the Victoria NSW Interconnector, Project Energy Connect and HumeLink which will provide electricity customers with safe, reliable and low cost electricity for many decades ahead.

The grid will however soon reach the point where connection of further renewable generation would only displace existing renewables due to downstream congestion on the network, which will reduce benefits to customers. This means that planning for and investing in the future grid has never been more important and never more urgent.

TransGrid is working in collaboration with the Australian Energy Market Operator (AEMO) to support the implementation of it's Integrated System Plan (ISP). We are also working with the NSW Government, on the implementation of the Transmission Infrastructure Strategy. Both plans provide a roadmap for the development of the future power system, as it adapts to the technological and economic developments shaping the nation.

The efficient development of the transmission network will provide system and economic benefits, and it will also benefit energy consumers. As a founding signatory of the Energy Charter we are committed to ensuring that any investment in the power system, is rigorously assessed within the regulatory regime, and is demonstrated to deliver benefit to energy customers. The needs of customers are at the centre of our business and the energy system.

We look forward to working with our customers, stakeholders, governments and industry, as we deliver the power system of the future, serving the needs of today and generations to come.

Paul Italiano

Paul Italiano
Chief Executive Officer
June 2020

About TransGrid

TransGrid operates and manages the high voltage electricity transmission network in NSW and the ACT. The network connects more than three million homes, businesses and communities to a safe, reliable and affordable electricity supply.

The transmission network transports electricity from generation sources such as wind, solar, hydro, gas and coal power plants to large directly connected industrial customers and the distribution networks that deliver it to homes and businesses. Comprising 110 substations, over 13,051 kilometres of high voltage transmission lines, underground cables and five interconnections to QLD and VIC, the network is instrumental to the electricity system and economy and facilitates energy trading between Australia's largest states.

Figure 1 sets out TransGrid's role in the electricity supply chain. **Figure 2** and **Figure 3** show TransGrid's network.

Figure 1 – TransGrid within the electricity supply chain

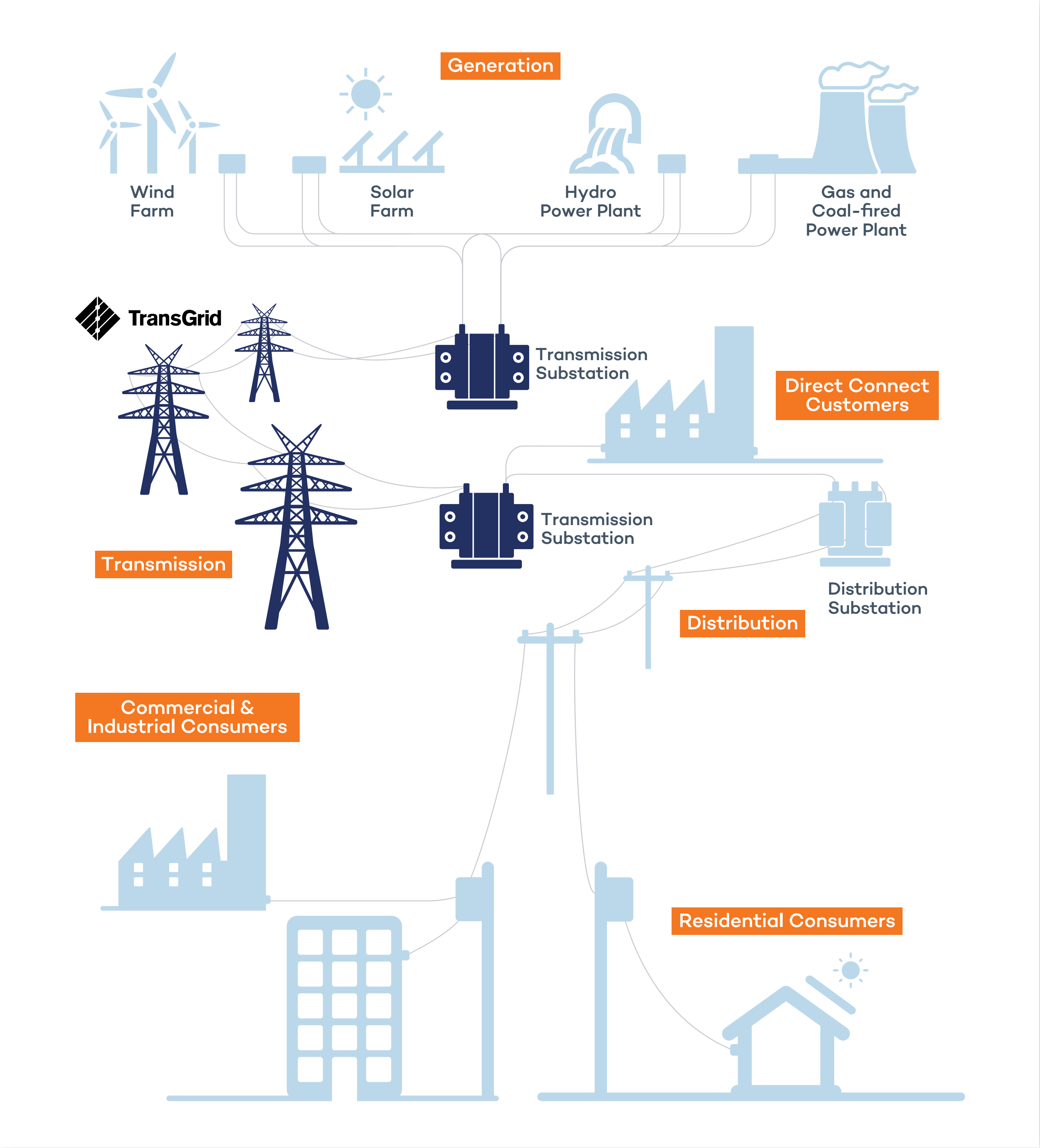
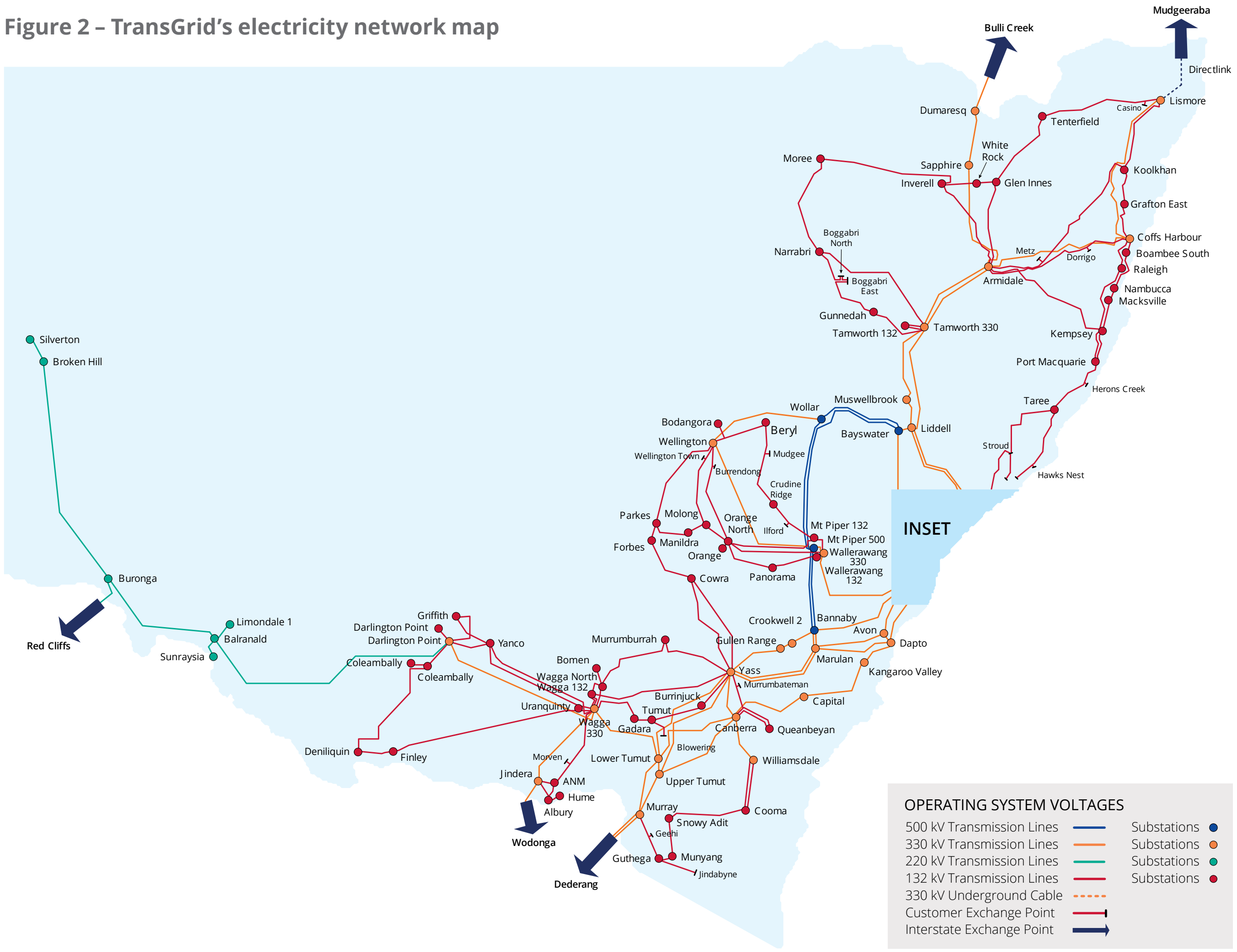


Figure 2 – TransGrid's electricity network map



500 kV Transmission Lines	━	Substations	●
330 kV Transmission Lines	━	Substations	●
220 kV Transmission Lines	━	Substations	●
132 kV Transmission Lines	━	Substations	●
330 kV Underground Cable	┅		
Customer Exchange Point	━┫		
Interstate Exchange Point	➡		

Figure 3 – TransGrid's electricity network map – Inset

Executive Summary

Transmission is central to the new energy system. TransGrid plays a critical role linking new generation to demand centres and maintaining system security.

A decade of transformation for Australia's energy system:

Chapter 1

Building the foundations for a resilient, low emissions electricity system this decade is critical to realising opportunities for Australia in coming years. New electricity transmission infrastructure is essential to unlocking and sharing new generation sources and to enabling a more secure, reliable and affordable energy system.

The underlying need to transform the power system remains. The supply/demand balance remains tight each summer. Scheduled retirements of coal-fired generators are approaching and available transmission capacity in areas of good renewable energy resources continues to decrease with the connection of more generation.

This transmission plan ensures that electricity customers will continue to benefit from a reliable power system which reduces emissions at the least cost.

Transmission network developments:

Chapter 2

The next decade will see electricity demand grow due to industrial and mining developments in regional NSW, transport infrastructure and priority growth areas in Greater Sydney, and growth in the digital economy.

It will also see energy supply shift away from coal-fired generation in the Sydney, Newcastle and Wollongong area to renewable generation in regional NSW.

We have identified major network developments and local supply projects to address emerging constraints and ensure future demand can be supplied.

We continue to replace or refurbish transmission lines, substation assets and secondary systems to maintain the reliability of the existing network.

Network support opportunities:

Chapter 3

Operation of a secure and reliable power system requires innovative approaches and technologies to improve the operation of our existing network.

We have identified five locations where an estimated reduction in forecast load would defer a forecast constraint for a period of 12 months.

A Request for Proposals has been issued (Round 3) for non-network solutions in Inner Sydney. Two further locations have been identified where there may be potential to issue Requests for Proposals for non-network solutions in the next 10 years, this will require the deployment of alternative means to ensure that energy is available at the times it is required to meet demand.

Forecasts and planning assumptions:

Chapter 4

Over the next decade, the annual NSW & ACT energy consumption is forecast to grow at an average rate of 0.8 per cent per annum (after an initial decline due to the effects of COVID-19).

540 MW of new renewable generation has committed to connect at various locations in NSW since June 2019.

The transmission network complies with the NSW transmission reliability standards from 1 July 2018. Expected changes at Broken Hill will likely require transmission developments to maintain compliance for the Broken Hill bulk supply point.

Assessment of power system security:

Chapter 5

Our transmission network provides the platform to transport energy from large-scale generation to major load centres. There is a predicted shortfall in generation to meet maximum demand following the expected retirement of Liddell Power Station in 2022-23.

The shortfall can be met by additional new generation, greater interconnection, storage and demand management. This is being managed by the connection of new generation to the network and projects to increase network capacity.

TransGrid has undertaken an assessment of power system security against each of the criteria that contribute to the stability of the power system.

We expect shortfalls in system strength following the retirements of Liddell and Vales Point Power Stations or if coal-fired power stations move to flexible operation.

We expect a shortfall in inertia following the retirements of Liddell, Vales Point and Eraring Power Stations or if coal-fired power stations move to flexible operation.

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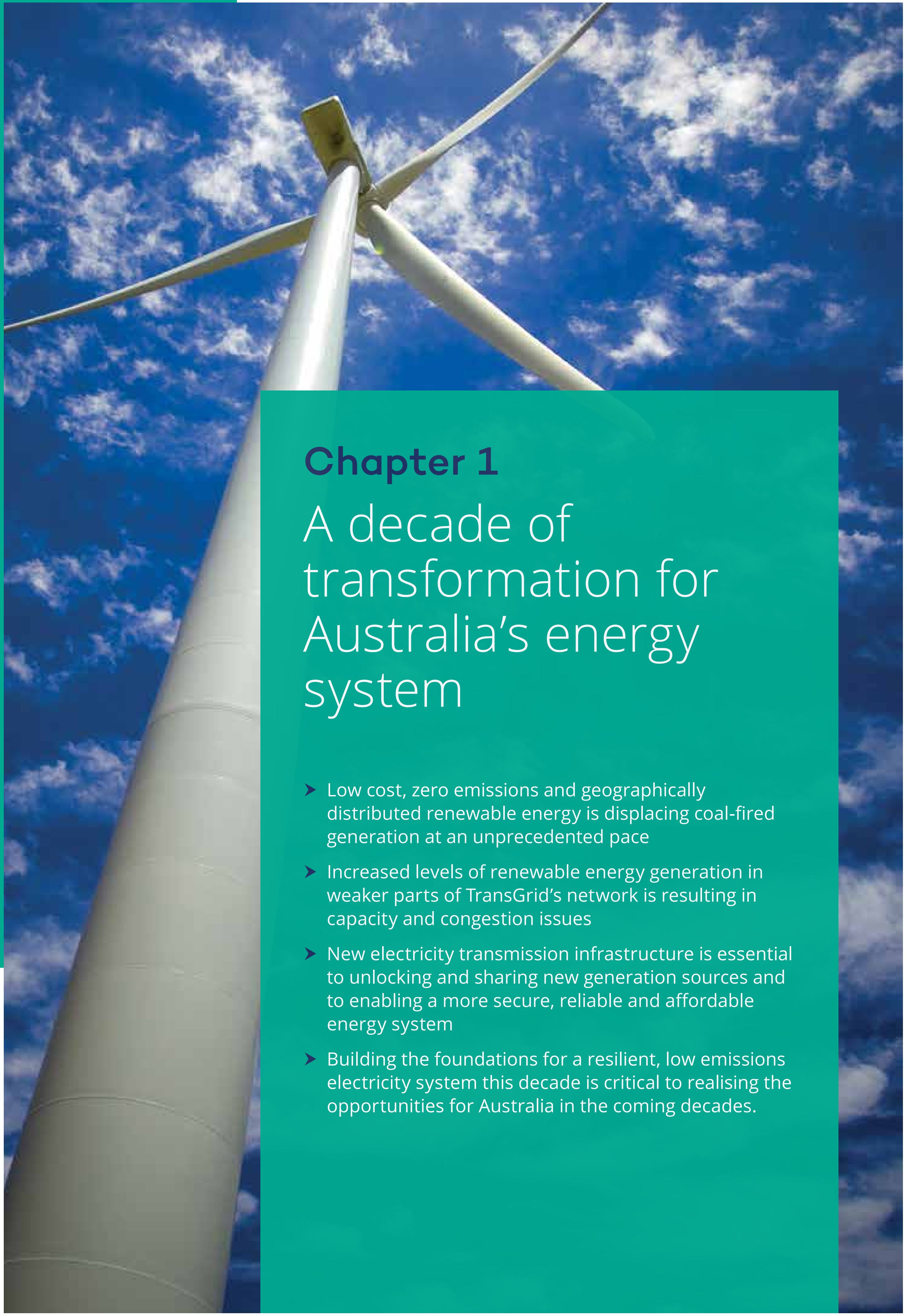


Chapter 1

A decade of transformation for Australia's energy system

- Low cost, zero emissions and geographically distributed renewable energy is displacing coal-fired generation at an unprecedented pace
- Increased levels of renewable energy generation in weaker parts of TransGrid's network is resulting in capacity and congestion issues
- New electricity transmission infrastructure is essential to unlocking and sharing new generation sources and to enabling a more secure, reliable and affordable energy system
- Building the foundations for a resilient, low emissions electricity system this decade is critical to realising the opportunities for Australia in the coming decades.

1.1 The year in review

The past year has been one of the most eventful for the power system in New South Wales.

During spring and summer, bushfires affected large areas of eastern Australia, placing the community and the power system under the greatest stress in the State's history. During autumn, demand for electricity was reduced due to the impact of COVID-19 pandemic.

Some of the changes over the past year have benefited electricity customers. In autumn, the wholesale electricity price fell to around $40/MWh, levels last experienced in 2016 and 2017 respectively, before the retirements of Northern and Hazelwood power stations.

The underlying need however, to transform the power system remains. The supply/demand balance continues to be tight each summer, scheduled retirements of coal-fired generators are approaching and available capacity in areas of good renewable energy resources continues to decrease with the connection of more generation.

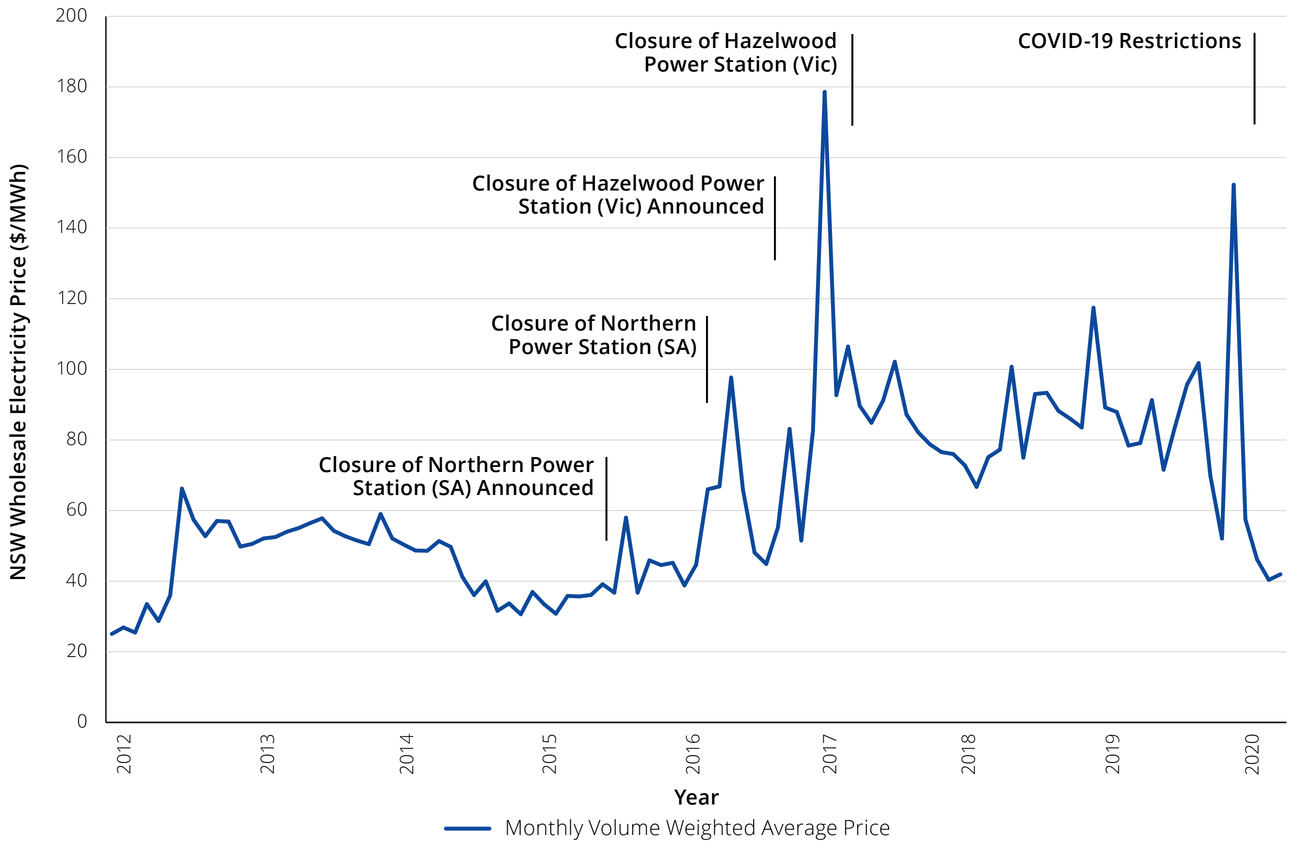
This ten year transmission plan aims to ensure that electricity customers continue to benefit from a reliable power system which reduces emissions at the least cost.

Wholesale electricity prices returned to sustainable levels

Since early autumn, the average wholesale electricity price in NSW has reduced to around $40/MWh, half the price experienced over the last four years. It returned levels similar to before the retirements of Northern and Hazelwood power stations.

The trend in wholesale electricity price is shown in **Figure 1.1**.

Figure 1.1: Wholesale electricity price in NSW



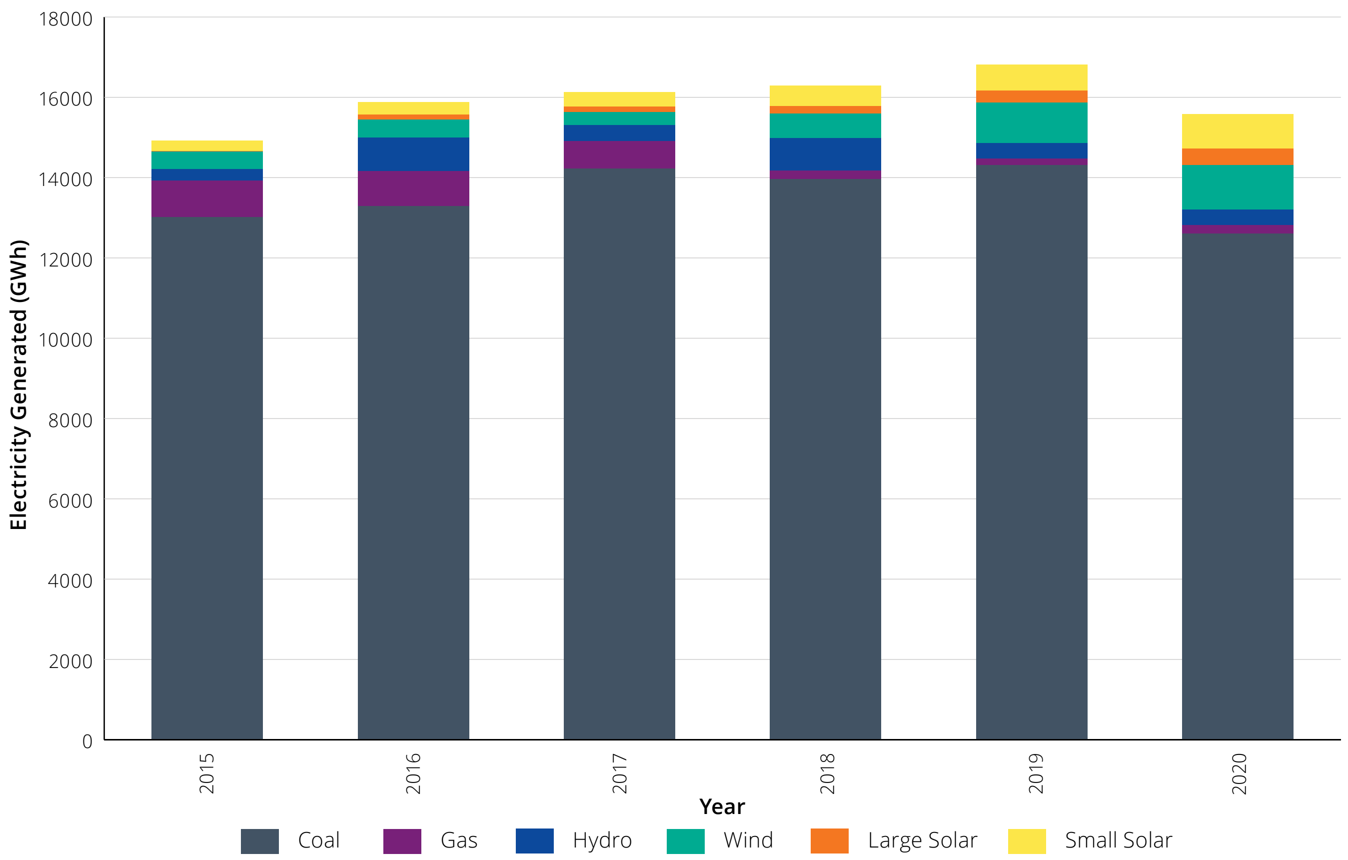
Source: AEMO Electricity Market Management System.

The drivers of the reduction are:

- Mild weather conditions in early autumn
- A reduction in electricity consumption due to impacts of the in the COVID-19 pandemic
- A temporary reduction in domestic gas prices, corresponding with reductions in international gas and oil prices
- Increasing renewable generation, including large-scale wind and solar and rooftop solar
- A reduction in coal-fired generation, to levels below those before the retirements of Northern and Hazelwood power stations.

Although the wholesale price has returned to levels last experienced in 2016 the generation mix has changed. Renewable generation has increased and coal-fired generation has been displaced. The trend in generation is shown in **Figure 1.2**.

Figure 1.2: Electricity generation in autumn



Source: TransGrid analysis of data from AEMO Electricity Market Management System; APVI.

Relief from high wholesale prices won't last without the transformation of the power system

If the recent reduction in wholesale electricity price is passed through to customers in full, it is expected to save average residential bills around $250 per year.[1]

Electricity consumption however, is forecast to increase as the economy recovers following the COVID-19 impact. Gas prices are forecast to increase due to the decline of legacy gas supply sources and expected increase in international gas and oil prices. These effects will place upward pressure on wholesale electricity prices, reversing the recent reductions.

It is essential to progress the transformation of the power system in a timely way. This will avoid greater reliance on gas powered generation than is economic, and maintain downward pressure on the wholesale electricity price.

The greatest benefits will come from the establishment of renewable energy zones intergrating new, low-cost generation and improvements in interconnection to better share existing generation. These initiatives will maintain downward pressure on the wholesale market price, and consequently, electricity bills.

The supply/demand balance remains tight in summer

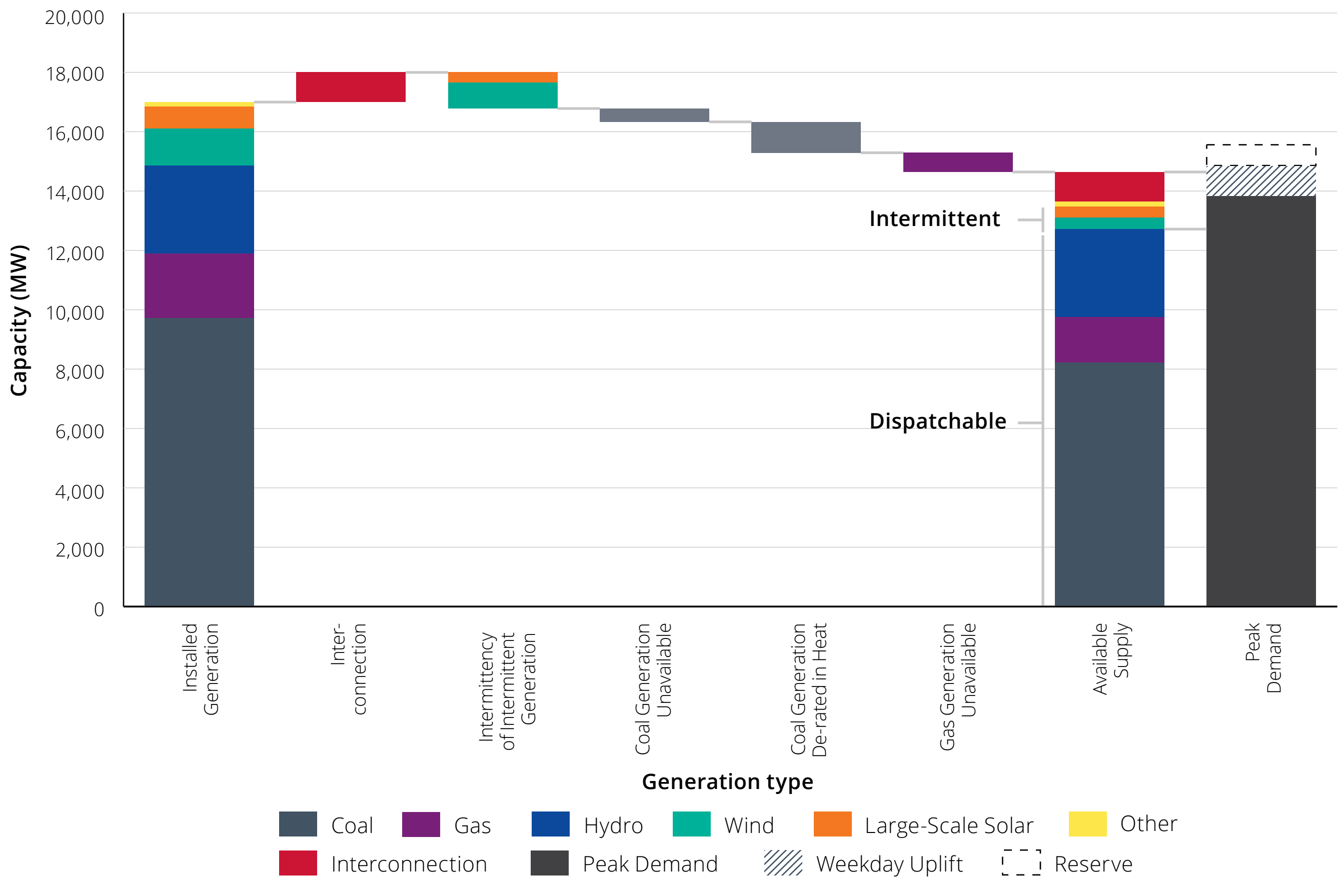
Summer temperature conditions were average overall this year, in terms of cooling degree days that correlate with energy consumption. NSW and the Australian Capital Territory however, experienced significant bushfire and weather events during spring and summer, placing the power system under extreme stress.

The summer peak demand of 13,957 MW on Saturday 1 February 2020 set a record for the highest weekend demand in NSW. Analysis of the supply-demand balance at peak demand is shown in **Figure 1.3**.

Key observations are:

- Intermittent generation, wind and large-scale solar, was generating at 38% of installed capacity. This is higher than at previous peak demand, on 10 February 2017, when it was generating at 10% of installed capacity.
- One coal-fired generating unit at Liddell Power Station was unavailable.
- Approximately 1,040 MW of coal-fired generation was unavailable due to a reduction in generator output ratings (de-rating) in the very hot temperatures.[2] This is the largest de-rating in NEM history, compared with de-ratings of between 490 MW and 805 MW previously.
- Colongra Power Station gas peaking generation re-bid its availability to zero at time of peak demand, due to being uneconomic to start. This created a lack of reserve condition, to which AEMO responded by issuing a direction.
- Of the available supply, 88% was dispatchable, 5% was intermittent and 7% was from interconnectors.
- Had the same conditions occurred on a normal working weekday, peak demand would have been over 1,000 MW higher.[3] This would have exceeded the available supply, and demand would only have been able to be met using load curtailment or load shedding.

Figure 1.3: Supply-demand balance on 1 February 2020



Source: TransGrid analysis of data from AEMO Electricity Market Management System.

The tight supply-demand balance on 1 February 2020 is not a one-off case. Occurrences of tight supply-demand balance, known as "lack of reserve", are classified by AEMO as follows:

- LOR 1: The power system is two incidents away from load shedding (an early warning)
- LOR 2: One incident with a generator, interconnector or transmission line may lead to load shedding
- LOR 3: Rotational load shedding (that is, rolling blackouts)

The trend in actual lack of reserve conditions is shown in **Figure 1.4**, indicating a tightening of the supply-demand balance in recent years.

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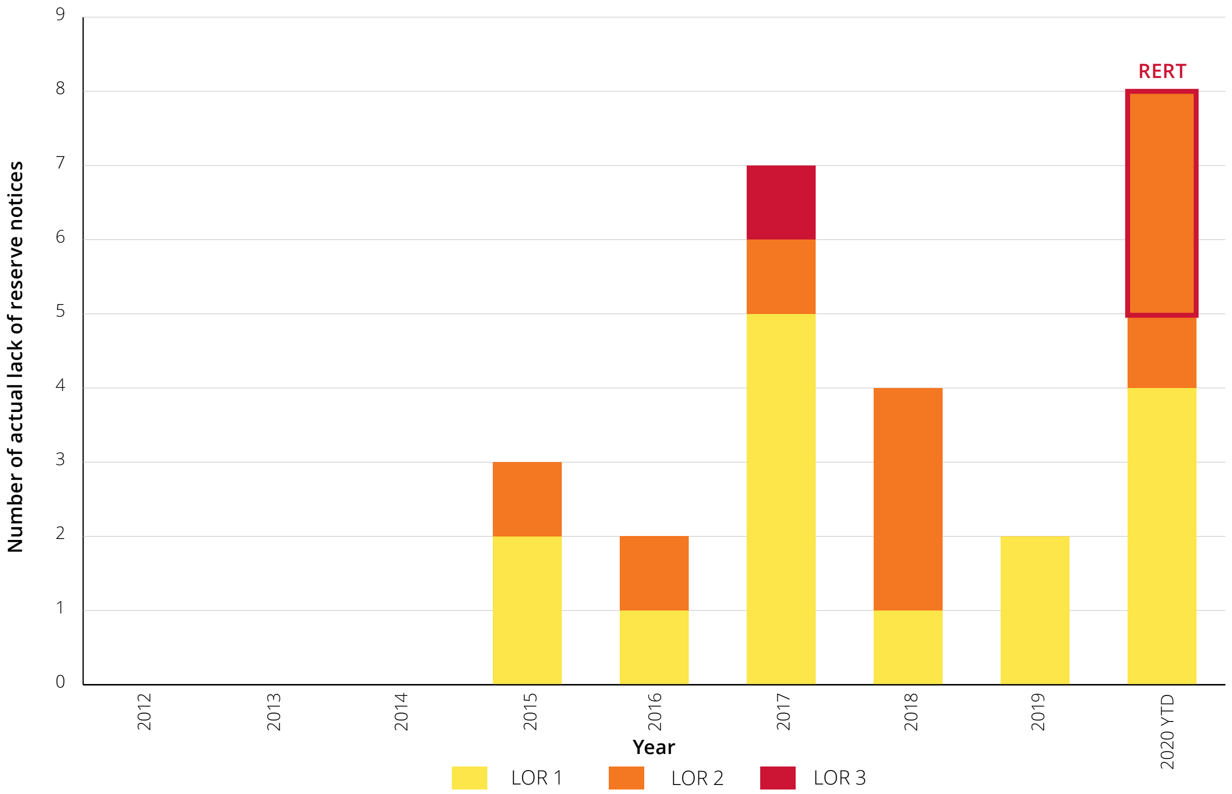
[1] AEMC, Residential Electricity Price Trends 2019 indicates that the wholesale electricity price is 39% of the average residential bill in New South Wales. Therefore, a reduction of the wholesale electricity price by around half is expected to reduce average residential bills by around 20%, or around $250 per year.

[2] When the temperature exceeds 42 degrees Celsius at Bankstown airport, National Electricity Market procedures allow generators to de-rate their available output due to the effect of high temperatures on their plant.

[3] Demand is lower on weekends than weekdays, due to lower commercial and industrial demand.

Figure 1.4: Actual lack of reserve conditions



Source: AEMO Electricity Market Management System.

There were four days in summer that had an actual LOR 2 condition (including 1 February 2020), leading to intervention by the AEMO to maintain reliability by issuing directions or activating demand reductions through the Reliability and Emergency Reserve Trader (RERT) mechanism.[4] The LOR 2 conditions were due to:

- High demand due to high temperatures;[5]
- Unavailability of generators, due to planned or unplanned maintenance;
- Reduction in generator output rating due to high temperatures;[6] and
- Unavailability of transmission lines due to damage or reclassification with bushfires in the vicinity.[7]

Coal-fired generators in NSW generally have a similar level of availability as those in international jurisdictions, at around 85%.[8] In summer however, ratings at high temperatures have reduced over time, as shown in **Figure 1.5**.

The summer rated capacity of coal-fired generators was reduced by 530 MW after a load shedding event on 10 February 2017. The level of de-rating at high temperatures has subsequently reduced available generation by a further 1,040 MW, observed on 1 February 2020. This was the largest de-rating in NEM history.

The impact of the bushfire and weather events on the power system over summer could have been significantly worse under different circumstances. For example:

- Liddell Power Station was generating between 1,100 MW and 1,700 MW at peak demand on the four very hot days. If Liddell Power Station had been unavailable, the demand required to be curtailed or shed on each of the four days would have been between 650 MW and 1,100 MW, equivalent to between 60,000 and 100,000 households.
- The Queensland to NSW Interconnector (QNI) was importing between 1,010 MW and 1,095 MW at peak demand on the four very hot days. If QNI had been unavailable (for example, affected by bushfires), the demand required to be curtailed or shed on each of the four days would have been between 325 MW and 750 MW, equivalent to between 30,000 and 70,000 households.

The regularity and extent of lack of reserve in summer indicates that similar consequences are likely to re-occur in future summers without action to address the tight supply-demand balance.

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[4] AEMO directed a generator on 1 February 2020, and activated demand reductions using the RERT on the other three days with high temperatures.

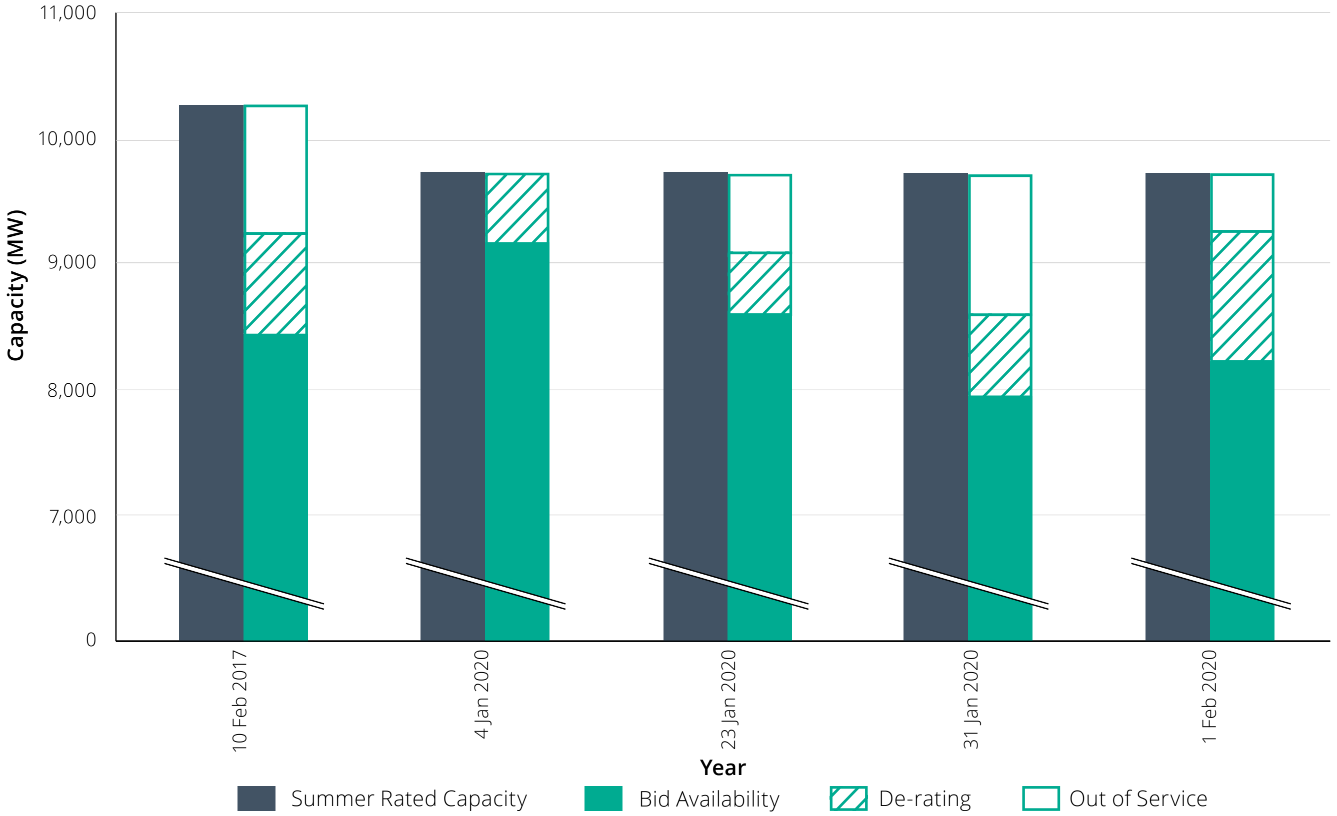
[5] Cooling loads such as air conditioning accounting for approximately one third of peak demand.

[6] When the temperature exceeds 42 degrees Celsius at Bankstown airport, National Electricity Market procedures allow generators to de-rate their available output due to the effect of high temperatures on their plant.

[7] The power system is normally operated to remain stable during an interruption to one transmission line (or one generator). During threats such as bushfires or storms in the vicinity of multiple transmission lines on the same towers or in the same corridor, the lines may be "reclassified". This means that the capacity of one transmission line in the corridor is withdrawn from the power system, so that the power system will remain stable for the loss of multiple transmission lines at the same time.

[8] National Renewable Energy Laboratory, Cost and Performance Assumptions for Modeling Electricity Generation Technologies, November 2010.

Figure 1.5: Coal-fired generator availability at high summer demand



Source: TransGrid analysis of data from AEMO System Event Report New South Wales 10 February 2017; AEMO Generation Information; AEMO Electricity Market Management System.

1.2 The outlook for the next decade

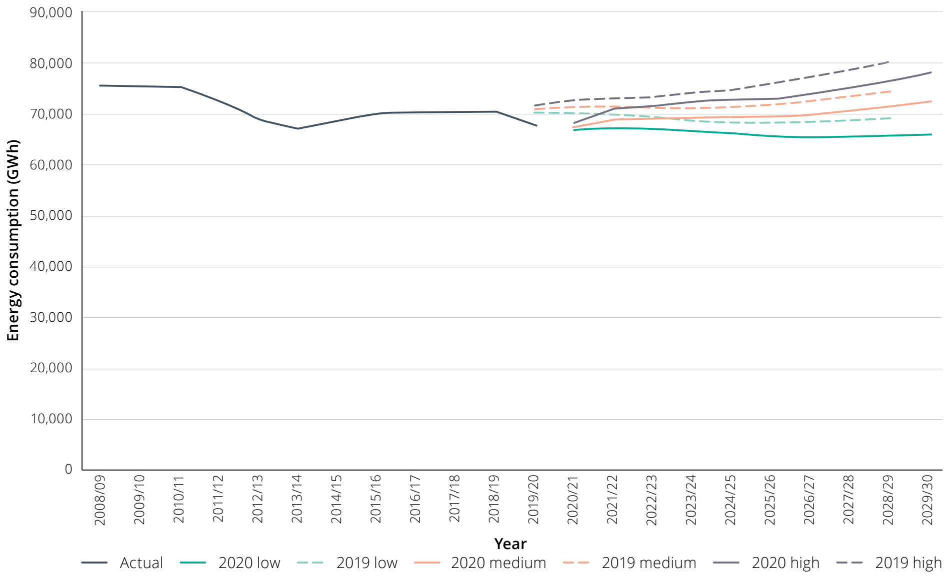
The next decade will see the transformation of the power system continue. Electricity demand is forecast to grow, following a slight reduction during the COVID-19 pandemic, driven by economic recovery. Coal-fired generators are scheduled to retire, and record levels of new renewable generation will progress through the connection process.

It is essential that the transformation is planned and co-ordinated to provide the best value to customers.

Electricity demand will return to growth

Forecast energy consumption shows an initial decline due to the effects on the economy of COVID-19, followed by average growth of 0.8 per cent per annum over the next 10 years. The forecast has reduced by around 4 per cent on average compared with last year's forecast, as shown in **Figure 1.6**.

Figure 1.6: NSW region sent-out annual energy consumption forecast



Source: TransGrid

The forecast includes demand from new and growing loads in NSW driven by expansion of mining activity in central and northern NSW, new transport infrastructure in Greater Sydney and growth of data centres.

The plans in this report include projects to meet the growth in demand, as shown in **Figure 1.11**.

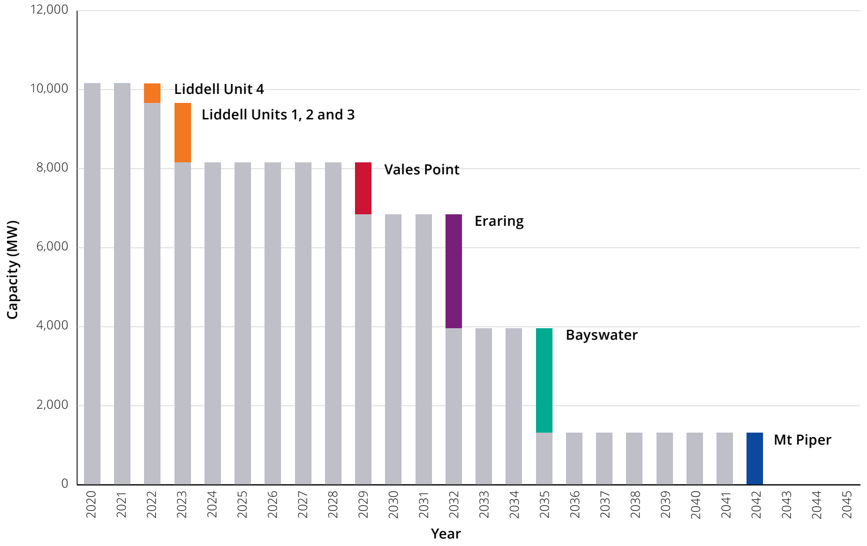
The generation mix will continue to change

The generation mix will continue to evolve as new, low-emissions generation replaces fossil fuel generation that is scheduled to retire in 2043.

Over 30% of the coal-fired generation capacity in NSW is scheduled to retire over the next decade, as shown in **Figure 1.7**.[9]

While scheduled retirement dates provide a useful indication for planning, generators are permitted under the Rules to close with as little as three years' notice. Some coal-fired generators are also considering the potential for moving to flexible operation.[10] These changes may come earlier due to market conditions and it is prudent to be prepared to bring forward projects to integrate new generation and improve capacity for existing generation.

Figure 1.7: Coal-fired generator scheduled retirement



Source: AEMO, Generating Unit Expected Closure Year, April 2020.

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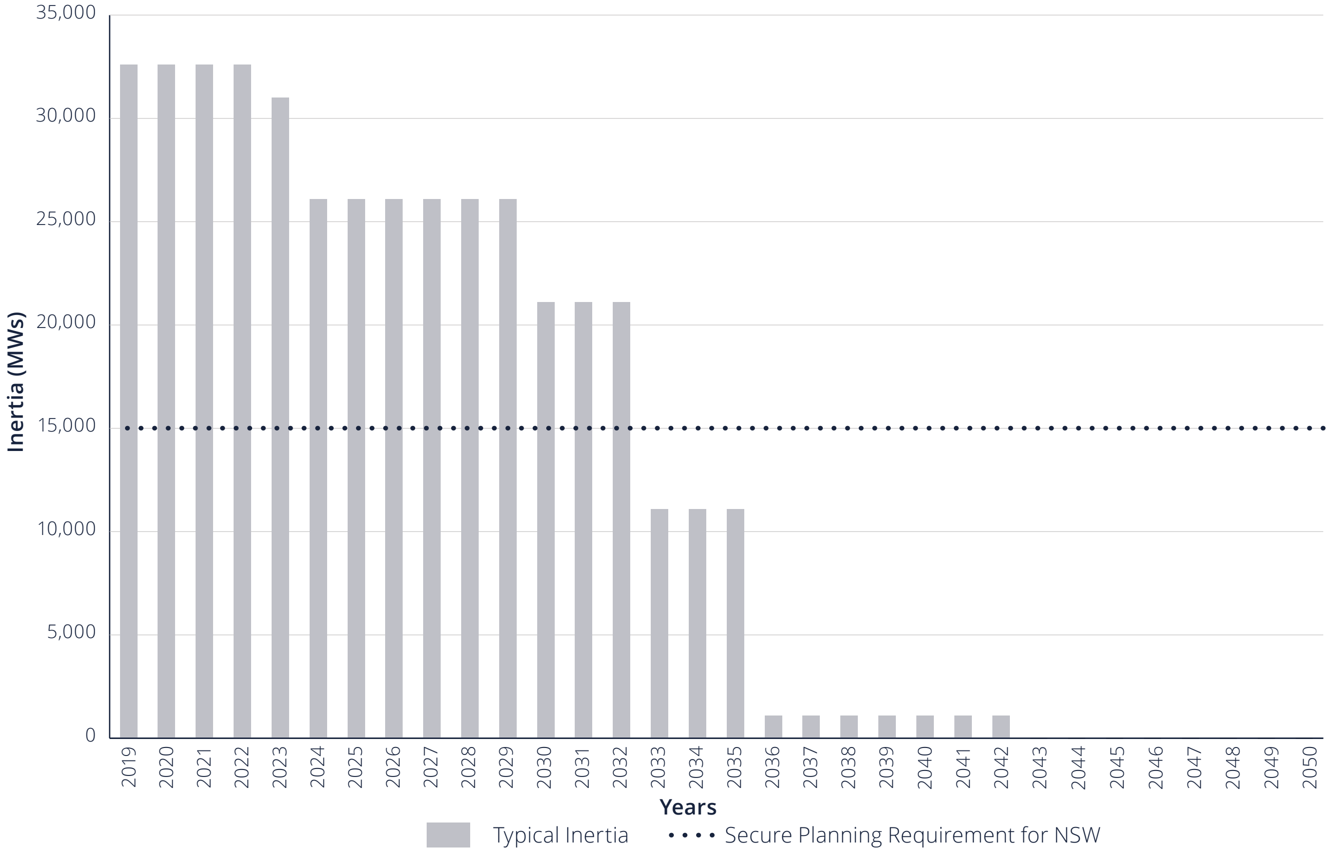
[9] The information on expected closure dates is provided to AEMO by market participants.

[10] For example, https://www.originenergy.com.au/blog/power-station-trial-aims-to-reduce-reliance-on-coal/.

Figure 1.8 – Forecast inertia in NSW



As generators retire or move to flexible operation, the levels of inertia and system strength in NSW will also reduce. Based on scheduled retirement dates, system strength remediation will be required in the late 2020s and inertia in the early 2030s, as shown in **Figure 1.8**.

The retirement schedule for existing generators highlights the pressing need for transformation of the power system.

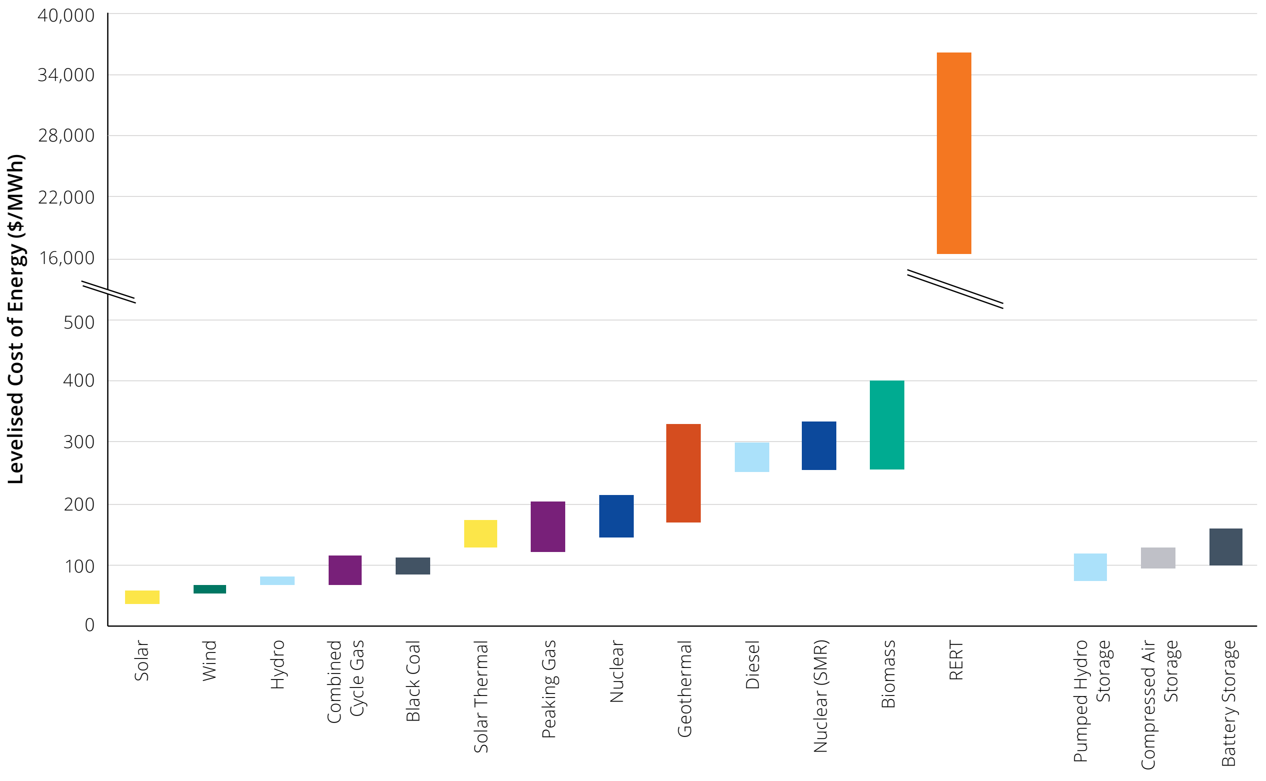
As more renewable generation is connected, however the power system will soon reach the point where further connection of renewable generation would displace other renewable generation. Timely investment in transmission is therefore essential for the continued transformation of the power system.

The costs of each type of new generation and storage are shown in **Figure 1.9**. Although a range of generation and storage technologies will have a role in the future power system, there are some key insights to consider:

- Solar and wind generation deliver the lowest cost energy per megawatt hour (MWh). Timely investment in the transmission backbone to renewable energy zones where solar and wind generation can access the best renewable resources is essential to sustain low wholesale electricity prices
- Pumped hydro provides the lowest cost energy storage and, depending on the depth of storage, can firm seasonal variations in renewable generation as well as daily variations
- Battery storage is well suited to firm daily variations, less capital-intensive than pumped hydro, faster to deploy and not constrained to particular locations. The cost of battery storage is also forecast to reduce
- Gas peaking generation is expensive compared with other firming options and will place upward pressure on the wholesale market price. Gas prices are expected to increase in the future
- Had AEMO not activated the RERT, load shedding would have been required for a single contingency event. RERT is expensive, however, with an average cost of around 500 times the normal wholesale market price. The use of RERT indicates that the wholesale electricity market is not delivering efficient outcomes, and highlights the need for timely investment in the transformation of the power system to improve access to existing generation and integrate new low-cost generation.
- Had an additional 900 MW of renewable generation have been available in summer 2019/20, activation of the RERT would not have been required. The renewable generation would also have delivered low-cost energy through the whole year, improving price outcomes for consumers.

Investment in transmission represents less than 10% of the cost of transformation of the power system going forward. Prudent and timely transmission development will ensure that investment in generation and storage, which makes up the remaining 90%, is cost-effective.

Figure 1.9: Cost of new generation, RERT and storage[11]



Sources: CSIRO, GenCost 2019-20: preliminary results for stakeholder review, 2019; CO2CRC, Australian Power Generation Technology Report, 2015; ANU, 100% renewable electricity in Australia, 2017; AEMO, RERT Quarterly Report Q1 2020, May 2020; NSW Transmission Annual Planning Report 2018; TransGrid analysis.

The plans in this report will increase capacity for existing generation, integrate new generation and address the forecast gaps in system strength and inertia to deliver the most efficient power system for customers.

In the short-term, TransGrid is progressing upgrades to Queensland NSW Interconnector (QNI) and the Victoria to NSW Interconnector (VNI) to improve the capacity for existing generation to meet peak demand. In the medium-term, TransGrid is progressing regulatory approval for for EnergyConnect and HumeLink to provide capacity for existing and new generation to meet peak demand. TransGrid is also working with the NSW Government planning the Central-West Orana Renewable Energy Zone to integrate new generation into the power system.

The plans and their alignment with expected generator retirements are shown in **Figure 1.11**.

1.3 Possibilities beyond the next decade

An array of new technologies will assist the transformation of Australia's energy system helping to stabilise and balance an increasingly variable energy system. Batteries, grid forming inverters, smart electric vehicle charging, vehicle to grid technology, intelligent grid, demand management, virtual power plants and low-emissions hydrogen production are all technologies which will be tested and refined over the next decade, to become commonplace in the energy system. Research development, changes to regulations and policy support will enable the coordinated rollout of these technologies in the decades beyond this plan.

All Australian State and Territory governments have aligned to the aspirational net zero emissions by 2050. ClimateWorks Australia has found that rapid decarbonisation of the electricity sector is essential for Australia to meet Paris Climate Agreement targets, and that electrification plays a critical role in decarbonising other sectors.

The least cost economy-wide emissions reduction trajectory required to hit net zero emissions by 2050 and hold global temperature rise to 2 degrees Celsius is shown in **Figure 1.10**. Under this trajectory, Australia's electricity sector decarbonises by 2035 and electrification enables significant emissions reduction in the building, transport and industry sectors.

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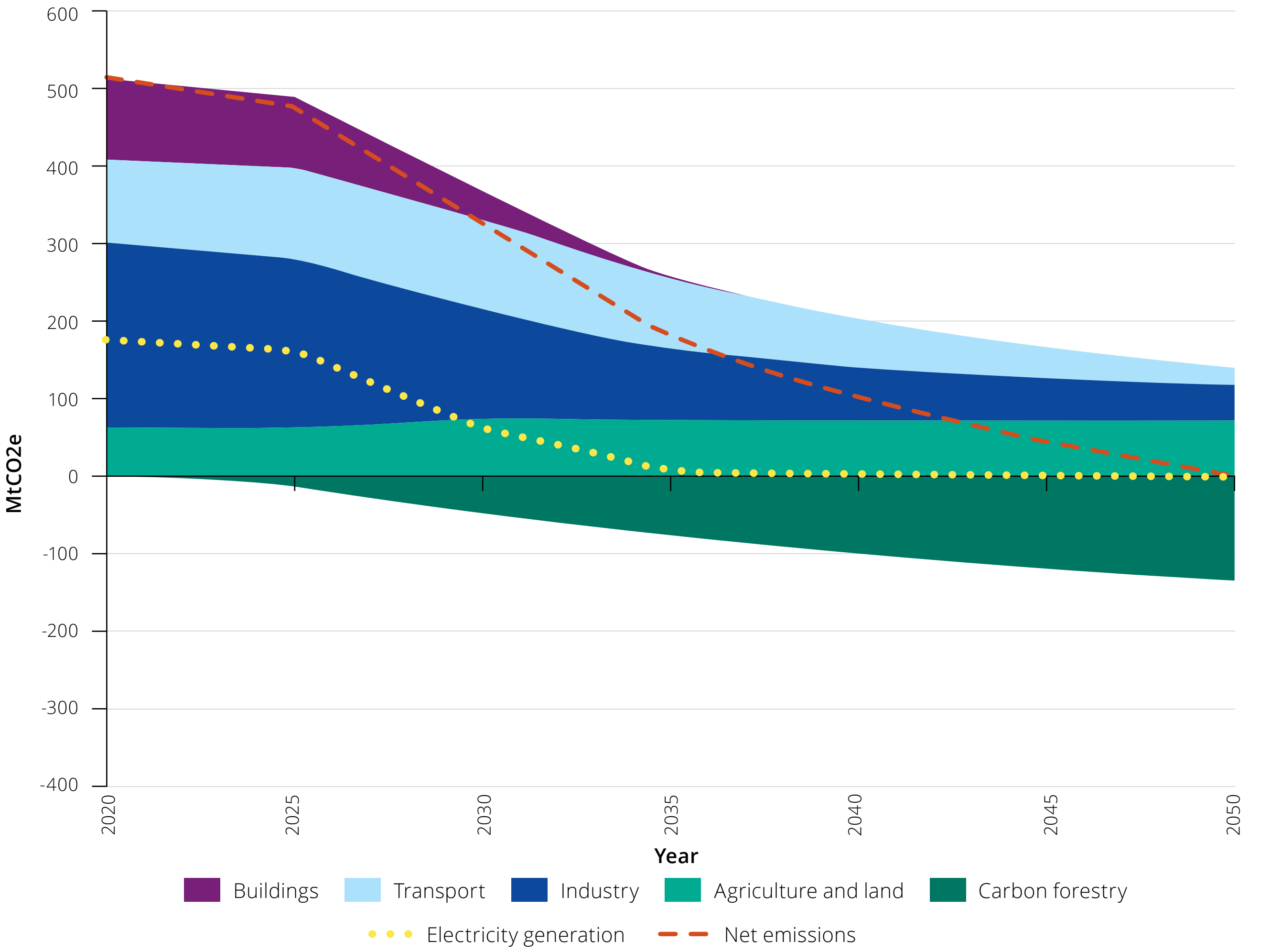
[11] The costs of storage in this figure include the cost of charging using solar or wind generation.

Figure 1.10: Australia's possible emissions trajectory under ClimateWorks Australia's '2ºC Deploy' scenario



Source: ClimateWorks Australia, Decarbonisation Futures: Solutions, Actions and Benchmarks for a Net Zero Emissions Australia, March 2020.

The opportunity to transform the Australian electricity system extends beyond domestic needs. Vast renewable energy resources, access to global trade routes and significant metal ores provide Australia with the opportunity to become a global superpower in the production and export of low carbon products.

Analysis for Australia's National Hydrogen Strategy suggests that in an optimistic hydrogen future, hydrogen production and export could add $26 billion to Australia's GDP and provide 20,000 jobs by 2050.[12]

Low cost renewable energy and an interconnected electricity system is critical to realise this future, with the National Hydrogen Strategy suggesting that a green hydrogen industry of scale would require over four times more electricity than the NEM currently consumes. The integration of renewable hydrogen production into the grid could create synergies which could lower electricity costs for consumers, by reducing grid requirements for balancing and storage.

The Grattan Institute has specifically identified the opportunity to embed renewable hydrogen into carbon intensive industries, such as steel production, for global export. Their analysis identifies that the Hunter Valley and central Queensland are ideal locations.[13]

The plans in this report will establish the foundations of a low emissions, low cost and reliable electricity system over the next decade that is essential to both underpin our economy and create the potential for Australia to realise the opportunities of a low carbon future.

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[12] Commonwealth of Australia, Australia's National Hydrogen Strategy, 2019.
[13] Grattan Institute, Start with Steel, 2020.

Figure 1.11: Timeline of planned projects in this report

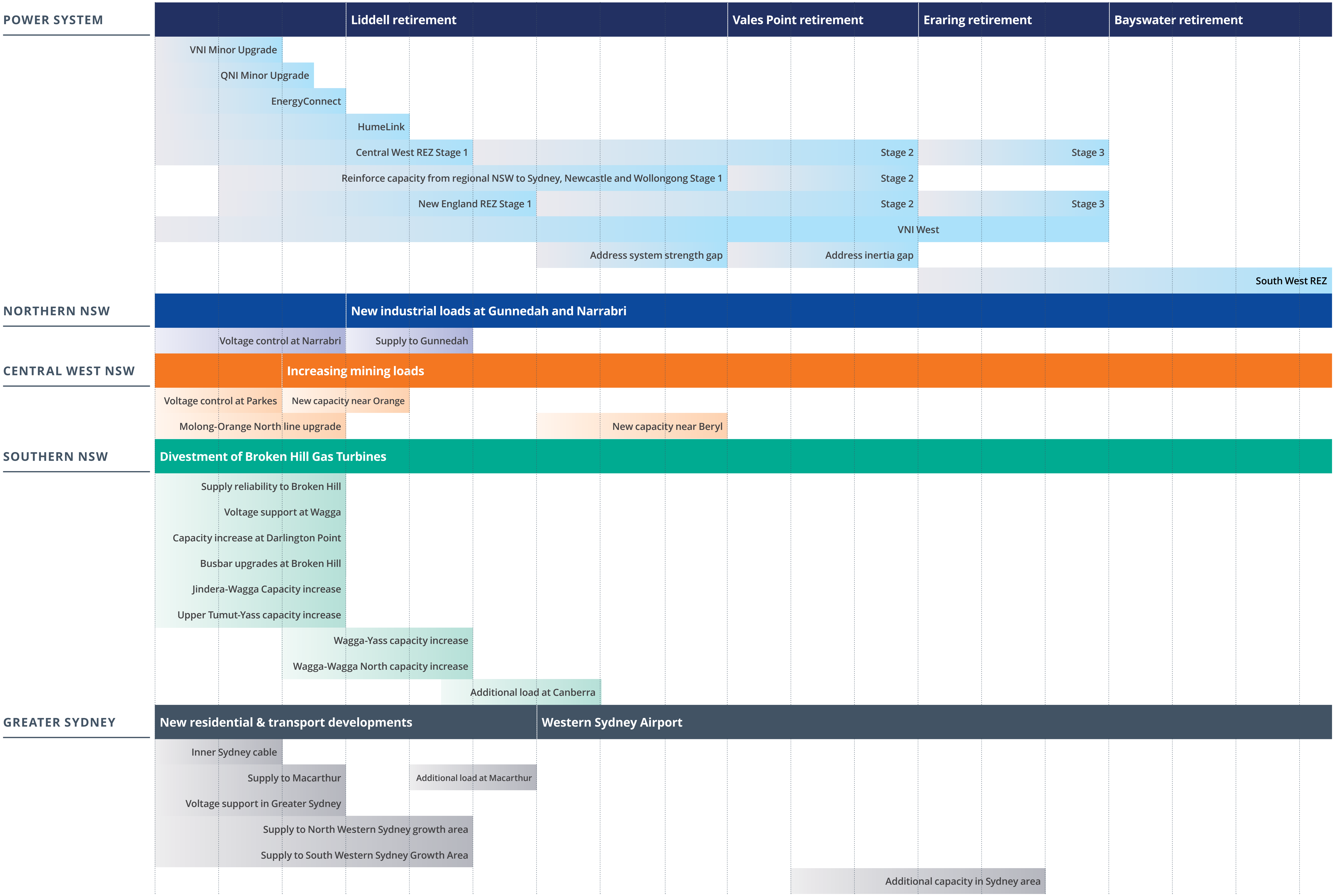
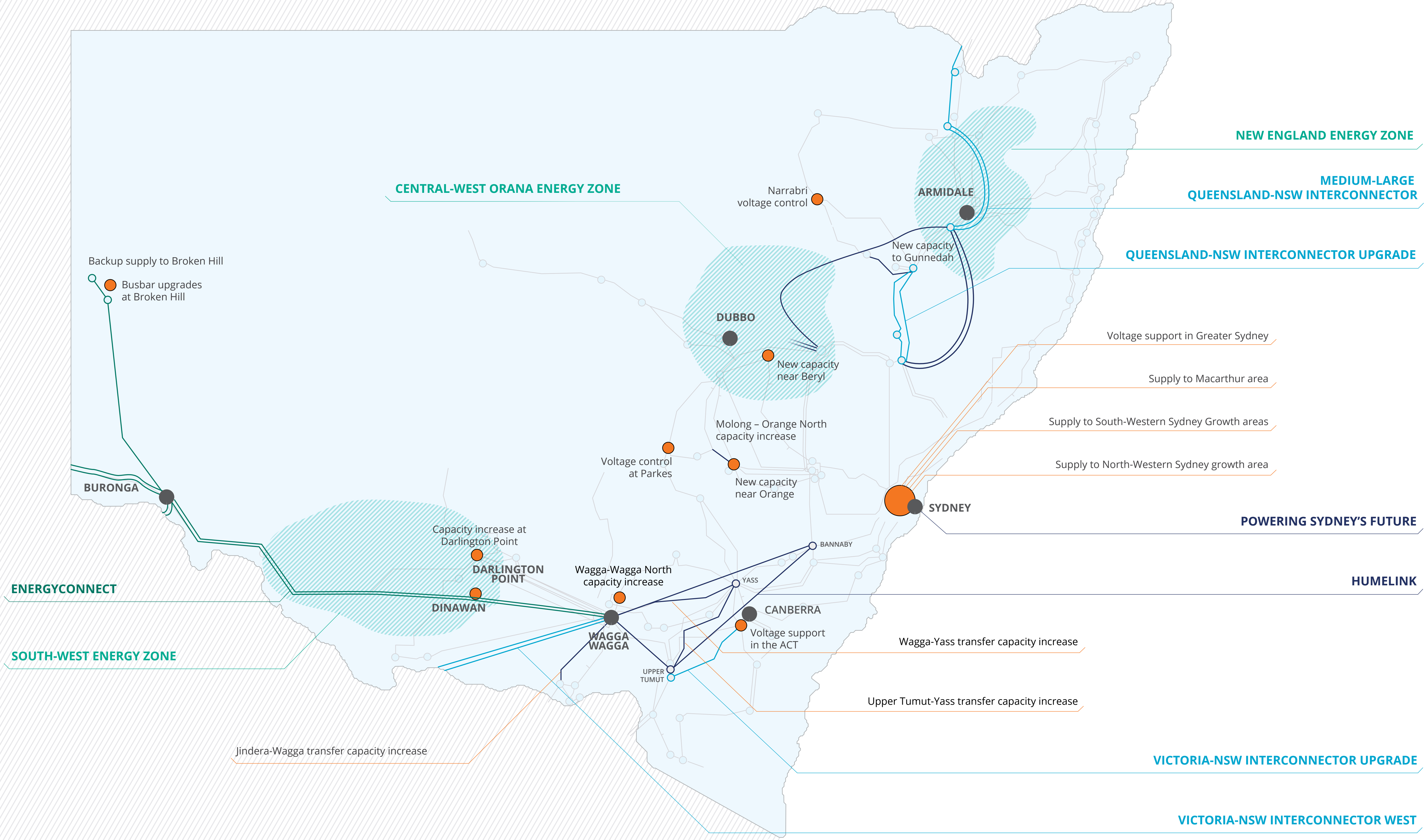
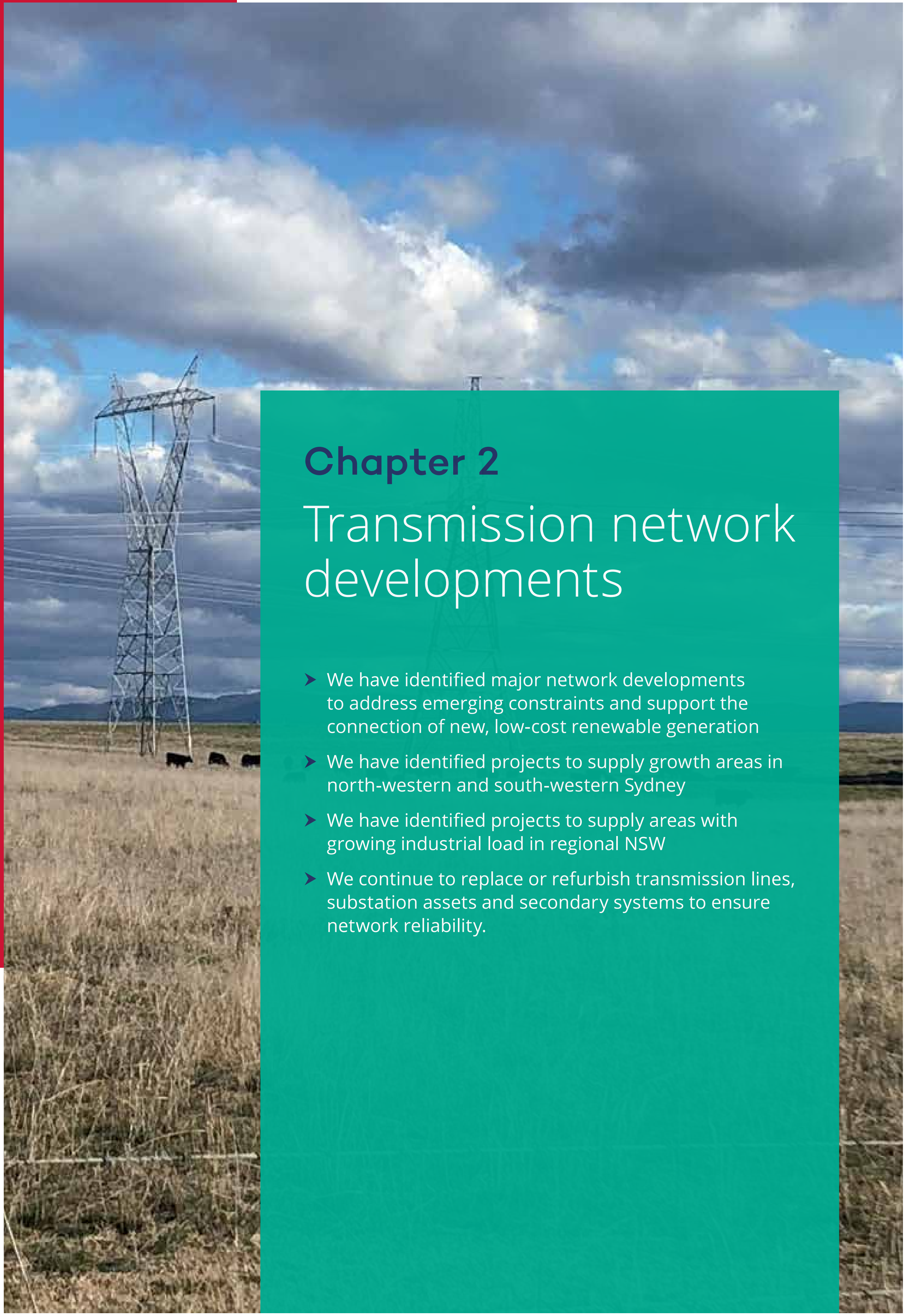


Figure 1.12: Planned projects in this report





Chapter 2

Transmission network developments

- We have identified major network developments to address emerging constraints and support the connection of new, low-cost renewable generation
- We have identified projects to supply growth areas in north-western and south-western Sydney
- We have identified projects to supply areas with growing industrial load in regional NSW
- We continue to replace or refurbish transmission lines, substation assets and secondary systems to ensure network reliability.

2.1 Proposed major developments

TransGrid has an unprecedented level of generation connection enquiries with over 55,000 MW of potential solar, wind and hydro projects at various stages of development. Most of these enquiries are seeking to connect to remote locations where the existing network capacity is limited.

At the same time, as large baseload generators are projected to retire, the integration of new generation and improvements to interconnection are essential to maintain secure supply and provide effective competition in the wholesale market.

In the 2020 annual planning review, we identified major network developments to address emerging constraints and support the connection of new renewable generation. The projects include:

Committed projects

- Expanding Queensland to NSW transfer capacity (QNI Upgrade)

Projects under regulatory consultation

- Victoria to NSW Interconnector upgrade (VNI Upgrade);
- A new interconnector between NSW and South Australia (EnergyConnect);
- Reinforcement of the Southern NSW network (HumeLink);
- Victoria to NSW Interconnector West (VNI West);

Planned projects

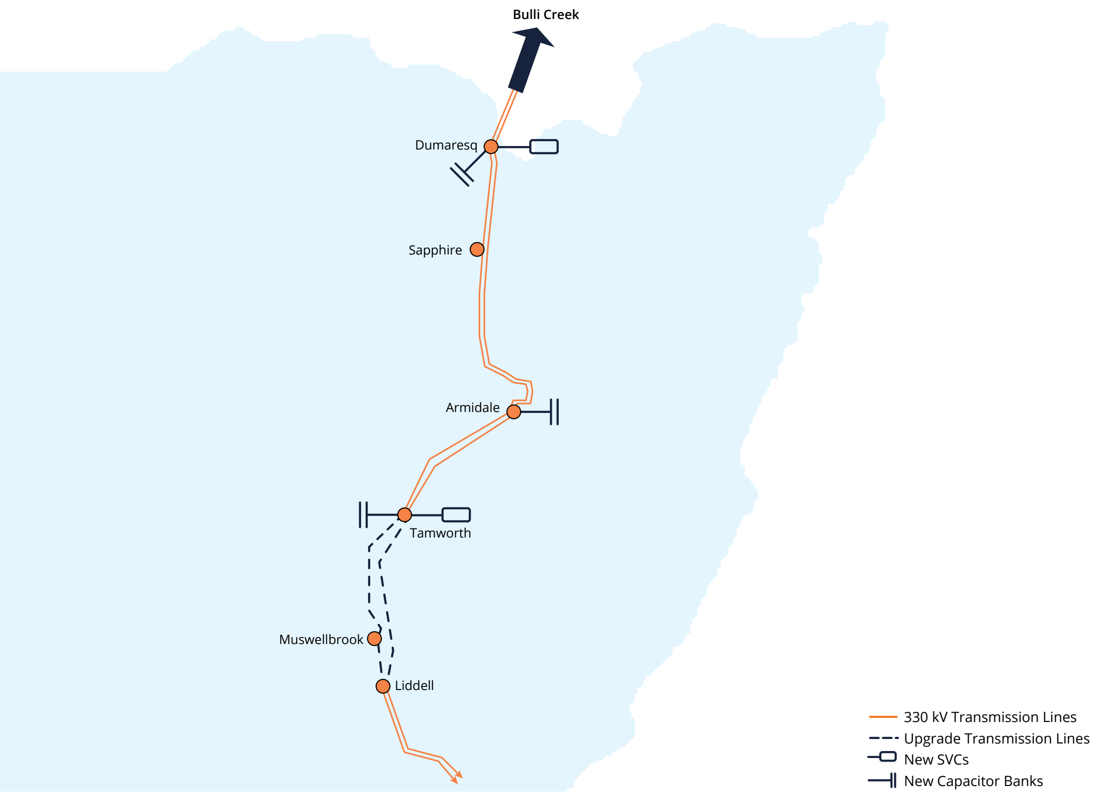
- Central-West Orana Renewable Energy Zone;
- Improving stability in South-West NSW;
- New England Renewable Energy Zone;
- Medium/large Queensland to New South Wales Interconnector; and
- Reinforcement to Sydney/Newcastle/Wollongong load centres.

These major developments are aligned with AEMO's 2020 ISP. They will provide greater interconnection in the NEM and support or facilitate the connection of large-scale energy zones.

Committed projects

2.1.1 Expanding Queensland to NSW transfer capacity (QNI Upgrade)

Figure 2.1: Minor Queensland to NSW interconnector upgrade



An upgrade to the transmission capacity between New South Wales and Queensland will provide greater access for low-cost generation in Queensland to the southern states. It will also provide additional capacity for new renewable generation in northern NSW, and for generation from the southern states to help meet peak demand in Queensland.

It will:

- Facilitate more efficient sharing of generation across the NEM, thereby avoiding the use of higher cost generators and deferring, or avoiding, the construction of new, more expensive generation and/or storage;
- Continue to provide reliable supply at the lowest cost by deferring the need to build new generation and storage capacity in New South Wales ahead of the forecast retirement of Liddell Power Station; and
- Facilitate the transition to a lower carbon emissions future and the adoption of new technologies through improving access to high quality renewable resources across regions, which further avoids the use of high-cost generators and defers, or avoids, the need to build new generation.

The project includes:

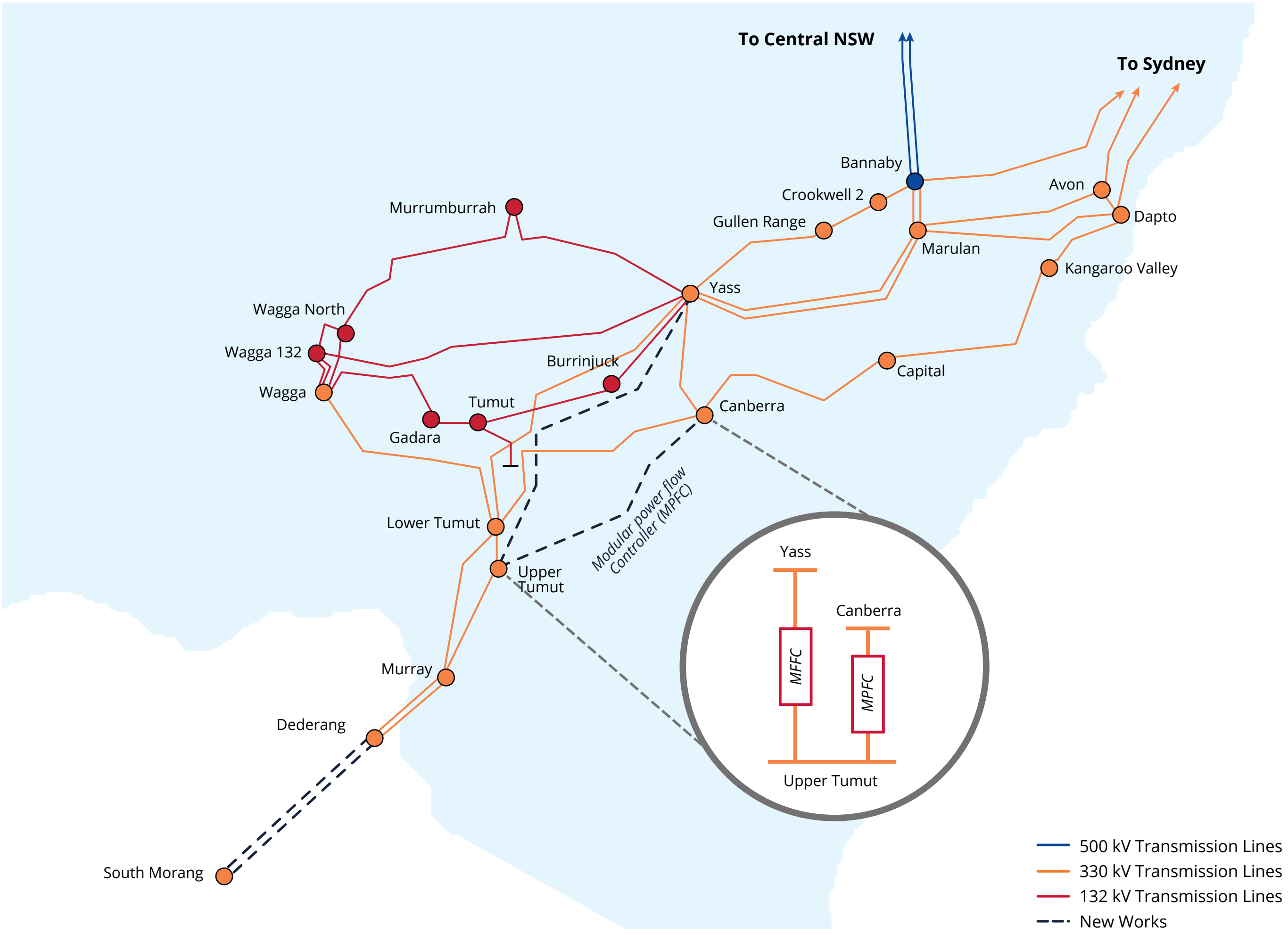
- Uprating the existing 330 kV Liddell to Tamworth lines, and
- Installing new dynamic reactive support at Tamworth and Dumaresq substations and shunt connected capacitor banks at Tamworth, Armidale and Dumaresq substations

QNI Upgrade is identified as a committed ISP project and is expected to be completed by June 2022 at a cost of $217 million.

Projects under regulatory consultation

2.1.2 Victoria to New South Wales Interconnector minor upgrade (VNI Upgrade)

Figure 2.2: VNI Upgrade preferred option



An upgrade to the Victoria to New South Wales Interconnector will provide greater access for low-cost generation in Victoria and renewable generation in southern NSW. It will also provide additional capacity for existing peaking generation in southern NSW to meet peak demand in the major load centres of Sydney, Newcastle and Wollongong, at lower cost than building new generation at the major load centres.

The network between southern NSW and Sydney is constrained at times of high demand, and has limited capacity to cater for further generation together with existing generation and import from Victoria to NSW. Thermal capacity constraints between the Riverina, Snowy Mountains and Sydney may limit generation output or import from VIC, as new generation is connected.

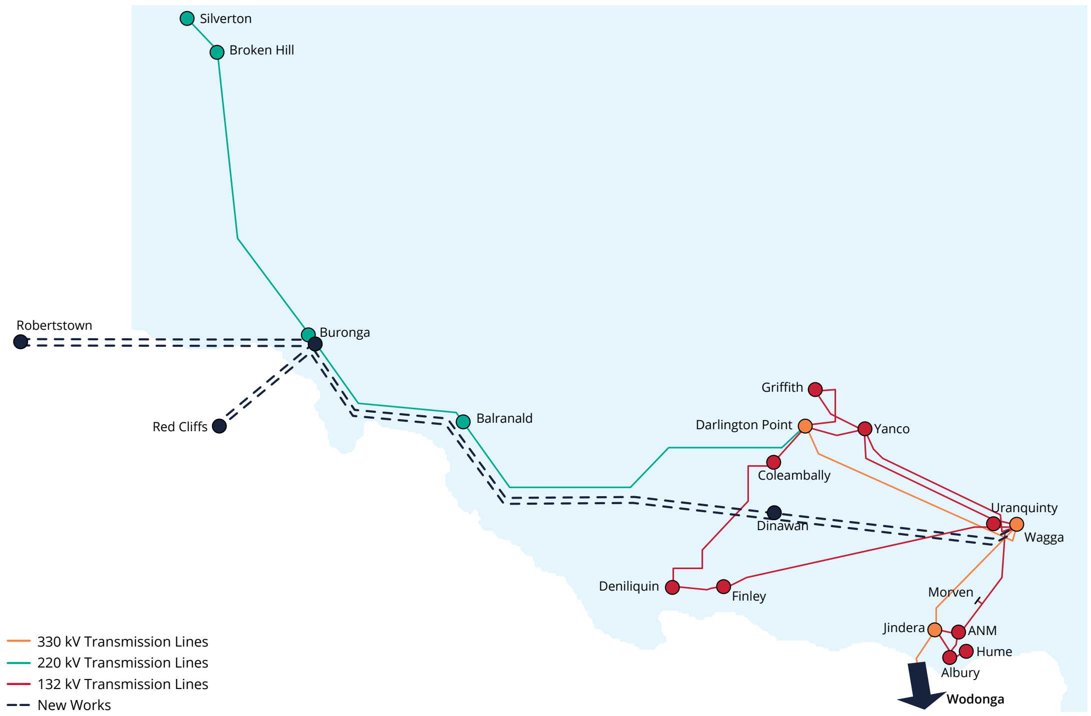
The preferred option includes:

- Installing a new 500/330 kV transformer at South Morang (Victorian works);
- Upgrade the South Morang – Dederang 330 kV lines 1 and 2 to allow operation at thermal rating (Victorian works);
- Install modular power flow controllers on both Canberra – Upper Tumut, and Yass – Upper Tumut 330 kV lines to balance power flows and increase transfer capacity across the region (NSW works).

The indicative increase in capacity of the interconnector option is approximately 170 MW. The VNI Upgrade project is identified as an actionable ISP project and is expected to be completed by December 2021 at an estimated cost for the NSW works of $45 million.

2.1.3 EnergyConnect

Figure 2.3: EnergyConnect preferred option



A new interconnector between NSW and South Australia (SA) will provide greater access for low-cost renewable energy in SA to supply the eastern states when variable renewable generation in SA is high. It will also allow lower-cost baseload generation in the eastern states to displace higher cost gas-fired generation in South Australia when variable renewable generation in SA is low.

It will also:

- Unlock additional renewable generation resources in the Murray River and Riverland area
- Enhance security of supply for South Australia
- Increase the level of firm contractible capacity and improve market liquidity in South Australia

TransGrid has optimised the route of the interconnector during its development. The preferred route features a direct path from Buronga to Wagga Wagga rather than via the existing Darlington Point substation, at which new line entries are physically constrained. It reduces the route length and avoids high-quality irrigated farming land in the Coleambally and Darlington Point areas.

As a result of the new route, the scope of the project now includes a new substation south of Darlington Point, known as Dinawan[14], and a double circuit from Dinawan to Wagga Wagga.

The benefits of the optimised scope include:

- A reduction in total route length;
- Optimised transmission development in south-west NSW, aligning with development of the south-west renewable energy zone in a way that avoids high-quality farming land. The establishment of Dinawan substation can also optimise transmission development, taking into account the future Victoria to New South Wales Interconnector West (VNI West).
- Reduction in project delivery risk, by improving transmission line land access[15] and reducing environmental and stakeholder/community impacts[16] to achieve the project completion date.

[14] The Dinawan site is approximately 50km south-west of Darlington Point

[15] Line route access to Dinawan is much less congested, with far less competing land use, compared to Darlington Point. This increases the certainty, and likely reduces the cost of acquiring land.

[16] The refined scope minimises impacts on higher value agricultural and sensitive irrigated land, and encounters a lower number of recorded Aboriginal cultural heritage sites

The optimised scope includes:

- A new 330 kV double circuit line between Robertstown (SA) and Buronga (NSW);
- A new 330 kV double circuit line between Buronga and Dinawan;
- A new 330 kV double circuit line between Dinawan and Wagga Wagga;
- A new 330 kV substation at Robertstown, including two 275/330 kV transformers at Robertstown (SA);
- New 330 kV Phase Shift Transformers (PSTs) at Buronga;
- New 330/220 kV transformers at Buronga;
- New double circuit 220 kV line from Buronga to Red Cliffs in Victoria to replace the existing 220 kV single circuit line;
- Augmentation of existing substations at Robertstown, Buronga, Wagga Wagga and Red Cliffs;
- A new 330 kV switching station at Dinawan;
- Turn in the existing 275 kV line between Robertstown and Para into Tungkillo;
- Static and dynamic reactive plant at Robertstown, Buronga and Dinawan; and
- A Special Protection Scheme.

The indicative capacity of this interconnector is 800 MVA. EnergyConnect is identified as an actionable ISP project. Subject to approval of the Contingent Project Application, it is expected to be completed by March 2024 at a total cost of $2.4 billion of which works in NSW comprise $1.9 billion.

2.1.4 Reinforcement of the southern NSW network (HumeLink)

Reinforcement of the southern NSW transmission network would provide access to renewable and peaking generation in southern NSW and Victoria, to meet demand in the major load centres of Sydney, Newcastle and Wollongong at lower cost than building new generation at the major load centres.

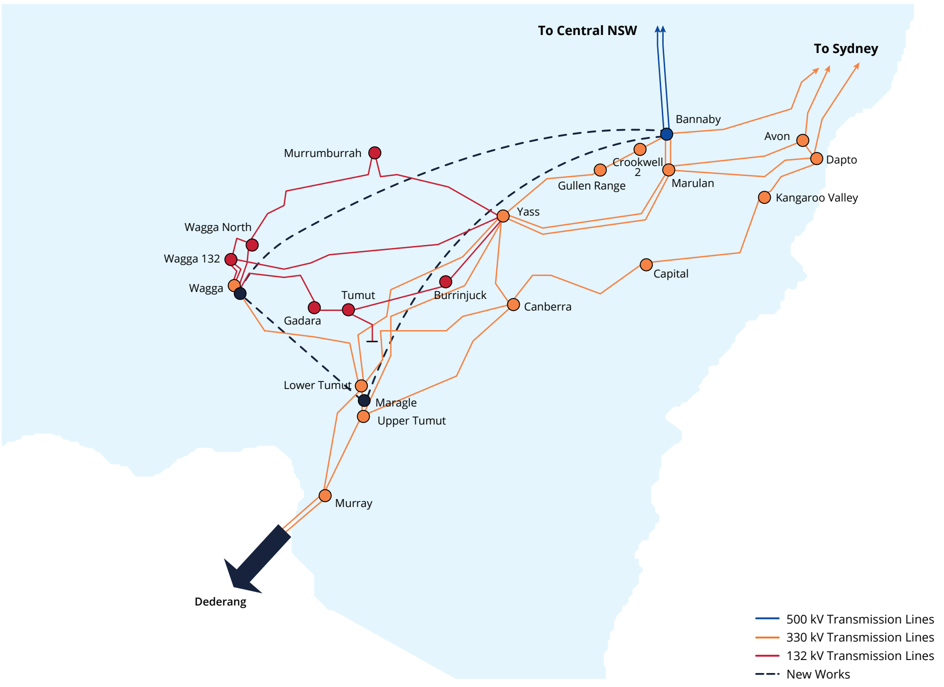
We have applications to connect from renewable generation projects in southern NSW totalling 1,900 MW and pumped hydro at Snowy 2.0 of 2,000 MW. However, the existing transmission capacity between southern NSW and major load centres of Sydney, Newcastle and Wollongong is already heavily utilised at times of peak demand. While the VNI Upgrade will maximise utilisation of the existing assets using modular power flow control devices, these will provide relatively small increases in capacity compared with the generation that has applied to connect. Around 500 MW of existing generation in southern NSW will still be unable to serve the major load centres at peak times.

TransGrid is investigating options to reinforce the NSW southern shared network to increase transfer capacity to the state's major load centres of Sydney, Newcastle and Wollongong. This would:

- Increase the transfer capacity and stability limits between the Snowy Mountains and major load centres of Sydney, Newcastle and Wollongong;
- Enable greater access to lower cost generation to meet demand in these major load centres; and
- Facilitate the development of renewable generation in high quality renewable resource areas in southern NSW as well as southern states, which will further lower the overall investment and dispatch costs in meeting NSW demand whilst also ensuring that emissions targets are met at the lowest overall cost to consumers.

The Project Assessment Draft Report (PADR), published in January 2020, found that a 500 kV option between Maragle, Wagga Wagga and Bannaby provides the greatest net market benefit and is the preferred option.

Figure 2.4: HumeLink preferred option



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[17] FTi, Benefits of Project EnergyConnect, June 2020

The scope includes:

- New Wagga Wagga 500/330 kV Substation and connection to the existing 330kV Wagga Wagga Substation
- Three 500 kV transmission lines:
  - Between Maragle and Bannaby 500 kV Substation;
  - Between Maragle and Wagga Wagga 500 kV Substation; and
  - Between Wagga Wagga and Bannaby 500 kV Substation
- Five 500/330/33 kV 1,500 MVA transformers, three at Maragle substation and two at Wagga Wagga Substation
- Equipment upgrades at Lower Tumut and Upper Tumut Substations to accommodate increased fault levels
- Expansion of the Wagga Wagga, Bannaby and Maragle substations to accommodate the additional transmission lines

HumeLink is identified as an actionable ISP project. The preferred option is expected to deliver gross benefits of approximately $2.3 billion, as assessed in the PADR.

2.1.5 Victoria to New South Wales Interconnector West (VNI West)

Additional interconnection between NSW and Victoria would help maintain reliability of supply in Victoria, as Victorian coal-fired generators are scheduled to retire in the late 2020s and the 2030s. It would mitigate reliability risks associated with diminishing reliability of the existing coal fleet ahead of their scheduled retirements, and provide insurance against unexpected early plant closures. A western route for additional interconnection would also provide a significant increase in capacity for low-cost renewable generation in south-western NSW and north-western Victoria.

The market benefits of additional interconnection come from:

- Efficiently maintaining supply reliability in Victoria following the closure of further coal-fired generation and the decline in ageing generator reliability – including mitigation of the risk that existing plant closes earlier than expected
- Facilitating efficient development and dispatch of generation in areas with high quality renewable resources in Victoria and southern NSW through improved network capacity and access to demand centres
- Enabling more efficient sharing of resources between NEM regions.

AEMO and TransGrid are jointly undertaking a RIT-T to assess the technical and economic viability of expanding the interconnector capacity between Victoria and New South Wales, to identify the preferred option to meet the identified need and its optimal timing.

The options proposed to meet the identified need include:

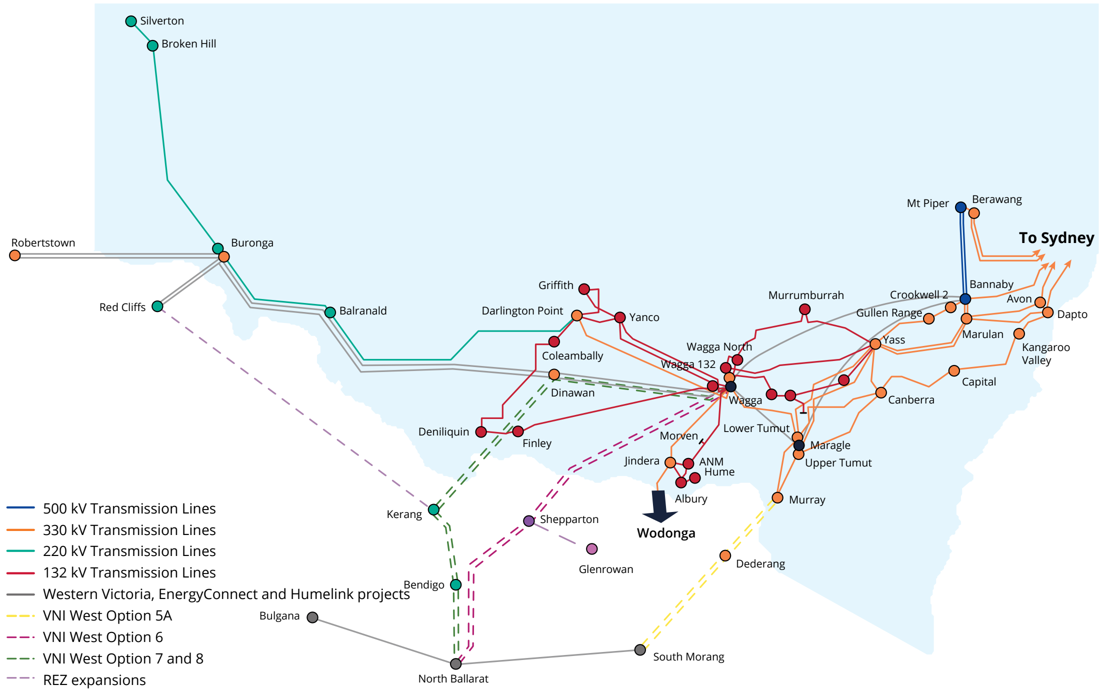
- New 330 kV transmission from South Morang via Dederang to Murray
- New 500 kV transmission from North Ballarat via Bendigo and Shepparton to Wagga Wagga
- New 500 kV transmission from North Ballarat via Bendigo, Kerang and Dinawan to Wagga Wagga
- New 330 kV transmission lines from North Ballarat via Kerang and Dinawan to Wagga Wagga.

Potential expansions to accommodate renewable energy connections are also being considered:

- Expansion A: New transmission lines to unlock generation capacity from Kerang to Red Cliffs
- Expansion B: New transmission lines to unlock generation capacity from Shepparton to Glenrowan.

VNI West is identified as an actionable ISP project with decision rules that allow for adaptation if circumstances change. AEMO and TransGrid are jointly progressing activities to publish a PADR under the actionable ISP framework by March 2021.

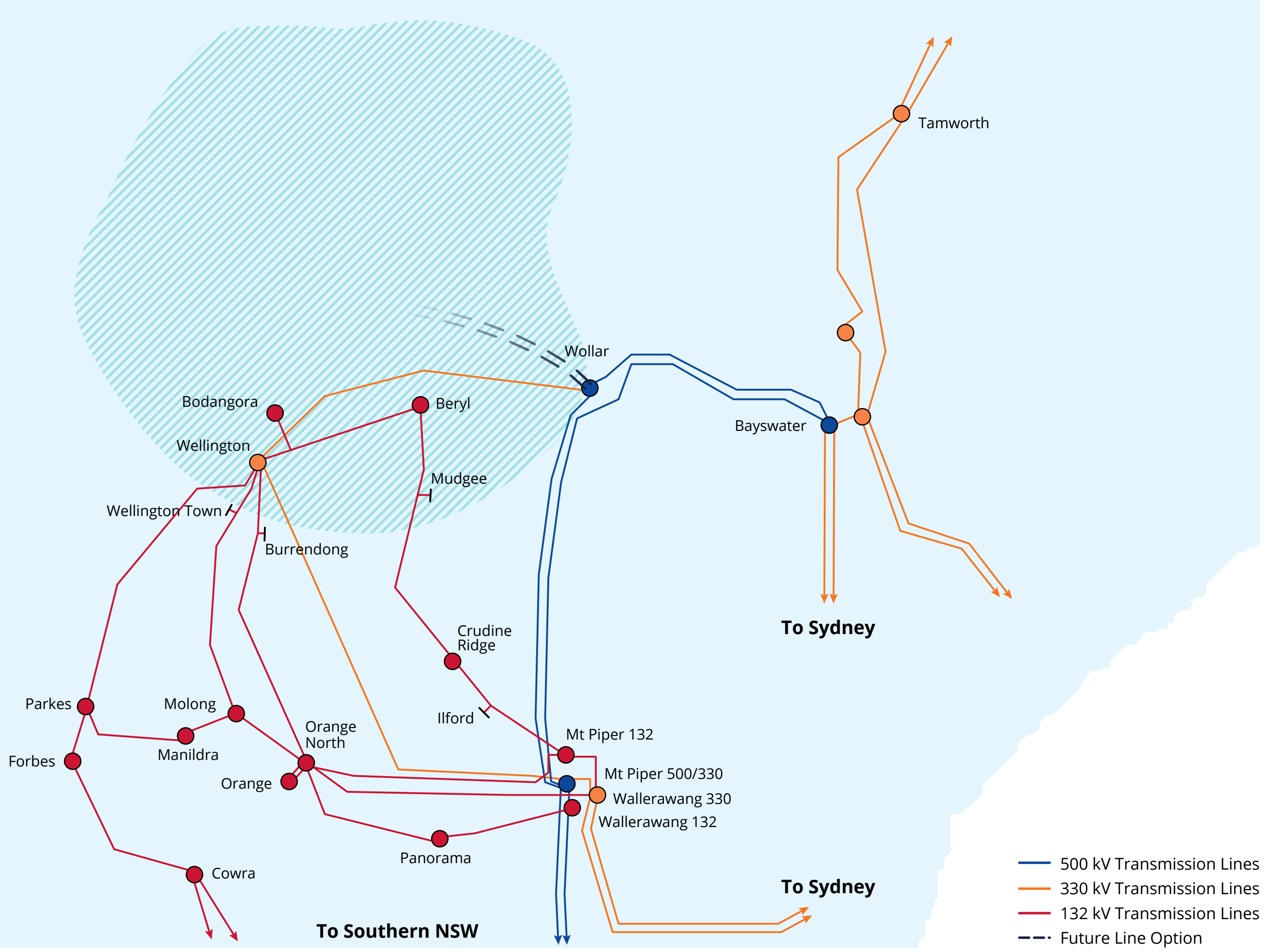
Figure 2.5: VNI West Credible Options



Planned Projects

2.1.6 Central-West Orana Renewable Energy Zone

Figure 2.6: Central-West Orana Renewable Energy Zone



The Central-West Orana REZ will facilitate scale-efficient development and integration of low-cost renewable generation into the power system. The REZ forms part of the NSW Electricity Strategy, and the first stage was announced by the NSW Government in June 2020.

The first stage is a pilot that will enable 3,000 MW of generation in the Central-West Orana region, unlocking regional investment and new generation infrastructure within the REZ. The pilot delivery model will inform the development of other REZs.

The NSW Government has received 113 registrations totalling 27 gigawatts of generation and storage in the REZ, in response to a call for expressions of interest.[18]

TransGrid is investigating options for transmission backbone infrastructure in the Central-West Orana REZ. The options would optimise the opportunities for scale-efficient generator connections, delivering benefits from:

- Lower costs to meet the reliability standard for NSW, by enabling access to the output from additional generation connections; and
- Lower market dispatch costs (and hence lower costs to consumers).

Central-West Orana REZ transmission is identified as an actionable ISP project and may be staged if required to maximise economic benefits.

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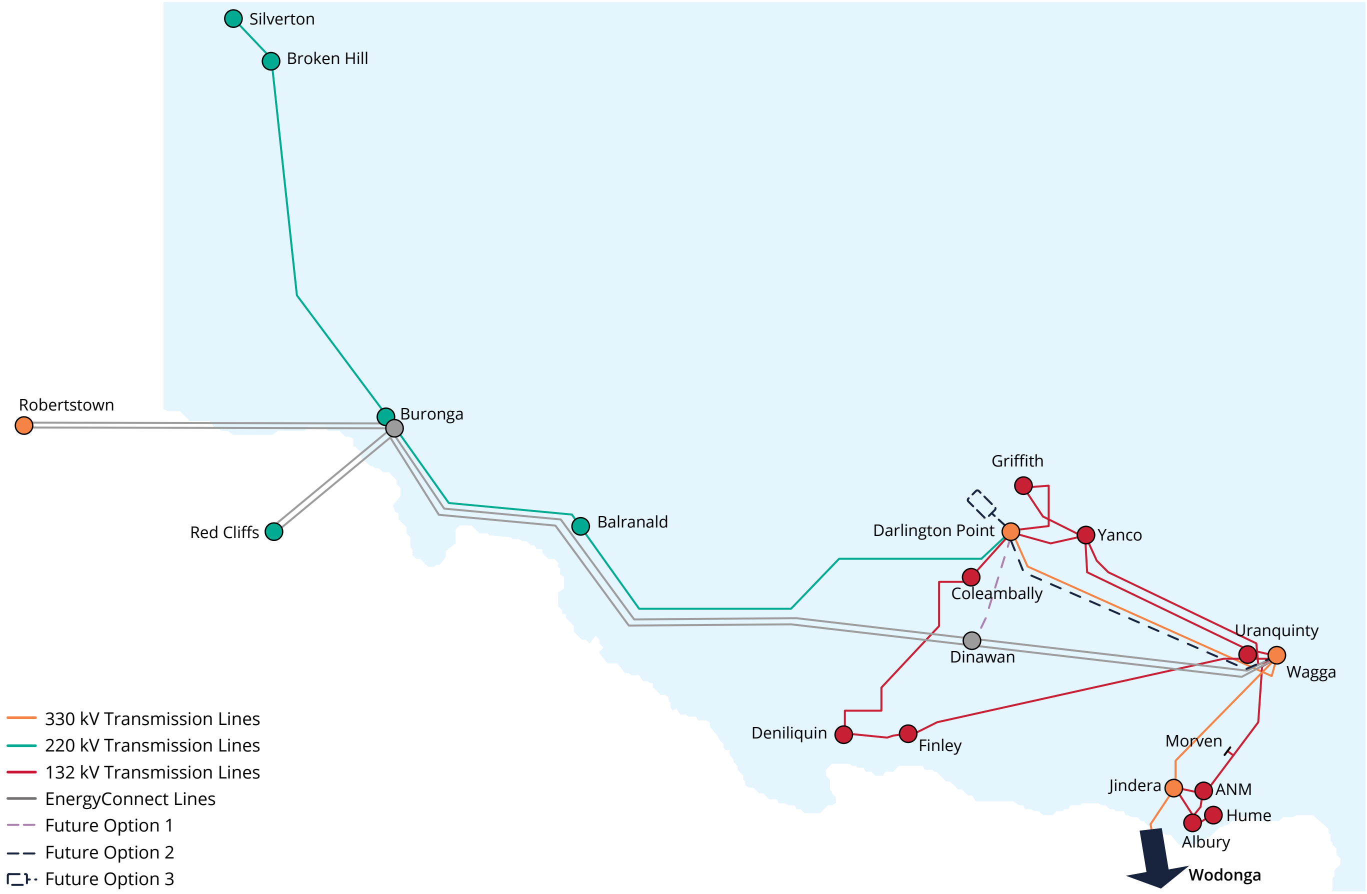
[18] https://energy.nsw.gov.au/renewable-energy-zone-sparking-investment-boom, accessed 26 June 2020.

2.1.7 Improving stability in South-West NSW

Figure 2.7: South-West NSW network



There is an opportunity to increase the level of renewable generation that can be integrated in south-west NSW by improving voltage stability. This will address a constraint on flows in an easterly direction on the 330kV transmission line from Darlington Point towards Wagga Wagga (63 Line).

The main power system in south western NSW consists primarily of a 330 kV transmission line from Darlington Point to Wagga Wagga (63 Line) and 220 kV transmission lines west of Darlington Point (including X5 Line). Smaller underlying 132 kV transmission lines supply regional towns.

The 132 kV system in south western NSW can experience significant stability issues during an outage of 63 Line. These have historically been prevalent during high power flows west from Wagga Wagga, and managed operationally. Power flows east towards Wagga Wagga have not been high enough to date to cause stability issues during an outage of 63 Line.

The commissioning of new generation in south western NSW is likely to result in high power flows east towards Wagga Wagga from mid-2020. Under these conditions, the 132 kV system will experience more significant stability issues during an outage of 63 Line. In particular, there is a risk of fast voltage collapse which would result in power electronics-based generation becoming unstable.

New operational measures have been implemented to maintain power system stability during high easterly power flows. Considering the very fast timeframe of voltage collapse, AEMO has recently implemented a constraint in the NEM Dispatch Engine (NEMDE) to limit power flows on 63 Line to approximately 300 MW (varying slightly with power system conditions). A further 800 MW generation is due to be commissioned in south-west NSW in the near future. This will result in material constraints to generation in the region under normal power system conditions.

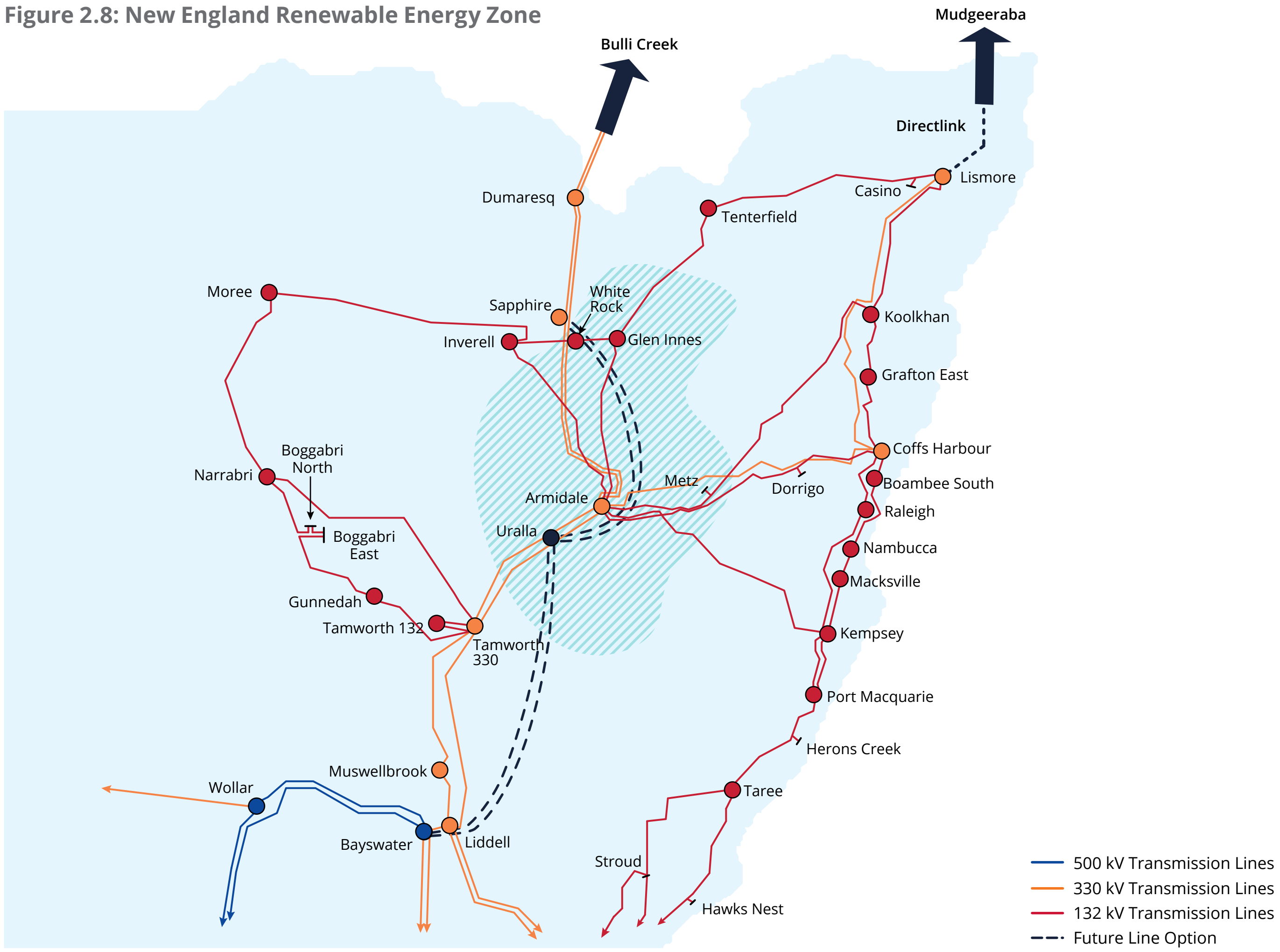
TransGrid is considering options to alleviate this constraint:

- Two variants of a new transmission line between Darlington Point and Dinawan substations;
- A new transmission line between Darlington Point and Wagga Wagga; and
- Alternative technologies such as a static synchronous compensator (STATCOM) solution.

A project to alleviate this constraint will deliver market benefits through relieving existing and forecast constraints on generation in south-west NSW.

2.1.8 New England Renewable Energy Zone

Figure 2.8: New England Renewable Energy Zone



The New England REZ will facilitate scale-efficient development and integration of low-cost renewable generation into the power system. The REZ forms part of the NSW Electricity Strategy, and will provide new generation ahead of the retirement of coal-fired generators in NSW.

TransGrid has received significant ongoing interest from renewable energy proponents seeking to connect to the network in this area.

Presently, there is approximately 520 MW of renewable generation connected in the area. A further 225 MW is committed to connect and more than 1,370 MW is at an advanced stage in the connection process.

However, the limited capacity of the existing 330 kV and 132 kV networks will result in output limitation of connecting generators as the generation in the area increases. Increasing transmission capacity would maximise the existing renewable energy generation opportunities and facilitate new generator connections in the New England area.

Benefits would be derived from:

- Lower costs to meet the reliability standard for NSW, by enabling access to the output from additional generation connections; and
- Lower market dispatch costs (and hence lower cost to consumers).

The project may be accelerated through NSW Government policy[19] and may be staged if required to maximise economic benefits.

New England REZ is identified as a future ISP project. TransGrid is undertaking preparatory activities and will publish a report on the outcome of these activities by 30 June 2021.

An alternative REZ in North West NSW has also been identified as a future ISP project. TransGrid is also undertaking preparatory activities for a North West NSW REZ and will publish a report on the outcome by 30 June 2021.

2.1.9 Medium/large Queensland to New South Wales Interconnector

We are investigating the potential benefits of further increases to transmission capacity between NSW and Queensland, beyond the capacity provided by the QNI Minor Upgrade.

Additional transmission capacity would need to deliver net market benefits, which could come from:

- Efficiently maintaining supply reliability in NSW following the closure of further coal-fired generation and the decline in ageing generator reliability
- Facilitating efficient development and dispatch of generation in areas with high quality renewable resources in northern NSW through improved network capacity and access to demand centres
- Enabling more efficient sharing of resources between NEM regions.

Options to deliver these benefits include:

- A "virtual transmission line" comprised of grid-scale batteries on both sides of a constraint (for bidirectional limit increases), or a grid-scale battery on one side and braking resistor on the other side (for unidirectional limit increases)
- Transmission lines at 500 kV or 330 kV from Bayswater, Wollar or Liddell (NSW) to southern Queensland.

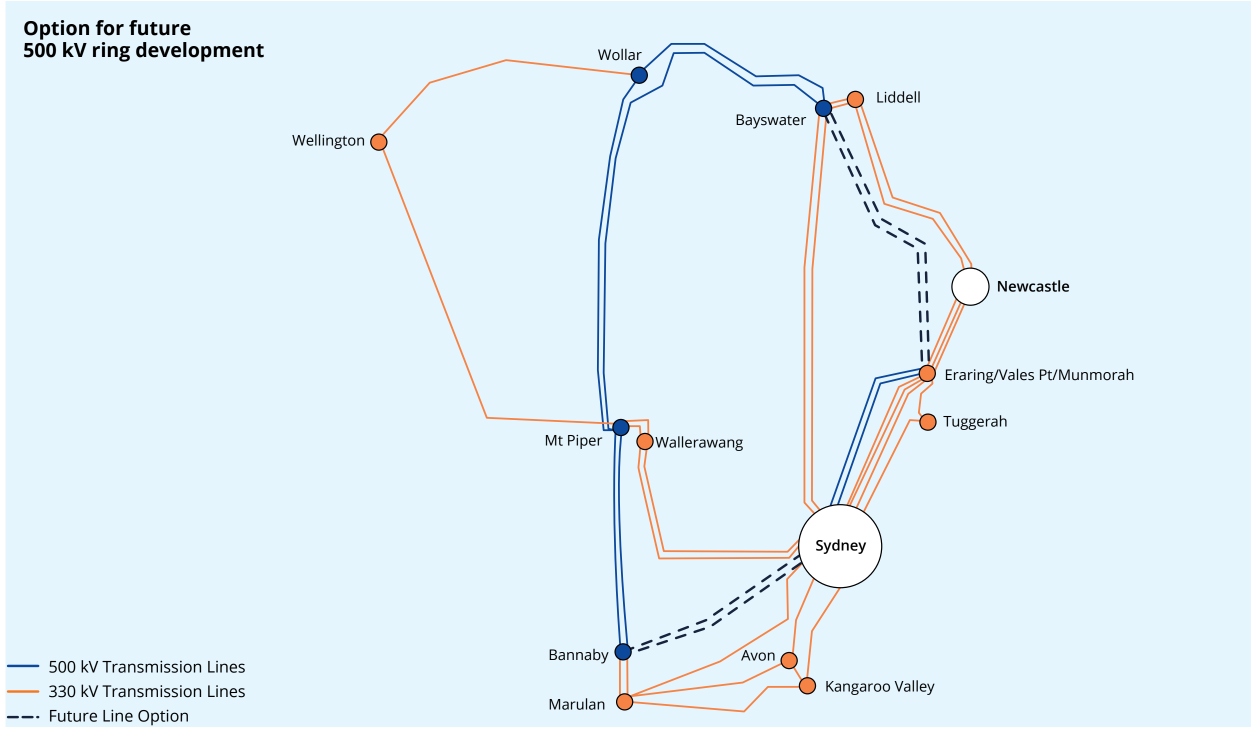
These options can be optimised with capacity to the New England REZ discussed in section 2.1.8, and can be staged by geography, operating voltage and number of circuits to maximise net economic benefits.

Following the development of a medium QNI upgrade, a larger QNI upgrade could be needed to increase the capacity of the network to host renewable energy and share both storage and firming services between the regions. This larger upgrade will depend on future generation developments and retirements in Queensland and NSW.

The medium or large QNI upgrade is identified as a future ISP project. TransGrid is undertaking preparatory activities and will publish a report on the outcome of these activities by 30 June 2021.

2.1.10 Reinforcement to Sydney/Newcastle/Wollongong load centres

Figure 2.9: Reinforcement to Sydney/Newcastle/Wollongong load centres



The Sydney, Newcastle and Wollongong area includes significant urban, commercial and industrial loads that comprise about three quarters of the demand for electricity in NSW.

When power stations at Vales Point and Eraring on the Central Coast retire, it is expected that future demand will be met by the generation outside of the load area. Therefore, there will be a need to increase the capacity from regional NSW to the major load centres. The network reinforcements are expected to be achieved through further development of the 500 kV ring between the Upper Hunter, Central West, Southern Tablelands and Sydney, Newcastle and Wollongong.

In future, the transmission capability within the core NSW network will be mainly determined by the thermal capacity of:

- The 330 kV transmission lines between power stations in the Upper Hunter (Liddell and Bayswater) and the Central Coast; and
- The 330 kV transmission lines from Bannaby to Sydney and the south coast.

Two sections of the 500 kV ring remain to be developed, as shown in **Figure 2.9**. They are:

- A double circuit 500 kV line between the Upper Hunter and Central Coast, which can also be connected in the Newcastle area at a later date; and
- A double circuit 500 kV line between Bannaby and Sydney.

The need and timing for both 500 kV sections are subject to the retirements of Vales Point and Eraring Power Stations or development of renewable generation in regional NSW beyond the Central-West Orana REZ Stage 1.

This project is identified as a future ISP project. TransGrid is undertaking preparatory activities and will publish a report on the outcome of these activities by 30 June 2021.

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[19] New South Wales Government. New England to light up with second NSW Renewable Energy Zone, at https://www.nsw.gov.au/media-releases/new-england-to-light-up-second-nsw-renewable-energy-zone.

2.2 Forecast of constraints

The NER Clause 5.12.2(c)(3) requires reporting the forecast of constraints and inability to meet the network performance requirements set out in the NER Schedule 5.1 or relevant NSW legislations or regulations over one, three and five years. The above information has been set out in this Chapter. TransGrid has provided additional connection point and transmission line data, on an external website. To access this information go to the TransGrid website and navigate to the Transmission Planning page at: https://www.transgrid.com.au/what-we-do/Business-Planning/transmission-annual-planning/Pages/default.aspx

TransGrid's Network Planning function analysed the expected future operation of its transmission networks over a 10 year period, taking into account the relevant forecast loads, any future generation, market network services, demand side and transmission developments and any other relevant data to determine the anticipated constraints over one, three and five years.

TransGrid's Network Planning group conducts its annual planning review which includes the following activities:

- Incorporation of the forecast loads as submitted or modified by relevant registered participants in accordance with the NER Clause 5.11.1;
- A review of the adequacy of existing connection points and relevant parts of the transmission system, and planning proposals for future connection points;
- Taking into account the most recent AEMO system planning updates, including the 2020 ISP, the National Transmission Network Development Plan, and the issue of the 2018 System Strength Impact Assessment Guidelines;
- Consideration of the potential for augmentations, or non-network alternatives to augmentations, that are likely to provide a net economic benefit to all those who produce, consume and transport electricity in the market;
- Consideration of the condition of network assets; and
- Consideration of the potential for replacements of network assets, or non-network options to replacements of network assets, that are likely to provide a net economic benefit to all those who produce, consume and transport electricity in the market.

These activities form the basis by which TransGrid reviews and updates the forecast constraints information provided in this report.

2.3 Subsystem developments

This section describes TransGrid's capital works that are proposed to address specific areas or regional network needs. The information provided in this section describes the work, the actual or potential constraint or inability to meet network performance requirements of the NER Schedule 5.1, the need or proposed operational date, the proposed solution and its cost estimate.

These augmentation works do not cause any material inter-network impact as they address localised or site specific needs within each region. In assessing whether an augmentation to the network will have a material inter-network impact TransGrid has examined if its proposed works will impose power transfer constraints within other Transmission Network Service Provider (TNSP) networks or adversely impact the quality of supply in other TNSP networks.

The information in this section also includes ongoing and recently completed replacement works to provide an integrated overall view of capital expenditure requirements within an area.

Planned projects included in the subsystem developments are aligned with the expenditure allowance approved in the AER's final determination for the 2018/19-2022/23 revenue period. TransGrid considered credible network and non-network options to address the actual or potential constraints or the inability to meet network performance requirements. This includes the use of interconnectors with other regions, generation options, demand side options, market network service options and inter-network options.

The proposed subsystem developments outlined in this section, covering augmentation and replacement works align with the primary objectives of AEMO's ISP and National Transmission Network Development Plan, those being:

- Enhancing interconnection capacity between NSW and the other states;
- Supporting the development and connection of large-scale renewable energy zones across the NEM; and
- Improving system strength and security in response to the decline of thermal generation sources and the increase in renewable energy sources, particularly in NSW and Victoria.

The information reported in this section meets the requirement of the NER Clause 5.12.2(c)(5) and (6).

TransGrid presently does not anticipate any additional subsystem development network investment beyond that given in the following sections, based on current planning information and requirements.

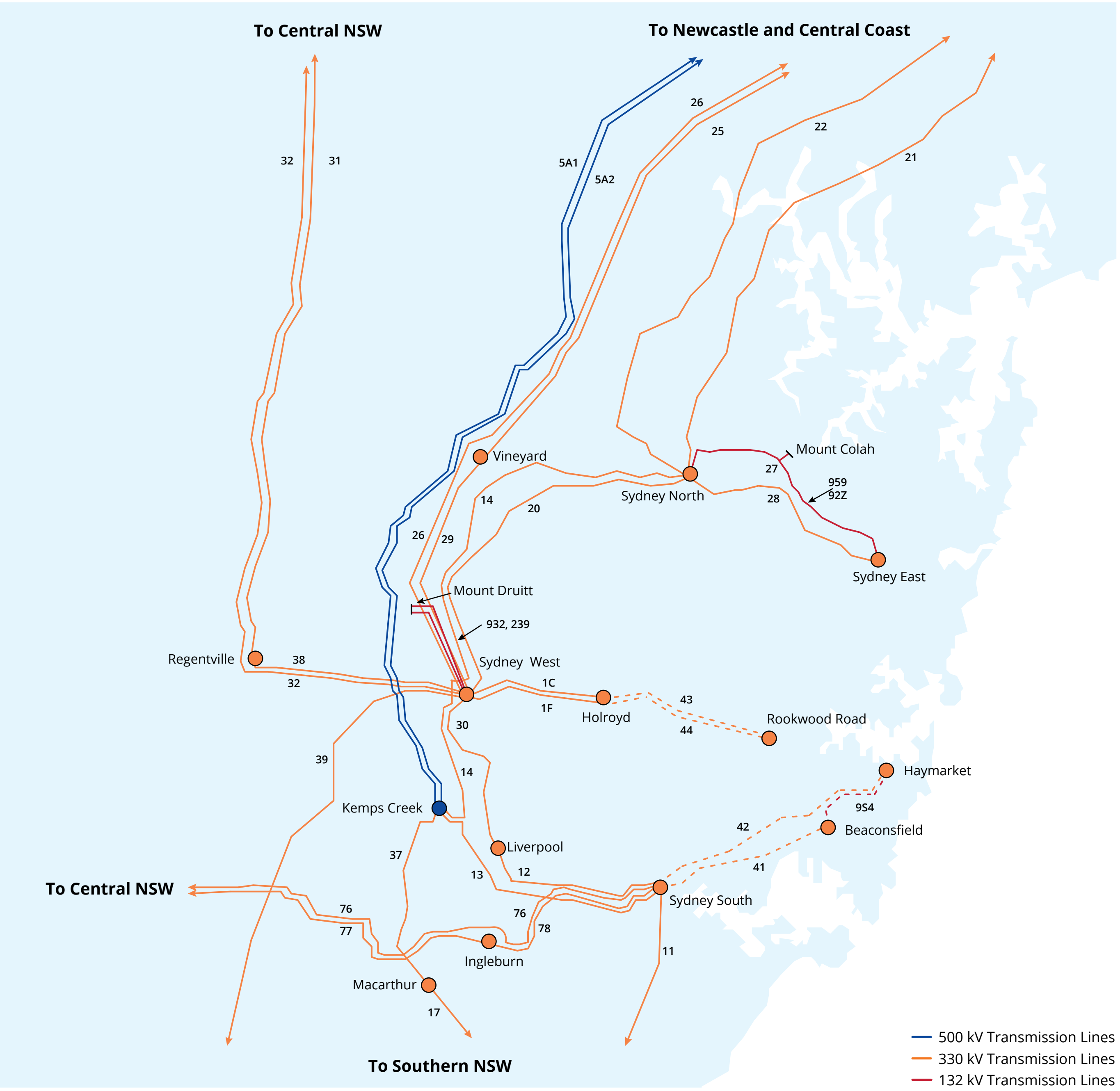
2.3.1 Greater Sydney

The Greater Sydney area includes the Central Business District (CBD) of Sydney which is the largest hub in Australia for economic activity, major transport infrastructure, industry and tourism. Increasingly, the Inner Sydney area is also home to a growing number of people attracted to shorter commutes and access to entertainment and recreation offered by the central Sydney precincts and the Sydney Harbour foreshore.

The Inner Sydney area also provides a base for a number of major infrastructure and transport networks including road tunnels, airports, ports, train networks and data centres. These entities require a high level of electricity reliability and security to maintain services required for Sydney to operate as a major international city. Many of these entities are currently implementing large developments or expansion plans, with many projects under construction or scheduled for the near term.

The following figure shows the Greater Sydney network, including transmission supplies to the area.

Figure 2.10: Greater Sydney network



Planned projects

The table below provide a list of planned augmentation projects to address forecast load growth and connect new distribution zone substations in the Greater Sydney area.

Low-cost investment opportunities that may deliver economic benefits or improve system security have also been identified.

Table 2.1: Planned projects in Greater Sydney

Project description	Planned date	Total cost ($million March-20)	Purpose and possible other options	Project justification
Installation of one 66 kV switchbay at Macarthur 330/132/66 kV Substation	Dec 2020	1.7	For connection of Endeavour Energy's planned Menangle Park Zone Substation to meet load growth in a new housing development at Menangle Park. Refer to Endeavour's DAPR for more details.	Load driven
Installation of two 132 kV switchbays at Sydney West 330/132 kV Substation	Jun 2021	3	For connection of Endeavour Energy's supply to a new data center load near Sydney West substation. Refer to Endeavour's DAPR for more details.	Load driven
Installation of one 330/66 kV transformer at Macarthur 330/132/66 kV Substation	Dec 2021	8.7	To address a capacity constraint in the Nepean area that has arisen from 2018. Temporary load transfers in the Endeavour Energy network are being enacted to defer the need date. To fully defer the need, demand management in the Nepean area of 100 MW would be required from 2019, increasing by 10-13 MW each year. This is not expected to be available at the required level.	Load driven
Installation of one 132 kV switchbay at Sydney West 330/132 kV Substation	Feb 2022	3	For connection of Endeavour Energy's planned South Erskine Park Zone Substation to meet load growth in Western Sydney Employment Area. Refer to Endeavour's DAPR for more details.	Load driven
Installation of one 100 MVAr shunt reactor in Greater Sydney Region	Feb 2023	9	For replacement of the reactive support temporarily provided by Kemps Creek No. 2 SVC shunt reactor. The installation location will be optimised within Greater Sydney region.	Voltage control
Installation of one 66 kV switchbay at Macarthur 330/132/66 kV Substation	Apr 2024	1.3	For connection of Endeavour Energy's planned Mt Gilead Zone Substation to meet load growth in a new housing development at Mt Gilead. Refer to Endeavour's DAPR for more details.	Load driven
Beaconsfield BSP supply	Dec 2024	10	To address the network constraints due to overloading of Beaconsfield 330/132 kV transformer under modified N-2 contingency	Load driven
Construction of a new bulk supply point in the vicinity of upcoming Western Sydney developments	Feb 2025	40 to 50	A new bulk supply point to be built and connected to TransGrid's 330 kV transmission line 39 Bannaby to Sydney West or adjacent to TransGrid's Kemps Creek Substation. The bulk supply point will support load growth in the Western Sydney region, including the new Western Sydney Airport and new residential and commercial precincts.	Load driven
Eraring to Kemps Creek 500 kV smart grid controls	Jun 2025	2.6	Installation of a special protection scheme to protect against trips of both of the 500 kV lines from Eraring to Kemps Creek. For a double circuit trip, the scheme will run back generation and load to avoid cascading outages and further loss of load in the Greater Sydney area.	Economic benefits
Sydney northwest 330 kV smart grid controls	Jun 2025	3	Installation of a special protection scheme to protect against trips of two or more of the following 330 kV lines: Sydney North to Tuggerah (21), Sydney North to Vales Point (22), Vineyard to Eraring (25), Sydney West to Tuggerah (26) and Munmorah to Tuggerah (2M). For multiple circuit trips, the scheme will run back generation and load to avoid cascading outages and further loss of load in the network.	Economic benefits
Sydney South 330 kV smart grid controls	Jun 2025	1.8	Installation of a special protection scheme to protect against trips of two or more of the 330 kV lines from Sydney South Substation. For multiple circuit trips, the scheme will run back generation and load to avoid cascading outages and further loss of load in the network.	Economic benefits
Bayswater to Sydney West 330 kV smart grid controls	Jun 2025	2.8	Installation of a special protection scheme to protect against trips of two or more of the following 330 kV lines: Bayswater to Regentville (31), Bayswater to Sydney West (32) and Regentville to Sydney West (38). For multiple circuit trips, the scheme will run back generation and load to avoid cascading outages and further loss of load in the Greater Sydney area.	Economic benefits
Installation of one 132 kV switchbay at Vineyard 330/132 kV Substation	Sep 2025	1.9	For connection of Endeavour Energy's planned Box Hill Zone Substation, to supply a new urban development at Box Hill. Refer to Endeavour's DAPR for more details.	Load driven
Facilitate Ausgrid connection works at Beaconsfield Substation.	Sep 2028	0.4	This project is to facilitate Ausgrid's replacement of 132 kV feeder 9SA and 92P Beaconsfield to Campbell Street and Belmore Park. Refer to Ausgrid's DAPR for more details.	Joint planning

Ongoing projects

Powering Sydney's Future

The Powering Sydney's Future project will ensure the reliability of supply to businesses and residents in surrounding Sydney's Central Business District and surrounding areas. The project is a new 20km, 330 kV cable between the existing Rookwood Road and Beaconsfield Substations with a capacity of ~750 MVA. To cater for future electricity demand growth, conduits for a second supply cable will be laid at the same time. Construction will commence in August 2020.

To keep customer representatives informed during project execution, a Stakeholder Management Committee (SMC) was formed to work with TransGrid through the delivery of the project. The SMC members are a subgroup of the TransGrid Advisory Council (TAC).

Fast Frequency Response

Grid-scale batteries are a relatively new technology for the industry, providing services to the transmission network, the wholesale electricity market, and frequency control ancillary service markets. A grid-scale battery co-located with a transmission substation can also provide cost savings through its connection to existing assets (BNEF 2019)[20].

A network-owned battery can reduce the cost to consumers by stacking multiple benefits. TransGrid does not participate in energy or FCAS markets, but can make capacity available to market participants where there are complementary use cases for a BESS, to allow various types of benefits to be realised.

As part of the RIT-T for Powering Sydney's Future, a 10 MW battery at Beaconsfield was investigated as one element of the demand management solution. Space constraints and available connection capacity limited the battery size and interest from market participants, which led to the consideration of alternative locations for providing Fast Frequency Response (FFR) services.

TransGrid is investigating the option of a 50 MW battery in Western Sydney to pilot the provision of fast frequency response and synthetic inertia as network services, which would enable TransGrid to understand its battery technology performance during disturbances over a wide range of system conditions and validate its characteristic in system stability models.

The installation of a pilot for fast frequency response is consistent with the AEMC's recommendations in its System Security Frameworks Review Final Report. The report recommends an obligation on TNSPs to provide minimum levels of inertia, or alternative equivalent services, to allow the power system to be maintained in a secure operating state.

If a grid connected storage solution is shared with other value streams, the cost allocation methodology will be applied to allocate the costs, as required under the Rules.

Completed projects

The following are projects which were completed after the 2019 TAPR was published:

- Replacement of Sydney North secondary system;
- Refurbishment work of line 20 from Sydney West to Sydney North;
- Various transformer refurbishment works for Kemps Creek No. 1 and No. 2, Ingleburn No. 1, Sydney North No. 3 and No. 4; and
- Cable 41 voltage control project to address the high voltage issues.

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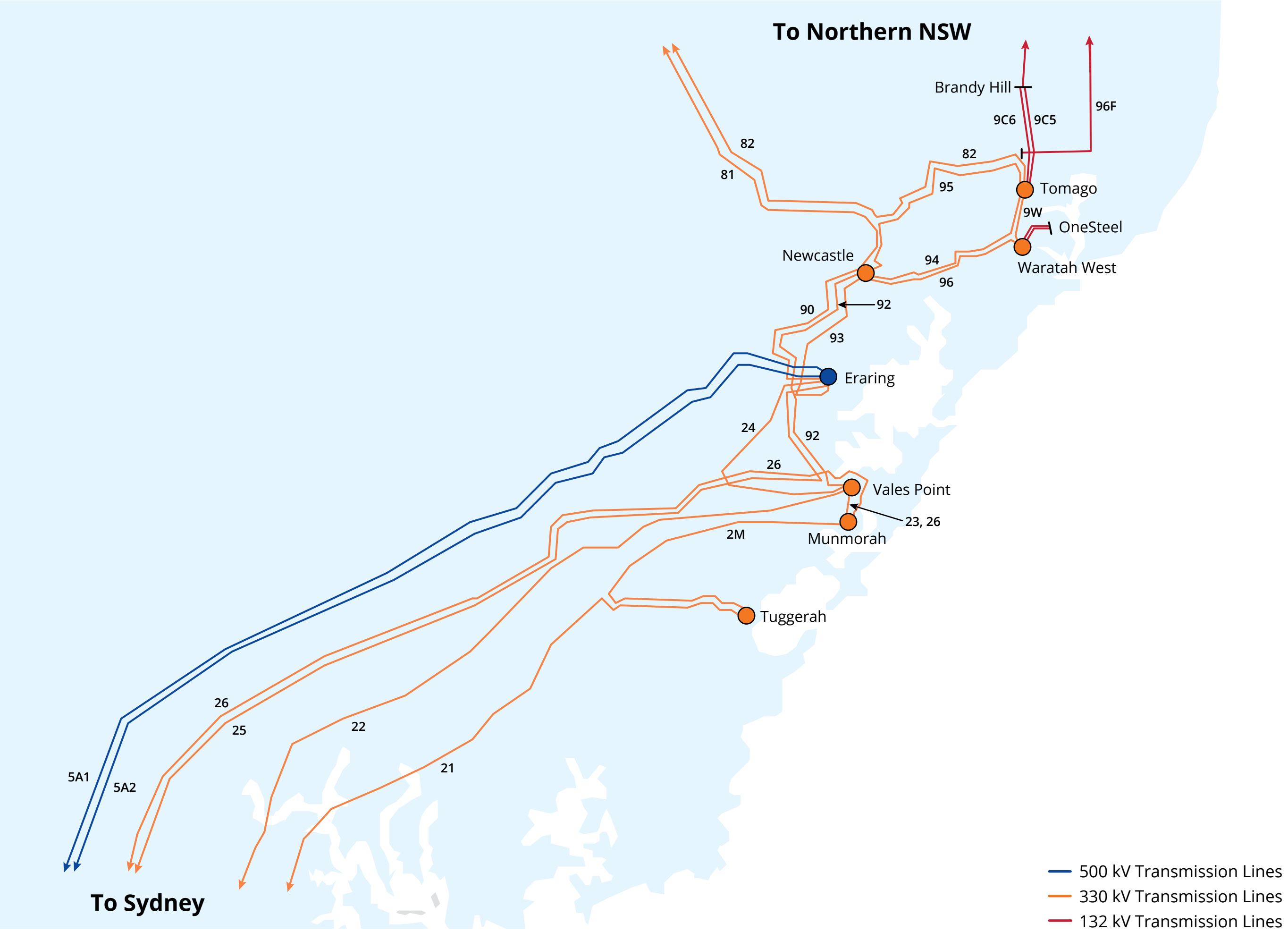
[20] BloombergNEF, Business Models for Energy Storage – Australian Examples, 1 August 2019.

2.3.2 Newcastle and Central Coast

Figure 2.11: Newcastle and Central Coast network



Planned projects

There are no planned prescribed augmentation projects in the Newcastle and Central Coast region.

Ongoing projects

There are no ongoing prescribed augmentation projects in the Newcastle and Central Coast region.

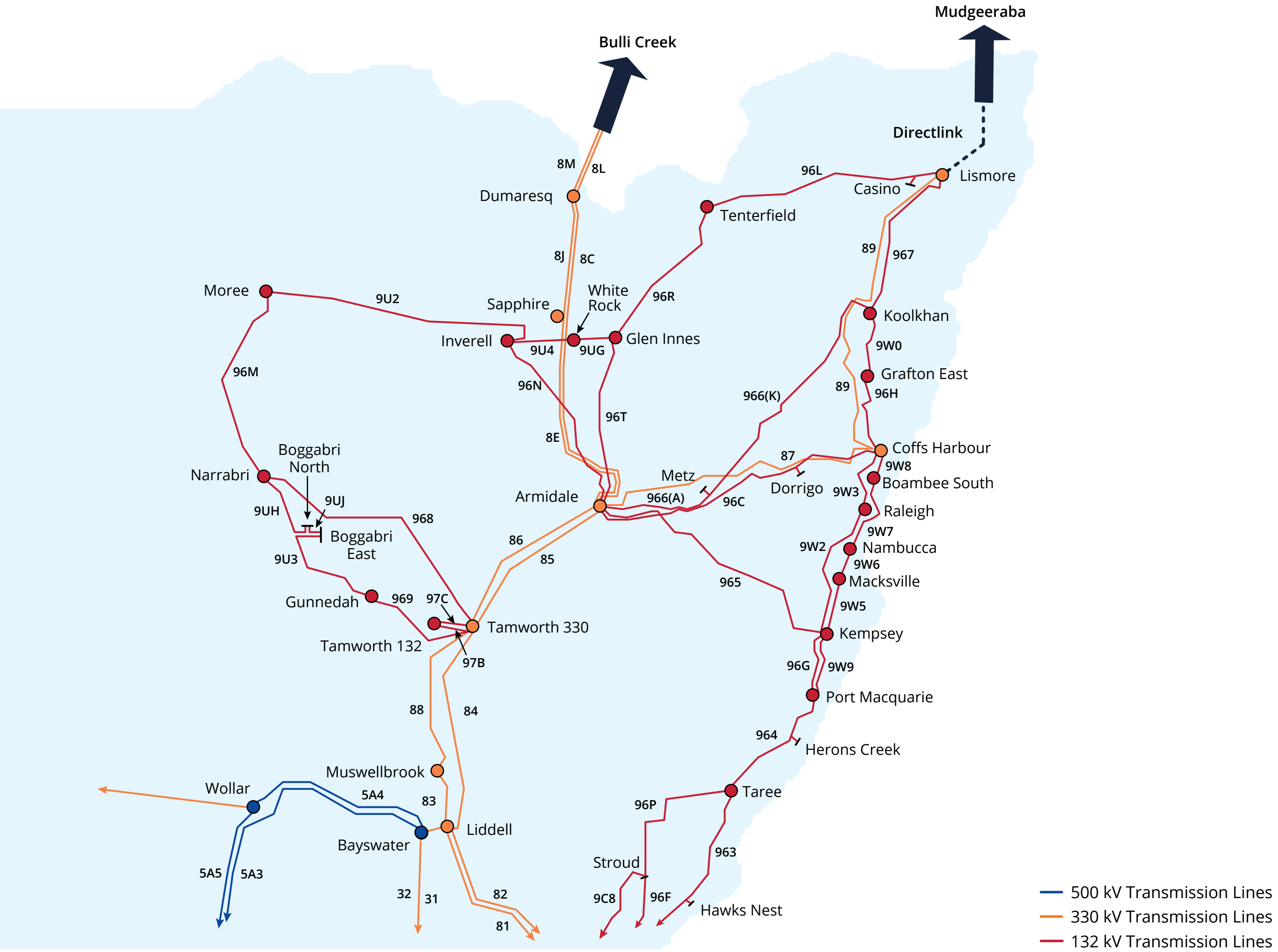
Completed projects

The following project was completed after the 2019 TAPR was published:

- Renewal works to address end-of-life condition of various Munmorah 330/132 kV Substation assets.

2.3.3 Northern NSW

Figure 2.12: Northern NSW network



Planned projects

The following projects are currently planned in the Northern region.

- Thermal and voltage constraints may arise in the Gunnedah area leading to an emerging risk to reliability if large mining or gas developments proceed in the area. These developments, along with other planned projects which improve security of supply to customers and provide economic benefits, are shown in **Table 2.2**.

Table 2.2: Planned projects in Northern NSW

Project description	Planned date	Total cost ($million March-20)	Purpose	Project justification
Armidale capacitor transfer tripping scheme	Jul 2021	0.3	Implementation of a transfer tripping scheme for the Armidale 132 kV capacitor bank to improve QNI transfer capability during an outage of an Armidale 330/132 kV transformer.	Improve transfer capability
Armidale North Coast Line Overload Load Shedding (LOLS) expansion	Jan 2022	<0.1	Modification of the LOLS tripping scheme to include Essential Energy's Koolkhan to Maclean 66 kV feeder.	Economic benefits
Transposition of 330 kV lines 87 (Coffs Harbour to Armidale) and 8C/8E/8J (Armidale to Dumaresq)	Jun 2022	1.5	These transpositions are to manage negative-sequence voltage levels greater than 0.5% within the northern NSW transmission network.	Economic benefits
Network augmentation of North Western 132 kV Subsystem and at Narrabri 132 kV Substation	Jan 2023	7 to 20	Strengthen the Narrabri area to manage emerging voltage and thermal limitations due to load growth.	Load driven
Gunnedah-Narrabri 66 kV Voltage Control	Jun 2023	<0.1	Provide Automatic Voltage Control of Capacitor Banks at Gunnedah. There is an opportunity to avoid loss of load by implementing smart auto-tripping of the Gunnedah capacitors following a critical contingency.	Economic benefits
Taree 132 kV bus capacity augmentation	Nov 2024	1.1	A trip of any 132 kV busbar section at Taree 132/66 kV Substation will interrupt supply to the Taree area. Installation of a new circuit breaker bay to allow two busbar protection zones at Taree Substation will allow continued supply to customers in the Taree area during a bus section outage.	Economic benefits
Reconductor and remediate the Gunnedah to Tamworth 132 kV line (969)	Nov 2024	20.7	Required to manage a thermal constraint due to the rating of the 969 line if large developments proceed in the area. 13 structures (26 poles) to be removed and replaced with concrete pole structures, and remediation of 81 existing structures.	Load driven
Northwest NSW 330 kV smart grid controls	Jun 2025	3.6	Installation of a special protection scheme to protect against trips of two or more of the 330 kV lines between Armidale and Liddell. For multiple circuit trips, the scheme will run back generation and load to avoid cascading outages and further loss of load in the network.	Economic benefits

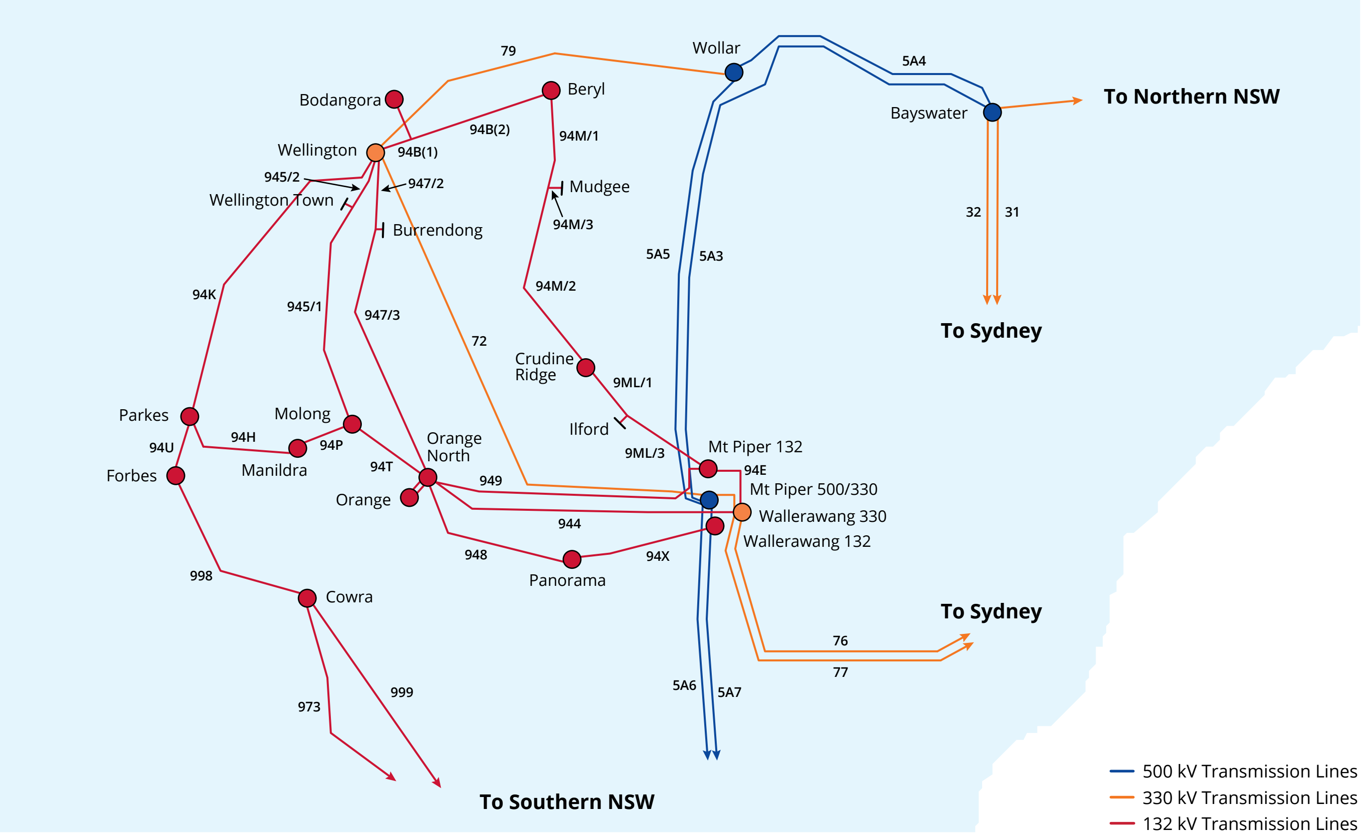
Completed projects

The following project was completed after the 2019 TAPR was published:

- Grafton East 132 kV Substation which was built in the NSW North Coast network to service a new load. The project involved cutting in and out line 96H Coffs Harbour to Koolkhan 132 kV transmission line. The split formed line 96H Coffs Harbour to Grafton East and 9W0 Grafton East to Koolkhan 132 kV lines.

2.3.4 Central NSW

Figure 2.13: Central NSW network



Planned projects

The following are planned projects in the Central NSW region:

- The central NSW network has limited available capacity and this limits connection of large loads or generation in the area. This is due to voltage and thermal limitations. Outages of elements in the network pose significant risks to the network due to the limited capability to connect generation, mostly in the 132 kV network.
- There is strong interest from renewable energy proponents seeking to connect to the 330 kV transmission line between Wollar and Wellington (79 line). TransGrid is currently investigating potential transmission augmentation within the Central West to support the development of the Central-West Orana REZ (Refer to Section 2.1.6).
- The Molong to Orange North 132 kV transmission line (94T line) has a relatively low thermal rating which makes it susceptible to overload as generators connect to the West of Molong Substation. This issue is emerging and in order to prevent output limitations on generation, the thermal capacity of the line will need to be increased. A number of options are being considered, with a preferred option yet to be identified.
- The Orange and Parkes areas are forecast to experience significant growth in industrial load demand. Recent studies have identified that the network will need to be reinforced in order to alleviate emerging voltage constraints.
- Other planned projects in the area includes those in **Table 2.3**.

Table 2.3: Planned projects in Central NSW

Project description	Planned date	Total cost ($million March-20)	Purpose	Project justification
Voltage support in the Parkes area	2021	5 to 40	It is expected that the demand in the Parkes area will increase over the next 10 years mainly due to the increased industrial demand. Further growth is expected in this area with the NSW Government's Parkes Special Activation Precinct. TransGrid have undertaken studies and concluded that the network will need to be reinforced to reliably supply the increased demand. This may include the installation of one or more capacitor banks at optimal locations in the Parkes area, to manage the load growth in the medium-term. The optimal size and location for the voltage support equipment is to be determined. It is expected that further network augmentation will be required in this area in the long-term. To manage the risk in the short-term, TransGrid has identified the need to install an UVLS scheme at Parkes Substation, as an emergency control measure.	Compliance
Voltage support in the Orange area	2021	4.6 to 40	The latest Essential Energy forecasts indicate that demand is increasing in the Orange area. TransGrid have undertaken studies and concluded that the network in the Orange area will need to be reinforced. Various network and non-network options are identified, including the addition of voltage support equipment in the Orange area or, establishment of a new 330/132 kV substation by cutting into Line 72 and linking with existing substations.	Compliance
Thermal Limitation on 94T Molong – Orange North 132 kV Line	2022	TBD	Increase the thermal capacity of Line 94T. With a number of renewable generators in service and committed to connect west of Molong Substation, studies indicate that curtailment of generation may be required due to the relatively low thermal rating of the line. TransGrid has identified a range of credible network and non-network options to address this issue including rebuilding the line or implementing dynamic line rating.	Economic benefits
Increase capacity to Beryl area	Subject to new generation in the Wellington to Mt Piper area	40 to 190	If all interested renewable generation proponents connect, their outputs will be constrained under system normal conditions to maintain the transmission network within acceptable limits. The existing line thermal limitations will limit the generation from the renewable sources. The operational management of voltage stability and minimum reactive margin may limit the load consumption at Beryl thereby imposing load shedding. TransGrid has identified a range of credible network options to address this network constraints including a new Beryl 330 kV Substation or upgrades to 132 kV lines from Mount Piper or Wellington.	Economic benefits

Ongoing projects

There are no ongoing prescribed augmentation projects in the Central Region.

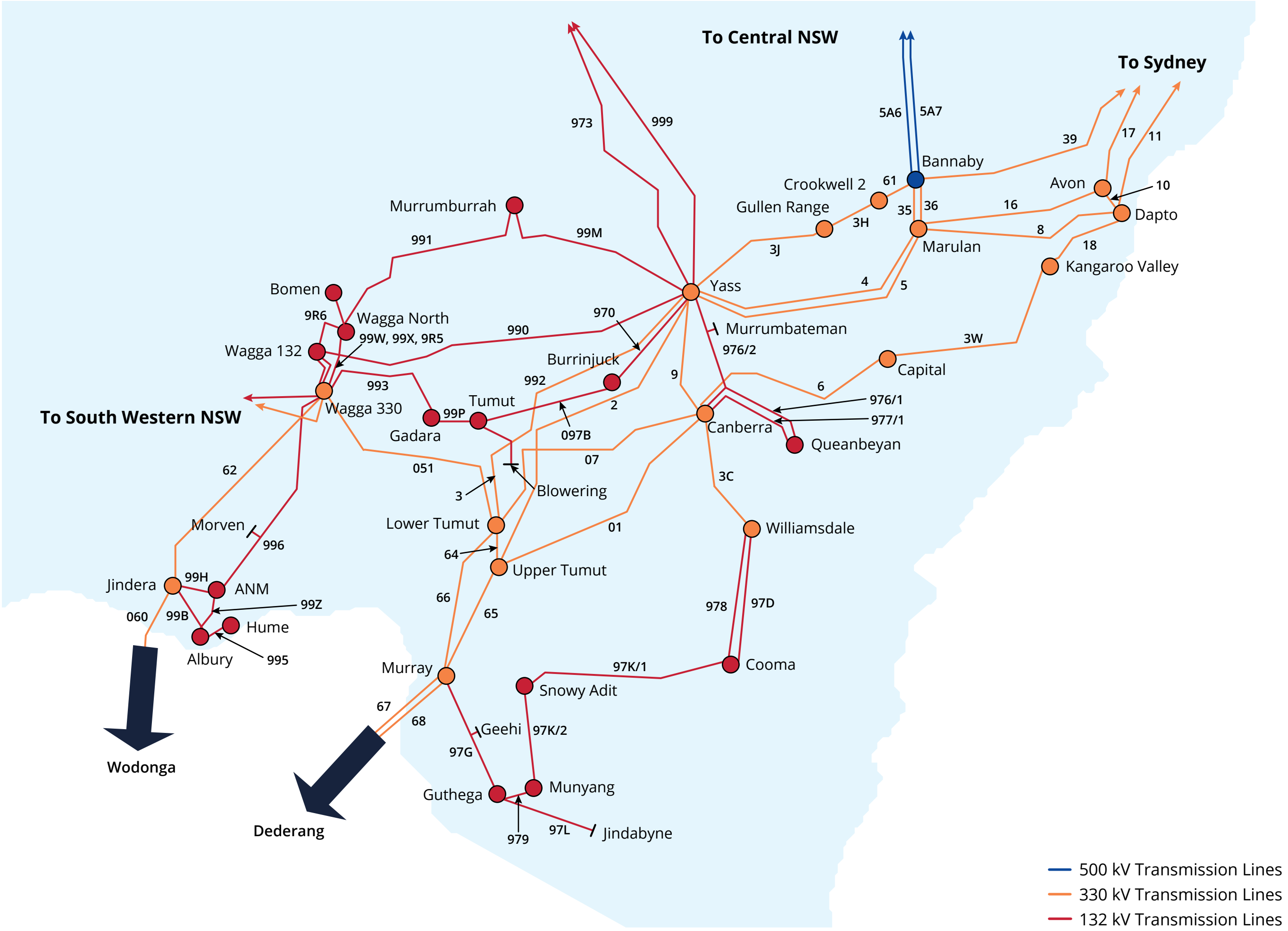
Completed projects

The following project was completed after the 2019 TAPR was published:

- Installation of an Under Voltage Load Shedding Scheme (UVLS) at Orange North Substation.

2.3.5 Southern NSW and ACT

Figure 2.14: Southern NSW and ACT network



Planned projects

The following are planned projects in the Southern NSW and ACT region:

- The major load centre in Southern NSW/ACT is Canberra where a number of residential, commercial and mixed developments are occurring. The transmission network augmentations required to facilitate these expected developments are well underway.
- There are a number of renewable generators proposed to connect to TransGrid's network in Southern NSW, especially in the far South West and Wagga area, as well as a substantial amount of embedded generation proposed to connect to the distribution network in this area. The development of the SA/NSW Interconnector will increase transfer capability from far West NSW to Wagga. However, to transmit the additional renewable generation to the major load centres in Canberra, Sydney and Wollongong will require additional transmission capability in the Southern area especially between Wagga and Yass.
- A number of projects have been identified to resolve potential thermal constraints in the sub system and increase the transfer capacity between Wagga and Yass. Network augmentations will also be required to unlock the renewable generation in far South-West area between Wagga and Jindera.
- Other planned projects in the area includes those in **Table 2.4**.

Table 2.4: Planned projects in Southern NSW and ACT

Project description	Planned date	Total cost ($million March-20)	Purpose	Project justification
99X Wagga 330 – Wagga 132 132 kV Line Capacity Augmentation	Mar 2021	0.64	Replace limiting equipment at Wagga 330 and Wagga 132. This will remove the need to reduce reliability of supply to Wagga Wagga at times of peak demand when there is high generation in the Wagga – Darlington Point area and high transfer on the main grid towards Yass / Canberra and Sydney.	Reliability
Installing an earthing transformer at Lower Tumut Substation	Jun 2021	2	To minimise the risks posed by the unearthed 11 kV network supplying the Talbingo town while being back-fed from the Lower Tumut Power Station.	Compliance
Installing Quality of Supply (QoS) meters at Munyang	Jun 2021	0.2	Due to the nature of the load characteristics, there is a potential for harmonic levels at Munyang to exceed the respective limits. This project installs QoS meters on the 33 kV side of Nos.1 and 2 transformers at Munyang to measure harmonics to ensure that supply standards are met.	Compliance
Installation of a 11 kV voltage regulator and a Quality of Supply (QoS) meter at Murray Substation	Jun 2021	1	To minimise the risk posed by the unearthed 11 kV reticulation in Khancoban town during outages of TransGrid's Murray Substation 330/132/11 kV transformers and to reduce the negative impact on the quality of power due to variations in 330 kV voltage and switching of shunt reactors at Murray substation.	Compliance
Install 132 kV line circuit breakers at Stockdill	Nov 2021	4.5	Evoenergy has identified a need to locate their mobile substation at Molonglo from 2021 to supply developments in the Molonglo Valley. Installation of two 132 kV line circuit breakers at Stockdill is required to provide the necessary protection functionality and reliability for this connection.	Load driven
Install a 100 MVAr 330 kV Capacitor at Wagga 330	May 2022	4.7	Possible voltage collapse in southern NSW for loss of the largest VIC generating unit or Basslink limits the NSW – VIC transfer limit. A 100 MVAr capacitor at Wagga will lift the southward transfer limit by 30 MW and northward transfer limit by 75 MW.	Economic benefits
Install Static Synchronous Series Compensation on 62 Jindera – Wagga 330 kV Line	Jun 2023	5.9	To improve the sharing between the three 330 kV lines 62, 65 and 66 and thereby enable higher power transfer across the group. This facility will achieve a 12.8 MW increase on the NSW-VIC thermal constraint and a 5.6 MW increase on the NSW-VIC voltage constraint.	Economic benefits
Install Static Synchronous Series Compensation on 2 Upper Tumut – Yass 330 kV Line	2023	5.7	To improve the sharing between the four 330 kV lines O1, 2, 3 and O7 and thereby enable higher transfer across the group. A 2Ω reduction in the line reactance will increase the Snowy to NSW transfer capability by 26 MW.	Economic benefits
Improving the power quality issues in ACT	2023	6	To minimise the temporary over or under voltage conditions that could occur during switching of existing capacitors at Canberra in distribution network. Options being considered include: • Modifying Evoenergy's existing scheme to preemptively vary 11 kV voltages • Reconfiguring the 120 MVAr 132 kV capacitors as 80 MVAr and add a 120 MVAr 330 kV capacitor	Compliance
Remote relay interrogation	Dec 2024	2.1	Rollout of the Fault Data Interrogation System (FDIS) to all TransGrid sites that currently have protection relays capable of communicating information via TCP/IP or serial connection. This will allow remote interrogation and provide a range of data about a fault.	Economic benefits
Increase transfer capability from Wagga to Yass	2025	TBD	A significant amount of renewable generation is being developed in Wagga area, especially North of Wagga. During times of high Snowy to NSW flow conditions, these generators need to be constrained to prevent system normal overloads in Wagga – Yass 132 kV subsystem. A number of options are being examined to increase the transfer capacity from Wagga to Yass that will improve market access for renewable generators in this area.	Economic benefits
Increased line capacity between Wagga North and Wagga	2025	TBD	Due to substantial developments of renewable generation at Wagga North and on the distribution network north of Wagga, 132 kV Lines 9R5 and 9R6 may become loaded above their normal rating. There are a number of options to upgrade the transmission capacity between Wagga and Wagga North Substations, though the preferred option is not yet finalised.	Economic benefits
Establishment of a new 132 kV switchbay at Canberra 330/132 kV Substation	Dec 2027	1.75	To facilitate the supply to the Evoenergy's proposed Strathnairn Zone Substation to be able to meet the projected load growth caused by new residential development in Canberra.	Load driven

Ongoing projects

Second supply to the ACT

The establishment of the second geographically separate bulk supply point to the ACT is in construction phase. The project comprises 5.6 km of transmission line, 20 towers, four poles, a 132 kV emergency bypass and the decommissioning of two 330/132 kV transformers and associated switchgear at Canberra Substation. The estimated cost of the project is $47 million with the Stockdill Substation energised by December 2020 and full project completed in June 2021.

Completed projects

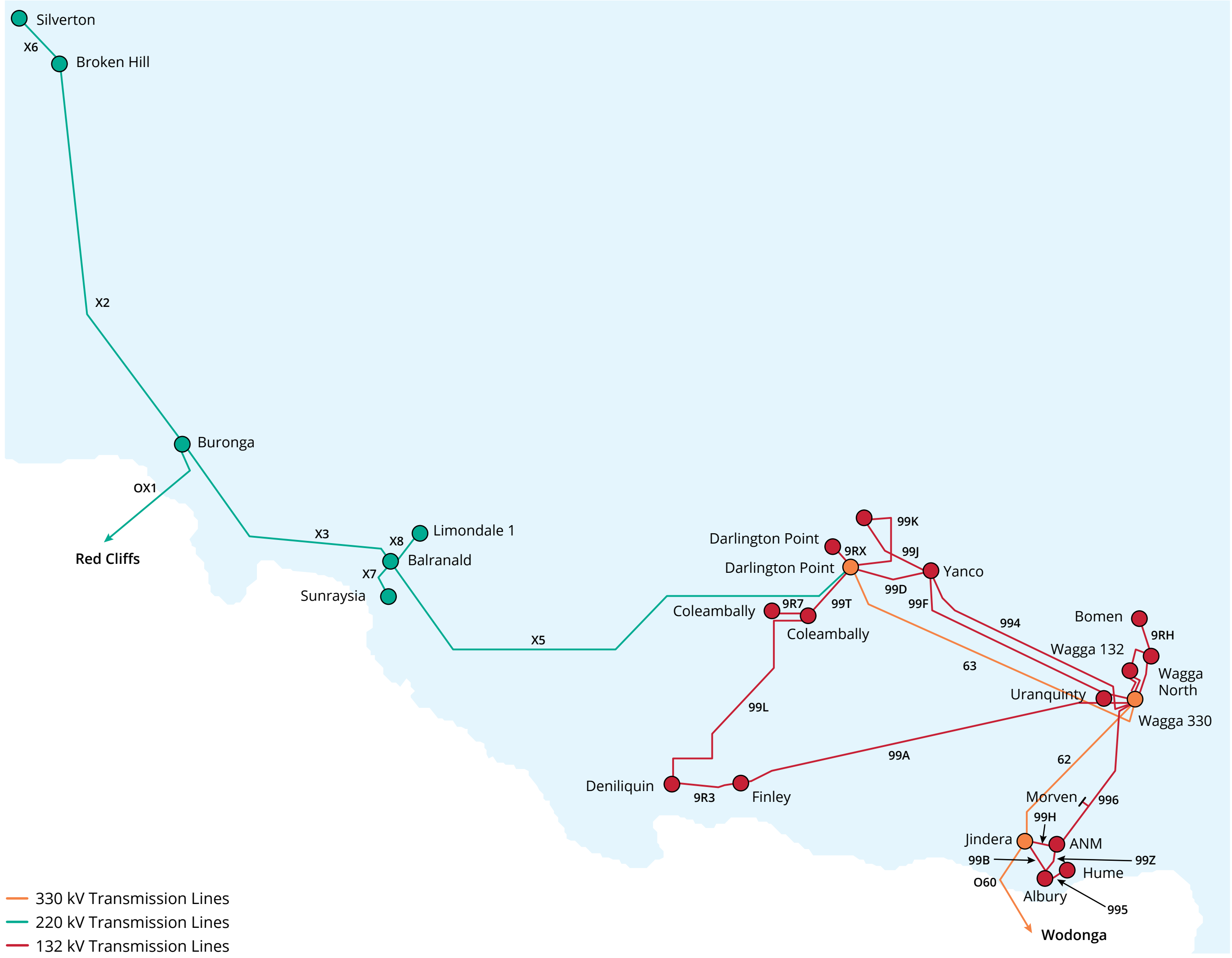
The following are projects that were completed after the 2019 TAPR was published:

- A cross-tripping control scheme. This was done because during an outage of 970 (Yass-Burrinjuck), 992 (Burrinjuck-Tumut), 99P (Gadara-Tumut) or 993 (Gadara-Wagga), a contingent trip of another of lines 99P, 970, 992 or 993 could form an unstable island involving load at Gadara and Tumut with generation at Blowering and Burrinjuck;
- Increased the summer day contingency rating of line 990 from 114 MVA to 137 MVA. This was done to remove equipment limiting the rating of 132 kV Line 990 Wagga 132 kV to Yass 132 kV.

Under the strategy for establishing telecommunications rings throughout the transmission network, a project is progressing to install Optical Fibre Ground Wire (OPGW) on Line 992 (Burrinjuck to Tumut). The scope also includes the replacement of 21 structures to remediate low spans, installation of 5 new poles for the OPGW, installation of OPGW and 14 joint boxes, strengthening of 22 structures to accommodate the increased loading from the OPGW and Civil works to support the works.

2.3.6 South Western NSW

Figure 2.15: South Western NSW network



Planned projects

The following are planned projects in the South Western region:

- The SA/NSW interconnector will require a number of network augmentations across South-Western NSW from Buronga to Wagga to strengthen the existing transmission network. The preferred option for the project includes construction of a 330 kV double circuit transmission line from Buronga to Wagga, an intermediate substation south of Darlington Point (Dinawan) and installation of dynamic and static reactive plant at Buronga, Dinawan and Wagga. Investigation is underway to look at ways to integrate this project to the existing sub system between Darlington Point and Wagga.
- Due to the recent renewable generation developments in Far West NSW, the fault level at Broken Hill Substation has substantially increased and will continue to increase with the planned network developments. TransGrid is currently investigating if the existing 220 kV equipment at Broken Hill Substation is suitable for the expected higher fault levels. Further, as part of joint planning, TransGrid has consulted with Essential Energy to review the fault rating of 22 kV equipment on the distribution network near Broken Hill Substation to confirm if any augmentation is required.
- TransGrid is currently investigating the feasibility of potential transmission augmentation within the South West to support the development of a Southern REZ (Refer to Section 2.1.5).
- Other projects planned in the area includes those in **Table 2.5**.

Table 2.5: Planned projects in South Western NSW

Project description	Planned date	Total cost ($million March-20)	Purpose	Project justification
Maintain supply reliability to Broken Hill	When the Broken Hill load exceeds capacity of backup gas turbines	52 to 177	To provide additional capacity to supply Broken Hill if the load exceeds the capacity of the backup gas turbines owned by Essential Energy and the expected unserved energy exceeds the unserved energy allowance for Broken Hill of 10 minutes at average demand. Possible options include: storage solutions to replace or complement the existing gas-turbines, additional gas turbine generation with a short start-up time, procuring demand management from the loads in the area and constructing a second 220 kV line from Buronga to Broken Hill.	Compliance
Installation of disturbance recorder and phase measurement units (PMU) at Broken Hill, Buronga and Darlington Point	2021	1.26	Connection of a number of solar farms in South West NSW and North West Victoria has led to post-contingent oscillatory instability impacting the power system in the north west Victoria and south west New South Wales. This project is to install disturbance recorders and PMUs at Buronga, Broken Hill and Darlington Point to monitor the following: • At Buronga - monitor lines OX1 Red Cliffs, X2 Broken Hill and X3 Balranald; • At Broken Hill - monitor lines X2 Buronga, X4 Broken Hill Mines and X6 Silverton, and the single Broken Hill Gas Turbines 22 kV connection point; • At Darlington Point – Monitor lines 63 Wagga to Darlington Point and X5 Darlington Point to Balranald)	Compliance
Uprating the Darlington Point 330/132 kV Transformers	2023	3.7	The rating of the Darlington Point 330/132 kV transformers is limited to 280 MVA due to the size of the cooler banks. Under this project, the cooler banks will be upgraded to increase the transformer rating to its nameplate rating of 375 MVA.	Economic benefits
Install dynamic transformer rating equipment on Darlington Point 330/220/33 kV Tie Transformers	June 2023	0.7	To optimise the operating capability of the tie transformers by using their real time ratings to reduce the constraints on the future SA/NSW interconnector and renewable generation.	Economic benefits
Uprating the 220 kV and 22 kV busbar capacity at Broken Hill	2023	10	Due to the network developments in far West NSW, the fault level at Broken Hill will increase beyond the fault rating of some primary equipment. Two projects have been initiated to upgrade the limiting equipment to increase the 220 kV and 22 kV busbar capacity at Broken Hill.	Compliance

Ongoing projects

Ongoing projects in the South Western region:

- Equipment limiting the rating of OX1 Buronga – Red Cliffs 220 kV Line was removed at the Buronga (NSW) end, which increased the summer day rating of the line from 265 MVA to 417 MVA. Complementary works at Red Cliffs are being carried out to remove the limitation at the Victoria end and are scheduled to be completed by June 2020.
- There are ongoing secondary systems upgrade projects at a number of substations including Coleambally, Darlington Point and Broken Hill Substations. Refer Section 2.4.3 for more details.

Completed projects

Completed projects in the South Western region:

- Equipment limiting the rating of 220 kV Line X5 Darlington Point to Balranald was removed, increasing the summer day contingency rating from 381 MVA to 461 MVA;
- Equipment limiting the rating of 220 kV Line X3 Balranald to Buronga was removed, increasing the summer day normal rating from 381 MVA to 419 MVA.
- The 99T line capacity upgrade project to re-conductor line 99T to increase its normal summer day rating to 190 MVA and summer day contingency rating to 225 MVA. This project has relieved the thermal constraints in the area allowing additional transfer capacity of up to 60 MW.

2.3.7 Across NSW

NSCAS needs

NSCAS are ancillary services procured in order to maintain power system security. Under the NER, AEMO identifies NSCAS needs and TransGrid is required to procure the services to address the needs in NSW. AEMO is the NSCAS Procurer of Last Resort if a TNSP is not able to procure the NSCAS to meet their requirements. The 2018 NTNDP published in June 2018 by AEMO did not identify any NSCAS gaps in NSW.

System strength and inertia requirements

With the retirement of coal fired power stations in the next 10 years, there is a risk of NSW not meeting the planning requirements for system strength and inertia. It is likely that additional measures will be required by the retirement of Eraring Power Station following the Liddell and Vales Point Power Station closures. These measures could include synchronous condensers with flywheels, conversion of retiring generators to synchronous condensers, contracting non-base load synchronous machines (generators), 'synthetic inertia' from wind generators and Fast Frequency Response from Battery Energy Storage Systems (BESS) and power electronic based generators.

Table 2.6 and **Table 2.7** give an indicative list of projects in the next 10 years to meet system strength and inertia requirements. These include shortfalls expected after Eraring retirement in 2032. The shortfalls can occur earlier than expected if coal-fired power stations retire early or move to flexible operation where they can go offline during times of light load or low price. Due to lead time in implementing, TransGrid will need to identify and commence these projects in the next 10 years.

Table 2.6: Indicative projects to meet system strength requirements (refer Table 5.3)

Location or Region	Indicative system strength remediation to meet shortfall
Armidale	Synchronous condensers or equivalent services that provide up to 30 MVA by 2028 and 50 MVA by 2032 at Armidale 330 kV
Darlington Point	Synchronous condensers or equivalent services that provide up to 20 MVA by 2028 and 50 MVA at Darlington Point 330 kV
Newcastle	Synchronous condensers or equivalent services that provide up to 280 MVA by 2028 and 3090 MVA by 2032 at Newcastle 330 kV
Sydney West	Synchronous condensers or equivalent services that provide up to 610 MVA by 2028 and 2330 MVA by 2032 at Sydney West 330 kV
Wellington	No remediation is required in the next 10 years

Table 2.7: Indicative measures in the next 10 years to meet inertia requirements (refer Table 5.5)

Location or Region	Indicative inertia remediation to meet double generator contingency inertia level of 15,000 MWs (MWs)
NSW	8,300 MWs in NSW by 2032 (which at least 3,300 MWs needs to be synchronous inertia)

Planned projects

Table 2.8: Planned projects across NSW

Project description	Planned date	Total cost ($million March-20)	Purpose	Project justification
Transformer automatic voltage regulator (AVR) function changes	Jan 2023	0.1	To fulfil the obligation under the National Electricity Rules (NER) to ensure voltage levels at customer connections points are controlled to an agreed supply point voltage. Modification of AVR logic to allow automatic voltage regulation during reverse power flow at locations with high levels of embedded renewable generation.	Economic benefits
Provide Dynamic Line Rating on various lines	May 2023	3.7	Weather stations will be installed to allow Dynamic Line Ratings to be calculated for a number of lines. Replacement of limiting equipment will permit use of higher ratings. Operating these lines to a dynamic rating appropriate to ambient conditions will facilitate construction and dispatch of additional low-cost generation.	Economic benefits
Overvoltage control following under frequency load shedding events	Jun 2025	4.1	Implementation of overvoltage control schemes to automatically switch existing reactive plant quickly to maintain system security when the system frequency falls below a certain level.	Economic benefits
VHF Radio Network Upgrade [Improve the Operational Telephone Network (OTN)]	Nov 2025	2.7	Domestic and international experience in emergencies such as system black or widespread bushfires has demonstrated that public switched telephone networks (including satellite telephones) suffer severe congestion and short battery life. We have an extensive VHF radio network that provides a crucial backup communications system between AEMO, generators, TNSPs and DSNPs. This project is to replace end-of-life equipment and enhance the functionality of the network to ensure its serviceability and capability in a critical network event.	Compliance
Remote or self-reset of busbar protection	Jan 2028	4.4	Installation of high definition Closed Circuit Television (CCTV) on busbars and facilities to reset busbar protections remotely at selected sites. This will reduce restoration time and duration of supply interruptions following busbar faults.	Economic benefits

Ongoing projects

Routine customer requests for changes to secondary equipment such as protection or voltage regulation are ongoing.

Completed projects

No prescribed augmentation state-wide projects were completed in the 2019/20 financial year.

2.4 Replacement projects

The retirement of assets is planned as they reach the end of their serviceable life. We continue to improve the asset management strategies and policies which underpin the capital investment process. The risk of asset failure is continually monitored, as well as its impact on reliability, safety and on communities through bushfire and other environmental damage. A risk profile for each major asset is used to identify when action needs to be taken for high risk assets.

Options to mitigate the risk are evaluated, including:

- Do nothing or increase maintenance interventions;
- Defer the need for replacement, if viable non-network options are available;
- Like-for-like replacement;
- Replacement with an asset of different capacity based on forecast demand; or
- Reconfigure the network.

By using economic analysis and consideration of TransGrid regulatory safety obligations to determine the appropriate course of action, TransGrid endeavours to invest and operate the network prudently in alignment with the National Electricity Objective (NEO) "…to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to – price, quality, safety, reliability, and security of supply of electricity; and the reliability, safety and security of the national electricity system…"

The projects described have used this approach to determine the best solution for the identified needs. This section will describe TransGrid's capital replacement works grouped by asset classes or work programs. The information provided in this section describes the work, the actual or potential constraint or inability to meet network performance requirements of the NER Schedule 5.1, the need date, proposed solution and its estimate. Given that they are mostly in-situ or like-for-like replacement projects, they do not cause any material inter-network impact.

The information reported in this section meets the requirement of the NER Clause 5.12.2(c)(5) and (6).

TransGrid presently does not anticipate any replacement project required to address an urgent and unforeseen network issue.

2.4.1 Transmission lines

Steel tower corrosion management

A refurbishment program that addresses steel tower corrosion issues is being undertaken on coastal tower transmission lines in the Newcastle, Central Coast, Sydney and Illawarra regions. The program includes refurbishment of rusted steel towers and the replacement of conductor fittings, earth wires and insulators at risk of failure.

These identified condition issues increase the probability of failure of a steel tower, conductor fittings, earth wires and insulators. Analysis has shown that risk costs can be offset by extending the lives of transmission lines through targeted refurbishment and replacement of specific components. The following table provides a list of transmission lines with steel towers requires corrosion management:

Table 2.7: Planned steel tower transmission line asset renewal projects

Transmission line location	Operational date required	Total estimated cost ($ million)
3W Capital Windfarm – Kangaroo Valley 330 kV line	Jun 2021	8.1
22 Vales Point – Sydney North 330 kV line	Jun 2021	10.6
959 & 92Z Sydney North – Sydney East 132 kV double circuit line	Jun 2021	5.7
81 Liddell – Newcastle 330 kV line	Jun 2022	10.6
27 Sydney North – Sydney East 330 kV line	Jun 2022	5.7
14 Kemps Creek – Sydney North 330 kV line	Jun 2022	5.7
8 Dapto – Marulan 330 kV line	Jun 2022	8.1
25 & 26 Eraring – Vineyard 330 kV line & Munmorah – Sydney West 330 kV double circuit line	Jun 2022	22.4
17 Macarthur – Avon 330 kV line	Jun 2022	5.9
28 Sydney North – Sydney East 330 kV line	Jun 2023	6.8
21 Sydney North – Tuggerah 330 kV line	Jun 2023	17.0
24 Eraring – Vales Point 330 kV line	Jun 2023	3.4
18 Dapto – Kangaroo Valley 330 kV line	Jun 2023	10.7
11 Dapto – Sydney South 330 kV Line	Jun 2023	23.7
16 Avon – Marulan 330 kV line	Jun 2024	6.7
23 Vales Point – Munmorah 330 kV line	Jun 2025	2.2
5A1/5A2 Eraring – Kemps Creek 500 kV line	Jun 2026	2.6
39 Bannaby – Sydney West 330 kV line	Jun 2026	3.7
90 Eraring – Newcastle 330 kV line	Jun 2026	3.3
93 Eraring – Newcastle 330 kV line	Jun 2026	1.8
88 Muswellbrook – Tamworth 330 kV line	Jun 2026	12.9
13 Kemps Creek – Sydney South 330 kV line – single circuit section only	Jun 2027	1.2
31/32 Bayswater – Regentville 330 kV double circuit line	Jun 2029	10.0

Wood pole replacements

TransGrid is replacing wood pole structures in poor condition on some 132 kV transmission lines with concrete or steel poles to address deterioration from wood rot, decay and termite attack. The following table provides a list of transmission lines with wood poles that requires replacement:

Table 2.8: Wood pole replacement projects

Transmission line location	Operational date required	Total estimated cost ($ million)
9U3 Gunnedah – Boggabri East 132 kV line and 9UH Boggabri North to Narrabri 132 kV line	Jun 2021	12.0
94K Wellington – Parkes 132 kV line	Jun 2021	15.3
99D Yanco – Darlington Point 132 kV line	Jun 2021	10.3
99A Uranquinty – Finley 132 kV line	Jun 2022	15.5
995 Hume – Albury, 97L Guthega – Jindabyne Pumps, 97G/3 Geehi – Guthega and 976 Canberra – Queanbeyan 132 kV lines	Jun 2022	5.2
99J Yanco – Griffith 132 kV line	Jun 2023	0.2
966 Armidale – Koolkhan 132 kV line	Jun 2031	0.1

Remediation of low spans

Transmission lines are designed and constructed to achieve standard electrical clearances of the conductor at specific operating conditions. The currently accepted industry standard is AS7000 for the Design of Overhead Lines, which specifies minimum electrical clearances that should be achieved when the conductor reaches its maximum operating temperature (also commonly referred to as the line design temperature).

TransGrid conducted aerial laser surveys of transmission lines to provide accurate measurement of span heights. Using this new technology which provides more accurate measurements than previous approaches, a number of transmission lines have been found to have spans violating AS7000 minimum clearances (low spans) at the normal foreseeable operating temperature. These low spans pose a risk to public safety. TransGrid also conducted a risk assessment on the identified low spans. The risk assessment method evaluates each low span violation in accordance with multiple risk criteria including magnitude (height and area), location and violation temperature.

The spans have been ranked accordingly and categorised as presenting a higher risk and lower risk to public safety. The remediation options considered include:

- Remediate all low spans; and
- Remediate higher risk low spans only, with the lower risk spans addressed by means of administrative control measures.

The remediation of higher risk low spans is proposed to reduce the level of risk to public safety across the network. TransGrid is required to fulfil the requirements of AS5577 Electricity Network Safety Management Systems, and the public safety risk presented by the low spans must be reduced As Low As Reasonably Practical (ALARP). The proposed remediation works aim to mitigate the public safety risk to an acceptable level. The following table provides a list of transmission lines with low spans:

Table 2.9: Low Span Projects

Transmission line location	Operational date required	Total estimated cost ($ million)
Low spans on various lines – Stage 2	Jun 2022	3.0

Grillage Towers

TransGrid's earliest transmission towers (now 50 to 60 years old) have been installed with grillage foundations where the footings are constructed from hot-dip galvanised steel members formed into a grill and direct buried.

This type of foundation did not use any concrete, relying on the steel frame and the encapsulated soil as the foundation support for the tower superstructure.

Sacrificial anodes have been installed at various times on these towers to provide galvanic cathodic protection as a mitigation measure against footing corrosion.

A field assessment of the cathodic protection system and grillage condition on a sample of towers conducted in April 2016 has concluded that the installed sacrificial anodes are no longer providing sufficient protection against tower footing steelwork corrosion.

It is expected that these anodes have been consumed while providing sacrificial protection to the buried tower foundations and therefore have reached the end of their useful life.

Corrosion of buried steelwork is coupled to the soil exposure classification, as described in AS2159, which determines the rate at which buried steel is expected to corrode in various ground and environmental conditions. Remediation could include tower footing concrete encapsulation (after required steel remediation) or anode replacement. The following table provides a list of transmission lines that requires grillage tower remediation:

Table 2.10: Grillage Tower Remediation

Transmission line location	Operational date required	Total estimated cost ($ million)
4 and 5 Yass – Marulan 330 kV lines	Jun 2021	9.0
01 Upper Tumut – Canberra and 9 Canberra – Yass 330 kV lines	Jun 2021	0.6
U1, U3, U5, U7 Upper Tumut 330 kV Group Lines; 65 Murray – Upper Tumut 330 kV line; 66 Murray – Lower Tumut 330 kV line and 97K Cooma – Munyang 132 kV line	Jun 2022	8.3
11 Sydney South – Dapto 330 kV line	Jun 2023	0.10
995 Hume Albury 132 kV line; 99X, 9R5, 9R6 and 990 Wagga area 132 kV double circuit structures; 970 Yass – Burrinjuck 132 kV lattice towers	Jun 2023	0.02
2 Upper Tumut – Yass 330 kV line	Jun 2023	11.8
999 – Yass – Cowra 132 kV line	Jun 2024	9.8

2.4.2 Substation plant

The condition of substation assets is continuously monitored to ensure safe and reliable operation. Asset replacement programs have been established to cover the replacement of identified circuit breakers, instrument transformers, bushings and disconnectors in poor condition.

The replacement programs comprise the most economic combination of replacement and refurbishment options for transmission equipment reaching a condition which reflects the end of its serviceable life. The asset replacement projects forming these programs are individually of relatively minor value.

The condition of larger assets such as transformers, reactors and capacitor banks is also monitored. The replacement, retirement or refurbishment options are evaluated which result in individual projects being raised to address the condition as required.

The condition based replacement programs and projects help to ensure the continued safety of employees, contractors, and the public, and to maintain a reliable electricity supply. The following table provides a list of substations where primary (HV) assets renewal or replacement projects have been identified:

Table 2.11: Planned substation primary (HV) asset renewal/replacement projects

Location	Area	Operational date required	Total estimated cost ($ million)
Armidale 330 kV Substation No.2 reactor renewal	Northern	Aug 2020	4.3
Wellington 330 kV Substation No.1 reactor replacement	Central	Mar 2022	4.6
Forbes 132 kV Substation transformer replacements	Central	Jun 2022	9.8
Sydney East 330 kV Substation No.2 and No.3 transformer replacements	Sydney	Jun 2022	26.4
Transformer renewals at Ingleburn, Kemps Creek, Liverpool, Moree, Murray, Murrumburrah, Panorama, Sydney North	Across NSW	Jun 2023	13.9
Steelwork renewals at Sydney South/East/North, Albury, Dapto, Tomago, Hume, Wagga and Upper Tumut	Across NSW	Jun 2025	85.2

2.4.3 Secondary systems

We continually strive to find leading solutions for managing the various facets of secondary systems which includes the protection, metering, control, communications, AC/DC supplies and alarm systems. New technologies such as IEC-61850 based automation solutions and MPLS-TP telecommunication systems, are under examination to further drive operational efficiencies.

To date, TransGrid has commissioned the first IEC-61850 digital substation employing both process bus and station bus, utilising optical fibre cables between substation switchyards and relay rooms. TransGrid have also completed the final round of vendor testing for our future MPLS-TP telecommunication network which is due to commence deployment in late 2020.

TransGrid has an accredited Asset Management System to ensure that assets are managed in accordance with best practice. This provides assurance to stakeholders and the community that assets are being operated, maintained and replaced based on sound qualitative analyses to provide optimum benefits.

Strategies currently being rolled out will deliver benefits in the foreseeable future in areas such as reduced maintenance requirements, improved operational efficiencies, increased utilisation, improved visibility of assets, reduced life cycle cost and increased reliability. The following table provides a list of planned substation secondary assets requiring renewal and replacements:

Table 2.12: Planned substation secondary asset renewal and replacement projects

Location	Area	Operational date required	Total estimated cost ($ million)
Marulan Secondary Systems Renewal	Southern	Jan 2021	11.6
Gadara Secondary System Renewal	South Western	Jan 2021	5.8
Tamworth 330 kV Secondary Systems Renewal	Northern	Jun 2022	5.8
Coleambally Secondary Systems Renewal	South Western	Jun 2022	2.5
Tuggerah Secondary Systems Renewal	Newcastle and Central Coast	Jun 2022	8.0
Haymarket Secondary Systems Replacement	Sydney	Feb 2023	12.2
Ingleburn Secondary System Renewal	Sydney	Feb 2023	11.1
Darlington Point Secondary Systems Renewal	South Western	May 2023	9.2
Tenterfield Secondary Systems Renewal	Northern	May 2023	4.6
Broken Hill Secondary Systems Renewal*	South Western	Jun 2023	13.3
Muswellbrook Secondary Systems Renewal	Newcastle and Central Coast	Jun 2023	9.0
Wagga 330 kV Secondary Systems Renewal	Southern	Jun 2023	10.3
Deniliquin Secondary Systems Renewal	South Western	Jun 2023	14.6
Molong Secondary Systems Renewal	Central	Jun 2023	1.5
Liverpool Secondary Systems Renewal	Sydney	Aug 2023	6.0
Murrumburrah Secondary Systems Renewal	Southern	Oct 2023	8.6

** Project includes some HV asset removals or replacements*

2.4.4 SCADA system

The Supervisory Control and Data Acquisition (SCADA) system is a vital tool which allows TransGrid to efficiently operate and maintain the network–providing real-time visibility of network status and alerting abnormal conditions. The SCADA system is used to operate, control and monitor the high voltage network remotely from the central control centre. The existing SCADA system has been in service since 2013 and uses an operating platform and assets no longer supported by the providers.

A project to replace the existing system is underway. This will provide a completely new platform running on new hardware and a modern network architecture. The expected project cost is $15 million and is planned to be completed by December 2020.

2.5 Asset retirements and deratings

Sydney East currently has four 330/132 kV transformers supplying the load in the surrounding area. Three of these are reaching their end-of-life. The 2018 demand forecast showed a decline in load growth such that it was not justifiable to replace all three transformers. It was decided that only two transformers will be replaced as shown in Section 2.4.2, and one will be retired.

One of the transformer replacements will be a new transformer, and the other will come from relocating a transformer from Rookwood Road to Sydney East.

The latest 2020 forecast load in Sydney East has however, increased due to a newly committed spot load which would lead to a constraint. We are investigating the installation of a fourth transformer or other network and non-network options.

TransGrid is not planning to retire or derate any other assets in our network over the next 10 years which would result in network constraints. The information reported in this section meets the requirement of NER Clause 5.12.2(c)(1A) and (1B).

Regulatory Investment Test for Transmission (RIT-T)

The importance of consulting with stakeholders to plan, develop and maintain the network to ensure it meets expectations now and into the future is recognised by TransGrid. For significant augmentation and renewal investments, one of the methods for consultation is the Regulatory Investment Test for Transmission (RIT-T).

This process is designed to notify stakeholders of the investment need examine, network or non-network solutions, and invite the public to submit delivery proposals and advise stakeholders of the selection process.

The RIT-T applies to transmission network investments where the cost of the most expensive credible option is greater than $6 million. It currently applies to all investments, except those relating to maintenance or urgent and unforeseen investments.

The RIT-T normally involves publication of three reports which highlight key milestones in the consultation process: the Project Specification Consultation Report (PSCR), the Project Assessment Draft Report (PADR) and the Project Assessment Conclusions Report (PACR). Minimum consultation periods following publication of the PSCR and PADR are specified and there is a requirement for submissions received in response to these documents to be considered. The PADR can be omitted under certain circumstances provided for in the NER.

For the category of 'replacement transmission network asset' there is a requirement to disclose information in annual planning reports which includes a brief project description, commissioning date, other reasonable options considered, estimated cost, and planned asset de-ratings and retirements.

TransGrid is presently drafting several PSCRs for asset condition driven investments.

Figure 2.16: RIT-T consultation documents

2.6 Regulatory Investment Test for Transmission (RIT-T) schedule

TransGrid will be preparing a number of RIT-T assessments for the projects outlined in this chapter for the upcoming year with capital investment cost above $6 million.

The table below outlines the expected commencement dates for various RIT-Ts.

Table 2.13: Planned RIT-T assessments

Project description	RIT-T Kick Off Quarter	Type of project
Western Sydney Development	2020Q1	Substation and Transmission Line
Maintaining compliance with performance standards applicable to Tuggerah Substation secondary systems	2020Q2*	Secondary Systems
Meeting demand growth in the greater Macarthur area	2020Q2*	Substation
Maintaining compliance with performance standards applicable to Ingleburn Substation secondary systems	2020Q3	Secondary Systems
Managing safety and environmental risks on Line 17 (Macarthur-Avon)	2020Q3	Transmission Line
Managing safety and environmental risks on Line 18 (Kangaroo Valley-Dapto)	2020Q3	Transmission Line
Managing asset risks at Forbes switching station	2020Q3	Substation
Managing safety and environmental risks on Line 27 (Sydney North-Sydney East)	2020Q3	Transmission Line
Managing safety and environmental risks on Line 28 (Sydney North-Sydney East)	2020Q3	Transmission Line
Maintaining compliance with performance standards applicable to Murrumburrah Substation secondary systems	2020Q3	Secondary Systems
Maintaining compliance with performance standards applicable to Darlington Point Substation secondary systems	2020Q4	Secondary Systems
Managing safety and environmental risks on Line 21 (Sydney North-Tuggerah)	2020Q4	Transmission Line
Increasing thermal capacity between Molong and Orange	2020Q4	Transmission Line
Increasing thermal capacity in the South-western NSW network	2020Q4	Transmission Line
Maintaining compliance with performance standards applicable to Liverpool Substation secondary systems	2020Q4	Secondary Systems
Increase transfer capability from Wagga to Yass	2021Q3	Transmission Line
Increased line capacity between Wagga North and Wagga	2021Q3	Transmission line
Beaconsfield BSP supply enhancement	2021Q4	Substation
Voltage support in the Orange area	2021Q4	Substation and Transmission line

A list of TransGrid's ongoing RIT-T consultations can be found at: https://www.transgrid.com.au/what-we-do/projects/regulatory-investment-tests/Pages/default.aspx

* Recently published and PSCR consultation periods will remain open until end of August 2020.

2.7 Changes from TAPR 2019

Updates in this chapter and referenced Appendices since TAPR 2019 includes the following:

- The RIT-T for Broken Hill Supply Reliability commenced in 2019Q4
- The RIT-T for maintaining compliance with performance standards applicable to Broken Hill Substation secondary systems commenced in 2019Q4
- The timing for the RIT-T for managing safety and environmental risks on Line 11 (Sydney South-Dapto) will be assessed in line with portfolio investment priorities
- The RIT-T for maintaining compliance with performance standards applicable to Ingleburn Substation secondary systems was deferred due to phasing of flood mitigation investigations and has been rescheduled to commence in 2020Q3
- The RIT-T for maintaining compliance with performance standards applicable to Tamworth Substation secondary systems did not commence in 2019Q3 as the project is no longer required to be assessed under the RIT-T because all technically and commercially feasible options are under $6 million. Due to QNI project phasing, elements of the scope were withdrawn and subsequently some options were deemed no longer feasible.

These changes are consistent with the requirements of NER Clause 5.12.2(c), (1A), (1B), (3), (5), (6), (7) and (8).

Chapter 3

Network support opportunities

- There are five locations where an estimated reduction in forecast load would defer a network constraint
- A Request for Proposals has been issued for non-network solutions in Inner Sydney (Round 3)
- There are three locations where there may be potential to issues Requests for Proposals for non-network solutions in the next 10 years.

3.1 Opportunities for network support

As NSW transitions to a lower emissions energy system, electricity will be supplied from a more diverse mix of sources.

These include large-scale baseload, peaking and renewable generation and distributed energy resources. The intermittent nature of variable renewable generation presents challenges to balancing supply and demand. Dispatchable generation can 'firm' renewables, and demand management (local load reductions, embedded generation, and energy storage) can also be used to balance supply intermittency or insufficiency.

These demand-side resources can also be used to address transmission network constraints.

We have identified the potential for network support opportunities in the Inner Sydney and Broken Hill areas. The network constraint for Broken Hill is discussed in Section 2.3.6. The intent to issue Requests for Proposals (RfP) is set out in Section 3.1.1.

Both NER Clause 5.12.2(c)(4) and the Transmission Annual Planning Report Guidelines require TransGrid to report the subset of forecast constraints, identified in Chapter 2, where an estimated reduction in forecast load would defer a forecast constraint for a period of 12 months. The 'TAPR data' for the subset of forecast constraints is shown in **Table 3.1**.

Table 3.1: Forecast constraint information

Constraint or anticipated constraint	Proposed timing	Annual deferral value	Demand reduction required to defer investment by 1 year
Supply to the Nepean area (augmentation)	2021/22	$513,300	82-153 MW
Sydney East No.1 to 3 330/132 kV transformers (replacement)	2021/22	$492,000	20-50 MW
Voltage support in the Parkes and Orange area (augmentation)	2021/22	To be assessed	50-80 MW
Voltage and thermal constraints in the Gunnedah/Narrabri area (augmentation)	2022/23	To be assessed	Up to 70 MW
Supply to the Broken Hill area (reliability)	From when Essential Energy gas turbines become unavailable	To be assessed	Up to 50 MW

3.1.1 Requests for Proposals

TransGrid plans to issue RfPs for augmentation, replacement of network assets, or non-network options for the constraints listed in **Table 3.2**.

Table 3.2: Anticipated issue of a RfP

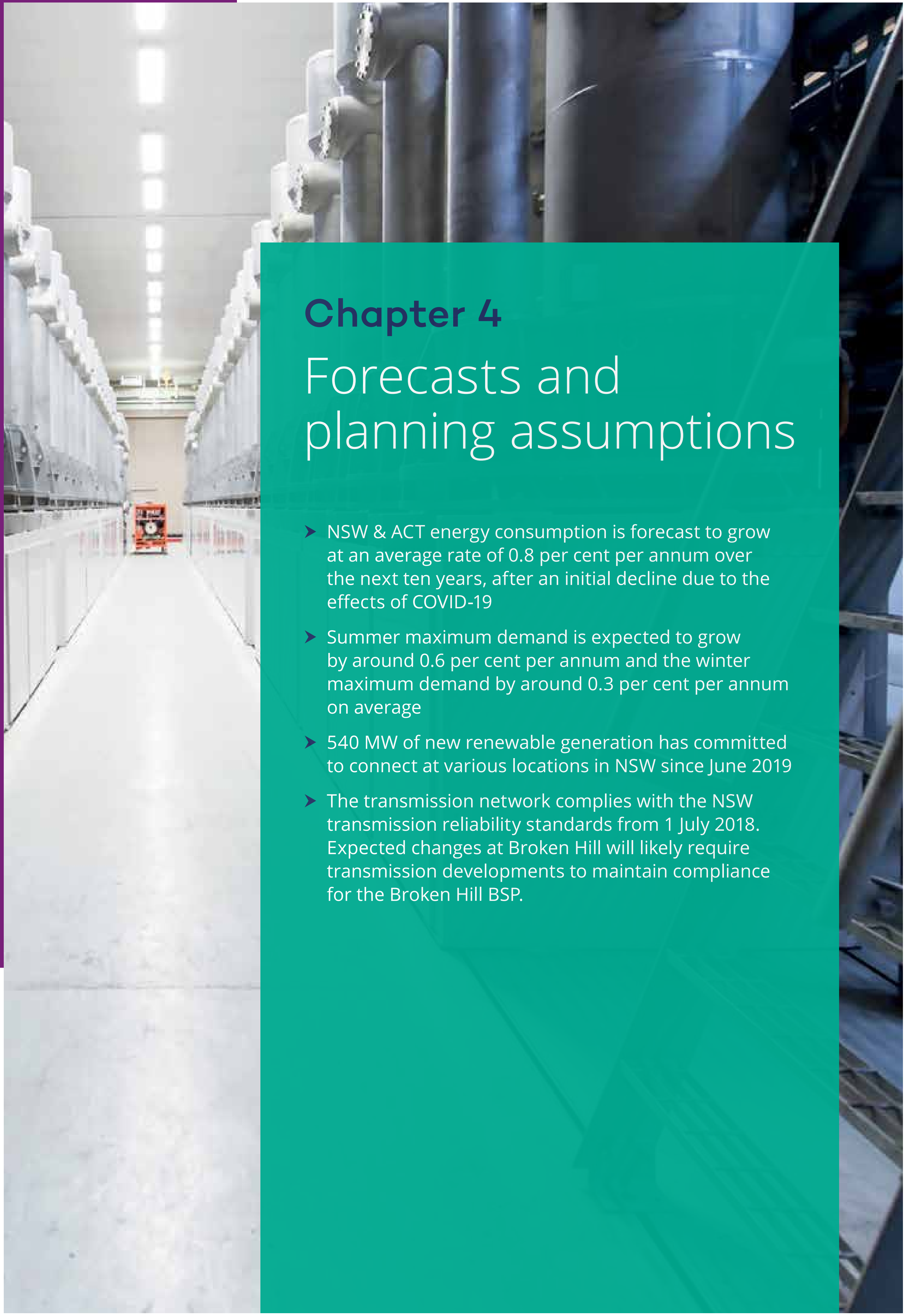
Constraint or anticipated constraint	Intent to issue RfP	Load reduction required	Constraint Date	Release Date
Powering Sydney's Future - Expected unserved energy associated with the deteriorating condition of Inner Sydney cables (replacement)	RfP – Round 3	20-30 MW from summer 2020/2021 to 2021/22	Summer 2021/22	26 March 2020
Voltage support in the Parkes and Orange area	To be assessed, depending on timing and size of spot loads	50-80 MW	2021/22	2020/21
Voltage and thermal constraints in the Gunnedah/Narrabri area	To be assessed, depending on timing and size of spot loads	Up to 70 MW	2022/23	2021/22

3.2 Changes from TAPR 2019

Updates in this chapter and referenced Appendices since TAPR 2019 include:

- References to 'TAPR data' on TransGrid's website consistent with the transmission annual planning report guidelines; and
- Network support opportunities have been updated.

These changes are consistent with the requirements of NER Clause 5.12.2(c)(4).



Chapter 4

Forecasts and planning assumptions

- NSW & ACT energy consumption is forecast to grow at an average rate of 0.8 per cent per annum over the next ten years, after an initial decline due to the effects of COVID-19
- Summer maximum demand is expected to grow by around 0.6 per cent per annum and the winter maximum demand by around 0.3 per cent per annum on average
- 540 MW of new renewable generation has committed to connect at various locations in NSW since June 2019
- The transmission network complies with the NSW transmission reliability standards from 1 July 2018. Expected changes at Broken Hill will likely require transmission developments to maintain compliance for the Broken Hill BSP.

4.1 Key highlights

4.1.1 Supply

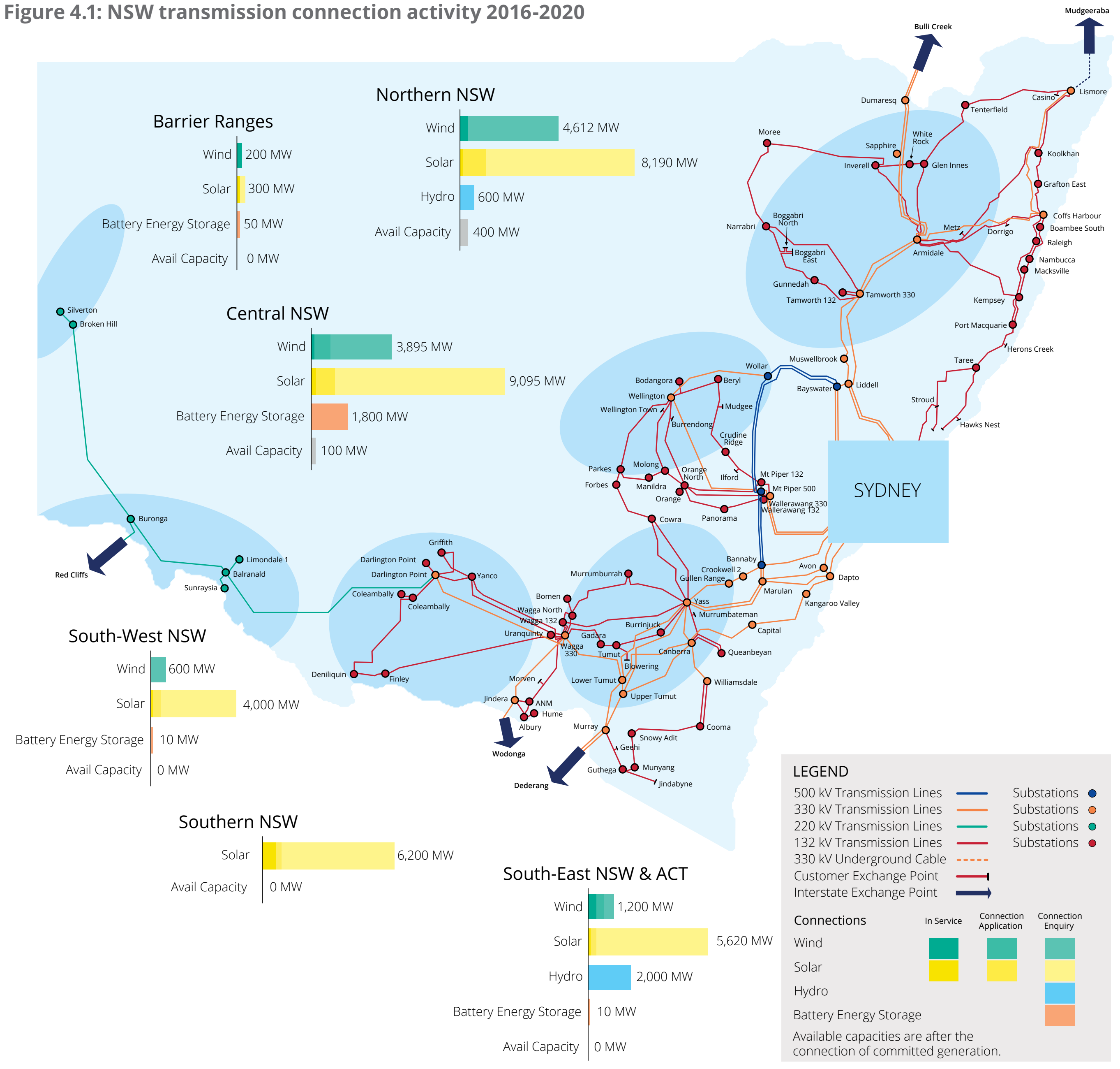
Since the publication of TAPR 2019, in June last year, more generation proponents have signed connection agreements, this has been incorporated in this planning review as committed generation. This includes:

- 540 MW of solar generation capacity; and
- 0 MW of wind generation capacity.

We expect further generation proponents to sign connection agreements over the next 12 months as projects advance through the connection process.

We continue to receive connection enquiries for projects at various stages of development across NSW. Only a fraction of this proposed generation can be accommodated in TransGrid's current network due to declining spare capacity. The approximate available network capacity for generation connections in NSW is presented in **Figure 4.1**.

Figure 4.1: NSW transmission connection activity 2016-2020



4.1.2 Demand

Demand growth was moderate in recent years and will most likely remain so over a 10 year forecast horizon, as shown in **Table 4.1**.

Table 4.1: NSW region medium scenario energy and demand (compound average annual growth rates)

	Actual/estimated 2014-15 to 2019-20 (2014 to 2019 for winter)	Forecast 50% POE 2020-21 to 2029-30 (2020 to 2029 for winter)
Annual energy	- 0.3%	0.8%
Maximum demand (Summer)	2.9%	0.6%
Maximum demand (Winter)	1.0%	0.3%

4.2 TransGrid 2020 NSW region forecast

4.2.1 Introduction

Demand forecasts for the NSW region over a 10 year horizon under three scenarios: medium growth (or most likely), high growth and low growth. The following sections describe the sources and assumptions behind the demand forecast and present the detailed forecast outcomes.

4.2.2 Definitions, assumptions and inputs

The forecasts include annual energy in GWh, summer maximum demand (MD) in MW and winter MD in MW. These measures are presented in terms of demand on the transmission network. This is measured by the output of all NEM connected scheduled, semi-scheduled and non-scheduled generating units. The sum of output from all these types of generating units is termed "native" energy or demand.

Generation measured at generator terminals includes any power used for generator auxiliaries and is termed "as generated". Generation measured at the point of connection with the network is termed "sent out". In this report, energy is on a sent out basis and MDs are on an as generated basis.

MDs are half-hourly averages and are highly dependent on the prevailing weather. High temperatures on summer afternoons and low temperatures on winter evenings typically produce half-hourly demand peaks. To account for the imprecise nature of long range weather forecasting, forecast MDs are prepared in terms of 10 per cent probability of exceedance (10% POE), 50 per cent probability of exceedance (50% POE) and 90 per cent probability of exceedance (90% POE). POE delineates the frequency with which probable demand is expected to exceed the stated level. For example, a 10% POE level of demand is expected to be exceeded 10 per cent of the time (i.e. once in every 10 years).

Around 18 per cent of TransGrid's load is accounted for by a handful of large industrial or mining customers, all of which are connected at very high voltages and some directly to the transmission network. These customers are not generally subject to incremental change as a result of economic conditions or population growth and are typically not sensitive to weather. As a result, these are not included in the forecast modelling process but are added back into the forecast at the end. The future large industrial load is reviewed every year with inputs from all major industrial load customers.

Forecasts have been prepared based on top-down models of underlying consumer behaviour, in the absence of recent above-trend energy efficiency, using a measure of electricity services. This measure includes the impacts of estimated energy efficiency and distributed energy resources (DER), including small-scale photovoltaic (PV) generation and stationary and electric vehicle charging/discharging.

To prepare the forecasts, we used projections of population, economic growth, retail electricity price, policy and program driven energy efficiency impacts and various DER components. Small projected changes to certain large mining, commercial and industrial loads including spot loads were informed by TransGrid customer data. The projections of DER and spot loads were used to modify modelled forecasts of underlying consumer demand.

Further information on the method of preparation for the forecast and a review of previous forecast accuracy is in Appendix 1.

4.2.3 Demand drivers

Underlying consumer demand for electricity is traditionally understood to be driven by population and economic growth, energy prices, in the long term, and by weather in the short term. In the past decade however, a coincidence of energy efficiency, take up of DER and rising electricity prices have apparently acted to moderate demand. In preparing the NSW region demand forecasts, TransGrid has therefore considered the combined impacts of underlying consumer behaviour, energy efficiency and DER on the transmission network.

The forecasts are determined from a measure of "electricity services" which is derived as native energy or demand, plus out of trend energy efficiency and PV generation, minus battery charging, plus discharging.[21] The economic drivers of electricity services remain consistent and are capable of being reliably modelled.

TransGrid models residential and non-residential electricity services separately. In these models, population, household disposable income (HDI), residential electricity and gas prices and temperature drive residential demand. While gross state product (GSP), non-residential electricity and gas prices and temperature, drive non-residential demand. TransGrid obtained independent projections of population and economic growth[22], as well as electricity and gas prices[23]. TransGrid's models predict that:

- a one per cent increase in HDI will lead to an increase in residential electricity services of 0.55 per cent;
- a one per cent increase in GSP will lead to an increase in non-residential electricity services of 0.74 per cent;
- a one per cent increase in the residential electricity price will lead to a decrease in residential electricity services of 0.21 per cent; and
- a one per cent increase in the non-residential electricity price will lead to a decrease in non-residential electricity services of around 0.21 per cent.

The models also predict small positive increases in electricity services as a result of an increase in gas prices, or increased summer or decreased winter temperatures.

It may be the case that, in addition to the pure price impacts allowed for in TransGrid's models, there could be "rebound" effects from increased energy efficiency, increased PV self-generation or the use of battery storage resulting in lower energy bills. TransGrid did not assess the potential for such rebound effects and as such the forecasts may be deemed to be relatively conservative. There is some evidence however, that electric vehicles may improve the payback for installing residential rooftop PV systems, which would increase the take-up of such systems above TransGrid's forecast allowance.

TransGrid obtained independent advice[24] on the impact of various energy efficiency programmes and policies to construct measures of electricity services for modelling purposes. The above-trend element of energy efficiency was subsequently removed from the modelled forecasts of electricity services to identify the expected grid impact.

TransGrid also obtained independent advice[25] on the expected take-up by both residential and non-residential consumers of rooftop PV generation and accompanying battery storage, externally charged electric vehicles, and each of their associated load impacts on the power system.

4.2.4 Temperature sensitivity

TransGrid's analysis of variation of maximum demand with temperature reveals that current summer temperature sensitivity is 388 MW per degree increase in the average daily temperature, which represents a doubling in sensitivity in percentage terms in the last 25 years.

The winter temperature sensitivity has increased only marginally in that time and is estimated to have been 199 MW increase per degree reduction in average daily temperature in 2019.

4.2.5 Climate change

TransGrid assumes that Australia will meet its existing obligation to reduce national greenhouse emissions by 26 per cent on 2005 levels by 2030. Existing renewable certificate schemes (the Small-scale Renewable Energy Target and the Large-scale Renewable Energy Target) and State based renewable energy schemes will contribute to the emissions reduction target, as will the planned closure of coal-fired power stations. Steady increases in renewable generation and withdrawal of non-renewable generation in large increments will affect the wholesale price of electricity and therefore indirectly affect demand.

Projected increases in future average temperatures of around 0.5 degrees every 10 years are consistent with NSW average temperature trends over the last 20 years. This will make a small but significant contribution to annual energy and summer demand growth, and will detract from winter demands.

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[21] Assuming all measures are expressed as positive terms.
[22] BIS Oxford Economics (2020) Economic Forecasts to 2039 – NSW and ACT, Final, May 2020.
[23] Jacobs (2020) TransGrid Retail Electricity Price Forecasts, Final Report, June 2020.
[24] Energy Efficient Strategies (2020) Impact of Energy Efficiency Programs on Electricity Consumption in NSW and the ACT from 2000 to 2039, Final Report, June 2020.
[25] CSIRO (2020) Rooftop PV and Battery scenarios for Future Grid, TransGrid, May 2020 & Energeia (2019) Electric Vehicle Modelling.

4.2.6 COVID-19 effects on the NSW Region economy

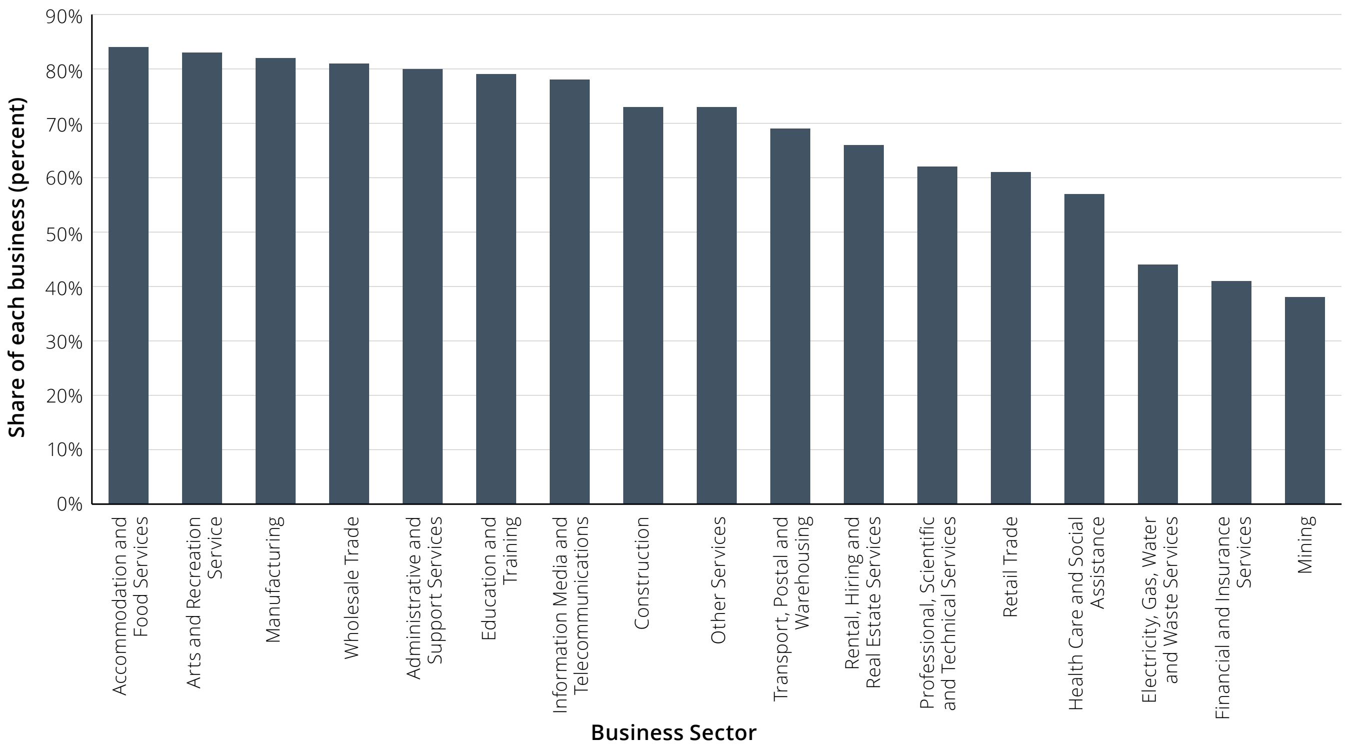
COVID-19 has caused major disruptions in economies worldwide, including Australia and New South Wales.

Figure 4.2 shows the proportion of businesses in each category which are anticipating a fall in demand for their goods and services due to COVID-19. Although the major economic impacts of the COVID-19 crisis have been borne by Accommodation, Food Services, Arts and Recreation sectors, every economic sector has experienced some impacts on business conditions.

An analysis of recent electricity consumption data in the NSW Region reveals that the reduction in electricity consumption and peak demand is primarily from commercial and smaller manufacturing loads.

Economic forecasts obtained from BIS Oxford Economics show that COVID-19 will have recessionary effects on the Australian and NSW economies which will lead to a temporary decrease in electricity consumption and maximum demands.

Figure 4.2: Reduced demand for goods and services in businesses in Australia due to COVID-19

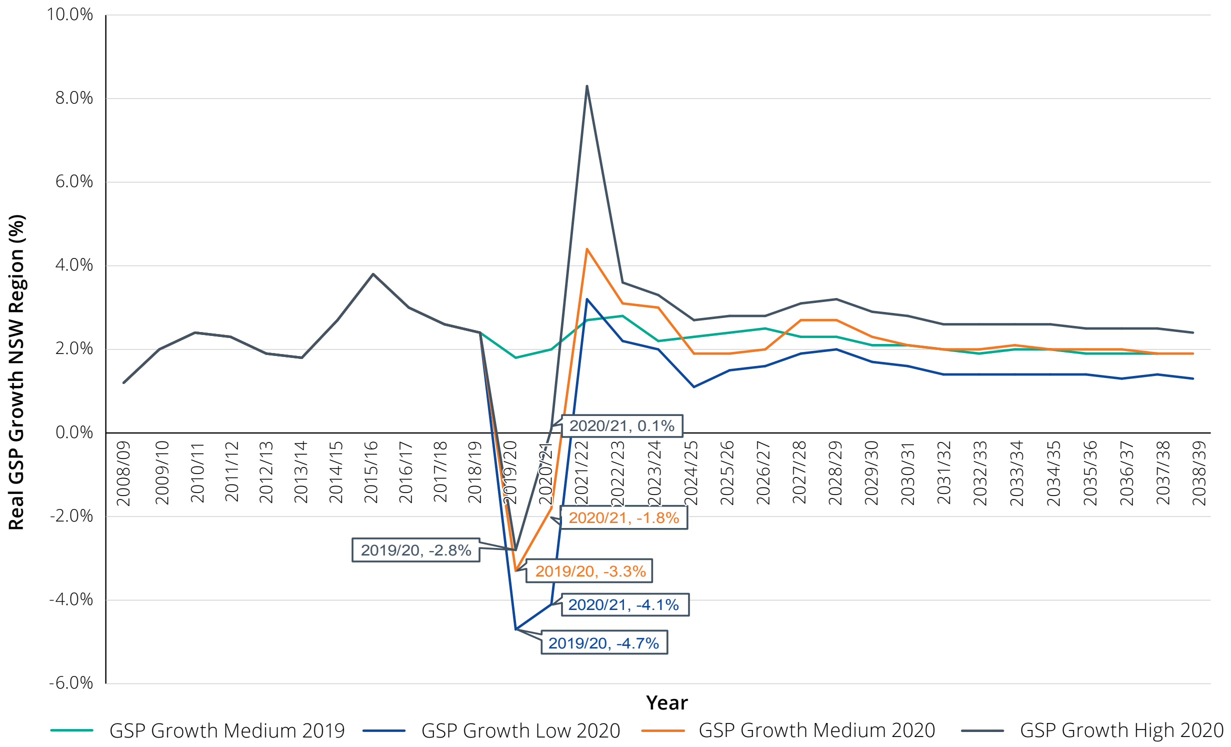


Source: Business Impacts of COVID-19 Survey, ABS, April 2020

BIS Oxford Economics has forecast two consecutive years of negative economic growth due to COVID-19 under the medium scenario as shown in **Figure 4.3**.

The low scenario forecasts a deeper economic downturn with prolonged negative effects on the NSW Region economy. Under both scenarios, grid electricity consumption initially decreases before starting to grow again from 2021/22 onwards.

Figure 4.3: NSW Region GSP Forecasts

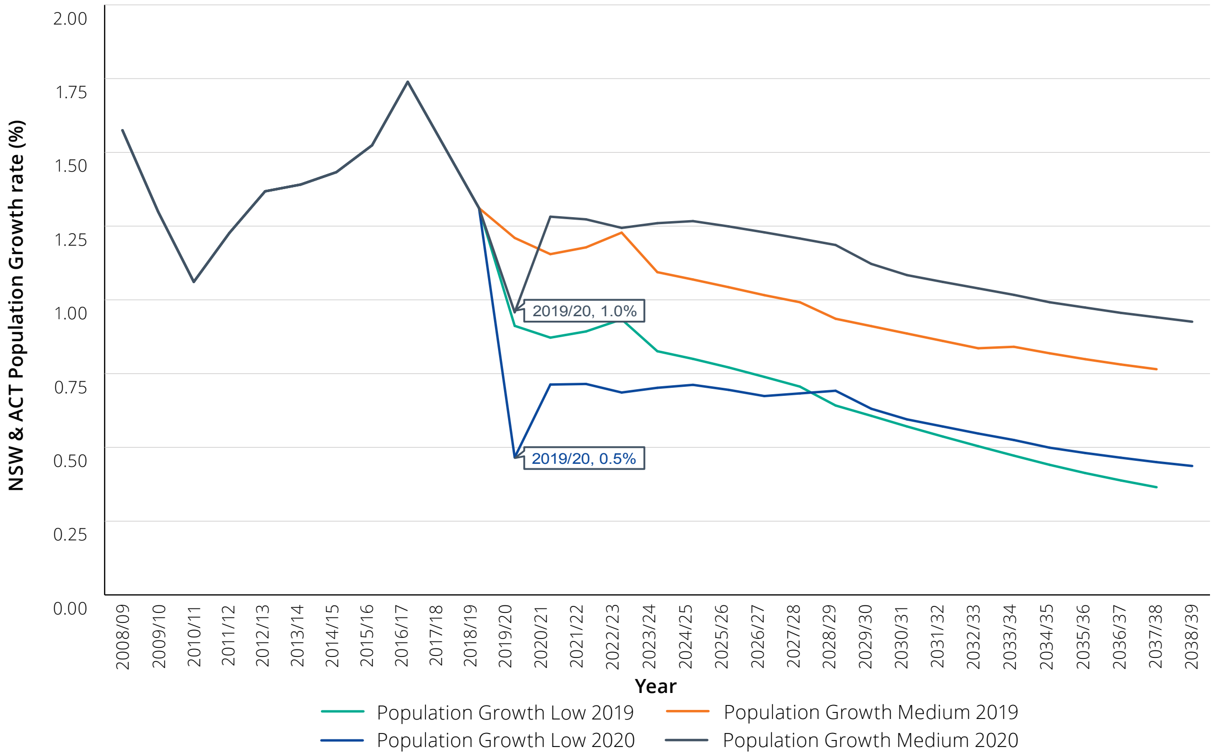


Source: Economic Forecasts to TAPR 2020, BIS Oxford Economics, May 2020

Population forecast obtained from BIS Oxford Economics (as shown in **Figure 4.4**) shows that population growth rate is predicted to dip in 2019/20 for the NSW Region under the medium scenario.

The low population growth scenario assumes a more protracted restriction on overseas migration due to COVID-19 which will lead to a decrease in overall population numbers in NSW Region. Both scenarios will result in a drop in electricity consumption from the grid.

Figure 4.4: NSW Region Population Forecasts

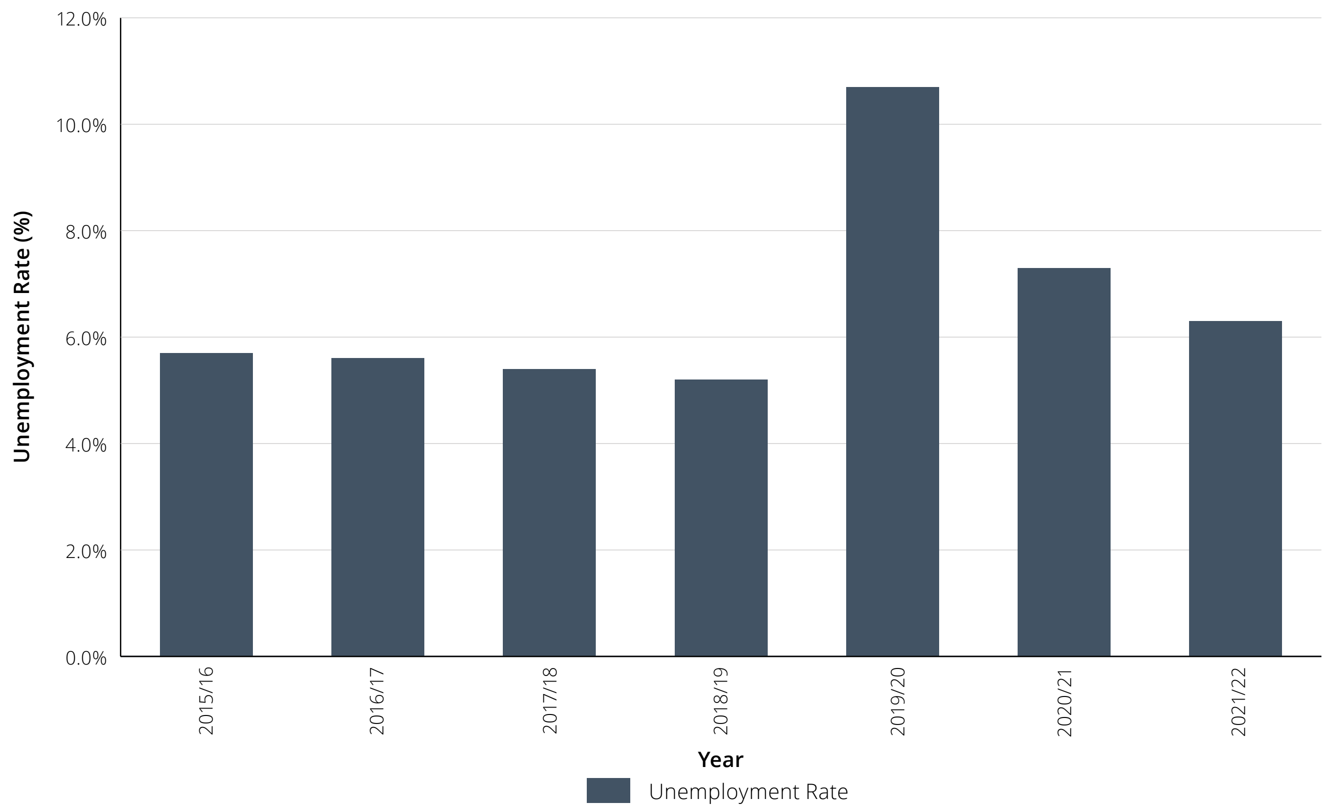


Source: Economic Forecasts to TAPR 2020, BIS Oxford Economics, May 2020

The unprecedented shut down of several sectors of the economy due to COVID-19 has led to significant job losses within a short time. BIS Oxford Economics (as shown in **Figure 4.5**) estimates that the unemployment rate in Australia will rise to 10% and above in 2019/20 and remain high in the subsequent years.

Recent forecast unemployment figures released by the Reserve Bank of Australia support this forecast. Although unemployment figures are not directly used for energy modelling, they are expected to have impacts on household disposable income and hence on economic growth, in the short to medium term.

Figure 4.5: Australia Unemployment Rate



Source: Economic Outlook, BIS Oxford Economics, 8 May 2020

4.2.7 Forecast scenarios

The annual energy and maximum demand models are conditional on a number of input variables. Each of these inputs is varied in correspondence to either the medium, high or low energy scenario. TransGrid judges the probability of the future approximating the medium scenario to be greater than the probability of either the high or low scenario.

The medium, high and low annual energy forecasts result from use of the corresponding input variables. The maximum demand forecasts are derived in part from the forecast annual energy growth forecast and in part from extensive analysis of maximum demand-temperature relationships. The load forecasts are therefore driven by the inputs provided by each scenario.

A summary of the three scenarios is presented in **Table 4.2**.

Table 4.2: Scenario inputs*

Input Variables	Medium energy scenario	High energy scenario	Low energy scenario
Population growth (average 2020 to 2029) %	1.2	1.6	0.7
Real household disposable income (average 2020 to 2029) %	2.4	3.6	1.6
Economic growth GSP (average 2020 to 2029) %	2.7	3.8	2.0
Real residential electricity price (average 2020 to 2029) %	-0.4	-0.7	0.2
Real non-residential electricity price (average 2020 to 2029) %	-0.7	-1.1	0.0
Real price of gas and other fuels (average 2020 to 2029) %	1.1	2.5	0.7
Average temperature increase (2020 to 2029), degrees	0.5	0.5	0.5
Additional energy residential efficiency savings in 2029 (compared to 2020), GWh	2,470	2,470	2,470
Additional energy non-residential efficiency savings in 2029 (compared to 2020), GWh	5,139	5,139	5,139
Residential rooftop PV generation in 2029, GWh	3,804	5,430	3,381
Non-residential rooftop PV generation in 2029, GWh	1,852	2,652	1,263
Stationary battery net charging in 2029, GWh	93	140	52
Vehicle battery charging in 2029, GWh	1,153	1,696	370

** Note: Compound average growth rates where shown as %.*

4.2.8 Annual energy forecasts

Figure 4.6 and **Table 4.3** show annual energy forecasts for the medium, high and low scenarios. Energy sent out, though on an upward trend since 2013/14, has moderated since late 2019 due to increases in rooftop PV, uptake of energy efficiency measures and COVID-19 restrictions.

Over the forecast horizon, the main drivers of change are:

- Continued population and economic growth albeit the COVID-19 related downturn in the first few forecast years;
- An increase in spot loads due to new mining and data centre loads;
- Fall in retail electricity prices following downward pressures on wholesale electricity prices due to decline in cost of renewable technologies;
- A small but significant increase in electric vehicle charging towards the end of the forecast horizon; and
- Offsets to growth as a result of existing and new energy efficiency programs and accelerating uptake of small-scale rooftop PV systems.

Figure 4.6: NSW region sent-out annual energy consumption (GWh) forecast

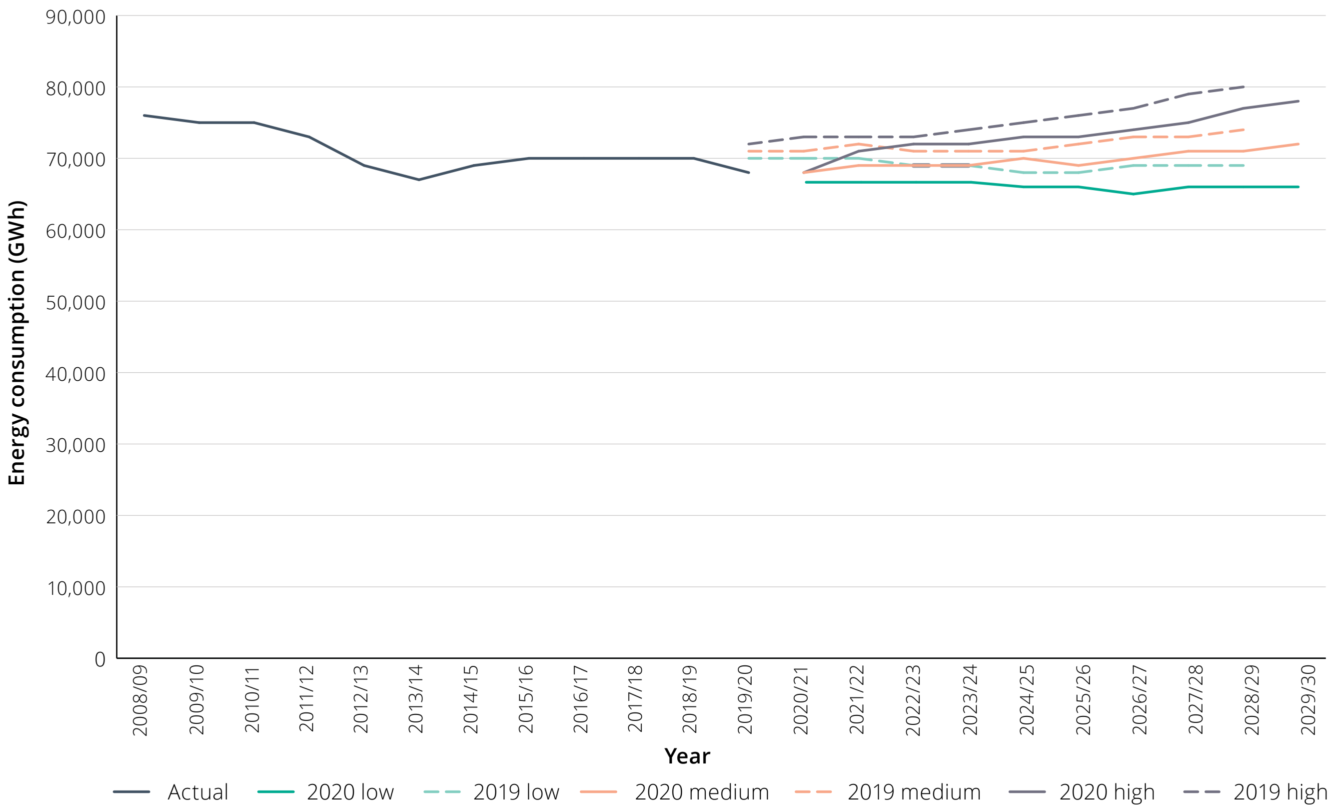


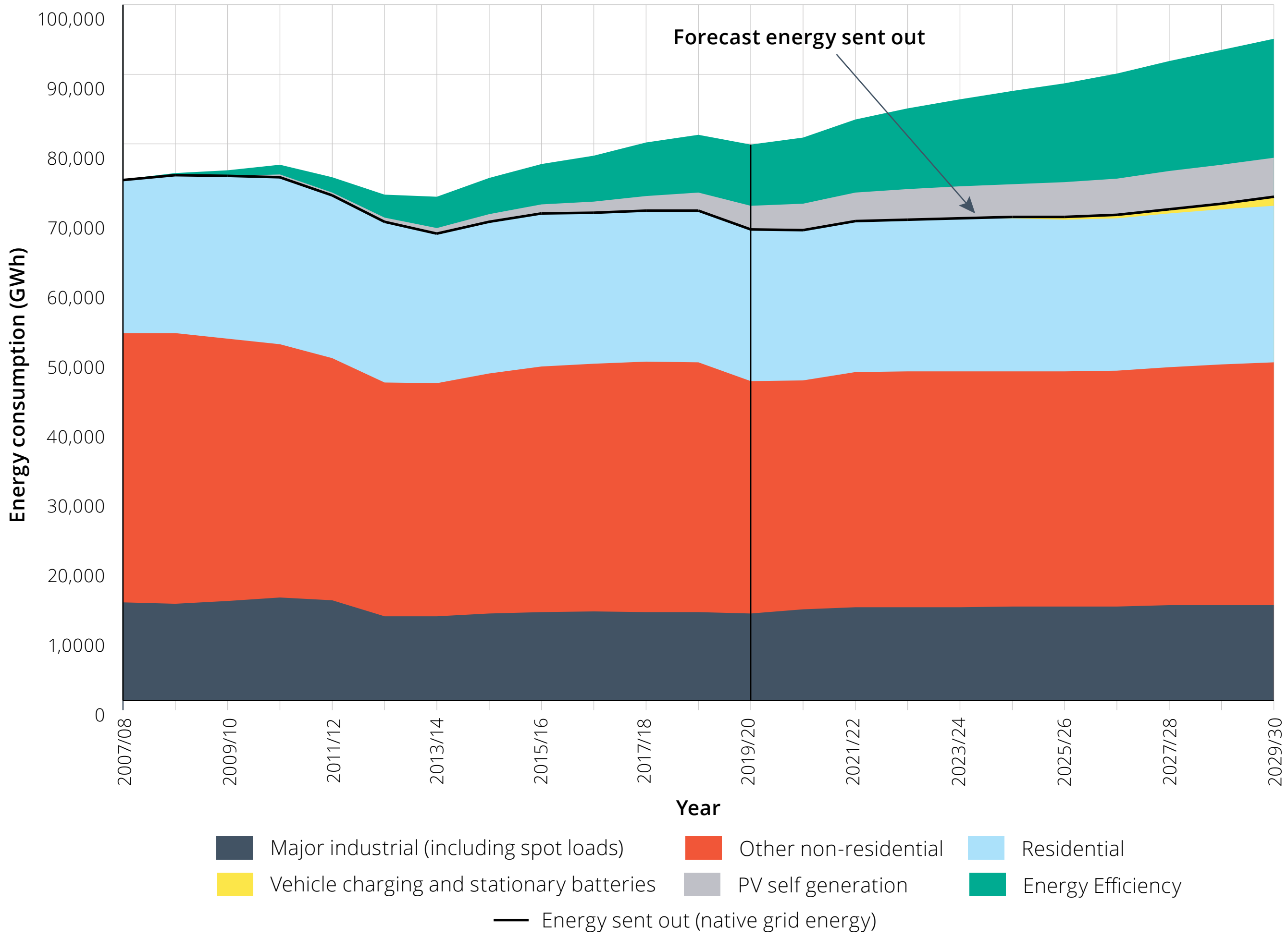
Table 4.3: NSW region sent-out annual energy consumption (GWh) forecast

	Actual	Medium	High	Low
2013/14	67,073			
2014/15	68,766			
2015/16	70,020			
2016/17	70,120			
2017/18	70,423			
2018/19	70,377			
2019/20 (Est.)	67,700			
2020/21		67,600	68,230	66,840
2021/22		68,900	71,030	67,200
2022/23		69,070	71,590	66,960
2023/24		69,260	72,380	66,580
2024/25		69,510	72,800	66,170
2025/26		69,450	72,890	65,610
2026/27		69,810	73,850	65,440
2027/28		70,600	75,190	65,520
2028/29		71,440	76,580	65,710
2029/30		72,370	78,090	65,830
Compound Average Growth Rate 2019/20 – 2028/29		0.8%	1.5%	-0.2%

Figure 4.7 shows the composition of historic energy and the medium growth forecast. A significant proportion of the decline in energy consumption in the initial years of the forecast period is accounted for by the non-residential sector as a result of disruption to small industrial/commercial loads due to COVID-19. A large amount of potential load increase has been, and is forecast to be, offset by accelerated energy efficiency and small-scale rooftop PV take up.

Meanwhile, the impact of battery charging on annual energy is projected to remain modest over the forecast horizon. Under the medium scenario, there is minimal effect of COVID-19 on major industrial loads and these are expected to increase at a modest pace due to additional mining and data centre loads.

Figure 4.7: Composition of NSW region annual energy consumption (actual and medium forecast)



4.2.9 Summer maximum demand forecast

Figure 4.8 and **Table 4.4** show summer maximum demand (MD) forecasts for the medium, high and low scenarios. The forecasts include the 10%, 50% and 90% POE levels for each scenario. Summer MD has moderated in the past year due to higher uptake of rooftop PV (causing lower grid demand) and mild weather conditions during the 2019/20 summer period.

Over the forecast horizon, the main drivers of change are:

- Moderation in underlying growth as reflected in the energy forecast;
- Continued – albeit moderating – growth in air-conditioning use, as air-conditioning ownership gets closer to saturation;
- Offsets to growth from energy efficiency, roof-top PV generation and net battery discharging, in combination with the fixed or variable timing of these resources; and
- Continued expected rise in summer average temperatures (as evident from historical summer temperature data) and effects of global warming.

Figure 4.8: NSW region summer as-generated maximum demand (MW) medium forecast

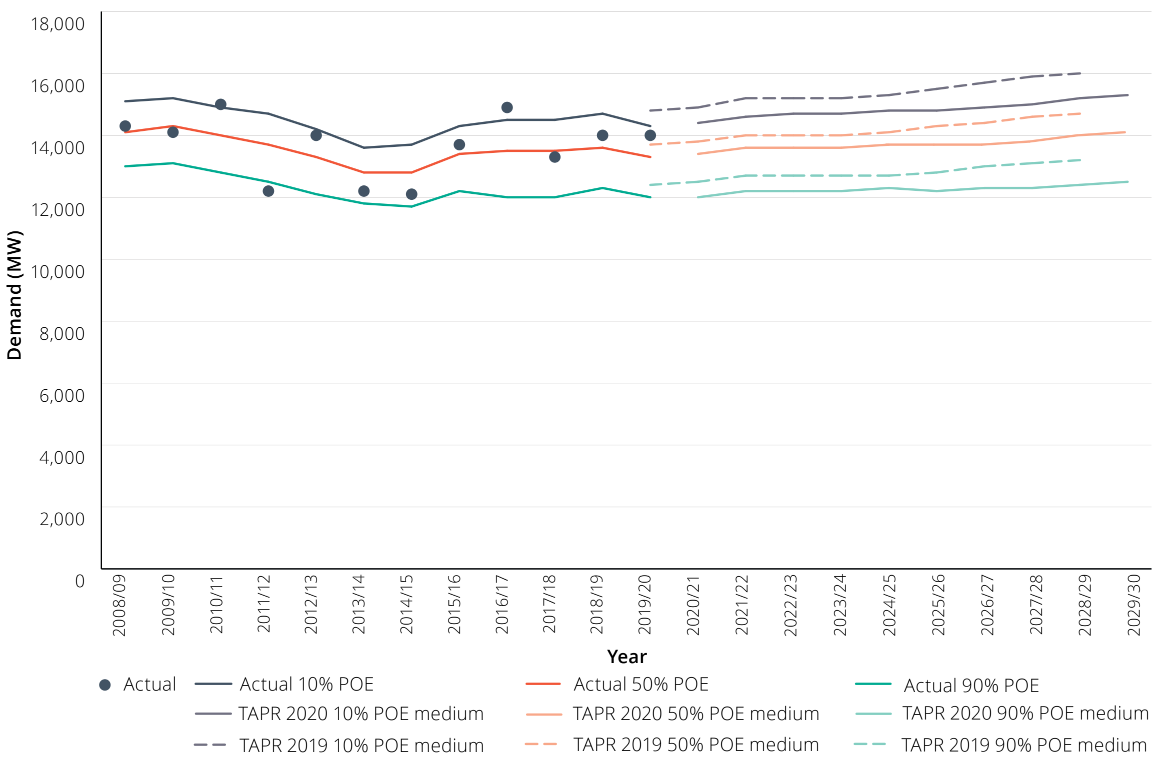


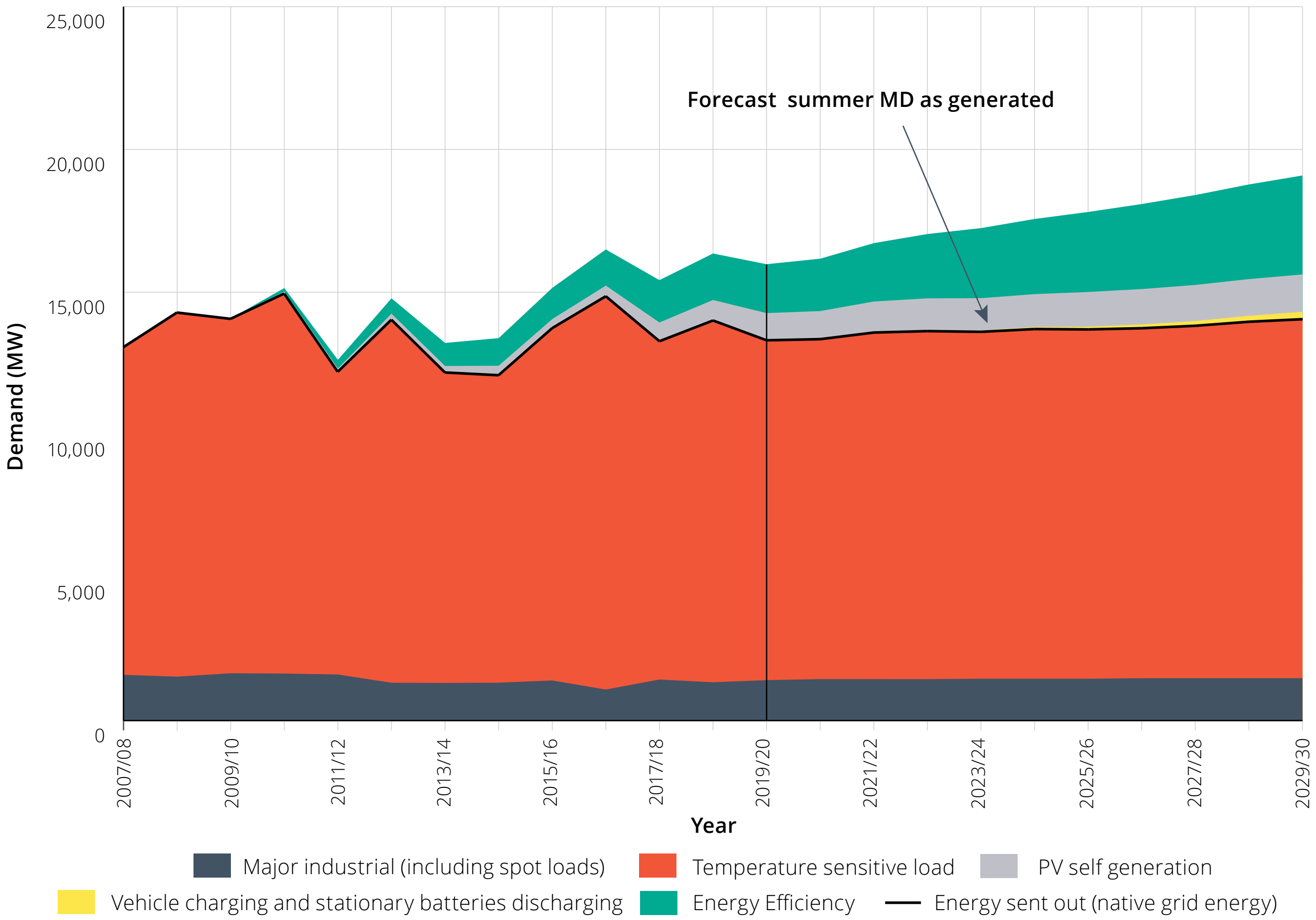
Table 4.4: NSW region summer as-generated maximum demand (MW) forecast

	Actual	Medium			High			Low		
		10% POE	50% POE	90% POE	10% POE	50% POE	90% POE	10% POE	50% POE	90% POE
2013/14	12,189	13,625	12,812	11,783						
2014/15	12,093	13,732	12,845	11,746						
2015/16	13,742	14,314	13,371	12,175						
2016/17*	14,859	14,514	13,462	12,039						
2017/18	13,284	14,523	13,463	12,025						
2018/19	14,010	14,691	13,636	12,298						
2019/20	13,957	14,285	13,316	11,986						
2020/21		14,380	13,360	12,030	14,510	13,470	12,140	14,200	13,190	11,880
2021/22		14,650	13,590	12,220	15,050	13,970	12,560	14,270	13,230	11,900
2022/23		14,720	13,640	12,250	15,210	14,090	12,660	14,240	13,190	11,840
2023/24		14,710	13,610	12,200	15,200	14,070	12,620	14,140	13,080	11,720
2024/25		14,830	13,710	12,270	15,370	14,210	12,720	14,140	13,070	11,690
2025/26		14,830	13,700	12,240	15,440	14,270	12,750	14,030	12,960	11,570
2026/27		14,890	13,740	12,250	15,610	14,410	12,860	14,010	12,920	11,510
2027/28		15,000	13,820	12,310	15,800	14,580	12,990	13,990	12,890	11,470
2028/29		15,160	13,970	12,420	16,060	14,800	13,180	14,050	12,930	11,490
2029/30		15,270	14,060	12,480	16,290	15,010	13,350	14,030	12,910	11,450
Compound Average Growth Rate 2020/21 – 2029/30		0.7%	0.6%	0.4%	1.3%	1.2%	1.1%	-0.1%	-0.2%	-0.4%

**Note: 2016/2017 Summer MD (on 10 February 2017) was recorded as 14,233 MW at a time of substantial load curtailment. Estimated MD in the absence of such curtailment was 14,859 MW.*

Figure 4.9 shows the composition of historic summer MD and the medium growth forecast. A significant amount of potential load increase in the grid has been, and will continue to be, offset by accelerated energy efficiency and small-scale rooftop PV take up. In the later forecast years, batteries discharging around the time of the network peak also act to depress the grid maximum demand.

Figure 4.9: Composition of NSW region summer MD (actual and 50% POE medium forecast)



4.2.10 Winter maximum demand forecast

Figure 4.10 and **Table 4.5** show winter maximum demand (MD) forecasts for the medium, high and low scenarios. The forecasts include the 10%, 50% and 90% POE levels for each scenario. Winter MD has increased at a lower rate than summer MD, mainly because average winter temperatures have been quite mild in the past few years.

Over the forecast horizon, the main drivers of change are:

- Decline and moderation in underlying growth as reflected by the energy forecast;
- Offsets to growth from energy efficiency and net battery discharging, in combination with the fixed or variable timing of these resources; and
- Comparative cost of using electrical appliances for heating (reverse cycle air conditioners) versus those using competing fuels like natural gas.

Figure 4.10: NSW region winter as-generated maximum demand (MW) medium forecast

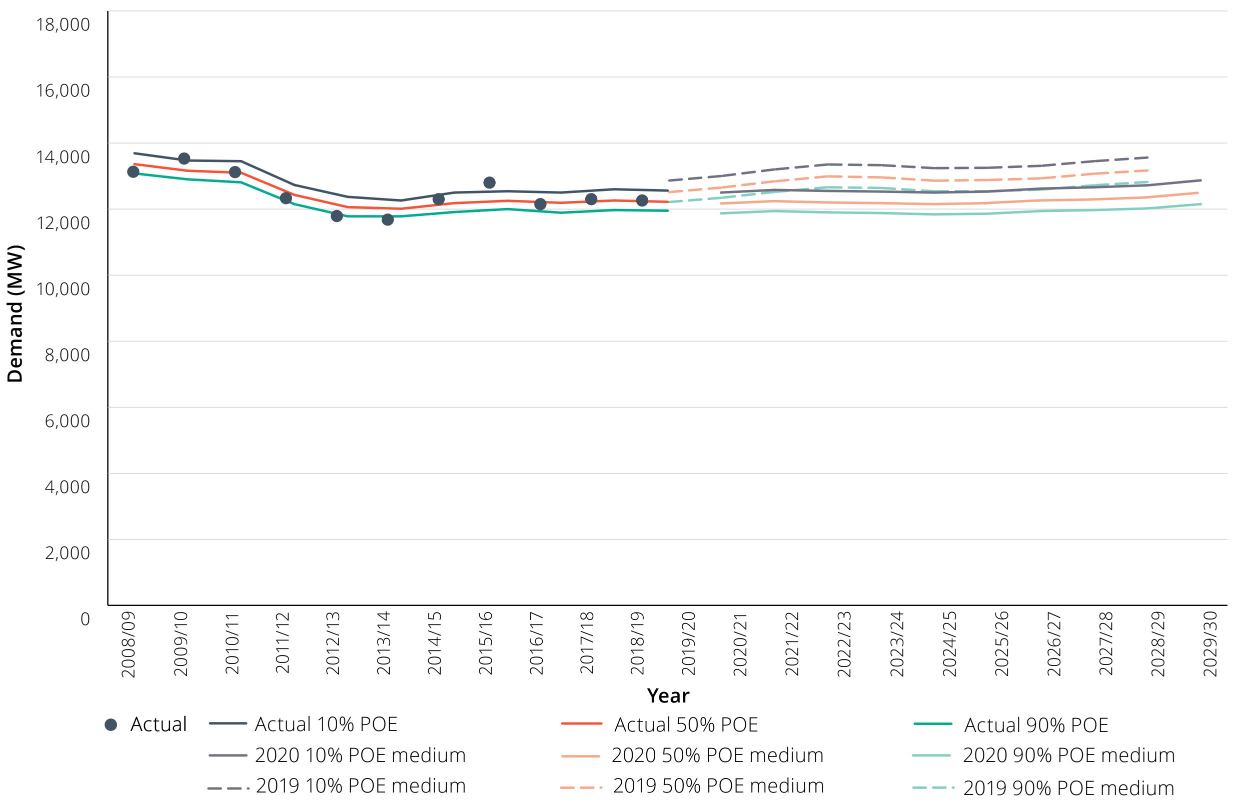


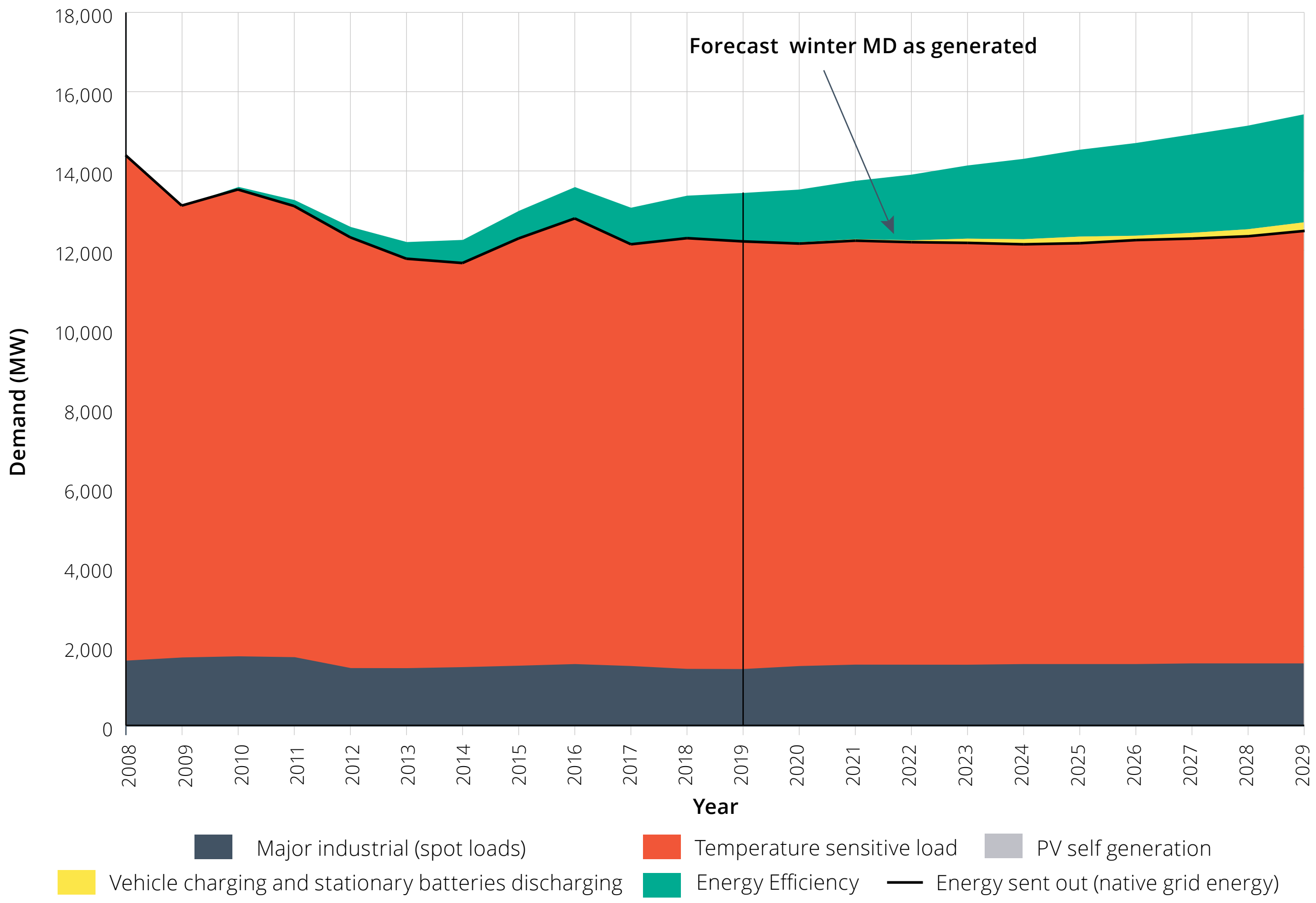
Table 4.5: NSW region winter as-generated maximum demand (MW) forecast

	Actual	Medium			High			Low		
		10% POE	50% POE	90% POE	10% POE	50% POE	90% POE	10% POE	50% POE	90% POE
2013	11,786	12,369	12,056	11,782						
2014	11,677	12,258	12,012	11,784						
2015	12,298	12,498	12,175	11,914						
2016	12,802	12,536	12,255	12,000						
2017	12,150	12,502	12,185	11,891						
2018	12,304	12,598	12,263	11,966						
2019	12,261	12,561	12,222	11,946						
2020		12,500	12,170	11,870	12,510	12,180	11,880	12,490	12,160	11,860
2021		12,580	12,240	11,940	12,640	12,300	11,990	12,440	12,100	11,800
2022		12,550	12,200	11,900	12,820	12,470	12,160	12,240	11,910	11,610
2023		12,530	12,180	11,880	12,970	12,620	12,300	12,140	11,800	11,500
2024		12,500	12,150	11,840	13,060	12,700	12,370	12,100	11,760	11,460
2025		12,530	12,180	11,860	13,190	12,820	12,490	12,050	11,710	11,410
2026		12,620	12,260	11,940	13,410	13,030	12,690	11,950	11,600	11,300
2027		12,660	12,290	11,970	13,560	13,170	12,820	11,930	11,580	11,270
2028		12,720	12,350	12,020	13,710	13,310	12,960	11,900	11,550	11,240
2029		12,870	12,490	12,150	13,940	13,540	13,180	11,870	11,520	11,210
Compound Average Growth Rate 2020 – 2029		0.3%	0.3%	0.3%	1.2%	1.2%	1.2%	-0.6%	-0.6%	-0.6%

Figure 4.11 shows the composition of historic winter MD and the medium growth forecast. A significant amount of potential load increase in the grid has been, and will continue to be, offset by energy efficiency. In the later forecast years, batteries discharging around the time of the network peak also act to moderate the impact of underlying demand on the grid maximum demand.

Sunset in NSW during the winter months is around 5:00 pm to 5:30 pm. Accordingly there is no offset in winter from rooftop PV generation as such generation is not available at the time of the winter which typically occurs between 6:00 pm to 6:30 pm.

Figure 4.11: Composition of NSW region winter MD (actual and 50% POE medium forecast)



4.3 Bulk supply point forecasts

Generally, the load changes at BSPs are organic. Where there are spot loads[26], however they will be included in the relevant forecasts. The BSP forecasts incorporate the local knowledge of the relevant DNSPs and directly connected customers.

Macroeconomic data is generally not available at a BSP level. Consequently, it is generally not possible to develop macroeconomic models for individual BSPs and to produce forecasts for different economic scenarios. In practice, the BSP forecasts are produced in a variety of ways, reflecting the amount of data available and the nature of the loads.

Figure 4.12 shows the forecast growth rates for BSPs serving the respective DNSPs in summer, with annualised growth rates. The detailed year-on-year forecasts of summer and winter maximum demands at the individual BSP level are set out in Appendix 2. This data was provided by the relevant distributor (i.e. DNSPs) and directly connected customers to TransGrid in early 2020. The DNSPs methodologies for load forecasting should be referred in the respective DNSP's annual planning report.

The BSPs with the highest growth rates are those serving the following areas.

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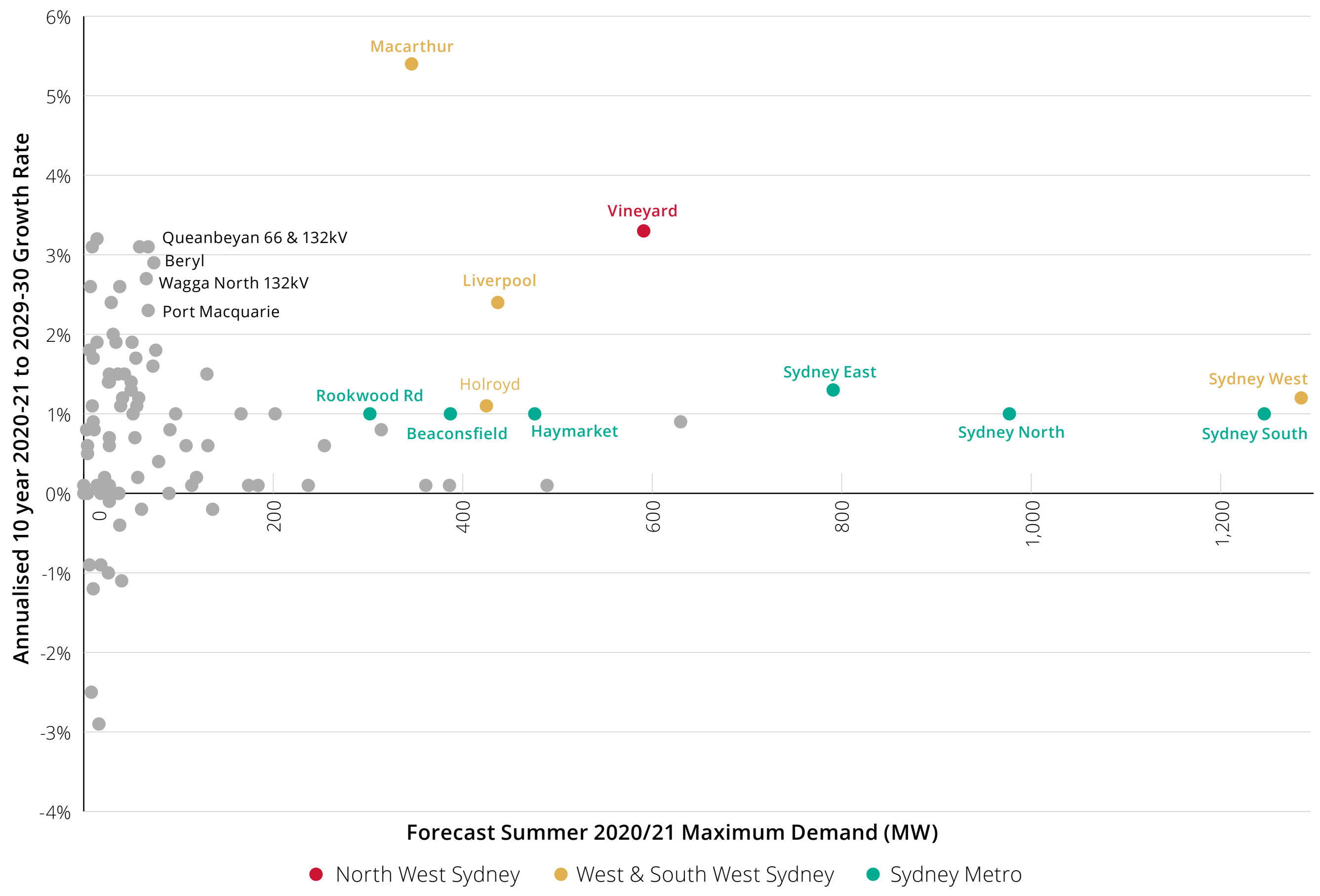
[26] Spot loads are step (one-off) increases in load for a BSP due to new commercial/housing developments or large industrial customer connections. There could be spot load decreases in cases where there are withdrawals of large load customers from the grid.

Figure 4.12: BSP summer forecast growth rates



West and South-West Sydney

This area is predominantly within the South West Sector Land Release and Broader Western Sydney Employment Area where a large number of residential lot releases are planned. Load increases are also expected due to the new Western Sydney Airport at Badgerys Creek and other associated residential and light industrial/ancillary services growth in this region. Load increases would also occur from expansion and construction of existing and prospective data centres.

North-West Sydney

The development and operation of North West Rail infrastructure and associated activity in medium/high density residential, commercial & industrial areas will drive load growth in this area.

Sydney Inner Metropolitan area

This area continues to grow at a higher rate than the overall NSW region average. Real income and population growth is forecast to result in higher load growth in the long run. The NSW Government is delivering and planning a range of projects (electricity loads) in Sydney Inner Metropolitan area including transport infrastructure and a number of precinct or urban developments (Waterloo, Bays, Ashmore, Barangaroo, Central Park, Green Square, Harold Park and the Southern Employment Lands).[27] Beaconsfield and Haymarket BSPs are two of our largest exit points which supply the Sydney Inner Metropolitan area.

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[27] City of Sydney project website, http://www.cityofsydney.nsw.gov.au/vision/changing-urban-precincts/city-transformation and http://www.cityofsydney.nsw.gov.au/vision/changing-urban-precincts. Viewed on 16 April 2018

4.3.1 TransGrid 2020 NSW region forecast vs aggregate DNSP BSP forecast

The forecasts obtained from DNSPs were prepared prior to the impacts of COVID-19, and therefore do not reflect these impacts on energy consumption and demand. Therefore, this year the comparison of bottom up BSP forecasts obtained from DNSPs is with TransGrid's top down NSW Region high forecast, as the high scenario reflects a bounce back to the pre-COVID-19 trends.

Unlike TransGrid's NSW region forecast, none of the BSP loads, by definition, include transmission network losses and power station auxiliary load. Despite this difference, the individual BSP forecasts for each season can be aggregated to provide a useful comparison with the overall NSW region demand forecast. In order to achieve this, we consider the following:

- Diversity of load or timing of maximum demand;
- Transmission network losses; and
- Power station auxiliary load.

TransGrid accounts the abovementioned limitations by:

- Using 50% POE forecasts where they are available, and where they are not available, by assuming that individual BSP projections are likely to have been based on enough historical data to converge towards an approximate 50% POE forecast;
- 'Diversifying' individual BSP forecasts to allow for the time diversity observed between historical local seasonal maximum demand and NSW maximum demand;
- Adding forecast aggregate directly connected industrial loads not included in the BSP forecasts; and
- Incorporating transmission network losses and power station auxiliary loads, derived from recent historical observations, to express the forecasts in the same 'as-generated' basis for comparison with TransGrid's 2020 NSW forecast.

Figure 4.13 and **Figure 4.14** show aggregate BSP summer and winter maximum demand forecasts compared with TransGrid's 10% and 50% POE high NSW region summer and winter maximum demand forecasts respectively for NSW and ACT region.

Figure 4.13: TransGrid's top down forecast vs aggregate BSPs forecast for summer maximum demand

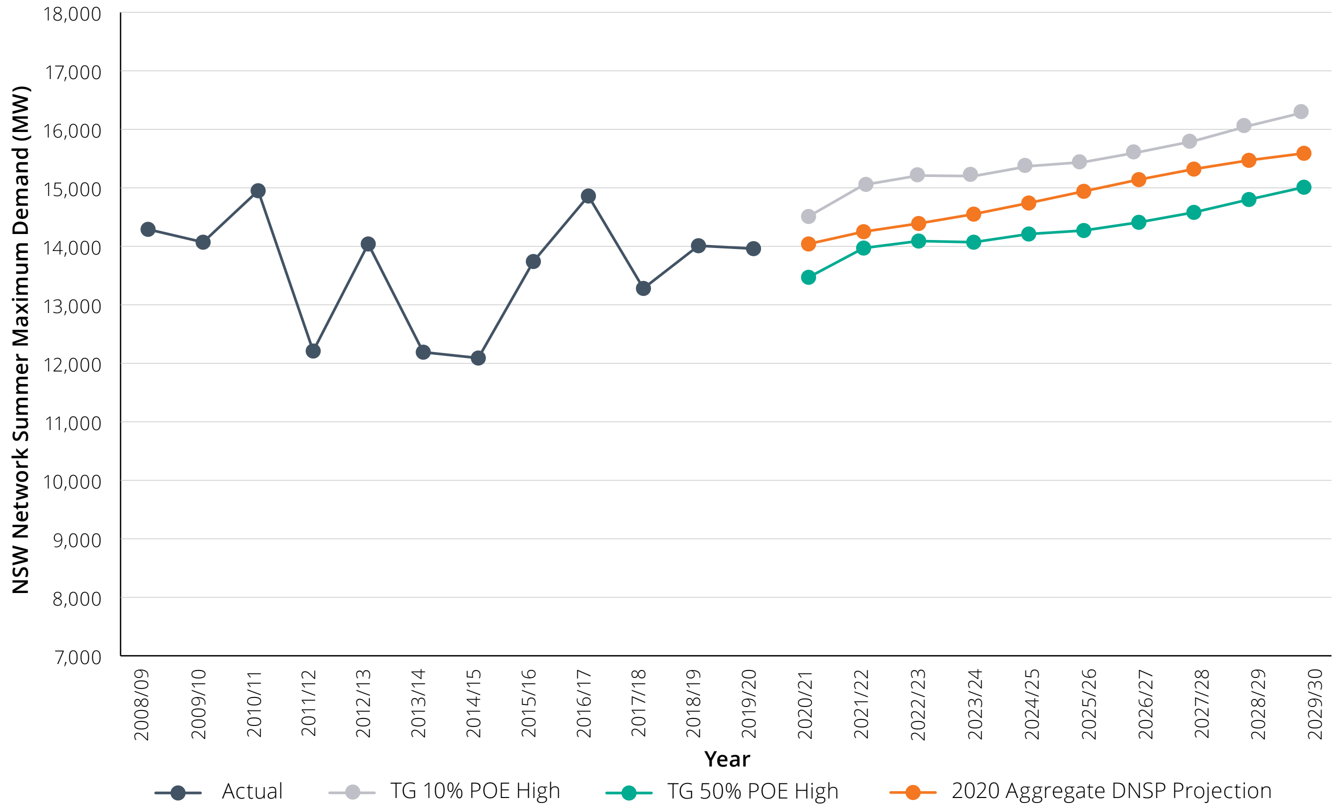
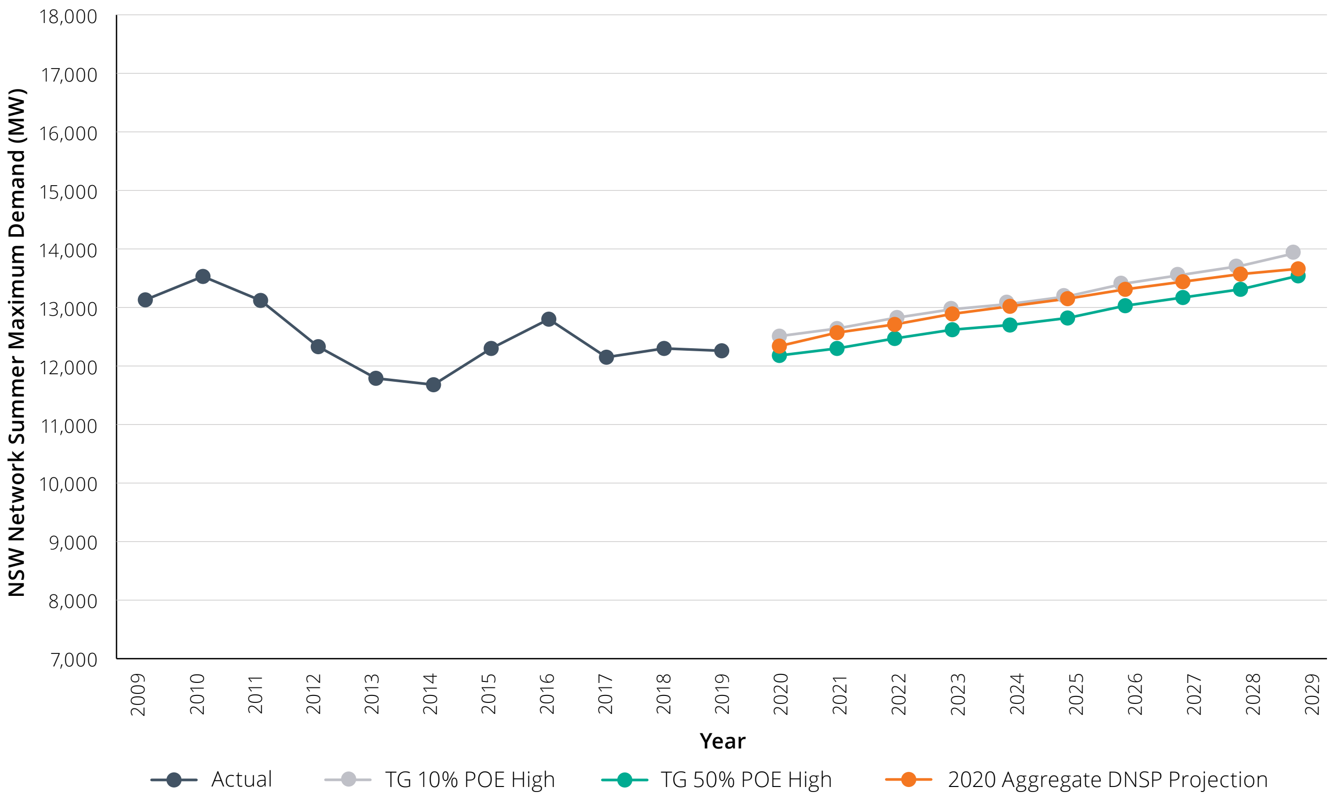


Figure 4.14: TransGrid's top down forecast vs aggregate BSPs forecast for winter maximum demand



It is evident from the graphs that aggregate BSP forecasts for summer and winter have similar trajectories. While aggregate DNSP projection for summer lie within TransGrid's 50% and 10%POE bands for summer, aggregate BSP forecast for winter align more closely to TransGrid's top down winter forecasts. The minor differences between the forecasts are understandable as the two sets of forecasts (DNSP aggregate BSP vs TransGrid top down) are produced on different basis.

Although the comparison between TransGrid's 2020 top down forecasts and the DNSPs' aggregate of BSP forecasts do not indicate which forecast is more accurate, they, nonetheless, allow for a high-level comparison to be made.

4.4 TransGrid's 2020 forecast vs AEMO's 2019 ESOO & 2019/20 ISP forecasts for NSW region

The most recent update of AEMO's top down forecasts for the NSW region was published in March 2020 as an update to the 2019 Electricity Statement of Opportunities (ESOO) and for use in AEMO's Integrated System Plan (ISP) 2019/20. This section compares TransGrid's 2020 top down maximum demand forecast and AEMO's latest maximum demand forecast update for the NSW region. It is to be noted that AEMO's March 2020 forecast update does not include impacts on load due to COVID-19 effects. As such the AEMO's forecasts are not strictly comparable to TransGrid's 2020 forecasts.

Both demand forecasts are presented on a 'native as-generated' basis. The details of AEMO's demand forecast is provided on the AEMO website.[28]

In order to compare the TransGrid and AEMO summer and winter maximum demand forecasts, TransGrid combined AEMO's 'native sent out' neutral 50% POE forecast and AEMO's 'auxiliary load' neutral 50% POE forecast. This summated AEMO forecast is compared to TransGrid's 'as-generated' medium 50% POE forecast and is shown in the following figures.

Figure 4.15 and **Figure 4.16** show a comparison between TransGrid's 2020 summer and winter maximum demand medium scenario forecasts and AEMO's most recent central scenario (summer and winter) maximum demand forecasts in its 2019 ESOO/ISP 2019/20. Both forecasts are expressed on a "native as generated basis" and hence can be directly compared.

Figure 4.15: TransGrid's 2020 vs AEMO's ESOO 2019/ISP 2019/20 summer maximum demand forecast for NSW region

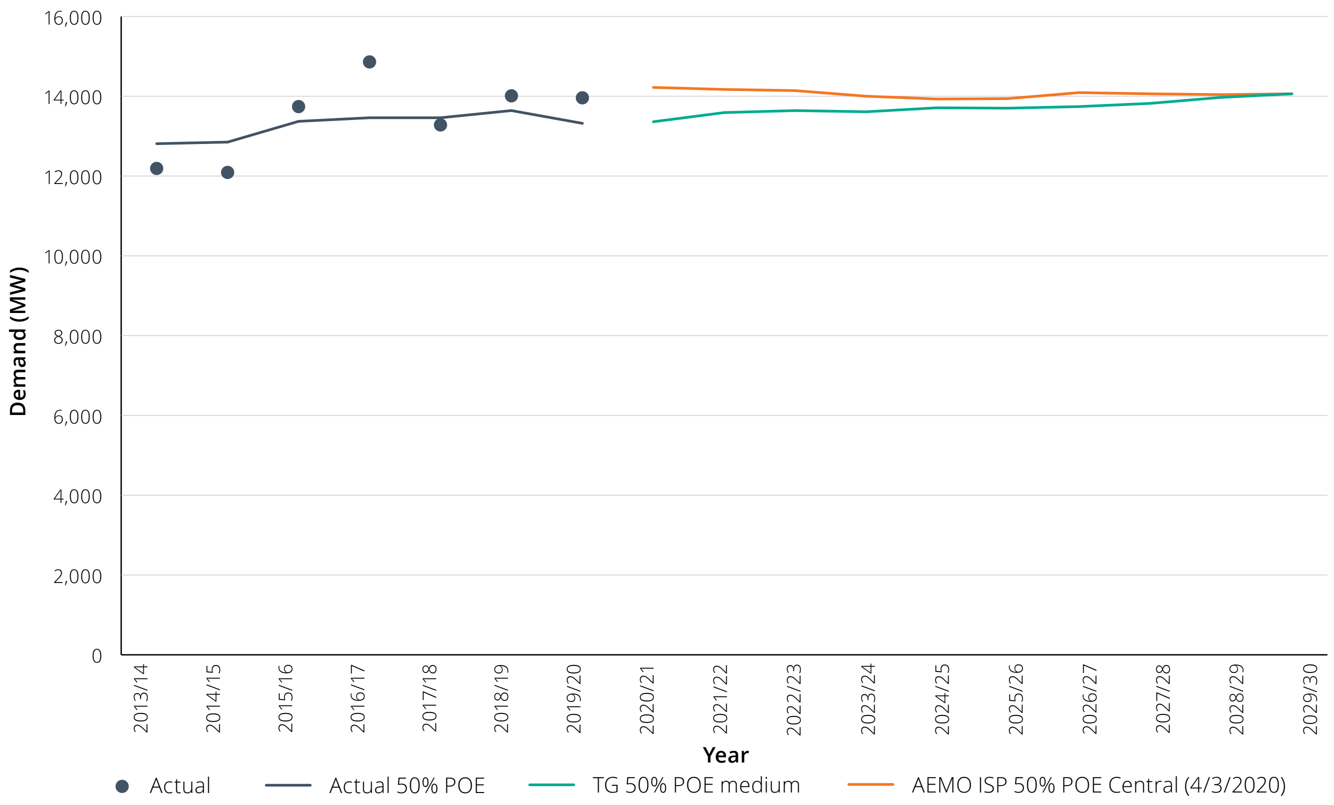
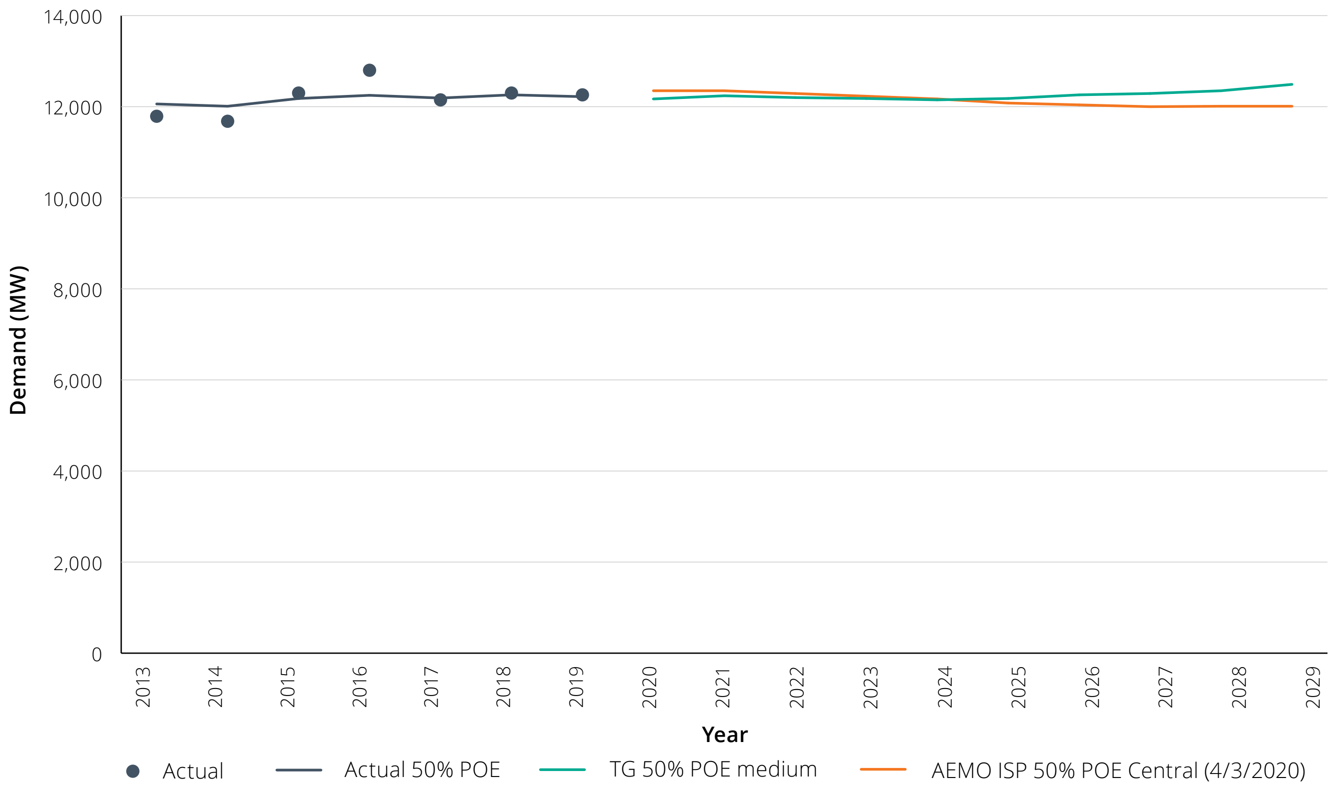


Figure 4.16: TransGrid's 2020 vs AEMO's ESOO 2019/ISP 2019/20 winter demand forecast for NSW region



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[28] https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2019/2019-electricity-statement-of-opportunities.pdf?la=en

4.5 Historical AEMO forecasts compared to actual outcomes

Figure 4.17 shows the forecast accuracy of AEMO energy forecasts for the NSW Region in the past 5 years. It appears from the figure that AEMO's forecasts for NSW Region energy consumption have been below the actual outcomes. This has been documented in a number of AEMO's forecasting accuracy reports[29] published in the recent past.

AEMO has attributed the under-forecasts to variations in patterns of weather variables, loss factor estimates and DER projections. Also the historical energy consumption figures for NSW Region reported in its various NEFR and ESOO publications have had moderate variations.

Figure 4.17: AEMO NSW region energy forecasts vs actual outcomes

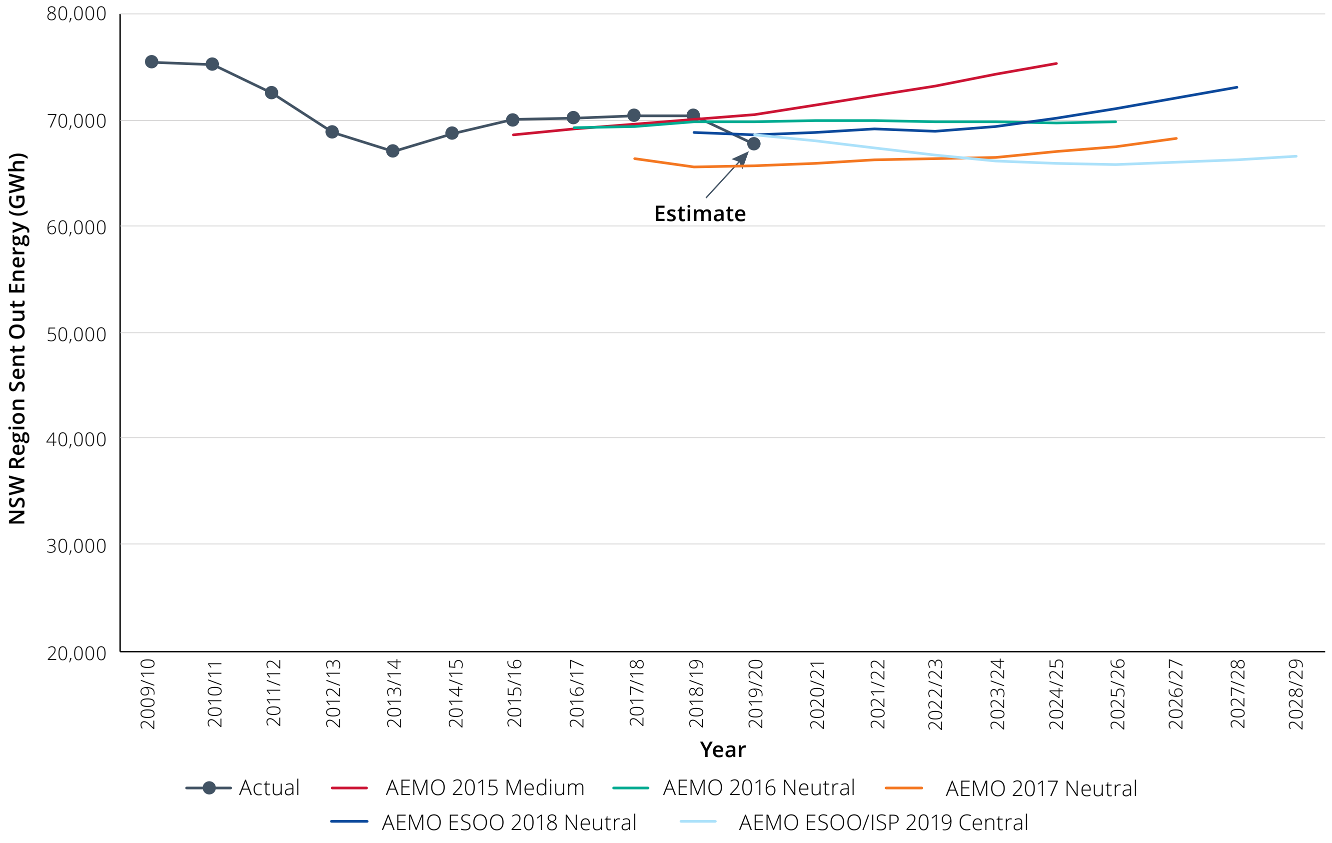

Figure 4.18 compares AEMO's summer maximum demand (as generated) forecasts[30] with summer raw actual maximum demands for the NSW Region. Although it would be difficult to compare summer raw maximum demands with AEMO 50% POE forecasts, it can be observed that AEMO's 50% POE forecasts in the last 5 years have had moderate variations. AEMO attributes the divergence in their forecasts to changes in input parameters and modelling techniques.

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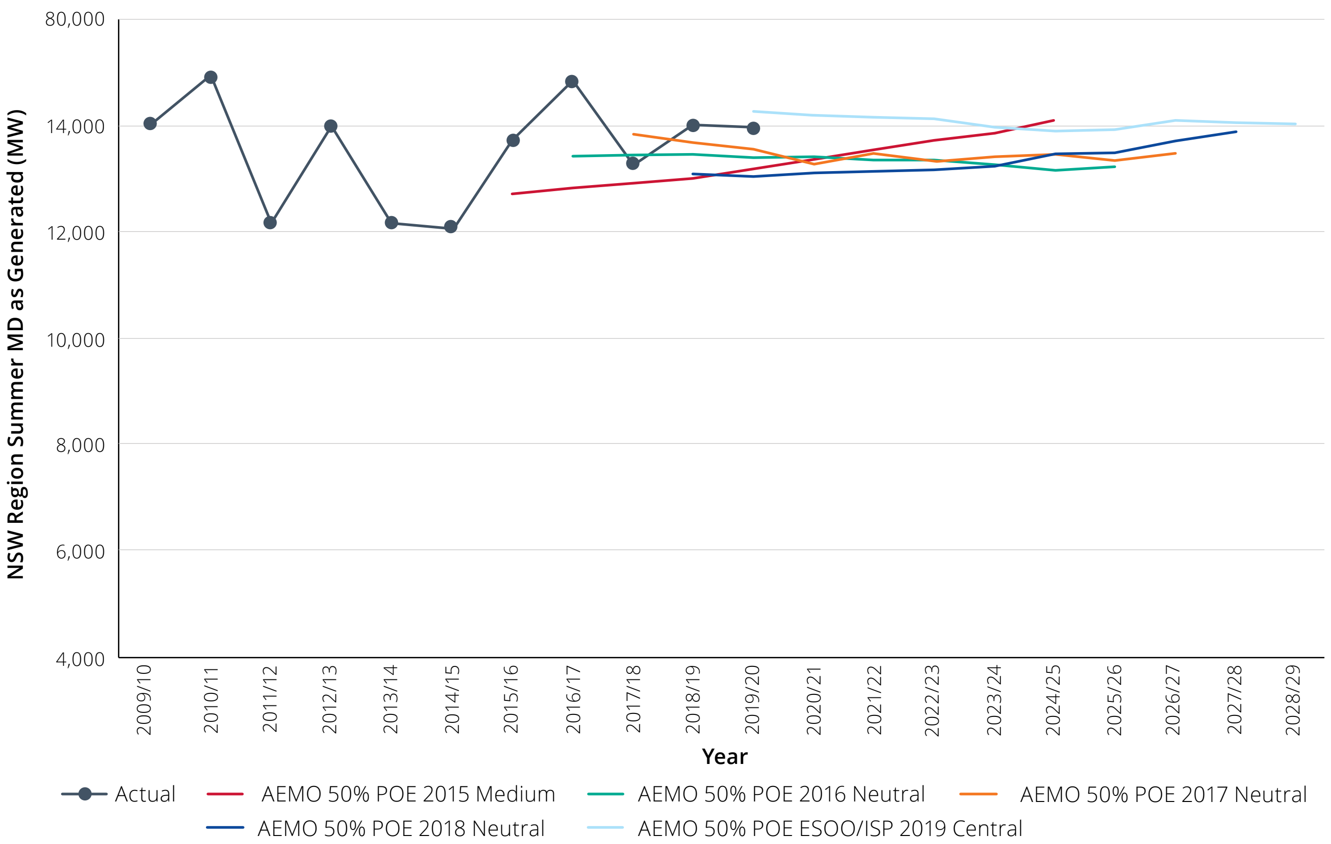
[29] https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/forecasting-accuracy-reporting

[30] AEMO publishes native sent out summer maximum demand forecasts. These have been converted to 'as generated' numbers by adding AEMO's forecasts of power station auxiliary loads.

Figure 4.18: AEMO NSW region summer MD forecasts vs actual outcomes



4.6 Joint planning

4.6.1 Co-ordination and working groups

TransGrid regularly undertakes joint planning with AEMO and Jurisdictional Planning Bodies from across the NEM. There are a number of working groups and reference groups in which TransGrid participates:

- Executive Joint Planning Committee;
- Joint Planning Committee;
- Regulatory Working Group;
- Regular coordination meetings; and
- NEM Planning & Design Working Group of the Energy Networks Association.

Executive Joint Planning Committee

The Executive Joint Planning Committee coordinates effective collaboration and consultation between Jurisdictional Planning Bodies and AEMO on electricity transmission network planning issues so as to:

- Develop a framework for the ISP;
- Continuously improve current network planning practices; and
- Coordinate on energy security across the NEM.

The Executive Joint Planning Committee directs and coordinates the activities of the Market Modelling Working Group, the Forecasting Reference Group, and the Regulatory Working Group as outlined below. These activities ensure effective consultation and coordination between Jurisdictional Planning Bodies, 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.

Joint Planning Committee

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

Market Modelling Working Group

The Market Modelling Working Group (MMWG) is a working committee supporting the EJPC in effective collaboration, consultation and coordination between Jurisdictional Planning Bodies, Transmission System Operators and AEMO on modelling techniques, technical knowledge, industry experience, and a broad spectrum of perspectives on market modelling challenges.

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.

Regulatory Working Group

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

Regular joint planning meetings

For the purpose of effective network planning, TransGrid conducts regular joint planning meetings with:

- AEMO National Planning;
- AEMO Victoria Planning;
- ElectraNet;
- Powerlink;
- Ausgrid;
- Endeavour Energy;
- Essential Energy; and
- Evoenergy.

4.6.2 Joint Planning Projects

TransGrid has coordinated with other jurisdictional planners on the following projects:

- 2020 ISP;
- South Australian Energy Transformation and EnergyConnect;
- Expanding NSW to Queensland Transmission Transfer Capacity (QNI Upgrade);
- Victoria to New South Wales Interconnector Upgrade (VNI Upgrade); and
- Victoria to NSW Interconnector West (VNI West)

Details of these projects are provided in Chapter 2

4.7 Service standards

NSW Electricity Transmission Reliability and Performance Standard

The NSW Electricity Transmission Reliability and Performance Standard 2017 is administered by IPART. This Standard specifies two reliability criteria for each BSP:

- The required level of network redundancy for each BSP or group of BSPs that function as a cohort; and
- An allowance of Minutes of Expected Unserved Energy, which is the maximum amount of energy at risk of being not supplied in a given year expressed as minutes at the average load on the BSP.

The Standard is a planning, rather than a performance standard. This means the network needs to be planned to meet the standards over the life-cycle of the assets on average, rather than be met in every year.

Network investment may be required to ensure compliance with the Standard. The Standard however, also provides flexibility to promote the most efficient network or non-network solution to meet the Minutes of Expected Unserved Energy allowance. This may include changes to the transmission network, the distribution network, network support arrangements (including the use of Demand Management options), existing backup supply arrangements, or a combination of these.

TransGrid's annual compliance report for 2019 found all BSPs are compliant with reliability standard.

ACT reliability standard

TransGrid is subject to the Electricity Transmission Supply Code July 2016 under the transmission licence that TransGrid holds in the ACT. The Code includes the requirement for the provision of two or more geographically separate points of supply at 132 kV or above. It also requires that there be a continuous electricity supply at maximum demand to the ACT network at all times, including following a single credible contingency event.

The Canberra and Williamsdale Substations currently supply the ACT load, however, Canberra Substation supplies Williamsdale Substation. The construction of Stockdill 330/132 kV Substation will separate Williamsdale from Canberra and achieve the Code requirement for two fully independent supply points. More detailed information about this project is available in Section 2.3.5.

4.8 Alignment with ESOO and ISP

TransGrid observes that there is an increased likelihood of load shedding in NSW following the retirement of Liddell Power Station. Load shedding is required to maintain the stability of the power system when there is a shortfall in supply to meet demand.

This is consistent with AEMO's projection of an emerging and increasing reliability gap after the retirement of Liddell Power Station in the 2019 Electricity Statement of Opportunities.[31]

Loss of an additional major power station in NSW after the retirement of Liddell Power Station could lead to a further shortfall in supply, unless sufficient additional firming capability is developed in time.

The plans set out in this report align with AEMO's 2018 National Transmission Network Development Plan and 2020 Integrated System Plan.

4.9 Changes from TAPR 2019

Updates in this chapter and referenced Appendices, since TAPR 2019, includes:

- TransGrid has updated its forecasts for NSW energy consumption and maximum demands to provide a detailed outlook for electricity consumption and maximum demand for the region as a whole;
- The method of preparation of the TransGrid forecast is explained in Appendix 1: including a description of models, model evaluation, input variables and scenarios, other assumptions and independent advice; and
- A comparison of annual energy consumption and maximum demand between TransGrid's 2020 forecast and AEMO's 2019 ESOO forecast has been added.

These changes are consistent with the requirements of NER Clause 5.12.2(c)(1), (6A), (9), (10) and (12).

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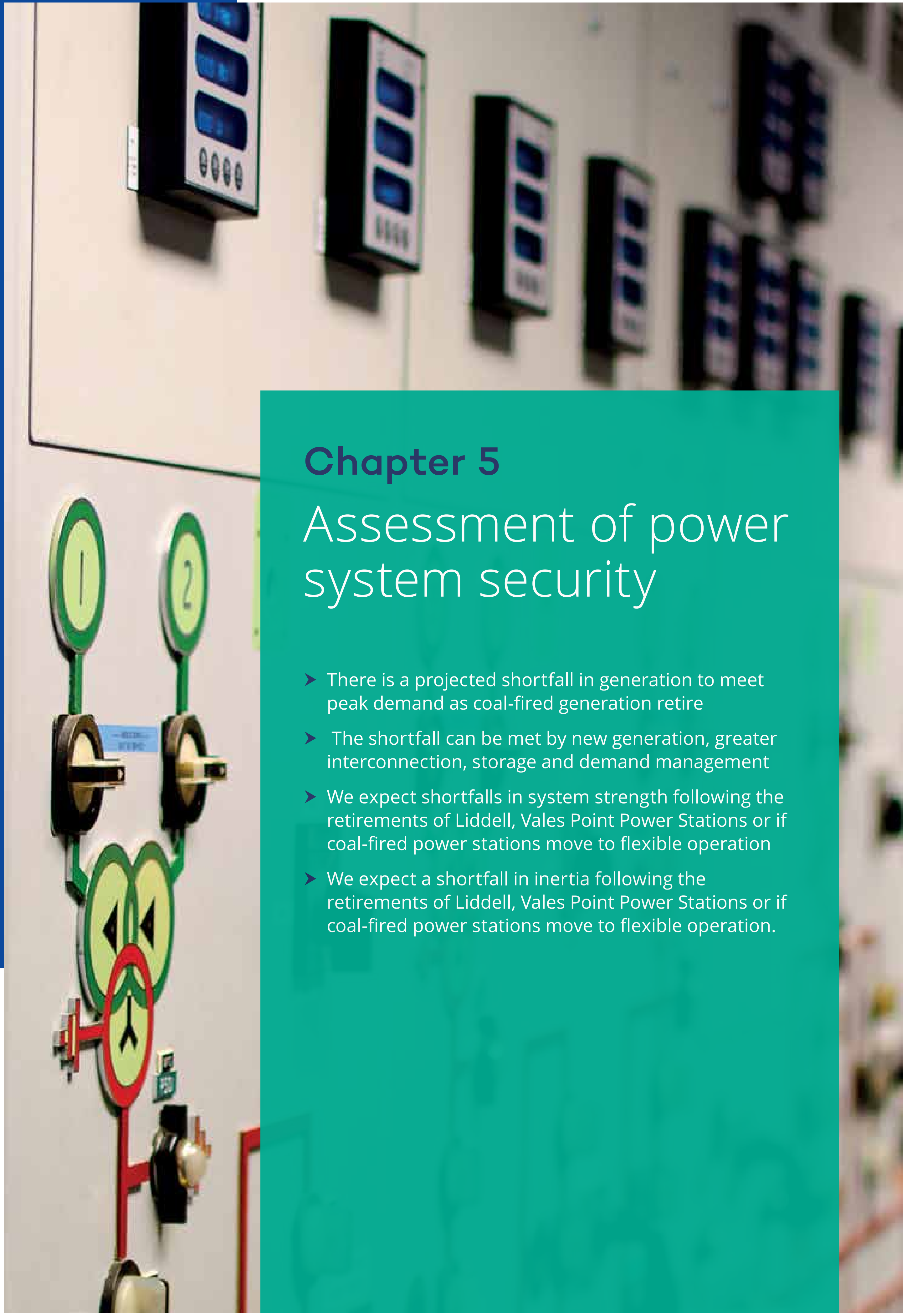
[31] The AEMO 2019 Electricity Statement of Opportunities, August 2019.



Chapter 5

Assessment of power system security

- There is a projected shortfall in generation to meet peak demand as coal-fired generation retire
- The shortfall can be met by new generation, greater interconnection, storage and demand management
- We expect shortfalls in system strength following the retirements of Liddell, Vales Point Power Stations or if coal-fired power stations move to flexible operation
- We expect a shortfall in inertia following the retirements of Liddell, Vales Point Power Stations or if coal-fired power stations move to flexible operation.

5.1 Assessment of power security

The transmission network provides the platform to transport energy from large-scale generation to major load centres. It also provides power system stability by sharing ancillary services provided by generators and some network assets.

TransGrid has undertaken an assessment of power system security against each of the criteria that contribute to the stability of the power system. The criteria are shown in **Table 5.1**.

Table 5.1: Key considerations when developing the transmission network

Criteria	Description
Maximum demand (or peak demand)	Demand is the amount of electricity being used at an instant in time. Maximum demand is the highest amount of electricity that has been used (or is expected to be used) at any instant in a period of time.
Minimum demand	Minimum demand is the lowest amount of electricity that is used at any instant. Low minimum demand can present challenges to the stability of the power system.
Energy	The total amount of electricity used over a period of time.
Voltage control	The ability to maintain voltages throughout the power system within stable and safe limits.
System strength	The ability of the power system to temporarily provide high energy to manage disturbances while maintaining voltage control. System strength is provided by synchronous rotating generators. Inverter-based generators such as wind and solar generators require system strength to operate correctly but do not produce it.
Frequency control	The ability to maintain the frequency of the power system within stable limits. Traditional frequency control acts quickly for small changes in frequency under normal conditions, but slowly for large changes in frequency during disturbances. Therefore, it is complemented by inertia to ensure the power system can "ride through" disturbances without significant frequency variation while it responds. Fast frequency response (FFR) is a newer approach enabled by high speed power electronics. Battery storage devices and solar generators use these electronics in their inverters. FFR has the potential to act quickly during disturbances.
Inertia	The ability of the power system to "ride through" disturbances without significant frequency variation. Inertia (shorthand for "synchronous inertia") measures the physical capability of synchronous rotating generators to continue without slowing down significantly during a disturbance. Unlike synchronous generators, wind generators do not always turn at the same speed as the power system frequency. Therefore, they connect to the power system using power electronics that converts either all of their output to the power system frequency, or a portion of their output that is then superimposed on the remaining portion of the output that comes directly from the wind turbines. Wind generators of the latter type are known as "type 3" generators. These generators can provide "synthetic inertia" using the inertia present in the wind turbines. This has slightly different characteristics to synchronous inertia.
Reserve	Extra generation that is readily available by increasing the output of generators already generating in the power system. The power system is normally operated with enough reserve to cover the loss of the largest generator unit.
Power system data communications	High speed data communications to provide visibility, monitoring and control of the power system. This includes dispatching generation and operating networks.

Maximum demand and energy

There is a projected shortfall in generation to meet maximum demand following the expected retirement of Liddell Power Station in 2022-23. A shortfall in generation to meet demand will result in unserved energy.

When the shortfall is limited to a small number of high-demand days, the unserved energy can be small. As the level of shortfall increases, however, the unserved energy increases significantly.

The shortfall can be met by additional new generation, greater interconnection, storage and demand management.

This is being managed by the connection of new generation to the network and projects to increase network capacity, discussed in **Chapter 2**.

Voltage control

Voltage control is provided by generators and network assets such as transformer tap changers, capacitor banks, reactors and Static VAr Compensators (SVCs).

There is sufficient voltage control capability in general in the NSW transmission network over the next 10 years. Additional voltage control issues are however emerging in the south west NSW network due to increased power transfers as a result of high levels of renewable generation in the area. At times of high renewable generation near Darlington Point, under-voltages can occur due to the trip of the Darlington Point to Wagga 330 kV transmission line. A new voltage stability limit has been introduced in generation dispatch to cater for this contingency.

There are opportunities to make small increases to interconnector export capacity to Queensland (Qld) through the installation of additional network assets for voltage control. The QNI Upgrade project to install capacitor banks and SVCs in Northern NSW to increase QNI import and export capacity is now included as an ongoing project in Section 2.1.1.

System strength

Presently, coal-fired synchronous generators provide the majority of system strength in the NSW transmission network. System strength can also be provided by other synchronous rotating generators and synchronous condensers.

We have reviewed the adequacy of system strength in the NSW transmission network for minimum synchronous generation conditions. System strength was analysed based on the system's ability to maintain the required minimum three-phase fault levels (specified by AEMO) and the availability of adequate synchronous generation in the network with forecasted generator retirements. A minimum of eight coal-fired synchronous generator units is adequate to meet the minimum fault levels required at the fault level nodes as per AEMO System Strength Requirements[32].

Figure 5.1 shows the cumulative probability of the number of coal-fired synchronous generation online with the removal of generator units (as a result of retirements of coal-fired generation units or them moving to flexible operation). This assessment is based on the historical number of coal-fired synchronous generators online in 2018.

Figure 5.1: Cumulative probability of Coal Generator Availability with generator retirements

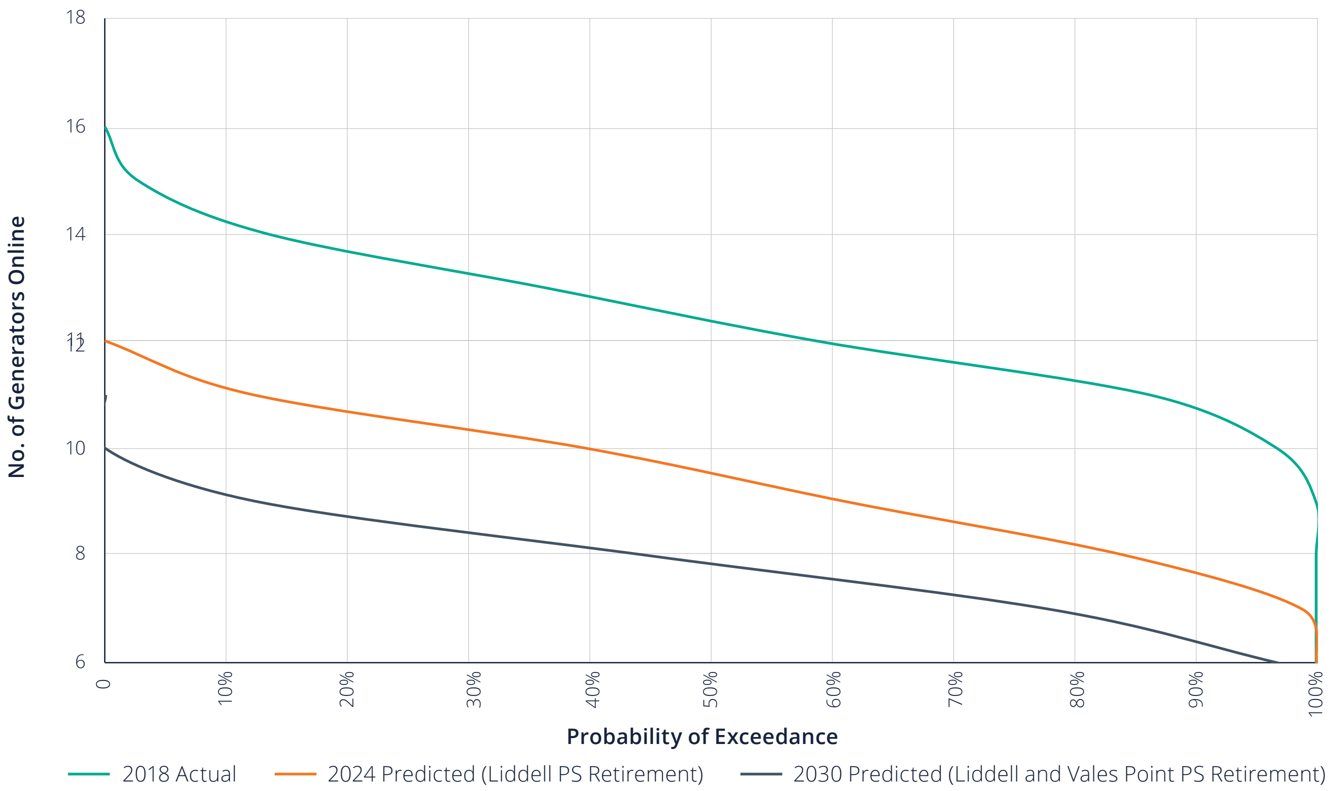


Table 5.2 shows the emergence of system strength shortfalls at NSW fault level nodes with the retirement of Liddell and Vales Point, Eraring and Bayswater Power Stations.

Table 5.2: Fault levels with minimum generation profile

330 kV Fault Level Node	AEMO expected minimum fault level[33]	Fault Level with minimum generation profile (MVA)					
		Liddell + Vales Point Retired		Liddell + Vales Point + Eraring Retired		Liddell + Vales Point + Eraring + Bayswater Retired	
Scenario		N	N - 1	N	N - 1	N	N- 1
Armidale	3000	3610	2970	3580	2950	2950	2610
Darlington Pt[34]	1550	1530	N/A	1500	N/A	1360	N/A
Newcastle	8400	9010	8120	6290	5310	3790	3520
Sydney West	9250	9080	8640	7060	6920	4260	4220
Wellington	1900	3330	2080	3240	2040	2610	1830

Table 5.3 shows the system strength shortfalls at NSW fault level nodes with the retirement of Liddell, Vales Point, Eraring and Bayswater Power Stations.

These shortfalls are based on the AEMO minimum fault levels as per published in 2018 System Strength Requirements document.

Table 5.3: Indicative Fault Level Shortfall with generation retirement

330 kV Fault Level Node	AEMO expected minimum fault level[33]	Indicative Fault Level Shortfall (MVA)		
		Liddell + Vales Point Retired	Liddell + Vales Point + Eraring Retired	Liddell + Vales Point + Eraring + Bayswater Retired
Armidale	3000	30	50	390
Darlington Pt[34]	1550	20	50	190
Newcastle	8400	280	3090	4880
Sydney West	9250	610	2330	5030
Wellington	1900	N/A	N/A	70

The review shows that:

- There is sufficient system strength presently in most parts of the NSW transmission network. The system strength in south-western NSW however is low and requires operational limits and measures to manage under contingent events.
- With the retirement of Liddell Power Station (refer orange curve in **Figure 5.1**), system strength is expected to be reduced to unsatisfactory levels for about 2% of the time (i.e. less than 8 coal-fired synchronous generator units online).
- With the Liddell and Vales Point Power Stations retirements (refer grey curve in **Figure 5.1**), system strength is expected to be reduced to unsatisfactory levels for about 21% of the time (i.e. less than 8 coal-fired synchronous generator units online).
- System strength shortfalls are expected to be much more pronounced following the additional retirement of Eraring Power Station. There will be system strength shortfalls for 100% of the time at this time (i.e. less than 8 coal-fired synchronous generator units).

The system strength shortfalls can occur earlier than expected if coal-fired power stations retire early or move to flexible operation where they can go offline during times of light load or low price.

System strength shortfalls can be addressed by careful management of synchronous generator outages (i.e. limiting concurrent generator planned outages), contracting additional synchronous generator services, converting retiring synchronous generators to operate as synchronous condensers, and introduction of synchronous condensers.

The assessments undertaken reveal that the potential for interconnectors to improve system strength is limited. Any benefits to system strength from interconnectors may only be regional and are not likely to improve system strength across the network.

Wind, solar and other inverter-based generators require system strength to operate correctly. As the penetration of inverter-based generators increases, there will be a need to procure additional network assets or schedule existing synchronous generators to provide the necessary system strength services at all times.

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[32] AEMO System Strength Requirements and Fault Level Shortfalls, 1 July 2018

[33] As per AEMO system strength requirements published in July 2018.

[34] Darlington Point has known low system strength issues for N – 1 contingencies. For this reason, N - 1 fault levels at this node have been excluded from the study.

Frequency control

Frequency control is provided across the NEM through inertia, Fast Frequency Response (FFR) and Frequency Control Ancillary Services (FCAS). There is sufficient frequency control capability in the NEM over the next 10 years, provided there is adequate inertia installed in the NEM.

FFR has the potential to act quickly during disturbances and is a partial substitute for synchronous inertia. A project to install a large-scale battery to understand its performance has been included in Section 2.3.1. This will enable its application in practice to be understood and validated in system stability models.

Inertia

We have reviewed the adequacy of inertia in NSW to limit the rate of change of frequency (RoCoF) and frequency deviation following a disturbance. We also modelled the NSW system frequency response for a single and multiple generator trip[35] events. **Table 5.4** summarises the Initial Rate of Change of Frequency (RoCoF) and Minimum Frequency for a single generator and double generator trip event with retirement of coal-fired synchronous generators.

Table 5.4: Frequency response for single and multiple generator trip events with NSW generation retirement

Power Stations Decommissioned	Estimated Remaining Minimum System Inertia (MWs)	Initial RoCoF (Hz/s)	Largest Generator Trip Minimum Frequency (Hz)	Double Generator Trip[36] Minimum Frequency (Hz)
None	23,000	-0.88	49.33	49.01
Liddell	18,100	-1.15	49.24	48.89
Liddell and Vales Point	15,600	-1.37	49.17	48.80
Liddell, Vales Point and Eraring	10,600	-2.15	48.97	N/A - Unstable
Liddell, Vales Point, Eraring and Bayswater	3,100	-5.538	N/A - Unstable	N/A – Unstable

The information in **Table 5.4** (above) reveals that the NSW system is unlikely to withstand a multiple generator trip event following the retirement of Liddell, Vales Point and Eraring Power Stations. Therefore, the actual requirements for the power system are likely to be greater than the levels considered and presently mandated. We need to consider multiple generator trips because such events happen on the power system[35] and inertia is essential for the stability and continuous operation of the power system. We have therefore used 15,000 MWs as the level of inertia to assess and plan to meet this, being the level that is secure for the trip of two generators.

Inertia and its contribution to frequency control in NSW were evaluated according to the forecast changes to typical and minimum inertia levels with scheduled synchronous generator retirements.

Figure 5.2 shows the reduction in inertia in NSW as the coal fired generators retire. The timeline for this analysis is based on published retirement dates.

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[35] For example, the trip of multiple generators at Bayswater on 2 July 2009.

[36] The 2 generator events were modelled 600ms apart based on 2009 Bayswater incident generator trip sequence

Figure 5.2: System inertia (typical) reduction due to synchronous generator retirement

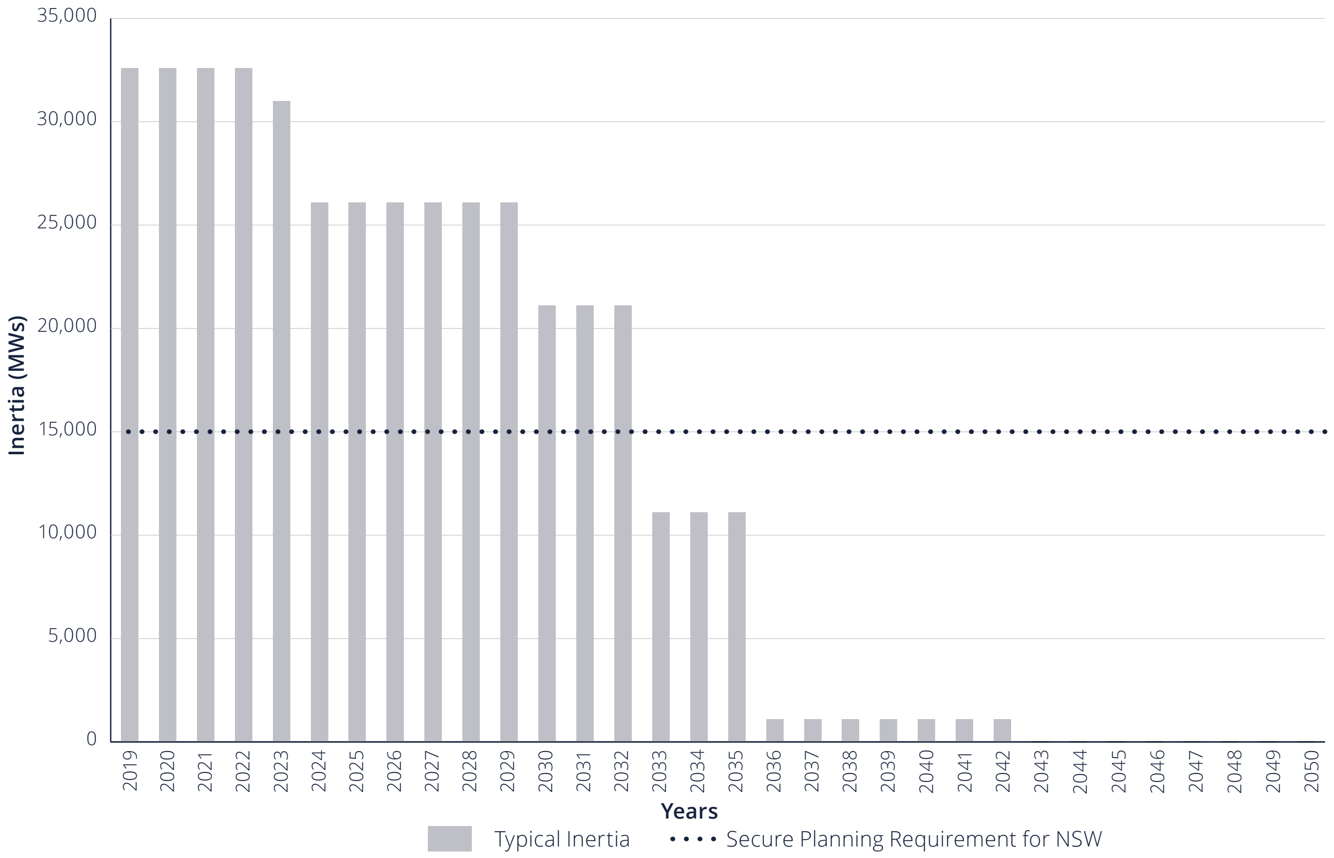


Figure 5.3 shows the cumulative probability of available inertia in NSW with the removal of generator units (as a result of retirements of coal-fired generation units or them moving to flexible operation). This assessment is based on the historical number of coal-fired synchronous generators online in 2018.

Figure 5.3: Cumulative probability of NSW system inertia with generator retirements

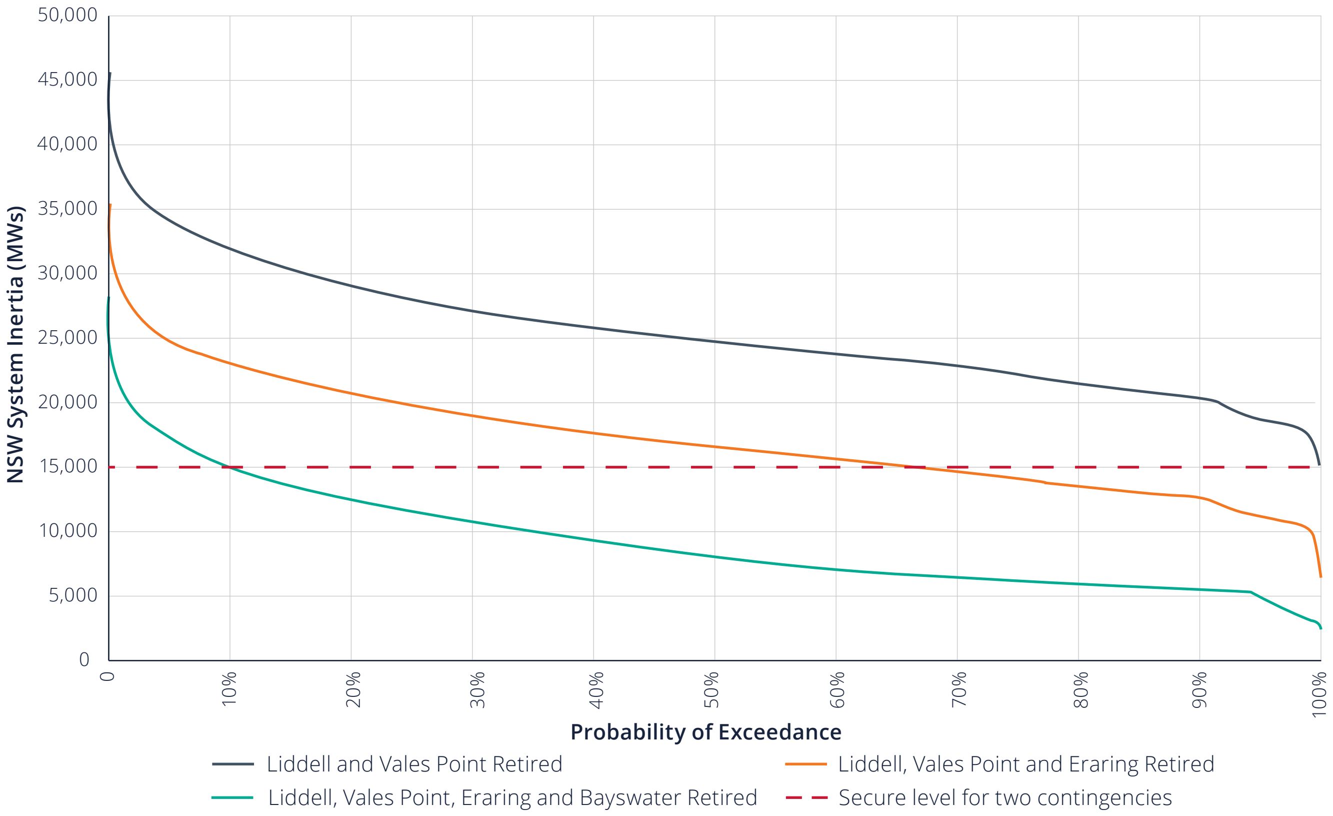


Table 5.5 shows the inertia shortfalls as the coal fired units retire to meet the AEMO's minimum inertia requirement of 10,000 MWs (as published in 2018) and the double contingency secure planning inertia level of 15,000 MWs, respectively.

Table 5.5: Inertia shortfalls in NSW with generation retirement

Scenario	Inertia Shortfall to meet AEMO's Minimum Inertia requirement of 10,000 MWs[37] (MWs)	Inertia Shortfall to meet the double contingency secure planning level of 15,000 MWs (MWs)
Liddell Power Station retired	N/A	N/A
Liddell and Vales Point Power Stations retired	N/A	N/A
Liddell, Vales Point and Eraring Power Stations retired	3,300	8,300
Liddell, Vales Point, Eraring and Bayswater retired	7,400	12,400

The review shows:

- The expected inertia level in NSW is unlikely to meet the double contingency secure planning inertia level of 15,000 MWs following the retirements of Liddell, Vales Point and Eraring Power Stations for about 32% of the time during a year (refer orange curve in **Figure 5.3**), and for about 90% of the time during a year following the retirements of Liddell, Vales Point, Eraring and Bayswater Power Stations (refer blue curve in **Figure 5.3**).
- Inertia shortfalls are expected to be much more pronounced following the retirement of Liddell, Vales Point and Eraring Power Stations. Up to 3,300 MWs of additional synchronous inertia will be required to meet AEMO's minimum inertia requirement of 10,000 MWs. Additional frequency control measures equivalent up to 8,300 MWs of inertia will be required to meet the double contingency planning inertia requirement (refer **Table 5.3**).

Inertia shortfalls can occur earlier than expected if coal-fired power stations retire early or move to flexible operation where they can go offline during times of light load or low price. These are likely to result in a lower availability of adequate inertia in the network requiring careful management of synchronous generator outages, contracting non-base load synchronous machines (generators), introduction of synchronous condensers with flywheels, conversion of retiring generators to synchronous condensers and 'synthetic inertia' (subject to successful trials).

The emergence of Fast Frequency Response (FFR) devices such as Battery Energy Storage Systems (BESS) also have the potential to support frequency control in the future, in particular in satisfying the Secure level of inertia requirement. However, the effectiveness of FFR devices in replacing reduction in inertia is dependent on the speed of response of FFR devices and the associated protection and control schemes as shown in **Figure 5.4**. This graph shows the BESS requirement to match the present NSW system frequency response for a large generator trip with increase in synchronous generator inertia retirements. Similarly, **Figure 5.5** indicates the battery requirements to securely manage frequency control in the event of a double generator trip. These analyses are based on assumptions made as to the potential speed of response of the BESS from the frequency event occurring, rather than BESS supplier reported speed from detecting the event.

Figure 5.4: BESS sizing requirements due to inertia retirements based on speed of response

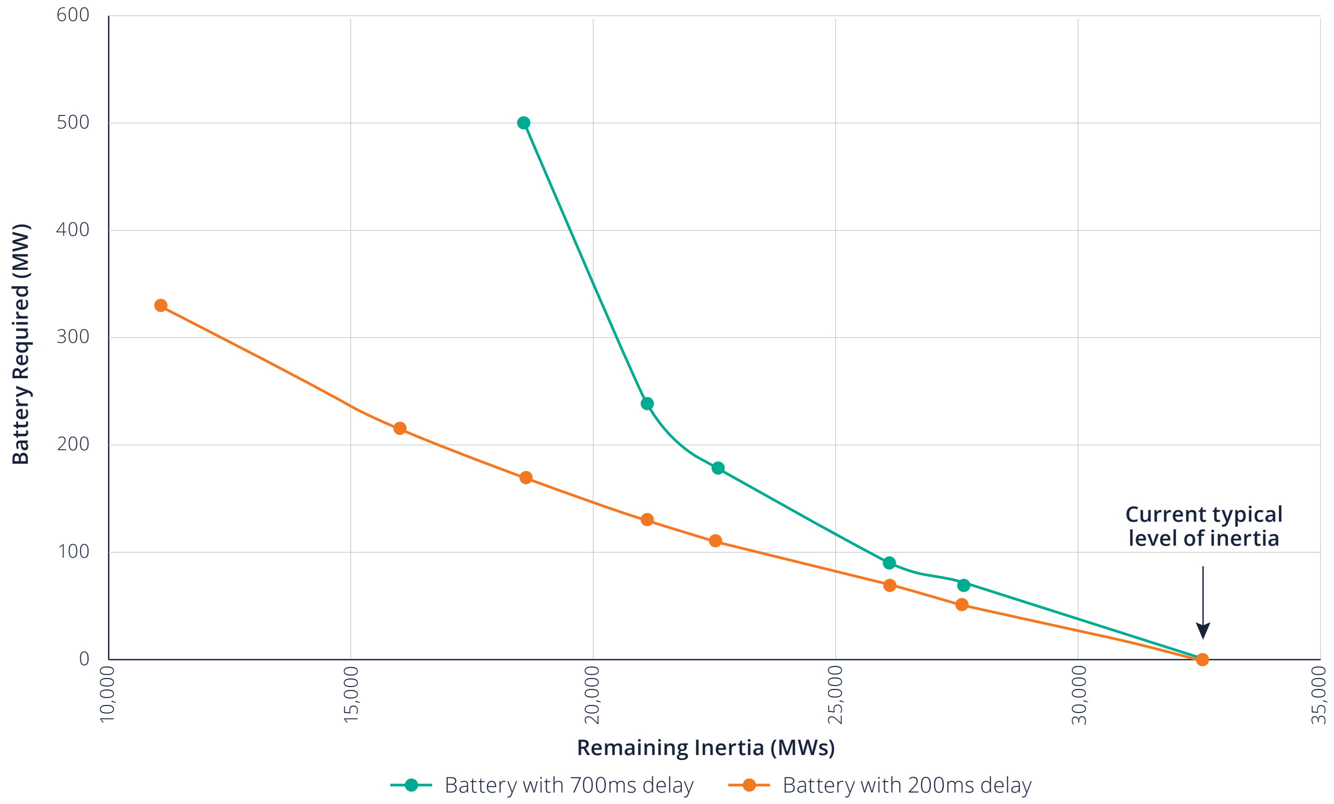
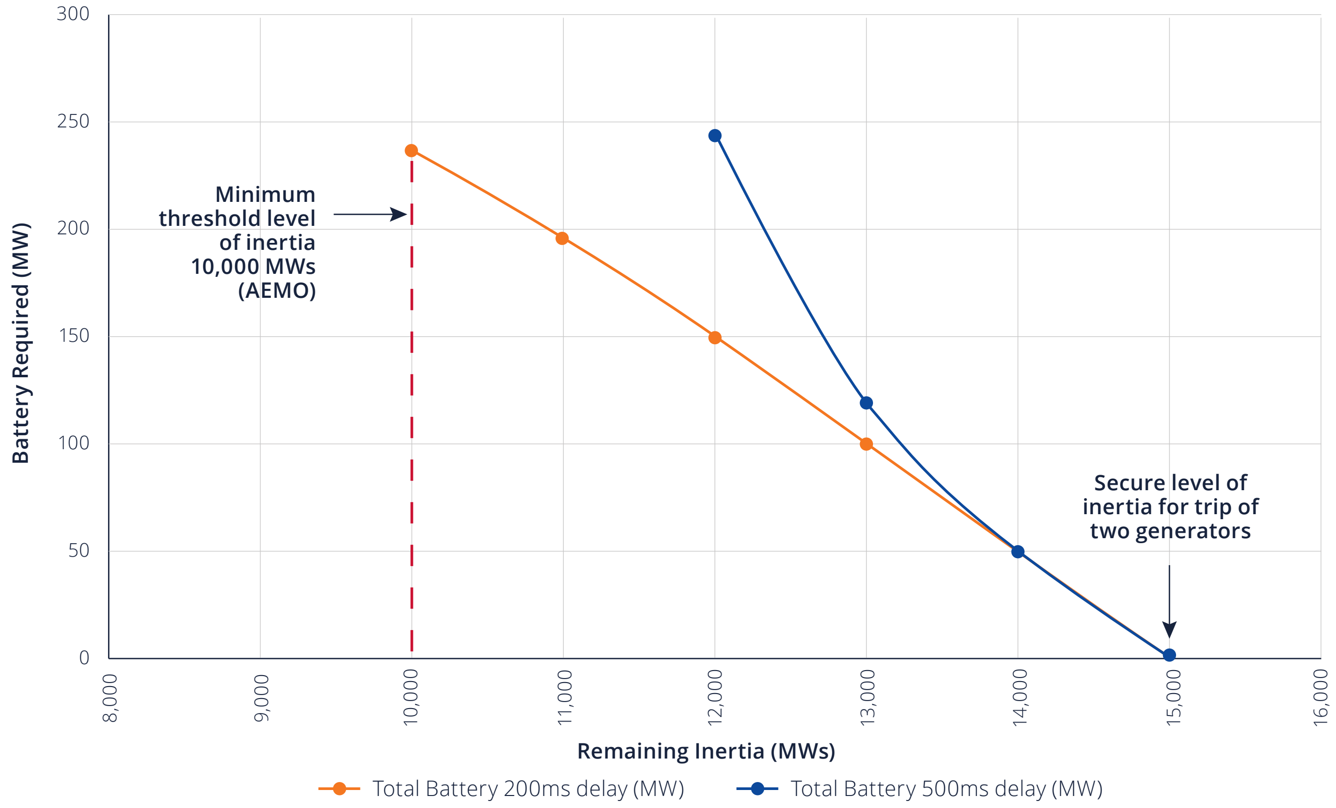


Figure 5.5: BESS sizing requirements for double generator contingency based on speed of response



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[37] As per AEMO Inertia Requirements published in July 2018 minimum and secure inertia requirements are 10,000 MWs and 12,500 MWs respectively.

The analysis reveals:

- The higher the speed of the BESS, the quicker it is able to respond to arrest the frequency deviation, and the smaller the overall battery requirement to achieve the same network stability
- The ability of the BESS to satisfy any shortfalls in secure planning requirement depends on the delay in response of the system. A delay less than 200ms would allow meeting full range of secure planning requirement above the minimum inertia requirement of 10,000 MWs to be met by BESS. However, if the delay is greater than 200ms, additional synchronous inertia will be required to meet the double contingency planning level of 15,000 MWs.

Reserve

In NSW, the power system is generally operated with a reserve level of 700 MW.

There will be a lack of reserve when there is a shortfall of generation to meet demand, or when the available generation is less than 700 MW above demand.

There is a projected shortfall in reserve under certain conditions over the period of this report. The shortfall can be met by additional new generation, greater interconnection, storage and demand management.

Power system data communications

High speed data communications contributes to power system security by providing visibility, monitoring and control of the power system.

TransGrid is also working to develop least-cost communications solutions to areas of NSW with the best renewable resources, as new generation connects and large-scale energy zones are established.

Appendix 1

TransGrid 2020 NSW region load forecasting methodology

This appendix describes the forecasting methodology including the sources of input information, applied assumptions, load forecast components, model schema, weather correction steps and input data variables.

A1.1 Overall schema

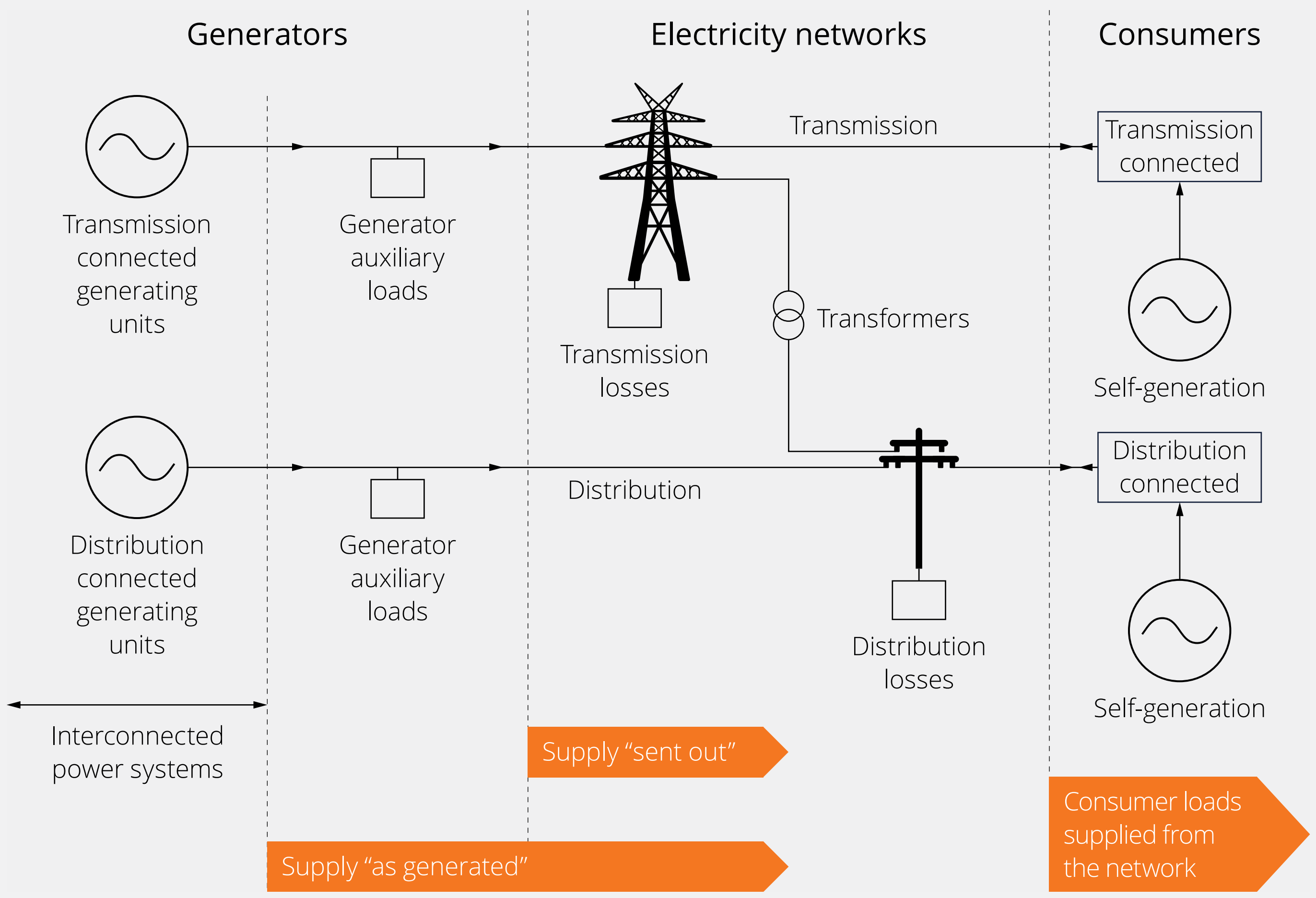
The NSW load forecast consists of medium, high and low future growth scenarios for annual energy and summer and winter maximum demands.

A1.1.1 Definitions

Figure A1.1 shows a typical power system such as that operating in the NSW region of the NEM. AEMO classifies each unit of generation connected to the NEM as either a scheduled, semi-scheduled or a non-scheduled generating unit. There are several potential points of measurement of energy flows and possible changes in direction of flows.

However, it is generally easier to record energy flowing into the network based on a relatively small number of generating units than to record the consumption of millions of consumers. Revenue meters are generally located at the connections of power stations with the network, and SCADA generally records large generating unit output.

Figure A1.1: Schematic power system[38]



"As generated" refers to energy or demand that includes generator auxiliary loads, and "sent out" refers to consumption or demand that excludes generator auxiliary loads.

"Native" energy is equal to "operational" energy as defined by AEMO, with the addition of energy supplied by non-scheduled generating units of less than 30 MW capacity, measured in GWh over a financial year. The operational measure includes generation by scheduled, semi-scheduled and non-scheduled generating units greater than or equal to 30 MW. TransGrid measures and forecasts native energy on a "sent out" basis.

"Native" demand is equal to "operational" demand as defined by AEMO, with the addition of demand supplied by non-scheduled generating units of less than 30 MW capacity. The operational measure includes generation by scheduled, semi-scheduled and non-scheduled generating units greater than or equal to 30 MW, measured in MW at a half-hourly resolution. TransGrid measures and forecasts native demand on an "as generated" basis.

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[38] Adapted from AEMO (2012) National Electricity Forecasting Report, Figure 2-1, p2-2.

A1.1.2 Recent NSW energy and demand compared to previous forecasts

The 2019 forecast of NSW region native energy for 2018/19 was 70,500 GWh, compared with an actual outcome of 70,377 GWh, an over-forecast of 123 GWh or 0.18 per cent. The forecast was based on a demand model informed by predicted input variables. TransGrid re-ran the forecasting model using actual right hand side (RHS) input variables to determine the extent to which the forecast outcome was driven by errors in predicted input variables, and the extent to which the model itself was inaccurate.

Table A1.1 shows the 2019 published medium forecast energy for 2018/19, the actual outcome and a new forecast using the same model with actual, rather than predicted values, for the input variables. The measures below show that the majority of the difference between the actual and forecast energy was due to the model itself, rather than the combined inaccuracy of all the input variables. This does not rule out that significant inaccuracies in the forecasts in one direction due to some input variables may have been offset by inaccuracies in others in the opposite direction.

Notwithstanding this breakdown, the energy model one year ahead forecasting gaps are relatively small.

Table A1.1: 2019 medium energy forecast for 2018/19 compared with the actual outcome

	GWh	
Actual	70,377	
Published forecast	70,500	
New model based prediction using actual RHS variables	70,515	
Forecasting gaps	**GWh**	**Difference**
Total gap (actual less published forecast)	-123	-0.18%
Model residual (actual less new model prediction)	-138	-0.20%
Error due to RHS variables and other inputs (total gap less model residual)	15	0.02%

There are two components to the assessment of the accuracy of MD forecasts. The first is a straight forward comparison between the actual and forecast POE levels. The second is the calculation of the unseen frequency distribution of possible seasonal MDs to determine the estimated POE levels. The accuracy of this process requires a certain level of judgement[39].

Table A1.2 shows the 2019 forecasts of 10%, 50% and 90% POE NSW region summer MD. These forecasts were 354 to 505 MW (around 2 to 4 per cent) higher than the now estimated POE values, based on actual data for the recent summer.

TransGrid estimates that the actual MD of 13,957 MW represents a 25 per cent POE level of demand. This may be compared to the maximum daily temperature in the recent summer of 34.8 degrees, which occurred on the day of MD and is also a record high daily average temperature[40].

Unusually, the actual MD occurred on a Saturday, in the half-hour ended 17:30 EST on 1 February 2020. Had this temperature occurred on a weekday, the actual MD could have been around 1,000 MW higher. By way of comparison, on the day of the second highest daily MD of summer in 2020, Thursday 23 January, an estimated 54 per cent POE demand of 13,339 MW occurred at an average temperature of only 30.9 degrees, which is exceeded as a maximum summer temperature 66 per cent of the time.

Table A1.2: 2019 medium maximum demand forecasts for summer 2019/20 compared with actual outcomes

	Actual MW	POE %	10% POE MW	50% POE MW	90% POE MW
Actual MD MW	13,957	25			
Estimated actual POE MD			14,285	13,316	11,986
Published forecast			14,790	13,670	12,400
Difference (estimated actual less published forecast)			-505	-354	-414
Average temperature degrees	34.8	0			

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[39] Weather correction of maximum demand and the estimation of POE levels is discussed in section A1.3 below.

[40] Measured as the average of maximum and minimum daily temperatures at Parramatta. Records at this location date from June 1967.

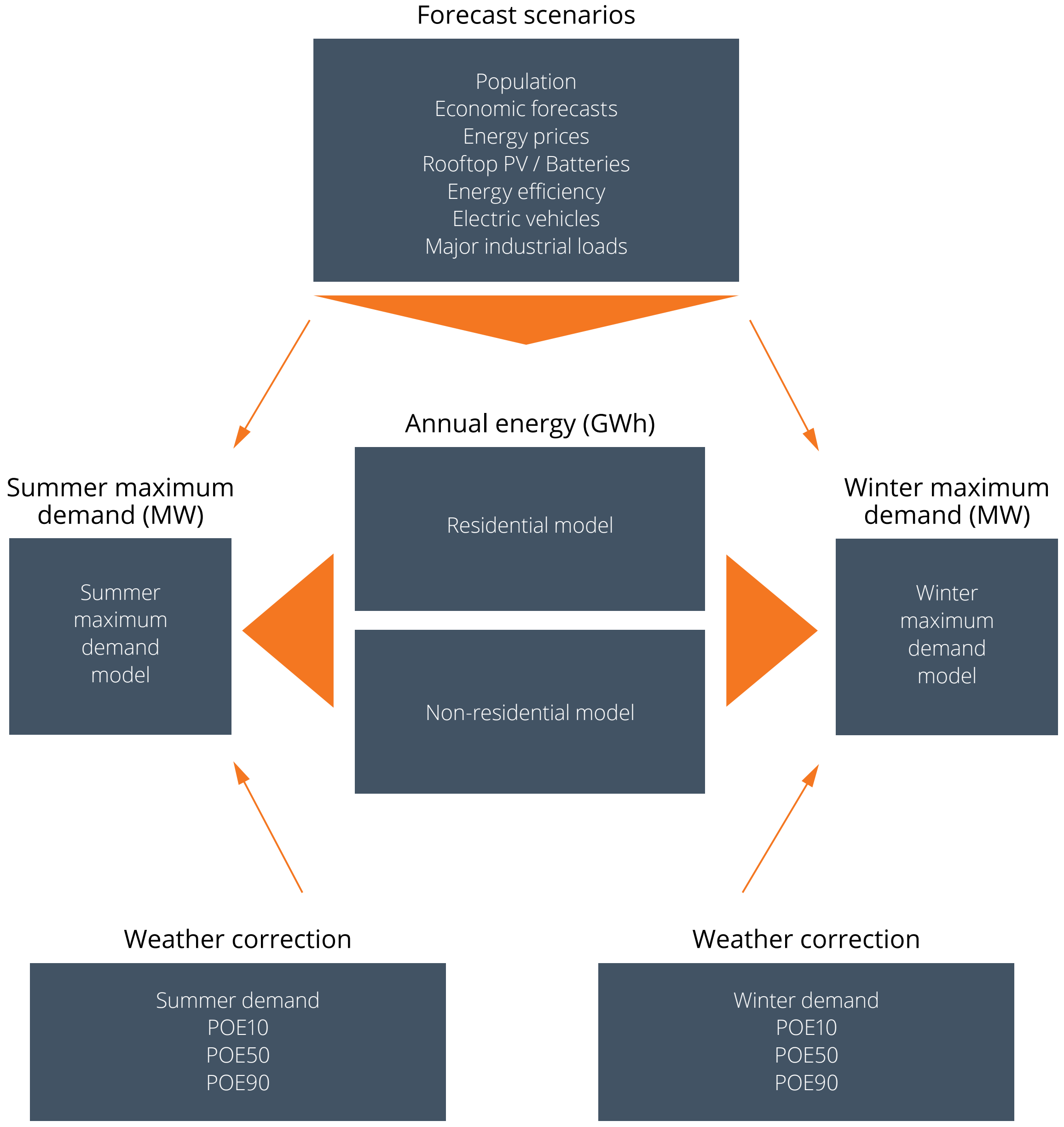
A1.1.3 Load forecast components

TransGrid prepared the 2020 NSW load forecast taking into account outputs from the following components:

- econometric modelling of the impacts of population, price, economic growth, weather and other drivers of underlying consumer behaviour – undertaken independently by TransGrid;
- weather correction of historical electricity maximum demands and the calculation of probability of exceedance levels – undertaken independently by TransGrid;
- regional demographic and economic forecast scenarios – provided by BIS Oxford Economics;[41]
- projections of future energy price paths – undertaken by Jacobs;[42]
- assessment of recent energy efficiency policies and standards, and quantification of the energy savings impacts – undertaken by Energy Efficient Strategies;[43]
- modelling of rooftop PV installation and generation, and distributed battery storage – undertaken by CSIRO;[44] and
- projections of the take-up of externally charging electric vehicles – undertaken by Energeia.[45]

Figure A1.2 presents these components schematically with their interactions and each is discussed in more detail in the following sections.

Figure A1.2: Overall schema



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[41] BIS Oxford Economics, "Economic and Dwelling Forecasts to FY2039 - NSW and ACT", May 2020.

[42] Jacobs, "Retail Price Projections for NSW", June 2020.

[43] Energy Efficient Strategies, "Projected Impacts of Energy Efficiency Programs", May 2020.

[44] CSIRO, "Rooftop PV and Battery Forecasts for Future Grid Scenarios", May 2020.

[45] Energeia, "Electric Vehicles Modelling", June 2019.

A1.2 Energy modelling

A1.2.1 Approach

Econometric modelling was used to estimate the independent impacts of population, electricity price, economic growth and weather on annual native energy. Native energy is composed of energy consumed by residential customers, energy consumed by non-residential customers and energy consumed by major industrial customers.

Separate models were used for residential and non-residential energy. Historical estimates of residential energy consumed in NSW and the ACT are estimated using survey data published by the Department of the Environment and Energy[46]. Remaining net generation supplying the NSW region is classified by TransGrid as either major industrial load (refer to section A1.5) or non-residential energy. Each model was developed as an equation, linear in logarithms, with annual "energy services" per head of population as the dependent (left-hand side) variable.

Energy services is derived by adding estimates of the following to metered network energy:

- historical out-of-trend energy efficiency savings; and
- rooftop PV generation.

Future energy services conceptually does not include the impacts of stationary or vehicle battery charging or discharging.

A1.2.2 Results

The energy services construct allows for the accurate identification of price impacts independently of changes in energy efficiency. The equations were estimated and this resulted in identifying the sensitivities shown in **Table A1.3** and **Table A1.4**.

Table A1.3: Estimated long-run price and income elasticities of demand for annual electrical energy per capita in NSW

Long run elasticity with respect to:	Residential estimated value	Non-residential estimated value
Electricity price	-0.21	-0.21
Residential gas and other fuels price	0.02	0.03
Real income	0.55	0.74

Table A1.3 should be interpreted as follows. For a one per cent increase in any variable in the left-hand column, the long run impact on electricity consumption (for the respective consumer category) is a long-run percentage change as indicated in the corresponding right-hand columns. For example, an increase in residential electricity price of one per cent would lead to a long-run decrease in residential electricity consumption (all other things remaining the same) of 0.21 per cent.

Weather is quantified as either heating or cooling degree days, or the number of degrees below or above the human comfort range inside buildings each day, for all days in a year. Future weather is modelled as a continuation of average warming trends over the last 30 years.

Table A1.4: Estimated short-run temperature sensitivities of annual energy in NSW

Short run temperature sensitivities of annual energy	
Residential sensitivity to cool weather	151 kWh/degree days below 18 degrees
Residential sensitivity to warm weather*	14 kWh/degree day above 21 degrees
Non-residential sensitivity to warm weather	92 kWh/degree day above 21 degrees
Non-residential sensitivity to cool weather**	-50 kWh/degree day below 18 degrees

**Not statistically significant.*
***Not statistically significant and not included in the model.*

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[46] Australian Energy Statistics, Department of the Environment and Energy, Australian Energy Statistics, Table F, September 2019

Table A1.4 shows that for each day, for each degree that the average temperature drops below 18 degrees, NSW region residential energy consumed increases by 151 kWh. Similarly, for each day, for each degree that the average temperature rises above 21 degrees, NSW region non-residential energy increases by 92 kWh. Residential energy is relatively insensitive to warm weather and non-residential sensitivity to cool weather cannot be reliably measured. This tells us that the transient effect of weather variation may have a small but significant impact on annual energy over the course of any individual year.

A1.2.3 Observations

The inverse impact of electricity prices on annual energy is important, albeit small relative to the impact of income and population growth.

In addition to forward projections of the items in **Table A1.3**, the forecasts of residential and non-residential energy are prepared subject to input forecasts of population, energy efficiency savings and distributed energy resources (DER) - including rooftop PV generation, stationary battery net charging and vehicle battery charging. The impact of future energy efficiency and DER comprises a large part of the overall forecasts.[47]

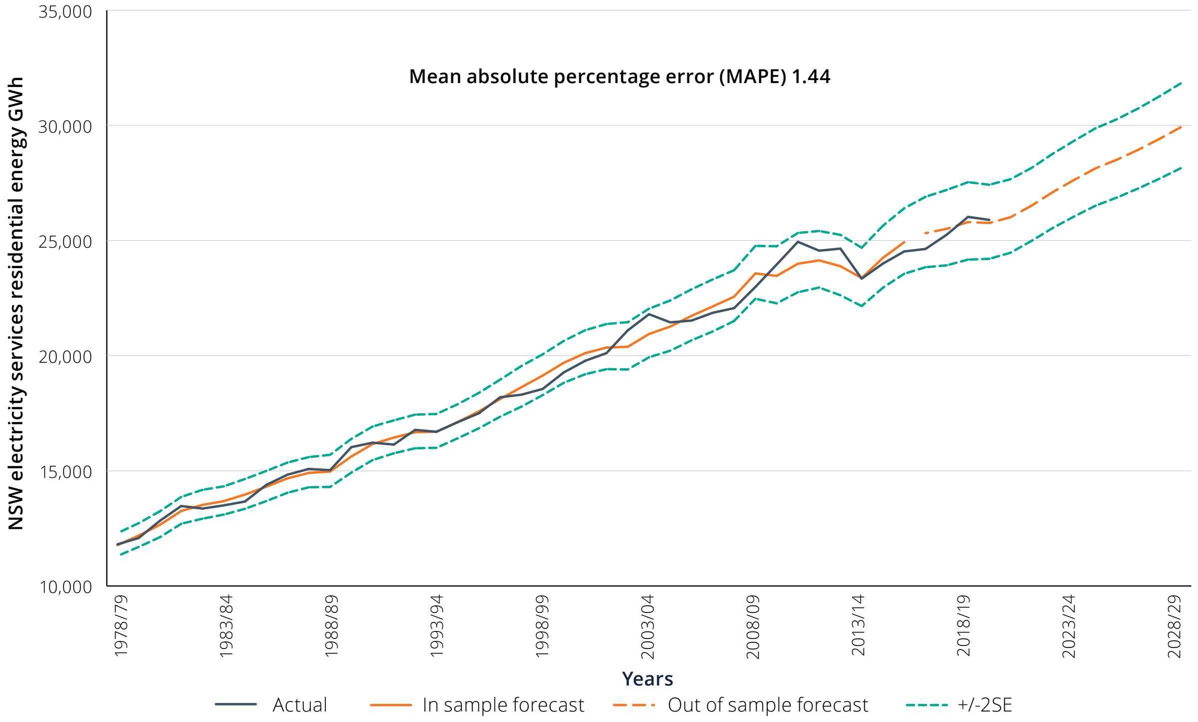
A1.2.4 Model accuracy

The residential and non-residential models' fit to the historical data sample and medium scenario forecasts are shown in **Figure A1.3** and **Figure A1.4**. These figures were produced with data up to 2015-16, with the last three actual years forecast out-of-sample to test the models[48]. Some key indications of the reliability of the forecasts are:

- the fitted lines are contained within a plus or minus two standard error band;
- the calculated accuracy measure -- Mean Absolute Percentage Error (MAPE) - is low (1.44 for the residential model and 1.26 for the non-residential model);
- there is little apparent bias indicating very little tendency for either model to produce long run forecasts that are persistently too high or too low[49]; and
- the downturn five years ago associated with rising prices is picked up in varying degrees by the residential and non-residential models.

The evidence suggests that the models are valid across the entire sample period, are relatively accurate and are not given to persistent bias up or down.

Figure A1.3: Electricity services residential energy in-sample/out-of-sample fit



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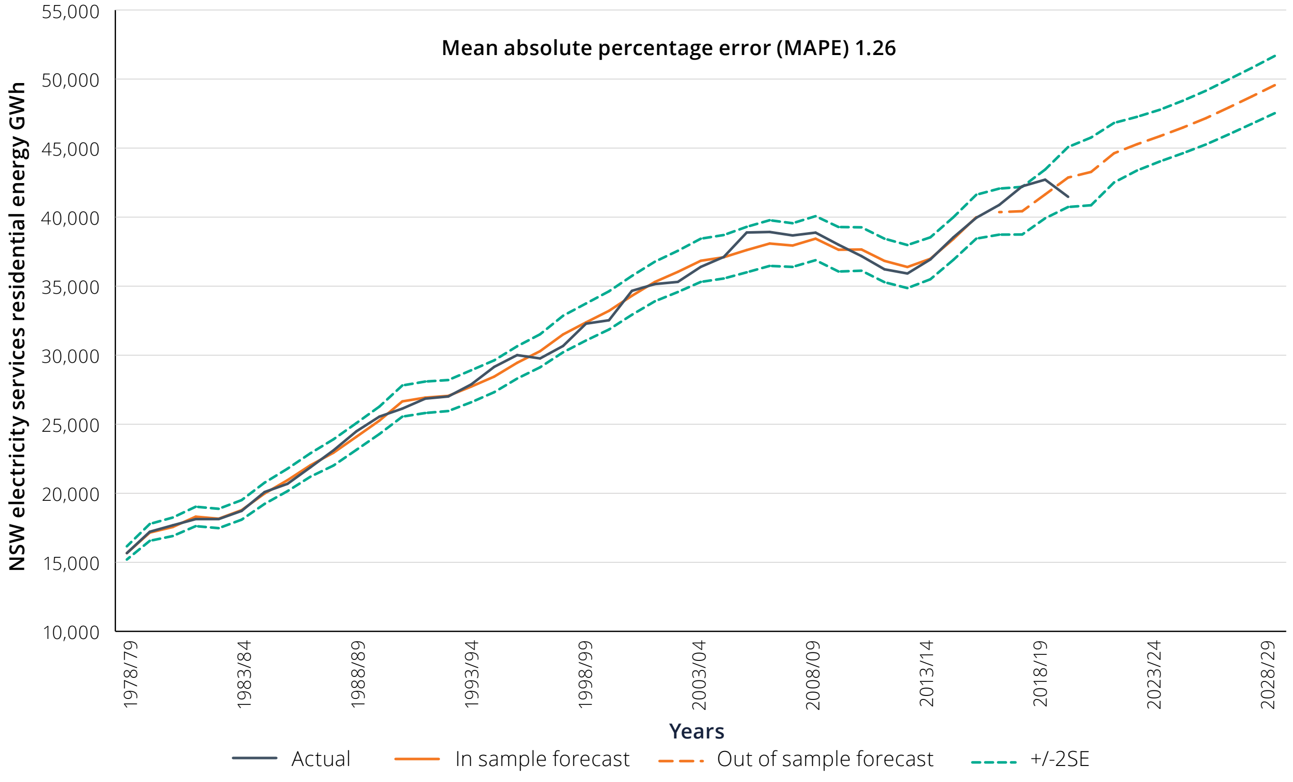
[47] Potential new sources of electricity demand are not included in the load forecast. For example, future electrification of transport may also entail new sources of demand for electricity as a result, not only of externally charged electric road vehicles, but also as a result of the potential production of hydrogen using electrolysis for fuel cells in domestic vehicle or for export, and extensions of the electrified rail network.

[48] The published forecasts of native energy have a starting point of 2019/20 and are based on actual and estimated data up to and including June 2019.

[49] Technically the model shows no sign of significant bias. However, potential COVID-19 related impacts on the structural relationships between economic activity and electricity demand represented by the model – such as a permanent increase in working from home – are essentially unquantifiable at this time.

Figure A1.4: Electricity services non-residential energy in-sample/out-of-sample fit



A1.3 Weather correction of maximum demand

The purpose of weather correction of historical demands is to remove the influence of weather variation between consecutive like seasons and to calculate levels of maximum demand for each season that accurately correspond to 10, 50 and 90 per cent POE. Weather correction was carried out separately for summer and winter, using daily native maximum demand observations, and for one season at a time.

Below is a description of the three steps in the weather correction process, which is undertaken independently for each season (summer and winter) and for each historical year.

A1.3.1. Statistical estimation of a demand-temperature equation

- Inputs are daily maximum demand – carefully reconstructed using half-hourly operational demand and TransGrid's records of additional small non-scheduled generation – and measures of cooling degrees and maximum daily temperature (for summer) and heating degrees (for winter);
- Only temperature and no other dimensions of weather are included – temperatures are the daily average of maximum and minimum temperatures at Sydney Observatory and Parramatta (for winter and summer respectively), with the summer measure using the minimum temperature from the following, rather than concurrent, morning;
- All days in a season are included, with dummy variables to account for weekends, public holidays and the two-week post-Christmas holiday period;
- A three-season rolling sample is used with dummy variables for the two previous seasons;
- A dummy variable for the months of January and February (a proxy for the coincidence of high working activity and the more frequent occurrence of high temperatures) is also included as it is found significant;
- Summer temperature sensitivity has more than doubled from 81 MW (0.9 per cent) per degree increase in average daily temperature in 1993-94 to 388 MW (2.8 per cent) in 2019-20; while the impact of an increase of one degree in the maximum daily temperature, for a similar daily average, brings about a further increase of 46 MW; and
- Winter temperature sensitivity has remained consistent in percentage terms from 1.4 per cent (137 MW) per degree in 1994 to 1.6 per cent (199 MW) per degree in 2019.

A1.3.2 Historical temperature variation

- The selected method uses a range of daily temperatures drawn in historically accurate time sequence from the past 20 years;
- The data are transformed in the same manner as the temperature data used for estimating the demand-temperature equation; and
- Alternative temperature years for the respective season are substituted in the demand-weather equation to produce a variety of alternative demand traces for that-season.

A1.3.3 Synthesis of alternative residual values

- Since the statistical demand-temperature relationship is inexact, the residuals from the estimated equation represent variation in demand that is not explained by variation in temperature from one day to the next;
- The mean estimated residual value is zero, and the most accurate forecast of daily maximum demand over the entire season would assume a zero residual value;
- Seasonal maximum demand (the maximum of the daily maximum demands in a respective season) is most likely to occur on a working weekday with extreme temperature, and a high proportion of 'unexplained' demand variation – i.e. a large residual; and
- Statistically likely variation in the residuals is simulated by drawing from a random normal distribution with the same equation standard error as the equation that generated the original residuals. This assumes that: (i) actual residuals are independent of each other and randomly occurring; and (ii) drawn from a distribution that approaches a normal distribution with increasing sample size.

A1.3.4 Resampling process

- Alternative, randomly selected residual values (drawing from the same underlying distribution) are applied to each alternative temperature year demand trace, resulting in more alternative demand traces ;
- For summer seasons, there are 20 alternative temperature sets and 600 alternative residual sets, resulting in a total of 12,000 alternative demand traces in each summer season; and
- For winter, there are 20 alternative temperature sets and 540 alternative residual sets, resulting in a total of 11,800 alternative demand traces in each winter season.

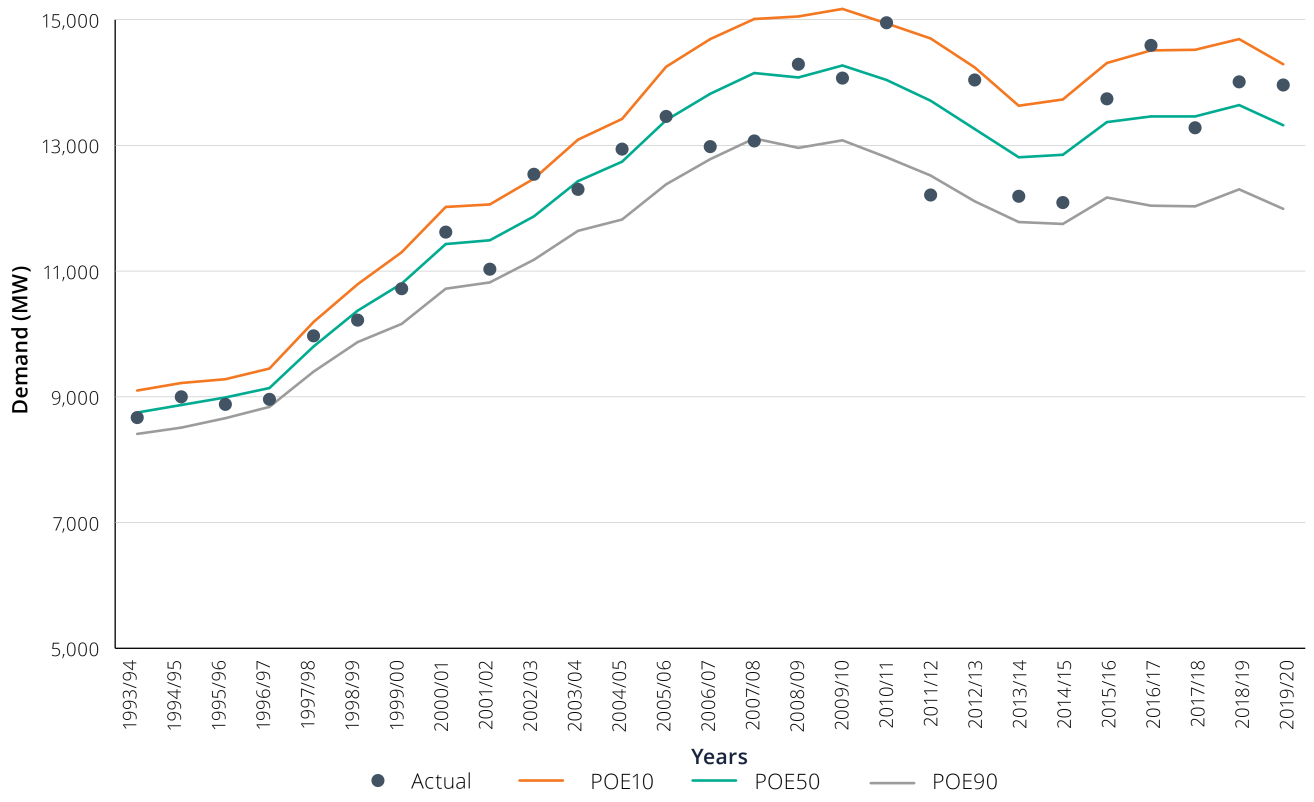
A1.3.5 Calculation of historical POE levels

- For each season, for each year, the maximum for each alternative demand trace is selected; and
- From each of the (approximately 12,000) alternative maxima for each season/year, the 90th, 50th and 10th percentiles are calculated as the POE10, POE50 and POE90 maximum demand levels, respectively.

A1.3.6 Results

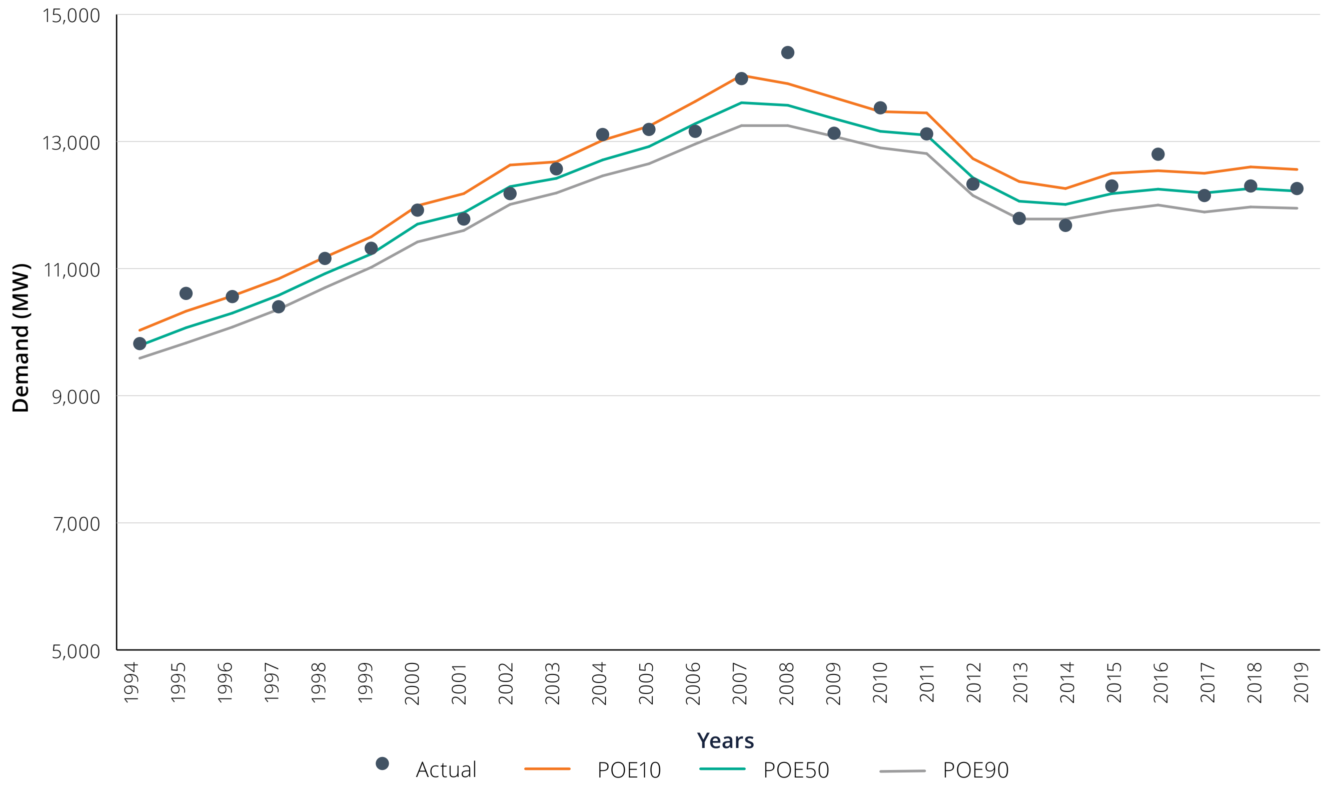
Historical maximum demands and the estimated POE10, POE50 and POE90 levels of demand are displayed in **Figure A1.5** and **Figure A1.6**.

Figure A1.5: Summer maximum demand



Source: TransGrid

Figure A1.6: Winter maximum demand



Source: TransGrid

A1.4 Summer and winter maximum demand models

1.4.1. Approach to forecasting electricity services maximum demands

It is useful conceptually to break down the maximum level of demand reached in a particular season into the following components:

- underlying, non-weather sensitive demand driven by factors that are similar to those driving annual energy, including population growth, income growth and changes in energy prices;
- adjustments to measured network demand at particular times, due to out of trend energy efficiency and distributed energy resources such as rooftop PV generation and battery storage and discharge;
- specific investment plans and/or closures driving changes in major industrial loads; and
- a highly variable, weather sensitive component which largely depends on prevailing weather conditions.

The non-weather sensitive component of demand may respond to prices in the same manner as energy. However, the weather-sensitive component is unlikely to be price-sensitive, as for the majority of consumers there is an insignificant impact on billing period energy charges for a few hours of additional consumption on a single day of extremely hot or cold weather.

In addition to traditional industrial loads, future electrification of transport will entail new sources of potential demand as a result of externally charged electric road vehicles.

Forecasts of summer and winter maximum demand are projected from the historical POE10, POE50 and POE90 electricity services maximum demands. This removes the year-to-year variability due to weather-sensitivity and the impact of accelerated energy efficiency and DER.

The maximum demand forecasts are prepared as follows:

- major industrial loads are removed from each historical POE level of demand and annual energy;
- historical electricity services maximum demands are calculated from the POE10, POE50 and POE90 levels of native maximum demand, plus the estimated impact of rooftop PV generation, out-of-trend energy efficiency and battery charging/discharging at the times of maximum demand;
- load factors (LF) are calculated for each of the electricity services POE10, POE50 and POE90 levels of MD as follows:
    - LF ratio =1000 × annual energy in GWh / (MD in MW × hours in the year);
- a statistical relationship between each LF and air-conditioning penetration in NSW is estimated;
- the estimated relationships are then used to predict future load factors, conditional on a projection of NSW air-conditioning penetration (currently around 55 per cent) that levels out around 60 per cent; and
- the predicted load factors are then converted back into their respective forecast electricity service MD levels using the energy forecast and values of major industrial loads at times of maximum demand.

This method maintains a link between the energy forecast and its underlying drivers and the level of maximum demand, and maintains observed historical links between increasing air-conditioning penetration and growth in the weather-sensitive component of demand.

A1.4.2 Calculating the impact and timing of distributed energy services and energy efficiency on electricity services

The forecasts of electricity services MDs are first reduced by estimates of the impact of above-trend energy efficiency at times of MD, based on the report by EES. The resulting MD forecasts are termed “underlying” MDs, as this measure can be calculated for historical MD days by adding an estimated rooftop PV profile to a half-hourly profile of native demand.

Historical underlying MD profiles are increased in successive years by the respective rates of growth of the underlying MD forecasts. Profiles for various DER elements are then added to the forecast underlying demand profiles. The native MDs calculated in this manner therefore reflect the changes in the respective underlying MDs caused by both the quantity and timing of each DER element.

Figure A1.7 and **Figure A1.8** show the construction of native POE50 MD for the 2029-30 summer and the 2029 winter. In each figure, underlying demand (i.e. demand in the absence of any DER) is shown by the blue line, while native demand (representing the net impact on the transmission network) is shown by the brown line. In that summer, the maximum underlying POE50 MD occurs at 16:00 hours EST, whereas, the impact of DER (mainly rooftop PV) is to both reduce and delay the maximum native MD until 17:00 hours EST.

Figure A1.7: Day of summer maximum demand 2029/30

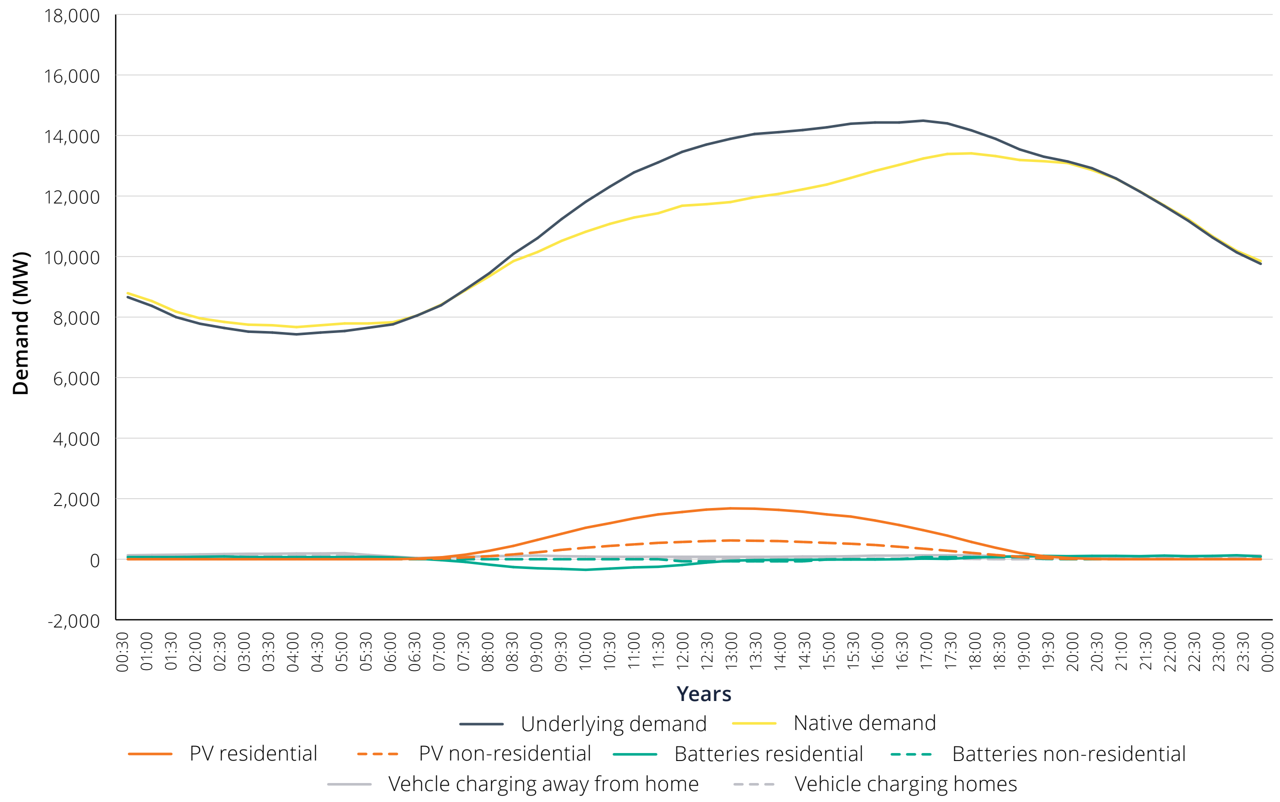
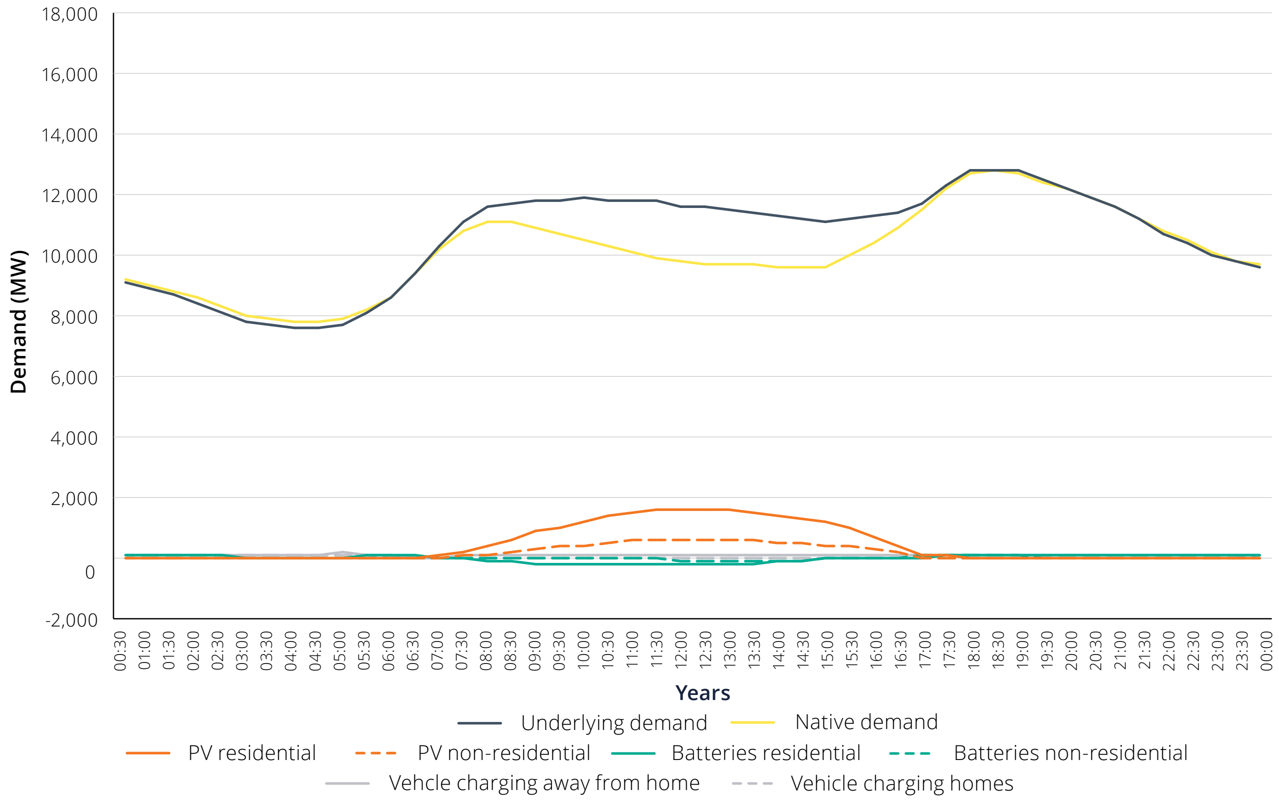


Figure A1.8: Day of winter maximum demand 2029



A1.4.3 Model accuracy

The summer and winter models' ability to fit the historical data sample and medium scenario forecasts are shown in **Figure A1.9** and **Figure A1.10**. These figures were produced with data up to 2015-16 (summer) and 2016 (winter), with the last two to three actual years forecast out of sample to test the models[50]. Some key indications of the reliability of the forecasts are:

- the fitted lines are contained within a plus or minus two standard error band;
- the calculated accuracy measure of Mean Absolute Percentage Error (MAPE) is low (1.38 for summer and 1.24 for winter); and
- there is no persistent bias indicating no tendency for either model to produce long run forecasts that are either too high or too low.

The evidence suggests that the models are valid across the entire sample period, are relatively accurate and are not given to persistent bias up or down.

Figure A1.9: Electricity services summer maximum demand 50% POE in-sample/out-of-sample fit

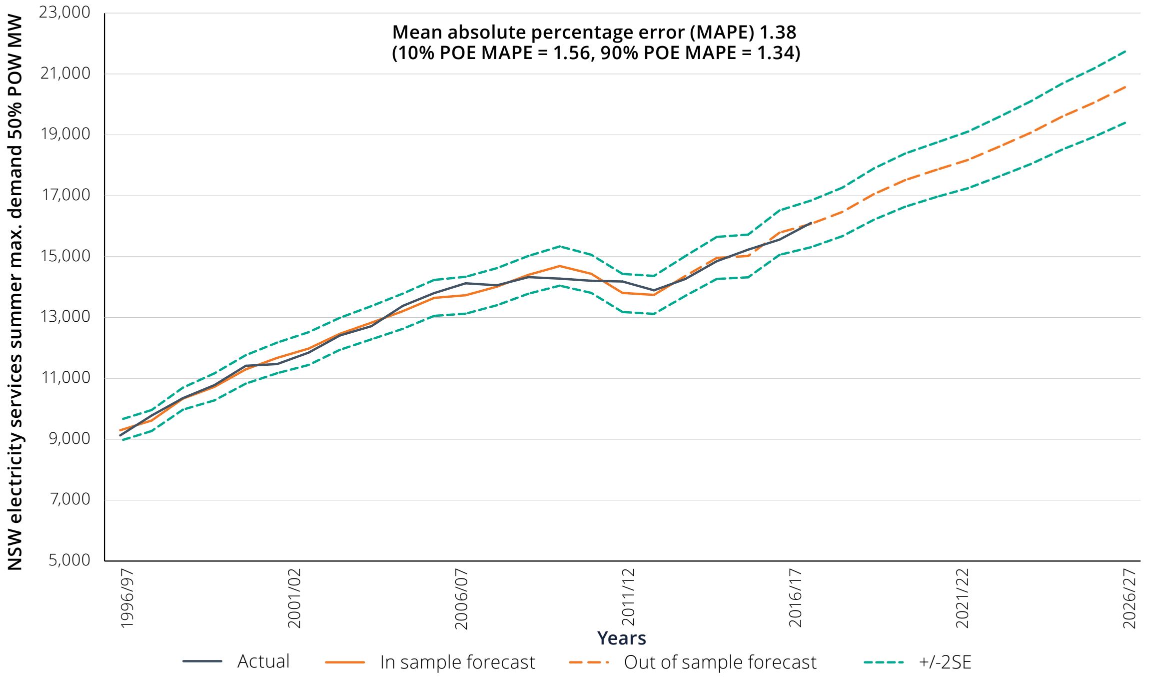
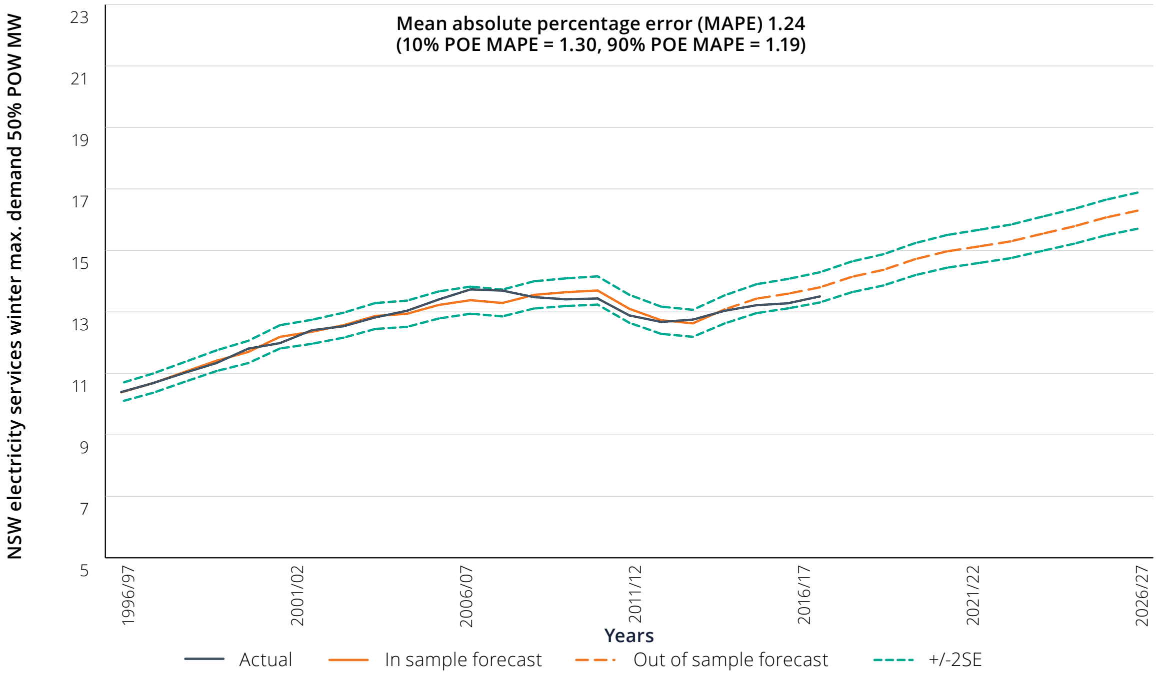


Figure A1.10: Electricity services winter maximum demand 50% POE in-sample/out-of-sample fit



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[50] The published forecasts of native MD have a starting point of 2020/21 (summer) and 2020 (winter), and are based on actual data up to and including March 2020. The estimated sample period fully includes summer 2019/20 and completely excludes winter 2020.

A1.5 Major industrial loads

Major industrial loads accounted for 18 per cent of annual energy in 2018/19 and 10 per cent of MD for summer 2019-20 which occurred on 1 February 2020. Major industrial loads include the following electricity consumers:

- Tomago Aluminium;
- Bluescope steel Port Kembla;
- Onesteel Waratah West;
- Visy Gadara;
- Norske Skog Albury;
- Broken Hill Mine;
- Cadia Mine Orange;
- North Parkes Mine;
- Lake Cowal Mine;
- Ulan Area Mines;
- Boggabri East and North Mines; and
- CSR Oberon.

New major industrial load (spot loads) of up to 142 MW introduced over the next five years is included in the forecast. This increase was based on information on existing businesses' expansion plans and committed new business projects, provided by TransGrid's customers, including DNSPs. The increase, which includes mine expansions, new industrial loads and large infrastructure projects, has been discounted to account for future risks of these loads going ahead. This discount rate was derived from historical variations between planned load requirements for projects and actual outcomes.

A1.6 Input data and scenario assumptions

Inputs to the load forecasting framework described above were supplied from independent advice on the following issues affecting the long-run use of electricity in NSW.

The tables below show changes in input variables corresponding to each respective NSW region energy and demand scenario.

A1.6.1. Demographic and economic forecasts

TransGrid obtained projections of future demographic and economic trends.[51]

Table A1.5: NSW population growth and key macroeconomic forecasts CAGR 2020/21-2029/30

Variable	Medium	High	Low
Resident population	1.2	1.6	0.7
Real household disposable income	2.4	3.6	1.6
Gross State Product	2.7	3.8	2.0

A1.6.2 Energy prices

Projections of future energy price paths were developed from the retail price projections report by using the yearly residential price changes and by averaging the separate non-residential price series.[52]

Table A1.6: NSW electricity and gas price forecasts CAGR 2020/21-2029/30

Variable	Medium	High	Low
Real residential electricity price	-0.4	-0.7	0.2
Real non-residential electricity price	-0.7	-1.1	0.0
Real gas and other fuels price	1.1	2.5	0.7

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[51] BIS Oxford Economics (2020) Economic and Dwelling Forecasts to FY2039 – NSW & ACT, May 2020.

[52] Jacobs (2020) Retail Price Projections for NSW, Final, June 2020.

A1.6.3. Rooftop PV and distributed battery storage

TransGrid rooftop PV and stationary battery charge/discharge forecasts were prepared by CSIRO[53]. Projected PV output and battery charging/discharging annual energy and profiles for specified days for all projected summer and winter periods were subtracted directly from the modelled energy and maximum demand forecast profiles, respectively, to estimate network energy and maximum demand.

Table A1.7: NSW rooftop PV and battery storage forecasts total increase 2020/21-2029/30 (2020-2029 for winter)

Variable	Medium	High	Low
Residential PV generation GWh	1,227	2,854	805
Non-residential PV generation GWh	1,009	1,809	420
Average shift in summer maximum demand due to PV and batteries (both due to capacity and time shift) MW	-1,022	-628	-399
Average battery discharge at time of respective summer and winter system maximum demand MW	63 / 96	78/123	39/67

A1.6.4 Energy efficiency policies

On behalf of TransGrid, Energy Efficient Strategies[54] conducted a thorough updated assessment of recent energy efficiency policies and standards, and quantified the aggregate energy savings impacts on electricity demand. TransGrid extracted the projected historical trend from 2001 to 2019 from the projected total savings.

Table A1.8: Energy efficiency out of trend total increase 2020/21-2029/30 (2020-2029 for winter)

Variable	Medium	High	Low
Residential savings GWh	2,470	2,470	2,470
Non-residential savings GWh	5,139	5,139	5,139
Total savings at time of summer maximum MW	1,631	1,631	1,631
Total savings at time of winter maximum MW	1,395	1,395	1,395

A1.6.5 Electric vehicles

An allowance is included in the load forecast to account for future take-up of externally charged electric vehicles. TransGrid has considered charging loads of existing electric vehicles and projected increasing take-up. The projections, including half-hourly profiles for specified days of interest, were sourced from Energeia[55].

Table A1.9: Electric vehicle charging total increase 2020/21-2029/30 (2020-2029 for winter)

Variable	Medium	High	Low
Annual charging energy GWh	1,136	1,659	355
Average discharge at time of summer and winter MD MW	46/25	69/44	14/10

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[53] CSIRO (2020): Rooftop PV and Battery Forecasts for Future Grid Scenarios, May 2020.

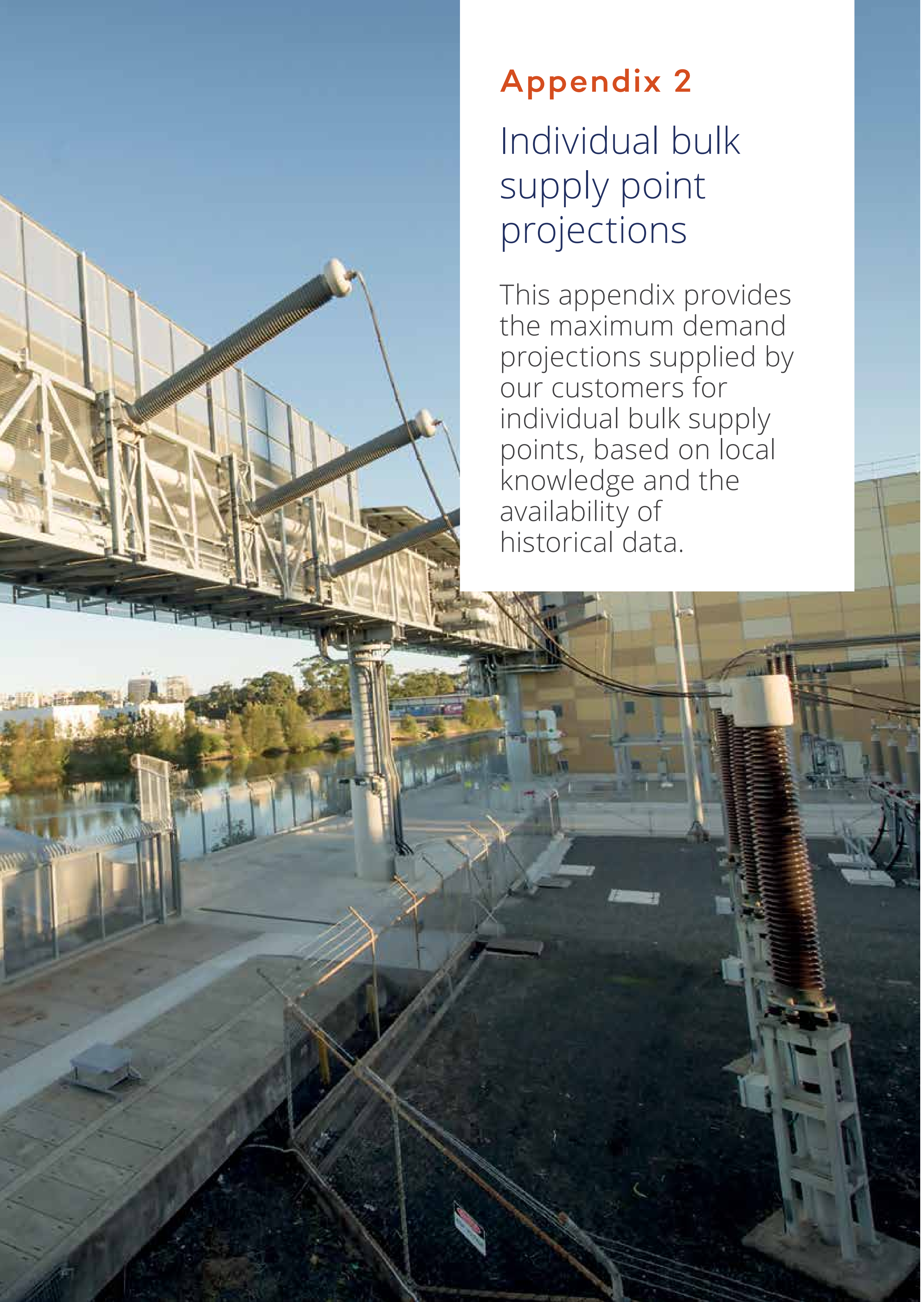
[54] Energy Efficient Strategies (2020) Impact of Energy Efficiency Programs on Electricity Consumption in NSW and ACT, Report for TransGrid, June 2020.

[55] Energeia (2019) Electric Vehicles Modelling, Final, June 2019.

Seen here in conversation are members from Native Title and Barkindji Maraura Elders Environment Team, working alongside Archaeologists who are undertaking a cultural heritage field survey for geotechnical studies, in Phase One of EnergyConnect from the NSW-SA border to Buronga.

A1.6.6 Glossary

Item	Description
As generated	Generation measured at the generator terminals
Cooling degree days	Cooling degree days is the addition of cooling degrees for all days in a period Cooling degrees (CD) are temperature deviations above a human comfort threshold, in this report taken to be 21 Celsius, therefore for a temperature measure t on any particular day, *For* $t \leq 21$, $CD = 0$ *For* $t > 21$, $CD = t - 21$
Demand, Operational	A measure of electricity use based on half-hourly measurements of all Scheduled, Semi-Scheduled and significant Non-Scheduled generation within the region, plus net imports into the region
Demand, Native	Operational demand as above plus small Non-Scheduled generation. Non-inclusion of this generation may significantly distort past electricity usage trends in NSW
Elasticity	A unit-less measure of responsiveness of demand to either price or income. For example, an own price elasticity of -0.5 means that a 1% increase in own price reduces demand by 0.5%
Electricity services	This concept is used in TransGrid's energy modelling and refers to an underlying, primary need to use appliances that happen to be powered by electricity. It includes both residential electricity services and non-residential electricity services Residential electricity services is constructed as the addition of residential grid supplied energy, residential rooftop PV generation and estimated above-trend residential energy efficiency savings Non-residential electricity services is constructed as the addition of non-residential native energy (minus major industrial loads) non-residential rooftop PV generation and an estimate of out-of-trend non-residential energy efficiency savings
Energy	Measures the capacity for work to be done by electricity that is supplied to consumers, generally expressed in this report by the measure of GWh a year
Heating degree days	Heating degree days is the addition of heating degrees for all days in a period Heating degrees (HD) are temperature deviations below a human comfort threshold, in this report taken to be 18 Celsius, therefore for a temperature measure t on any particular day, For $t \geq 18$, $HD = 0$ For $t < 18$, $HD = 18 - t$
Load factor	The ratio of average demand to maximum demand. This can relate to maximum demand and energy via the formulation: Load factor = 1000 × GWh energy/(MW maximum demand × 8760)
Major industrial load	Electricity usage by a defined group of large electricity customers with whom TransGrid has a direct relationship and who are not significantly responsive to price or temperature
Maximum demand	Measures the highest rate, within a defined period such as summer or winter, at which energy is absorbed by the network, generally expressed in this report by the measure of MW averaged over a half-hour
NSW Region	State of NSW and the Australian Capital Territory (ACT)
Sent-out	Generation measured at the point of connection with the transmission network
Small non-scheduled generation	Non-Scheduled generation that is not included in Operational Demand
Spot Load	Spot loads are step (one-shot) increases in load for a BSP due to new commercial/housing developments or large industrial customer connections. There could be spot load decreases in cases where there are withdrawals of large load customers from the grid.
Summer	In this report, all days from 16 November in a particular year to 15 March in the immediately following year, inclusive
Winter	In this report, all days in a particular year from 16 May to 31 August, inclusive



Appendix 2

Individual bulk supply point projections

This appendix provides the maximum demand projections supplied by our customers for individual bulk supply points, based on local knowledge and the availability of historical data.

A2.1 Individual bulk supply point projections

Our customers have provided maximum demand projections, in terms of both megawatts (MW), megavolt ampere reactive (MVAr) and megavolt ampere (MVA) for individual bulk supply points between the NSW transmission network and the relevant customer's network. These projections are produced using methodologies that are likely to have been tailored to the circumstances relating to the load(s) at particular bulk supply point(s) such as the degree of local knowledge and the availability of historical data. The projections are given in the tables below.

Some large and relatively stable industrial loads mainly connected directly to TransGrid's network that we isolate for modelling purposes have been removed from the bulk supply point projections and aggregated. The removal of this data affects the projections shown for Broken Hill. Other industrial loads are included in bulk supply point forecasts provided by distributors. Aggregate projections for all identified major industrial loads (excluding those that are also in the bulk supply point forecasts) at the time of maximum NSW Region demand are given in **Table A2.11** and **Table A2.12**. Additional spot loads of about 225 MW are expected to be added to TransGrid's network in the next 10 years. These have been included in **Tables A2.11** and **A2.12**

Table A2.1 to **Table A2.10** provide projections of non-coincident maximum demand occurring during a particular season at a particular bulk supply point (or group of bulk supply points) on the NSW transmission network. They do not represent projections of demand contributions at these bulk supply points to the overall NSW region maximum demand.

The individual bulk supply point projections were produced by the DNSPs prior to the occurrence of COVID-19 and as such do not factor in any likely effects on load that COVID-19 would have caused. These projections are likely to be reviewed by DNSPs later this year.

Table A2.1: Ausgrid bulk supply point summer maximum demand[56]

	2020/21			2021/22			2022/23			2023/24			2024/25			2025/26			2026/27			2027/28			2028/29			2029/30		
	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA
Beaconsfield West 132 kV	387	87	397	390	87	400	472	33	474	515	62	519	508	19	508	516	49	518	493	1	493	497	12	497	505	40	506	513	52	516
Rookwood Rd 132 kV	302	10	302	302	3	302	236	1	236	250	12	250	255	15	256	257	8	257	246	-8	246	249	5	249	251	3	251	255	8	255
Haymarket 132 kV	476	118	491	480	123	496	467	102	478	497	103	507	501	107	512	505	98	514	534	93	542	545	98	554	544	89	551	550	95	558
Liddell 33 kV	18	9	20	18	9	20	18	9	20	18	9	20	18	9	20	18	9	20	18	9	20	18	9	20	18	9	20	18	9	20
Munmorah 132 kV & 33 kV	131	30	134	132	31	135	133	31	136	132	31	136	133	30	136	132	28	135	132	29	135	133	31	137	134	31	137	134	32	138
Muswellbrook 132 kV	174	113	207	173	113	207	173	112	206	172	112	206	172	112	206	173	113	206	174	114	208	174	113	208	175	114	208	175	114	209
Newcastle 132 kV	489	193	526	488	183	521	492	192	528	491	191	527	486	163	512	488	184	521	489	176	519	491	166	518	493	167	520	495	168	522
Sydney East 132 kV	791	85	795	795	86	799	801	93	807	809	98	815	814	106	821	833	111	840	853	125	862	866	130	876	880	143	892	886	142	897
Sydney North 132 kV	977	247	1008	986	257	1018	981	253	1013	897	323	954	918	342	979	935	350	999	955	368	1023	974	382	1047	996	400	1073	1004	403	1082
Sydney South 132 kV	1246	240	1269	1254	249	1278	1262	296	1296	1290	279	1320	1306	322	1345	1320	306	1355	1354	311	1389	1359	232	1379	1378	249	1401	1383	242	1404
Tomago 132 kV	361	96	373	364	116	382	351	97	364	352	96	365	356	109	372	349	90	360	357	112	374	360	109	376	362	108	378	363	109	379
Tuggerah 132 kV	254	73	264	254	69	264	257	69	266	256	66	265	259	75	269	259	78	271	263	79	274	264	78	276	266	79	277	267	80	279
Vales Point 132 kV	108	25	111	107	24	110	116	24	118	115	24	118	116	27	119	116	27	119	115	27	118	116	27	119	117	27	120	117	28	120
Waratah West 132 kV	237	104	259	237	100	257	231	104	253	229	103	252	230	114	257	229	101	250	230	99	250	234	116	261	235	117	262	236	117	263

Table A2.2: Ausgrid bulk supply point winter maximum demand

	2020			2021			2022			2023			2024			2025			2026			2027			2028			2029		
	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA
Beaconsfield West 132 kV	326	96	340	327	90	340	330	101	345	409	42	412	435	52	438	436	42	438	416	74	422	419	34	421	422	46	424	425	47	427
Rookwood Rd 132 kV	257	-4	257	258	0	258	258	16	259	203	-2	203	217	12	217	219	16	219	208	19	209	209	-1	209	208	-10	208	209	-9	209
Haymarket 132 kV	405	124	423	405	117	421	408	117	424	403	114	419	420	108	433	423	127	442	445	108	458	452	113	466	453	107	465	455	115	470
Liddell 33 kV	17	8	19	17	8	19	17	8	19	17	8	19	17	8	19	17	8	19	17	8	19	17	8	19	17	8	19	17	8	19
Munmorah 132 kV & 33 kV	125	19	127	126	19	127	125	15	126	125	13	126	124	13	125	125	14	126	124	14	125	125	15	126	126	15	127	128	13	129
Muswellbrook 132 kV	143	89	168	142	89	167	141	88	167	141	88	166	140	88	165	140	87	165	140	88	165	140	88	165	141	88	166	141	86	165
Newcastle 132 kV	372	82	381	375	119	394	370	89	380	371	87	381	368	86	378	368	85	378	367	85	377	368	86	378	369	86	379	377	95	388
Sydney East 132 kV	709	46	710	711	49	713	709	46	710	712	40	713	715	46	717	719	50	721	734	56	737	745	62	748	755	74	759	759	75	763
Sydney North 132 kV	794	232	827	775	237	811	774	232	808	789	245	826	717	295	775	734	308	795	745	315	809	760	321	825	775	333	843	779	335	848
Sydney South 132 kV	1050	138	1059	1082	179	1097	1073	139	1082	1082	213	1103	1105	204	1124	1110	199	1128	1137	194	1153	1137	148	1146	1145	160	1156	1149	161	1160
Tomago 132 kV	267	55	273	266	47	270	267	57	273	264	62	271	261	60	268	262	58	268	260	57	267	262	58	268	261	58	268	262	65	270
Tuggerah 132 kV	229	34	231	229	34	231	225	23	226	226	22	227	224	21	225	224	22	225	225	22	226	226	23	227	226	23	228	227	29	229
Vales Point 132 kV	95	14	96	95	12	96	95	14	95	102	12	102	101	12	101	101	12	102	100	12	101	101	12	102	101	13	102	101	18	103
Waratah West 132 kV	189	109	218	184	81	201	184	90	205	177	90	199	176	89	197	175	89	196	175	89	196	176	89	197	176	89	197	176	71	190

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[56] Zone substation projections aggregated to TransGrid bulk supply points using agreed load flow models.

Table A2.3: Endeavour Energy bulk supply point summer maximum demand[57]

	2020/21			2021/22			2022/23			2023/24			2024/25			2025/26			2026/27			2027/28			2028/29			2029/30		
	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA
Dapto 132 kV	630	101	638	641	103	650	652	105	660	660	106	668	669	108	678	672	108	680	678	109	686	679	109	688	682	110	691	684	110	693
Holroyd 132 kV	425	31	426	435	32	436	438	32	439	442	32	443	446	33	447	450	33	452	454	33	455	459	34	460	463	34	465	468	34	469
Ilford 132 kV	6	0	6	10	0	10	14	0	14	19	0	19	24	0	24	30	0	30	35	0	35	39	0	39	43	0	43	47	0	47
Ingleburn 66 kV	136	37	141	136	37	141	136	37	141	135	37	140	135	37	140	135	37	140	134	37	139	134	37	139	134	37	139	134	37	139
Liverpool 132 kV	437	80	444	454	83	461	477	87	485	496	90	504	508	93	516	520	95	529	528	96	536	533	97	542	538	98	546	542	99	551
Macarthur 132 kV & 66 kV	346	61	352	363	64	369	373	66	379	385	68	391	417	74	423	444	79	451	469	84	477	502	90	510	528	95	537	554	100	563
Marulan 132 kV	76	23	80	76	23	80	78	24	81	84	26	88	88	27	92	90	28	94	90	28	95	90	28	94	90	28	94	90	27	94
Mount Piper 66 kV	33	13	35	33	13	35	33	13	35	33	13	35	33	13	35	33	13	35	33	13	35	33	13	35	33	13	35	33	13	35
Regentville 132 kV	314	83	324	321	85	332	328	86	339	330	87	341	331	87	342	333	88	344	333	88	345	334	88	346	335	88	346	336	88	347
Sydney North 132 kV	38	6	39	38	6	38	38	6	38	38	6	38	37	6	38	37	6	38	37	6	38	37	6	38	37	6	37	37	6	37
Sydney West 132 kV	1285	328	1326	1309	334	1351	1339	342	1382	1353	345	1396	1373	350	1417	1394	356	1439	1409	360	1454	1422	363	1468	1425	364	1471	1428	365	1474
Vineyard 132 kV	591	121	603	622	127	635	650	133	664	685	140	700	711	146	725	735	151	750	755	155	771	773	158	789	781	160	798	790	162	806
Wallerawang 132 kV & 66 kV	61	14	63	61	14	63	61	14	63	61	14	62	61	14	62	61	14	62	60	14	62	60	14	62	60	14	62	60	14	62

Table A2.4: Endeavour Energy bulk supply point winter maximum demand[58]

	2020			2021			2022			2023			2024			2025			2026			2027			2028			2029		
	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA
Dapto 132 kV	653	91	659	681	95	688	695	97	702	699	97	706	705	98	712	712	99	719	716	99	722	717	100	724	720	100	727	721	100	728
Holroyd 132 kV	320	28	321	335	29	336	343	30	344	345	30	346	354	31	355	356	31	358	360	31	362	363	32	365	367	32	368	371	32	372
Ilford 132 kV	5	0	5	6	1	6	9	1	9	13	1	13	16	2	17	20	2	20	25	2	25	29	3	29	32	3	32	35	3	35
Ingleburn 66 kV	116	12	117	118	13	119	119	13	120	119	13	120	119	13	120	119	13	119	119	13	120	119	13	119	119	13	119	119	13	119
Liverpool 132 kV	304	45	307	323	48	327	337	50	341	355	52	359	370	55	374	378	56	382	387	57	391	392	58	397	396	59	400	399	59	403
Macarthur 132 kV & 66 kV	286	29	288	306	30	308	314	31	316	326	32	328	354	35	356	378	38	379	404	40	406	438	43	440	467	46	469	494	49	497
Marulan 132 kV	84	31	89	84	31	90	85	32	91	88	33	94	92	34	98	94	35	101	95	35	102	95	35	101	95	35	101	95	35	101
Mount Piper 66 kV	34	11	36	35	11	36	35	11	36	35	11	36	35	11	36	34	11	36	34	11	36	34	11	36	34	11	36	34	11	36
Regentville 132 kV	213	56	221	223	59	230	231	61	239	235	62	243	237	62	245	238	63	246	240	63	248	241	63	249	241	64	250	242	64	250
Sydney North 132 kV	25	3	26	25	3	26	25	3	26	25	3	25	25	3	25	25	3	25	25	3	25	25	3	25	25	3	25	25	3	25
Sydney West 132 kV	993	208	1014	1038	217	1060	1068	224	1091	1080	226	1104	1103	231	1127	1120	235	1144	1136	238	1160	1147	240	1172	1155	242	1180	1156	242	1181
Vineyard 132 kV	359	45	361	390	49	393	413	52	416	433	55	437	457	58	460	475	60	479	493	62	497	509	64	513	523	66	527	530	67	534
Wallerawang 132 kV & 66 kV	79	18	81	79	18	81	79	18	81	79	18	81	79	18	81	78	18	80	78	18	80	78	18	80	78	18	80	78	18	80

Table A2.5: Essential Energy (North) bulk supply point summer maximum demand

	2020/21			2021/22			2022/23			2023/24			2024/25			2025/26			2026/27			2027/28			2028/29			2029/30		
	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA
Armidale 66 kV	26	2	27	26	2	26	26	2	26	26	2	26	25	2	25	25	2	25	25	2	25	25	2	25	24	2	24	24	2	24
Boambee South 132 kV	22	2	22	22	2	23	23	2	23	23	2	23	23	2	23	24	2	24	24	2	24	24	2	24	24	2	25	25	2	25
Casino 132 kV	29	10	31	30	10	32	31	10	32	32	10	33	32	11	34	33	11	35	34	11	36	35	11	36	35	12	37	36	12	38
Coffs Harbour 66 kV	57	6	57	57	6	57	57	6	57	56	6	57	56	6	57	56	6	56	56	6	56	56	6	56	56	6	56	56	6	56
Dorrigo 132 kV	2	1	3	2	1	3	2	1	3	2	1	3	2	1	3	2	1	3	2	1	3	2	1	3	2	1	3	2	1	3
Dunoon 132 kV	7	-1	7	7	-1	7	7	-1	7	8	-1	8	8	-1	8	8	-1	8	8	-1	8	8	-1	8	9	-1	9	9	-1	9
Glen Innes 66 kV	10	-2	10	10	-2	10	10	-2	10	10	-2	10	9	-2	10	9	-2	10	9	-2	10	9	-2	9	9	-2	9	9	-2	9
Gunnedah 66 kV	27	3	27	27	3	27	27	3	27	26	3	27	26	3	27	26	3	27	26	3	27	26	3	27	26	3	26	26	3	26
Hawks Nest 132 kV	10	1	10	10	1	10	10	1	10	11	1	11	11	1	11	11	1	11	11	1	11	11	1	11	12	1	12	12	1	12
Herons Creek 132 kV	14	2	14	14	3	15	15	3	15	15	3	16	16	3	16	16	3	17	17	3	17	17	3	18	18	3	18	18	3	19
Inverell 66 kV	36	-4	36	36	-4	37	37	-4	37	38	-4	38	38	-4	38	39	-4	39	39	-4	40	40	-4	40	41	-4	41	41	-4	41
Kempsey 33 kV	27	4	27	27	4	28	28	4	28	28	4	28	29	4	29	29	4	29	29	4	30	30	4	30	30	4	30	31	4	31
Koolkhan 66 kV	58	4	58	59	4	59	59	4	60	60	4	60	61	4	61	62	4	62	62	4	62	63	4	63	64	4	64	64	4	65
Lismore 132 kV	114	13	114	114	13	114	114	13	114	114	13	115	114	13	115	114	13	115	114	13	115	114	13	115	114	13	115	114	13	115
Macksville 132 kV	9	2	9	9	2	9	9	2	9	9	2	10	10	2	10	10	2	10	10	2	10	10	2	10	10	2	10	10	2	10
Moree 66 kV	27	1	27	27	1	27	27	1	27	27	1	27	28	1	28	28	1	28	28	1	28	28	1	28	28	1	28	29	1	29
Mullumbimby 132 kV	51	-1	51	52	-1	52	53	-1	53	54	-1	54	55	-1	56	57	-1	57	58	-2	58	59	-2	59	60	-2	60	61	-2	61
Nambucca 66 kV	6	-1	6	6	-1	6	6	-1	6	6	-1	6	6	-1	6	6	-1	6	6	-1	6	6	-1	6	6	-1	6	6	-1	6
Narrabri 66 kV	55	1	55	56	1	56	57	1	57	58	0	58	59	0	59	60	0	60	61	0	61	62	0	62	63	0	63	64	0	64
Port Macquarie 33 kV	68	9	68	70	9	70	71	9	72	73	10	74	75	10	75	77	10	77	78	10	79	80	11	81	82	11	82	83	11	84
Raleigh 132 kV	10	2	10	10	2	10	10	2	10	10	2	10	10	2	10	10	2	11	10	2	11	11	2	11	11	2	11	11	2	11
Stroud 132 kV	38	-1	38	39	-1	39	40	-1	40	41	-1	41	43	-1	43	44	-1	44	45	-2	45	46	-2	46	47	-2	47	48	-2	48
Tamworth 66 kV	130	25	133	132	26	135	134	26	137	136	27	139	138	27	141	140	27	143	142	28	145	144	28	147	146	28	149	149	29	151
Taree 33 kV	34	6	34	34	6	35	35	6	35	36	6	36	36	6	37	37	6	38	38	6	38	38	6	39	39	6	40	40	7	40
Taree 66 kV	52	8	52	52	8	53	53	8	53	53	8	54	54	8	54	54	8	55	55	8	55	55	9	56	56	9	57	56	9	57
Tenterfield 22 kV	4	0	4	4	0	4	4	0	4	4	0	4	4	0	4	4	0	4	4	0	4	4	0	4	4	0	4	4	0	4
Terranora 110 kV	91	5	91	92	5	92	98	5	98	99	5	99	99	5	99	99	5	99	99	5	99	98	5	99	98	5	99	98	5	99

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[57] Marulan 132 kV: Both Endeavour Energy and Essential Energy take supply from Marulan. This forecast is for Endeavour Energy component. A diversity factor of 3% in summer should be applied to obtain the total forecast load at Marulan

[58] Marulan 132 kV: Both Endeavour Energy and Essential Energy take supply from Marulan. This forecast is for Endeavour Energy component. A diversity factor of 2% in winter should be applied to obtain the total forecast load at Marulan

Table A2.6: Essential Energy (North) bulk supply point winter maximum demand

	2020			2021			2022			2023			2024			2025			2026			2027			2028			2029		
	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA
Armidale 66 kV	39	2	39	39	2	39	39	2	39	39	2	39	38	2	39	38	2	38	38	2	38	38	2	38	38	2	38	38	2	38
Boambee South 132 kV	19	-1	19	19	-1	19	20	-1	20	20	-1	20	20	-1	20	21	-1	21	21	-1	21	22	-1	22	22	-1	22	22	-1	22
Casino 132 kV	24	2	24	24	2	24	24	2	24	25	2	25	25	2	25	25	3	25	26	3	26	26	3	26	26	3	26	27	3	27
Coffs Harbour 66 kV	53	-3	53	53	-3	53	53	-3	53	53	-3	53	54	-3	54	54	-3	54	54	-3	54	55	-3	55	55	-3	55	55	-3	55
Dorrigo 132 kV	3	0	3	3	0	3	3	0	3	3	0	3	3	0	3	3	0	3	3	1	3	3	1	3	3	1	3	3	1	3
Dunoon 132 kV	7	0	7	7	0	7	7	0	7	7	0	7	7	0	7	7	0	7	7	0	7	7	0	7	7	0	7	7	0	7
Glen Innes 66 kV	13	-2	13	13	-2	13	13	-2	13	13	-2	13	13	-2	13	13	-2	13	13	-2	13	13	-2	13	13	-2	13	13	-2	13
Gunnedah 66 kV	23	3	23	23	3	23	23	3	23	23	3	23	23	3	23	23	3	24	23	3	24	23	3	24	23	3	24	23	3	24
Hawks Nest 132 kV	9	2	9	9	2	9	9	2	9	9	2	9	9	2	9	9	2	9	9	2	10	9	2	10	10	2	10	10	2	10
Herons Creek 132 kV	12	1	12	13	1	13	13	1	13	13	1	13	13	1	13	13	2	13	13	2	13	13	2	14	14	2	14	14	2	14
Inverell 66 kV	29	-9	31	30	-9	31	30	-9	32	31	-9	32	31	-9	32	32	-9	33	32	-9	33	33	-9	34	33	-10	34	33	-10	35
Kempsey 33 kV	29	3	29	29	3	30	30	3	30	31	3	31	32	3	32	33	3	33	33	3	34	34	3	34	35	3	35	36	3	36
Koolkhan 66 kV	53	-5	53	54	-5	54	55	-6	55	55	-6	56	56	-6	56	57	-6	57	58	-6	58	58	-6	59	59	-6	59	60	-6	60
Lismore 132 kV	87	5	87	86	5	86	86	5	86	86	5	86	85	5	86	85	5	85	85	5	85	84	5	85	84	5	84	84	5	84
Macksville 132 kV	9	0	9	9	0	9	9	0	9	9	0	9	10	0	10	10	0	10	10	0	10	10	0	10	10	0	10	10	0	10
Moree 66 kV	32	2	32	32	2	32	32	2	32	32	2	32	32	2	32	32	2	32	32	2	32	32	2	32	32	2	32	32	2	32
Mullumbimby 132 kV	56	-2	56	56	-2	56	56	-2	56	56	-2	56	56	-2	56	56	-2	56	56	-2	56	56	-2	56	56	-2	56	56	-2	56
Nambucca 66 kV	8	1	8	8	1	8	8	1	8	8	1	8	8	1	8	8	1	8	8	1	8	8	1	8	8	1	8	8	1	8
Narrabri 66 kV	46	-1	46	45	-1	46	45	-1	45	45	-1	45	45	-1	45	45	-1	45	45	-1	45	45	-1	45	45	-1	45	45	-1	45
Port Macquarie 33 kV	73	8	73	75	8	76	77	8	78	80	9	80	82	9	83	84	9	85	87	9	87	89	10	89	91	10	92	93	10	94
Raleigh 132 kV	9	1	9	10	1	10	10	1	10	10	1	10	10	1	10	10	1	10	10	1	10	10	1	10	11	1	11	11	1	11
Stroud 132 kV	31	-5	31	31	-5	31	32	-5	32	32	-5	32	33	-5	33	33	-5	33	33	-5	34	34	-6	34	34	-6	35	35	-6	35
Tamworth 66 kV	94	8	95	95	8	96	96	8	96	97	8	97	97	8	98	98	8	98	99	8	99	100	8	100	100	8	101	101	8	101
Taree 33 kV	27	3	28	28	3	28	28	3	28	28	3	28	28	3	29	29	3	29	29	3	29	29	4	29	30	4	30	30	4	30
Taree 66 kV	54	5	54	54	5	54	54	5	54	54	5	54	54	5	54	54	5	55	54	5	55	54	5	55	55	5	55	55	5	55
Tenterfield 22 kV	5	0	5	5	0	5	5	0	5	5	0	5	5	0	5	5	0	5	5	0	5	5	0	5	5	0	5	5	0	5
Terranora 110 kV	91	-7	91	92	-7	92	93	-7	93	100	-7	100	101	-7	101	101	-7	101	102	-7	102	102	-8	102	103	-8	103	103	-8	104

Table A2.7: Essential Energy (Central) bulk supply point summer maximum demand

	2020/21			2021/22			2022/23			2023/24			2024/25			2025/26			2026/27			2027/28			2028/29			2029/30		
	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA
Beryl 66 kV	74	10	75	79	11	80	81	11	82	83	11	84	85	11	86	88	12	88	90	12	91	92	12	93	94	13	95	96	13	97
Cowra 66 kV	39	4	39	40	4	40	40	3	40	41	3	41	41	3	41	42	3	42	42	3	42	43	3	43	43	3	43	43	3	44
Forbes 66 kV	37	6	38	37	6	38	37	6	38	37	6	38	37	6	38	37	6	38	37	6	38	37	6	38	37	6	38	37	6	38
Manildra 132 kV	11	4	11	11	4	11	11	4	11	11	4	12	11	4	12	11	4	12	11	4	12	11	4	12	11	4	12	11	4	12
Molong 66 kV	6	0	6	6	0	6	6	0	6	6	0	6	6	0	6	6	0	6	6	0	6	6	0	6	6	0	6	7	0	7
Mudgee 132 kV	27	4	27	27	4	27	28	4	28	28	4	28	28	4	29	29	4	29	29	4	29	30	4	30	30	4	30	30	4	31
Orange 66 kV	56	9	57	56	9	57	57	9	58	58	9	58	58	9	59	59	8	60	60	8	60	60	8	61	61	8	62	62	8	62
Orange 132 kV	166	25	168	183	27	185	180	27	182	179	27	181	180	27	182	180	27	182	180	27	182	181	27	183	181	27	183	181	27	183
Panorama 66 kV	79	13	80	79	13	80	79	13	81	80	13	81	80	13	81	80	13	81	81	13	82	81	13	82	81	13	82	82	13	83
Parkes 66 kV	31	10	32	32	10	33	32	9	34	33	9	34	34	9	35	34	9	35	35	9	36	36	9	37	36	8	37	37	8	38
Parkes 132 kV	50	20	54	50	20	54	51	21	55	52	21	56	53	21	57	53	22	58	54	22	58	55	22	59	56	23	60	56	23	61
Wallerawang 66 kV	4	1	4	4	1	4	4	1	4	4	1	4	4	1	4	4	1	4	4	1	4	4	1	5	4	1	5	4	1	5
Wallerawang 132 kV	27	16	31	27	16	31	27	16	32	27	16	32	27	16	32	28	16	32	28	17	32	28	17	33	28	17	33	28	17	33
Wellington 132 kV incl Town	202	17	203	204	17	205	206	17	207	208	17	209	210	18	211	213	18	213	215	18	216	217	18	218	219	18	220	221	19	222

Table A2.8: Essential Energy (Central) bulk supply point winter maximum demand

	2020			2021			2022			2023			2024			2025			2026			2027			2028			2029		
	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA
Beryl 66 kV	82	6	82	87	7	87	90	7	90	92	7	92	95	7	95	97	8	98	100	8	100	102	8	103	105	8	105	107	8	108
Cowra 66 kV	29	-2	29	30	-2	30	30	-2	30	31	-2	31	31	-2	31	32	-2	32	32	-2	32	33	-2	33	33	-2	34	34	-2	34
Forbes 66 kV	25	-3	26	25	-3	26	25	-3	26	25	-3	26	25	-3	26	25	-3	26	26	-3	26	26	-3	26	26	-3	26	26	-3	26
Manildra 132 kV	10	3	10	10	3	10	10	3	10	10	3	10	9	3	10	9	3	10	9	3	10	9	3	10	9	3	10	9	3	10
Molong 66 kV	5	-1	5	5	-1	5	5	-1	5	5	-1	5	5	-1	5	5	-1	5	5	-1	5	5	-1	5	5	-1	5	5	-1	5
Mudgee 132 kV	25	1	25	26	1	26	26	1	26	27	1	27	28	1	28	29	1	29	29	1	29	30	1	30	31	1	31	32	1	32
Orange 66 kV	61	8	62	61	8	62	61	8	62	61	8	62	61	8	62	61	8	62	61	8	62	61	8	62	61	8	62	61	8	62
Orange 132 kV	150	17	151	166	19	167	183	21	184	180	20	182	179	20	181	180	20	181	180	20	181	180	20	181	181	21	182	181	21	182
Panorama 66 kV	72	8	73	72	8	73	73	8	73	73	8	73	73	8	74	73	8	74	74	8	74	74	8	74	74	8	74	74	8	75
Parkes 66 kV	26	4	27	27	4	27	27	4	27	27	4	28	28	4	28	28	4	28	28	4	29	29	4	29	29	4	29	29	4	30
Parkes 132 kV	50	21	54	50	21	54	51	21	55	51	21	56	52	22	56	53	22	57	53	22	57	54	22	58	54	22	59	55	23	59
Wallerawang 66 kV	6	2	6	6	2	6	6	2	6	6	2	6	6	2	6	6	2	6	6	2	6	6	2	6	6	2	6	6	2	6
Wallerawang 132 kV	27	16	31	27	16	32	28	16	32	28	17	33	29	17	33	29	17	34	30	18	35	30	18	35	31	18	36	31	18	36
Wellington 132 kV incl Town	170	-4	170	172	-4	172	173	-4	173	174	-4	174	175	-4	175	177	-4	177	178	-4	178	179	-4	179	180	-4	180	181	-4	182

Table A2.9: Essential Energy (South) and Evoenergy bulk supply point summer maximum demand

	2020/21			2021/22			2022/23			2023/24			2024/25			2025/26			2026/27			2027/28			2028/29			2029/30		
	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA
Albury & Finley 132 kV	119	26	122	119	26	122	119	26	122	120	26	122	120	26	123	120	26	123	120	26	123	121	26	123	121	26	124	121	26	124
Balranald 22 kV	4	0	4	4	0	4	4	0	4	4	0	4	4	0	4	4	0	4	4	0	4	4	0	4	4	0	4	4	0	4
Broken Hill 22 kV	41	10	43	42	10	43	43	10	44	43	11	44	44	11	45	44	11	45	45	11	46	45	11	46	46	11	47	46	11	48
Canberra 132 kV Evoenergy	386	221	445	256	147	295	256	147	295	255	146	294	257	147	296	261	150	301	260	149	300	261	150	301	264	151	304	263	151	303
Coleambally 132 kV	14	6	15	14	6	15	14	6	15	14	6	16	15	6	16	15	6	16	15	6	17	16	6	17	16	7	17	16	7	17
Cooma 66 kV	16	2	16	15	2	15	15	2	15	15	2	15	14	2	14	14	2	14	13	2	13	13	2	13	13	2	13	12	1	12
Cooma 132 kV	43	-8	44	44	-8	44	44	-8	45	45	-8	46	46	-8	46	46	-8	47	47	-9	48	48	-9	49	48	-9	49	49	-9	50
Darlington Point 132 kV	24	-11	26	24	-11	26	24	-11	26	24	-11	26	24	-11	26	24	-11	26	24	-11	26	24	-11	26	24	-11	26	24	-11	26
Deniliquin 66 kV	54	5	54	55	5	55	55	5	55	55	5	56	56	5	56	56	4	56	57	4	57	57	4	57	58	4	58	58	4	58
Finley 66 kV	18	3	18	18	3	18	18	3	18	18	3	18	17	3	18	17	3	17	17	3	17	17	3	17	17	3	17	17	3	17
Griffith 33 kV	97	10	98	98	10	99	99	10	100	100	10	101	102	10	102	103	10	103	104	10	104	105	10	105	106	10	106	107	10	107
Marulan 132 kV	73	-14	74	74	-14	75	75	-14	76	76	-14	78	78	-14	79	79	-15	80	80	-15	81	81	-15	83	82	-15	84	84	-16	85
Morven 132 kV	8	2	8	8	2	8	8	2	8	7	1	7	7	1	7	7	1	7	7	1	7	7	1	7	6	1	7	6	1	6
Munyang 33 kV	3	-1	3	3	-1	3	3	-1	4	3	-1	4	3	-1	4	3	-1	4	3	-1	4	3	-1	4	3	-1	4	3	-1	4
Murrumbateman 132 kV	6	0	6	7	0	7	7	0	7	7	0	7	7	0	7	7	0	7	7	0	7	7	0	7	7	0	7	8	0	8
Murrumburrah 66 kV	40	11	42	40	11	41	39	11	41	39	11	40	39	10	40	38	10	40	38	10	39	37	10	39	37	10	38	36	10	38
Queanbeyan 66 kV Essential Energy	59	10	59	60	10	61	61	10	62	59	10	60	60	10	61	60	10	61	60	10	61	61	10	62	61	10	62	61	10	62
Queanbeyan 66 kV Evoenergy	27	8	28	27	8	28	27	8	28	27	8	28	27	8	28	28	8	29	28	8	29	28	8	29	28	8	29	28	8	29
Queanbeyan 132 kV	9	-3	10	11	-3	11	12	-3	12	16	-4	16	18	-5	18	20	-6	20	22	-6	23	24	-7	25	26	-7	27	28	-8	29
Snowy Adit 132 kV	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Stockdill 132 kV Evoenergy	0	0	0	132	76	152	132	76	152	131	75	151	132	76	152	134	77	154	134	77	154	134	77	154	136	78	157	135	77	156
Tumut 66 kV	37	11	38	37	12	39	38	12	40	39	12	41	40	12	42	41	13	43	41	13	43	42	13	44	43	13	45	44	14	46
Wagga 66 kV	90	21	92	90	21	92	90	21	92	90	21	92	90	21	92	90	21	92	90	21	92	90	21	92	90	21	92	90	21	92
Wagga North 132 kV	66	-4	67	84	-5	85	84	-5	85	84	-5	85	84	-5	85	84	-5	85	84	-5	85	84	-5	85	84	-5	85	84	-5	85
Wagga North 66 kV	26	10	28	26	10	28	29	11	31	29	11	32	29	11	32	30	11	32	30	11	32	30	12	32	30	12	32	30	12	32
Williamsdale 132 kV Evoenergy	184	51	191	185	51	192	185	51	192	184	51	191	186	51	193	188	52	195	188	52	195	189	52	196	191	53	198	190	52	197
Yanco 33 kV	50	4	50	50	4	50	51	4	51	52	4	52	52	4	53	53	4	53	54	4	54	55	4	55	55	5	55	56	5	56
Yass 66 kV	14	-2	15	14	-2	15	14	-2	15	14	-2	15	14	-2	15	14	-2	15	14	-2	15	15	-2	15	15	-2	15	15	-2	15

Table A2.10: Essential Energy (South) and Evoenergy bulk supply point winter maximum demand

	2020			2021			2022			2023			2024			2025			2026			2027			2028			2029		
	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA	MW	MVAr	MVA
Albury & Finley 132 kV	89	6	89	89	6	89	89	6	90	90	6	90	90	6	90	90	6	90	90	6	90	90	6	91	90	6	91	91	6	91
Balranald 22 kV	3	-1	3	3	-1	3	3	-1	3	3	-1	3	3	-1	3	3	-1	3	3	-1	3	3	-1	3	3	-1	3	3	-1	3
Broken Hill 22 kV	33	3	33	33	3	33	33	3	34	33	3	34	34	3	34	34	3	34	34	3	34	34	3	34	34	3	34	34	3	34
Canberra 132 kV Evoenergy	443	80	450	292	52	297	292	52	297	289	52	294	288	51	293	287	51	292	288	51	293	288	51	293	288	51	293	288	52	293
Coleambally 132 kV	8	2	8	8	2	8	8	2	8	8	2	8	8	2	8	8	2	8	8	2	8	8	2	8	8	2	8	8	2	8
Cooma 66 kV	36	2	36	36	2	36	36	2	36	35	2	35	35	2	35	35	2	35	34	2	34	34	2	34	34	2	34	33	2	33
Cooma 132 kV	45	0	45	45	0	45	45	0	45	45	0	45	45	0	45	45	0	45	46	0	46	46	0	46	46	0	46	46	0	46
Darlington Point 132 kV	20	-14	25	20	-14	25	20	-14	25	20	-14	25	20	-14	25	20	-14	25	20	-14	25	20	-14	25	20	-14	25	20	-14	25
Deniliquin 66 kV	31	-1	31	31	-1	31	31	-1	31	31	-1	31	31	-1	31	31	-1	31	31	-1	31	31	-1	31	31	-1	31	31	-1	31
Finley 66 kV	13	-1	13	13	-1	13	13	-1	13	13	-1	13	13	-1	13	13	-1	13	13	-1	13	13	-1	13	13	-1	13	13	-1	13
Griffith 33 kV	58	9	58	62	10	63	63	10	64	64	10	64	64	10	65	65	11	66	65	11	66	66	11	67	67	11	68	67	11	68
Marulan 132 kV	70	-8	70	73	-9	73	74	-9	75	76	-9	76	77	-9	77	78	-9	79	80	-9	80	81	-9	82	82	-10	83	84	-10	84
Morven 132 kV	7	0	7	7	0	7	7	0	7	7	0	7	7	0	7	7	0	7	7	0	7	7	0	7	7	0	7	7	0	7
Munyang 33 kV	29	9	31	34	11	35	33	11	35	33	11	34	33	10	34	32	10	34	35	11	37	35	11	37	34	11	36	36	12	38
Murrumbateman 132 kV	7	-1	7	7	-1	7	7	-1	7	7	-1	7	7	-1	7	7	-1	7	8	-1	8	8	-1	8	8	-1	8	8	-1	8
Murrumburrah 66 kV	38	1	38	38	1	38	38	1	38	39	1	39	39	1	39	39	1	39	40	1	40	40	1	40	40	1	40	41	1	41
Queanbeyan 66 kV Essential Energy	62	6	62	63	6	63	64	6	64	64	6	65	62	6	63	62	6	63	62	6	63	62	6	62	62	6	62	62	6	62
Queanbeyan 66 kV Evoenergy	23	4	23	23	4	23	23	4	23	23	4	23	23	4	23	23	4	23	23	4	23	23	4	23	23	4	23	23	4	23
Queanbeyan 132 kV	9	-2	10	11	-2	11	12	-3	12	13	-3	13	17	-4	17	19	-4	19	21	-5	21	23	-5	23	24	-6	25	26	-6	27
Snowy Adit 132 kV	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Stockdill 132 kV Evoenergy	0	0	0	148	25	150	147	25	149	147	26	149	146	26	148	146	26	148	146	26	148	146	26	148	146	26	148	146	26	148
Tumut 66 kV	32	13	35	32	13	35	32	13	35	32	13	35	32	13	35	33	13	35	33	13	35	33	13	35	33	13	35	33	13	35
Wagga 66 kV	77	7	77	77	7	77	77	7	77	77	7	77	77	7	77	77	7	77	77	7	77	77	7	77	77	7	77	77	7	77
Wagga North 132 kV	56	-11	57	56	-11	57	74	-14	75	74	-14	75	74	-14	75	74	-14	75	74	-14	75	74	-14	75	74	-14	75	74	-14	75
Wagga North 66 kV	23	3	23	23	3	23	23	3	23	26	3	27	26	3	27	26	3	27	26	3	27	26	3	27	26	3	27	26	3	27
Williamsdale 132 kV Evoenergy	205	39	209	204	39	208	203	38	207	202	38	206	201	38	205	200	38	204	201	38	205	201	38	205	201	38	205	201	38	205
Yanco 33 kV	38	5	39	38	5	39	39	5	39	39	5	39	39	5	39	39	5	39	39	5	39	39	5	40	39	5	40	40	5	40
Yass 66 kV	15	-3	16	15	-3	16	16	-3	16	16	-3	16	16	-3	16	16	-3	17	16	-3	17	17	-3	17	17	-3	17	17	-3	17

Table A2.11: Major industrial customers – Sum of individual summer maximum demands

	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2027/28	2029/30
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Industrial Loads	1129	1129	1188	1218	1229	1251	1253	1270	1274	1278

Table A2.12: Major industrial customers – Sum of individual winter maximum demands

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Industrial Loads	1027	1111	1105	1167	1200	1208	1230	1232	1249	1253

Appendix 3

How we plan

Our network investment process is designed to respond to the changing needs of stakeholders and ensure the efficient delivery of our capital program.

A3.1. Network investment process

The network investment process adopted at TransGrid includes the following:

- An integrated, whole-of-business approach to capital program management;
- Optimisation of investments, and operating and maintenance costs, while meeting augmentation and asset management requirements;
- Early resolution of key risk areas such as environmental approvals, property acquisition and scope definition in the project delivery process; and
- Documented options evaluations and project scoping to enhance transparency.

The key processes and steps, including where and how we engage with stakeholders, are set out in the figure below.

Figure A3.1: Planning Methodology

		TransGrid planning process	Stakeholder involvement
STAGE 1	Identify need	Look at demand forecasts, expected generation patterns and the condition of existing assets. Will there be a shortfall in supply if we do nothing?	Sense-check forecasts with • Distributors • Directly connected customers • AEMO Seek feedback from end users and their representatives on need assessment.
STAGE 2	Review options	Identify possible network and non-network options to fulfil the need, including: • Demand management • Local or distributed generation • Network infrastructure optimised to expected requirements • Improved operational and maintenance regimes.	Input from large energy users, service providers and experts on potential for non-network options. Communicate with local community that may be impacted by network infrastructure.
STAGE 3	Plan in detail	Request proposals and undertake investment analysis on most viable options.	Encourage proposals from market participants for non-network options. Engage impacted communities in network corridor selection, if relevant. Involve end users and their representatives in final investment decision.
STAGE 4	Implement solution	Enter into contracts for network or non-network solutions. Build or renew network infrastructure, if required.	Work with impacted community to support best local outcomes. Report progress in meeting identified need to end users and their representatives.

Planning approach

As a TNSP, we are obliged to meet the requirements of the NER. In particular, we are obliged to meet the requirements of clause S5.1.2.1:

> *'Network Service Providers must plan, design, maintain and operate their transmission networks and distribution networks to allow the transfer of power from generating units to Customers with all facilities or equipment associated with the power system in service and may be required by a Registered Participant under a connection agreement to continue to allow the transfer of power with certain facilities or plant associated with the power system out of service, whether or not accompanied by the occurrence of certain faults (called 'credible contingency events').'*

The NER sets out the required processes for developing networks as well as minimum performance requirements of the network and connections to the network. It requires us to consult with Registered Participants and interested parties and to apply the AER's Regulatory Investment Test – Transmission (RIT-T) as appropriate to development proposals.

Our planning obligations are interlinked with the reliability obligations placed on DNSPs in NSW. We must ensure that the network is adequately planned to enable these licence requirements to be met.

We plan the network to achieve supply at least cost to the community, without being constrained by state borders or ownership considerations.

The approach to network planning includes consideration of non-network options, including demand side response and demand management and/or embedded generation, as an integral part of the planning process. Joint planning with DNSPs, directly supplied industrial customers, generators and interstate TNSPs is carried out to ensure that the most economic options, whether network options or non-network options, consistent with customer and community requirements are identified and implemented.

Jurisdictional planning requirements

In addition to meeting the requirements of the NER, environmental legislation and other statutory instruments, we are required to comply with the Electricity Transmission Reliability Standards 2017, which came into effect on 1 July 2018. The standards use an economic probabilistic-based framework to determine the appropriate level of reliability for each of our bulk supply points. This TAPR has been prepared in accordance with our obligations in the standards.

The new probabilistic approach to determining the reliability standard at each of our bulk supply points has allowed us to develop alternate network plans with greater net market benefit, as demonstrated by using the cost-benefit methodology defined in the RIT-T process.

In fulfilling our obligations, we recognise specific customer requirements as well as AEMO's role as system operator for the NEM. We consider the following circumstances based on the demonstration of greater net market benefit than the requirement to merely comply with the new standard:

- Where agreed with a distribution network owner or major directly connected end-use customer, agreed levels of supply interruption can be accepted for particular single outages, before augmentation of the network is undertaken (for example, the situation with radial supplies);
- Where requested by a distribution network owner or major directly connected end-use customer and agreed with us, there will be no inadvertent loss of load (other than load which is interruptible or dispatchable) following events more onerous than N–1 such as concurrent outages of two network elements; and
- The main transmission network should have sufficient capacity to accommodate AEMO's operating practices without inadvertent loss of load (other than load which is interruptible or dispatchable) or uneconomic constraints on the energy market. AEMO's operating practices include the re-dispatch of generation and ancillary services following a first contingency, such that within 30 minutes the system will again be 'secure' in anticipation of the next critical credible contingency.

These jurisdictional requirements and other obligations require the following to be observed in the planning process:

- At all times when the system is either in its normal state with all elements in service or following a credible contingency:
  - Electrical and thermal ratings of equipment will not be exceeded;
  - Stable control of the interconnected system will be maintained, with system voltages maintained within acceptable levels;
- A quality of electricity supply at least to NER requirements is to be provided;
- A standard of connection to individual customers as specified by Connection Agreements is to be provided;
- As far as possible connection of a customer is to have no adverse effect on other connected customers;
- Environmental and social objectives are to be satisfied;
- Acceptable safety standards are to be maintained; and
- The power system in NSW is to be developed at the lowest cost possible whilst meeting the constraints imposed by the above factors.

A further consideration is the provision of sufficient capability in the system to allow components to be maintained in accordance with our asset management strategies.

Also, consistent with a responsible approach to the managing environmental impacts, the planning approach is also aimed at reducing system energy losses where it is economic to do so.

National planning requirements

AEMO has the role of the national transmission planner and is required to produce a NTNDP and ISP. The ISP, which incorporates elements of NTNDP, has regard to jurisdictional planning and regulatory documents (such as TAPRs) and, in turn, the jurisdictional planning bodies need to have regard to the NTNDP/ISP in formulating their plans. The 2020 ISP is currently under development and our plans are consistent with the development of the 2020 ISP.

The network planning process

The network planning process is undertaken at three levels:

1. Connection planning

Connection planning is focussed on local electricity networks that are directly related to the connection of loads and generators. Connection planning typically includes connection enquiries and the formulation of draft connection agreements leading to a preliminary review of the capability of connections. Further discussions are held with specific customers where there is a need for augmentation or for provision of new connection points.

2. Network planning within the NSW region

The main 500 kV, 330 kV and 220 kV transmission system is planned and developed in response to overall load growth and generation developments and may also be influenced by interstate power transfers through interconnections with other regions in the NEM. Any proposed developments are assessed through liaison with affected NSW and interstate parties using the joint planning processes.

The assessment of the adequacy of 132 kV bulk supply transmission systems requires that joint planning be undertaken in conjunction with DNSPs. This ensures that development proposals are optimal with respect to both transmission and distribution requirements, leading to the lowest possible overall network costs to the end customer. This is particularly important where the DNSP's network operates in parallel with the transmission network.

3. Inter-regional planning

The development of interconnectors between regions and of augmentations within regions that have a material effect on inter-regional power transfer capability are coordinated with network owners in other states in accordance with Clause 5.14.3 of the NER.

Consideration of non-network alternatives

Where economic to do so, our planning process includes consideration and adoption of non-network alternatives which can address the emerging constraints, and which may defer or cancel the need for some network augmentations. These opportunities are assessed on a case-by-case basis.

Compliance with NER requirements

Our approach to the development of the network since the commencement of the NEM is in accordance with the NER, other rules and guidelines published by the AER and the AEMC.

Planning horizons and reporting

Transmission planning is carried out over a short-term time frame of one to seven years, medium-term time frames of seven to 15 years and long-term time frames of 15 to 50 years. The short-term planning supports commitments to network developments with relatively short lead-times. The medium-term planning looks at currently emerging technologies and their impact on the power system. The long-term planning considers options for future major developments and provides a framework for the orderly and economic development of the transmission network and the strategic acquisition of critical line and substation sites.

In this TAPR, the constraints that appear over long-term time frames are considered to be indicative. The timing and capital cost of possible network options to relieve them may change as system conditions evolve.

Identifying network constraints and assessing possible solutions

An emerging constraint is identified during various planning activities covering the relevant planning horizon. It may be identified through:

- Our planning activities, including joint planning with DNSPs;
- The impact of network developments undertaken by other TNSPs;
- The impact of prospective generation developments;
- The occurrence of constraints affecting generation dispatch in the NEM; or
- As a result of a major load development.

During the initial planning phase, a number of options for addressing the constraint are developed. In accordance with NER requirements, consultation with interested parties is carried out to determine a range of options including network, demand management and local generation options and/or to refine existing network development options.

A cost-effectiveness or cost-benefit analysis is carried out, whereby the costs and benefits of each option are compared in accordance with the RIT–T process. The cost and benefit factors may include:

- Avoiding unserved energy caused by either a generation shortfall or inadequate transmission capability or reliability;
- Reduction in greenhouse gas emissions or increased capability to apply low emissions plant;
- Loss reductions;
- Alleviating constraints affecting generation dispatch;
- Avoiding the need for generation developments;
- More efficient generation and fuel type alternatives;
- Improvement in marginal loss factors;
- Deferral of related transmission works; and
- Reduction in operation and maintenance costs.

Options with similar net present value would be assessed with respect to factors that may not be able to be quantified and/or included in the RIT–T, but nonetheless may be important from environmental or operational viewpoints.

These factors include, but may not be limited to:

- Improvement in quality of supply above minimum requirements; and
- Improvement in operational flexibility.

Application of power system controls and technology

We seek to take advantage of the latest proven technologies in network control systems and electrical plant where it may be economic to do so. For example, the application of SVCs has had a considerable impact on the power transfer capabilities of parts of the main grid, and in the past has deferred or removed the need for higher cost transmission line developments.

System protection schemes have been applied in several areas of the NSW system to reduce the impact of network limitations on the operation of the NEM, and to facilitate the removal of circuits for maintenance.

The broad approach to planning and consideration of these technologies, together with related issues of protection facilities, transmission line design, substation switching arrangements and power system control and communication, is set out in the following sections. This approach is in line with international practice and provides a cost effective means of maintaining a safe, reliable, secure and economic supply system consistent with maintaining a responsible approach to environmental and community impacts.

A3.2 Planning criteria

Our planning obligations specify the minimum and general technical requirements in a range of areas including:

- A definition of the minimum level of credible contingency events to be considered for a specified allowance of unserved energy in a year;
- The power transfer capability during the most critical single element outage. This can range from zero in the case of a single element supply to a portion of the normal power transfer capability;
- Frequency variations;
- Magnitude of power frequency voltages;
- Voltage fluctuations;
- Voltage harmonics;
- Voltage unbalance;
- Voltage stability;
- Synchronous stability;
- Damping of power system oscillations;
- Fault clearance times;
- The need for two independent high speed protection systems; and
- Rating of transmission lines and equipment.

In addition to adherence to the NER and regulatory requirements, our transmission planning approach takes into account the historical performance of the components of the NSW system, the sensitivity of loads to supply interruption, and state-of-the-art asset maintenance procedures. It has also been recognised that there is a need for an orderly development of the system taking into account the requirement to meet future load and generation developments.

A set of criteria, detailed below, are applied as a point of first review, from which point a detailed assessment of each individual case is made.

Main transmission network

The NSW main transmission system is the transmission system connecting the major power stations and load centres and providing the interconnections from NSW to QLD and VIC. It includes the majority of the transmission system operating at 500 kV, 330 kV and 220 kV.

Power flows on the main transmission network are subject to overall State load patterns and the dispatch of generation within the NEM, including interstate export and import of power. AEMO applies operational constraints on generator dispatch to maintain power flows within the capability of the NSW and other regional networks. These constraints are based on the ability of the networks to sustain credible contingency events that are defined in the NER. These events mainly cover forced outages of single generation or transmission elements, but also provide for multiple outages to be redefined as credible from time to time. Constraints are often based on short-duration loadings on network elements, on the basis that generation can be re-dispatched to relieve the line loading within 15 minutes.

The rationale for this approach is that, if operated beyond a defined power transfer level, credible contingency disturbances could potentially lead to system-wide loss of load with severe social and economic impact.

Following any transmission outage, for example during maintenance or following a forced line outage for which line reclosure[59] has not been possible, AEMO applies more severe constraints within a short adjustment period, in anticipation of the impact of a further contingency event. This may require:

- The re-dispatch of generation and dispatchable loads;
- The redistribution of ancillary services; and
- Where there is no other alternative, the shedding (interruption) of load.

AEMO may direct the shedding of customer load, rather than operate for a sustained period in a manner where overall security would be at risk for a further contingency.

The risk is, however, accepted over a period of up to 30 minutes. We consider AEMO's imperative to operate the network in a secure manner.

The planning for the main network concentrates on the security of supply to load connection points under sustained outage conditions, consistent with the overall principle that supply to load connection points must be satisfactory after any single contingency.

The main 500 kV, 330 kV and 220 kV transmission system is augmented in response to the overall load growth and generation requirements and may be influenced by interstate interconnection power transfers. Any developments include negotiation with affected NSW and interstate parties including AEMO to maintain power flows within the capability of the NSW and other regional networks.

The reliability of the main system components and the ability to withstand a disturbance to the system are critically important in maintaining the security of supply to NSW customers. A high level of reliability implies the need for a robust transmission system. The capital cost of this system is balanced by:

- Avoiding the large cost to the community of widespread shortages of supply;
- Providing flexibility in the choice of economical generating patterns;
- Allowing reduced maintenance costs through easier access to equipment; and
- Minimising electrical losses which also provides benefit to the environment.

The planning of the main system must take into account the risk of forced outages of a transmission element coinciding with adverse conditions of load and generation dispatch. Two levels of load forecast (summer and winter) are considered, as follows.

Loads at or exceeding a one in two year probability of occurrence (50% POE)

The system will be able to withstand a single contingency under all reasonably probable patterns of generation dispatch or interconnection power flow. In this context, a single contingency is defined as the forced outage of a single transmission circuit, generating unit, transformer, reactive plant or a busbar section.

Provision is made for a prior outage (following failure) of a single item of reactive plant.

Further, the system will be able to be secured by re-dispatching generation (AEMO action), without the need for pre-emptive shedding (interruption) of load, so as to withstand the impact of a second contingency.

Loads at or exceeding a one in ten year probability of occurrence (10% POE)

The system will be able to withstand a single contingency under a limited set of patterns of generation dispatch or interconnection power flow.

Further, the system will be able to be secured by re-dispatching generation (AEMO action), without the need for pre-emptive load shedding, so as to withstand the impact of a second contingency.

These criteria do not apply to radial sections of the main system.

The patterns of generation applied to the 50% POE load level cover patterns that are expected to have a relatively high probability of occurrence, based on the historical performance of the NEM and modelling of the NEM generation sources into the future. The limited set of patterns of generation applied to the 10% probability of exceedance load level cover two major power flow characteristics that occur in NSW. The first power flow characteristic involves high output from base-load generation sources throughout NSW and high import to NSW from QLD. The second power flow characteristic involves high import to NSW from VIC, southern and south west NSW generation coupled with high output from the NSW base-load generators.

Under all conditions there is a need to achieve adequate voltage control capability. We have traditionally assumed that all online generators can provide reactive power support within their rated capability. However, in the future, we intend to align with other utilities in relying only on the reactive capability given by performance standards. Reactive support beyond the performance standards may need to be procured under network support arrangements.

A further consideration is the provision of sufficient capability in the system to allow components to be maintained in accordance with our asset management strategies.

Supply in NSW is heavily dependent on base load coal fired generation in the Hunter Valley, the western area and Central Coast. These areas are interconnected with the load centres via numerous single and double circuit lines. In planning the NSW system, taking into account AEMO's operational approach to the system, there is a need to consider the risk and impact of overlapping outages of circuits under high probability patterns of load and generation.

The analysis of network adequacy must take into account the probable load patterns, typical dispatch of generators and loads, the availability characteristics of generators (as influenced by maintenance and forced outages), energy limitations and other factors relevant to each case.

Options to address an emerging inability to meet all connection point loads would be considered with allowance for the lead time for a network augmentation solution.

Before this time, consideration may be given to the costs involved in re-dispatch in the energy and ancillary services markets to manage single contingencies. In situations where these costs appear to exceed the costs of a network augmentation, this will be brought to the attention of network load customers for consideration. We may then initiate the development of a network or non-network solution through a consultation process.

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[59] TransGrid lines have automatic systems to return them to service (reclose them) following a fault.

Relationship with inter-regional planning

We monitor the occurrence of constraints in the main transmission system that affects generator dispatch. Our planning therefore considers the scope for network augmentations to reduce constraints that may satisfy the RIT-T.

Under the provisions of the NER, a Region may be created where constraints to generator dispatch are predicted to occur with reasonable frequency when the network is operated in the 'system normal' (all significant elements in service) condition. The creation of a Region does not consider the consequences to load connection points if there should be a network contingency.

The capacity of interconnectors that is applied in the market dispatch is the short-time capacity determined by the ability to maintain secure operation in the system normal state in anticipation of a single contingency. The operation of the interconnector at this capacity must be supported by appropriate ancillary services. AEMO does not operate on the basis that the contingency may be sustained but - considers the impact of a prolonged plant outage.

As a consequence, it is probable that for parts of the network that are critical to the supply of loads, we would initiate augmentation, if needed, to meet the new NSW Electricity Transmission Reliability and Performance Standard 2017 before the creation of a new Region.

The development of interconnectors between regions is undertaken where the augmentation satisfies the RIT-T. The planning of interconnections is undertaken in consultation with the jurisdictional planning bodies of the other states.

It is not planned to maintain the capability of an interconnector where relevant network developments would not satisfy the RIT-T.

Networks supplied from the main transmission network

Some parts of the network are primarily concerned with supply to local loads and are not significantly impacted by the dispatch of generation (although they may contain embedded generators). The loss of a transmission element within these networks does not have to be considered by AEMO in determining network constraints, although ancillary services may need to be provided to cover load rejection in the event of a single contingency.

Supply to major load areas and sensitive loads

The NSW system contains six major load areas: Northern; Newcastle and Central Coast; Greater Sydney; Central; Southern; and South Western NSW.

Some of these load areas, including individual smelters, are supplied by a limited number of circuits, some of which may share double circuit line sections. It is strategically necessary to ensure that significant individual loads and load areas are not exposed to loss of supply in the event of multiple circuit failures for an extended duration of time. As a consequence, it is necessary to assess the impact of contingency levels that exceed the specified level of redundancy and expected unserved energy for the respective network nodes.

Outages of network elements for planned maintenance must also be considered. Generally this requires 75% of the maximum load to be supplied during the outage. While every effort is made to secure supplies in the event of a further outage, this may not be always possible. In this case attention is directed to minimising the duration of the plant outage.

Urban and suburban areas

Generally, urban and suburban networks are characterised by a high load density served by high capacity underground cables and relatively short transmission lines. The connection points to the network are usually the low voltage (132 kV) busbars of 330 kV substations. There may be multiple connection points and significant capability on the part of the DNSP to transfer load between connection points, either permanently or to relieve short-time loadings on network elements after a contingency.

The focus of joint planning with DNSPs is the capability of the meshed 330/132 kV system and the capability of the existing connection points to meet expected maximum loadings. Joint planning addresses the need for augmentation to the meshed 330/132 kV system and the connection point capacity or to provide a new connection point where this is the most economic overall solution.

Consistent with good international practice, supply to high-density urban and central business districts is given special consideration. For example, the inner Sydney metropolitan network serves a large and important part of the State load. Supply to this area is largely via 330 kV and 132 kV underground cable network. The 330 kV cables are part of our network and the 132 kV cables are part of Ausgrid's network.

The criterion applied to the Inner Sydney area is consistent with that applied in the electricity supply to major cities throughout the world. Most countries use an N–2 criterion, whereas some countries apply an N–1 criterion with some selected N–2 contingencies that commonly include two cables sharing the one trench or a double circuit line. This is similar to the approach adopted previously in NSW. Using the probabilistic approach specified under the NSW Electricity Transmission Reliability Standard 2017, supply to the Inner Sydney load is required to be designed for Category 3 level of redundancy[60] and maximum unserved energy allowance corresponding to 0.6 minute per year at average demand[61].

Also, it should be noted that the reliability criteria (redundancy level and unserved energy allowance per year) at bulk supply points outside the Inner Sydney area are less onerous than those for Inner Sydney area.

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[60] NSW Electricity Transmission Reliability and Performance Standard 2017 Clause 3

[61] NSW Electricity Transmission Reliability and Performance Standard 2017 Clause 4

Outages of network elements for planned maintenance must are also considered. Generally this requires 75% of the maximum load to be supplied during an outage.

While every effort is made to secure supplies in the event of a further outage, this may not always be possible. In this case attention is directed to minimising the duration of the outage.

Non-urban areas

Generally, these areas are characterised by lower load densities and, generally, lower reliability requirements than urban systems. The areas are sometimes supplied by relatively long, often radial, transmission systems. Connection points in those areas are either on 132 kV lines or on the low voltage busbars of 132 kV substations. Although there may be multiple connection points to a DNSP, they are often far apart and there may be little capacity for power transfer between them. Frequently supply limitations may apply to the combined capacity of several supply points together.

The focus of joint planning with DNSPs usually relates to:

- Augmentation of connection point capacity;
- Duplication of radial supplies;
- Extension of the 132 kV system to reinforce or replace existing lower voltage systems and to reduce losses; and
- Development of a higher voltage system to provide major augmentations and to reduce network losses.

Supply to one or more connection points is sometimes considered to require augmentation when the transmission network supplying the load does not provide the specified redundancy level or the probability of unserved energy (i.e function of network failure rate, restoration duration and average load) at the end of the planning horizon exceeds the specified reliability criteria.

As a result of the application of the criteria, some radial parts of the 330 kV and 220 kV network are not able to withstand the forced outage of a single circuit line at time of maximum load, and in these cases provision is made for under-voltage load shedding.

Provision is also required for the maintenance of the network. Additional redundancy in the network is required where maintenance cannot be scheduled without causing load restrictions or an unacceptable level of risk to the security of supply.

Transformer augmentation

In considering the augmentation of transformers, appropriate allowance is made for the transformer cyclic rating[62] and the practicality of load transfers between connection points. Allowance is made for the outage of a single transformer (or single-phase unit) or a transmission line that supports the load carried by the transformer.

Provision is also required for the maintenance of transformers. This has become a critical issue at a number of sites in NSW where there are multiple transformers in service. To enable maintenance to be carried out, additional transformer capacity or a means of transferring load to other supply points via the underlying lower voltage network may be required.

Consideration of low probability events

Although there is a low probability that supply to loads may need to be interrupted as a result of system disturbances, no power system can be guaranteed to deliver a firm capability 100% of the time, particularly when subjected to disturbances that are severe or widespread. It is also possible that extreme loads, above the level allowed for in planning, can occur, usually under extreme weather conditions.

The NSW network contains numerous lines of double circuit construction and, whilst the probability of overlapping outages of both circuits of a line is very low, the consequences could be widespread supply disturbances.

Thus there is a potential for low probability events to cause localised or widespread disruption to the power system. These events can include:

- Loss of several transmission lines within a single corridor, as may occur during bushfires;
- Loss of a number of cables sharing a common trench;
- Loss of more than one section of busbar within a substation, possibly following a major plant failure;
- Loss of a number of generating units; or
- Occurrence of three-phase faults[63], or faults with delayed clearing.

In our network, appropriate facilities and mechanisms are put in place to minimise the probability of such events and to lessen their impact. The decision process considers the underlying economics of facilities or corrective actions, taking account of the low probability of the occurrence of extreme events.

We take measures, where practicable, to minimise the impact of disturbances to the power system by implementing power system control systems at minimal cost in accordance with the NER.

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[62] Transformer nominal ratings are based on them carrying a constant load. However, loads are often cyclic (they vary throughout the day). In these cases transformers may be able to carry more than their nominal rating for a short period around the time of the maximum load as they are loaded less heavily before and after that period. A cyclic loading takes this into account.

[63] Alternating current power systems generally have three phases. Faults on those systems can involve one, two or all three of those phases. Faults involving three phases are generally the most onerous.

A3.3 Protection requirements

Basic protection requirements are included in the NER. The NER requires that protection systems be installed so that any fault can be detected by at least two fully independent protection systems. Backup protection is provided against circuit breaker failure. Provision is also made for detecting high resistance earth faults.

Required protection clearance times are specified by the NER and determined by stability considerations as well as the characteristics of modern power system equipment. Where special protection facilities or equipment are required for high-speed fault clearance, they are justified on either NER compliance or a benefit/cost basis.

All modern distance protection systems on the main network include the facility for power swing blocking (PSB). PSB is utilised to control the impact of a disturbance that can cause synchronous instability. At the moment PSB is not enabled, except at locations where demonstrated advantages apply. This feature has become increasingly more important as the interconnected system is developed and extended.

A3.4 Transient stability

In accordance with the NER, transient stability is assessed on the basis of the angular swings following a solid fault on one circuit at the most critical location that is cleared by the faster of the two protections (with intertrips assumed in service where installed). The determination of the transient stability capability of the main grid is undertaken using software that has been calibrated against commercially available system dynamic analysis software.

To assess this at the main system level a two phase-to-ground fault is applied. On 132 kV systems, which are to be augmented, a three-phase fault is applied.

Recognition of the potential impact of a three-phase fault at the main system level is made by instituting maintenance and operating precautions to minimise the risk of such a fault.

Where transient stability is a factor in the development of the main network, preference is given to the application of advanced control of the power system or high-speed protection systems, before consideration is given to the installation of high capital cost plant.

A3.5 Steady state stability

The requirements for the control of steady state stability are included in the NER. For planning purposes, steady state stability (or system damping) is considered adequate under any given operating condition if, after the most critical credible contingency, simulations indicate that the halving time of the least damped electromechanical mode of oscillation is not more than five seconds.

The determination of the steady state stability performance of the system is undertaken using software that has been calibrated against commercially available software and from data derived from the monitoring of system behaviour.

In planning the network, maximum use is made of existing plant, through the optimum adjustment of plant control system settings before consideration is given to the installation of high capital cost plant.

A3.6 Line and equipment thermal ratings

Line thermal ratings have often traditionally been based on a fixed continuous rating and a fixed short-time rating. We apply probabilistic-based line ratings, which are dependent on the likelihood of coincident adverse weather conditions and unfavourable loading levels. This approach has been applied to selected lines whose design temperatures are about 100°C or less. For these lines, a contingency rating and a short-time emergency rating have been developed. Typically, the short-time rating is based on a load duration of 15 minutes, although the duration can be adjusted to suit the particular load pattern to which the line is expected to be exposed. The duration and level of loading takes into account any requirements for re-dispatch of generation or load control.

Ambient condition monitors have been installed on a number of transmission lines to enable the application of real-time line conductor ratings in the generation dispatch systems.

Transformers are rated according to their specification. Provision is also made for use of the short-time capability of the transformers during the outage of a parallel transformer or transmission line.

The 330 kV cables are rated according to the manufacturer's recommendations and have been checked against an appropriate thermal model of the cable.

The rating of line terminal equipment is based on the manufacturers' advice.

A3.7 Reactive support and voltage stability

It is necessary to maintain voltage stability, with voltages within acceptable levels, following the loss of a single element in the power system at times of maximum system loading. The single element includes a generator, a single transmission circuit, a cable and single items of reactive support plant.

To cover fluctuations in system operating conditions, uncertainties of load levels, measurement errors and errors in the setting of control operating points, it is necessary to maintain a margin from operating points that may result in a loss of voltage control. A reactive power margin is maintained over the point of voltage instability or alternatively a margin is maintained with respect to the power transfer compared to the maximum feasible power transfer.

The system voltage profile is set to standard levels during generator dispatch to minimise the need for post-contingency reactive power support.

Reactive power plant generally has a low cost relative to major transmission lines, and the incremental cost of providing additional capacity in a shunt capacitor bank can be relatively low. Such plant can also have a very high benefit/cost ratio and therefore the timing of reactive plant installations is generally less sensitive to changes in load growth than the timing of other network augmentations. Even so, the aim is to make maximum use of existing reactive sources before new installations are considered.

We have traditionally assumed that all online generators can provide reactive power support within their rated capability. However, now the assumption is aligned with other utilities in relying only on the reactive capability given by agreed performance standards of the generator. Reactive support beyond the performance standards may need to be procured under network support arrangements.

Reactive power plant is installed to support planned power flows up to the capability defined by limit equations, and is often the critical factor determining network capability.

On the main network, allowance is made for the unavailability of a single major source of reactive power support in the critical area affected at times of high load, but not at the maximum load level.

It is also necessary to maintain control of the supply voltage to the connected loads under minimum load conditions.

The factors that determine the need for reactive plant installations are:

- In general it has proven prudent and economic to limit the voltage change between the pre- and post-contingency operating conditions;
- It has also proven prudent, in general, and economic to ensure that the post-contingency operating voltage at major 330 kV busbars lies above a lower limit;
- The reactive margin from the point of voltage collapse is maintained to be greater than a minimum acceptable level;
- A margin between the power transmitted and the maximum feasible power transmission is maintained; and
- At times of light system load, it is essential to ensure that voltages can be maintained within the system highest voltage limits of equipment.

Following forced outages, relatively large voltage changes are accepted at some locations on the main network, and agreed with customers, providing voltage stability is not placed at risk. These voltage changes can approach, and in certain cases, exceed 10% at maximum load.

On some sections of the network, the possibility of loss of load due to depressed voltages following a contingency is also accepted. However, there is a preference to install load shedding initiated by under-voltage so that the disconnection of load occurs in a controlled manner.

When determining the allowable rating of switched reactive plant, the requirements of the NER are observed.

A3.8 Transmission line voltage and conductor sizes determined by economic considerations

Consideration is given to the selection of line design voltages within the standard nominal 132 kV, 220 kV, 275 kV, 330 kV and 500 kV range, taking due account of transformation costs.

Minimum conductor sizes are governed by losses, radio interference and field strength considerations.

We strive to reduce the overall cost of energy and network services by the economic selection of line conductor size. The actual losses that occur are governed by generation dispatch in the market.

For a line whose design is governed by economic loading limits, the conductor size is determined by a rigorous consideration of capital cost versus loss costs.

Hence the impact of the development on generator and load marginal loss factors in the market is considered.

For other lines, the rating requirements will determine the conductor requirements.

Double circuit lines are built in place of two single circuit lines where this is considered to be both economic and is able to provide adequate reliability. Consideration is given to the impact of a double circuit line failure, both over relatively short terms and for extended durations. This means that supply to a relatively large load may require single rather than double circuit transmission line construction where this is environmentally acceptable.

In areas prone to bushfire, any parallel single circuit lines are preferably routed well apart to avoid the risk of simultaneous outage during a bushfire event.

A3.9 Short-circuit rating requirements

Substation high voltage equipment is designed to withstand the maximum expected short circuit duty in accordance with the applicable Australian Standard.

Operating constraints are enforced to ensure equipment is not exposed to fault duties beyond the plant ratings.

In general, the short circuit capability of all of the plant at a site would be designed to match or exceed the maximum short circuit duty at the relevant busbar. In order to achieve cost efficiencies when augmenting an existing substation, the maximum possible short circuit duty on individual substation components may be calculated and applied in order to establish the adequacy of the equipment.

Short circuit duty calculations are based on the following assumptions:

- All main network generators that are capable of operating, as set out in connection agreements are assumed to be in service;
- All generating units that are embedded in distribution networks are assumed to be in service;
- The maximum fault contribution from interstate interconnections is assumed;
- The worst-case pre-fault power flow conditions are assumed;
- Normally open connections are treated as open;
- Networks are modelled in full;
- Motor load contributions are not modelled at load substations; and
- Generators are modelled as a constant voltage behind sub-transient reactance.

At power station switchyards, allowance is made for the contribution of the motor component of loads. Further analysis of the impact of the motor component of loads is performed and this is done to assess the need to include such contributions when assessing the adequacy of the rating of load substation equipment.

A3.10 Substation configurations

Substation configurations are adopted that provide acceptable reliability at minimum cost, consistent with the overall reliability of the transmission network. In determining a switching arrangement, consideration is also given to:

- Site constraints;
- Reliability expectations with respect to connected loads and generators;
- The physical location of 'incoming' and 'outgoing' circuits;
- Maintenance requirements;
- Operating requirements; and
- Transformer arrangements.

The following configurations are being applied:

- Single busbar;
- Double busbar;
- Multiple element mesh; and
- Breaker-and-a-half.

In general, at main system locations, a mesh or breaker-and-a-half arrangement are the preferred minimum-requirement standard configurations.

Where necessary, the expected reliability performance of potential substation configurations can be compared using equipment reliability parameters derived from local and international data.

The forced outage of a single busbar zone is generally provided for. Under this condition, the main network is planned to have adequate capability although loss of load may eventuate. In general, the forced outage of a single busbar zone should not result in the outage of any baseload generating unit.

Where appropriate, a 330 kV bus section breaker would ordinarily be provided to segregate 'incoming' lines when a second 'incoming' 330 kV line is connected to the substation.

A 132 kV bus section circuit breaker would generally be considered necessary when the maximum load supplied via that busbar exceeds 120 MW. A bus section breaker is generally provided on the low voltage busbar of 132 kV substations when supply to a particular location or area is taken over more than two low voltage feeders.

A3.11 Autoreclosure

As most line faults are of a transient nature, all of our overhead transmission lines are equipped with autoreclose facilities. Slow speed three-pole reclosure is applied to most overhead circuits. On the remaining overhead circuits, under special circumstances, high-speed single-pole autoreclosing may be applied.

For public safety reasons, reclosure is not applied to underground cables.

Autoreclose is inhibited following the operation of breaker-fail protection.

A3.12 Power system control and communication

In the design of the network and its operation to designed power transfer levels, reliance is generally placed on the provision of some of the following control facilities:

- Automatic excitation control on generators;
- Power system stabilisers on generators and SVCs;
- Load drop compensation on generators and transformers;
- Supervisory control over main network circuit breakers;
- Under-frequency load shedding;
- Under-voltage load shedding;
- Under and over-voltage initiation of reactive plant switching;
- High speed transformer tap changing;
- Network connection control;
- Check and voltage block synchronisation;
- Control of reactive output from SVCs; and
- System Protection Schemes (SPS).

The following communication, monitoring and indication facilities are also provided where appropriate:

- Network wide SCADA and Energy Management;
- System (EMS);
- Telecommunications and data links;
- Mobile radio;
- Fault locators and disturbance monitors;
- Protection signalling; and
- Load monitors.

Protection signalling and communication is provided over a range of media including pilot wire, power line carrier, microwave links and, increasingly, optical fibres in overhead earthwires.

A3.13 Scenario planning

Scenario planning assesses network capacity, based on the factors described above, for a number of NEM load and generation scenarios. The process entails:

1. Identification of possible future load growth scenarios. These are developed based on TransGrid's NSW region forecasts along with consideration of respective DNSPs' bulk supply point load forecasts and directly connected customer demand outlook. It considers key data for each scenario to prepare load forecasts for NSW. These are published in the TAPR. The forecast can also incorporate specific possible local developments such as the establishment of new loads or the expansion or closure of existing industrial loads.
2. Development of a number of generation scenarios for each load growth scenario. These generation scenarios relate to the development of new generators and utilisation of existing generators, and considers expected or possible future retirements. This is generally undertaken by a specialist electricity market modelling consultant, using their knowledge of relevant factors, including:
    - Generation costs;
    - Impacts of government policies;
    - Impacts of energy related developments such as gas pipeline projects;
3. Modelling of the NEM for load and generation scenarios to quantify factors which affect network performance, including:
    - Generation from individual power stations;
    - Interconnector flows;
4. Modelling of network performance for the load and generation scenarios utilising the data from market modelling.

The resulting set of scenarios is then assessed over the planning horizon to establish the adequacy of the system and to assess network and non-network augmentation options.

The planning scenarios developed by TransGrid take into account AEMO's outlook stated in its latest ESOO and the scenarios considered in the ISP.

A3.14 Asset management approach

Our Asset Management System (AMS) manages our transmission network assets over their entire lifecycle. The AMS covers management of assets from the planning stage through the build/acquire, operate, maintain, renew and decommissioning stages. Our approach to asset management encompasses our jurisdictional requirements and obligations to meet the service level requirements of our customers, consumers and other stakeholders. Development of our asset renewal program involves assessment of the most economic combination of replacement and refurbishment options.

The AMS has been developed in accordance with the principles of ISO 55001, the international standard for asset management. TransGrid has obtained external certification[64] that this system meets or exceeds the requirements of ISO 55001.

The following figure illustrates our AMS structure under ISO 55001.

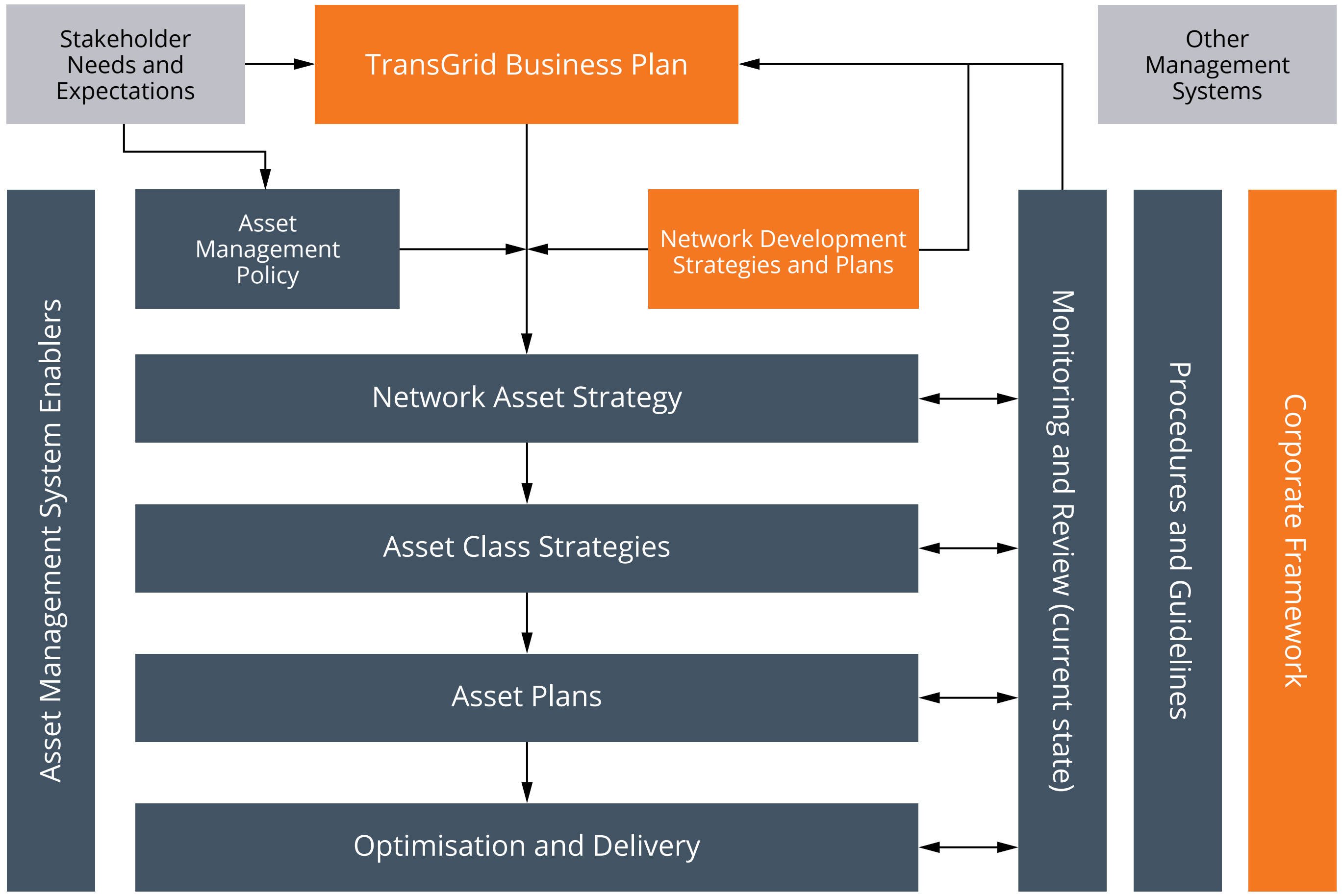

Figure A3.2: Asset Management System (AMS)

The decision-making processes within our AMS have improved through the development of a quantified methodology for assessing risk. This risk assessment methodology combines an understanding of the failure behaviour of an asset (the likelihood), and the expected consequences of failure (the consequence), to value the risk associated with an asset in monetary terms.

This risk management approach ensures that we are managing our significant risks as so far as practicable, or where this is not possible as low as reasonably practicable. The processes for managing key safety risks under this framework are described in our Electricity Network Safety Management System.

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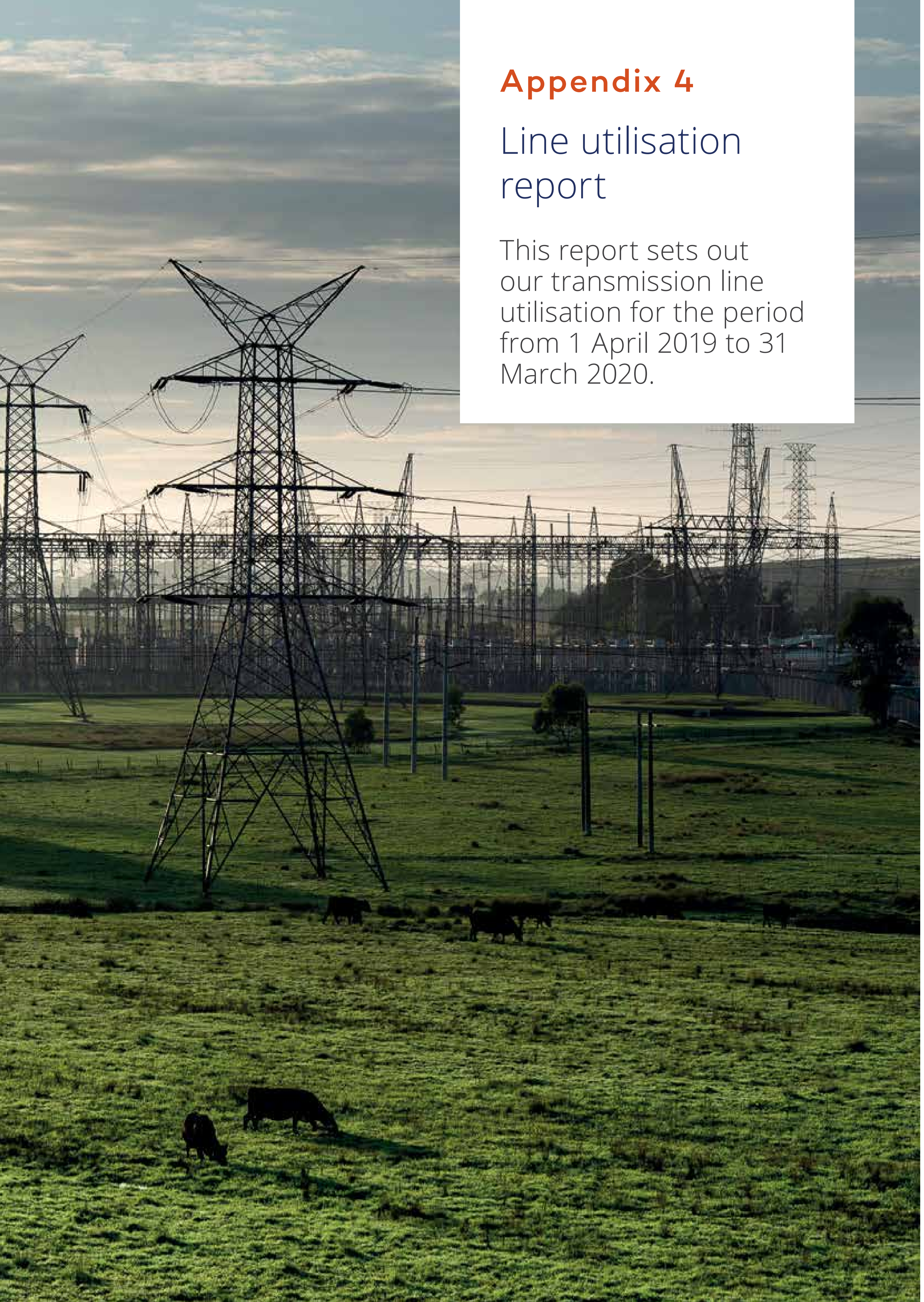
[64] Currently the certification covers the extent of our prescribed NSW-based assets under our NSW operating licence. In practice, we apply the same processes and procedures to all our physical asset related activities.



Appendix 4

Line utilisation report

This report sets out our transmission line utilisation for the period from 1 April 2019 to 31 March 2020.

A4.1 Line utilisation report

The line loading information from 1 April 2019 to 31 March 2020 was obtained from AEMO's Operations and Planning Data Management System (OPDMS). This system produces half hourly system load flow models (snapshots) of the NEM.

For each half-hour period, the utilisation (loading) of each line was calculated as a proportion of the relevant rating.

The highest values of these proportions are reported here.

The utilisation of each line was calculated based on two conditions:

1. With all network elements in service, referred to as the 'N utilisation'. These utilisation figures are based on normal line ratings; and
2. With the most critical credible contingency (usually an outage of another line in the area), referred to as the 'N–1 utilisation'. These utilisation figures are based on the line contingency ratings.

The N utilisation and N–1 utilisation of the transmission lines in the NSW transmission network are shown in **Figures A4.2–9**. For each line, the utilisations are shown in the box placed adjacent to the line. The box shows:

A. The transmission line number;

B. The maximum N utilisation of the transmission line;

C. The maximum N–1 utilisation of the transmission line; and

D. The identity of the line that creates the critical contingency in the event of an outage.

The box layout is shown in **Figure A4.1**.

Figure A4.1: Key to interpreting the information shown in Figures A4.2 to A4.9

A – Line number: B – Maximum N Utilisation % C – Maximum N–1 Utilisation % [D – Line number out for N–1]

In some situations, the N–1 utilisation has been estimated to be more than 100 per cent. These situations could be because of:

- A higher level of line loading being allowed, considering the operational line overloading control schemes, runback schemes available for managing the line loadings, and generation re-dispatch capability by AEMO; and
- The predicted dispatch conditions that change over the five-minute dispatch period, causing the line loadings to increase above the predicted values.

Figure A4.2: TransGrid N and N–1 line utilisations – Sydney and Newcastle

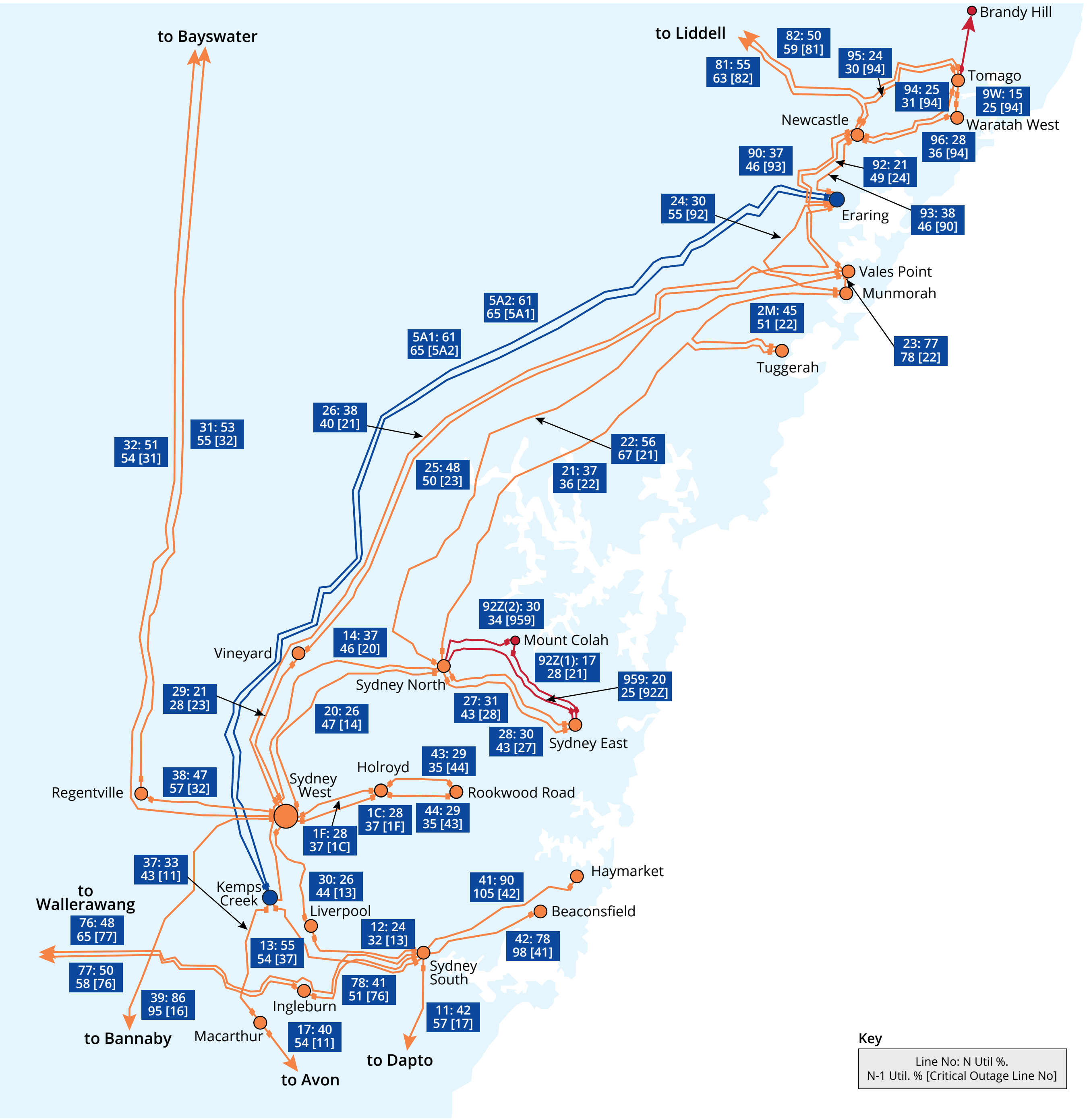


Figure A4.3: TransGrid N and N–1 line utilisations – North East NSW and Northern NSW

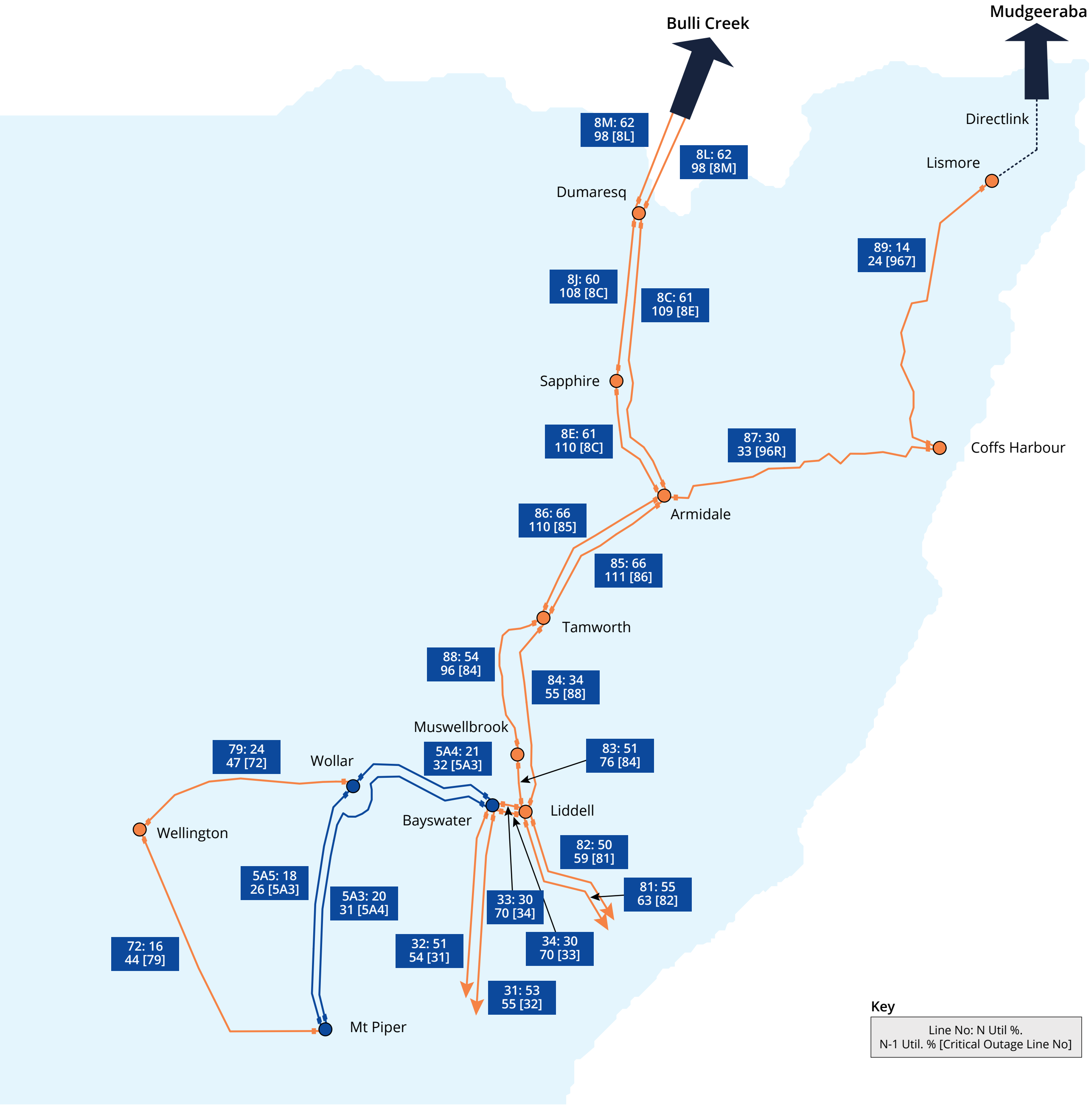
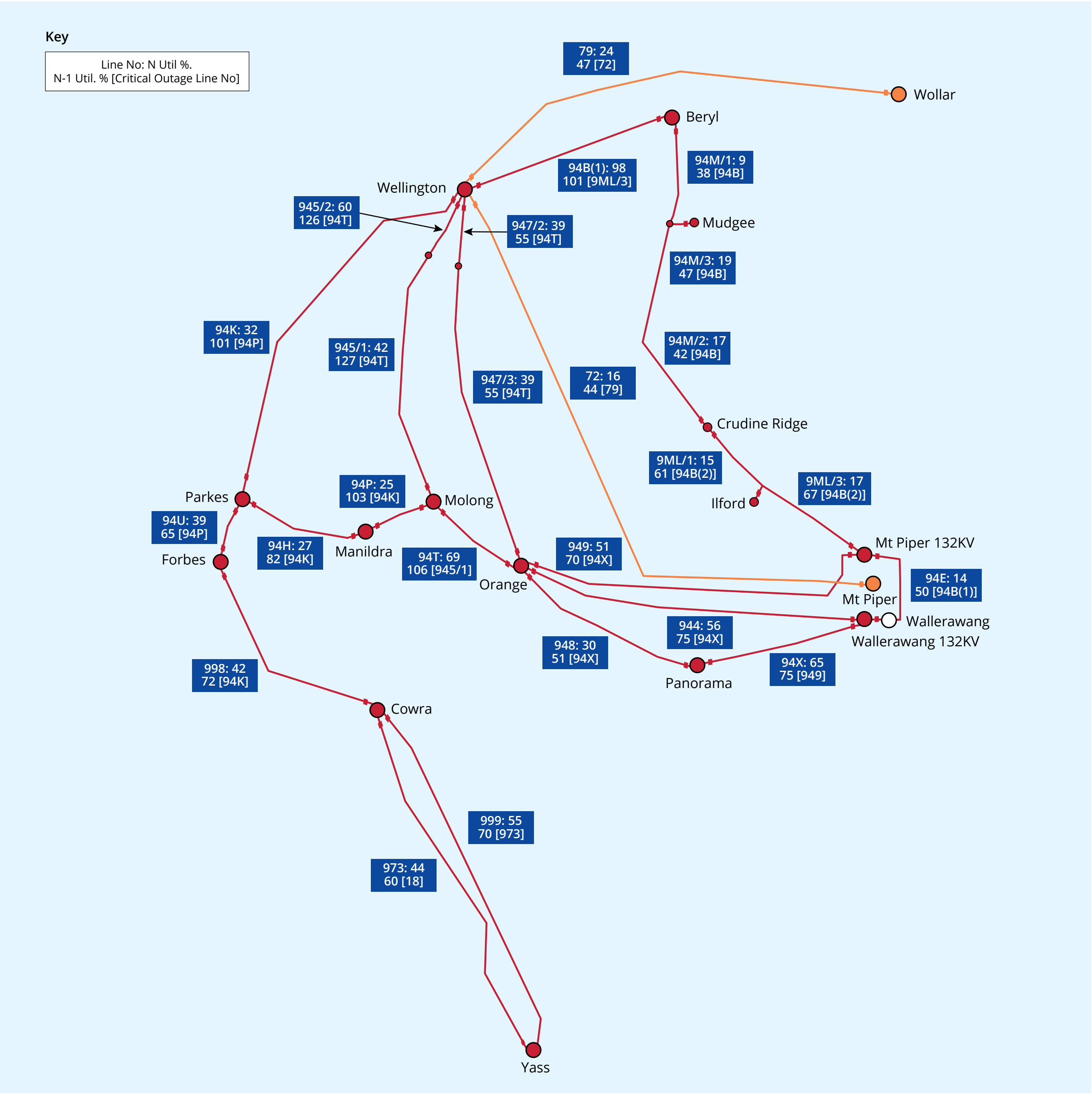


Figure A4.4: TransGrid N and N–1 line utilisations – South and South East

Figure A4.5: TransGrid N and N–1 line utilisations – Far West

Figure A4.6: TransGrid N and N–1 line utilisations – North Coast and North West 132 kV System

Figure A4.7: TransGrid N and N–1 line utilisations – Central West



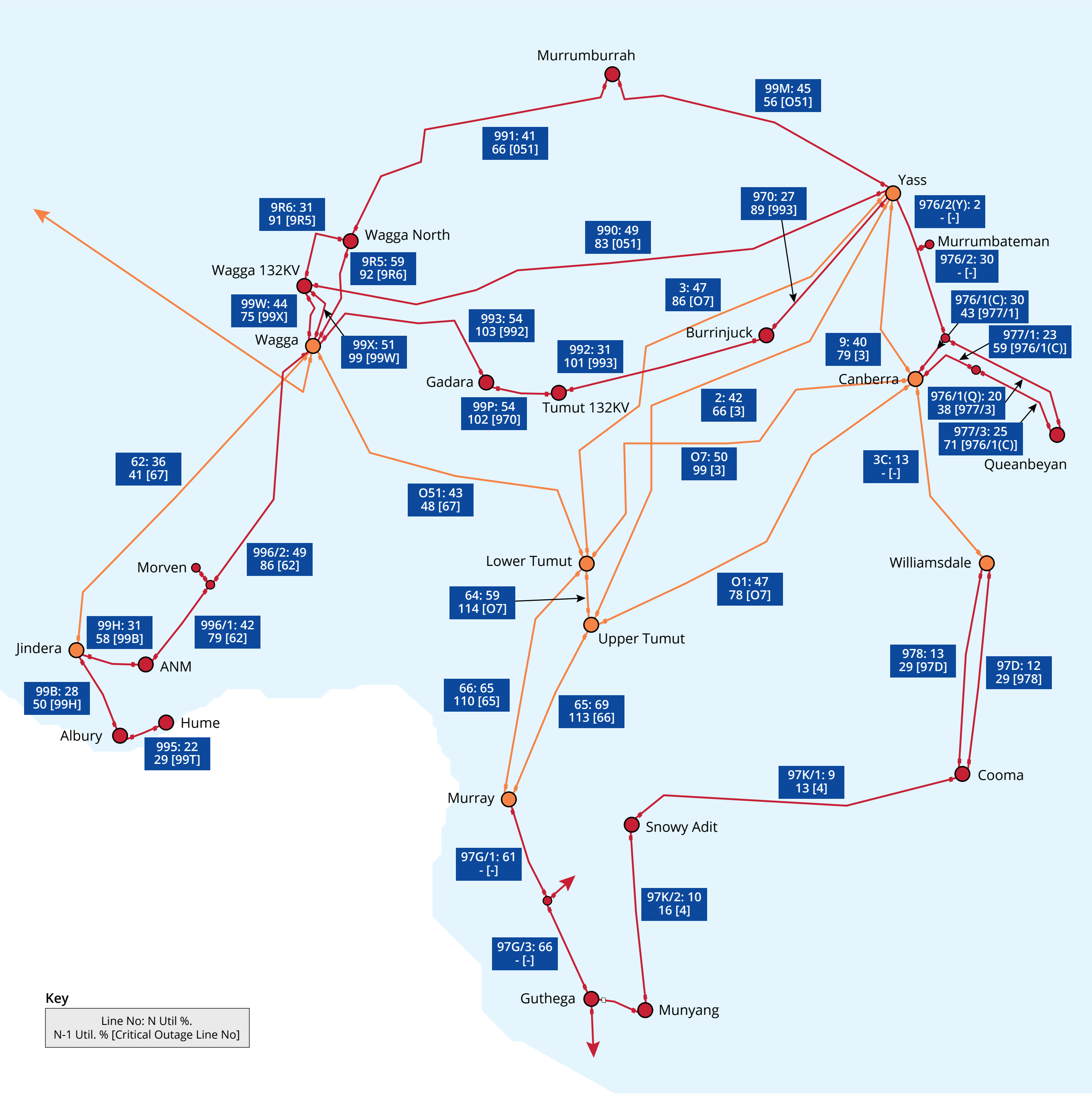


Figure A4.8: TransGrid N and N–1 line utilisations – South East

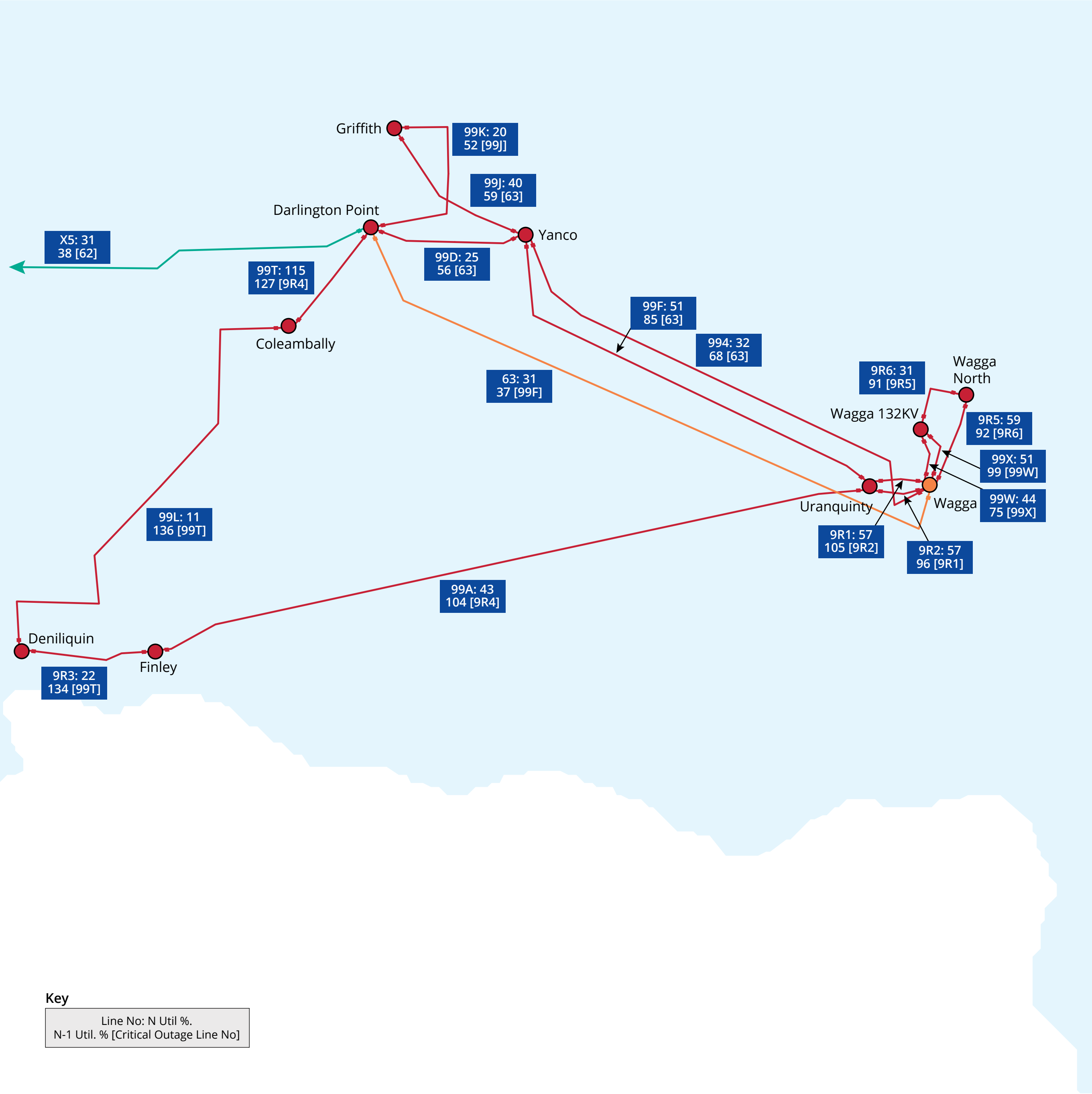


Figure A4.9: TransGrid N and N–1 line utilisations – South West

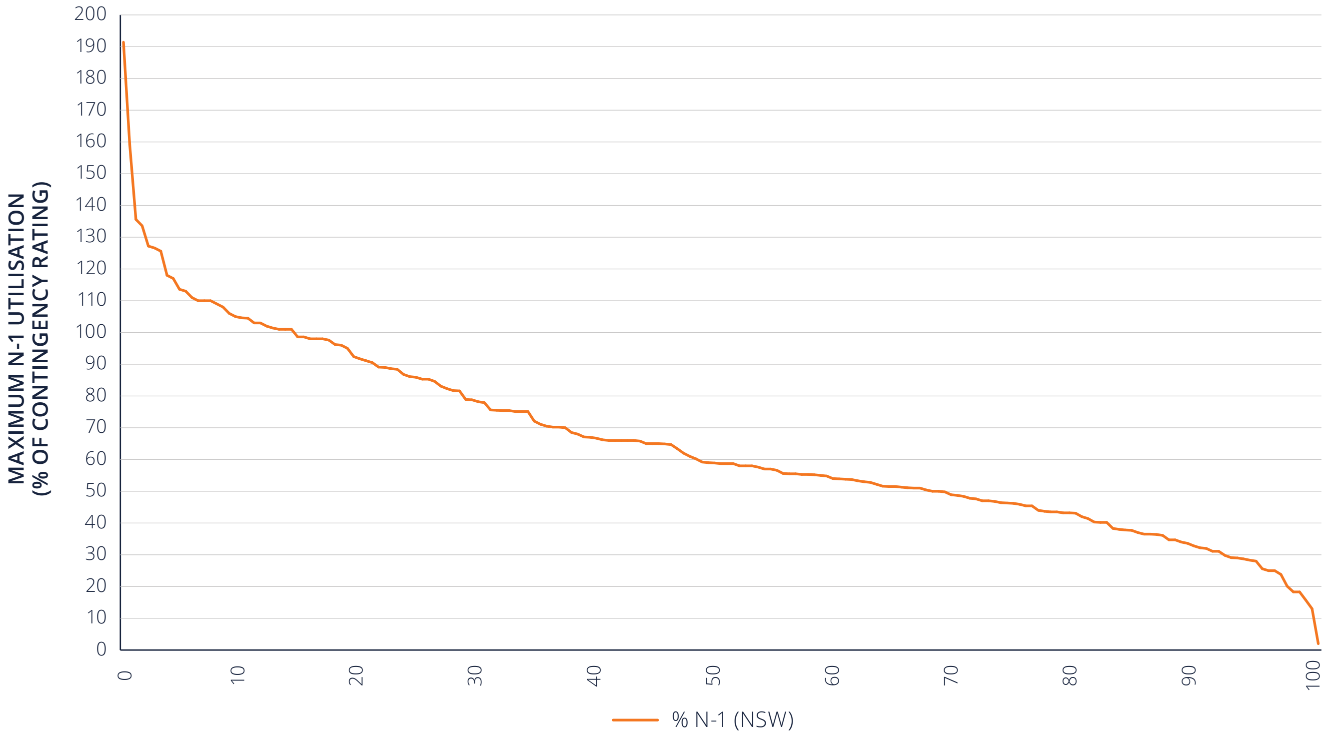
Summary of the N–1 utilisation of the transmission lines in the TransGrid’s network

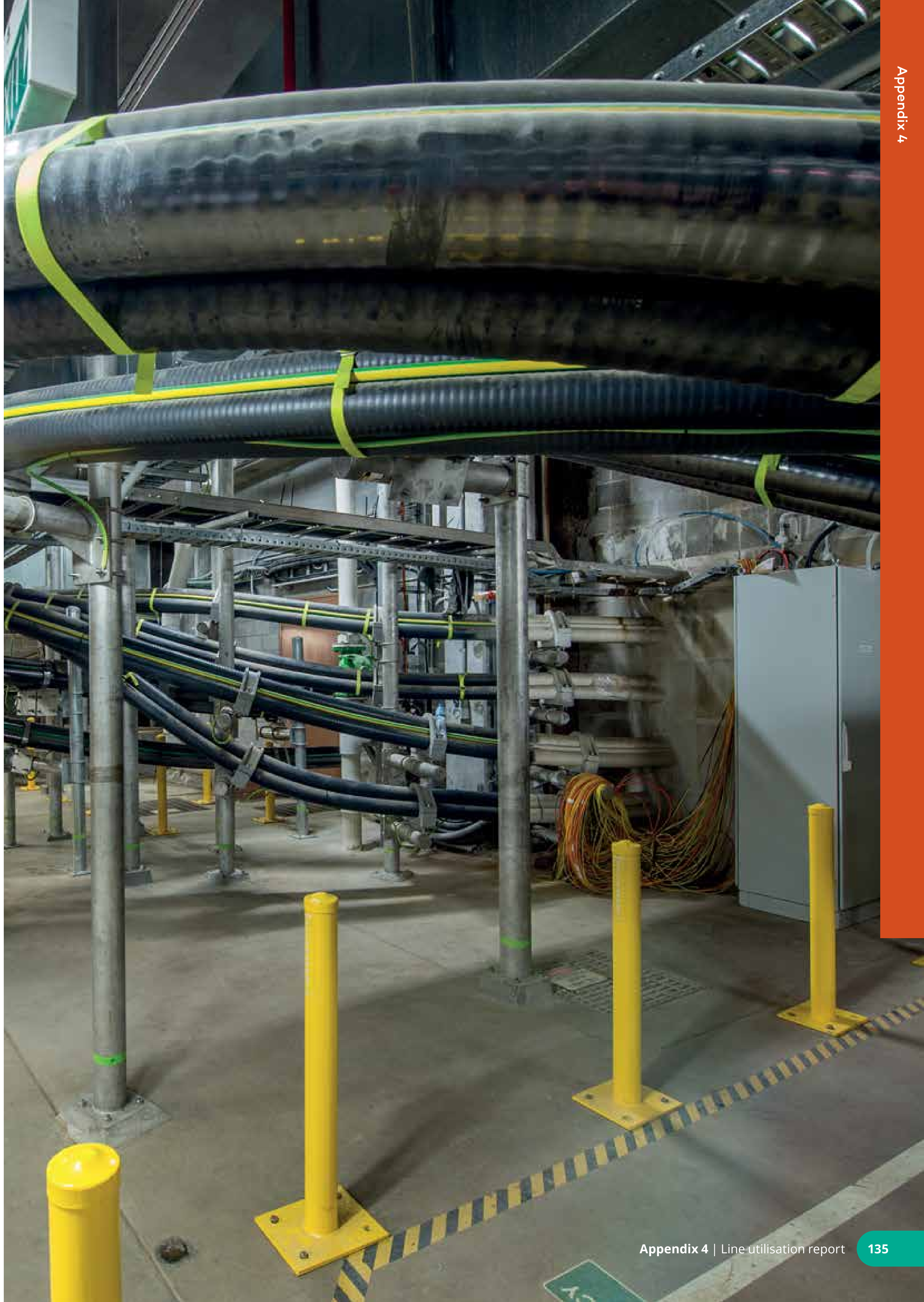
The distribution of the N-1 utilisation of the transmission lines across our network is shown in **Figure A4.10**.

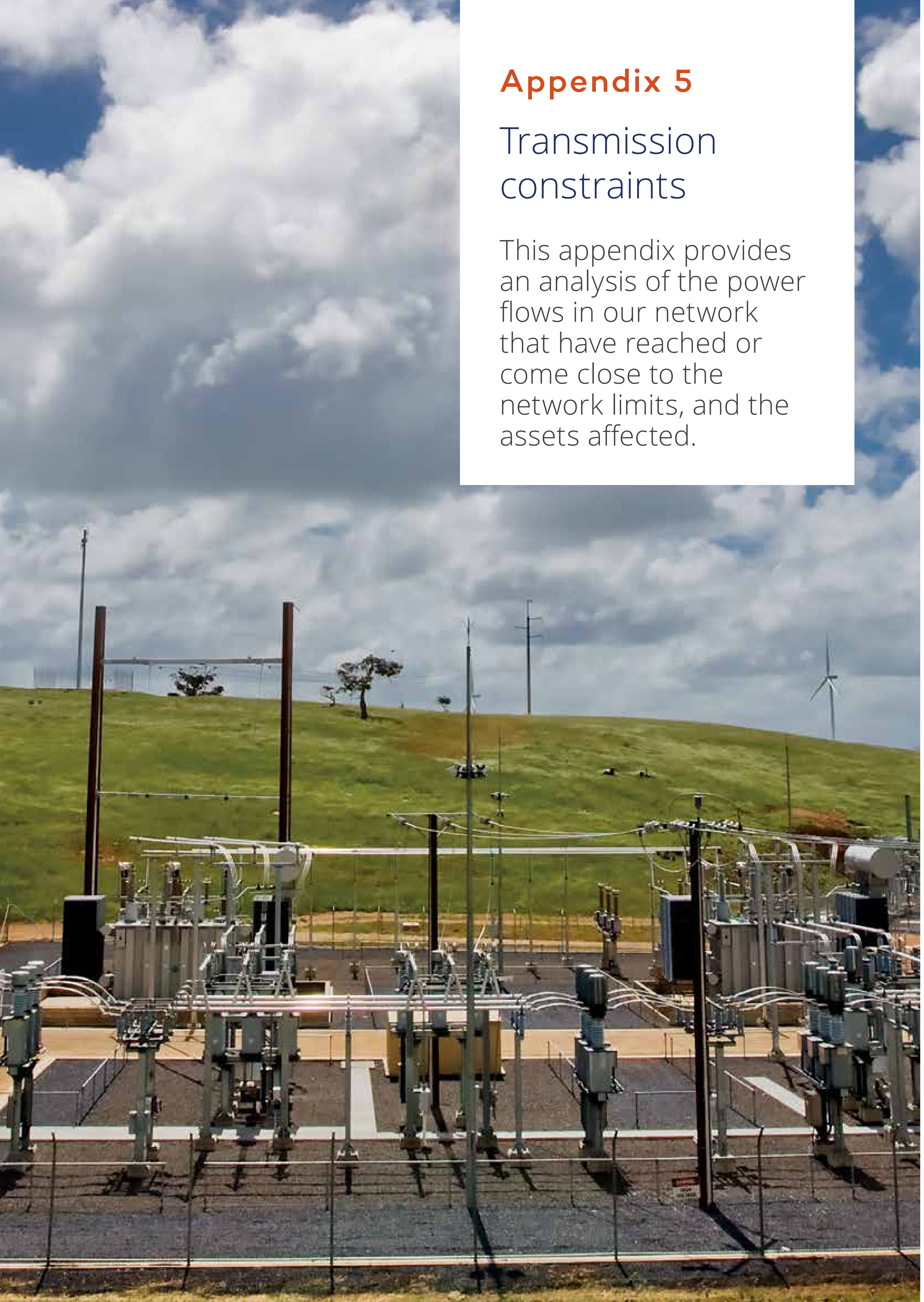
The distribution shows that approximately 14 per cent of the transmission lines in the network are utilised at more than their installed maximum capacity and over half of the lines are utilised at more than 68 per cent of their installed capacity.

The distribution of the N–1 line utilisations reflects at least 40 years of planning history of the transmission network. It is considered to be typical of a well-planned network where various parts of the network are well-established, while other parts have had recent step augmentations that will be further utilised in future years.

Figure A4.10: Distribution of TransGrid N–1 utilisations (1 April 2019-31 March 2020)







Appendix 5

Transmission constraints

This appendix provides an analysis of the power flows in our network that have reached or come close to the network limits, and the assets affected.

A5.1 Introduction

This appendix describes an analysis of how close the flows in our network are to its capacity limits. It identifies the transmission elements where flows have been at, or close to, the limits.

Capacity could be limited due to the power flows reaching:

- The maximum rating of a single transmission element, such as a transmission line or a transformer;
- The combined capacity of a group of transmission elements, such as several parallel transmission lines constituting inter regional links; and
- The limits set by system wide considerations such as voltage, transient or oscillatory stability.

TransGrid provides the capability of its transmission network to AEMO. AEMO manages the power flows in the transmission network to be within the capability of the declared limits of the individual assets or the capability of the transmission system. AEMO does so by automatically adjusting the quantity of generation dispatched, so that the transmission flows will be maintained under the prevailing operating conditions, including the flows to be expected under credible unplanned outages.

The optimal generation dispatch, the dispatch which minimises total cost while ensuring the capability limits of the transmission system are not violated, is determined using the National Electricity Market Dispatch Engine (NEMDE). The capability limits are included within NEMDE as mathematical equations, which are known as the 'Constraint Equations'. Each constraint equation has a unique identifier, and contains information including the capability limit and the factors which describe or determine the limiting power flows, such as power flow in a transmission line or generator power outputs, which contribute to the limiting power flow.

The constraints reported here cover the transmission system capability limitation experienced during the period 1 March 2019 to 29 February 2020.

A5.2 Transmission system performance – Binding duration

Table A5.1 summarises the top 20 constraints where higher cost generation may have been dispatched because some transmission elements or parts of the transmission network have reached their maximum capability. The table shows the constraint identifier, its description, type of limitation addressed by the constraint equation, and length of the time period where the transmission element, or the part of the transmission system, was operated at its maximum capability for the 12 month period (1 March 2019 – 29 February 2020).

Table A5.1: Constraints operating at the capability limit

Rank	Constraint ID	Total duration (dd:hh:mm)	Type	Impact	Reason
1	N^^V_NIL_1	72:17:40	Voltage Stability	Vic - NSW Interconnector + Generators	Avoid voltage collapse at Southern NSW for loss of the largest Vic generating unit or Basslink
2	Q^^NIL_QNI_SRAR	34:20:25	Voltage Stability	Qld Generation + Interconnectors	Avoid voltage instability on trip of Sapphire to Armidale (8E) 330 kV line
3	N>N-NIL_CLDP_1	31:19:05	Thermal	NSW Generation	Avoid O/L Coleambally to Darlington Point 132 kV line (99T) on Nil trip
4	Q::N_NIL_AR_2L-G	7:18:55	Transient Stability	NSW Generation + Interconnectors	Avoid transient instability for a 2L-G fault at Armidale
5	V^^N_NIL_1	6:14:25	Voltage Stability	Vic - NSW Interconnector + Generators	Avoid voltage collapse around Murray for loss of all APD potlines
6	N^^Q_NIL_B1	5:14:15	Voltage Stability	Qld Generation + Interconnectors	Avoid voltage collapse on loss of Kogan Creek generator
7	V^^SML_NSWRB_2	4:01:30	Voltage Stability	Victorian Generation + Interconnectors	Avoid voltage collapse for loss of either the Darlington Point to Balranald or Balranald to Buronga 220 kV lines
8	N>N-NIL_MBDU	2:22:15	Thermal	Terranora Interconnector	Avoid overloading Mullumbimby to Dunoon 132 kV line (9U6 or 9U7) on trip of other Mullumbimby to Dunoon

Rank	Constraint ID	Total duration (dd:hh:mm)	Type	Impact	Reason
9	N>N-NIL_LSDU	2:14:40	Thermal	Terranora Interconnector	Avoid overloading Lismore to Dunoon 132 kV line (9U6 or 9U7) on trip of other Lismore to Dunoon
10	V>>N-NIL_HA	2:06:55	Thermal	Victorian Generation + Interconnectors	Avoid O/L Murray to Upper Tumut (65) on Murray to Lower Tumut (66) trip
11	N>N-NIL_DC	2:05:35	Thermal	NSW Generation + Interconnectors	Avoid O/L Armidale to Tamworth (85 or 86) on trip of the other Armidale to Tamworth line (85 or 86)
12	V^SML_BUDP_3	1:22:25	Voltage Stability	Victorian Generation + Interconnectors	Avoid voltage collapse for loss of Bendigo to Kerang 220 kV line, X3 line out
13	N^^V_BUDP_1	1:12:00	Voltage Stability	Vic - NSW Interconnector + Generators	Avoid voltage collapse at Darlington Point for loss of the largest Vic generating unit or Basslink, X3 line out
14	N^N_CHLS_1	1:06:15	Voltage Stability	Terranora Interconnector	Avoid voltage collapse on trip of Koolkhan to Lismore (967) line, 89 line out
15	N^^Q_NIL_A	1:05:25	Voltage Stability	NSW - Qld (QNI) Interconnector + Directlink	Avoid voltage collapse on loss of Liddell to Muswellbrook (83) line
16	N^N-LS_SVC	1:01:45	Voltage Stability	Terranora Interconnector	Avoid voltage collapse on trip of Armidale to Coffs Harbour (87) line, Lismore SVC out
17	Q:N_1078	1:00:50	Oscillatory Stability	NSW - Qld (QNI) Interconnector	QNI oscillatory stability limit
18	N::V_UTYS_2	0:20:45	Transient Stability	Vic - NSW Interconnector + Generators	Avoid transient instability for fault at various location between Yass and South Morang area, 2 line out
19	V::N_HWSM_V1	0:20:25	Transient Stability	Victorian Generation + Interconnectors	Prevent transient instability for fault and trip of a HWTS-SMTS 500 kV line in VIC
20	N^^V_CNCW_1	0:16:20	Voltage Stability	Vic - NSW Interconnector + Generators	Avoid voltage collapse at Darlington Point for loss of the largest Vic generating unit or Basslink, 6 line out

The constraints listed in **Table A5.1** above are reviewed by TransGrid to fully understand their nature, and to provide possible solutions to reduce the market impact of the transmission constraints. The solutions for highly ranked constraints impacting the generators, NSW-QLD and VIC-NSW interconnectors are included in our proposed major developments and in subsystem developments described in Sections 2.1.1 and 2.1.2 respectively.

A5.3 Transmission system performance – Market Impact

Table A5.2 summarises the top 20 constraints with the highest market impacts, measured by the marginal value. The table shows the constraint identifier, its description, type of limitation addressed by the constraint equation, the sum of the marginal values of the constraint binding and length of the time period where the transmission element, or the part of the transmission system, was operated at its maximum capability for the 12 month period (1 March 2019 to 29 February 2020).

Table A5.2: Marginal value of binding constraints

Rank	Constraint ID	Sum of Marginal Values	Total duration (dd:hh:mm)	Type	Impact
1	N>N-NIL_CLDP_1	$ 9,796,500.77	31:19:05	Thermal	NSW Generation
2	N^^V_NIL_1	$ 1,208,866.18	72:17:40	Voltage Stability	Vic - NSW Interconnector + Generators
3	Q^^NIL_QNI_SRAR	$ 520,146.58	34:20:25	Voltage Stability	Qld Generation + Interconnectors
4	Q>NIL_MUTE_757	$ 519,362.46	0:13:30	Thermal	Terranora Interconnector
5	VN_ZERO	$ 494,730.49	0:00:35	Interconnector Zero	Vic - NSW Interconnector
6	NQ_VST_ISLE_A	$ 431,877.65	0:04:20	Region Separation	Vic - NSW Interconnector
7	Q::N_NIL_AR_2L-G	$ 373,399.73	7:18:55	Transient Stability	NSW Generation + Interconnectors
8	V^^SML_NSWRB_2	$ 367,682.96	4:01:30	Voltage Stability	Victorian Generation + Interconnectors
9	V>>V-LTWG_RADIAL_2	$ 293,505.53	0:03:10	Thermal	Vic - NSW Interconnector + Generators
10	N_NIL_TE_B	$ 271,764.95	0:14:55	Other	Terranora Interconnector
11	V>>V_NIL_5	$ 199,376.53	0:03:55	Thermal	Victorian Generation + Interconnectors
12	N::V_UTYS_2	$ 177,202.25	0:20:45	Transient Stability	Vic - NSW Interconnector + Generators
13	V>>V_NIL_3	$ 172,448.88	0:04:15	Thermal	Victorian Generation + Interconnectors
14	Q>NIL_MUTE_758	$ 171,763.89	0:05:45	Thermal	Terranora Interconnector
15	N>N-FLML_9R4	$ 138,699.95	0:11:05	Thermal	NSW Generation
16	QNI_SOUTH_1150_DYN	$ 107,068.58	0:05:35	Transient Stability	NSW - Qld (QNI) Interconnector
17	V::V_1900	$ 99,171.48	0:01:10	Oscillatory Stability	Vic - NSW Interconnector + Generators
18	V^^N_NIL_1	$ 90,243.54	6:14:25	Voltage Stability	Vic - NSW Interconnector + Generators
19	NV_0500	$ 49,740.72	0:04:35	Discretionary	Vic - NSW Interconnector
20	N^^V_DDSM1	$ 45,666.57	2:05:05	Voltage Stability	Vic - NSW Interconnector + Generators

A5.4 Possible future transmission system performance

Table A5.3 summarises the maximum demand event for each of NSW, QLD and VIC were analysed for the constraints that were binding (or violating) and the 10 constraints that were closest to binding at the time of the maximum demand in the period 1 March 2019 – 29 February 2020. The constraints that were not binding but close to binding were assessed to identify possible future transmission system limitations.

Table A5.3: Maximum demand event in NSW, QLD and VIC

Region	Max demand	Date and time
NSW	13,717 MW	Saturday 1 February 2020, 16:55
QLD	9,838 MW	Monday 3 February 2020, 17:30
VIC	9,608 MW	Friday 31 January 2020, 16:55

A5.4.1 Maximum demand event in New South Wales

Figure A5.1 shows a NEM overview map on the maximum demand event day in NSW. It summarises the power flow directions when the maximum demand occurred on Saturday 1 February 2020 at 16:55.

Figure A5.1: NEM overview map on Saturday 1 February 2020, 16:55

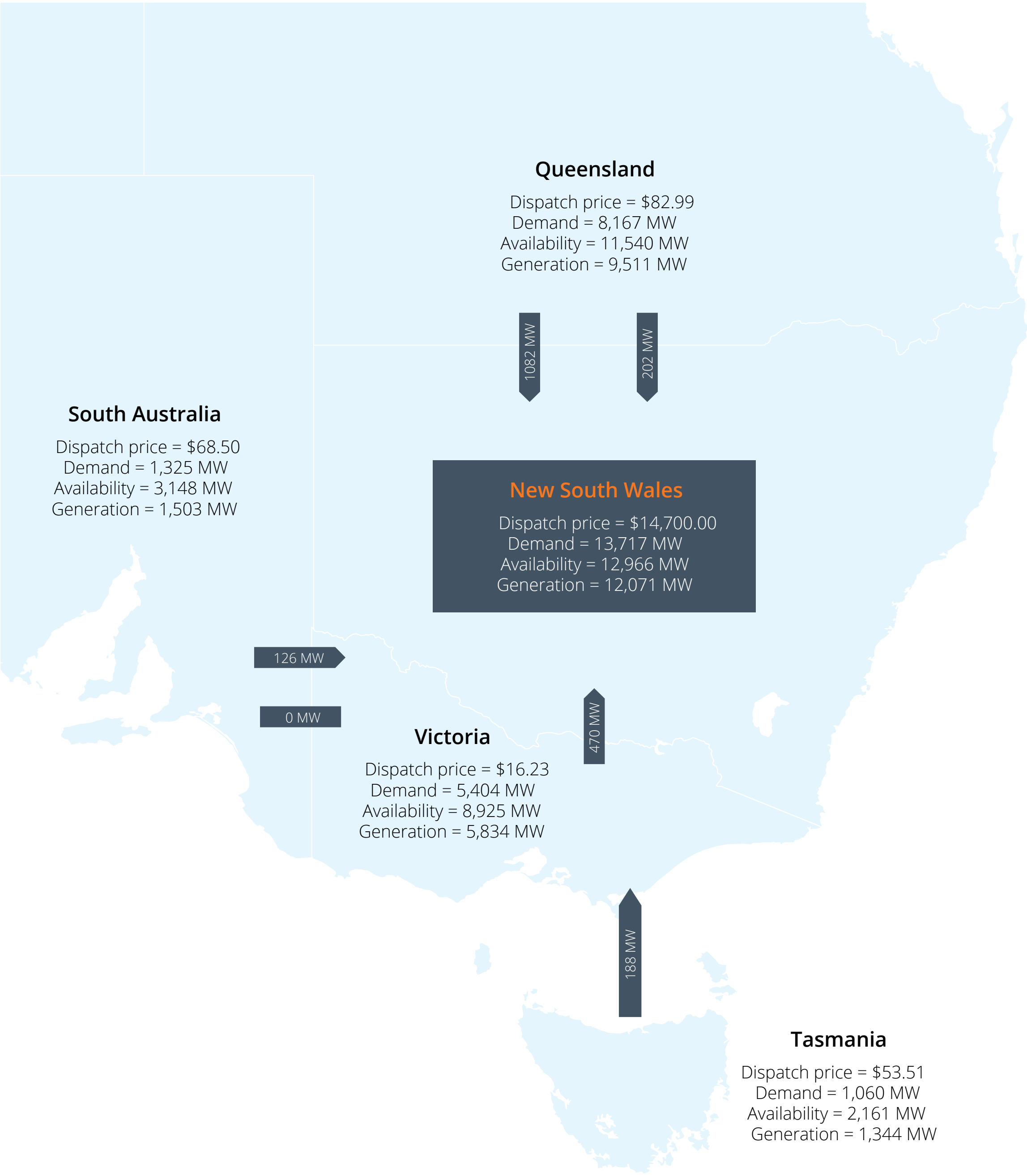


Table A5.4 summarises the NSW binding constraints on the maximum demand day of Saturday 1 February 2020 at 16:55.

Table A5.4: NSW binding constraints on Saturday 1 February 2020, 16:55

Constraint ID	Type	Impact	Reason
N>>N-WGYS_OPEN_4	Thermal	Vic - NSW Interconnector + Generators	Avoid O/L Lower Tumut to Canberra (07) on trip of Lower Tumut to Yass (3) line, Wagga-Yass 132 kV parallel lines Opened
Q^^NIL_QNI_SRAR	Voltage Stability	Qld Generation + Interconnectors	Avoid voltage instability on trip of Sapphire - Armidale (8E) 330 kV line

Table A5.5 summarises the NSW constraints that were close to binding on the maximum demand day of Saturday 1 February 2020 at 16:55.

Table A5.5: NSW constraints that were close to binding on Saturday 1 February 2020, 16:55

Rank	Constraint ID	Headroom (MW)	Type	Impact	Reason
1	N_NIL_TE_B	19.90	Other	Terranora Interconnector	Upper limit on Directlink Qld to NSW
2	N>N-NIL_MBDU	22.73	Thermal	Terranora Interconnector	Avoid overloading Mullumbimby to Dunoon line (9U6 or 9U7) on trip of the other Mullumbimby to Dunoon line (9U7 or 9U6)
3	N>>N-NIL__H_15M	37.60	Thermal	Vic - NSW Interconnector + Generators	Avoid O/L Lower Tumut to Canberra (07) on trip of Lower Tumut to Yass (3)
4	N^^N_NIL_1	50.99	Voltage Stability	Vic - NSW Interconnector + Generators	Avoid voltage instability, maximum northerly flow on 01, 2, 3 and 07 cut-set
5	N>>N-NIL__B_15M	81.20	Thermal	Vic - NSW Interconnector + Generators	Avoid O/L Upper Tumut to Canberra (01) on trip of Lower Tumut to Canberra (07)
6	N>>N-WGYS_OPEN_2	86.49	Thermal	Vic - NSW Interconnector + Generators	Avoid O/L Upper Tumut to Canberra (01) on trip of Lower Tumut to Canberra (07), Wagga - Yass 132 kV parallel opened
7	N>N-NIL_CLDP_1	91.49	Thermal	NSW Generation	Avoid O/L Coleambally to Darlington Point 132 kV line (99T) on Nil trip
8	N>>N-WGYS_OPEN_3	92.85	Thermal	Vic - NSW Interconnector + Generators	Avoid O/L Lower Tumut to Canberra (07) on trip of Upper Tumut to Canberra (01), Wagga - Yass 132 kV parallel opened
9	N>>N-NIL__A_15M	126.53	Thermal	Vic - NSW Interconnector + Generators	Avoid O/L Lower Tumut to Canberra (07) on trip of Upper Tumut to Canberra (01)
10	N>>N-NIL_01N	142.06	Thermal	NSW Generation + Interconnectors	Avoid O/L Canberra to Yass (9) on trip of Kangaroo Valley to Dapto (18)

A5.4.2 Maximum demand event in Queensland

Figure A5.2 shows a NEM overview map on the maximum demand event day in QLD. It summarises the power flow directions when the maximum demand occurred on Monday 3 February 2020 at 17:30.

Figure A5.2: NEM overview map on Monday 3 February 2020, 17:30

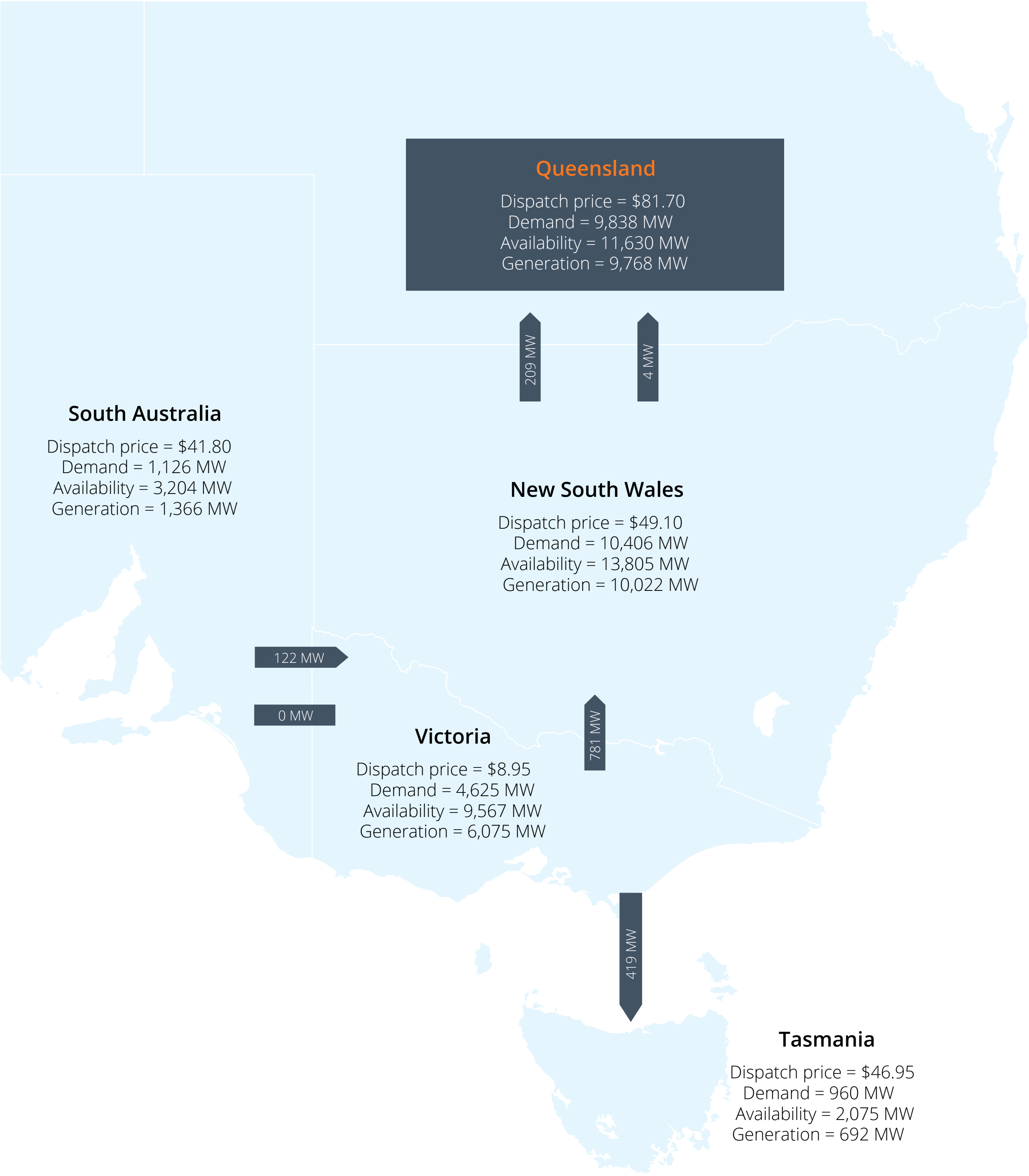


Table A5.6 summarises the NSW binding constraints on the maximum demand day in QLD (Monday 3 February 2020 at 17:30).

Table A5.6: NSW binding constraints on Monday 3 February 2020, 17:30

Constraint ID	Type	Impact	Reason
N>N-NIL_CLDP_1	Thermal	NSW Generation	Avoid O/L Coleambally to Darlington Point 132 kV line (99T) on Nil trip
N^^Q_NIL_B1	Voltage Stability	Qld Generation + Interconnectors	Avoid Voltage Collapse on loss of Kogan Creek
N>N-NIL_LSDU	Thermal	Terranora Interconnector	Avoid overloading Lismore to Dunoon line (9U6 or 9U7) on trip of the other Lismore to Dunoon line (9U7 or 9U6)

Table A5.7 summarises the NSW constraints that were close to binding on the maximum demand day in QLD (Monday 3 February 2020 at 17:30).

Table A5.7: NSW constraints that were close to binding on Monday 3 February 2020, 17:30

Rank	Constraint ID	Headroom (MW)	Type	Impact	Reason
1	N>LSDU9U6_LSDU9U7	29.11	Thermal	Terranora Interconnector	Avoid overloading Lismore to Dunoon line (9U6 or 9U7) on trip of the other Lismore to Dunoon line (9U7 or 9U6)
2	N^^Q_NIL_A	39.47	Voltage Stability	NSW - Qld (QNI) Interconnector + Directlink	Avoid voltage collapse on trip of Liddell to Muswellbrook (83)
3	N>N-NIL_TE_D2	78.23	Thermal	Terranora Interconnector	Avoid O/L of Lismore 330 to Lismore 132 (9U8 or 9U9) for trip of Lismore 330 to Lismore 132 (9U9 or 9U8)
4	N_NIL_TE_A	115.05	Other	Terranora Interconnector	Upper limit on Directlink NSW to Qld
5	N>>N-NIL__3_OPENED	124.12	Thermal	NSW Generation + Interconnectors	Avoid O/L of Liddell to Muswellbrook (83) for trip of Liddell to Tamworth (84)
6	N>>N-NIL__2_OPENED	131.37	Thermal	NSW Generation + Interconnectors	Avoid O/L of Liddell to Tamworth (84) for trip of Liddell to Muswellbrook (83)
7	N>>N-NIL_DPTX_2	186.98	Thermal	NSW Generation + Interconnectors	Avoid overloading a Darlington Point transformer on trip of the other Darlington Point transformer
8	N^^Q_NIL_B4	230.00	Voltage Stability	Qld Generation + Interconnectors	Avoid voltage collapse on loss of Tarong North
9	N_NIL_TE_B	244.95	Other	Terranora Interconnector	Upper limit on Directlink Qld to NSW
10	N^^Q_NIL_B6	249.00	Voltage Stability	Qld Generation + Interconnectors	Avoid voltage collapse on loss of Callide C unit 4

A5.4.3 Maximum demand event in Victoria

Figure A5.3 shows a NEM overview map on the maximum demand event day in VIC. It summarises the power flow directions when the maximum demand occurred on Friday 31 January 2020 at 16:55.

Figure A5.3: NEM overview map on Friday 31 January 2020, 16:55

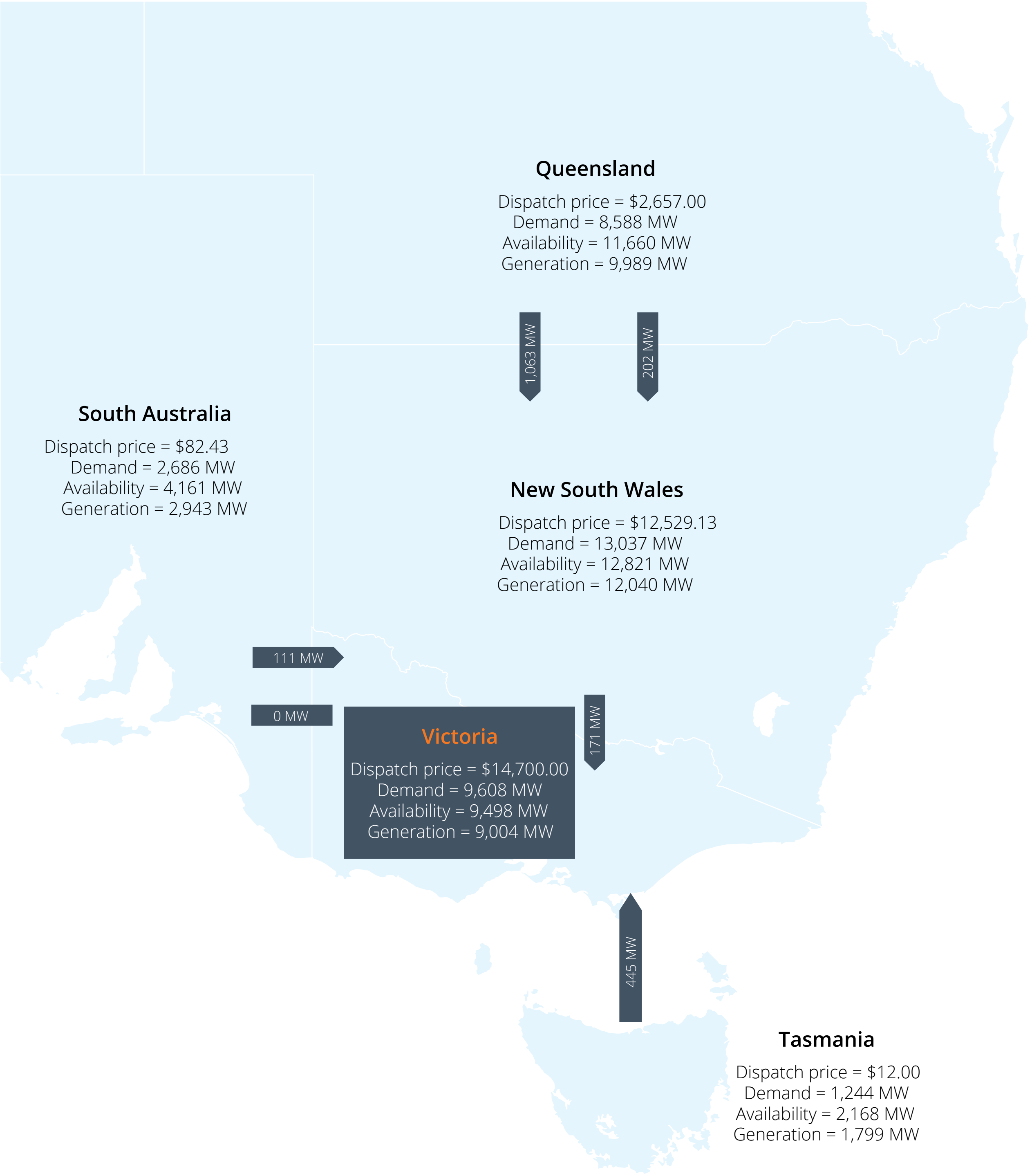


Table A5.8 summarises the NSW binding constraints on the maximum demand day in VIC (Friday 31 January 2020, 16:55).

Table A5.8: NSW binding constraints on Friday 31 January 2020, 16:55

Constraint ID	Type	Impact	Reason
N>N-NIL_CLDP_1	Thermal	NSW Generation	Avoid O/L Coleambally to Darlington Point 132 kV line (99T) on Nil trip

Table A5.9 summarises the NSW constraints that were close to binding on the maximum demand day in VIC (Friday 31 January 2020, 16:55).

Table A5.9: NSW constraints that were close to binding on Friday 31 January 2020, 16:55

Rank	Constraint ID	Headroom (MW)	Type	Impact	Reason
1	N_NIL_TE_B	22.70	Other	Terranora Interconnector	Upper limit on Directlink Qld to NSW
2	N>N-NIL_MBDU	30.20	Thermal	Terranora Interconnector	Avoid overloading Mullumbimby to Dunoon line (9U6 or 9U7) on trip of the other Mullumbimby to Dunoon line (9U7 or 9U6)
3	N>>N-NIL_996_IN	126.76	Thermal	NSW Generation + Interconnectors	Avoid O/L of Wagga to ANM (996) on trip of Wagga to Jindera (62) line
4	N>N-NIL_8J_8C	165.86	Thermal	NSW - Qld (QNI) Interconnector	Avoid O/L of Dumaresq to Sapphire (8J) on trip of Dumaresq to Armidale (8C)
5	N>>N-NIL_8E_8C	176.18	Thermal	Qld Generation + Interconnectors	Avoid O/L of Sapphire to Armidale (8E) on trip of Dumaresq to Armiddale (8C)
6	N>DULS9U6_ LSDU9U7	222.82	Thermal	Terranora Interconnector	Avoid overloading Lismore to Dunoon line (9U6 or 9U7) on trip of the other Lismore to Dunoon line (9U7 or 9U6)
7	N>>N-NIL_DPTX	229.37	Thermal	NSW Generation + Interconnectors	Avoid overloading a Darlington Point transformer on trip of the other Darlington Point transformer
8	N>N-NIL_LSDU	231.04	Thermal	Terranora Interconnector	Avoid overloading Lismore to Dunoon line (9U6 or 9U7) on trip of the other Lismore to Dunoon line (9U7 or 9U6)
9	N>>V-NIL_0X1	271.87	Thermal	NSW Generation + Interconnectors	Avoid O/L Buronga to Redcliff (OX1) on Nil trip
10	N>N-NIL_DC	307.55	Thermal	NSW Generation + Interconnectors	Avoid O/L Armidale to Tamworth (85 or 86) on trip of other Armidale to Tamworth (86 or 85)

Appendix 6

Glossary

Term	Explanation/Comments
AEMC	The Australian Energy Market Commission
AEMO	The Australian Energy Market Operator. Responsible for operation of the NEM and has the role of Victorian Jurisdictional Planning Body (JPB)
AER ('the regulator')	The Australian Energy Regulator
Assets	TransGrid's 'towers and wires', all the substations and electricity transmission lines that make up the network
Augmentation	Expansion of the existing transmission system or an increase in its capacity to transmit electricity
Bulk supply point (BSP)	A point of supply of electricity from a transmission system to a distribution system
Connection point	The agreed point of supply established between the network service provider and another registered participant or customer
Constraint (limitation)	An inability of a transmission system or distribution system to supply a required amount of electricity to a required standard
Consumers	Any end user of electricity including large users, such as paper mills, and small users, such as households
Demand	The total amount of electrical power that is drawn from the network by consumers. This is talked about in terms of 'maximum demand' (the maximum amount of power drawn throughout a given period) and 'total energy consumed' (the total amount of energy drawn across a period)
Demand management (DM)	A set of initiatives that are put in place at the point of end-use to reduce the total and/or maximum consumption of electricity
Direct customers	TransGrid's customers are those directly connected to our network. They are either Distribution Network Service Providers, directly connected generators, large industrial customers, customers connected through inter-regional connections or potential new customers
Distribution Network Service Provider, DNSP (Distributor)	An organisation that owns, controls or operates a distribution system in the National Electricity Market. Distribution systems operate at a lower voltage than transmission systems and deliver power from the transmission network to households and businesses
Easement	A designated area in which TransGrid has the right to construct, access and maintain our assets, while ownership of the property remains with the original land owner
Electricity Statement of Opportunities (ESOO)	A document produced by AEMO that focuses on electricity supply demand balance in the NEM
Embedded generation	A generating unit connected to the distribution network, or connected to a distribution network customer. (Not a transmission connected generator)
Generator	An organisation that produces electricity. Power can be generated from various sources, e.g. coal fired power plants, gas-fired power plants, solar and wind farms
Interconnection	The points on an electricity transmission network that cross jurisdictional/state boundaries
ISP	Integrated System Plan
Jurisdictional Planning Body (JPB)	The organisation nominated by a relevant minister as having transmission system planning responsibility in a jurisdiction of the NEM
Load	The amount of electrical power that is drawn from the network
Local generation	A generation or cogeneration facility that is located on the load side of a transmission constraint
LRET	Large Scale Renewable Energy Target
'N – 1' reliability	The system is planned for no loss of load on the outage of a single element such as a line, cable or transformer
National Electricity Law	Common laws across the states which comprise the NEM, which make the NER enforceable
National Electricity Market (NEM)	The National Electricity Market, covering Queensland, New South Wales, Victoria, South Australia and Tasmania
National Electricity Rules (NER or 'the Rules')	The rules that govern the NEM. The Rules are administered by the AEMC

Term	Explanation/Comments
Native energy (demand)	Energy (demand) that is inclusive of Scheduled, Semi-Scheduled and Non-Scheduled generation
NEFR	National Electricity Forecasting Report
Non-network options	Alternatives to network augmentation which address a potential shortage in electricity supply in a region, e.g. demand response or local generation
NSCAS	Network Support and Ancillary Services. Services used by AEMO that are essential for managing power system security, facilitating orderly trading, and ensuring electricity supplies are of an acceptable quality.
NSW region	With respect to energy consumption and demand, the term 'NSW region' refers to the combined NSW and ACT electricity loads
NTFP	National Transmission Flow Path
NTNDP	National Transmission Network Development Plan
Outage	An outage is when part of the network is switched off. This can be either planned (i.e. when work needs to be done on the line) or unplanned
POE	Probability of Exceedence. This is the probability a forecast would be met or exceeded, e.g. a 50% POE demand implies there is a 50% probability of the forecast being met or exceeded
PV	Photovoltaic
Reliability	Reliability is a measure of a power system's capacity to continue to supply sufficient power to satisfy customer demand, allowing for the loss of generation capacity
RET	Renewable Energy Target
RIT-T	Regulatory Investment Test for Transmission
Secondary system	Equipment used to control, automate, protect and monitor the network
Substation	A set of electrical equipment used to step high voltage electricity down to a lower voltage. Lower voltages are used to deliver power safely to small businesses and residential consumers
SVC	Static VAr Compensator. An electrical device installed on the high voltage transmission system to provide fast acting voltage control to regulate and stabilise the system
Transmission Annual Planning Report (TAPR)	This document that sets out issues and provides information to the market that is relevant to transmission planning in NSW
Transmission line	A high voltage power line running at 500 kV, 330 kV, 220 kV or 132 kV. The high voltage allows delivery of bulk power over long distances with minimal power loss
Transmission Network Service Provider, TNSP	A body that owns controls and operates a transmission system in the NEM

The following table gives some of the common electricity measurements used:

Property	Unit
Voltage	Volts (V) and kilovolts (kV). 1 kV = 1,000 V
Power	Watts (W), usually expressed in kilowatts (kW) and megawatts (MW). 1 MW = 1,000 kW = 1 million W
Energy consumption	The amount of energy consumed in an hour is usually expressed as kilowatt-hours (kWh) or megawatt-hours (MWh). 1 MWh = 1,000 kWh
Maximum power that a transformer can deliver	Usually expressed in megavolt-ampere (MVA)
Reactive power	Usually expressed in megavolt-ampere reactive (MVAr)

Connecting Lines Through Community Artist: Casey Coolwell

We recognise that our transmission lines, substations and other assets exist on land that has belonged to Aboriginal and Torres Strait Islander peoples for millennia. Our Innovate RAP focuses on driving greater cultural awareness within our organisation and in communities, where we are actively engaged in major projects.

CONTACT DETAILS

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Comment Updated to confirm alignment with the 2020 ISP and include forecast load growth at Parkes