2018

New South Wales Transmission Annual Planning Report
### Purpose of the Transmission Annual Planning Report

This is a forward-looking document which provides useful information for stakeholders in relation to network planning and potential opportunities for non-network alternatives.

The National Electricity Rules (NER) requires us to undertake 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 that enables us to deliver required services at an efficient cost.

The review 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) (Evonergy) as well as with Powerlink in Queensland (QLD), AusNet Services in Victoria (VIC), ElectraNet in South Australia (SA) 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 consumers.

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.

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Foreword

Australia is embarking on the largest transformation of the power system since it was established mid-last century. The forecast retirement of existing generation, together with significant reductions in the cost of new renewable generation, is driving the transition to the energy system of the future.

The energy system is rapidly evolving, successful transformation requires a strategic approach.

This Transmission Annual Planning Report (TAPR) provides an assessment of the capability and limitations of the New South Wales (NSW) transmission network over the next ten years. It outlines the outcomes of our planning review and provides advance information to our stakeholders, and market participants, on the nature and location of emerging network constraints. Our plans to prepare the transmission networks to move to the energy system of the future, are detailed in this TAPR.

Incremental planning and investment decision making based on the next marginal investment required is unlikely to produce the best outcomes for consumers or for the system as a whole over the long-term or support a smooth transition. Proactively planning key elements of the network now, in order to create the flexibility to respond to changing technologies and preferences has the potential to reduce the cost of the system over the long term.

Over the last 12 months, TransGrid has worked with the Australian Energy Market Operator (AEMO) and the other jurisdictional planning bodies to develop the first Integrated System Plan (ISP) for the National Electricity Market (NEM).

As expected, the ISP has found that the least-cost development pathway for the NEM will be delivered by proactive planning of the power system, and establishment of large-scale energy zones. The ISP is expected to save consumers over $1 billion during the transformation, compared with the alternative sub-optimal generation development, that would eventuate if limited by the existing network.

The energy system of the future will be more reliant on renewable generation, and will need to manage the challenge of increasing intermittency of generation. Transmission networks enable geographic diversity to help firm intermittent renewables, using the high voltage network and interconnection to support the flow of energy between regions and take advantage of naturally diverse weather patterns in a cost-effective manner.

TransGrid is further developing techniques and technologies to ensure the resilience and performance of the network, as renewable penetration increases.

In the last year, we have continued to connect record levels of renewable generation to the transmission network in NSW. Although several locations are now fully subscribed with commissioned and committed generation, we have maximised the levels of new generation that can connect in these areas through the use of low-cost capacity upgrades, smart control schemes and world-class power system analysis. The use of technology solutions to improve the integration of new generation has been underpinned by the availability of high-bandwidth telecommunications infrastructure, which has been progressively delivered over the last 20 years.

At the same time, we provided advice to the NSW Energy Security Taskforce, led by the NSW Chief Scientist & Engineer. The taskforce was established to examine and make recommendations on the resilience of the power system in NSW following the load curtailment and load shedding events of 10 February 2017. The taskforce considered factors such as extreme weather events, generation availability, supply and demand balance and preparedness for a black system event and made nine recommendations that are being implemented by the NSW Government.

In the context of a tightening supply and demand balance, the provision of good forecasts is of paramount importance. This year, TransGrid has resumed the preparation of state demand forecasts for NSW region. The forecasts take into account the most recent developments in distributed energy resources, energy efficiency, projections of electric vehicle adoption and economic outlook. The forecasts are published in Chapter 4 of this report.

TransGrid is further developing techniques and technologies to ensure the resilience and performance of the network, as renewable penetration increases.

An essential element of the transition to the energy system of the future is increasing consumer participation. In December 2017, we completed regulatory consultation on a project to maintain an appropriate level of reliability to Inner Sydney – Powering Sydney’s Future. This flagship project has successfully proposed the use of four years of demand management to economically defer the installation of a transmission cable. Consumers will benefit from this project through both participation in demand management and a lower total cost of the power system. I encourage you to participate in this initiative through the request for tender available on the TransGrid website.

The transmission system has a long track record as the platform for both a reliable power system for NSW and the competitive wholesale market across the NEM. We stand ready to deliver the platform to integrate reliable, affordable and low-emissions electricity supply as we transition to the energy system of the future.

Gerard Reiter
Executive Manager/ Network Planning & Operations
June 2018
About TransGrid

TransGrid operates and manages the high voltage electricity transmission network in NSW and the ACT. The network connects more than 3 million homes, businesses and communities to a safe, reliable and affordable supply of electricity.

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 102 substations, over 13,000 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

Figure 3 – TransGrid’s electricity network map – Inset
Executive summary

At TransGrid, we’re focused on providing safe, reliable, affordable and sustainable transmission services – meeting your energy needs now and into the future.

Chapter 1:
The energy system of the future

Australia is embarking on the largest transformation of the power system since it was established mid-last century. The forecast retirement of existing generation, in conjunction with significant reductions in the cost of new renewable generation, is driving the transition to the energy system of the future. Electricity consumption in NSW has increased consistently over the last three years, and is forecast to continue to increase over the next ten years.

At the same time, the locations of generation are expected to progressively shift from coalfields in the Upper Hunter, Central Coast and Central Tablelands to new energy zones in areas of high-quality renewable resources and sources of firming such as pumped hydro and gas.

Analysis has demonstrated that for a transition to be delivered at the lowest total cost, co-ordinated and proactive planning of the energy system of the future is required. With a co-ordinated approach, electricity consumers will save over $1 billion over the course of the transition, compared with the sub-optimal generation development that would eventuate if limited by the existing network.

We have developed a plan to transition to the energy system of the future, which identifies optimum locations for large-scale energy zones and the network connections required to support their development. The plan will deliver a low cost platform to underpin the transition to low emissions generation, maintain system security and reduce wholesale market prices across the NEM.

This chapter describes the key considerations for the development of the transmission system and summarises our ten year plan to underpin the transition to the energy system of the future.

Chapter 2:
Transmission network developments

This chapter describes the major developments identified for our network over ten years.

Strengthening our network to facilitate connection of a greater proportion of renewable generation and interstate trading of electricity is at the forefront of our network development plans. We have proposed transmission network developments to upgrade the network to increase the capacity of renewable generation that can be connected and improve interconnection to adjacent states to maintain reliability by sharing energy resources and leveraging geographical diversity.

We also have projects to address the reliability of supply in some parts of the network to comply with the new Electricity Transmission Reliability Standards administered by the Independent Pricing and Regulatory Tribunal (IPART). We are progressing with works to provide the ACT with a second and independent supply, as required by our transmission license.

In the last year, we have conducted extensive stakeholder consultation on the Powering Sydney’s Future Project. The final option selected to address forecast constraints in the supply to Inner Sydney comprises the use of non-network solutions for four years, followed by the installation of a new underground cable with provision for a second cable at a later stage.

Our asset management strategies and projects deliver a low-cost solution to ensure a secure and reliable supply to our customers.

Chapter 3:
Generation connection and network support opportunities

This chapter sets out information on existing network capacity available for new generation in various areas of NSW and opportunities for network support. We are actively planning to further increase transmission network capacity to cater for the large volume of new generation connection interest, and underpin the transition to a low emissions energy system.

Chapter 4:
Forecasts and planning assumptions

Forecasts and assumptions on developments across the energy industry are inputs to our assessments of the network capacity and capability required. Generation retirement and connection, economic forecasts, new spot loads, and changes in the condition and rating of network assets all contribute to the utilisation of the network and its forecast performance.

Over the next ten years, energy consumption and maximum demand are expected to continue to grow due to economic growth, investment in major transport infrastructure and population growth. The uptake of energy efficiency measures, rooftop PV generation, distributed battery systems and electric vehicles have been taken into account in the forecasts.

We have assessed power system security over the next ten years against the criteria for stability of the power system. We have identified some stability services that may be required following further retirement of baseload generation and/or connection of new inverter-based generation.

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Chapter 1

The energy system of the future

- Australia is embarking on the largest transformation of the power system since it was established mid-last century
- Ageing coal-fired power stations will retire and need to be replaced
- Demand for grid supplied power remains important to consumers
- Large-scale renewable energy will be the lowest cost generation source
- Coordinated transmission development will be needed to unlock lower cost energy for consumers.
Australia is embarking on the largest transformation of the power system since it was established mid-last century. Over the next two decades, the electricity system will be substantially transformed as generation shifts from coal fired to renewable sources, with growing uptake of distributed energy resources.

The rapid transformation is characterised by changing consumer expectations, a trajectory to reduce greenhouse gas emissions to limit global warming and significant advances in small and large-scale energy technologies. The share of electricity generated by variable renewable sources, such as solar and wind, is increasing as the technologies become more cost competitive. Like many countries, Australia is seeking to ensure that electricity supply is reliable, affordable and sustainable as we navigate this transition.

Compounding these challenges within the National Electricity Market (NEM), many of the coal fired power stations that have historically generated low-cost, baseload power are reaching the end of their design lives and are beginning to retire. The supply-demand balance in the NEM has tightened substantially following the withdrawal at short notice of Northern Power Station in South Australia (SA) in 2016 and Hazelwood Power Station in Victoria (VIC) in 2017. This has led to a sharp increase in wholesale and retail electricity prices and raised concerns about power system security.

Stakeholders are increasingly concerned that a lack of energy policy coordination and planning is resulting in high prices and poor reliability for consumers. Several inquiries have recently been conducted to review whether current electricity market structures, regulatory settings and governance arrangements are fit for purpose for the future.

Most notably, the Independent Review into the Future Security of the NEM (the ‘Finkel Review’) provides a blueprint for the future electricity system: to increase security, ensure future reliability, reward consumers for their participation in energy markets and integrate climate and energy policy.

As the recommendations from the Finkel Review are implemented, we will continue to play a role in relation to:

- system planning and delivery of priority projects – as the Jurisdictional Planning Body for New South Wales (NSW) and the Australian Capital Territory (ACT), we are working with the Australian Energy Market Operator (AEMO) and other stakeholders to deliver the Integrated System Plan, to facilitate the efficient development and connection of large-scale energy zones across the NEM; and
- engaging consumers to avoid network costs – we are seeking to procure non-network solutions, such as consumer-driven demand response and embedded generation, to defer network investment. We are also conducting trials to better understand how embedded energy storage can be leveraged to provide network services.

Consumer choice and control will be at the centre of the future energy system. Changing consumer expectations together with rapid technological development suggest that electricity consumers are likely to participate in future energy markets more actively than ever before.

The growing installation of distributed energy resources (DER) including rooftop solar, distributed storage, smart energy management and microgrids will empower consumers to choose how and when they produce, use and trade energy. If DER are aggregated, their capabilities can be leveraged to provide services along the electricity supply chain, facilitated by an increasingly interconnected and smart electricity network. Business models will continue to evolve to share value for high-quality renewable energy resources and incorporate dispatchable capacity, including energy storage, to firm intermittent supplies.

A plan to transition to the energy system of the future must recognise that:

- Ageing coal-fired power stations will retire and need to be replaced
- Demand for grid supplied power remains important to consumers
- Large-scale renewable energy will be the lowest cost generation source
- Coordinated transmission development will be needed to unlock lower cost energy for consumers.

Across the NEM, several coal-fired power stations are starting to reach the end of their design lives. In NSW, over 1,700 MW of coal fired generation has retired in the last ten years (the Murrumbool, Redbank and Walkerawang C power stations). In other states, the Northern Power Station in SA, and Hazelwood Power Station in VIC both withdrew from the NEM with little notice, significantly shifting the supply-demand balance and raising wholesale electricity prices. In NSW alone, Figure 4 shows that a further 6,800 MW of coal fired generation capacity is expected to retire over the next 20 years, representing around 80% of the state's existing baseload capacity. While the exact retirement dates of most power stations are currently unknown, it is reasonable to expect that several will cease operating over this time horizon.

As generation capacity withdraws from the market, new generation needs to be available to ensure an orderly replacement of energy supply and capacity. The types of generation being developed and their locations are now changing, as it is unlikely that new coal power stations will be developed in the NEM to replace the retiring capacity.

Technology cost trends suggest that large-scale wind and solar are already the lowest cost energy options to replace retiring thermal generation and deliver cost-effective electricity to consumers.

The existing transmission network was established to transport electricity primarily from generators in fossil-fuel rich areas to population and load centres. As the supply mix evolves, transmission networks will need to connect precincts with high-quality renewable energy resources and incorporate dispatchable capacity, including energy storage, to firm intermittent supplies.

While significant volumes of additional renewable capacity have been committed, there remains a risk of load shedding following the expected closure of Liddell Power Station in 2022 unless additional dispatchable capacity is established. Several market participants have indicated that they are considering such developments. Additional policy and regulatory mechanisms to improve energy reliability are also currently under consideration, including the National Energy Guarantee and a review of reliability frameworks by the AEMC.
1.2 Demand for grid supplied power remains important to consumers

Consumers will continue to rely on electricity supplied from the grid. Both maximum and underlying demand for grid supplied electricity at the NSW region level are forecast to increase over the next ten years. This is due to population growth, economic activity and delivery of major infrastructure projects including road, rail and airport developments in Greater Sydney and mining developments in regional NSW. The increase is expected to be partially offset by ongoing developments in energy efficiency and the installation of distributed generation, particularly solar PV (see Figure 5).

With grid supplied power remaining important to consumers, new generation will need to be connected to replace ageing power stations before they retire. The connection of large-scale renewable generation to the existing network will continue to provide supply to meet consumer demand. These developments will require a reliable and secure transmission system to meet consumer expectations.

Figure 5 – NSW region electricity summer maximum demand and annual energy forecasts

1.3 Large-scale renewable energy will be the lowest cost generation source

Large-scale wind and solar generation can supply energy at a lower levelised cost than new coal and gas power stations, as shown in Figure 6. As technology costs continue to decline, renewable energy is expected to supply a growing share of electricity in the NEM. This change is already taking place, as evidenced by the recent acceleration in renewables development, with over 5,000 MW of large scale projects under construction, committed or completed in Australia since the beginning of 2017. TransGrid currently has an unprecedented volume of generation connection enquiries, with over 40,000 MW of potential solar, wind and hydro projects at various stages of development throughout the network. Only a fraction of these projects can be accommodated in the spare capacity of the current network.

Figure 7 presents a possible scenario of how electricity supply in the NEM may change over time. Energy Networks Australia and CSIRO forecast in the Electricity Network Transformation Roadmap that by 2050, around 30-50% of electricity generation could be sourced from distributed energy resources (DER), up from about 3% currently. However, even in this scenario with high DER uptake, the volume of electricity supplied from large-scale generation and delivered via the transmission and distribution networks does not decline. Contributions from both large-scale renewables and DER are needed as existing thermal capacity retires.

Figure 7 – Plausible projection of Australia’s changing electricity supply mix to 2050

3 AEMO 2017 ESOO dated September 2017
5 Compiled by TransGrid from various sources
6 ENA and CSIRO, Electricity Network Transformation Roadmap, 2017
Chapter 1

1.4 Coordinated transmission development can unlock lower energy costs for consumers

Transmission networks form the platform on which the competitive wholesale market operates. When transmission capacity is sufficient, the least cost generation is dispatched. When transmission capacity is insufficient, least cost generation can be constrained and higher cost generation used instead, resulting in higher market prices. Over the past two years, wholesale electricity prices across the NEM have been unsustainably high. Improving transmission connections to high quality energy zones will enable the development of low cost renewable energy projects at scale, increasing supply and market competition and reducing wholesale electricity prices.

TransGrid’s existing transmission network in NSW is already fully utilised in some areas, representing a barrier to the connection of new generation. Establishing energy zones will signal to project developers the locations where renewable projects will be supported, and where network capacity will be developed enabling timely connections and unconstrained energy dispatch.

Properly planned energy zones represent the most efficient way to connect new large-scale renewable generation to the grid, because they:

- connect the lowest-cost renewable energy generation in regions with the best quality renewable resources, in which generators operate at higher capacity factors, and deliver lower energy unit costs to consumers;
- minimise transmission costs by reusing existing infrastructure as much as possible, and realising economies of scale where new transmission connection is required;
- facilitate renewable generation development in areas with compatible and low opportunity cost land uses and where it contributes to regional development priorities; and
- minimise the risk of stranded transmission assets by ensuring new transmission lines serve multiple types of generation.

Increasing the level of system interconnection will also support the future renewable-based energy system. Interconnection developments offer opportunities to route transmission pathways through renewable resource rich precincts to facilitate greater connection, leverage geographic diversity and promote inter-regional competition and sharing of energy and ancillary services.

The International Energy Agency has identified interconnectors as one of the most cost-effective approaches to integrating and aggregating a large share of variable renewable energy and maintaining energy security.

Geographic diversity can be a cost-effective method of mitigating the risks of intermittent generation from wind and solar if different time zones and weather patterns can be captured in a complementary way. AEMO data shows that the further farms are located from one another, the more likely they are to have diverse generation profiles. NSW has relatively low levels of coincident weather patterns with other jurisdictions, making it a good choice for renewable energy development. Geographic diversity of solar generation also mitigates the effect of reductions in output during periods of localised cloud cover.

1.5 Plan to transition to the energy system of the future

We have developed a plan to transition to the energy system of the future and the meet the objectives of energy security and reliability, affordability and reduced emissions.

The plan will address supply shortfalls by facilitating the development of new generation capacity as ageing coal power stations retire, place downward pressure on the wholesale market price and maintain the resilience of the power system by sharing ancillary services between all mainland states.

The plan comprises:

- connection of priority large-scale energy zones to the electricity network to facilitate new, low cost generation;
- interconnection to share energy and ancillary services between states and place downward pressure on wholesale market prices;
- large-scale energy storage (and other firm capacity) to smooth the intermittency of variable renewable generation; and
- demand side participation, where consumers are rewarded for using and producing energy in a way that reduces system wide costs, such as shifting energy use away from peak times.

For major infrastructure projects, the lead time for planning and development approvals can take several years. Therefore, it is essential to initiate plans now to ensure energy reliability and the timely connection of new generation ahead of expected generator retirements, expected to commence in 2022.

TransGrid has identified large-scale energy zones within NSW and the staged development of the transmission network that will enable the timely connection of new generation ahead of expected thermal generator retirements. This aligns with the approach of the Integrated System plan in development by AEMO.

The identified large-scale energy zones have high quality solar and wind resources, compatible land use with low opportunity cost and the lowest transmission augmentation costs. Several are located on corridors between major population centres and maximise the use of the existing network. For the stages of development in the next ten years, the economic benefits of connecting lower cost renewable generation and strengthening interconnection will outweigh the cost of the transmission investment.

The large-scale energy zones, main sources of emerging generation and plan for the energy system of the future are shown in Figure 8.

1.6 Next steps

The energy system is embarking on significant transformation, therefore it is imperative that policy and regulatory frameworks support the proactive development of transmission services, as the platform of the energy system of the future.

The transmission developments set out in this plan will improve competition in the wholesale electricity market and facilitate connection of the lowest-cost new generation. If the plan proceeds in a timely way, the total cost of the power system to consumers will be significantly lower than it would be in the absence of a plan with the existing network.

The risk to consumers if the plan is not implemented is a higher total cost of the power system due to ongoing introduction of high-cost generation and potential last-resort procurement of reserves at short notice. Our analysis shows that the total cost of the power system in the NEM, across both generation and transmission, would be at least $1 billion higher if the plan is not implemented than under the plan.

Under well-functioning wholesale and retail electricity markets, the benefits of the plan will flow through to consumers in the form of lower electricity bills.

For the plan to be delivered in a timely way, regulatory changes are required to support proactive transmission investment

and, in particular, the delivery of the Integrated System Plan developed by AEMO. There are two regulatory reviews currently underway that have the potential to provide appropriate regulatory changes:

- the AEMC’s review of Co-ordination of Generation and Transmission Investment; and
- the AER’s review of the Regulatory Investment Test for Transmission Application Guideline.

We look forward to the outcomes of these reviews and stand ready to deliver the plan to integrate reliable, affordable and low-emissions electricity supply as we transition to the energy system of the future.

When developing the plan, we have considered the potential generation capacity that may eventually be developed in each zone and the staging of transmission development over different time horizons to align with the ultimate capacity plan. The staging of transmission development will minimise the capital at risk and preserve optionally to cater for different futures.

NSW Transmission Annual Planning Report 2018


AEMO observations: Operational and market challenges to reliability and security in the NEM

Net present value of total power system cost to 2050, in 1 July 2018 dollars.
**Figure 8 – Our plan to transition to the energy system of the future**

### NSW Government priority energy zones

- **High-quality wind resource**
- **High-quality solar resource**
- **High-quality pumped hydro resource**
- **Proposed new gas generation**
- **Distributed energy resources**
- **Transmission developments within 10 years**
- **Transmission developments beyond 10 years or due to specific local driver**

### Northern NSW

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<td>Uprate QLD to NSW Interconnector (330 kV)</td>
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<td>Uprate Armidale to Tamworth (330 kV)</td>
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<td>Second QLD to NSW Interconnector (330 kV)</td>
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<td>Uralla to Bayswater (500 kV)</td>
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<td>15-20 years</td>
<td>Tamworth via Gunnedah to Wollar (330 kV)</td>
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### Central NSW

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### South-Western NSW

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<td>Uprate Upper Tumut to Canberra (330 kV)</td>
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<td>Uprate Yass to Bannaby and Marulan (330 kV)</td>
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<td>Upgrade Rye Park to Yass (to 330 kV)</td>
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<td>Wagga Wagga via South-Western NSW and North-Western Victoria to Ballarat (330 kV) and Melbourne (500 kV)</td>
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<td>Upgrade Bannaby to Sydney (to 500 kV)</td>
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### South-Eastern NSW & ACT

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<th>Timing</th>
<th>Development</th>
<th>Additional capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>0-5 years</td>
<td>Uprate Upper Tumut to Canberra (330 kV)</td>
<td>200 MW</td>
</tr>
<tr>
<td></td>
<td>Uprate Yass to Bannaby and Marulan (330 kV)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Wagga Wagga via Rye Park to Bannaby (500 kV)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Upgrade Rye Park to Yass (to 330 kV)</td>
<td></td>
</tr>
<tr>
<td>5-10 years</td>
<td>Wagga Wagga via Tumut to Bannaby (500 kV)</td>
<td>2,000 MW</td>
</tr>
<tr>
<td>10-15 years</td>
<td>Upgrade Bannaby to Sydney (to 500 kV)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Uprate Bannaby and Marulan to Sydney (330 kV)</td>
<td></td>
</tr>
</tbody>
</table>
Chapter 2

Transmission network developments

- Our transmission network developments have been selected to transition to the energy system of the future, ensure network resilience and support emissions reduction targets at the least cost.
- We have deferred network investment to supply Inner Sydney using demand management, following extensive consultation, in the largest deferral in the NEM to date.
- A portfolio of low-cost investments will provide connections to distribution networks to meet growing demand, improve network reliability and deliver economic benefits.
- We plan to replace or refurbish transmission lines, substation assets and secondary systems to ensure network reliability.
Transmission network developments

Chapter 2

20 | NSW Transmission Annual Planning Report 2018

2 Transmission network developments

Regulatory Investment Test for Transmission (RIT-T)

We recognise the importance of consulting with our stakeholders to plan, develop and maintain the network to ensure it meets expectations now and into the future. For significant augmentation and renewal investments, one of the avenues for consultation is the Regulatory Investment Test for Transmission (RIT-T). This process is designed to notify stakeholders of the investment need, network or non-network solutions, 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 that highlight key milestones in the consultative process: the Project Specification Consultation Report (PSCR), the Project Assessment Draft Report (PADR) and the Project Assessment Conclusion Report (PACR). Minimum consultation periods following publication of the PSCR and PADR are specified and there is a requirement for the consideration of submissions received in response to these documents. The PACR 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 that includes a brief project description, commissioning date, other reasonable options considered, estimated cost, and planned asset de-ratings and retirements.

2.1 Proposed major developments

TransGrid has an unprecedented volume of generation connection enquiries with approximately 40,000 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. Further details of this volume of generation connection enquiries and TransGrid network capacity limitations are described in Chapter 3. At the same time, large baselead generators are projected to retire, making the integration of new generation essential to maintain secure supply and provide sufficient competition in the wholesale market. In our 2018 annual planning review, we identified possible major network developments to address emerging constraints and support the connection of new renewable generation. These major projects include:

- New South Wales (NSW) to South Australia (SA) Interconnector
- Reinforcement of Southern NSW Network in response to Snowy 2.0
- Reinforcement of Southern NSW Network
- Reinforcement of Northern NSW Network (QNI upgrade)
- Support South Western NSW Network for Renewables
- Support Central Western NSW Network for Renewables
- Support North Western NSW Network for Renewables
- Support South Australian Network for Renewables
- Support South Australian Network for Renewables
- Support South Australian Network for Renewables
- Support North Western NSW Network for Renewables
- Support North Western NSW Network for Renewables

One RIT-T consultation has been completed since publication of TAPR 2017. In December 2017 TransGrid and Ausgrid published the PACR for augmentations proposed in the inner Sydney area, known as Powering Sydney’s Future. TransGrid is presently drafting several PSCRs pertaining to asset condition driven investments and some major transmission developments.

Figure 9 – RIT-T consultation documents

2.1.1 New South Wales to South Australia Interconnector

Figure 10 shows the proposed interconnector options between NSW and SA.

Figure 10 – NSW to SA Interconnector possible options

TransGrid presently does not anticipate any proposed major developments to be required to address an urgent and unforeseen network issue.

Source: ElectraNet SAET PSCR

SA has one of the highest penetrations of variable renewable generation in the world. This can lead to low reserve conditions and introduce challenges in managing system security.

Figure 10 | NSW to SA Interconnector possible options

Interconnection from NSW to SA, along with other options to address this risk, is being investigated in ElectraNet’s South Australian Energy Transformation Project Specification and Consultation Report 10

This project is expected to support the export of renewable energy, address low reserve conditions and address potential power system security issues in SA. There would be significant market benefits to the NEM through reduced energy cost by dispatch of lower cost generating plant, and increased competition of generators through reinforcing the south western NSW transmission network. This would establish a renewable generation precinct in NSW.

The interconnection options from NSW to SA include:

- 275 kV line from mid-north SA to Wagga Wagga via Buronga
- 330 kV line from mid-north SA to Wagga Wagga via Buronga
- 330 kV line from mid-north SA to Wagga Wagga via Buronga plus series compensation

### 2.1.2 Reinforcement of southern NSW network in response to Snowy 2.0

Figure 11 shows the existing network between Snowy and Sydney.

Figure 11 – Snowy to Sydney transmission network

There is an emerging risk of constraining northerly power flows from southern NSW. An upgrade to the southern network is proposed to facilitate the connection of an additional 2,000 MW of generation resulting from an upgrade of the Snowy Hydro Scheme.¹

Upgrading the southern network transfer capacity may include new transmission lines and generation runback (load curtailment) schemes, with low to high capacity options.

Transmission line options include new 330 kV or 500 kV transmission lines between Long Creek (in the Snowy Mountains) and Bannaby. These may run directly or with one transmission line routed via Wagga Wagga to better enable connection of more renewable generation in southern NSW.

The most likely option comprises:

- One 500 kV transmission line from Long Creek to Bannaby
- One 500 kV transmission line from Long Creek to Wagga Wagga
- One 500 kV transmission line from Wagga Wagga to Bannaby

These upgrade options cost between $831 million and $1,228 million. The market benefits from transmission to connect the new Snowy 2.0 include:

- Lower costs associated with meeting the supply reliability standard in NSW, through facilitating access to the output from expanded Snowy 2.0 generation.

2.1.3 Reinforcement of southern NSW network

Southern NSW is a strong area of interest for the connection of new renewable generation. The network between southern NSW and Sydney is constrained at times by high demand, and has limited capacity to cater for further generation together with existing generation and import from Victoria (VIC) 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.

Upgrading 330 kV lines Yass to Marulan (4 and 5), Canberra to Yass (8), Kangaroo Valley to Dapto (18), Sydney West to Bannaby (59), Gullen Range to Bannaby (81) and Yass to Gullen Range (3J) to meet a 120°C design temperature is estimated to provide approximately 160 MW of increased transfer capacity.

Staged upgrades of 330 kV lines 39 and Canberra to Upper Tumut (O1) to a 120°C design temperature, lines 4 and 5 to a design temperature of 100°C, installing phase shifting transformers at Bannaby and Marulan substations, and construction of a new transmission line between Yass and Bannaby can provide an estimated 970 MW of increased transfer capacity.

These works are estimated to cost between $300 million and $350 million. It is noted that this project is different to the other major project titled ‘Reinforcement of Snowy to Sydney Network’. The scale of transmission augmentation works required to connect Snowy 2.0 cannot be accommodated in this project.

- Lower market dispatch costs (and hence lower prices for consumers) resulting from the additional output from Snowy 2.0 and the facilitation of additional output from new renewable generators.

Figure 12 shows the existing network in southern NSW.

Figure 12 – Southern NSW network

¹ Available at Snowy Hydro website: http://www.snowyhydro.com.au/our-scheme/snowy20/; Viewed on 16 March 2018
2.1.4 Reinforcement of northern NSW network (QNI upgrade)

The connection of further new generation in northern NSW could be constrained due to transmission system limitations, particularly in the Liddell to Armidale corridor. Increasing the transmission capacity north of Liddell and/or transfer capacity of QNI is expected to deliver generation cost savings and increased competition by allowing transmission of electricity from Qld and renewable energy from northern NSW. The options to reinforce capacity to northern NSW include:

- Tying both transmission lines along QNI into two switching stations at Sapphire and mid-way between Dumanesq and Bully Creek (96 MW increase southbound)
- New SVCs at Dumanesq and Tamworth, capacitor banks at Tamworth, Armidale and Dumanesq and upgrades to

330 kV lines 83, 84 and 88 to 120 degrees C temperature rating (190 MW increase southbound and 460 MW increase northbound)

- The use of batteries with fast response to increase stability limits (up to 300 MW)
- New 330 kV single circuit transmission between Liddell and Western Downs via existing transmission substations (approximately 400 MW increase southbound and 700 MW northbound)
- New 330 kV double circuit transmission between Liddell and Western Downs via a diverse transmission path, which would increase the footprint for renewable energy connections in northern NSW (approximately 800 MW increase southbound, 1,000 MW northbound and 3,500 MW capacity for new renewable generation connections)
- Back-to-back HVDC (up to 700 MW)
- New 500 kV transmission between Bayswater/Wollar and Uralla, and new 330 kV transmission between Uralla and Western Downs, which would further increase the capacity for renewable energy connections in northern NSW (approximately 800 MW increase southbound, 1,000 MW northbound and 3,500 MW capacity for new renewable generation connections).

These options are estimated to cost between $63 million and $1.6 billion. Subject to evaluation of economic benefits, a project is expected to be initiated with the timing determined by the economic evaluation. The project may be staged if required to maximise economic benefits.

2.1.5 Support south-western NSW network for renewables

South-western NSW is a strong area of interest for the connection of new renewable generation. The south-western NSW network was originally developed to service demand, and has limited capacity to integrate further generation in the area. Thermal capacity constraints between Broken Hill and Wagga Wagga in the 220 kV and 330 kV networks, and voltage control issues in the southern NSW network, can limit the connection of new generation or increases to imports from VIC.

We are investigating the most economic option that will facilitate an increased penetration of renewable generation in the south-western NSW and north-western VIC. This will require greater transmission capacity in these areas, requiring network augmentations to relieve the constraints and realise market benefits.

Review of information published by AEMO and accounting for TransGrid’s own discussions with possible proponents, it is possible that up to 1,000 MW of renewable generation could request a connection in the south-western network. However, new renewable generation (combined with an import from VIC primarily as a result of renewables developments in north west Victoria) could be constrained due to transmission system limitations. These include:

- Transmission capacity (thermal) limitations between Buronga and Broken Hill
- Transmission capacity (thermal) limitations between Buronga and Darlington Point
- Transmission capacity (thermal) limitations between Darlington Point and Wagga Wagga
- Voltage control issues in the South Western transmission network.
Reinforcing the transmission network in this area (west of Wagga Wagga) to enable additional renewable generation could provide market benefits to NSW as well as the wider National Electricity Market. Benefits would likely include reduced energy costs (dispatch of lower cost generation) and increased generator competition.

A low capacity upgrade option could provide approximately 300 MVA of increased network capacity. This would involve upgrading the 220 kV lines between Buronga and Darlington Point to single circuit 275 kV, uprating the Darlington Point to Wagga 330 kV conductor capacity, and installation of additional voltage support in the area. This will also increase the NSW-VIC transfers by relieving the voltage stability limit.

A medium capacity upgrade option could provide approximately 820 MVA of increased network capacity. This would involve uprating the existing 220 kV lines between Buronga and Darlington Point to single circuit 275 kV, building a new 275 kV single circuit line between Buronga, Baharaid and Darlington Point, building a new single circuit 330 kV line between Darlington Point and Wagga Wagga, and installation of additional voltage support in the area. This will also increase the NSW-VIC transfers by relieving the voltage stability limit.

2.1.6 Support central-western NSW network for renewables

This project has a cost estimate ranging between $89 million to $470 million.

**Buronga to Red Cliffs upgrade**

We have initiated a low-cost upgrade to increase the capacity of the Buronga to Red Cliffs 220 kV line from 265 MVA to 417 MVA by replacing wave traps at Buronga with higher rated units.

Increasing the line capacity avoids curtailment of renewable generation in the area, accommodates higher transfers between NSW to VIC and across Murraylink, and will assist in meeting Victorian summer maximum demand.

Equipment replacement at Red Cliffs is also required and we have initiated a project with AEMO and AusNet Services to perform these works.

Further transmission capacity can be made available by building a second 220 kV transmission line between Buronga in NSW and Red Cliffs in VIC. This would also improve system strength in the area under a credible contingency. TransGrid is considering this option in joint planning with AEMO Victoria Planning and will initiate a project if net economic benefits can be demonstrated.

**Figure 16 – Northern NSW network**

Figure 16 shows the transmission network in northern NSW.

TransGrid has interest from renewable energy proponents seeking to connect to its network in central NSW. It is likely that central NSW will be identified as a large-scale energy zone in AEMO’s Integrated System Plan as its consultation paper has indicated interest in connecting.

This network is impacted around the Wagga Wagga area. It is a parallel network of 132 kV and 330 kV lines connecting to the 500 kV substations at Mt Piper and Wollar.

There is around 150 MW of generation currently connected in the area. A further 230 MW of new generation is committed and more than 400 MW of capacity is well advanced.

If transmission constraints are addressed, it is anticipated that new generator connections in Central Western NSW would deliver market benefits. Sources of benefits include:

- Lower costs for meeting the supply reliability standard in NSW, through facilitating access to the output from these generation connections

Connections directly to the 330 kV network are also expected. There is 270 MW of committed generation capacity and 200 MW at an advanced stage of development. There is little spare capacity on this part of the 330 kV network. Across this whole network area, over 10,000 MW of generation has expressed interest in connecting.

**2.1.7 Support north-western NSW network for renewables**

This project has a cost estimate ranging between $120 million to $455 million.

TransGrid has received applications for a number of generator connections to the north-western NSW transmission system. Some of these projects are proposed to connect to the 132 kV and 66 kV network, increasing the power flow from the local 132 kV network to 330 kV network. One generator of 170 MW is partially commissioned and other well advanced projects have a total capacity of 280 MW.

Connections directly to the 330 kV network are also expected. There is 270 MW of committed generation capacity and 200 MW at an advanced stage of development. There is little spare capacity on this part of the 330 kV network. Across this whole network area, over 10,000 MW of generation has expressed interest in connecting.

If transmission constraints are addressed, it is anticipated that new generator connections in north-western NSW would deliver market benefits. Sources of benefits include:

- Lower costs for meeting the supply reliability standard in NSW, through facilitating access to the output from these generation connections
- Lower market dispatch costs (and hence lower prices for consumers) assuming these are low cost generators

This project has a cost estimate ranging between $500 million to $945 million.
NER Clause 5.12.2(c)(9) requires reporting the forecast of constraints and inability to meet the network performance requirements set out in NER Schedule 5.1 or relevant NSW legislations or regulations over one, three and five years. This forecast is provided in Table 1. Information such as timing and likelihood of constraints, descriptions of solutions that addressed the constraints, and other relevant information to enable further understanding of forecast constraints are described in the following Section 2.3 and Section 2.4. This table does not report the forecast constraints associated with the proposed major developments described in Section 2.1 as these will be determined by market dispatch modeling.

Table 1 Forecast constraint information

<table>
<thead>
<tr>
<th>Network regions</th>
<th>Constraint or anticipated constraint</th>
<th>Bulk supply point(s) at which solution is proposed</th>
<th>Associated subsystem development area</th>
</tr>
</thead>
</table>
| Greater Sydney | Forecast unserved energy in Inner Sydney due to asset deratings, retirements and condition issues | TransGrid’s Inner Sydney BSP
|                  |                                                   | Macarthur, Vineyard and Kamps Creek. | Refer to Section 2.3.1 for planned solutions in Greater Sydney network region |
|                 | Load growth in Minamanga Park, Nepalan area, Mt Gilead, Box Hill and new Western Sydney Airport | Supply risk mitigation measures or economic benefits | |
| Northern NSW   | Forecast thermal constraint due to load growth, Supply risk mitigation measures or economic benefits | Gundedah, Narriari, Tamworth, Coffs Harbour, Armidale, Dunedoo and Tarcoola | Refer to Section 2.3.3 for planned solutions in Northern NSW network region |
|                 | Voltage constraints arising due to connections and load growth | Beryl | Refer to Section 2.3.4 for planned solutions in Central NSW network region |
| Central NSW    | Reliability obligation to meet ACT Electricity Transmission Supply Code | Canberra, Yass, Goulbrough, Murrumbateman and Albury | Refer to Section 2.3.5 for planned solutions in Southern NSW and the ACT network regions |
| Southern NSW   | Reliability obligation to meet the NSW standard Supply risk mitigation or economic benefits | Broken Hill, Deniliquin and Finley | Refer to Section 2.3.6 for planned solutions in South Western NSW network regions |
|                 | and ACT network regions | Supply risk mitigation or economic benefits | |
|                 | Supply risk mitigation or economic benefits | Multiple BSPs across NSW | Refer to Section 2.3.7 for planned solutions across NSW |
|                 | Supply risk mitigation or economic benefits | Multiple asset types and work programs | Refer to Section 2.4 for planned solution across NSW |
| South western NSW | Asset condition issues, Reliability correction or improvement | Safety and supply risk mitigation | |

TransGrid’s Network Planning analyses the expected future operation of its transmission networks over a ten-year period, taking into account the relevant forecast loads, any future generation, market network service, demand side and transmission developments and other relevant data to determine the anticipated constraints over one, three and five years. TransGrid’s Network Planning conducts its annual review which includes the following activities:

- incorporate the forecast loads as submitted or modified by relevant registered participants in accordance with NER Clause 5.11.1;
- include a review of the adequacy of existing connection points and relevant parts of the transmission system and planning proposals for future connection points.

2.3 Subsystem developments

This section will describe TransGrid’s capital augmentation works grouped by network regions which address area or regional specific network needs. The information provided in this section describes the work, the actual or potential constraint or inability to meet network performance requirements of NER Schedule 5.1, need or proposed operational date, proposed solution and its estimate. These augmentation works do not cause any material inter-network impact as they address localised or site specific needs. In assessing whether an augmentation to the network will have a material inter-network impact TransGrid examined if its augmentation works will impose power transfer constraints within another TNSP’s network or adversely impact the quality of supply in another TNSP’s network. The information in this section also includes ongoing and recently completed replacement works to provide an one-stop overall area capital expenditure description.

2.3.1 Greater Sydney

Figure 17 – Greater Sydney network

The Inner Sydney area includes the Central Business District (CBD) which is a hub for economic activity, major transport infrastructure, industry and tourism. Increasingly, it is also home to a growing number of people attracted to shorter commutes, harbour views and the many benefits that city living has to offer. The Inner Sydney area 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 with many of these entities having large development or expansion plans under construction or scheduled for the near term.

Figure 17 shows the Greater Sydney network, including transmission supplies to the area.
Further details of the identified need, options assessment including non-network solutions, stakeholder consultation, cost benefit analysis and conclusion can be found in the Project Specification Consultation Report (PSCR), Project Assessment Draft Report (PADR) and Project Assessment Conclusion Report (PACR).

TransGrid and Ausgrid assessed ten credible options, covering a range of network and non-network technologies. After an extensive stakeholder consultation, consideration of various non-network proposals, thorough analysis and rigorous review process, TransGrid and Ausgrid will be delivering the following solutions:

- the use of non-network solutions to defer network build up by one year from when it would need to be commissioned without this support (i.e. from 2021/22). This is the largest deferral of largest capital expenditure by utilising non-

network solutions in Australia to date. TransGrid has released a tender in the market for non-network service providers to submit their solutions. Submissions to this tender are due in July 2018; and

- installing one 330 kV cable by 2020/23 summer, with provision for a second 330 kV cable at a later date; and

- decommissioning six Ausgrid cables.

This solution achieves the balance between minimising wider community disruption and having a lower initial capital cost as well as the ‘optionality’/flexibility that comes with staging the installation of 330 kV cables. This option will cost approximately $252 million and delivers positive net benefits.

12 ‘Expected unserved energy’ is defined in NSW Electricity Transmission Reliability and Performance Standard 2017 as the “expected amount of energy that cannot be supplied, taking into account the probability and expected impact (including expected outage duration and forecast load) of the failure of a single system element; double transformer failure, or failure of equivalent system elements; and double line failure, or failure of equivalent system elements.”

Figure 18 – Forecast of expected unserved energy in Inner Sydney 2017/18 to 2026/27

Other Planned projects

We have planned several substantial augmentation projects to address forecast load growth and connect new distribution zone substations. We have also identified low-cost investment opportunities that may deliver economic benefits or improve system security through:

- Improvements in power quality, e.g. voltage unbalance
- Reduction in load restoration times
- Improvements in network resilience during extreme weather events
- Improvements in operational efficiencies
- Improvements in our ability to respond during grid emergencies.

These projects are shown in Table 2.

Table 2 – Planned projects in Greater Sydney

<table>
<thead>
<tr>
<th>Project description</th>
<th>Planned date</th>
<th>Total cost ($million June–18)</th>
<th>Purpose and possible other options</th>
<th>Project justification</th>
</tr>
</thead>
<tbody>
<tr>
<td>Installation of one 66 kV switchyard at Macarthur/330/1265 kV substation</td>
<td>Nov 2020</td>
<td>1.3</td>
<td>For connection of Endeavour Energy’s planned Menangle Park Zone Substation to meet load growth in a new housing development at Menangle Park</td>
<td>Load driven</td>
</tr>
<tr>
<td>Installation of one 330/66 kV transformer at Macarthur/330/1265 kV substation</td>
<td>Nov 2022</td>
<td>5.0</td>
<td>To address a capacity constraint in the Nepean area arising from 2016</td>
<td>Load driven</td>
</tr>
<tr>
<td>Construction of a new 132 kV switchyard at TransGrid’s Kemps Creek (500/330 kV substation) (Western Sydney development)</td>
<td>Jun 2023</td>
<td>1.3</td>
<td>For connection of Endeavour Energy’s planned Mt Glaced Zone Substation to meet load growth in a new housing development at Mt Glaced</td>
<td>Load driven</td>
</tr>
<tr>
<td>Construction of a new 132 kV switchyard at TransGrid’s Kemps Creek (500/330 kV substation) (Western Sydney development)</td>
<td>Jun 2024</td>
<td>6.4</td>
<td>For connection of Endeavour Energy’s planned Box Hill Zone Substation, to supply a new urban development at Box Hill</td>
<td>Load driven</td>
</tr>
<tr>
<td>Load shedding scheme for mitigating risks of multiple 330 kV cable outages</td>
<td>By Jun 2023</td>
<td>0.15</td>
<td>A new Kemps Creek 132 kV substation will initially be built at TransGrid’s Kemps Creek substation as a switching station. It will be used to build a larger Kemps Creek substation (230/132 kV) with the new substation completing the task.</td>
<td>This project implements a SCADA control scheme to selectively shed low-priority load. The project will also be of benefit in the event of a double circuit trip, the scheme will run back generation and load to avoid cascading outages. The project is expected to be economic at the required level</td>
</tr>
<tr>
<td>Replacement of Cables at 500 kV smart grid control</td>
<td>Jun 2023</td>
<td>0.2</td>
<td>A new Kemps Creek 132 kV substation will initially be built at TransGrid’s Kemps Creek substation as a switching station. It will be used to build a larger Kemps Creek substation (230/132 kV) with the new substation completing the task.</td>
<td>This project implements a SCADA control scheme to selectively shed low-priority load. The project will also be of benefit in the event of a double circuit trip, the scheme will run back generation and load to avoid cascading outages. The project is expected to be economic at the required level</td>
</tr>
<tr>
<td>Eraring to Kemps Creek 500 kV smart grid control</td>
<td>By Jun 2023</td>
<td>2.6</td>
<td>Installation of a special protection scheme to protect against trips of both of the 500 kV lines from Eraring to Kemps Creek in the event of 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</td>
<td>Load driven</td>
</tr>
</tbody>
</table>

13 This project is not related to Powering Sydney’s Future, and the two projects meet separate needs.
### Sydney northwest 330 kV smart grid controls

**Purpose and possible other options**: 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 (23), Sydney West to Tuggerah (24) and Munmorah to Tuggerah (2M).

**Project justification**: Economic benefit

**Total cost ($million June-18)**: 3.0

**Planned date**: By Jun 2023

For multiple circuit trips, the scheme will run back generation and load to avoid cascading outages and further loss of load in the network.

### Sydney South 330 kV smart grid controls

**Purpose and possible other options**: Installation of a special protection scheme to protect against trips of two or more of the 330 kV lines from Sydney South substation.

**Project justification**: Economic benefit

**Total cost ($million June-18)**: 1.8

**Planned date**: By Jun 2023

For multiple circuit trips, the scheme will run back generation and load to avoid cascading outages and further loss of load in the network.

### Bayswater to Sydney West 330 kV smart grid controls

**Purpose and possible other options**: 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).

**Project justification**: Economic benefit

**Total cost ($million June-18)**: 2.8

**Planned date**: By Jun 2023

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.

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### Ongoing projects

TransGrid is replacing the secondary systems at its Sydney North BSP. This work will ensure a reliable supply of electricity to the Sydney Metropolitan Area into the future and ensure that the substation is maintained to a safe and serviceable condition. This project will also meet compliance requirements with the National Electricity Rules and the Australian Energy Market Operator’s Standard for Power Systems Data Communications. The work includes a range of small scale construction activities including removal of old equipment, digging trenches, laying foundations and installing new equipment including new monitoring systems.

TransGrid is diverting line 39 and installing OPGW between Sydney West substation and the diversion point, to facilitate the development of Western Sydney Airport.

### Completed projects

Beaconsfield 330/132 kV substation was rebuilt to address end-of-life condition issues and meet a requirement to connect additional 132 kV Ausgrid feeders into the site.

Due to space limitations, two new 132 kV GIS buildings either side of the existing substation site were built, a new pre-fabricated communications building was built, necessary equipment has been replaced and redundant equipment has been removed.

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### 2.3.2 Newcastle and Central Coast

Figure 19 shows the transmission network in Newcastle and Central Coast region of NSW.

**Figure 19 – Newcastle and Central Coast network**

**Planned projects**

We do not have any planned augmentation projects in Newcastle and Central Coast region.

**Ongoing projects**

Vales Point substation forms an integral part of the 330 kV transmission system on the Central Coast, connecting Vales Point Power Station and supplying Ausgrid’s 132 kV network through two 200 MVA transformers.

Ongoing secondary systems asset replacement works at Vales Point substation are expected to be completed by December 2018. These works address the risk of failure from assets that are reaching the end of their serviceable lives.

**Completed projects**

No project was completed in 2017/18 in Newcastle and Central Coast network.
2.3.3 Northern NSW

Figure 20 shows the transmission network in northern NSW.

Figure 20 – Northern NSW network

Planned projects

Thermal constraints may arise in the Gunnedah area, leading to an emerging risk to reliability if large mining or gas developments proceed in the area. This development, along with other planned minor projects that improve security of supply to customers and provide economic benefits are shown in Table 3.

Table 3 – Planned projects in northern NSW

<table>
<thead>
<tr>
<th>Project description</th>
<th>Planned date</th>
<th>Total cost ($million June 18)</th>
<th>Purpose</th>
<th>Project justification</th>
</tr>
</thead>
<tbody>
<tr>
<td>Install capacitor banks at Narrabri substation</td>
<td>Nov 2020</td>
<td>4.9</td>
<td>Required to manage voltage constraints if large mining or gas developments proceed in the area</td>
<td>Load driven</td>
</tr>
<tr>
<td>Reconductor the Gunnedah to Tamworth 132 kV line (969)</td>
<td>Nov 2020</td>
<td>3.3</td>
<td>Required to manage a thermal constraint due to the rating of the 969 line if large mining or gas developments proceed in the area</td>
<td>Connection driven</td>
</tr>
<tr>
<td>Transposition of 330 kV lines 97 (Coffs Harbour to Armidale) and 962/81E (Armidale to Dunargue)</td>
<td>By Jun 2023</td>
<td>1.2</td>
<td>These transpositions are to make the network more resilient to negative-sequence voltage levels greater than 0.5% within the northern NSW transmission network</td>
<td>Economic benefits</td>
</tr>
<tr>
<td>Provide auto control of capacitor banks</td>
<td>By Jun 2023</td>
<td>&lt;0.1</td>
<td>Improve the voltage capability at various northern NSW substations to reduce the probability of under or over voltage load shedding</td>
<td>Economic benefits</td>
</tr>
<tr>
<td>Armidale North Coast Line Overload Load Shedding (LOLS) expansion</td>
<td>By Jun 2023</td>
<td>&lt;0.1</td>
<td>Modification of the LOLS tripping scheme to include Essential Energy’s Killarney to Maclean 66 kV feeder</td>
<td>Economic benefits</td>
</tr>
<tr>
<td>Northwest NSW 330 kV smart grid controls</td>
<td>By Jun 2023</td>
<td>3.6</td>
<td>Installation of a special protection scheme to protect against trips of two or more of the 330 kV lines between Armidale and Lithgow</td>
<td>Economic benefits</td>
</tr>
<tr>
<td>North-western transfer tripping scheme</td>
<td>By Jun 2023</td>
<td>0.1</td>
<td>The proposed tripping scheme is to avoid opening a 132 kV parallel between Tamworth and Armidale by a 330 kV line (line 85 or 86) to prevent potential thermal overloading and voltage stability issues</td>
<td>Improve transfer capability</td>
</tr>
<tr>
<td>Tamworth 132 kV bus capacity augmentation</td>
<td>By Jun 2023</td>
<td>1.0</td>
<td>A trip of any 132 kV busbar section at Tamworth 330 kV substation will interrupt supply to the Taree area. Installation of a new circuit breaker bay to allow two busbar protection zones at Tamworth substation will allow continued supply to customers in the Taree area during a bus section outage</td>
<td>Economic benefits</td>
</tr>
<tr>
<td>Gunnedah-Narrabri 66 kV Voltage Control</td>
<td>By Jun 2023</td>
<td>&lt;0.1</td>
<td>Provide Automatic Voltage Control of Capacitor Banks at Gunnedah. There is an opportunity to avoid the loss of load by implementing smart auto-tripping of the Gunnedah capacitors following a critical contingency</td>
<td>Economic benefits</td>
</tr>
<tr>
<td>Transformer AVR Functional Change</td>
<td>By Jun 2023</td>
<td>0.1</td>
<td>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 for AVR function blocks at Dapto, Moruya, Wagga Wagga, Willar打仗 and Yass to allow automatic voltage regulation during reverse power flow</td>
<td>Economic benefits</td>
</tr>
<tr>
<td>Capacitor bank to increase NSW to QLD transfer limit</td>
<td>By Jun 2023</td>
<td>4.7</td>
<td>Installation of a 330 kV, 120 MVar shunt capacitor bank at Armidale 330/132 kV substation to increase voltage stability limits on QNI</td>
<td>Improve transfer capability</td>
</tr>
<tr>
<td>Armidale capacitor transfer tripping scheme</td>
<td>By Jun 2023</td>
<td>0.2</td>
<td>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</td>
<td>Improve transfer capability</td>
</tr>
</tbody>
</table>
2.3.4 Central NSW

Figure 21 shows the transmission network in central NSW.

Figure 21 – Central NSW network

Planned projects

The network in central NSW currently limits the connection of large loads or generation due to voltage and thermal limitations. Outages of elements in the network risk significantly limiting the capability to connect generation, mostly in the 132 kV network.

There is strong interest from at least three renewable energy proponents seeking to connect to the 132 kV network between Mt Piper and Wellington in NSW.

As a result of the implementation of the new reliability standard from 1 July 2018, we have initiated works in the DNSP network via joint planning to reduce expected unserved energy at the Mudgee 132 kV BSP. Planned projects that are driven by connection growth are shown in Table 4.

Completed projects

The northern telecommunications link project was completed during 2017/18. It involved setting up six new telecommunications sites to connect communication systems between TransGrid’s Dumaresq Switching Station near Dumaresq Valley through to an existing telecommunications pole on Parrots Nest Road in South Gundurimba.

Table 4 – Planned projects in central NSW

<table>
<thead>
<tr>
<th>Project description</th>
<th>Planned date</th>
<th>Total cost ($million June-18)</th>
<th>Purpose</th>
<th>Project justification</th>
</tr>
</thead>
<tbody>
<tr>
<td>Replace limiting high voltage plant on Mount Piper to Wallerawang 330 kV lines</td>
<td>By Jun 2023</td>
<td>3.3</td>
<td>Replace limiting HV plant and upgrade secondary plant on Mount Piper to Wallerawang 330 kV lines to improve supply reliability and address an emerging risk to the integration of low-emissions generation in central NSW</td>
<td>Economic benefits</td>
</tr>
<tr>
<td>Two-way disconnector on Beryl to Mount Piper 132 kV line (94M) to the tee connection to Ilford substation</td>
<td>By Jun 2023</td>
<td>2.9</td>
<td>Installing a two-way disconnector on line 94M to Ilford substation to reduce duration of supply interruption to customers following trip of the line</td>
<td>Economic benefits</td>
</tr>
<tr>
<td>Increase capacity to the Beryl area</td>
<td>New generation more than 150 MW</td>
<td>~40.0 to 190.0</td>
<td>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 line thermal limitations will limit the generation from the renewable sources. Also, the operational management of voltage and security may limit the load consumption at Beryl thereby imposing load shedding. Initial market modelling indicates there would be net market benefits from augmenting the transmission network to provide additional capacity. TransGrid has identified a range of credible network options to address this network constraints ranging from a new Beryl 330 kV substation or upgrades to 132 kV lines from Mount Piper or Wellington</td>
<td>Economic benefits</td>
</tr>
</tbody>
</table>

Ongoing projects

TransGrid is replacing approximately seventy wood pole structures on Line 944 between Orange and Wallerawang with concrete poles. The new poles are being installed along the same transmission line alignment and within the existing easement. This project addresses the requirement for critical voltage support to Orange and other Central West areas during emergency contingency events, and also supports the forecast increase in the Central NSW Region load.

Completed projects

Works to address the condition of substation equipment reaching end of serviceable life were recently completed at Orange 132/66 kV substation. These works included:

- Rearrangement of poles and overhead wires around the substation
- Replacement of the 330 kV high voltage equipment
- Installation of a modular building to house GIS and secondary system equipment
- Replacement of the 330 kV equipment and secondary systems
- Installation of an additional 66 kV capacitor bank to improve voltage support.
2.3.5 Southern NSW and ACT

Figure 22 shows the transmission network in southern NSW and ACT.

Figure 22 – Southern NSW and ACT network

Planned projects

Second supply to the Australian Capital Territory (ACT)

We are required to provide two independent, geographically separate 330 kV supplies to the ACT as a condition of the ACT transmission licence. Canberra 330/132 kV substation provides the existing supply.

We are planning to establish a second geographically separate supply at Stockdill Drive by diverting 330 kV lines O1 and 3C into a new substation, with a 330/132 kV transformer providing 132 kV supply to Evoenergy. This provides an efficient solution to both comply with the ACT Electricity Transmission Supply Code and address the need to replace one of the existing 330/1152 kV transformers at Canberra that has reached the end of its serviceable life. It is expected to be completed by December 2020 at an estimated cost of $314 million.

Other projects

Several precincts in Canberra are experiencing high localised load growth from new residential and commercial developments, and several low-cost investment opportunities that can deliver economic benefits have been identified. These are shown in Table 5.

Table 5 – Planned projects in southern NSW and ACT

<table>
<thead>
<tr>
<th>Project description</th>
<th>Planned date</th>
<th>Total cost (million June 18)</th>
<th>Purpose</th>
<th>Project justification</th>
</tr>
</thead>
<tbody>
<tr>
<td>Installation of one 132 kV switchyard at Canberra 330/132 kV substation</td>
<td>Nov 2020</td>
<td>1.7</td>
<td>For connection of Evoenergy’s planned Strathnairn (formerly West Balloonova) Zone Substation, being built to meet the high maximum load growth caused by a new housing development in Canberra</td>
<td>Load driven</td>
</tr>
<tr>
<td>Modification of Canberra to Woden 132 kV line to connect to TransGrid’s planned Stockdill 330 kV substation</td>
<td>Nov 2021</td>
<td>1.9</td>
<td>For connection of Evoenergy’s planned Molonglo Zone Substation in ACT, connecting to Evoenergy’s Canberra to Woden 132 kV transmission line</td>
<td>Load driven</td>
</tr>
</tbody>
</table>

Ongoing projects

Wagga 132/66 kV substation is being rebuilt in situ due to end-of-life condition of assets. The works include replacement of substation equipment and secondary systems. Two new 132/66 kV 120 MVA transformers will replace the existing 132/66 kV 60 MVA transformers. This work is expected to be completed in mid-2019.

Completed projects

TransGrid has recently constructed a steel or concrete radio repeater pole, (approximately 45 metres in height) at the existing Buronga substation, located on Arumpo Road, Buronga, NSW. The project was needed to improve the strength and reliability of electricity supply in the far south-west region of NSW. Specifically, this requires a robust communications connection between Red Cliffs, Buronga and Broken Hill substations.
TransGrid recently remediated and replaced conductor and structures of Line 97K that runs between TransGrid’s Cooma and Munyang substations. This work included remediation of approximately 115 low spans including structure replacements, double circuit steel pole installation, dummy strain installation, re-tensioning, landscaping works, access track upgrades, straightening wood poles and other repairs works.

### 2.3.6 South western NSW

Figure 23 shows the transmission network in south western NSW.

Figure 23 – South western NSW network

Planned projects

Broken Hill is part of the south western network and is supplied by a single transmission line from Buronga that is around 200 kilometres long. The existing gas turbines at Broken Hill owned by Essential Energy have a start-up time of approximately 30 minutes, in which time the loads in the area would not be supplied. Redundancy capacity will be required in the event of a change in the capability of the gas turbines such that the total 220 kV and 22 kV load exceeds the capacity of the turbines and

Canberra 330/132 kV substation equipment replacement works were recently completed. The replacement works were due to assets reaching end of serviceable lives and substation noise issues.

Broken Hill 132/11 kV substation in-site renewal works were recently completed. The works addressed the end-of-life condition of assets in the substation.

The expected annual unserved energy exceeds the allowance for Broken Hill as per the NSW Electricity Transmission Reliability and Performance Standard 2017. TransGrid has identified options to meet the Standard in case of such events. This option and other low-cost projects in south western NSW with economic benefits are shown in Table 6.

Canberra 330/132 kV substation equipment replacement works were recently completed. The replacement works were due to assets reaching end of serviceable lives and substation noise issues.

Burrajack 132/11 kV substation in-site renewal works were recently completed. The works addressed the end-of-life condition of assets in the substation.

The expected annual unserved energy exceeds the allowance for Broken Hill as per the NSW Electricity Transmission Reliability and Performance Standard 2017. TransGrid has identified options to meet the Standard in case of such events. This option and other low-cost projects in south western NSW with economic benefits are shown in Table 6.

### 2.3.7 Across NSW

### NSW needs

We are contracted to provide 600 MVAR of absorbing reactive power services to meet a Network Support and Control Ancillary Services (NSCAS) gap until 30 June 2019. It is planned to continue providing these absorbing reactive power services as a prescribed service following expiry of the current contract, AEMO has outlined that we are expected to include these reactors in the regulated asset base and continue to provide the required reactive voltage absorbing capability.

The second update to the 2016 NTNDP published in October 2017 by AEMO did not identify any NSCAS gaps in NSW. It is noted that the AEMO did not publish the 2017 NTNDP. It is intended that the information included in the annual NTNDP will be incorporated into AEMO’s Integrated System Plan.

NSCAS are ancillary services procured in order to maintain power system security. Under the NER, AEMO identifies NSCAS needs and we are required to procure NSCAS services to address needs in NSW. AEMO is the NSCAS Procurer of Last Resort if a TNSP is not able to procure NSCAS to meet their requirements.

### Planned projects

TransGrid is experiencing an unprecedented growth in wind and solar generation network connection enquiries and applications, driven initially by the Renewable Energy Target

![Figure 23 – South western NSW network](image)

### Table 6 – Planned projects in south western NSW

<table>
<thead>
<tr>
<th>Project description</th>
<th>Planned date</th>
<th>Total cost ($million June 18)</th>
<th>Purpose</th>
<th>Project justification</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maintain supply reliability to Broken Hill</td>
<td>When the load exceeds capacity of backup gas turbines</td>
<td>$52.0 to 177.0</td>
<td>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</td>
<td>Reliability compliance</td>
</tr>
<tr>
<td></td>
<td>Increase capacity to Coleambally</td>
<td>New generation in Coleambally, Deniliquin and Finley areas</td>
<td>10.0</td>
<td>If all invested renewable generation proponents connect, their outputs will be constrained under system normal conditions to maintain the transmission network within acceptable limits. Options being considered include new 152 kV lines from Darlington Point to Coleambally</td>
</tr>
<tr>
<td>Dynamic reactive support installations at Broken Hill and Buronga</td>
<td>Nov 2020</td>
<td>26.8</td>
<td>Installation of reactors and SVCs at Broken Hill and Buronga to address voltage constraints should a large mining development proceed in the area</td>
<td>Load driven</td>
</tr>
<tr>
<td>Deniliquin full SCADA augmentation</td>
<td>By Jun 2023</td>
<td>0.4</td>
<td>SCADA capacity augmentation at Deniliquin 132/66 kV substation to reduce supply restoration time for an unplanned outage of 66 kV feeders or substation equipment</td>
<td>Economic benefits</td>
</tr>
<tr>
<td>Finley full SCADA augmentation</td>
<td>By Jun 2023</td>
<td>0.3</td>
<td>Full SCADA control and monitoring improvements at Finley to reduce supply restoration time for an unplanned outage of 66 kV feeders or substation equipment</td>
<td>Economic benefits</td>
</tr>
<tr>
<td>Dynamic rating system for Darlington Point 330/220 kV tie transformers</td>
<td>By Jun 2023</td>
<td>0.6</td>
<td>Develop and implement dynamic rating system for Darlington Point 330/220 kV transformers to increase their thermal rating</td>
<td>Economic benefits</td>
</tr>
</tbody>
</table>

### Completed projects

No project was completed in 2017/18 in south western NSW network.

### Ongoing projects

TransGrid is constructing a radio repeater pole (approximately 45 metres in height) at the existing Broken Hill substation, located off Pinnacles Road, Broken Hill, NSW. The project is needed to improve the strength and reliability of electricity supply in the far south-west region of NSW. Specifically, this requires a robust communications connection between Red Cliffs, Buronga and Broken Hill substations.
It is estimated that dynamic reactive power compensation will be required in at least four transmission locations where significant renewable generation is seeking to connect, most likely the south western, southern, central and northern NSW. The installation of dynamic reactive plant is likely to be required by 2020.

Other planned projects that improve security of supply for consumers and provide economic benefits are shown in Table 7.

### 2.4 Asset management projects

The retirement of assets is planned as they reach the end of their serviceable lives. We have made improvements to the asset management strategies and policies which underpin our 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.

### Table 7 – Planned projects across NSW

<table>
<thead>
<tr>
<th>Project description</th>
<th>Planned date</th>
<th>Total cost ($million June-18)</th>
<th>Purpose</th>
<th>Project justification</th>
</tr>
</thead>
<tbody>
<tr>
<td>Various Locations Dynamic Voltage Support</td>
<td>By June 2023</td>
<td>24.4</td>
<td>Corrective actions needed to address the forecast voltage stability/capacity issues at the large-scale energy zones identified by TransGrid. Given the uncertainty of specific timing and triggers for the exact locations it is proposed that projects will be required to facilitate the renewable uptake in NSW.</td>
<td>Connection driven</td>
</tr>
<tr>
<td>Improve the Operational Telephone Network (OTN)</td>
<td>By June 2023</td>
<td>2.6</td>
<td>Reliable communication for use during supply disruptions</td>
<td>Economic benefit</td>
</tr>
<tr>
<td>Overvoltage control following under frequency load shedding events</td>
<td>By June 2023</td>
<td>4.1</td>
<td>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.</td>
<td>Economic benefit</td>
</tr>
<tr>
<td>Remote or self-reset of busbar protection</td>
<td>By June 2023</td>
<td>4.1</td>
<td>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.</td>
<td>Economic benefit</td>
</tr>
<tr>
<td>Miscellaneous DNSP Secondary Systems Works</td>
<td>By June 2023</td>
<td>1.6</td>
<td>A number of sites supplying Evenergy and Endavour Energy will require minor secondary system works. These projects will be initiated by the respective DNSPs and work requested made to TransGrid.</td>
<td>Load driven</td>
</tr>
</tbody>
</table>

### Ongoing projects

No significant project is being delivered presently across NSW that has not already been described in the earlier sections.

### Completed projects

Existing static line ratings consider the probabilistic nature of weather and line loading conditions. The weather information used to determine these line ratings may not always reflect the weather conditions on critical spans of these transmission lines where conductor sag is the constraining issue, particularly for long transmission lines.

### 2.4.1 Transmission lines

#### Rebuild of 330 kV line 86

330 kV line 86 is a wood pole line between Armidale and Tamworth substations in northern NSW. The line forms part of the flow path for QNI. Emerging condition issues associated with the wood pole structures on this line are continuing to be assessed by TransGrid in line with the current wood pole replacement program that has been ongoing since 2011 to address prevalent wood rot throughout the line. It is currently planned to replace the existing composite wood pole structures with larger concrete pole structures and restringing with a larger conductor to improve the rating of the line. The project is estimated to cost $70.3 million and be delivered by June 2023. Concrete poles are proposed to be used as they have longer lifespan than wood poles and provide greater network security. We also considered using the existing conductor on new concrete poles.

<table>
<thead>
<tr>
<th>Transmission line location</th>
<th>Operational date required</th>
<th>Total estimated cost ($ million)</th>
</tr>
</thead>
<tbody>
<tr>
<td>8Dipto – Marulan 330 kV line</td>
<td>By Jun 2023</td>
<td>3.6</td>
</tr>
<tr>
<td>2M Munmorah – Tuggerah 330 kV line</td>
<td>By Jun 2023</td>
<td>2.8</td>
</tr>
<tr>
<td>24 Eraring – Vales Point 330 kV line</td>
<td>By Jun 2023</td>
<td>3.1</td>
</tr>
<tr>
<td>25 &amp; 26 Eraring – Vineyard 330 kV line &amp; Munmorah – Sydney West 330 kV double circuit line</td>
<td>By Jun 2023</td>
<td>6.7</td>
</tr>
<tr>
<td>3W Capital Windfarm – Kangaroo Valley 330 kV line</td>
<td>By Jun 2023</td>
<td>3.7</td>
</tr>
<tr>
<td>81 Ulladulla – Newcastle 330 kV line</td>
<td>By Jun 2023</td>
<td>2.9</td>
</tr>
<tr>
<td>21 Sydney North – Tuggerah 330 kV line</td>
<td>By Jun 2023</td>
<td>1.7</td>
</tr>
<tr>
<td>16 Avon – Marulan 330 kV line</td>
<td>By Jun 2023</td>
<td>2.4</td>
</tr>
<tr>
<td>18 Vales – Kangaroo Valley 330 kV line</td>
<td>By Jun 2023</td>
<td>1.9</td>
</tr>
<tr>
<td>11 Dipto – Sydney South 330 kV line</td>
<td>By Jun 2023</td>
<td>25.2</td>
</tr>
<tr>
<td>21 Bayswater – Regentville 330 kV line</td>
<td>By Jun 2023</td>
<td>5.5</td>
</tr>
<tr>
<td>88 Muswellbrook – Tarmouth 330 kV line</td>
<td>By Jun 2023</td>
<td>3.5</td>
</tr>
<tr>
<td>90 Eraring – Newcastle 330 kV line</td>
<td>By Jun 2023</td>
<td>1.6</td>
</tr>
<tr>
<td>22 Vales Point – Sydney North 330kV line</td>
<td>By Jun 2023</td>
<td>10.5</td>
</tr>
</tbody>
</table>

#### 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 insulated composite wood pole structures with larger concrete pole structures and restringing with a larger conductor to improve the rating of the line. The project is estimated to cost $70.3 million and be delivered by June 2023.

Concrete poles are proposed to be used as they have longer lifespan than wood poles and provide greater network security. We also considered using the existing conductor on new concrete poles.
and to facilitate the remote interrogation and analysis of unmanned high voltage transmission sites within the network required between sites to maintain the visibility and control of communications backbone network are used to service the existing assets servicing our medium bandwidth microwave installation.

Table 9 – Wood pole replacement projects

<table>
<thead>
<tr>
<th>Transmission line location</th>
<th>Operational date required</th>
<th>Total estimated cost ($ million)</th>
</tr>
</thead>
<tbody>
<tr>
<td>944 Wallawarre – Orange North 132 kV line</td>
<td>Mar 2018</td>
<td>5.3</td>
</tr>
<tr>
<td>96F Urangquirrel – Yanco 132kV line</td>
<td>Jul 2018</td>
<td>26.6</td>
</tr>
<tr>
<td>936 Tumbarumba – Brindley Hill 132kV line</td>
<td>Dec 2018</td>
<td>1.4</td>
</tr>
<tr>
<td>94X Wallawarre – Panorama 132kV line</td>
<td>By Jun 2023</td>
<td>2.9</td>
</tr>
<tr>
<td>96U Yanco – Griffith 132kV line</td>
<td>By Jun 2023</td>
<td>4.1</td>
</tr>
<tr>
<td>948 Panorama – Orange North 132kV line</td>
<td>By Jun 2023</td>
<td>1.7</td>
</tr>
<tr>
<td>966 Armidale – Koolekhan 132kV line</td>
<td>By Jun 2023</td>
<td>2.1</td>
</tr>
<tr>
<td>963 Gadara – Wagga Wagga 132kV line</td>
<td>By Jun 2023</td>
<td>7.0</td>
</tr>
<tr>
<td>9U3 Gunnedah – Biogupra East 132kV line</td>
<td>By Jun 2023</td>
<td>4.7</td>
</tr>
<tr>
<td>95L Goulbourn – Jindabyne Pump 132kV line</td>
<td>By Jun 2023</td>
<td>2.1</td>
</tr>
<tr>
<td>96L Tenterfield – Lismore 132kV line</td>
<td>By Jun 2023</td>
<td>6.6</td>
</tr>
<tr>
<td>96F Tumbarumba – Stroud 132kV line</td>
<td>By Jun 2023</td>
<td>6.8</td>
</tr>
<tr>
<td>94K Wellington – Parkes 132kV line</td>
<td>By Jun 2023</td>
<td>10.0</td>
</tr>
<tr>
<td>95A Urangquirrel – Finley 132kV line</td>
<td>By Jun 2023</td>
<td>10.4</td>
</tr>
<tr>
<td>96D Yanco – Darlington Point 132kV line</td>
<td>By Jun 2023</td>
<td>7.1</td>
</tr>
</tbody>
</table>

Optical fibre network installation

The existing assets servicing our medium bandwidth microwave communications backbone network are used to service protection and communication links throughout many parts of the network. High speed communications are increasingly required between sites to maintain the visibility and control of unmanned high voltage transmission sites within the network and to facilitate the remote interrogation and analysis of conditions and assets at all sites.

Additional operational benefits have been identified in the deployment of optical fibre links throughout the network to increase data capacity capabilities. These benefits include increased visibility and remote monitoring of assets, reduced maintenance requirements as monitoring can report imminent asset failure, remote analysis of failures before sending technicians to site and increased visibility of high quality CCTV systems.

The installation of an interconnected fibre optic network addresses our long term vision of an intelligent network with real time asset management capabilities.

Wood pole replacements

We are 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 list of projects is shown in Table 9.

The following lines will have optical fibres installed on their routes to replace the existing microwave area network. This has been identified as the most efficient way to increase data capacity in the transmission network. This type of installation is typically achieved by replacing one of a transmission line’s earthwires with an optical fibre cable encased in aluminium conductor known as Optical Ground Wire (OPGW).

This is part of our 15 year strategy for rolling out OPGW across the transmission network, beginning with the formation of three new communications rings over the next 2 years. Works on the central west ring between Mount Piper to Orange, Wellington, Parkes and Forbes, will be complete by mid-2018. Works on the north coast ring between Newcastle and Lismore and the southern ring between Yass and Wagga Wagga will be complete by the end of 2018. The list of projects is shown in Table 10.

Table 10 – Fibre network projects

<table>
<thead>
<tr>
<th>Transmission line location</th>
<th>Operational date required</th>
<th>Total estimated cost ($ million)</th>
</tr>
</thead>
<tbody>
<tr>
<td>94U Forbes – Parkes 132 kV line</td>
<td>Feb 2018</td>
<td>1.8</td>
</tr>
<tr>
<td>96F Urangquirrel – Yanco 132 kV line</td>
<td>Jul 2018</td>
<td>26.6</td>
</tr>
<tr>
<td>9W1 Warialda West to Togo 330 kV line, 964 Port Macquarie – Taree, and 96P Tare – Stroud 132 kV lines</td>
<td>Jul 2018</td>
<td>12.1</td>
</tr>
<tr>
<td>962 Bialupock – Tumut 132 kV line</td>
<td>Jul 2018</td>
<td>10.5</td>
</tr>
<tr>
<td>963 Gadara – Wagga Wagga 132 kV line</td>
<td>Jun 2019</td>
<td>11.4</td>
</tr>
<tr>
<td>945 Wellington – Molong and 947 Wellington – Orange North 132 kV lines</td>
<td>Aug 2018</td>
<td>7.0</td>
</tr>
<tr>
<td>967 Lismore – Koolekhan and 96H Coffs Harbour – Koolekhan 132 kV lines</td>
<td>Nov 2018</td>
<td>5.5</td>
</tr>
<tr>
<td>9W2 Raleigh – Kempsey and 9W3 Coffs Harbour – Raleigh 132 kV lines</td>
<td>Jun 2018</td>
<td>8.3</td>
</tr>
<tr>
<td>96P Gadara – Tumut 132 kV line</td>
<td>Jun 2018</td>
<td>2.7</td>
</tr>
<tr>
<td>949 Sydney North – Sydney East 132 kV line</td>
<td>By Jun 2023</td>
<td>2.5</td>
</tr>
<tr>
<td>97 Avon – Macarthur 330 kV line</td>
<td>By Jun 2023</td>
<td>3.8</td>
</tr>
</tbody>
</table>

† These projects also include wood pole and steel tower remediation works

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).

We have conducted aerial laser surveys of its transmission lines to provide accurate measurement of span heights. Using this new technology that 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.

We have 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 then 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
> 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. We are 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 remediations are expected to mitigate the public safety risk to an acceptable level.

The list of low span remediation projects to meet statutory clearances is shown in Table 11 (not including those bundled with fibre network projects listed in Table 10).

Table 11 – Low Span Projects

<table>
<thead>
<tr>
<th>Transmission line location</th>
<th>Operational date required</th>
<th>Total estimated cost ($ million)</th>
</tr>
</thead>
<tbody>
<tr>
<td>966 Armidale – Koolekhan and 96H Coffs Harbour – Koolekhan 132 kV lines</td>
<td>Jun 2018</td>
<td>7.6</td>
</tr>
<tr>
<td>Various other steel tower lines</td>
<td>By Jun 2023</td>
<td>6.5</td>
</tr>
</tbody>
</table>
2.4.2 Substation plant

We continually monitor the condition of our substation assets to ensure safe and reliable operation. We have established asset replacement programs to cover the replacement of identified circuit breakers, instrument transformers, bushing and disconnectors with poor condition.

Our replacement programs comprise the most economic combination of replacement and refurbishment options for transmission equipment reaching a condition that 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 and replacement, retirement or refurbishment options are evaluated to result in individual projects to address 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.

Table 12 shows substation projects planned until 2023.

### Table 12 – Planned substation primary (HV) asset renewal/replacement projects

<table>
<thead>
<tr>
<th>Location</th>
<th>Area</th>
<th>Operational date required</th>
<th>Total estimated cost ($ million)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sydney East 330 kV substation No.2 and No.3 transformer replacements</td>
<td>Sydney</td>
<td>By Jun 2023</td>
<td>15.6</td>
</tr>
<tr>
<td>Armidale 330 kV substation No.2 reactor renewal</td>
<td>Northern</td>
<td>By Jun 2023</td>
<td>3.0</td>
</tr>
<tr>
<td>Kempes Creek &amp; Earling 550 kV substations 33kV tertiary reactor replacements</td>
<td>Sydney to Central Coast</td>
<td>By Jun 2023</td>
<td>1.5</td>
</tr>
<tr>
<td>Forbes 132 kV substation transformer replacements</td>
<td>Central</td>
<td>By Jun 2023</td>
<td>8.7</td>
</tr>
<tr>
<td>Wellington 330 kV substation No.1 reactor replacement</td>
<td>Central</td>
<td>By Jun 2023</td>
<td>4.1</td>
</tr>
<tr>
<td>Marulan 330 kV substation No.4 transformer renewal</td>
<td>Southern</td>
<td>By Jun 2023</td>
<td>1.9</td>
</tr>
</tbody>
</table>

2.4.3 Secondary systems

We are currently deploying our first secondary system that uses IEC-61850. We will achieve savings by reducing the number of traditional copper-core cables and instead using optical fibre cables between substation switchyards and relay rooms.

The condition of various categories of automation assets such as protection relays, control systems, AC distribution, DC supply systems, and market meters creates a need for modernisation. This will deliver benefits such as reduced maintenance requirements, minimal reinvestment over the life of the assets, improved operational efficiencies, better utilisation of our high speed communications network, improved visibility of all assets using modern technologies and reduced reliance on routine maintenance and testing.

Where sites featured a large proportion of assets in poor condition, several options were identified and we commissioned an economic evaluation of risks and benefits to determine the most efficient solution. Options included running to failure, secondary system building installations, strategic replacements, and IEC 61850 deployments.

Works to address data capacity in the network are discussed in the optical fibre network installations in section 2.3.1. The secondary system renewal and replacement projects are listed in Table 13.

### Table 13 – Planned substation secondary asset renewal and replacement projects

<table>
<thead>
<tr>
<th>Location</th>
<th>Area</th>
<th>Operational date required</th>
<th>Total estimated cost ($ million)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sydney North Secondary System Replacement</td>
<td>Sydney</td>
<td>By Oct 2018</td>
<td>37.9</td>
</tr>
<tr>
<td>Regentville Secondary Systems Renewal</td>
<td>Sydney</td>
<td>By Jun 2023</td>
<td>4.3</td>
</tr>
<tr>
<td>Tuggerah Secondary Systems Renewal</td>
<td>Newcastle and Central Coast</td>
<td>By Jun 2023</td>
<td>1.5</td>
</tr>
<tr>
<td>Muswellbrook Secondary Systems Renewal</td>
<td>Newcastle and Central Coast</td>
<td>By Jun 2023</td>
<td>4.3</td>
</tr>
<tr>
<td>Haymarket Secondary Systems Replacement</td>
<td>Sydney</td>
<td>By Jun 2023</td>
<td>8.1</td>
</tr>
<tr>
<td>Wallarawang 330kV Sec Systems Renewal*</td>
<td>Central</td>
<td>By Jun 2023</td>
<td>4.7</td>
</tr>
<tr>
<td>Manilar Secondary Systems Renewal</td>
<td>Southern</td>
<td>By Jun 2023</td>
<td>4.6</td>
</tr>
<tr>
<td>Ingleburn Secondary System Renewal</td>
<td>Sydney</td>
<td>By Jun 2023</td>
<td>4.0</td>
</tr>
</tbody>
</table>


### 2.4.4 SCADA system

The Supervisory Control and Data Acquisition (SCADA) system is a vital tool that allows us to efficiently operate and maintain our network, providing real-time visibility of the network status and alerting abnormal conditions. We use the SCADA system to operate, control and monitor the high voltage network remotely from our central control centre. The existing SCADA system uses an operating platform and assets no longer supported by the providers.

Options to address the need included running to failure or replacement with a modern solution.

We consider that replacement is the only viable option. Replacement will ensure that the SCADA system uses the most current technology available, including security features and functionality that will enhance situational awareness and operability of the modern transmission network. This project will cost $15.0 million and is expected to be completed in 2020.

### 2.5 Asset retirements and deratings

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

### 2.6 Changes from TAPR 2017

Updates in this chapter and referenced Appendices since TAPR 2017 includes the following:

- The description of forecast constraints that triggers the corresponding subsystem development planned projects.
- A description of asset retirements and asset deratings that would result in a network constraint and that are planned over the next 10 years planning horizon.
- Asset management approach describing our asset management systems, associated risk management framework and business processes that delivers our asset management strategy in Appendix A3.13.

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

Generation connection and network support opportunities

- We have an unprecedented volume of generator connection enquiries with over 40,000 MW of potential solar, wind and hydro projects at various stages of development.
- We provide information on existing network capacity that is available for new generation in various areas of New South Wales (NSW).
- The interest in new generation connection exceeds the existing network capacity in many areas of NSW.
- We are proposing the development of large-scale energy zones to open up additional capacity for new low-emissions generation.
- Energy storage and other network support may provide solutions to challenges arising from the transition to the energy system of the future.
- There are opportunities for non-network options in the Inner Sydney area. Further opportunities may arise in the next five years in the Gunnedah/Narrabri and Broken Hill areas, depending on changes to load and generation in these areas.
TransGrid has analysed the potential for renewable energy development throughout New South Wales (NSW). This considered the quality of renewable energy resources, existing land use, proximity to the existing transmission network and factors that affect the feasibility of generation development (such as terrain).

The analysis has been undertaken to 50m resolution to ensure that the results are robust and suitable to support strategic planning and ultimately investment decisions. A map of the ratings for wind generation is shown in Figure 24 and for solar generation in Figure 25. In these figures, the most favourable locations for renewable development are shown in green, and the least favourable zones are shown in red.

Research by the Australian National University in late 2017 has indicated that NSW region has 200 times more pumped hydro energy storage resources than that required to decarbonise the electricity supply within this region. Many of these sites have good colocation with infrastructure, such as transmission lines, and are also located within the large-scale energy zones. The identified sites for such resources are shown in Figure 26 and consider criteria such as head, reservoir areas and storage capacity.

Figure 24 – NSW wind generation development suitability ratings

Figure 25 – NSW solar generation development suitability ratings
Taking these findings into account, TransGrid has identified six potential large-scale energy zones in NSW that could be developed over time to facilitate the connection of high quality renewable generation, ahead of the expected retirement of ageing coal power stations. Table 14 summarises the key features of potential large-scale energy zones.

Table 14 – Potential NSW large-scale energy zones

<table>
<thead>
<tr>
<th>Zone</th>
<th>Ultimate high quality resource potential</th>
<th>Current generation connection enquiries</th>
<th>Proximity to firming capacity</th>
<th>Proximity to load centres</th>
<th>Indicative transmission cost $/MW additional capacity (2018 $)</th>
<th>Strategic alignment and optionality</th>
</tr>
</thead>
<tbody>
<tr>
<td>South-East NSW &amp; ACT</td>
<td>Wind &gt;5 GW, Solar &gt;5 GW, Hydro 6 GW</td>
<td>Wind 2 GW, Solar 2.3 GW, Hydro 2 GW, Gas 0.4 GW</td>
<td>Pumped hydro in Snowy Mountains, Gas transmission between Yass and Berrinba/Warlan</td>
<td>330 km</td>
<td>$224 k</td>
<td>On path between Sydney and Melbourne</td>
</tr>
<tr>
<td>Northern NSW</td>
<td>Wind &gt;4 GW, Solar &gt;5 GW, Hydro 2 GW</td>
<td>Wind 4.6 GW, Solar 6.6 GW</td>
<td>Pumped hydro east of Armidale, Potential for gas production at Narrabri</td>
<td>500 km</td>
<td>$285 k</td>
<td>On path between Sydney and Brisbane</td>
</tr>
<tr>
<td>Southern NSW (and North-West Victoria)</td>
<td>Wind 4 GW (incl potential resources in north-west VIC), Solar &gt;5 GW</td>
<td>Wind 5.3 GW</td>
<td>Not applicable</td>
<td>520 km</td>
<td>$376 k</td>
<td>On path between Sydney, Melbourne and Adelaide</td>
</tr>
<tr>
<td>South-West NSW</td>
<td>Wind 5 GW, Solar &gt;5 GW</td>
<td>Wind 0.4 GW, Solar 4.2 GW</td>
<td>Not applicable</td>
<td>410 km (Melbourne)</td>
<td>$620 k</td>
<td>On path between Sydney, Melbourne and Adelaide</td>
</tr>
<tr>
<td>Central NSW</td>
<td>Wind 2 GW, Solar &gt;5 GW</td>
<td>Wind 3 GW, Solar 6.0 GW</td>
<td>Not applicable</td>
<td>310 km</td>
<td>$285 k</td>
<td>Not located on a path between population centres and represents a higher asset stranding risk</td>
</tr>
<tr>
<td>Barrier Ranges</td>
<td>Wind &gt;5 GW, Solar &gt;5 GW</td>
<td>Wind 0.3 GW, Solar 0.3 GW</td>
<td>Not applicable</td>
<td>820 km (Melbourne)</td>
<td>$660 k</td>
<td>Potential path between NSW and SA and potential future redundant supply to Olympic Dam</td>
</tr>
</tbody>
</table>
There is currently an unprecedented volume of generation connection enquiries at various stages of development across NSW. Only a fraction of this generation can be accommodated in the spare capacity of TransGrid’s current network.

Figure 27 – Current generation connection enquiries to TransGrid network and available capacity

The approximate available network capacity for generation connections in TransGrid’s identified large-scale energy zones in NSW is presented in Figure 27.

The current available network capacity is based on the current maximum demand, with all committed network and customer projects, and allowing for N-1 contingencies.

New generation at any of the identified locations will affect the utilisation of the transmission network and the capacity at adjacent network locations.

The current generation connection enquiries in Table 14 and Figure 27 include all enquiries received by TransGrid, which are presently free of cost for enquiring proponents, and also proposed connections from proponents who have engaged us to complete network feasibility studies as of 31 May 2018.

We continuously monitor and evaluate the network capacity at these locations.
Table 15 – Connection opportunities at specific sites

<table>
<thead>
<tr>
<th>Connection sites</th>
<th>Voltage level</th>
<th>Available capacity (MW)</th>
<th>Generation connection interest (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Yass, Barmaby</td>
<td>330 kV</td>
<td>1,700</td>
<td>1,099</td>
</tr>
<tr>
<td>Wollar, Wellington, Parkes</td>
<td>330 kV</td>
<td>900</td>
<td>7,384</td>
</tr>
<tr>
<td>Bayswater, Liddell</td>
<td>330 kV</td>
<td>500</td>
<td>768</td>
</tr>
<tr>
<td>Tamworth, Armidale</td>
<td>330 kV</td>
<td>800</td>
<td>4,035</td>
</tr>
</tbody>
</table>

We are committed to transitioning to the energy system of the future and are working to identify solutions to the emerging network constraints. The additional capacity would deliver significant benefits in facilitating the connection of renewable generators in high interest areas with an abundance of renewable resources.

3.3 Opportunities for network support

The transition to a low emissions energy system will see a substantial change to the way electricity is generated. Traditional carbon intensive large-scale generation is expected to progressively retire, and replacement sources are likely to be a mix of large-scale variable renewable generation and distributed energy resources.

Operation of a secure and reliable power system will require the deployment of generation firming and ancillary services by alternative means. Energy storage is ideally placed to provide some of these ancillary services. Energy storage, in the form of pumped storage and batteries, can complement renewable generation by balancing energy produced from intermittent sources to ensure that it is available at the times it is required to meet demand.

Existing synchronous base load generation provides inertia, helping to stabilise the power system following disturbances on the system. Batteries with appropriate inverter technology can provide fast frequency response, helping to stabilise the power system by slowing the rate of change of frequency as the level of system inertia is decreased. In addition to fast frequency response, batteries are also able to provide Frequency Control Ancillary Services (FCAS).

A further value stream for batteries is the ability to deliver reactive support to the system, potentially lessening the need for dynamic reactive plant.

We have identified the potential for network support opportunities to arise in the Narrabri/Gunnedah and Broken Hill areas over the next ten years. The network constraints in these areas are discussed in Section 2.3.3 and Section 2.3.6 respectively. The intent to issue Requests for Proposals (RfP) is set out in Section 3.4.

3.4 Requests for Proposals

NER Clause 5.12.2(c)(4) requires reporting the subset of forecast constraints identified earlier in Section 2.2, where an estimated reduction in forecast load would defer a forecast constraint for a period of 1 year. This is provided in Table 16 with the statement of whether TransGrid plans to issue a request for proposal (RfP) for augex, repex or non-network works, and the expected date of issuing the RfP.

Table 16 – Anticipated issue of a RfP

<table>
<thead>
<tr>
<th>Constraint or anticipated constraint</th>
<th>Intent to issue RfP</th>
<th>Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Forecast voltage and thermal constraints (Supply to the Gunnedah/Narrabri area)</td>
<td>To be assessed</td>
<td>To be assessed</td>
</tr>
<tr>
<td>Reliability correction or improvement (Supply to the Broken Hill area)</td>
<td>To be assessed</td>
<td>To be assessed</td>
</tr>
</tbody>
</table>

3.5 Changes from TAPR 2017

Updates in this chapter and referenced Appendices since TAPR 2017 includes the following:

- The opportunity to connect the identified potential large-scale energy zones in NSW is assessed against the planning criteria. This aligns with our response to AEMO’s ISP consultation paper.

These changes are consistent with the requirements of NER Clause 5.12.2(c)(2).
Chapter 4

Forecasts and planning assumptions

- Annual New South Wales (NSW) region energy consumption is forecast to grow at an average rate of 0.7% per annum over the next ten years under the medium scenario, due to population and economic growth in conjunction with falling retail electricity prices.

- Under the medium scenario and 50% Probability of Exceedance (POE) conditions, summer maximum demand is expected to grow by around 0.4% per annum and winter maximum demand by around 0.7% per annum on average. This is higher than last year’s forecast and is mainly driven by long run growth in underlying sensitive demand.

- In addition to its own forecast, TransGrid has reviewed and compared forecasts from the respective DNSPs’ Bulk Supply Point (BSP) and AEMO’s March 2018 National Electricity Forecasting Report (NEFR).

- 972 MW of new generation has committed to connect at various locations in NSW. This is expected to continue to grow as advances in renewable generation technologies improve the cost competitiveness of new renewable generation.

- We have undertaken an assessment of power system security against each of the criteria that contribute to the stability of the power system, and identified some stability services that may be required following further retirement of baseload generation and/or connection of new inverter-based generation.

- New NSW transmission reliability standards will commence from 1 July 2018. We have assessed that the transmission network will comply with the standards from 1 July 2018. However, during the next ten years, expected changes at Broken Hill will likely require transmission developments to maintain compliance with Broken Hill BSP. A project to address this has been included in Chapter 2.
## 4 Forecasts and planning assumptions

### 4.1 Key highlights

#### 4.1.1 Supply

Since the publication of TAPP 2017, the following levels of generation have signed connection agreements and are incorporated in our planning review as committed generation:

- 100 MW of coal generation capacity
- 170 MW of solar generation capacity

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

#### 4.1.2 Demand

A summary of the NSW region forecasts, including forecast energy transmitted on the network, and summer and winter demand, are termed “as generated”. Measures of network connected terminals include power used to power generator auxiliaries and includes contributions from NEM Scheduled, Semi-Scheduled generation. This is known as ‘native’ energy and demand and transmits energy on the network, and summer and winter demand. The DNSPs’ forecasts of their respective BSPs are in Appendix 2 and the winter maximum demand from 2018 to 2027 is shown in Table 17.

#### Table 17 – NSW region energy and demand forecasts (compound average annual growth rates)

<table>
<thead>
<tr>
<th></th>
<th></th>
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<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>0.9%</td>
<td>0.7%</td>
<td>0.4%</td>
<td>0.7%</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Summer Maximum Demand</td>
<td>Summer Maximum Demand</td>
<td>Summer Maximum Demand</td>
<td>Summer Maximum Demand</td>
<td>Summer Maximum Demand</td>
<td>Summer Maximum Demand</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>0.1%</td>
<td>0.4%</td>
<td>0.7%</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Winter Maximum Demand</td>
<td>Winter Maximum Demand</td>
<td>Winter Maximum Demand</td>
<td>Winter Maximum Demand</td>
<td>Winter Maximum Demand</td>
<td>Winter Maximum Demand</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1.9%</td>
<td>0.4%</td>
<td>0.7%</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

#### 4.2 TransGrid’s 2018 NSW region forecast

TransGrid’s 2018 NSW region forecasts include annual energy, maximum summer demand and maximum winter demand and are defined in terms of all network connected, metered generation. This is known as ‘native’ energy and demand and includes contributions from NEM Scheduled, Semi-Scheduled and Non-Scheduled generating units.

Measures of network connected generation at generator terminals include power used to power generator auxiliaries and are termed “as generated”. Measures of network connected generation at the point of generator connection with the network are termed “sent out”. In this report, annual energy is provided on a sent out basis and the maximum demands are on an as-generated basis.

Maximum demands are highly dependent on prevailing weather conditions, with high summer temperatures and low winter temperatures providing a predominant explanation for the timing of maxima in each respective season. In accordance with the NEM convention maximum demands are described in this report in terms of ‘probability of exceedance’ or PoE, which delineates the frequency with which probable demands could exceed the stated level. For example, a 50% PoE level of demand is expected to be exceeded 50% of the time (i.e., once in every two years).

The forecast for NSW as a whole has been prepared by TransGrid and incorporates specialist advice on likely movements in population and economic activity, energy prices, rooftop PV penetration, distributed battery storage installation, energy savings due to energy-efficiency policies and the take-up of zero or low-emissions vehicles. The method of preparation of TransGrid’s load forecast is described in Appendix 1.

The DNSPs’ forecasts of their respective BSPs are in Appendix 2 which provides the summer maximum demand from 2018/19 to 2027/28 and the winter maximum demand from 2019 to 2027.

Consumption behaviour of directly connected customers is incorporated into our forecasts.

#### 4.2.2 Demand drivers

The traditional drivers of demand for energy include demographic change, economic growth and energy prices, and these measures are routinely used to develop forecasting models. However, the recent upsurge in distributed energy resources – especially residential rooftop PV – play a significant role in reducing network demand, as does accelerated energy efficiency. For an energy market in transition, therefore, a credible forecast needs to carefully consider each element that either contributes to or detracts from load on the NSW transmission network.

Population growth directly affects household formation and new residential dwelling construction, while income growth both stimulates the purchase of additional household appliances and reflects additional business output. TransGrid forecasts are derived from an empirical model that results in an increase of around 0.27 per cent in residential energy consumption for each one per cent increase in real Household Disposable Income, and an increase of around 0.26 per cent in non-residential energy consumption for each one per cent increase in Gross State Product.

Electricity consumption is negatively correlated with electricity prices as they directly affect consumer behaviour. In the short run, consumers may economise on their consumption when faced with higher electricity bills by, for example, having shorter showers and ensuring that the lights are turned off in unoccupied rooms. However when faced with an expectation or even a possibility of permanently higher electricity prices, consumers will have an incentive to seek out more efficient alternatives when purchasing new appliances, and to invest in energy saving technologies (from the consumers’ point of view) such as solar power and batteries. Lower electricity prices, on the other hand, have an opposite effect, freeing consumers from high energy bill concerns and encouraging greater energy use.

The forecasts are derived from a measure of underlying demand called ‘electricity services’ which includes network supplied electricity, rooftop PV generation and battery storage, and an estimate of above trend energy efficiency. This measure reflects an understanding that the traditional drivers actually influence customers’ use of electrical appliances for specified purposes, and the supply of electrical energy from the grid is only an indirect consequence of this usage.

The take-up of increasingly more energy efficient appliances has been one of the largest contributors to the reduction of electricity usage on a per customer basis that occurred between 2009 and 2016 and the subsequent reduction and stabilisation of growth in maximum demand. This includes improvements in the energy efficiency of homes and other buildings. As energy efficiency savings continue to grow it is implicitly incorporated into historical load data. The historic change in energy efficiency improvement also coincided with a time of rapidly rising electricity prices. The customer price response and the energy efficiency savings both had a material impact on electricity demand, but collectively it makes difficult to determine the independent effects of each.

Use of the electricity services measure removes the effect of historical energy efficiency and reveals the true underlying demand for the services that require electricity. Long run price elasticities are then derived from the electricity services model that identifies the true price impact on consumer demand.

On the basis of specialist advice and TransGrid forecasts include the negative impact of additional out-of-trend increases in energy efficiency savings amounting to 1.1 per cent reduction in energy consumption per year for the next ten years.

TransGrid also obtained independent advice on the expected future take-up by both residential and non-residential consumers of rooftop PV generation and accompanying battery storage, and their associated impact on maximum demand. The projections of rooftop PV are sufficient to offset 50% of annual energy growth by 2027-28 under the medium scenario.

#### 4.2.3 Temperature sensitivity

TransGrid’s analysis of variation of maximum demand with temperature reveals that current summer temperature sensitivity is 311 MW per degree increase in the average daily temperature, which represents a doubling in sensitivity in percentage terms in the last 24 years. Winter temperature sensitivity has barely changed in that time and is estimated to have been 197 MW increase per degree reduction in average daily temperature in 2017.
4.2.4 Modelling climate change responses

Australia is assumed to be on track over the next 10 years to meet its existing obligation to reduce national greenhouse gas emissions by 26% on 2005 levels by 2030. Reductions are mainly met through the current Renewable Energy Certificate scheme and, after the closure of that scheme, through the National Energy Guarantee (NEG). This assumption indirectly affects the demand for electricity through its impact on pricing. State based renewable energy schemes are also assumed to contribute to the emissions reduction target.

4.2.5 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 a medium, high or low 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 scenarios are predicated on the assumption that sufficient renewable generation is sourced in line with the existing national emissions target. The high and low scenarios project slightly lower and higher National Electricity Market outcomes from this assumption respectively. Future above trend energy savings are assumed under current energy efficiency policies and programs combined with stock turnover. The high and low scenarios build in slightly fewer and slightly greater extensions to these programs respectively. All scenarios include a small allowance for electric vehicle charging, using take-up as assumed by AEMO in 2017 Electricity Forecasting Insights.

The annual energy forecast scenarios 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 the 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 18.

Table 18 – Scenario inputs changes 2018-19 to 2027-28*

<table>
<thead>
<tr>
<th>Input Variables</th>
<th>Medium</th>
<th>High</th>
<th>Low</th>
</tr>
</thead>
<tbody>
<tr>
<td>Population growth %</td>
<td>1.3</td>
<td>1.5</td>
<td>1.2</td>
</tr>
<tr>
<td>Real household disposable income %</td>
<td>2.5</td>
<td>3.5</td>
<td>1.8</td>
</tr>
<tr>
<td>Economic growth GSP %</td>
<td>2.5</td>
<td>3.0</td>
<td>1.8</td>
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<tr>
<td>Real residential electricity price %</td>
<td>-2.2</td>
<td>-2.3</td>
<td>-1.6</td>
</tr>
<tr>
<td>Real non-residential electricity price %</td>
<td>-2.7</td>
<td>-2.8</td>
<td>-2.2</td>
</tr>
<tr>
<td>Real price of gas and other fuels %</td>
<td>-1.9</td>
<td>-0.6</td>
<td>-3.3</td>
</tr>
<tr>
<td>Trend average temperature increase degrees</td>
<td>0.5</td>
<td>0.5</td>
<td>0.5</td>
</tr>
<tr>
<td>Residential rooftop PV generation GWh</td>
<td>4,038</td>
<td>4,155</td>
<td>3,915</td>
</tr>
<tr>
<td>Non-residential rooftop PV (generation GWh)</td>
<td>2,077</td>
<td>2,136</td>
<td>2,015</td>
</tr>
<tr>
<td>Summer maximum demand shift due to PV/ batteries</td>
<td>1,146/189</td>
<td>1,255/251</td>
<td>1,066/51</td>
</tr>
<tr>
<td>Distributed battery contribution to winter maximum MW</td>
<td>161</td>
<td>275</td>
<td>81</td>
</tr>
<tr>
<td>Out of trend energy residential efficiency savings GWh</td>
<td>642</td>
<td>248</td>
<td>777</td>
</tr>
<tr>
<td>Out of trend energy non-residential efficiency savings GWh</td>
<td>7,006</td>
<td>4,156</td>
<td>9,178</td>
</tr>
<tr>
<td>Out of trend energy efficiency savings summer MW</td>
<td>1,966</td>
<td>1,289</td>
<td>2,437</td>
</tr>
<tr>
<td>Out of trend energy efficiency savings winter MW</td>
<td>1,304</td>
<td>878</td>
<td>1,585</td>
</tr>
<tr>
<td>Major industrial load GWh / MW</td>
<td>418 / 56</td>
<td>419 / 56</td>
<td>418 / 56</td>
</tr>
<tr>
<td>Electric vehicle changing GWh / MW</td>
<td>1,078 / 13</td>
<td>1,078 / 13</td>
<td>1,078 / 13</td>
</tr>
</tbody>
</table>

* Note: Values are shown as changes from 2018-19 to 2027-28, and as compound annual growth rates where shown as %.

4.2.6 Summary of annual energy consumption forecast

Energy consumption has been on an upward trend since 2013/14 even with the recent increases in wholesale prices, increases in rooftop PV and uptakes of energy efficiency measures. Over the forecast horizon, electricity prices are expected to fall, placing further upward pressure on electricity demand.

The main components of annual energy, both historically and for the medium growth forecast, are shown in Figure 28, while annual energy consumption forecasts for the medium, high and low scenarios are shown in Table 19. The main drivers of change are:

- Continuing population and economic growth
- Falling retail electricity prices
- Increasing offsets provided as a result of energy efficiency programs and the up-take of rooftop PV and battery storage systems.
### Table 19 – NSW region sent-out annual energy consumption (GWh) forecast

<table>
<thead>
<tr>
<th>Year</th>
<th>Actual</th>
<th>Medium</th>
<th>High</th>
<th>Low</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013/14</td>
<td>67,073</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2014/15</td>
<td>68,766</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2015/16</td>
<td>70,020</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2016/17</td>
<td>70,120</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2017/18 (Est)</td>
<td>69,800</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2018/19</td>
<td>70,110</td>
<td>70,790</td>
<td>69,550</td>
<td></td>
</tr>
<tr>
<td>2019/20</td>
<td>70,370</td>
<td>71,280</td>
<td>69,790</td>
<td></td>
</tr>
<tr>
<td>2020/21</td>
<td>71,520</td>
<td>72,380</td>
<td>70,690</td>
<td></td>
</tr>
<tr>
<td>2021/22</td>
<td>72,100</td>
<td>73,450</td>
<td>71,170</td>
<td></td>
</tr>
<tr>
<td>2022/23</td>
<td>72,910</td>
<td>74,580</td>
<td>70,590</td>
<td></td>
</tr>
<tr>
<td>2023/24</td>
<td>73,200</td>
<td>75,390</td>
<td>70,520</td>
<td></td>
</tr>
<tr>
<td>2024/25</td>
<td>73,140</td>
<td>75,850</td>
<td>69,710</td>
<td></td>
</tr>
<tr>
<td>2025/26</td>
<td>74,260</td>
<td>77,380</td>
<td>69,920</td>
<td></td>
</tr>
<tr>
<td>2026/27</td>
<td>74,450</td>
<td>78,180</td>
<td>69,320</td>
<td></td>
</tr>
<tr>
<td>2027/28</td>
<td>74,450</td>
<td>78,970</td>
<td>68,640</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Year</th>
<th>10% POE</th>
<th>50% POE</th>
<th>90% POE</th>
<th>10% POE</th>
<th>50% POE</th>
<th>90% POE</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013/14</td>
<td>12,189</td>
<td>13,602</td>
<td>12,791</td>
<td>11,763</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2014/15</td>
<td>12,093</td>
<td>13,709</td>
<td>12,824</td>
<td>11,726</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2015/16</td>
<td>13,742</td>
<td>14,260</td>
<td>13,348</td>
<td>12,154</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2016/17</td>
<td>14,869*</td>
<td>14,469</td>
<td>13,439</td>
<td>12,019</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2017/18</td>
<td>13,284</td>
<td>14,437</td>
<td>13,347</td>
<td>11,907</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2018/19</td>
<td>14,480</td>
<td>13,370</td>
<td>12,000</td>
<td>11,780</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2019/20</td>
<td>14,490</td>
<td>13,380</td>
<td>11,960</td>
<td>11,740</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2020/21</td>
<td>14,650</td>
<td>13,460</td>
<td>12,010</td>
<td>11,630</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2021/22</td>
<td>14,860</td>
<td>13,740</td>
<td>12,070</td>
<td>11,670</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2022/23</td>
<td>15,080</td>
<td>13,810</td>
<td>12,230</td>
<td>11,850</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2023/24</td>
<td>15,090</td>
<td>13,880</td>
<td>12,200</td>
<td>11,850</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2024/25</td>
<td>15,140</td>
<td>13,790</td>
<td>12,120</td>
<td>11,520</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2025/26</td>
<td>15,160</td>
<td>13,770</td>
<td>12,050</td>
<td>11,330</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2026/27</td>
<td>15,240</td>
<td>13,920</td>
<td>12,000</td>
<td>11,560</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2027/28</td>
<td>15,350</td>
<td>13,000</td>
<td>12,050</td>
<td>11,560</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Annual Average Growth Rate 2018/19 – 2027/28

<table>
<thead>
<tr>
<th>10% POE</th>
<th>50% POE</th>
<th>90% POE</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.7%</td>
<td>0.4%</td>
<td>0.1%</td>
</tr>
</tbody>
</table>

* Note: This actual denotes the estimated uncurtailed maximum demand on the 10 February 2017. The actual maximum demand with load curtailment was 14,233 MW.

### 4.2.7 Summary of summer maximum demand forecast

Increases in summer maximum demand are attributed to long run increases in non-temperature sensitive demand and changes in the sensitivity of demand to hot weather. Maximum demand offsets due to energy efficiency and rooftop PV differ from the average offset to annual energy.

Forecasts for the medium, high and low scenarios are shown in Figure 30 and Table 20. They include the 10%, 50% and 90% POE levels for each scenarios. The main drivers of change are:

- Long run growth in underlying demand
- Limited impact from growth in air-conditioning ownership, as NSW ownership is already close to saturation
- Relatively small offsets (compared to energy) from energy efficiency, rooftop PV generation and time-shifting due to increasing take-up of distributed battery storage.

### 4.2.8 Summary of winter maximum demand forecast

Increases in winter maximum demand are attributed to long run increases in non-temperature sensitive demand and changes in the sensitivity of demand to cold weather. Maximum demand offsets due to energy efficiency and rooftop PV differ from the average offset to annual energy.

Forecasts for the medium, high and low scenarios are shown in Figure 31 and Table 21. They include the 10%, 50% and 90% POE levels for each scenarios. The main drivers of change are:

- Long run growth in underlying demand
- Relatively small offsets (compared to energy) from energy efficiency
- Time-shifting due to increasing take-up of distributed battery storage.

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 6:00 pm to 6:30 pm peak.
### Table 21 – NSW region winter as-generated maximum demand (MW) forecast

<table>
<thead>
<tr>
<th>Year</th>
<th>10% POE</th>
<th>50% POE</th>
<th>90% POE</th>
<th>10% POE</th>
<th>50% POE</th>
<th>90% POE</th>
<th>10% POE</th>
<th>50% POE</th>
<th>90% POE</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013</td>
<td>11,766</td>
<td>12,483</td>
<td>12,167</td>
<td>11,890</td>
<td></td>
<td></td>
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<td></td>
<td></td>
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<tr>
<td>2014</td>
<td>11,877</td>
<td>12,370</td>
<td>12,122</td>
<td>11,892</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2015</td>
<td>12,208</td>
<td>12,612</td>
<td>12,296</td>
<td>12,023</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2016</td>
<td>12,822</td>
<td>12,651</td>
<td>12,526</td>
<td>12,310</td>
<td>12,020</td>
<td>12,360</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>2017</td>
<td>12,150</td>
<td>12,616</td>
<td>12,207</td>
<td>12,000</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2018</td>
<td>12,770</td>
<td>12,430</td>
<td>12,110</td>
<td>12,040</td>
<td>12,000</td>
<td>12,020</td>
<td>12,020</td>
<td>12,040</td>
<td>12,050</td>
</tr>
<tr>
<td>2019</td>
<td>12,880</td>
<td>12,520</td>
<td>12,180</td>
<td>12,120</td>
<td>12,060</td>
<td>12,020</td>
<td>12,020</td>
<td>12,040</td>
<td>12,050</td>
</tr>
<tr>
<td>2020</td>
<td>13,070</td>
<td>12,690</td>
<td>12,330</td>
<td>13,040</td>
<td>12,880</td>
<td>12,600</td>
<td>12,600</td>
<td>12,520</td>
<td>12,550</td>
</tr>
<tr>
<td>2021</td>
<td>13,270</td>
<td>12,870</td>
<td>12,460</td>
<td>13,700</td>
<td>13,310</td>
<td>12,910</td>
<td>13,010</td>
<td>12,610</td>
<td>12,650</td>
</tr>
<tr>
<td>2022</td>
<td>13,420</td>
<td>13,000</td>
<td>12,550</td>
<td>13,970</td>
<td>13,560</td>
<td>13,140</td>
<td>13,040</td>
<td>12,650</td>
<td>12,210</td>
</tr>
<tr>
<td>2023</td>
<td>13,410</td>
<td>12,900</td>
<td>12,550</td>
<td>14,120</td>
<td>13,700</td>
<td>13,260</td>
<td>12,920</td>
<td>12,510</td>
<td>12,070</td>
</tr>
<tr>
<td>2024</td>
<td>13,440</td>
<td>13,010</td>
<td>12,560</td>
<td>14,280</td>
<td>13,880</td>
<td>13,400</td>
<td>12,850</td>
<td>12,430</td>
<td>11,980</td>
</tr>
<tr>
<td>2025</td>
<td>13,480</td>
<td>13,050</td>
<td>12,570</td>
<td>14,450</td>
<td>14,020</td>
<td>13,540</td>
<td>12,790</td>
<td>12,360</td>
<td>11,900</td>
</tr>
<tr>
<td>2026</td>
<td>13,510</td>
<td>13,070</td>
<td>12,580</td>
<td>14,630</td>
<td>14,200</td>
<td>13,710</td>
<td>12,700</td>
<td>12,280</td>
<td>11,800</td>
</tr>
<tr>
<td>2027</td>
<td>13,610</td>
<td>13,190</td>
<td>12,670</td>
<td>14,030</td>
<td>14,500</td>
<td>13,990</td>
<td>12,710</td>
<td>12,250</td>
<td>11,800</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Year</th>
<th>Annual Average Growth Rate 2018 – 2027</th>
</tr>
</thead>
<tbody>
<tr>
<td>2018</td>
<td>0.7%</td>
</tr>
<tr>
<td>2019</td>
<td>0.7%</td>
</tr>
<tr>
<td>2020</td>
<td>0.5%</td>
</tr>
<tr>
<td>2021</td>
<td>1.6%</td>
</tr>
<tr>
<td>2022</td>
<td>1.6%</td>
</tr>
<tr>
<td>2023</td>
<td>1.4%</td>
</tr>
<tr>
<td>2024</td>
<td>0.1%</td>
</tr>
<tr>
<td>2025</td>
<td>0.0%</td>
</tr>
<tr>
<td>2026</td>
<td>-0.1%</td>
</tr>
</tbody>
</table>

### 4.3 Bulk supply point forecasts

Generally, the load changes at bulk supply points (BSPs) are organic. However, where there are spot loads, 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 32 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 DNSPs and directly connected customers to TransGrid in early 2018. The DNSPs methodologies for load forecasting should be referred to in the respective DNSP’s annual planning report.

### 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 sales are planned. There are also some applications for industrial loads and plans for a Liverpool CBD development over a longer period of time (>10 years).

### North-west Sydney

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

#### 4.3.1 Aggregate of bulk supply point forecasts

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
- Power station auxiliary load

We attempt to account for the above mentioned limitations by:

- Using 50% POE forecasts where they are available, and where they are not available, by assuming that individual bulk supply point projections are likely to have been based on enough historical data to converge towards an approximate 50% POE forecast.
- ‘Diversifying’ individual bulk supply point 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.
- 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 2018 NSW forecast.

### 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 next ten years, an extra one million people will call Sydney home. To cope with this extraordinary growth, the NSW Government is delivering and planning a range of projects (electricity loads) in Sydney Inner Metropolitan area including transportation infrastructures and a number of precinct or urban developments (Waterloo, Bays, Ashmores, Barangaroo, Central Park, Green Square, Harold Park and the Southern Employment Lands). The City of Sydney project website, http://www.cityofsydney.nsw.gov.au/vision/changing-urban-premints/city-transformation and http://www.cityofsydney.nsw.gov.au/vision/changing-urban-premints. Viewed on 16 April 2018

Figure 32 – BSP summer forecast growth rates

<table>
<thead>
<tr>
<th>Growth Rate</th>
<th>North West Sydney</th>
<th>South West Sydney</th>
<th>Sydney Metropolitan</th>
</tr>
</thead>
<tbody>
<tr>
<td>2%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1%</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>-1%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>-2%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>-3%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>-4%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>-5%</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Index

- North West Sydney
- South West Sydney
- Sydney Metro

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

**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 sales are planned. There are also some applications for industrial loads and plans for a Liverpool CBD development over a longer period of time (>10 years).

**North-west Sydney**

The development of North West Rail infrastructure and associated activity (medium/high density residential), commercial & industrial areas will drive load growth in this area.
Figure 33 and Figure 34 show the NSW and ACT aggregate BSPs summer and winter maximum demand forecasts respectively. Over the next ten years (2018-19 to 2027-28), the aggregate BSPs summer and winter maximum demand 50% POE forecasts are expected to grow at an annual average rate of 1.3% and 1.3% respectively.

**Figure 33 – Aggregate BSPs summer maximum demand forecast**

![Figure 33](image)

**Figure 34 – Aggregate BSPs winter maximum demand forecast**

![Figure 34](image)

4.3.2 TransGrid’s 2018 NSW region forecast vs aggregate BSPs forecast

Figure 35 and Figure 36 show aggregate BSPs summer and winter maximum demand forecasts compared with TransGrid’s 50% POE medium NSW region summer and winter maximum demand forecasts respectively for NSW and ACT region.

**Figure 35 – TransGrid’s top down forecast vs aggregate BSPs forecast for summer maximum demand**

![Figure 35](image)

**Figure 36 – TransGrid’s top down forecast vs aggregate BSPs forecast for winter maximum demand**

![Figure 36](image)

Although the comparison between TransGrid’s 2018 top down forecasts and the DNSPs’ aggregate of BSPs forecasts do not indicate which forecast is more accurate, they allow a high-level comparison to be made.
TransGrid’s TAPR 2017 referred to AEMO’s 2017 load forecast, while this TAPR has TransGrid’s own NSW region load forecasts. Therefore, analysis and explanation of any aspects of forecast loads provided in this TAPR that have changed significantly from forecasts provided in 2017 TAPR in accordance to the NER Clause 5.12.2(c)(1)(ii) is extraneous as the basis of the respective forecasts are different.

However, observation between the TransGrid’s 2018 demand forecast and AEMO’s demand forecast in its 2018 Electricity Forecasting Insight – March 2018 update26 for NSW region is provided in this section. TransGrid notes that its demand forecast is presented on ‘as-generated’ basis, whereas AEMO’s demand forecast is presented on ‘native sent out’ basis. The methodology underpinning the AEMO’s demand forecast is provided in the AEMO website.27

In order to compare these two forecast trends expressed on different basis, TransGrid combined the AEMO’s ‘native sent out’ neutral 50% POE forecast and the AEMO’s ‘auxiliary load’ neutral 50% POE forecast. This summated AEMO’s forecast is compared to TransGrid’s ‘as-generated’ medium 50% POE forecast and is shown in the following Figure 37.

Figure 37 – TransGrid’s 2018 vs AEMO’s March 2018 maximum demand forecast for NSW region

The analysis and explanation regarding the differences in the annual energy consumption forecasts between TransGrid and AEMO is relatively straightforward as both forecasts in this comparison are expressed on ‘native sent out’ basis.

TransGrid’s 2018 (medium) and AEMO’s 2018 (neutral) annual energy consumption forecast can be compared as is shown in the following Figure 38.

Figure 38 – TransGrid’s 2018 vs AEMO’s March 2018 energy consumption forecast for NSW region

In recent years, the actual native energy consumption in NSW region has consistently been higher than the AEMO native energy consumption forecasted in the preceding National Electricity Forecasting Reports (NEFR) as shown in Figure 39.

Figure 39 – AEMO historical NSW region native energy forecast vs actual consumption

This phenomenon has been well documented by AEMO in its annual forecast accuracy report where it analyses the variance between the historical annual native energy consumption forecast against the actual outcome for previous year. The actual consumption have been 1,794 GWh, 751 GWh and 600 GWh more than the forecasted annual native energy in 2014/15, 2015/16 and 2016/17 respectively. The common reasons provided for these variances are either higher than expected consumption and/or significantly warmer weather than expected.
With an exception of the summer maximum demand forecast for 2017/18 included in the 2017 TAPR (i.e. AEMO’s forecast), the AEMO has been under forecasting maximum demand in NSW region because the actual outcome (i.e. raw maximum demand) has been closer to 10% POE forecast in recent years.

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

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 Executive Joint Planning Committee (EJPC) in achieving effective collaboration, consultation and coordination between Jurisdictional Planning Bodies, 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 Executive Joint Planning Committee (EJP) in achieving 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.

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
- Market Modelling Working Group
- Planning Reference Group
- Forecasting Reference Group
- Regulatory Working Group
- Regular coordination meetings

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 Integrated System Plan (ISP)
- Continuously improve current network planning practices
- Coordinate on energy security across the NEM.

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, Transmission System Operators and AEMO on electricity transmission network planning issues.

Market Modelling Working Group
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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 Executive Joint Planning Committee (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 (VIC) Planning
- Powerlink
- ElectraNet
- Ausgrid
- Endeavour Energy
- Essential Energy
- Evonergy

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

- Integrated System Plan
- Power System Frequency Risk Review
- South Australian Energy Transformation
- QNI Upgrade
- VIC to NSW Upgrade
- Voltage Control in Southern NSW.

Integrated System Plan
The Independent Review into the Future Security of the National Electricity Market (Finkel Review) recommended34:

- By mid-2018, the Australian Energy Market Operator, supported by transmission network service providers and relevant stakeholders, should develop an integrated grid plan to facilitate the efficient development and connection of renewable energy zones across the National Electricity Market.

TransGrid has worked with AEMO to support the development of the 2018 ISP. The ISP has clear observations and recommendations for the short-term development of the transmission network, which form the basis of an overarching long-term strategy.

Process
TransGrid provided a range of network planning inputs to AEMO’s ISP modelling process35, supported the development of the ISP through regular engagement, and reviewed the long-term network development strategy and findings. Throughout its development, AEMO conducted workshops and regular coordination meetings to incorporate input from the industry. AEMO’s public consultation received 68 formal submissions, which are available on AEMO’s website36.

Methodology
The ISP methodology is outlined on AEMO’s website37.

South Australian Energy Transformation
Process
Under ElectraNet’s lead, Jurisdictional Planning Bodies participated in a working group to co-ordinate network analysis and cost estimation for ElectraNet’s South Australian Energy Transformation RAT.

Methodology
TransGrid provided support with network analysis and cost estimating for interconnector options between NSW and South Australia (SA).

Outcomes
Refer to Section 2.11.1 of this TAPR.

4.6.2 Joint Planning Projects

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

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- Power System Frequency Risk Review
- South Australian Energy Transformation
- QNI Upgrade
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- Voltage Control in Southern NSW.

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Methodology
The ISP methodology is outlined on AEMO’s website37.

Outcomes
The primary outcome of the ISP that relates to TransGrid’s network planning is the ISP’s network development plan. This plan sets out a long-term strategy for the efficient development of the NEM transmission network, and the connection of Renewable Energy Zones over the coming 20 years. This plan will be available on AEMO’s website38. TransGrid has reviewed, and supports, the ISP network development plan. This TAPR aligns with the ISP network development plan.

Power System Frequency Risk Review (PSFRR)
The Power System Frequency Risk Review (PSFRR)39 is an integrated, periodic review of power system frequency risks associated with non-credible contingency events in the National Electricity Market (NEM).

Process
TransGrid supported AEMO in identifying non-credible contingencies and emergency control schemes that could be within the scope of the PSFRR. From a preliminary list of events, AEMO, in consultation with TNSPs, ruled out some events and prioritised others for assessment based on criteria consistent with the NER. AEMO shared and discussed initial findings with TNSPs and preliminary versions of the PSFRR draft report. AEMO incorporated feedback from TNSPs into the draft and final PSFRR.

Methodology
With support from TransGrid, AEMO assessed the performance of existing Emergency Frequency Control Schemes (EFCs), AEMO also assessed high priority non-credible contingency events identified in consultation with TNSPs. Techniques used for assessment varied on a case by case basis and included:

- Review of previous studies, or reports on historical events
- PSQAD studies
- PSS/E studies
- Single Mass Model Studies

From these assessments AEMO determined whether further action may be justified to manage frequency risks. TransGrid has reviewed AEMO’s work and supports the outcomes of the PSFRR.

Outcomes
The existing mainland NEM Under-Frequency Load Shedding (UFLS) schemes are currently sufficient to contain frequency within the Frequency Operating Standard (FOS) for large under-frequency events. AEMO is currently reviewing the need to modify the mainland NEM UFLS schemes to account for potential over correction.

Current mechanisms to protect against frequency risks are appropriate. AEMO did not identify any immediate need to modify any EFCs. While AEMO has no recommendations on managing frequency risks due to non-credible contingencies in NSW, AEMO supports TransGrid exploring options to mitigate risks of major supply disruption which may be caused by transient, or voltage instability. Several instances of such risks have been identified by TransGrid, and were also observed in AEMO’s studies.

South Australian Energy Transformation

Under ElectraNet’s lead, Jurisdictional Planning Bodies participated in a working group to co-ordinate network analysis and cost estimation for ElectraNet’s South Australian Energy Transformation RAT.

Methodology
TransGrid provided support with network analysis and cost estimating for interconnector options between NSW and South Australia (SA).

Outcomes
Refer to Section 2.11.1 of this TAPR.
The transmission network provides the platform to transport energy from large-scale generation to major load centres. It also provides the platform for power system stability by sharing ancillary services provided by generators and some network assets.

<table>
<thead>
<tr>
<th>Criteria</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maximum demand (or peak demand)</td>
<td>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.</td>
</tr>
<tr>
<td>Minimum demand</td>
<td>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.</td>
</tr>
<tr>
<td>Energy</td>
<td>The total amount of electricity used over a period of time.</td>
</tr>
<tr>
<td>Voltage control</td>
<td>The ability to maintain voltages throughout the power system within stable and safe limits.</td>
</tr>
<tr>
<td>System strength</td>
<td>The ability of the power system to temporarily provide high energy to manage disturbances while maintaining voltage control.</td>
</tr>
<tr>
<td>Inertia</td>
<td>The ability of the power system to provide frequency control during disturbances.</td>
</tr>
<tr>
<td>Reserve</td>
<td>Extra generation that is readily available by increasing the output of generators already generating in the power system.</td>
</tr>
<tr>
<td>Power system data communications</td>
<td>High speed data communications to provide visibility, monitoring and control of the power system. This includes dispatching generation and operating networks.</td>
</tr>
</tbody>
</table>

We have 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 22.

**Table 22 – Key considerations when developing the transmission network**

<table>
<thead>
<tr>
<th>Criteria</th>
<th>Description</th>
</tr>
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<tbody>
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<td>Power system data communications</td>
<td>High speed data communications to provide visibility, monitoring and control of the power system. This includes dispatching generation and operating networks.</td>
</tr>
</tbody>
</table>

We are extending our high speed data communications optical fibre network as set out in section 2.3.1. We are also working to develop low-cost communications solutions to areas of NSW with the best renewable resources to support the connection of new generation and establishment of large-scale energy zones.

**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 contribute to power system security by providing visibility, monitoring and control of the power system.
4.8 Service standards

New reliability standards

The new NSW Electricity Transmission Reliability and Performance Standard 2017 for NSW was issued by the NSW Government in June 2017. The Standard comes into effect on 1 July 2018 and is administered by IPART. This Reliability Standard comprises of two components for each bulk supply point (BSP):

- A required level of network redundancy for each BSP or group of BSPPs that function as a cohort, appropriate to the size and the significance of the load being supplied; and
- The maximum amount of time the average load on the BSP (or BSP group) that may be at risk of not being supplied.

When assessing the level of redundancy the Standard provides that at some BSPPs, supply interruption is allowed following the outage of a single transmission network element (Category 1 BSPP). In other BSPPs, a “non-zero” amount of load is required to be supplied following the outage of a single transmission network element (Category 2 BSPP). In the remaining group of BSPPs, non-zero amount of load is required to be supplied following the outages of a combination of any two of three types of transmission network elements.

With regards to the amount of time that there is a risk of energy not being supplied, the Standard provides for the maximum Minutes of Expected Unserved Energy at each BSP (or group of BSPPs) based on the average demand on the BSP and the combination of:

- the configuration of the network supplying the BSP
- the probabilities of network element failure; and
- average restoration times.

The maximum permissible Minutes of Expected Unserved Energy allowances range from 0.6 minutes per year for Inner Sydney to 115 minutes in one area in NSW’s west.

The standards are planning standards, rather than performance standards. This means that 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.

TransGrid may be required to invest in the network to ensure that the requirements of the Standards are met. However, the Standard 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.

Our preliminary compliance assessment has shown full compliance is expected to be achieved at the commencement date of the Standard for all BSPPs. Under the flexibility provisions in the Standard TransGrid has submitted a business case for works in DNSP control systems to meet the Expected Unserved Energy allowance at Mudgee 132kV BSP by 30 June 2019. The business case has been approved by IPART as the most efficient option to meet the Standard.

This report includes network developments to meet the new reliability standards in section 2.3.

ACT reliability standard

We are also subject to the Electricity Transmission Supply Code which comes into effect on 1 July 2018 under the transmission licence we hold in the ACT. The Code includes the requirement for the provision of two or more geographically separate points of supply at 33 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.

We currently supply the ACT load via the Canberra and Williamsdale substations. However, Williamsdale substation is supplied through Canberra substation. The construction of a new substation located at Stockdale Drive will meet the requirements for a second, fully independent supply point. More detailed information about this project is available in section 2.2.5.

AEMO’s 2017 ESOO projected that the risk of unserved energy in NSW is 0.0004%, of energy consumption in 2022-23, and this will increase after the retirement of Liddell Power Station announced for 2024 (assuming demand increasing up to 0.0015% in 2024-25. Loss of an additional major power station in NSW after Liddell withdraws could lead to a Low Reserve Condition (LRC), unless sufficient additional firming capability is developed in time.

AEMO did not publish a NTNDP in 2017. The first and second updates of the 2016 NTNDP in September 2017 and October 2017 respectively were limited to the discussion of the Network Support and Control Ancillary Services (NSCAS) gap for system strength in SA. AEMO’s inaugural 2018 ISP will present a long-term strategic development plan (considering a range of scenarios) to deliver continued reliability and security, at least long-term cost for consumers, while meeting emissions reduction targets. As this inaugural ISP purpose and scope encompass those which would normally be covered in the NTNDP, TransGrid plans to incorporate it into the inaugural ISP.

Our plan to transition to the energy system of the future aligns with AEMO’s ISP.

4.10 Changes from TAPR 2017

Updates since in this chapter and referenced Appendices since TAPR 2017 includes the following:

- TransGrid has prepared its own forecasts for NSW energy consumption and maximum demands to provide a transparent understanding of the outlook for electricity consumption and maximum demand for the region as a whole. This chapter has been restructured to accommodate this change and to more fully describe the forecast.

- The method of preparation of the TransGrid forecast is explained in Appendix 1, including a description of models, model testing, input variables and scenarios, other assumptions and independent advice.

- A comparison of annual energy consumption and maximum demand between TransGrid’s 2018 forecast and AEMO’s 2018 forecast has been added.
Appendix 1

NSW region load forecasting methodology
This appendix describes our 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 New South Wales (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

'Native' energy is equal to operational (that is, grid-supplied) energy, in GWh summed over a financial year, plus energy generated by other small non-scheduled generation to supply electricity in NSW. Native energy is measured and forecast on a 'sent-out' basis.

'Native' demand is equal to operational (that is, grid-supplied) demand, in MW at a half-hourly resolution, plus energy generated by other small non-scheduled generation to supply electricity in NSW. Native demand is measured and forecast on an 'as-generated' basis.

#### A1.1.2 Load forecast components

The NSW load forecast was prepared by TransGrid 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 to TransGrid by BIS Oxford Economics34
- Projections of future energy price paths – undertaken for TransGrid by Jacobs35
- Modelling of rooftop PV installation and generation, and distributed battery storage – undertaken for TransGrid by GHD36
- Assessment of recent energy efficiency policies and standards, and quantification of the energy savings impacts – undertaken for TransGrid by Energy Efficient Strategies37
- Projections of the take-up of zero or low emissions vehicles (requiring either grid battery charging or electrically produced hydrogen) – undertaken by Energeia and provided to AEMO in 2017.38

These components are presented schematically with their interactions in Figure 40 and each is discussed in more detail in the following sections.

### A1.2 Energy modelling

#### A1.2.1 Approach

Econometric modelling was used to estimate the independent impacts of population, 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 developed for residential and 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
- Rooftop PV generation

#### 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 23 and Table 24.
The inverse impact of electricity prices on annual energy is significant, albeit small relative to the impact of income and residential consumption. A long-run decrease in residential electricity consumption (all other things remaining the same) of 1 per cent per year would lead to a long-run decrease in residential electricity consumption of 0.1 per cent per year. However, the inverse impact of electricity prices on annual energy is relatively small, with the estimated price elasticity of demand being 0.027. This means that a one per cent increase in the retail price of electricity would lead to a 0.027 per cent decrease in residential electricity consumption.

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. Forecasts of residential and non-residential electricity also require forecasts of population, energy efficiency savings and rooftop PV generation, in addition to forward projections using the models in Tables 23 and 24. Post-modelling assumptions, including future energy efficiency savings and rooftop PV generation, comprise a significant component of the overall forecasts. Future electrification of transport may entail new sources of demand for electricity as a result of externally charged electric road vehicles, the production of hydrogen for fuel cells in domestic vehicles or for export, and extensions of the electrified rail network.

Table 23 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 of 0.114 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. As shown in Table 24, the transient effect of weather variation has virtually no measurable effect on annual energy over the course of a year, although the number of cold days does have a significant impact on residential consumption.

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 41 and Figure 42. These figures were produced with data up to 2014-15, with the last two actual years forecast out-of-sample to test the models. Some key indications of the reliability of the forecasts are:

- The fitted lines are well-contained within a plus or minus two standard error band
- Calculated accuracy measures are low, for example Mean Absolute Percentage Error (MAPE) is low (1.49 for the residential model and 2.15 for the non-residential model)
- The bias proportion of the Theil statistic is very low (0.003 for the residential model and around 0.000008 for the non-residential model) indicating very little tendency for either model to produce long run forecasts that are persistently too high or too low
- The recent downturn associated with rising prices is captured in varying degrees by the residential and non-residential models (with the larger impact of price rises in the non-residential model indicating that energy efficiency may have had a greater effect in the residential sector).

These results suggest that the models are valid across the entire sample period, are relatively accurate and are not given to persistent bias up or down.

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 calculation levels of maximum demand for each season that accurately correspond to 10, 50 and 90 per cent Probability of Exceedance (PCE). 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 (equally weighted), 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 degree increase in average daily temperature in 1969-94 to 311 MW (2.3%) in 2017-18; 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 86 MW.
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.

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.

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.

For winter, there are 20 alternative temperature sets and 540 alternative residual sets, resulting in a total of 11,880 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.

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 43 and Figure 44.

A1.4 Summer and winter maximum demand models
A1.4.1 Approach
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
- 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, the production of hydrogen for fuel cells in domestic vehicle or for export, and extensions of the electrified rail network.

Forecasts of summer and winter maximum demand are projected from the historical POE10, POE50 and POE90 maximum demands, thus removing the year-to-year variability in the weather-sensitive component.

The maximum demand forecasts are prepared as follows:

- using the energy model, a new measure of annual energy is estimated as the native energy that would have occurred in the absence of any historical change in the real electricity price
- major industrial loads are removed from each historical POE level of demand and annual energy
- a weighted average of the original energy and the adjusted measure is used from here on to include 55 per cent of the estimated price impact
- equivalent adjustments are made to the historical and forecast weighted average measure of annual energy
- load factors (LF) are calculated for each of the POE10, POE50 and POE90 demand (Md) levels in MW, using the number of hours in each year as follows:
  \[ LF = \frac{1000 \times \text{weighted average energy}}{\text{MD} \times \text{hours}} \]
- a statistical relationship between each calculated load factor and air-conditioning penetration in NSW is then estimated
- using the estimated relationships to calculate future load factors, conditional on a projection of NSW air-conditioning penetration (currently around 55 per cent) that levels out around 60 per cent.

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.

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.

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.

For winter, there are 20 alternative temperature sets and 540 alternative residual sets, resulting in a total of 11,880 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.

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 43 and Figure 44.

A1.4 Summer and winter maximum demand models

A1.4.1 Approach

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
- 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, the production of hydrogen for fuel cells in domestic vehicle or for export, and extensions of the electrified rail network.

Forecasts of summer and winter maximum demand are projected from the historical POE10, POE50 and POE90 maximum demands, thus removing the year-to-year variability in the weather-sensitive component.

The maximum demand forecasts are prepared as follows:

- using the energy model, a new measure of annual energy is estimated as the native energy that would have occurred in the absence of any historical change in the real electricity price
- major industrial loads are removed from each historical POE level of demand and annual energy
- a weighted average of the original energy and the adjusted measure is used from here on to include 55 per cent of the estimated price impact
- equivalent adjustments are made to the historical and forecast weighted average measure of annual energy
- load factors (LF) are calculated for each of the POE10, POE50 and POE90 demand (Md) levels in MW, using the number of hours in each year as follows:
  \[ LF = \frac{1000 \times \text{weighted average energy}}{\text{MD} \times \text{hours}} \]
- a statistical relationship between each calculated load factor and air-conditioning penetration in NSW is then estimated
- using the estimated relationships to calculate future load factors, conditional on a projection of NSW air-conditioning penetration (currently around 55 per cent) that levels out around 60 per cent.
A1.4.2 Model accuracy

The summer and winter models’ fit to the historical data sample and medium scenario forecasts are shown in Figure 45 and Figure 46. Some key indications of the reliability of the forecasts are:

- the fitted lines are well-contained within a plus or minus two standard error band
- calculated accuracy measures are low, for example Mean Absolute Percentage Error (MAPE) is low (1.25 for the summer model and 1.19 for the winter model)
- the bias proportion of the Theil statistic is very low (0.00006 for the summer model and 0.00007 for the winter model)

These results suggest that the models are valid across the entire sample period, are relatively accurate and are not given to persistent bias up or down.

Figure 45 – Summer underlying load factor POE50 within and out-of-sample fit

Figure 46 – Winter underlying load factor POE50 within and out-of-sample fit

A1.5 Major industrial loads

Very little change is predicted in major industrial loads. These loads accounted for 16 per cent of annual energy in 2016/17 and 11 per cent of last summer’s maximum demand which occurred on 19 December 2017. Existing major industrial loads include:

- Tomago Aluminium
- BlueScope steel Port Kembla
- Onesteel Wararbah West
- Visy Gadara
- Norske Skog Albury
- Broken Hill Mine
- Caddia Mine Orange
- North Parkes Mine
- Lake Cowal Mine
- Ulan Area Mines
- Boggabri East and North Mines
- CSR Oberon

An estimated 185 MW of additional major industrial load is included in the forecasts based on information provided by TransGrid’s customers, including DSOs. Additional loads include mine expansions, new industrial loads and large infrastructure projects, and has been generally discounted by 15 per cent to allow for historical variations between planned power requirements 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.

A1.6.1 Demographic and economic forecasts

TransGrid obtained projections of future demographic and economic trends.40

Table 25 – NSW population growth and key macroeconomic forecasts CAGR 2019-2028

<table>
<thead>
<tr>
<th>Variable</th>
<th>Medium</th>
<th>High</th>
<th>Low</th>
</tr>
</thead>
<tbody>
<tr>
<td>Resident population</td>
<td>1.3</td>
<td>1.5</td>
<td>1.2</td>
</tr>
<tr>
<td>Real household disposable income</td>
<td>2.5</td>
<td>3.5</td>
<td>1.8</td>
</tr>
<tr>
<td>Gross State Product</td>
<td>2.5</td>
<td>3.5</td>
<td>1.8</td>
</tr>
</tbody>
</table>

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.41

Table 26 – NSW electricity and gas price forecasts CAGR 2019-2028

<table>
<thead>
<tr>
<th>Variable</th>
<th>Medium</th>
<th>High</th>
<th>Low</th>
</tr>
</thead>
<tbody>
<tr>
<td>Real residential electricity price</td>
<td>-2.2</td>
<td>-1.6</td>
<td>-2.3</td>
</tr>
<tr>
<td>Real non-residential electricity price</td>
<td>-2.7</td>
<td>-2.0</td>
<td>-3.2</td>
</tr>
<tr>
<td>Real gas and other fuels price</td>
<td>-1.9</td>
<td>-0.6</td>
<td>-3.3</td>
</tr>
</tbody>
</table>

A1.6.3 Rooftop PV and distributed battery storage

TransGrid load forecasts were prepared using a model of rooftop PV installation and generation, and distributed battery storage41. Annual PV output and battery discharging quantities were subtracted directly from the modelled energy and maximum demand forecasts to estimate network energy and maximum demand.

Table 27 – NSW rooftop PV and battery storage forecasts total increase 2019-2028 (2018-2027 for winter)

<table>
<thead>
<tr>
<th>Variable</th>
<th>Medium</th>
<th>High</th>
<th>Low</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential PV generation GWh</td>
<td>4,038</td>
<td>4,155</td>
<td>3,915</td>
</tr>
<tr>
<td>Non-residential PV generation GWh</td>
<td>2,077</td>
<td>2,136</td>
<td>2,015</td>
</tr>
<tr>
<td>Shift in summer maximum demand due to PV</td>
<td>1,146</td>
<td>1,255</td>
<td>1,066</td>
</tr>
<tr>
<td>Battery discharge at time of summer and winter maximum MW</td>
<td>195/61</td>
<td>251/275</td>
<td>51/81</td>
</tr>
</tbody>
</table>

A1.6.4 Energy efficiency policies

A thorough assessment of recent energy efficiency policies and standards, and quantification of the energy savings impacts resulted in a series of energy efficiency savings impacting on electricity demand. TransGrid extracted the projected historical trend from 2001 to 2009 from the projected total savings.42

Table 28 – Energy efficiency out of trend total increase 2019-2028 (winter 2018-2027)

<table>
<thead>
<tr>
<th>Variable</th>
<th>Medium</th>
<th>Low</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential savings GWh</td>
<td>642</td>
<td>777</td>
</tr>
<tr>
<td>Non-residential savings GWh</td>
<td>7,006</td>
<td>9,178</td>
</tr>
<tr>
<td>Total savings at time of summer maximum MW</td>
<td>1,066</td>
<td>2,437</td>
</tr>
<tr>
<td>Total savings at time of winter maximum MW</td>
<td>1,304</td>
<td>1,585</td>
</tr>
</tbody>
</table>

A1.6.5 Low emissions transport

An allowance is included in the load forecast to account for future take-up of zero or low emissions vehicles (requiring either grid battery charging or electrically produced hydrogen). TransGrid has considered charging loads of existing electric vehicles and projected increasing take-up.43

Annual energy used for charging is extracted from the latest AEMO Insights March 2018 Update. This was in turn derived from the report commissioned by AEMO from Energeia. TransGrid also attributed a small charging load to times of summer and winter system maximum that was not so attributed by AEMO.

A1.6.6 Glossary

<table>
<thead>
<tr>
<th>Item</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>As generated</td>
<td>Generation measured at the generator terminals</td>
</tr>
<tr>
<td>Cooling degree days</td>
<td>Heating degree days is the addition of heating degrees for all days in a period. Heating degrees (HDs) 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 &lt; 18, HD = 0 ( t - 18 ) For t &gt; 21, CD = -0.5 as a % increase in own price reduces demand by 0.5%</td>
</tr>
<tr>
<td>Demand, Operational</td>
<td>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</td>
</tr>
<tr>
<td>Demand, Native</td>
<td>Operational demand as above plus small Non-Scheduled generation. Non-inclusion of this generation may significantly distort past electricity usage trends in NSW</td>
</tr>
<tr>
<td>Elasticity</td>
<td>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%</td>
</tr>
<tr>
<td>Electricity services</td>
<td>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.</td>
</tr>
<tr>
<td>Energy</td>
<td>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/yr.</td>
</tr>
<tr>
<td>Heating degree days</td>
<td>Heating degree days is the addition of heating degrees for all days in a period. Heating degrees (HDs) 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 &lt; 18, HD = 0 ( t - 18 ) For t &gt; 21, CD = -0.5 as a % increase in own price reduces demand by 0.5%</td>
</tr>
<tr>
<td>Load factor</td>
<td>The ratio of average demand to maximum demand. This can relate to maximum demand and energy via the formulation. Load factor = 1000 x GWh energy/MW maximum demand x 8760</td>
</tr>
<tr>
<td>Major industrial load</td>
<td>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</td>
</tr>
<tr>
<td>Maximum demand</td>
<td>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</td>
</tr>
<tr>
<td>NSW Region</td>
<td>State of NSW and the Australian Capital Territory (ACT)</td>
</tr>
<tr>
<td>Sent-out</td>
<td>Generation measured at the point of connection with the transmission network</td>
</tr>
<tr>
<td>Small non-scheduled generation</td>
<td>Non-Scheduled generation that is not included in Operational Demand</td>
</tr>
<tr>
<td>Summer</td>
<td>In this report, all days from 16 November in a particular year to 15 March in the immediately following year, inclusive</td>
</tr>
<tr>
<td>Winter</td>
<td>In this report, all days in a particular year from 16 May to 31 August, inclusive</td>
</tr>
</tbody>
</table>


<table>
<thead>
<tr>
<th>Variable</th>
<th>Medium</th>
<th>High</th>
<th>Low</th>
</tr>
</thead>
<tbody>
<tr>
<td>Annual energy GWh</td>
<td>1,078</td>
<td>1,078</td>
<td>1,078</td>
</tr>
<tr>
<td>Load at time of summer and winter maximum MW</td>
<td>13</td>
<td>13</td>
<td>13</td>
</tr>
</tbody>
</table>

Table 29 – Electric vehicle charging total increase 2019-2028 (winter 2018-2027)
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.

### Appendix 2

#### Individual bulk supply point projections

| Table 30 – Ausgrid bulk supply point summer maximum demand |
|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|
| Liddell 33 kV  | 375              | 390              | 398              | 402             | 409              | 418              | 427              | 431              | 434             | 437             |                |                |                |                |                |                |                |                |                |
| Newcastle 33 kV | 120              | 120              | 120              | 120             | 120              | 120              | 120              | 120              | 120             | 120             |                |                |                |                |                |                |                |                |                |
| Muswellbrook 33 kV | 163            | 163              | 163              | 163             | 163              | 163              | 163              | 163              | 163             | 163             |                |                |                |                |                |                |                |                |                |
| Dapto 132 kV    | 634              | 636              | 638              | 638             | 638              | 638              | 638              | 638              | 638             | 638             |                |                |                |                |                |                |                |                |                |
| Waratah West 132 kV | 94              | 92              | 92              | 92              | 92              | 92              | 92              | 92              | 92              | 92              |                |                |                |                |                |                |                |                |                |
| Vales Point 132 kV | 104            | 104              | 104              | 104             | 104              | 104              | 104              | 104              | 104             | 104             |                |                |                |                |                |                |                |                |                |

| Table 31 – Ausgrid bulk supply point winter maximum demand |
|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|
| Liddell 33 kV  | 375              | 390              | 398              | 402             | 409              | 418              | 427              | 431              | 434             | 437             |                |                |                |                |                |                |                |                |                |
| Newcastle 33 kV | 120              | 120              | 120              | 120             | 120              | 120              | 120              | 120              | 120             | 120             |                |                |                |                |                |                |                |                |                |
| Muswellbrook 33 kV | 163            | 163              | 163              | 163             | 163              | 163              | 163              | 163              | 163             | 163             |                |                |                |                |                |                |                |                |                |
| Dapto 132 kV    | 634              | 636              | 638              | 638             | 638              | 638              | 638              | 638              | 638             | 638             |                |                |                |                |                |                |                |                |                |
| Waratah West 132 kV | 94              | 92              | 92              | 92              | 92              | 92              | 92              | 92              | 92              | 92              |                |                |                |                |                |                |                |                |                |
| Vales Point 132 kV | 104            | 104              | 104              | 104             | 104              | 104              | 104              | 104              | 104             | 104             |                |                |                |                |                |                |                |                |                |

| Table 32 – Endeavour Energy bulk supply point summer maximum demand |
|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|
| Liddell 33 kV  | 375              | 390              | 398              | 402             | 409              | 418              | 427              | 431              | 434             | 437             |                |                |                |                |                |                |                |                |                |
| Newcastle 33 kV | 120              | 120              | 120              | 120             | 120              | 120              | 120              | 120              | 120             | 120             |                |                |                |                |                |                |                |                |                |
| Muswellbrook 33 kV | 163            | 163              | 163              | 163             | 163              | 163              | 163              | 163              | 163             | 163             |                |                |                |                |                |                |                |                |                |
| Dapto 132 kV    | 634              | 636              | 638              | 638             | 638              | 638              | 638              | 638              | 638             | 638             |                |                |                |                |                |                |                |                |                |
| Waratah West 132 kV | 94              | 92              | 92              | 92              | 92              | 92              | 92              | 92              | 92              | 92              |                |                |                |                |                |                |                |                |                |
| Vales Point 132 kV | 104            | 104              | 104              | 104             | 104              | 104              | 104              | 104              | 104             | 104             |                |                |                |                |                |                |                |                |                |

44 Zone substation projections aggregated to TransGrid bulk supply points using agreed load flow models.
45 Marulan 132 kV: Both Endeavour Energy and Essential Energy take supply from Marulan. This forecast is for the Endeavour Energy component. Diversity factors of 3% in summer should be applied to obtain the forecast total summer load at Marulan.
### Table 34 – Essential Energy (North) bulk supply point summer maximum demand

<table>
<thead>
<tr>
<th>Supply Point</th>
<th>MW</th>
<th>MVAr</th>
<th>MW</th>
<th>MVAr</th>
<th>MW</th>
<th>MVAr</th>
<th>MW</th>
<th>MVAr</th>
<th>MW</th>
<th>MVAr</th>
<th>MW</th>
<th>MVAr</th>
<th>MW</th>
<th>MVAr</th>
</tr>
</thead>
<tbody>
<tr>
<td>Kempsey 33 kV</td>
<td>11 2</td>
<td>11 2</td>
<td>11 2</td>
<td>11 2</td>
<td>11 2</td>
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<td>11 2</td>
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<td>11 2</td>
<td>11 2</td>
<td>11 2</td>
<td>11 2</td>
</tr>
<tr>
<td>Inverell 66 kV</td>
<td>18 0</td>
<td>18 0</td>
<td>18 0</td>
<td>18 0</td>
<td>18 0</td>
<td>18 0</td>
<td>18 0</td>
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<td>18 0</td>
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<tr>
<td>Herons Creek 132 kV</td>
<td>9 0</td>
<td>9 0</td>
<td>9 0</td>
<td>9 0</td>
<td>9 0</td>
<td>9 0</td>
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<td>9 0</td>
<td>9 0</td>
</tr>
<tr>
<td>Narrabri 66 kV</td>
<td>50 6</td>
<td>50 6</td>
<td>51 6</td>
<td>51 6</td>
<td>52 6</td>
<td>52 6</td>
<td>53 6</td>
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<tr>
<td>Narrabri 66 kV</td>
<td>50 6</td>
<td>50 6</td>
<td>51 6</td>
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</tr>
<tr>
<td>Moree 66 kV</td>
<td>36 4</td>
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<td>36 4</td>
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<td>36 4</td>
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</tr>
<tr>
<td>Macksville 132 kV</td>
<td>9 1</td>
<td>9 1</td>
<td>9 1</td>
<td>9 1</td>
<td>9 1</td>
<td>9 1</td>
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<td>9 1</td>
</tr>
<tr>
<td>Moonee 66 kV</td>
<td>32 8</td>
<td>32 8</td>
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</tr>
<tr>
<td>Macarthur 132 kV</td>
<td>84 3</td>
<td>84 3</td>
<td>84 3</td>
<td>84 3</td>
<td>84 3</td>
<td>84 3</td>
<td>84 3</td>
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<td>84 3</td>
<td>84 3</td>
<td>84 3</td>
</tr>
<tr>
<td>Marulan 132 kV</td>
<td>80 2</td>
<td>80 2</td>
<td>80 2</td>
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### Table 35 – Essential Energy (North) bulk supply point winter maximum demand

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**Table 36 – Essential Energy (Central) bulk supply point winter maximum demand**

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**Table 37 – Essential Energy (Central) bulk supply point winter maximum demand**

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**Table 38 – Essential Energy (South and Far West) and Evoenergy bulk supply point summer maximum demand**

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47 Endeavour Energy and Essential Energy take supply from Marulan. This forecast is for the Essential Energy component.

Diversity factors of 1% in summer should be applied to obtain the forecast total summer load at Marulan.
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48 Marulan 132 kV: Both Endeavour Energy and Essential Energy take supply from Marulan. This forecast is for the Essential Energy component. Diversity factors of 2% in winter should be applied to obtain the forecast total winter load at Marulan.
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.

The process includes:

- Early engagement with stakeholders throughout the planning cycle, involving end-users and impacted communities
- 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

The key processes and steps, including where and how we engage with stakeholders, are set out in Figure 47.

### Stakeholder involvement

- Sense-check forecasts with
  - Distributors
  - Directly connected customers
  - AEMO
- Seek feedback from end users and their representatives on need assessment.
- Engage impacted community that may be impacted by network infrastructure.
- Communicate with local community that have been identified to need assessment.
- Identify possible network and non-network options to the need, including:
  - Demand management
  - Local or distributed generation
  - Network infrastructure optimised to expected requirements
  - Improved operational and maintenance regimes
- Identify network and non-network options.
- Engage impacted communities in network corridor selection, if relevant.
- Invite end users and their representatives in final investment decision.
- Encourage proposals from market participants for non-network options.
- Engage impacted communities in network corridor selection, if relevant.
- 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.
- Early resolution of key risk areas such as environmental approvals, property acquisition and scope definition in the project delivery process
- Documented options evaluations and project scoping to enhance transparency.

### Planning approach

As a TNSP, we are obliged to meet the requirements of the National Electricity Rules (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 Australian Energy Regulator’s (AER) 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 its system is adequately planned to enable these licence requirements to be met.

### Jurisdictional planning requirements

In addition to meeting requirements imposed by the NER, environmental legislation and other statutory instruments, we have been required to comply with the Transmission Network Design and Reliability Standard for NSW 2010 set by the NSW Government. This standard has generally required us to plan and develop our transmission network in NSW on an N–1²⁹ basis. That is, unless specified otherwise with the affected distribution network owner or major directly connected end-use customer, there will be no inadvertent loss of load (other than load which is interruptible or dispatchable) following an outage of a single circuit (a line or a cable) or transformer, during periods of forecast high load.

From 1 July 2015, we will be required to comply with the new ‘National Electricity Transmission Reliability Standards 2017’ established by IPART. The new standards allow us to undertake probabilistic investment planning and decision to develop our transmission network. This TAPP has been prepared in accordance with the new standards.

The new standards allow us to develop alternate network plans that deviate from the standard provided a greater net-benefit, using the cost-benefit methodology defined in the RIT-T process, can be demonstrated.

In fulfilling our obligations, we must recognise specific customer requirements as well as AEMO’s role as system operator for the NEM. To accommodate this, we can consider the following circumstances based on demonstration of greater net-benefit, using the cost-benefit methodology defined in RIT-T process, than the net-benefit of complying 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
- 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 planning:

- 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

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49 N–1 reliability means the system is planned for no loss of load on the outage of a single element such as a line, cable or transformer.
Appendix 3

1. Connection planning

Connection planning is concerned with the local network 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 developed in response to overall load growth and generation developments and may be influenced by interstate power transfers through interconnection. Any developments include liaison with affected NSW and interstate parties.

The assessment of the adequacy of 132 kV systems requires joint planning with other NSPs. This ensures that development proposals are optimal with respect to both transmission and distribution requirements leading to the lowest possible cost of transmission to the end customer. This is particularly important where the DNSPs' network operates in parallel with the transmission network, forming a meshed system.

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 the NER Clause 5.14.3.

A3.1 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
- Rating of transmission lines and equipment.

In addition to adherence to NER and regulatory requirements, our transmission planning approach has been developed taking into account the historical performance of the components of the NSW system, the sensitivity of loads to supply interruption, and the cost of short-term 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 reference for planning the future developments of our system.

### Applicability of planning criteria

- Allowing 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
- 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 are not limited to):

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

### 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 considered 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-deployed 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 reclosure44 has not been possible, AEMO applies more severe constraints within a short adjustment period, in anticipation of the occurrence of a further contingency. This may require:

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

44 Transmission lines have automatic systems to return them to service (reclose them) following a fault.
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.

For the main network across the states, the security of supply to load connection points under sustained outage conditions and may be influenced by inter-state 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 load shedding
- Providing flexibility in the choice of economical generating patterns
- Allowing reduced maintenance costs through easier access to equipment
- 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 or consumer, or a single network fault. Provision will be 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 in 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 and southern 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 generation and transmission power network with 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 network, 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 load time for a network augmentation solution.

Before this time, consideration may be given to the costs involved in replacement of 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.

**Relationship with inter-regional planning**

We monitor the occurrence of constraints in the main transmission system that affects generator dispatch. Our planning therefore also 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 accuracy where 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 security measures. AEMO does not operate on the basis that the contingency may be sustained but we must consider 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 to loads, we would initiate a network 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 will be undertaken where the configuration satisfies the RIT-T. The planning of interconnectors will be undertaken in conjunction 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 our network are primarily concerned with supply to loads and are not significantly impacted by the dispatch of generation (although they may contain embedded generation). The loss of a transmission element within these networks does not necessarily require action 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 will require 75% of the maximum load to be supplied during an outage. While every effort would be made to secure supplies in the event of a further outage, that may not always be possible. In this case attention would be 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 our network are usually the low voltage (102 kV) busbar of 330 kV substations. There may be multiple connection points and significant capacity on the part of the DSPN 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 DSPNs 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 our connection point capacity to or from 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 a 330 kV and 132 kV underground cable network. The 330 kV cables are part of our network to the COX MV substations. Under the new NSW Electricity Transmission Reliability Standard 2017, supply to the Inner Sydney load is required to design for Category 3 level of redundancy and maximum unserved energy allowance corresponding to 0.6 minute per year at average demand.

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. 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.

The requirement for reliability criteria (redundancy level and unserved energy allowance per year) at bulk supply points outside the Inner Sydney area are less onerous than that for Inner Sydney area.

Outages of network elements for planned maintenance must also be considered. Generally this will require 75% of the maximum load to be supplied during an outage. While every effort would be made to secure supplies in the event of a further outage, that may not always be possible. In this case attention would be 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, transmission lines either on 132 kV lines or on the low voltage busbars of 132 kV substations. Although there may be multiple connection points, this may not always be possible. In this case attention would be directed to minimising the duration of the outage.

**Joint planning**

The focus of joint planning with DSPNs will usually relate 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
- Development of a higher voltage system to provide a major augmentation and to reduce network losses.

Supply to one or more connection points would be considered for augmentation when the transmission network supplying

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50 NSW Electricity Transmission Reliability and Performance Standard 2017 Clause 3
51 NSW Electricity Transmission Reliability and Performance Standard 2017 Clause 4
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 those cases provision has been 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 rating52 and the practicality of load transfers between connection points. The outage of a transformer (or single-phase unit) or a transmission line that supports the load carried by the transformer is allowed for.

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 loads will need to be shed (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
- Occurrence of three-phase faults53, 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 will 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.

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 will become increasingly more important as the interconnected system is developed and extended.

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. 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.

A3.4 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 taking time of the least damped electromechanical mode of oscillation is not more than five seconds.

A3.5 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 temperature is about 105°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 must take into account requirements for re-dispatch of generation or load control.

We have installed ambient condition monitors 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.

We own 330 kV cables and these are rated according to the manufacturer’s recommendations that have been checked against an appropriate thermal model of the cable.

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

A3.6 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 load 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 short capacitor bank can be very 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, we aim 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, but in the future 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.

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. At times of light system load, it is essential to ensure that voltages can be maintained within the system highest voltage limits of equipment.

A3.7 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 to 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 to provide adequate reliability. Consideration would be given to the impact of a double circuit line failure, both on 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 environmentally acceptable. In areas prone to bushfire, any parallel single circuit lines would preferably be routed well apart.

A3.8 Short-circuit rating requirements

Substation high voltage equipment is designed to withstand the maximum expected short circuit duty\(^\dagger\) in accordance with the applicable Australian Standard. Operating constraints are enforced to ensure equipment is not exposed to fault duties beyond the plant rating.

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
- 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. We are further analysing the impact of the motor component of loads and is assessing the need to include such contributions when assessing the adequacy of the rating of load substations equipment.

A3.9 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
- Transformer arrangements.

We have applied the following configurations in the past:

- Single busbar
- Double busbar
- Multiple element mesh
- Breaker-and-a-half

In general, at main system locations, a mesh or breaker-and-a-half arrangement is now usually adopted.

A3.10 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.

A3.11 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
- System Protection Schemes (SPS)
- The following communication, monitoring and indication facilities are also provided where appropriate:
  - Network-wide SCADA and Energy Management Systems (EMS)
  - Telecommunications and data links
  - Mobile radio
  - Fault locators and disturbance monitors
  - Protection signalling
  - 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.

A3.12 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 DN Spinout bulk supply point load forecasts and directly connected customer demand outlook. We consider key data for each scenario to prepare load forecasts for NSW. These are published in the TAPP. 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

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 base load 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.

For public safety reasons, reclosure is not applied to underground cables.

Autoreclose is inhibited following the operation of breaker-fail protection.

Appendix 3

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\(^{\dagger}\) The maximum fault current that the equipment may be subjected to.
the development of new generators and utilisation (including retirement) of existing generators. 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 ES30 and the scenarios considered in the ISP.

A3.13 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 certification55 that this system meets or exceeds the requirements of ISO 55001.

Figure 48 illustrates our AMS structure under ISO 55001.

The decision-making processes within our AMS have improved through the development of a quantified or highly qualified 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.

55 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
Appendix 4

Line utilisation report

This report sets out our transmission line utilisation for the period from 1 April 2017 to 31 March 2018.

Line utilisation report

The line loading information from 1 April 2017 to 31 March 2018 was obtained from AEMO’s Operation Planning and 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.

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 A3.2 to A3.9. 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
- D. The identity of the line that creates the critical contingency in the event of an outage.

The box layout is shown in Figure 49.

Figure A3 – Key to interpreting the information shown in Figures 50 to 57

In some situations, the N–1 utilisation has been estimated to be more than 100%. 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.

- The predicted dispatch conditions that change over the five-minute dispatch period, causing the line loadings to increase above the predicted values.

![Figure 50 – TransGrid N and N–1 line utilisations – Sydney and Newcastle](image-url)
It is noted that the new Sapphire Wind Farm connection substation did not commence full operation during 1 April 2017 to 31 March 2018.
It is noted that Line X6 connects Silverton Wind Farm to Broken Hill substation. This is not shown in the above diagram as this new generator did not commence full operation during 1 April 2017 to 31 March 2018.
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 58.

The distribution shows that approximately 12% 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 73% 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 58 – Distribution of TransGrid N–1 utilisations (1 April 2017-31 March 2018)
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 power 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
- The limits set by system wide considerations such as voltage, transient or oscillatory stability

We provide the capability of our transmission network to AEMO. AEMO manages the power flows in the transmission network to be within the capacity 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 unplanned outages.

The optimal generation dispatch, the dispatch which minimises total cost while ensuring the capacity 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 2017 to 28 February 2018. The constraints reported here cover the transmission system capability limitation experienced during the period 1 March 2017 to 28 February 2018.

Table 42 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 constraint was in effect.

A5.2 Transmission system performance – Binding duration

The constraints listed in tables 42 and 43 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 and 2.3 respectively.

Table 42 – Constraints operating at the capability limit

<table>
<thead>
<tr>
<th>Rank</th>
<th>Constraint ID</th>
<th>Total duration (dd:hh:mm)</th>
<th>Type</th>
<th>Impact</th>
<th>Reason</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>N^N-NIL_I</td>
<td>89:23:30</td>
<td>Voltage Stability</td>
<td>VIC – NSW Interconnector + Generators</td>
<td>Avoid voltage collapse at Darlington Point for loss of the largest VIC generating unit or Bel放缓。</td>
</tr>
</tbody>
</table>
| 2    | Q
\textsuperscript{N}-NIL\_FL\_G | 21:06:10                    | Transient Stability | NSW – QLD (QNI) Interconnector | Avoid transient instability for fault at Armidale and trip of 330 kV line 9C or 9B from Dunmoya to Armidale |
| 3    | V-N-NIL\_V2  | 7:23:15                    | Transient Stability | Victorian Generation + Interconnectors | Prevent transient instability for fault and trip of a Hazelwood – South Morang 500 kV line in VIC |
| 4    | V-N-NIL\_S2  | 2:08:15                    | Transient Stability | Victorian Generation + Interconnectors | Prevent transient instability for fault and trip of a Hazelwood – South Morang 500 kV line in VIC |
| 5    | Q-N-NIL\_BL\_ POT | 2:00:55                      | Transient Stability | NSW – QLD (QNI) Interconnector | Limit QNI to prevent transient instability for a trip of a Boyne Island potline (400 + 189 MW) |
| 6    | N^N\_Q-NIL\_B1 | 1:16:50                       | Voltage Stability | QLD Generation + Interconnectors | Avoid voltage collapse for loss of Kogan Creek generator |
| 7    | V-N-NIL\_V1  | 1:08:50                    | Transient Stability | Victorian Generation + Interconnectors | Prevent transient instability for fault and trip of a Hazelwood – South Morang 500 kV line in VIC |
| 8    | N^N\_Q-NIL\_A | 1:02:50                       | Voltage Stability | NSW – QLD (QNI) Interconnector + Directlink | Avoid voltage collapse for trip of Liddell to Muswellbrook (83) line |
| 9    | N-NIL\_TEL\_B | 0:23:25                      | Other | Terranora Interconnector | Avoid reaching lower limit on Directlink |
| 10   | N^N\_N-NIL\_3\_OPENED | 0:22:05                       | Thermal Generation + Interconnectors | Avoid overload Liddell to Muswellbrook (83) line on trip of Liddell to Tamworth (84) 330 kV line |
| 11   | N^N\_N-NIL\_A | 0:15:20                       | Voltage Stability | NSW – QLD (QNI) Interconnector + Directlink | Avoid voltage collapse for trip of Liddell to Muswellbrook (83) line |
| 12   | N\_SLEU\_ LSDU | 0:13:30                       | Thermal | Terranora Interconnector | Avoid overloading Lismore to Dunoon line (8U or 8U) on trip of the other Lismore to Dunoon line (8L or 8L) |
| 13   | V-N-NIL\_SD  | 0:12:55                    | Transient Stability | Victorian Generation + Interconnectors | Prevent transient instability for fault and trip of a Hazelwood – South Morang 500 kV line in VIC |
| 14   | N-N-NIL\_DC  | 0:10:55                    | Thermal Generation + Interconnectors | Avoid overloading Armidale to Tamworth (86) line for trip of Armidale to Tamworth (85) line |
| 15   | Q-N-NIL\_ AR\_G | 0:10:35                       | Transient Stability | NSW Generation + Interconnectors | Avoid transient instability for fault at Armidale and trip of 330 kV line 8C or 8E from Dumaresq to Armidale |
| 16   | V\_N\_N-NIL\_HA | 0:10:10                       | Thermal Generation + Interconnectors | Avoid overloading Murray to Upper Tumut (80) 300 kV line on trip of Murray-Lower Tumut (96) 330 kV line |
| 17   | N\_N\_N-NIL\_O | 0:08:00                       | Thermal Generation + Interconnectors | Avoid overloading Upper Tumut to Murray (89) line for trip of G31 line and 300,000 and 330 kV lines ex Yass |
| 18   | N\_N-NIL\_ MREDU | 0:03:30                       | Thermal Generation + Interconnectors | Avoid overloading Mulwamba to Dunoon line (9U or 9U) on trip of the other Mullumbimby to Dunoon line (8U or 8U) |
| 19   | N\_N\_N-NIL\_2\_ OPENED | 0:03:25                      | Thermal Generation + Interconnectors | Avoid overloading Liddell to Muswellbrook (83) line on trip of Liddell to Tamworth (84) 330 kV line |
| 20   | V-N-NIL\_S1  | 0:02:35                    | Transient Stability | Victorian Generation + Interconnectors | Prevent transient instability for fault and trip of a Hazelwood – South Morang 500 kV line in VIC |
A5.3 Transmission system performance – Market Impact

Table 43 summarises the constraints with the 20 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 part of the transmission system, was operated at its maximum capability for the 12 month period from March 2017 to March 2018.

<table>
<thead>
<tr>
<th>Rank</th>
<th>Constraint ID</th>
<th>Sum of Marginal Values</th>
<th>Total duration (dd:hh:mm)</th>
<th>Type</th>
<th>Impact</th>
<th>Reason</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>N^A-NL NIL</td>
<td>$1,446,305</td>
<td>89:23:30</td>
<td>Voltage Stability</td>
<td>VIC – NSW Interconnector + Generators</td>
<td>Avoid voltage collapse at Darlington Point for loss of the largest VIC generating unit or Basslink.</td>
</tr>
<tr>
<td>2</td>
<td>Q-N-NL NIL</td>
<td>$125,674</td>
<td>21:00:10</td>
<td>Transient Stability</td>
<td>NSW – QLD (QNI) Interconnector</td>
<td>Avoid transient instability for fault at Armidale and trip of 330 kV line 8C or 8E from Dumaresq to Armidale.</td>
</tr>
<tr>
<td>3</td>
<td>V-N-NL Q2</td>
<td>$64,438</td>
<td>00:00:10</td>
<td>Transient Stability</td>
<td>Victorian Generation + Interconnectors</td>
<td>Prevent transient instability for fault and trip of a Hazelwood – South Morang 500 kV line in VIC.</td>
</tr>
<tr>
<td>4</td>
<td>N&gt;Q-NL NIL 3</td>
<td>$44,784</td>
<td>02:22:05</td>
<td>Thermal</td>
<td>NSW Generation + Interconnectors</td>
<td>Avoid overload Liddell to Muswellbrook (83) line on trip of Liddell to Tamworth (84) 330 kV line.</td>
</tr>
<tr>
<td>5</td>
<td>V-N-NL V2</td>
<td>$39,807</td>
<td>7:23:15</td>
<td>Transient Stability</td>
<td>Victorian Generation + Interconnectors</td>
<td>Prevent transient instability for fault and trip of a Hazelwood – South Morang 500 kV line in VIC.</td>
</tr>
<tr>
<td>6</td>
<td>N^Q-NL A</td>
<td>$21,693</td>
<td>1:02:50</td>
<td>Voltage Stability</td>
<td>NSW – QLD (QNI) Interconnector + Directlink</td>
<td>Avoid voltage collapse for trip of Liddell to Muswellbrook (83) line.</td>
</tr>
<tr>
<td>7</td>
<td>N^A-Q-NL_B1</td>
<td>$12,164</td>
<td>1:16:50</td>
<td>Voltage Stability</td>
<td>QLD Generation + Interconnectors</td>
<td>Avoid voltage collapse for loss of Kogan Creek generator.</td>
</tr>
<tr>
<td>8</td>
<td>Q-N-NL Bil</td>
<td>$11,918</td>
<td>2:00:55</td>
<td>Transient Stability</td>
<td>NSW – QLD (QNI) Interconnector</td>
<td>Limit QNI to prevent transient instability for a trip of a Byron Island potline (400 + j189 MVA).</td>
</tr>
<tr>
<td>9</td>
<td>V-N-NL B2</td>
<td>$11,139</td>
<td>2:08:15</td>
<td>Transient Stability</td>
<td>Victorian Generation + Interconnectors</td>
<td>Prevent transient instability for fault and trip of a Hazelwood – South Morang 500 kV line in VIC.</td>
</tr>
<tr>
<td>10</td>
<td>V-N-NL V1</td>
<td>$7,058</td>
<td>1:08:50</td>
<td>Transient Stability</td>
<td>Victorian Generation + Interconnectors</td>
<td>Prevent transient instability for fault and trip of a Hazelwood – South Morang 500 kV line in VIC.</td>
</tr>
<tr>
<td>11</td>
<td>N-LSDU LSDU</td>
<td>$6,145</td>
<td>0:13:30</td>
<td>Thermal</td>
<td>Tamrona Interconnector</td>
<td>Avoid overloading Lismore to Dunoon line (9U6 or 9U7) on trip of the other Lismore to Dunoon line (9U7 or 9U8).</td>
</tr>
<tr>
<td>12</td>
<td>V-N-NL_B3</td>
<td>$6,428</td>
<td>0:12:55</td>
<td>Transient Stability</td>
<td>Victorian Generation + Interconnectors</td>
<td>Prevent transient instability for fault and trip of a Hazelwood – South Morang 500 kV line in VIC.</td>
</tr>
<tr>
<td>13</td>
<td>N-NL TE B</td>
<td>$5,284</td>
<td>0:23:25</td>
<td>Other</td>
<td>Tamrona Interconnector</td>
<td>Avoid reaching lower limit on Directlink.</td>
</tr>
<tr>
<td>14</td>
<td>V–N-NL_B3_A</td>
<td>$4,739</td>
<td>0:10:10</td>
<td>Thermal</td>
<td>NSW Generation + Interconnectors</td>
<td>Avoid overloading Murray to Upper Tumut (85) 330kV line on trip of Murray-Lower Tumut (66) 330 kV line.</td>
</tr>
<tr>
<td>15</td>
<td>N-V-NL_O</td>
<td>$3,338</td>
<td>0:08:00</td>
<td>Thermal</td>
<td>VIC – NSW Interconnector + Generators</td>
<td>Avoid overloading Upper Tumut to Murray (86) line for trip of 9U6 and 9U7 lines and trip of 99M lines.</td>
</tr>
<tr>
<td>16</td>
<td>N-V-NL_B1_2</td>
<td>$3,019</td>
<td>0:03:25</td>
<td>Thermal</td>
<td>NSW Generation + Interconnectors</td>
<td>Avoid overload Liddell to Tamworth (84) on trip of Liddell to Muswellbrook (83) line.</td>
</tr>
<tr>
<td>17</td>
<td>N^Q-NL_A</td>
<td>$2,800</td>
<td>0:15:20</td>
<td>Voltage Stability</td>
<td>NSW – QLD (QNI) Interconnector + Directlink</td>
<td>Avoid voltage collapse on loss of Liddell to Muswellbrook (83) line.</td>
</tr>
<tr>
<td>18</td>
<td>N-N-NL MRDU</td>
<td>$1,942</td>
<td>0:03:30</td>
<td>Thermal</td>
<td>Tamrona Interconnector</td>
<td>Avoid overloading Mullumbimby to Dunoon line (9U6 or 9U7) on trip of the other Mullumbimby to Dunoon line (9U7 or 9U8).</td>
</tr>
<tr>
<td>19</td>
<td>Q-N-NL AR 2L</td>
<td>$1,883</td>
<td>0:10:35</td>
<td>Transient Stability</td>
<td>NSW Generation + Interconnectors</td>
<td>Avoid transient instability for fault at Armidale and trip of 330 kV line 8C or 8E from Dumaresq to Armidale.</td>
</tr>
<tr>
<td>20</td>
<td>N-N-NL OC</td>
<td>$1,875</td>
<td>0:10:55</td>
<td>Thermal</td>
<td>NSW – QLD (QNI) Interconnector + Tamrona</td>
<td>Avoid overloading Armidale to Tamworth (85) line for trip of Armidale to Tamworth (86) line.</td>
</tr>
</tbody>
</table>

A5.4 Possible future transmission system performance

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 March 2017 to March 2018 period. The constraints that were not binding but close to binding were assessed to identify possible future transmission system limitations.

A5.4.1 Maximum demand event in New South Wales

Figure 59 – NEM overview map on 19 December 2017 at 16:25

<table>
<thead>
<tr>
<th>Region</th>
<th>Max demand</th>
<th>Date and time</th>
</tr>
</thead>
<tbody>
<tr>
<td>NSW</td>
<td>13,044 MW</td>
<td>Tuesday 19th December 2017, 16:25</td>
</tr>
<tr>
<td>QLD</td>
<td>9,024 MW</td>
<td>Wednesday 14th February 2018, 16:50</td>
</tr>
<tr>
<td>VIC</td>
<td>9,126 MW</td>
<td>Sunday 29th January 2018, 18:00</td>
</tr>
</tbody>
</table>

Victoria

Dispatch price = $109.66
Demand = 7,936 MW
Availability = 8,883 MW
Generation = 7,265 MW

Tasmania

Dispatch price = $87.63
Demand = 1,013 MW
Availability = 2,079 MW
Generation = 1,615 MW

Queensland

Dispatch price = $97.48
Demand = 8,093 MW
Availability = 11,197 MW
Generation = 9,565 MW
There were no binding or violating constraints in NSW on 19 December 2017 at 16:25, i.e. when the demand in NSW reached maximum during March 2017 to March 2018 period.

Table 45 – NSW constraints that were close to binding on 19 December 2017 at 16:25

<table>
<thead>
<tr>
<th>Rank</th>
<th>Constraint ID</th>
<th>Headroom (MW)</th>
<th>Type</th>
<th>Impact</th>
<th>Reason</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>N^N_KKLS_1</td>
<td>8</td>
<td>Voltage Stability</td>
<td>Terranora Interconnector</td>
<td>Avoid voltage collapse on loss of Coffs Harbour (89) line when Directlink and Koolkhan to Lismore (967) O/S</td>
</tr>
<tr>
<td>2</td>
<td>N-N_KKLS_TE_2</td>
<td>9</td>
<td>Thermal</td>
<td>Terranora Interconnector</td>
<td>Avoid overloading Glen Innes to Tenterfield (96R) line on loss of Coffs Harbour to Lismore (89) line when Directlink and Koolkhan to Lismore (967) O/S</td>
</tr>
<tr>
<td>3</td>
<td>N_MBTE1_B</td>
<td>81</td>
<td>Other</td>
<td>Terranora Interconnector</td>
<td>QLD to NSW limit with one Directlink cable O/S</td>
</tr>
<tr>
<td>4</td>
<td>Q:N NIL_AR_3L-G</td>
<td>92</td>
<td>Transient Stability</td>
<td>NSW - QLD (QNI) Interconnector</td>
<td>Avoid transient instability for fault at Armidale and trip of 330 kV line 8C or 8E from Dumaresq to Armidale</td>
</tr>
<tr>
<td>5</td>
<td>Q:N NIL_PPOT_</td>
<td>127</td>
<td>Thermal</td>
<td>Terranora Interconnector</td>
<td>Avoid overloading Lismore to Dunoon (9U6 or 9U7) line on trip of the other Lismore to Dunoon (9U7 or 9U6) line</td>
</tr>
<tr>
<td>6</td>
<td>Q:N NIL_PPOT_</td>
<td>127</td>
<td>Thermal</td>
<td>Terranora Interconnector</td>
<td>Avoid overloading Mullumbimby to Dunoon line (9U6 or 9U7) on trip of the other Mullumbimby to Dunoon line (9U7 or 9U6)</td>
</tr>
<tr>
<td>7</td>
<td>N-N NIL_LSDU</td>
<td>128</td>
<td>Other</td>
<td>Terranora Interconnector</td>
<td>Avoid reaching lower limit on Directlink</td>
</tr>
<tr>
<td>8</td>
<td>N-N NIL_TE_B</td>
<td>141</td>
<td>Other</td>
<td>Terranora Interconnector</td>
<td>Avoid reaching lower limit on Directlink</td>
</tr>
</tbody>
</table>

A5.4.2 Maximum demand event in Queensland

Figure 60 – NEM overview map on 14 February 2018 at 16:50
Table 46 – NSW binding constraints on 14 February 2018 at 16:50

<table>
<thead>
<tr>
<th>Constraint ID</th>
<th>Type</th>
<th>Impact</th>
<th>Reason</th>
</tr>
</thead>
<tbody>
<tr>
<td>N&gt;&gt;N-NIL__3_OPENED</td>
<td>Thermal</td>
<td>NSW Generation + Interconnectors</td>
<td>Avoid overload Liddell to Muswellbrook (83) line on trip of Liddell to Tamworth (84) line</td>
</tr>
<tr>
<td>N_X_MBTE2_A</td>
<td>Other</td>
<td>Terranora Interconnector</td>
<td>NSW to QLD limit with two Directlink cables O/S</td>
</tr>
</tbody>
</table>

Table 47 – NSW constraints that were close to binding on 14 February 2018 at 16:50

<table>
<thead>
<tr>
<th>Rank</th>
<th>Constraint ID</th>
<th>Headroom (MW)</th>
<th>Type</th>
<th>Impact</th>
<th>Reason</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>N&gt;&gt;N-NIL_01N</td>
<td>7</td>
<td>Thermal</td>
<td>NSW Generation + Interconnectors</td>
<td>Avoid overload Canberra to Yass (9) line on trip of Kangaroo Valley to Dapto (18) line</td>
</tr>
<tr>
<td>2</td>
<td>N&gt;&gt;N-NIL__2_OPENED</td>
<td>7</td>
<td>Thermal</td>
<td>NSW Generation + Interconnectors</td>
<td>Avoid overload Liddell to Muswellbrook (83) line on trip of Liddell to Tamworth (84) 330 kV line</td>
</tr>
<tr>
<td>3</td>
<td>N&gt;LSDU_LSDU</td>
<td>16</td>
<td>Thermal</td>
<td>Terranora Interconnector</td>
<td>Avoid overloading Lismore to Dunoon line (9U6 or 9U7) on trip of the other Lismore to Dunoon line (9U7 or 9U6)</td>
</tr>
<tr>
<td>4</td>
<td>N&gt;N-NIL_LSDU</td>
<td>20</td>
<td>Thermal</td>
<td>Terranora Interconnector</td>
<td>Avoid overloading Lismore to Dunoon (9U6 or 9U7) line on trip of the other Lismore to Dunoon (9U7 or 9U6) line</td>
</tr>
<tr>
<td>5</td>
<td>N_MBTE1_A</td>
<td>60</td>
<td>Other</td>
<td>Terranora Interconnector</td>
<td>NSW to QLD limit with one Directlink cable O/S</td>
</tr>
<tr>
<td>6</td>
<td>N&gt;Q_NIL_B1</td>
<td>84</td>
<td>Voltage</td>
<td>QLD Generation + Interconnectors</td>
<td>Avoid voltage collapse for loss of Kogan Creek generator</td>
</tr>
<tr>
<td>7</td>
<td>N&gt;NIL_TE_D2</td>
<td>96</td>
<td>Thermal</td>
<td>Terranora Interconnector</td>
<td>Avoid overload Lismore330 to Lismore132 (9U6 or 9U7) on trip of Lismore330 to Lismore132 (9U6 or 9U7)</td>
</tr>
<tr>
<td>8</td>
<td>N&gt;NIL_TE_A</td>
<td>120</td>
<td>Other</td>
<td>Terranora Interconnector</td>
<td>Avoid reaching upper limit on Directlink</td>
</tr>
<tr>
<td>9</td>
<td>N_X_MBTE2_B</td>
<td>120</td>
<td>Other</td>
<td>Terranora Interconnector</td>
<td>NSW to QLD limit with two Directlink cables O/S</td>
</tr>
<tr>
<td>10</td>
<td>N&gt;&gt;N-NIL_64</td>
<td>141</td>
<td>Thermal</td>
<td>NSW Generation + Interconnectors</td>
<td>Avoid overload Bannaby to Sydney West (39) line on trip of Dapto to Sydney South (11) line</td>
</tr>
</tbody>
</table>

A5.4.3 Maximum demand event in Victoria

Figure 61 – NEM overview map on 28 January 2018 at 18:00

There were no binding or violating constraints in NSW on 28 January 2018 at 18:00, i.e. when the demand in VIC reached maximum during March 2017 to March 2018 period.
Table 48 – NSW constraints that were close to binding on 28 January 2018 at 18:00

<table>
<thead>
<tr>
<th>Rank</th>
<th>Constraint ID</th>
<th>Headroom (MW)</th>
<th>Type</th>
<th>Impact</th>
<th>Reason</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>N_MBTE1_B</td>
<td>78</td>
<td>Unit Zero</td>
<td>Terranora Interconnector</td>
<td>NSW to QLD limit with one Directlink cable O/S</td>
</tr>
<tr>
<td>2</td>
<td>N&gt;N-NIL_LSDU</td>
<td>127</td>
<td>Thermal</td>
<td>Terranora Interconnector</td>
<td>Avoid overloading Lismore to Dunoon (9U6 or 9U7) line on trip of the other Lismore to Dunoon (9U6 or 9U7) line</td>
</tr>
<tr>
<td>3</td>
<td>N&gt;N-NIL_MBDU</td>
<td>129</td>
<td>Thermal</td>
<td>Terranora Interconnector</td>
<td>Avoid overloading Mullumbimby to Dunoon line (9U6 or 9U7) on trip of the other Mullumbimby to Dunoon line (9U7 or 9U6)</td>
</tr>
<tr>
<td>4</td>
<td>N^+V-NIL_1</td>
<td>135</td>
<td>Voltage Stability</td>
<td>VIC– NSW Interconnector + Generators</td>
<td>Avoid voltage collapse at Darlington Point for loss of the largest VIC generating unit or Basslink</td>
</tr>
<tr>
<td>5</td>
<td>NNIL_TE_B</td>
<td>138</td>
<td>Other</td>
<td>Terranora Interconnector</td>
<td>Avoid reaching lower limit on Directlink</td>
</tr>
<tr>
<td>6</td>
<td>N_MBTE1_A</td>
<td>161</td>
<td>Other</td>
<td>Terranora Interconnector</td>
<td>NSW to QLD limit with one Directlink cable O/S</td>
</tr>
<tr>
<td>7</td>
<td>N&gt;N-NIL_DPTX</td>
<td>206</td>
<td>Thermal</td>
<td>NSW Generation + Interconnectors</td>
<td>Avoid overload Darlington Point Tx3 or Tx4 on trip of the other</td>
</tr>
<tr>
<td>8</td>
<td>N NIL_TE_A</td>
<td>207</td>
<td>Other</td>
<td>Terranora Interconnector</td>
<td>Avoid reaching upper limit on Directlink</td>
</tr>
<tr>
<td>9</td>
<td>N&gt;N-NIL_TE_D2</td>
<td>242</td>
<td>Thermal</td>
<td>Terranora Interconnector</td>
<td>Avoid overload Lismore 330 to Lismore 132 (9U9) on trip of Lismore 330 to Lismore 132 (9U8)</td>
</tr>
<tr>
<td>10</td>
<td>N&gt;N-NIL_996_IN</td>
<td>425</td>
<td>Thermal</td>
<td>NSW Generation + Interconnectors</td>
<td>Avoid overload Wagga 330 to ANM (996) line on trip of Wagga 330 to Jindera (92) line</td>
</tr>
</tbody>
</table>
Appendix 6

Glossary
<table>
<thead>
<tr>
<th>Term</th>
<th>Explanation/Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>AEMC</td>
<td>The Australian Energy Market Commission</td>
</tr>
<tr>
<td>AEMO</td>
<td>The Australian Energy Market Operator. Responsible for operation of the NEM and has the role of Victorian JPS</td>
</tr>
<tr>
<td>AER ('the regulator')</td>
<td>The Australian Energy Regulator</td>
</tr>
<tr>
<td>Assets</td>
<td>TransGrid’s ‘towers and wires’, all the substations and electricity transmission lines that make up the network</td>
</tr>
<tr>
<td>Augmentation</td>
<td>Expansion of the existing transmission system or an increase in its capacity to transmit electricity</td>
</tr>
<tr>
<td>Bulk supply point (BSP)</td>
<td>A point of supply of electricity from a transmission system to a distribution system</td>
</tr>
<tr>
<td>Connection point</td>
<td>The agreed point of supply established between the network service provider and another registered participant or customer</td>
</tr>
<tr>
<td>Constraint (limitation)</td>
<td>An inability of a transmission system or distribution system to supply a required amount of electricity to a required standard</td>
</tr>
<tr>
<td>Consumers</td>
<td>Any end user of electricity including large users, such as paper mills, and small users, such as households</td>
</tr>
<tr>
<td>Demand</td>
<td>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)</td>
</tr>
<tr>
<td>Demand management (DM)</td>
<td>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</td>
</tr>
<tr>
<td>Direct customers</td>
<td>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</td>
</tr>
<tr>
<td>Distribution Network Service Provider, DNSP (Distributor)</td>
<td>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</td>
</tr>
<tr>
<td>Easement</td>
<td>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</td>
</tr>
<tr>
<td>Electricity Statement of Opportunities (ESOO)</td>
<td>A document produced by AEMO that focuses on electricity supply-demand balance in the NEM</td>
</tr>
<tr>
<td>Embedded generation</td>
<td>A generating unit connected to the distribution network, or connected to a distribution network customer. (Not a transmission connected generator)</td>
</tr>
<tr>
<td>Generator</td>
<td>An organisation that produces electricity. Power can be generated from various sources, e.g. coal-fired power plants, gas-fired power plants, wind farms</td>
</tr>
<tr>
<td>Interconnection</td>
<td>The points on an electricity transmission network that cross jurisdictional/state boundaries</td>
</tr>
<tr>
<td>ISP</td>
<td>Integrated System Plan</td>
</tr>
<tr>
<td>Jurisdictional Planning Body (JPB)</td>
<td>The organisation nominated by a relevant minister as having transmission system planning responsibility in a jurisdiction of the NEM</td>
</tr>
<tr>
<td>Load</td>
<td>The amount of electrical power that is drawn from the network</td>
</tr>
<tr>
<td>Local generation</td>
<td>A generation or cogeneration facility that is located on the load side of a transmission constraint</td>
</tr>
<tr>
<td>LRET</td>
<td>Large Scale Renewable Energy Target</td>
</tr>
<tr>
<td>N-1 reliability</td>
<td>The system is planned for no loss of load on the outage of a single element such as a line, cable or transformer</td>
</tr>
<tr>
<td>National Energy Law</td>
<td>Common laws across the states which comprise the NEM, which make the NER enforceable</td>
</tr>
<tr>
<td>National Electricity Law (NELM)</td>
<td>The National Electricity Market, covering Queensland, New South Wales, Victoria, South Australia and Tasmania</td>
</tr>
</tbody>
</table>

The following table gives some of the common electricity measurements used:

<table>
<thead>
<tr>
<th>Property</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Voltage</td>
<td>Volts (V) and kilovolts (kV). 1 kV = 1,000 V</td>
</tr>
<tr>
<td>Power</td>
<td>Watts (W), usually expressed in kilowatts (kW) and megawatts (MW). 1 MW = 1,000 kW = 1 million W</td>
</tr>
<tr>
<td>Energy consumption</td>
<td>The amount of energy consumed in an hour is usually expressed as kilowatt-hours (kWh) or megawatt-hours (MWh). 1 MWh = 1,000 kWh</td>
</tr>
<tr>
<td>Maximum power that a transformer can deliver</td>
<td>Usually expressed in megavolt-ampere (MVA)</td>
</tr>
<tr>
<td>Reactive power</td>
<td>Usually expressed in megavolt-ampere reactive (MVAr)</td>
</tr>
</tbody>
</table>
Contact details

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