Revenue Proposal
2023–28

Transgrid

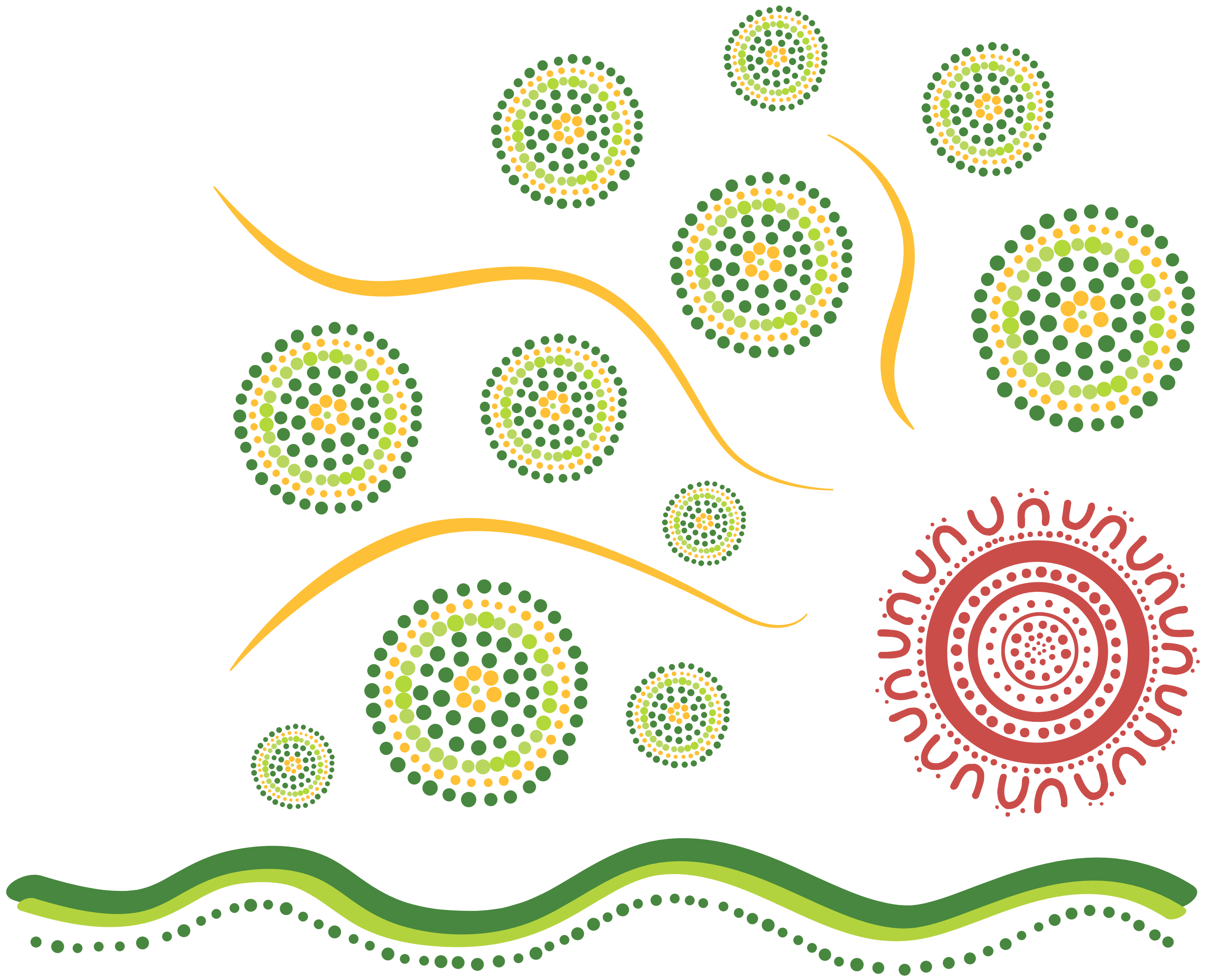
People. Power. Possibilities.

Contents

Acknowledgement of Country

In the spirit of reconciliation Transgrid acknowledges the Traditional Custodians of the lands where we work, the lands we travel through and the places in which we live.

We pay respects to the people and the Elders past, present and emerging and celebrate the diversity of Aboriginal peoples and their ongoing cultures and connections to the lands and waters of New South Wales and the Australian Capital Territory.



A message from our CEO

I am pleased to present our Revenue Proposal for the 2023–28 regulatory period. We are committed to playing a key role in Australia's energy transition towards net zero emissions and placing downward pressure on electricity prices.

The 2023–28 regulatory period will be one of profound change in the Australian energy market and our proposal outlines how we will meet the new service delivery challenges in a rapidly evolving operating environment.

We are a key partner in implementing:

- the Australian Energy Market Operator's (AEMO's) Integrated System Plan (ISP), which has identified the pathways to deliver the projects required for Australia's energy transition, and
- the NSW Government's Electricity Infrastructure Roadmap (NSW Electricity Infrastructure Roadmap), which is its plan to transform our electricity system into one that is cheap, clean and reliable including through the development of five Renewable Energy Zones (REZs).

To deliver on the ISP, we are currently delivering vital upgrades and expansions to NSW's interconnectors to Queensland, Victoria and South Australia, which will enable low-cost renewables to enter the market, delivering both environmental benefits and savings to our customers. Subject to regulatory approvals, we will also deliver the Victoria to New South Wales Interconnector (VNI) West, HumeLink, other ISP projects and the NSW REZs.

The energy transition will be monumental in its impact across all sectors of our economy and community. Our network upgrades will return economic benefits several times greater than the cost of our investment.

As the new CEO of Transgrid, I am conscious of our responsibility to be a vital part of this energy transition, and also of the importance of our work to our customers and other stakeholders. We are strongly focused on delivering the full benefits of the energy transition to customers, including by providing greater access to low-cost renewable energy.

At the same time, we must maintain a robust transmission network that will be resilient to support the connection of a rapidly changing mix and location of energy resources, while continuing to provide strong security, reliability and safety performance.

We acknowledge our role as a provider of critical infrastructure and will support the Australian and State Governments' enhanced cyber-security protection requirements. We will also strengthen our network's resilience by replacing assets with more climate-resilient alternatives, where the opportunity arises.

Over the current period we delivered on the following priorities identified by our customers and other stakeholders. We will continue to deliver on these priorities over the 2023–28 period:

- **On affordability**, based on this proposal we expect to deliver transmission cost savings of $19.55 per annum for residential customers and $73.05 per annum for small business customers, which in both cases is a 13.4 per cent reduction over this period. Delivering these savings will depend on the outcome of this revenue determination process.
- **On safety, security and reliability**, we will continue to invest to maintain the long-term condition of our network. We will also strengthen network resilience, where it is efficient to do so, and enhance our cyber and physical security capability to meet the Australian and NSW Governments' new obligations.
- **On rapid localised demand growth**, we will upgrade our network to address high load growth in parts of our network and enable compliance with mandated voltage stability, thermal limits and reliability standards.
- **On the energy transition**, we will continue to support the transition to a low carbon future through our investments in the projects identified in AEMO's ISP and the NSW Electricity Infrastructure Roadmap. These projects will involve extensive public consultation and require approval from AEMO, the AER and the NSW Government to proceed.
- **On technology and innovation**, we will continue to innovate and collaborate with our partners to accelerate the identification and development of new technologies.

These priorities will guide our activities as we lead the energy transition.

We are grateful to our TransGrid Advisory Council, customers and other stakeholders for actively participating in the preparation of our 2023–28 Revenue Proposal. We believe our proposal demonstrates we are an efficient and customer orientated electricity network provider that will drive the outcomes needed to support Australia's energy transition. We look forward to feedback from, and further engagement with, customers and other stakeholders as we develop our final proposal during 2022.

Brett Redman
Chief Executive Officer
January 2022

1. Who We Are

Transgrid operates and manages the high voltage electricity transmission network in NSW and the ACT, connecting generators, distributors and major end users. Our network is the backbone of the National Energy Market, enabling energy trading between Australia's three largest states along the east coast and supporting the competitive wholesale electricity market.

Our assets and network performance

End use customers
About 4 million
NSW and ACT

Total network length
High voltage transmission line and underground cable
12,953 km of overhead transmission line up to 500kV

1,023 km	5,487 km	681 km	5,701 km	61 km
500kV	330kV	220kV	132kV	below 132kV

86km of underground cables up to 330kV

Transmission line structures
37,305 structures
15,690 steel lattice tower and pole structures
12,958 Wood pole structures
8,657 Concrete pole structures

Transmission substations
95 substations
215 power transformers
1,489 circuit breakers
5,676 instrument transformers

Communications infrastructure
4,000 km Optical fibre
85 Telecommunication sites

Peak demand
13,700 MW

Maximum system demand[1]
11,700 MW
At end 2020-21

Annual energy
71,300 GWh
At end 2020-21

Network reliability
99.99999%
At end 2020-21

Our values

Safety
We put safety first

Integrity
We act with integrity

Achievement
We make a difference

Service
We deliver for our customers and communities

2. Our Network

Our network forms the backbone of the National Energy Market (NEM) – extending throughout NSW and the ACT, with connections to Queensland and Victoria.

3. Our Five Focus Areas

1. Affordability
2. Safety, security and reliability
3. Rapid localised demand growth
4. Energy transition
5. Technology and innovation

4. Our Projects

Delivered or in progress

Powering Sydney's Future	Victoria to NSW Interconnector Minor Upgrade (VNI Minor Upgrade)	Queensland to NSW Interconnector Minor Upgrade (QNI Minor Upgrade)	Project EnergyConnect – linking NSW and South Australia

RIT-Ts in progress

Managing risk on Line 86 (Tamworth – Armidale)	Improving stability in south western NSW	Supply to North West Slopes	Stage one – supply to Bathurst, Orange and Parkes

Subject to regulatory approvals

AEMO, Integrated System Plan Projects

HumeLink	VNI West (via Kerang)	Sydney Ring[1]	QNI Connect

Notes: 1. Reinforcing Sydney, Newcastle, and Wollongong Supply

NSW Renewable Energy Zones (REZs)

Central-West Orana REZ	New England REZ	South-West REZ	Hunter-Central Coast REZ	Illawarra REZ

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Executive summary

Transgrid operates the high voltage transmission network in New South Wales (NSW) and the Australian Capital Territory (ACT), which services about 4 million customers. Our transmission network supplies higher peak loads and transmits more energy annually than any other transmission network in Australia. This Revenue Proposal explains our expenditure, revenues and transmission prices for the next regulatory period, which commences on 1 July 2023 and ends on 30 June 2028.

Our Revenue Proposal reflects valuable feedback from our customers. We will continue to engage with customers throughout 2022 to inform our Revised Revenue Proposal, which we will submit to the Australian Energy Regulator (AER) in late 2022.

Customer outcomes

This Revenue Proposal prioritises the following outcomes:

1. Affordability
2. Safety, security and reliability
3. Serving rapid localised demand growth
4. Supporting the energy transition, and
5. Supporting technology and innovation.

These were identified after extensive consultation and engagement with our customers and the Transgrid Advisory Council (TAC), which comprises a range of key customer representatives and other stakeholders. Our engagement included:

- independent qualitative and quantitative research into customers' attitudes towards energy and their priorities and preferences
- regular TAC meetings, including deep-dives into the issues that are of most concern to our customers, and
- on 5 October 2021, publishing our Preliminary Revenue Proposal.

Affordability

Affordability is our customers' highest priority because electricity is central to Australians' quality of life and economic prosperity. This Revenue Proposal balances expenditure needed to maintain a safe and reliable electricity supply and to build our future network with the need to deliver real savings to customers. We are committed to doing everything we can to deliver value for money by focusing on the efficient delivery of services. Based on this proposal, from 30 June 2023 to 30 June 2028, we expect to deliver transmission cost savings of $19.55 per annum for residential customers and $73.05 per annum for small business customers, which in both cases is a 13.4 per cent reduction over this period. Delivering these savings will depend on the outcome of this revenue determination process.

In support of these cost savings, we:

- propose capex forecasts that are broadly in line with our expected capex for the current period, while ensuring we are delivering a safe and reliable network as our assets age and condition-related issues increase
- propose opex forecasts using 2021–22 opex as the base year, which we expect will be $11.9 million below the AER's opex allowance for that year. This will result in a saving of $59.6 million[1] to our customers in the 2023–28 period (compared to our base year allowance)[2]
- have not at this stage included:
  - a real increase in materials costs in our expenditure forecasts although, like AEMO, we forecast that the cost of materials will increase at a rate faster than CPI. In our Revised Revenue Proposal, we will revisit this matter in consultation with our customers and other stakeholders,[3] and
  - any cost impacts associated with the long-term effects of the COVID-19 pandemic given that the economic effects are still highly uncertain
- have ensured our operations are efficient compared to our peers, as demonstrated by the AER's benchmarking and the independent analysis that we have commissioned from HoustonKemp, and
- have incorporated the benefits of successful recent innovation activity. We will continue to pursue a range of innovation initiatives in the 2023–28 period, although at this stage we have not included any specific innovation expenditure in our forecasts.

Safety, security and reliability

Our core responsibility is to ensure that electricity is delivered safely, securely and reliably to homes and businesses in NSW and the ACT. This is challenged by the operational complexity arising from the rapid transformation of the energy system as more variable large-scale renewable generation connects to the NEM and ageing coal-fired generation retires.[4]

Our customers want us to deliver low-cost renewable energy that secures the decarbonisation objectives of the energy transition within a framework of reliability and affordability. We will achieve this in the 2023–28 period by:

- renewing and replacing ageing, obsolete and deteriorated network assets to maintain the long-term condition of our electricity network
- replacing assets with more resilient alternatives, where it is efficient, so that our network can withstand more frequent, intense and longer climate-driven extreme weather events
- aligning with the Australian and NSW Governments' new cyber and physical security obligations, and
- rolling out new Information and Communication Technology (ICT) platforms and continue to refresh or replace legacy applications and systems.

Rapid localised demand growth

We are committed to meeting residential and business customers' needs as new developments across Sydney and regional NSW drive demand growth. We need to serve strong maximum demand growth in regions such as western Sydney, north west Sydney, the North West Slopes and central and far west NSW. This strong demand growth is due to new residential, commercial, transport and data centre developments in western Sydney and the development of mining and industrial precincts in regional NSW.

We have not included in our forecast capex demand driven projects that are the subject of current Regulatory Investment Tests for Transmission (RIT-Ts) where the preferred option has not yet been identified, such as for supply to the North West Slopes and central west NSW (Bathurst, Orange and Parkes). We will update our capex forecasts for the preferred options, as appropriate, in our Revised Revenue Proposal.

1 Calculated by multiplying the base year underspend of $11.9 million by five years ($11.9 million x 5 years = $59.6 million).
2 Calculated as the $11.9 million underspend against the AER's allowance in 2021–22 multiplied by 5 years ($11.9 million X 5 years = $59.6 million)
3 AEMO, Draft 2022 Integrated System Plan, December 2021, p. 15. This acknowledges that the acceleration in global infrastructure and energy investment over the next two decades will significantly increase demand for expertise, materials, and equipment, putting pressure on costs for transmission projects.
4 2GW of large scale solar and wind capacity was added to the NEM in 2020, and a further 8GW of large scale solar and wind generation is currently under construction. The pipeline is even larger – 300 generation and storage projects, totalling 55,000 MW – see https://assets.cleanenergycouncil.org.au/documents/resources/reports/clean-energy-australia/clean-energy-australia-report-2021.pdf and https://aemo.com.au/newsroom/media-release/aemo-updates-2020-esoo

Energy transition

We are submitting our Revenue Proposal at a time when Australia's energy market faces its most challenging period as it seeks to transition to decarbonisation. At the heart of this transition is our transmission network that connects geographically and technologically diverse, low-cost generation to deliver renewable energy to customers. The NSW Electricity Infrastructure Roadmap includes five REZs to deliver 'cheap, reliable and clean electricity'. AEMO's Draft 2022 ISP finds that investment in transmission projects on its optimal development path is expected to deliver net market benefits of $29 billion, which is 2.5 times their cost.[5] This is supported by the Grattan Institute's findings that transmission networks are the most cost-effective way to reduce emissions and provide customers with access to low-cost renewable generation sources.[6]

As outlined in AEMO's Draft 2022 ISP, timely investment in transmission is urgently needed to:

- deliver the energy transition at the lowest possible cost to ensure customers have an affordable supply of energy. AEMO finds that without transmission investment, the NEM would require more expensive generation nearer to load centres[7]
- increase the capability of the transmission network to enable the connection of expected generation to secure the full benefit of zero-emission renewable generation. AEMO finds that the benefits of transmission investment increase 'as the speed of the NEM's emission reductions accelerate'[8]
- develop REZs, including those outlined in the NSW Electricity Infrastructure Roadmap, which will be a 'critical enabler for economy-wide emissions reductions' and 'improve grid reliability and security'
- support faster and larger scale renewable generation and greater storage as coal retires
- reduce network congestion and improve system stability as renewables rapidly connect in new locations and households continue to install more solar PV systems
- address further pressures on the network by the increasing penetration of electric vehicles (EV)[9] and new green hydrogen manufacturing developments which will see a significant increase in energy demand, and
- increase transfer capacity between jurisdictions to support reliability and share available resources including surplus renewable energy where possible.

Our customers support the energy transition and investment that lowers emissions. More than half of residential and small to medium business customers surveyed indicated they would be willing to pay more on their bills to reduce emissions.[10]

The transition to renewables is happening faster than previously expected as governments commit to decarbonisation,[11] technology advances and renewable energy costs fall. The NSW[12] and ACT[13] Governments have set targets of net zero emissions by 2050, with the NSW Government also recently committing to reduce emissions by up to 50 per cent below 2005 levels by 2030.[14] The ACT Government has also committed to reducing emissions by 50 to 60 per cent below 1990 levels.[15] The modelling we have undertaken as part of our Energy Vision, finds that transmission is central to achieving Australia's net zero emissions targets.

5 AEMO, Draft 2022 Integrated System Plan, December 2021.
6 Grattan Institute, Go for Net Zero – A practical plan for reliable, affordable, low emissions electricity, April 2021, section 2.
7 AEMO, Draft 2022 Integrated System Plan, December 2021, p. 57
8 AEMO, Draft 2022 Integrated System Plan, December 2021, p. 57
9 AEMO finds that EVs are expected to surge in the 2030s, driven by falling costs, greater model choice and more charging infrastructure.
10 Forethought, Revenue Reset Stakeholder Engagement – Executive Report, p.7
11 Meet the 1.5°C global warming target in the Paris Agreement.
12 NSW Government – Department of Planning, Industry and Environment (DPIE) Net Zero Plan Stage 1: 2020–2030.
13 The targets set under the Climate Change and Greenhouse Gas Reduction Act 2010.
14 Meet the 1.5°C global warming target in the Paris Agreement. See: https://www.nsw.gov.au/media-releases/nsw-set-to-halve-emissions-by-2030
15 ACT Government, ACT Climate Change Strategy 2019-25, 2019, p. 1

In the 2023–28 period, we will support the energy transition through programs that:

- relieve network congestion to enable additional generation from low cost and low emission sources, and
- install voltage control devices in southern NSW, north west NSW and Greater Sydney to maintain voltage levels within prescribed limits as minimum demand falls due to the increased uptake of household solar PV generation.

These programs are essential as network congestion and constraints prevent prospective renewable generation projects.

We will deliver projects in accordance with AEMO's ISPs and the NSW Electricity Infrastructure Roadmap, as they are required, which will facilitate the uptake of new low cost renewable generation. By delivering these projects we will be demonstrating our commitment to the energy transition. We will adhere to the National Electricity Rules (NER or Rules) automatic contingent project provisions for Actionable ISP projects and the NSW Electricity Infrastructure Investment (EII) Regulations for REZs and other projects under the NSW Electricity Infrastructure Roadmap. The costs of these projects are therefore not included in our expenditure forecasts in this proposal and customers will only pay for these projects if, after public consultation, AEMO and the NSW Government determine that they are needed and their costs have been assessed as prudent and efficient by the AER.

We are currently examining the nature and scope of costs that we may incur to ready our network for 100 per cent renewables by 2025.[16] Subject to this work, we propose to either include the forecast costs, or a further cost pass through event, in our Revised Revenue Proposal.

Technology and innovation

Our customers have told us they support investment in innovation to improve affordability and address climate change, with the majority of surveyed residential customers willing to forgo savings to invest in innovation and technology to reduce emissions. In the 2023–28 regulatory period, we will continue to collaborate with industry partners, contracting suppliers, customers and other third parties to:

- leverage innovative techniques and approaches to help us increase productivity and improve customer outcomes
- identify low-cost non-network alternatives to traditional network options, including through the RIT-T process, and
- promote the creation and trial of new innovative practices to assess their suitability for broader adoption across the business.

These projects will support the delivery of new technology and innovation in the electricity market. As noted above, at this stage we have not included any specific innovation expenditure in our forecasts. We will continue to engage with customers and other stakeholders about innovation initiatives and whether they should be reflected in our Revised Revenue Proposal.

We will also identify projects that can be funded under the Demand Management Innovation Allowance Mechanism (DMIAM) and have included projects under the Network Capability Incentive Parameter Action Plan (NCIPAP). These include low cost innovative projects that improve the capability of the transmission system, typically by alleviating transmission constraints and providing additional transmission capacity.

16 AEMO, NEM Engineering Framework Initial Roadmap, December 2021. This finds by 2025 the NEM could reach up to 100 per cent instantaneous renewables at times

Basis for this Revenue Proposal

In this Revenue Proposal, we have outlined how we will meet our customers' priorities and how we will balance affordability and reliability, while supporting the energy transition.

This Revenue Proposal adopts the AER's regulatory framework in full. As required under the National Electricity Law (NEL) and Rules, we have applied the AER's 2018 Rate of Return Instrument (RORI), which determines the allowed rate of return.[17] The AER is currently reviewing the 2018 RORI and is expected to publish its 2022 RORI in December 2022. The AER will reflect the outcomes of the 2022 RORI in its Final Decision on our 2023–28 Revenue Proposal. We do not consider the current level of returns are adequate and have set out our positions in the AER's RORI review process.

We have also indexed our Regulatory Asset Base (RAB), which delays the recovery of our expenditure.[18] The Australian Energy Market Commission (AEMC) is considering this matter as part of its Transmission Planning and Investment Review.[19] The outcome of this review may impact how our RAB is indexed and therefore our forecast revenues and prices. We are actively participating in this review and would welcome the opportunity to work with the AER and the AEMC, in consultation with our customers and other stakeholders, to resolve this matter.

We have also adopted the AER's Framework and Approach (F&A),[20] including its service classification and each of its incentive schemes that encourage efficient costs and service performance. We look forward to participating in the AER's review of these schemes and understand that the updated versions will be published in the second half of 2022 and will be reflected in the AER's Final Decision on our 2023–28 Revenue Proposal. We support the AER's intention to:

- forecast depreciation to determine the Regulatory Asset Base (RAB) at the start of the subsequent period
- work with us to develop a 'sandbox' waiver process to allow us to test small scale innovative concepts
- apply its expenditure forecast assessment guideline to assess our capex and opex forecasts for the next regulatory period, and
- apply its framework for customer engagement when assessing our Revenue Proposal.

Our forecast opex

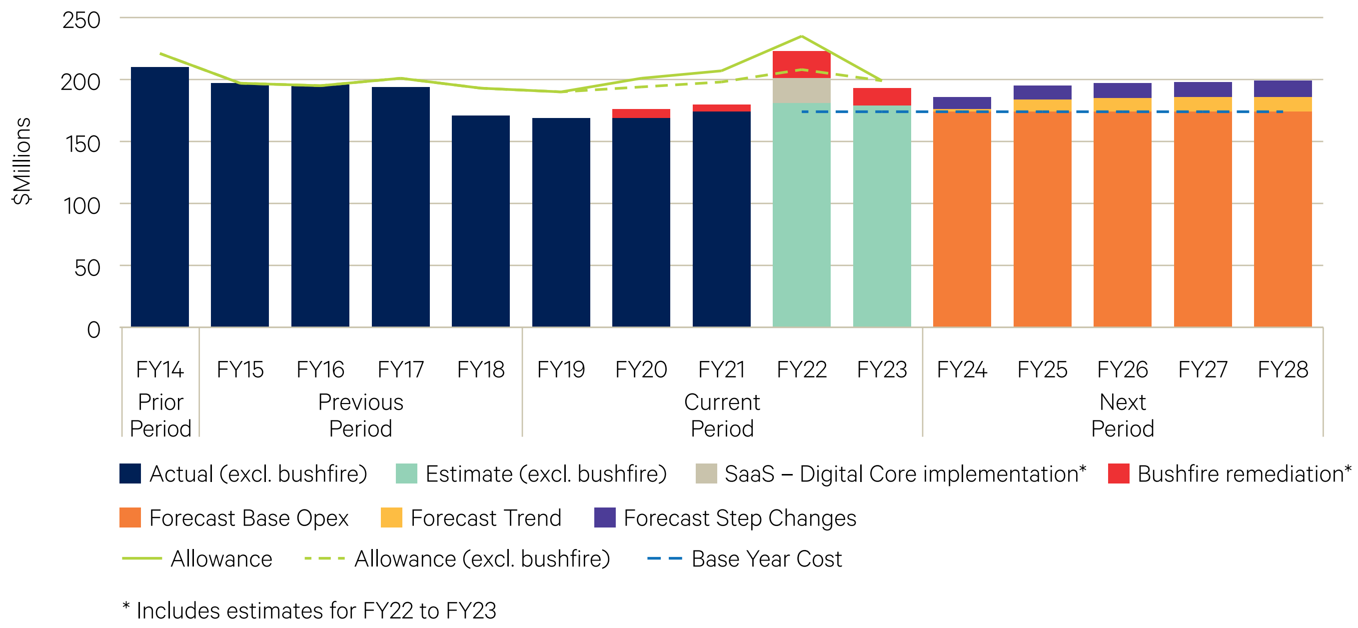
Our opex forecast for the 2023–28 regulatory period balances providing safe and reliable electricity supply, complying with new regulatory requirements, and promoting affordability for customers. We have reduced our forecast opex in response to customer feedback on our Preliminary Revenue Proposal.

Our total forecast opex for the 2023–28 regulatory period is $1,015.0 million (including debt raising costs):[21]

- We have applied the base-step-trend method to forecast our opex, which is the AER's preferred forecasting method.[22]
- We are using 2021–22 opex as the base year.[23] We estimate our base year opex to be $11.9 million below the AER's opex allowance for that year reflecting the operational efficiencies we have achieved. This will result in savings of $59.6 million[24] to our customers in the 2023–28 period (compared to our base year allowance).
- We have included step changes in our opex forecast for externally driven costs that we will incur that are not in our base year opex and are too material for us to absorb in the 2023–28 regulatory period. This opex was supported by our customers and relates to:
  - insurance premiums
  - cyber and critical infrastructure security, and
  - ISP preparatory activity.
- We have included a positive productivity growth improvement of 0.5 per cent per annum, which reduces our overall opex by around $14.3 million in the 2023–28 period.

17 NEL, section 18H – Rate of return instrument is binding on AER and network service providers
18 Indexation is calculated by multiplying the opening RAB value by forecast inflation.
19 AEMC, Transmission Planning and Investment Review.
20 AER, Framework and Approach Transgrid – Regulatory control period commencing 1 July 2021, 30 July 2021
21 This includes debt raising costs of $25.7 million
22 Transgrid, 2023–28 Expenditure Forecasting Methodology, June 2021
23 We have removed expenditure on Bushfires from our 2021–22 opex base year
24 Calculated by multiplying the base year underspend of $11.9 million by five years ($11.9 million x 5 years = $59.6 million)

Figure 1: Forecast opex for the 2023–28 period ($M, Real 2022–23)



Our forecast capex

Our forecast capex for the 2023–28 regulatory period is broadly in line with our expected capex for the current period, while ensuring we meet our customers' priorities to maintain a safe, secure, reliable and resilient network that supports the changing energy system and increased localised demand. We have reduced our forecast capex in response to customer feedback on our Preliminary Revenue Proposal to deliver on affordability – our customers' highest priority.

Our 2023–28 forecast capex is $1,368.5 million (excluding pre-approved forecast capex for Project EnergyConnect), which is $23.0 million or 1.7 per cent higher than our estimated capex of $1,345.6 million (excluding expenditure on ISP Projects),[25] for the 2018-23 regulatory period. Figure 2 compares the composition of our capex between the 2018–23 and 2023–28 regulatory periods. It shows that, whereas capex in the 2018–23 regulatory period was almost entirely driven by safety, security and reliability needs, in the 2023–28 regulatory period, 15 per cent of capex will address localised maximum demand growth and 6 per cent will support the energy transition.

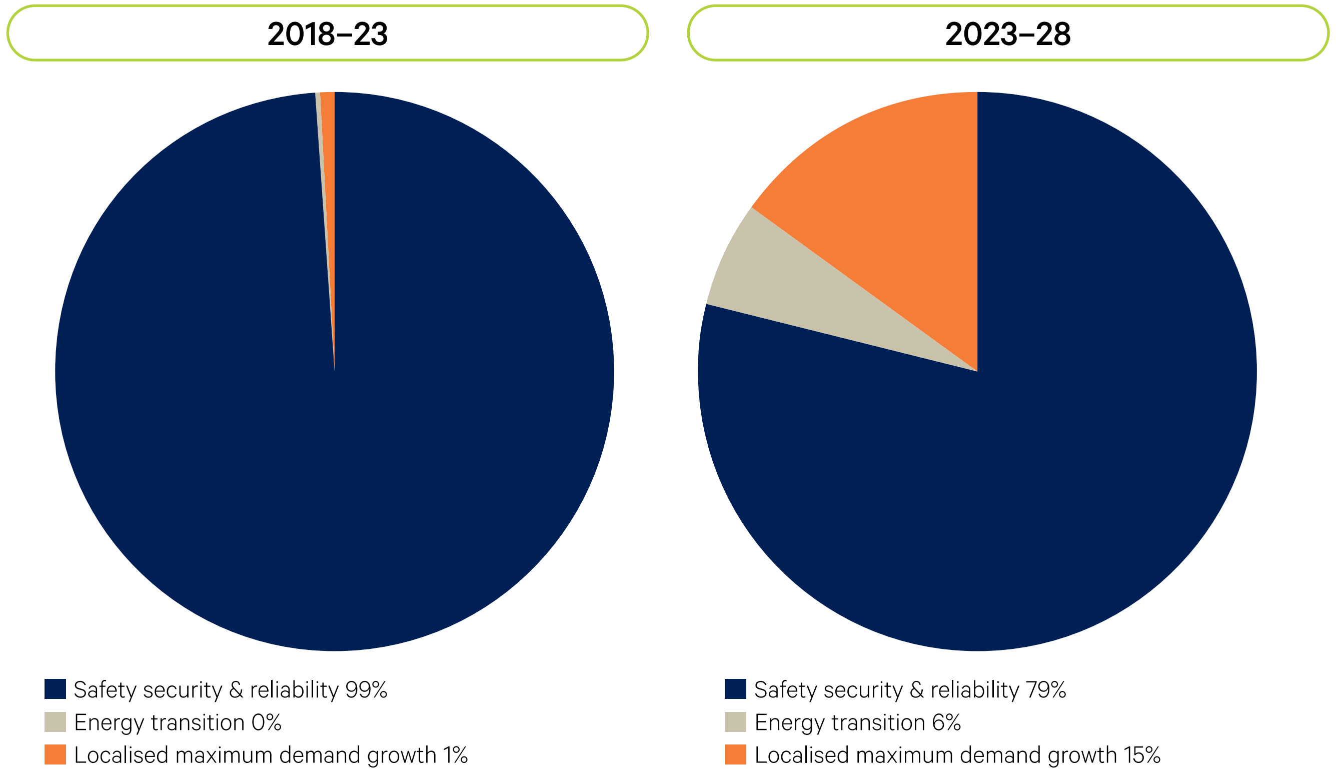
Our 2023–28 forecast capex has been independently reviewed for consistency with good industry practice. These reviews support our forecast capex as being prudent and efficient.

As noted above, given the economic effects of the COVID-19 pandemic are still highly uncertain, we have not included any costs associated with the long-term impacts in our capex forecasts. We will continue to assess the impact of the COVID-19 pandemic on our proposed 2023–28 capital program and will incorporate any changes arising from the pandemic's effects in our Revised Revenue Proposal.

Our forecast capex does not include the costs that we may incur if we are required to ready our network for 100 per cent renewables by 2025.[26] We are currently examining the nature and scope of these costs and will work closely with AEMO, our industry peers and our customers to understand and quantify the investment required to facilitate an orderly transition towards this future state. Subject to this work, we propose either to include the forecast costs, or a further cost pass through event, in our Revised Revenue Proposal.

25 Excluding our expenditure of $1,769.2 million on actionable ISP Projects approved by the AER as contingent projects for the 2018–23 regulatory period (i.e. Project EnergyConnect, QNI minor and VNI minor).
26 AEMO, NEM Engineering Framework Initial Roadmap, December 2021. This finds by 2025 the NEM could reach up to 100 per cent instantaneous renewables at times.

Figure 2: Capex composition for the 2018–23 and 2023–28 periods

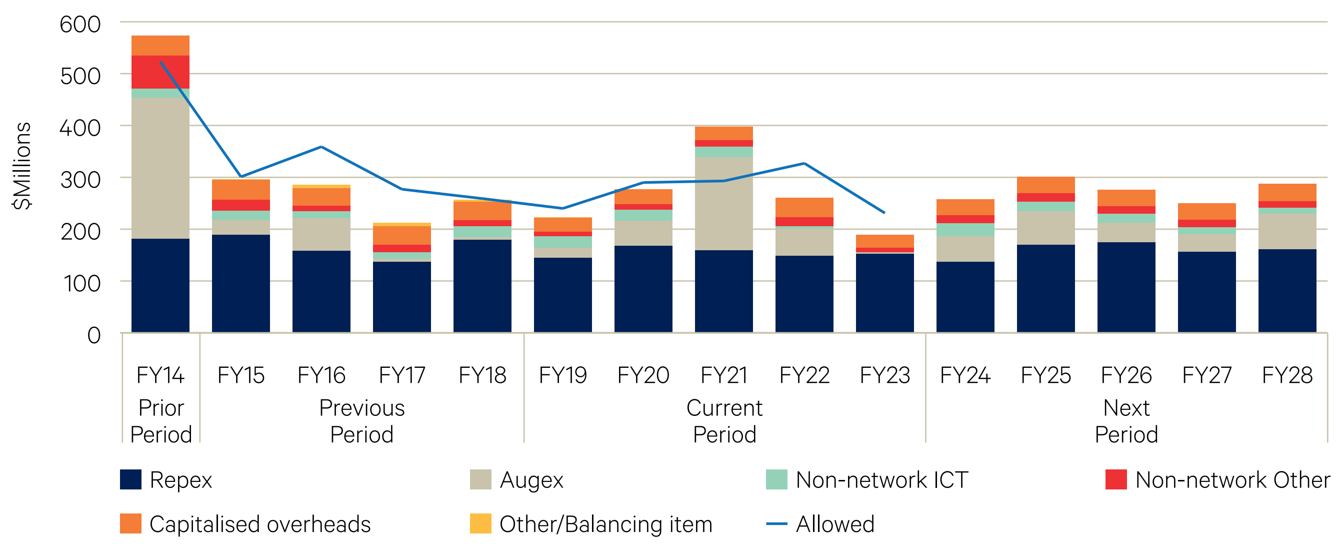


In May 2021, the AER published its Determination for Project EnergyConnect, which approved total capex of $2,008.0 million[27] for the 2018–23 regulatory period. Project delays mean that the delivery date is now anticipated to be 2024–25. As a result, we expect to spend $532.8 million of the approved capex for this Project (pre-approved forecast capex) in the 2023–28 period. We will add this pre-approved capex to our forecast for the first two years of the 2023–28 period. We are committed to delivering Project EnergyConnect in line with the total approved capex allowance of $2,008.0 million and are not seeking any additional capex for this Project in this Revenue Proposal.

Figure 3 details the breakdown of our 2023–28 forecast capex by sub-category, excluding pre-approved capex and compares this with our capex over the 2018–23 period. To aid comparison, we have excluded our expenditure of $1,769.2 million on actionable ISP Projects approved by the AER as contingent projects for the 2018–23 regulatory period (i.e. Project EnergyConnect, QNI minor and VNI minor).

27 Excluding equity raising costs

Figure 3: Forecast capex for the 2023–28 period, excluding pre-approved forecast capex, ISP Projects and NSW Electricity Infrastructure Roadmap projects ($M, Real 2022–23)



- Our Replacement capex (Repex) forecast of $797.6 million is the largest component (58.3 per cent) of our total capex forecast and will increase slightly (3.6 per cent) above our 2018–23 expenditure to deliver a safe and reliable network as our network ages and condition-related issues increase. We will also:
  – invest to enhance our cyber and physical security capability and respond to the changing generation mix, and
  – focus on climate change and network resilience to maintain our network safety, reliability and security during extreme climate events.
- Our Augmentation capex (Augex) forecast of $253.6 million contributes 18.5 per cent of our proposed total capex and is about 16.9 per cent lower than our estimate for 2018–23. Our 2018–23 Augex included Powering Sydney's Future, which is expected to cost $235.2 million and is nearing completion. The key drivers of our 2023–28 forecast Augex are:
  – addressing rapid localised load growth and spot loads in certain regions including central west and western Sydney, which if not addressed, will lead to the network in those areas not complying with NER voltage stability and thermal limits and Independent Pricing and Regulatory Tribunal's (IPART's) reliability standards, and
  – maintaining compliance with voltage stability which is being impacted by decreasing minimum demand as household solar PV generation increases.
- Our Non-network ICT capex forecast of $86.9 million is 29.1 per cent higher than our estimate for the current period, and will enable us to rollout new technology and continue to refresh or replace legacy applications and systems at the end of their lives.
- Our Non-network Other capex forecast (property, fleet, plant and equipment) of $71.4 million is 22.1 per cent higher than our estimate for the current period as we continue to provide safe, compliant and productive offices and depots to support the increase in our network operations activity and invest to maintain the suitability and safety of our fleet, plant and equipment.
- Our capitalised overheads forecast of $159.0 million is 10.2 per cent higher than our estimate for the current period to enable us to deliver a larger capital works program.

Our Revenue forecast and price path

Our forecast revenue will fund our expenditure program to meet our customers' needs and maintain the reliability, security and safety of our transmission network, while supporting the energy transition. Table 1 shows the building blocks that make up our total Annual Building Block Revenue Requirement (ABBRR) of $3,925.1 million for the 2023–28 period. It also shows our Maximum Allowed Revenue (MAR), which is our smoothed revenue.

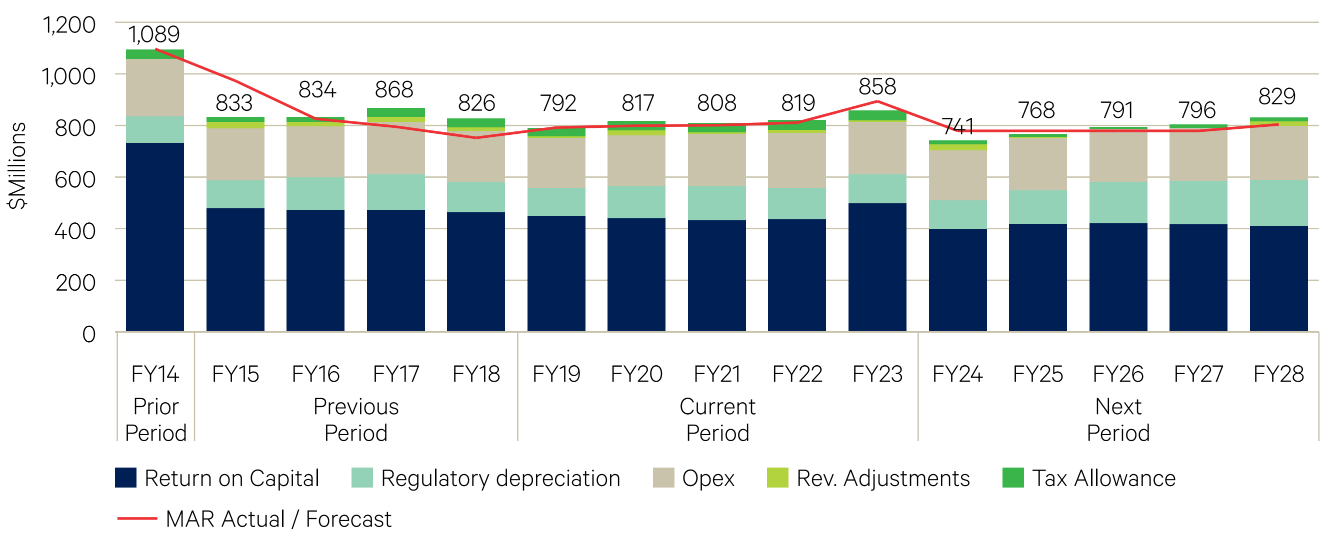
Table 1: Forecast revenue ($M, Real 2022–23)

	Total 2018–23	2023–24	2024–25	2025–26	2026–27	2027–28	Total 2023–28
Return on capital (2023–28 rate of return: 4.7%)[1]	2,254.2	400.4	419.1	420.9	416.5	410.6	2,067.6
Depreciation	601.2	108.8	129.0	160.0	167.8	177.7	743.3
Opex	1,009.1	193.8	202.8	205.2	205.5	207.7	1,015.0
Revenue adjustments[28]	47.9	22.6	4.4	(4.8)	(7.3)	18.6	33.5
Corporate income tax	181.6	15.7	13.0	9.4	13.2	14.6	65.7
ABBRR (unsmoothed revenue)	4,094.0	741.3	768.3	790.6	795.6	829.2	3,925.1
MAR (smoothed revenue)	4,096.7	779.3	779.3	779.3	779.3	804.3	3,921.6

Notes: 1. Calculated using the AER's binding 2018 Rate of Return Instrument and recent observable market data.

Figure 4 shows the trends in our revenues over the 2014–18, 2018–23 and 2023–28 periods and that our estimated 2023–28 ABBRR is $168.9 million or 4.1 per cent less than our expected 2018–23 ABBRR.

Figure 4: Forecast revenue ($M, Real 2022–23)[29]

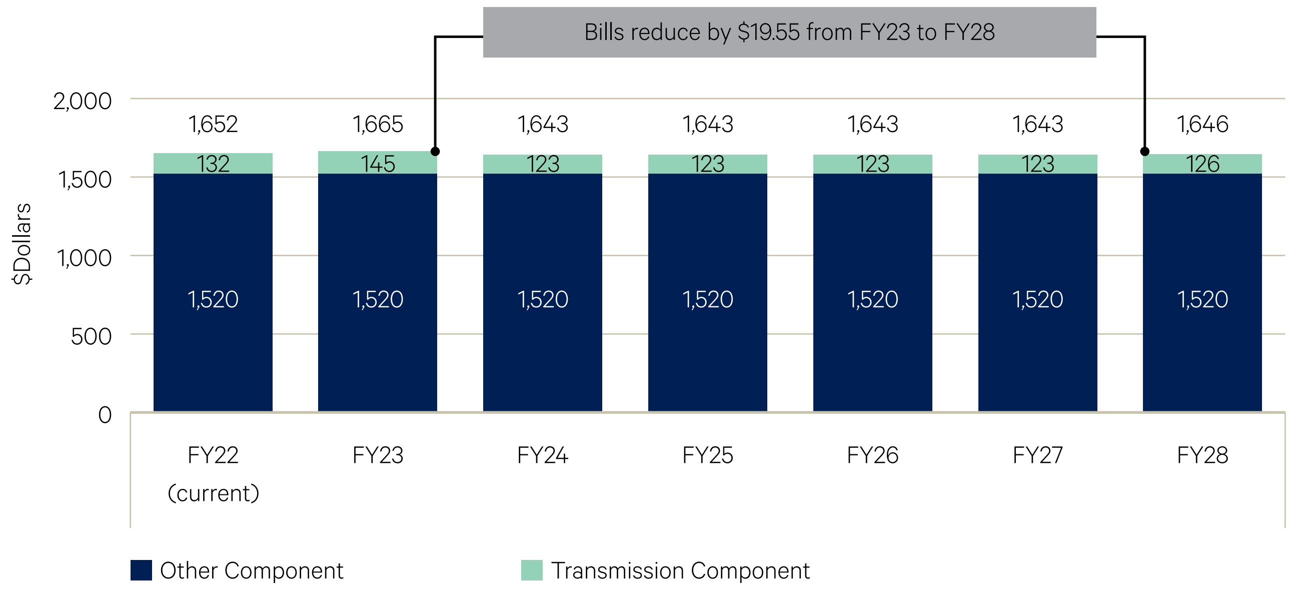


Transmission costs comprise 7 to 8 per cent of indicative residential household and small business bills. We use our MAR to set our annual transmission prices. Based on our forecast MAR, we expect transmission costs to reduce over the period 30 June 2023 to 30 June 2028 by $19.55 per annum for residential customers and $73.05 per annum for small business customers, which in both cases is a 13.4 per cent reduction over this period.[30] This will help to deliver on affordability – our customers' highest priority. Delivering these savings will depend on the outcome of this revenue determination process.

28 Revenue adjustments include carryover amounts from the EBSS and CESS, a negative adjustment for shared asset revenue, and the DMIA.
29 The values shown on the figure are the total building blocks revenue.
30 By 2027–28.

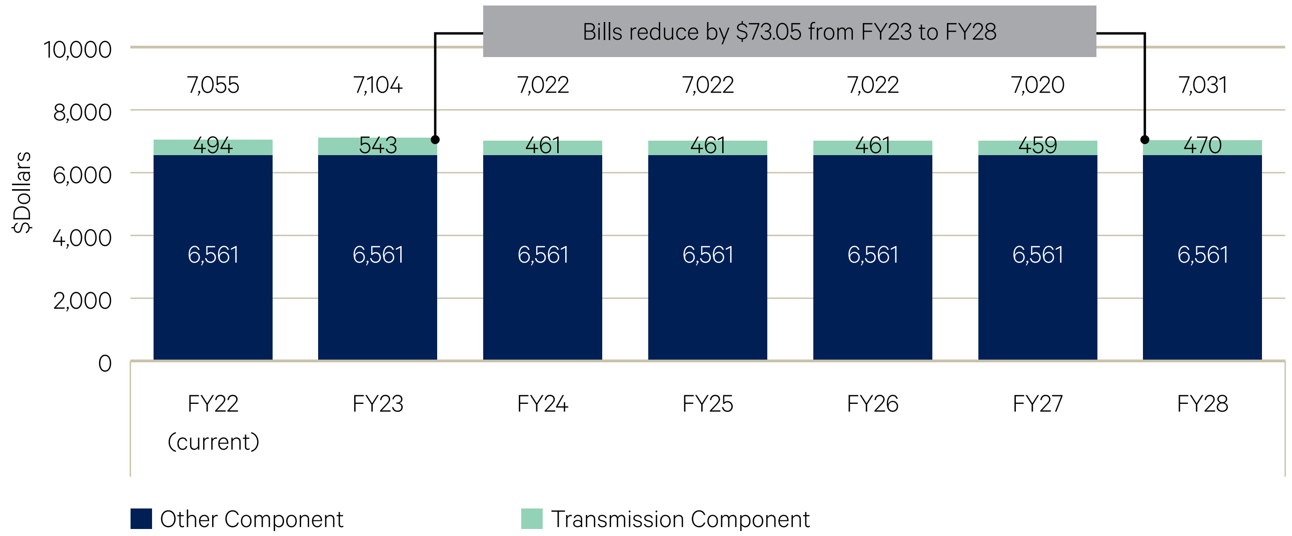
Figure 5 shows the indicative household bills over the 2023–28 regulatory period and Figure 6 shows the equivalent for small business customers.

Figure 5: Indicative household bill ($, Real 2022–23)



Notes 1. The indicative bill uses average bill information published by the AER and AEMC and assumes that the non-transmission components of the bill stay constant in real dollars.

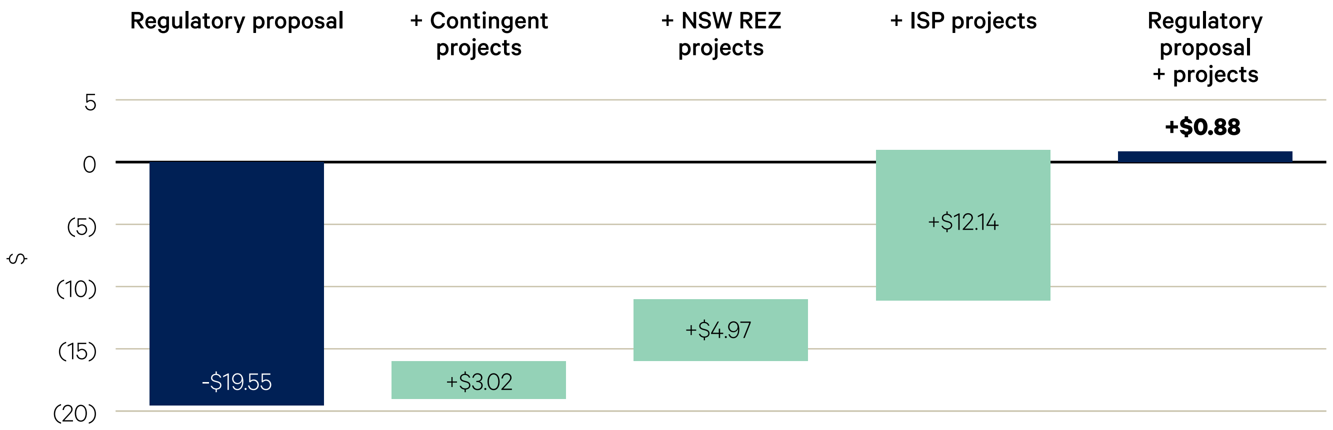
Figure 6: Indicative small business bill ($, Real 2022–23)



As noted above, our expenditure forecasts do not include the costs of projects in AEMO's ISP, the NSW Electricity Infrastructure Roadmap or the contingent projects discussed in Chapter 17. Customers will only pay for these projects if they are approved by the relevant regulators and their costs are reflected into our transmission prices as approved by the AER. In accordance with the regulatory framework, ISP projects and NSW REZs will only proceed if they deliver net benefits to customers such that the expected savings in wholesale costs outweigh the increase in the transmission costs.

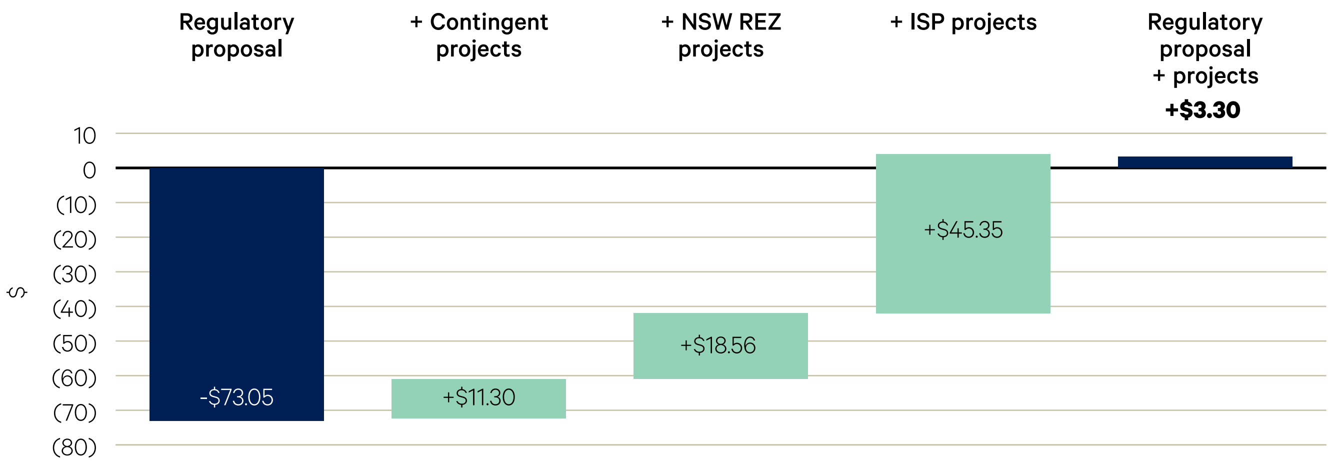
We recognise that our customers are interested in understanding the total potential transmission price impact including if these projects proceed. Figure 7 and Figure 8 show that the transmission cost savings in this Revenue Proposal will largely be offset by these projects if they proceed in the 2023–28 period.

Figure 7: Residential bill impact – transmission component ($, Real 2022–23)[31]



Notes: 1. The values do not sum exactly due to impact of equity raising costs. 2. The estimated impact of adding the contingent, NSW REZ and ISP projects is indicative. 3. Values are estimated annual bills for residential customers.

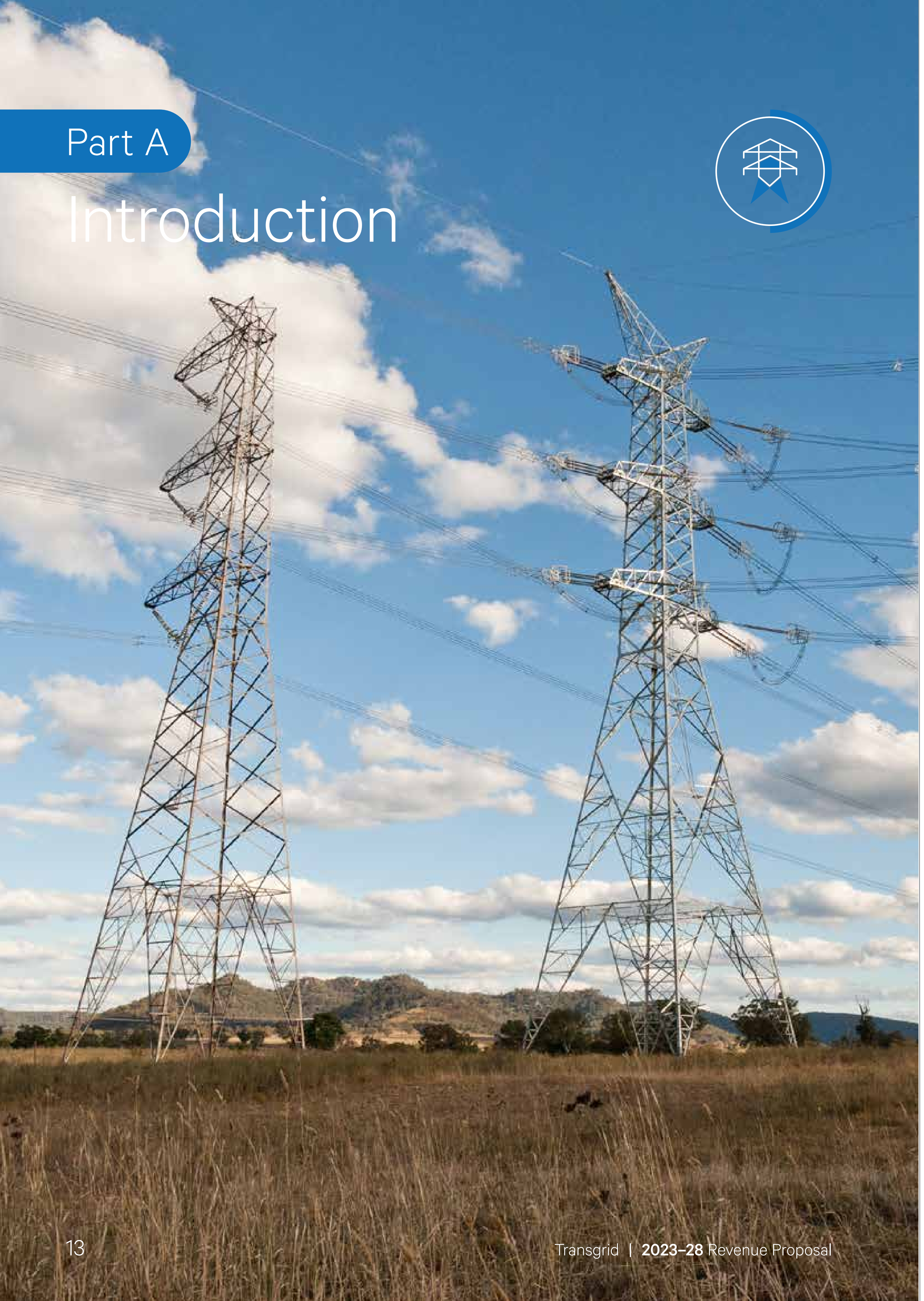
Figure 8: Small business customers bill impact – transmission component ($, Real 2022–23)



Notes: 1. The values do not sum exactly due to impact of equity raising costs. 2. The estimated impact of adding the contingent, NSW REZ and ISP projects is indicative. 3. Values are estimated annual bills for small business customers.

31 Capex for ISP projects is projected to be incurred earlier than for NSW REZ projects. As a consequence, the ISP projects would impact revenue and prices sooner.

Part A
Introduction



1. About us and our Revenue Proposal

Key messages

- We operate the high voltage transmission network in NSW and the ACT, which services about 4 million customers.
- Our transmission network supplies higher peak loads and transmits more energy annually than any other transmission network in Australia.
- This is our Revenue Proposal that details our proposed revenues for our next regulatory period, 1 July 2023 to 30 June 2028. It reflects extensive feedback from our customers and other stakeholders.
- We welcome our customers and other stakeholders' feedback on this Revenue Proposal to inform our future plans and the AER's decision-making.

1.1 About us

1.1.1 What we do

We provide safe, reliable and affordable electricity supply to around 4 million customers in NSW and the ACT.[32]

In providing prescribed transmission services we must comply with the NER and our licences, customer expectations and other regulatory and legislative obligations. This includes performing our roles as the jurisdictional transmission planning body, and the transmission system operator, for NSW and the ACT. In undertaking these roles, we plan, build, operate and maintain the transmission network effectively and efficiently to benefit customers.

We plan and develop our network in response to overall demand growth and generation developments. In doing so, we have regard for customer requirements as well as AEMO's role as the market operator for the NEM. We annually plan our network at three levels – connection planning, network planning in NSW and the ACT and inter-regional planning. Our plans are published in our Transmission Annual Planning Report (TAPR), which identifies areas of our network that are expected to require network development or support over a 10 year period. We have regard for the NSW Electricity Infrastructure Roadmap as well as AEMO's latest ISP and Electricity Statement of Opportunities (ESOO) in developing these plans.

As system operator, we ensure that the transmission network always provides safe and reliable electricity to our customers, even in the most challenging conditions.

We are currently the only provider of prescribed transmission services in our service area. Because of this, the revenues and transmission prices that we charge are regulated by the AER to ensure that we provide our transmission services efficiently.

The AER is the economic regulator of electricity transmission services in all Australian states and territories, other than Western Australia. It applies the NEL and NER. Its role is to set the revenues we can recover from our customers for the efficient costs of prescribed transmission services and to approve the manner in which we can recover those revenues through our transmission prices.

The AER does this by making transmission revenue determinations for five-year periods. In May 2018, the AER made its transmission determination for our current regulatory period, 1 July 2018 to 30 June 2023 (the 2018–23 regulatory period).

32 Economic Insights, AER TNSP Benchmarking Report Draft, August 2021.

This is Transgrid's Revenue Proposal for the next regulatory control period, 1 July 2023 to 30 June 2028 (the 2023–28 regulatory period). It has been informed by the priorities and preferences of our customers and other stakeholders. The AER will make its final transmission determination in April 2023.

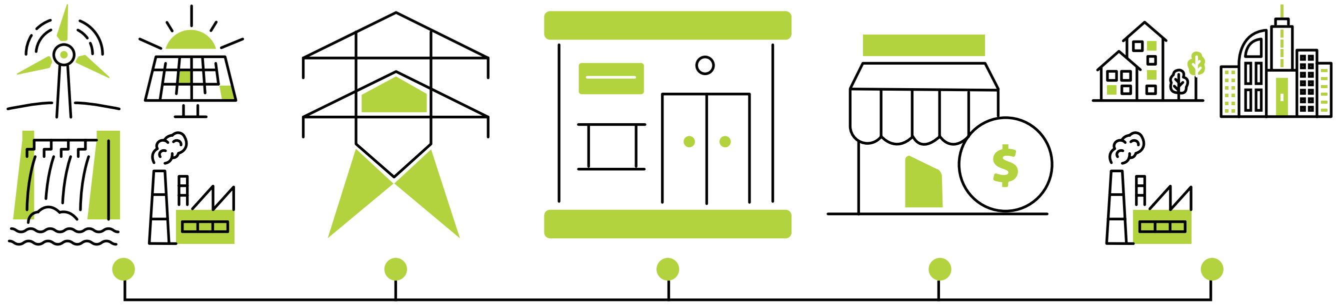
We also offer a range of unregulated infrastructure and telecommunication services through our (ring-fenced) commercial arm, Lumea, to meet the growing needs of a range of our customers. Where those services involve the use of prescribed assets, other customers benefit from the shared use of our assets through lower transmission prices. This is discussed in Chapter 18.

1.1.2 Our role in the electricity supply chain

Our transmission network is at the heart of the NEM and is vital to achieving NSW and ACT's net-zero emissions target.

Our electricity transmission network forms the physical connection between regions in the NEM.[33] It is essential for the connection of new low-cost renewable generation and stronger interconnection across the NEM to ensure the safety, security and reliability of supply and to enable customers to access affordable electricity.

Figure 1-1: Electricity supply chain



Generation and storage

Electricity is generated from a range of energy sources including wind, solar, hydro, coal and gas.

Grid-scale batteries are also emerging and have the potential to help maintain reliable supply during times of peak demand.

Transmission

The transmission network connects to large generators and transports electricity long distances to large directly-connected industrial customers and distribution networks that deliver it to homes and businesses.

Distribution

Distribution networks transport electricity at lower voltages to households and businesses. They also provide metering services to measure the amount of electricity being consumed.

Retail

Retailers are responsible for billing customers for the electricity they use and managing payments. There are approximately 102 electricity retailers operating in NSW and the ACT.

Customers

There are around four million electricity customers in NSW and the ACT. Increasingly our customers generate their own electricity through rooftop solar and feed surplus electricity back to the grid, impacting the traditional flow of electricity.

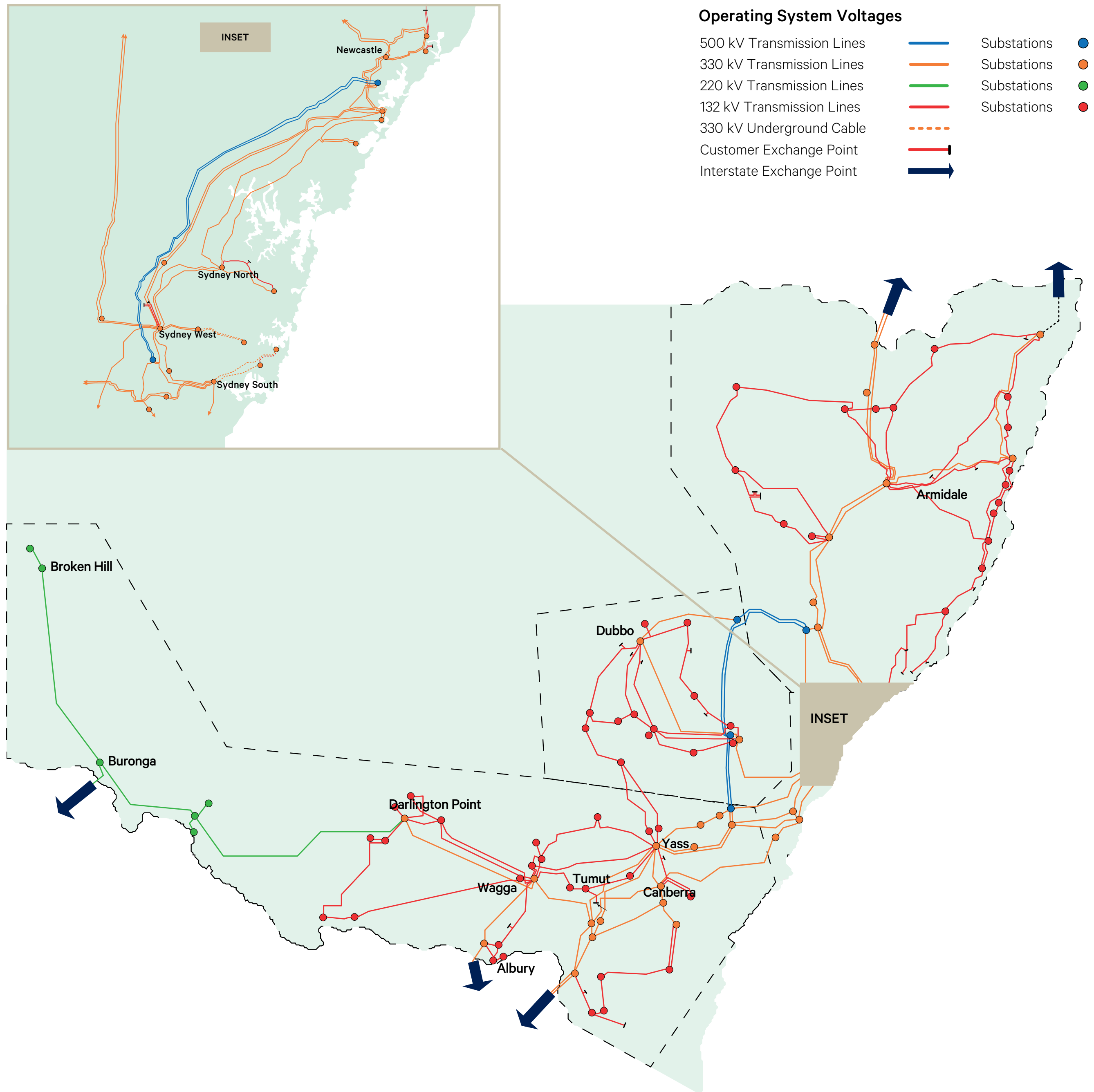
33 The NEM is comprised of five physically connected regions on the east coast of Australia: Queensland, New South Wales (which includes the Australian Capital Territory), Victoria, Tasmania, and South Australia.

1.1.3 Our geographic coverage

As shown in Figure 1-2 our transmission network has four geographic areas:

- Northern NSW – this covers an area from Tomago in the Hunter Valley to Lismore in the north eastern corner of NSW, north west through to Moree and back to Tamworth. Our network connects with Queensland in the north.
- Greater Sydney – this includes the CBD of Sydney, which is a hub for economic activity, major transport infrastructure, industry and tourism, as well as the Blue Mountains, the Central Coast and Newcastle. A high level of reliability and security is needed to maintain services required for Sydney to operate as a major international city.
- Central West NSW – this connects to Greater Sydney at Mt Piper and Wallerawang and extends west to Orange, Parkes and Forbes. It extends up to Wellington and Wollar where it connects to northern NSW and down to Cowra where it connects to southern NSW at Yass.
- Southern NSW and ACT – this covers Marulan to Wagga Wagga in the south of the State, to Albury in the far-south, and extends to Broken Hill in the far-west. This region includes Canberra, and connects with Victoria in the south, and will soon connect with South Australia once Project EnergyConnect is operational.

Figure 1-2: NSW transmission network

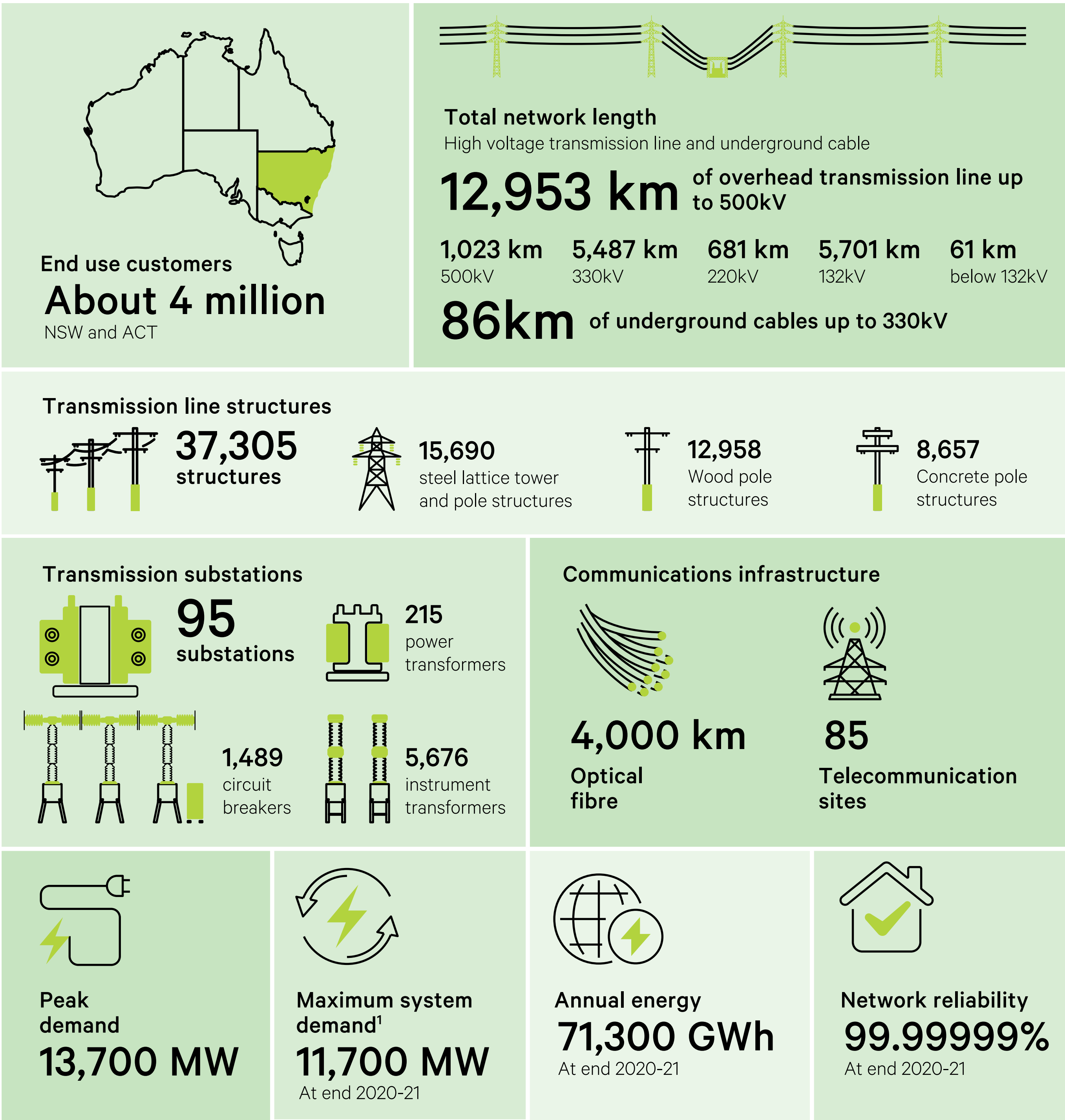


1.1.4 Our network assets and performance

We have the highest peak and system demand in the NEM and transport almost 40 per cent of the energy in the NEM, more than any other network business.

Our transmission network is the backbone of the NEM and underpins the Australian economy by facilitating energy trading between Australia's largest states. It comprises 95 substations, over 13,039 kilometres of high voltage transmission lines, underground cables and five interconnections between NSW and ACT and Queensland and Victoria.

Figure 1-3: Our assets and network performance



Notes: 1. Transmission system coincident maximum demand in 2020–21, which occurred on 10 June 2021.

1.1.5 Our support of the energy transition

Australia's energy system is undergoing a 'once-in-a-century' transformation.[34] The transition to a new energy market is happening quickly, as the cost of renewables decline, technology advances, and governments commit to decarbonisation. AEMO's Draft 2022 ISP finds that 'coal is retiring two or three times faster than anticipated' as competitive and operational pressures intensify 'with the ever-increasing penetration of cheap renewable generation'. AEMO's NEM Engineering Framework Initial Roadmap, published in December 2021, finds that by 2025 the NEM could reach up to 100 per cent instantaneous renewables at times.[35]

The NSW[36] and ACT[37] Governments have both adopted a goal of achieving net zero emissions by 2050, or sooner. By 2030, the NSW Government's goal is to reduce emissions by 50 per cent against 2005 levels. By 2025, the ACT Government's goal is to reduce emissions by at least 50 per cent against 1990 levels.

We support the NSW and ACT Governments' goals of achieving net zero emissions. We are working closely with the NSW Government on its Electricity Infrastructure Roadmap, which is expected to see the development of five REZs. We also plan our network to facilitate the ACT Government's net zero commitment as it develops a transition plan to decarbonise the natural gas distribution network.

As Australia's largest electricity transmission network, our infrastructure is vital to Australia's successful energy transition and achieving net zero emissions. Decarbonisation, electrification and new green industries require a significant expansion of renewable generation and associated transmission infrastructure. AEMO's Draft 2022 ISP finds that 'significant investment in the NEM' is needed to support the transition. In particular, AEMO has identified that 'more than 10,000 km of new transmission' is required 'to connect geographically and technologically diverse, low-cost generation and firming with the consumers who rely on it'.[38]

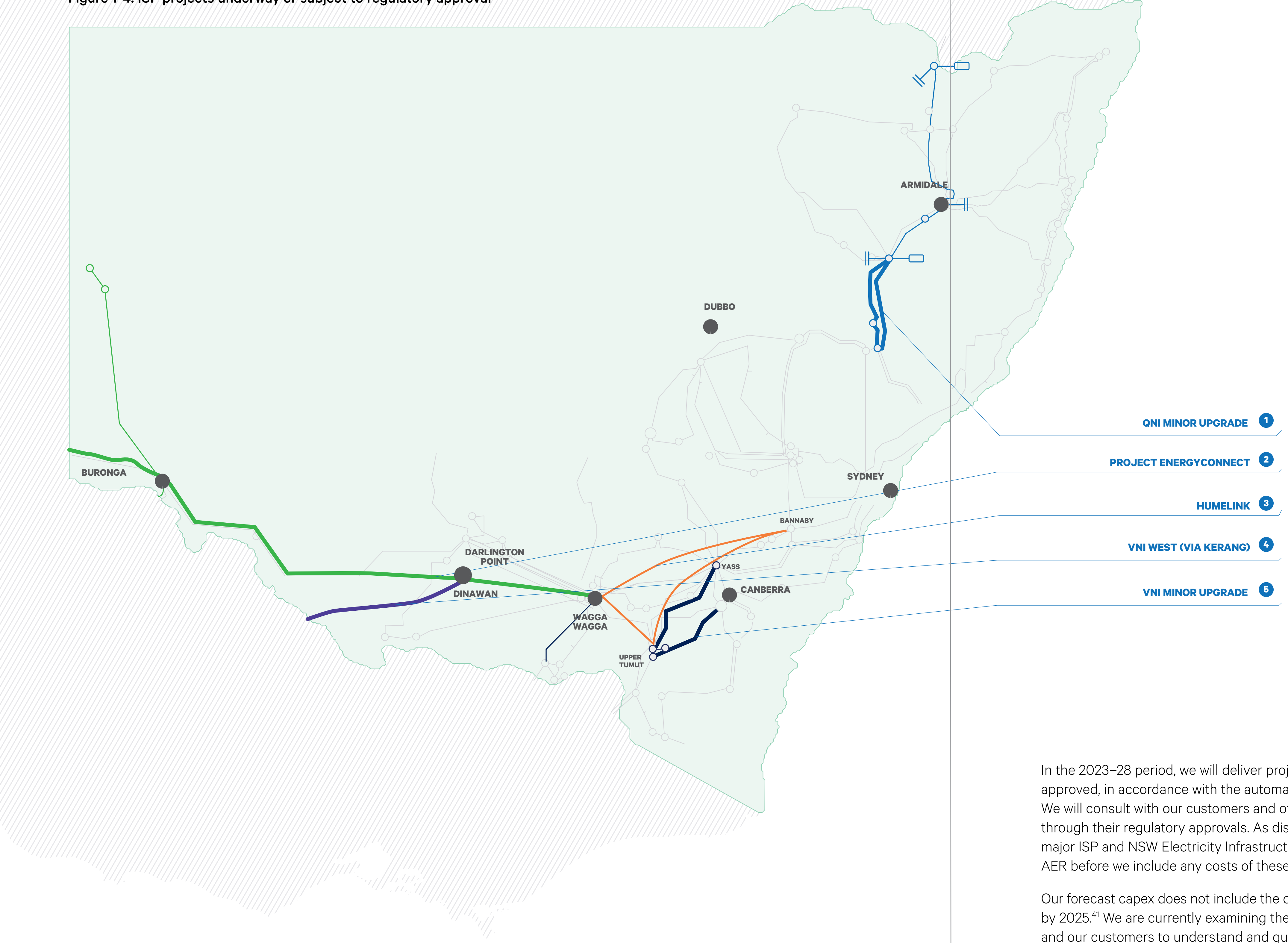
AEMO's ISP identifies the optimal development path for eastern Australia's power system to facilitate this transition to deliver the lowest cost energy solutions consistent with an electrified, low carbon future. Coordinated transmission investment based on AEMO's ISP will reduce customers' final electricity bills by helping to share reliable generation resources across the NEM, improve wholesale market competition, open-up the development of REZs and facilitate the development of large scale storage.

AEMO's Draft 2022 ISP finds that transmission projects on its optimal development path 'add $29 billion in value while enabling the transformation' and that these investments return '2.5 times' their cost.[39] It also finds that these investments will 'cost-effectively serve the needs of consumers, support Australia's transition to net zero emissions, and support regional employment and economic growth'. The NSW Electricity Infrastructure Roadmap sets out the 'NSW Government's plan to transform our electricity system into one that is cheap, clean and reliable'. It expects to deliver at least 12GW of new transmission capacity through its REZs, reduce carbon emissions by 90 million tonnes, create 6,300 construction and 2,800 ongoing jobs and reduce electricity bills.

We are supporting the energy transition in the current period by investing in three nationally significant ISP projects identified in the optimal development path in AEMO's ISP. These projects are critical to ensuring the security and reliability of the NEM as well as enabling the energy market transition, which will significantly reduce customers' overall electricity bills through wholesale market cost reductions. We will commence delivering HumeLink and VNI West subject to receiving regulatory approvals from AEMO and the AER and the necessary land access and environmental and heritage approvals.

34 AEMO, Draft 2022 Integrated System Plan, December 2021, p. 8
35 AEMO, NEM Engineering Framework Initial Roadmap, December 2021.
36 NSW Government – Department of Planning, Industry and Environment (DPIE) Net Zero Plan Stage 1: 2020-2030.
37 The targets, set under the Climate Change and Greenhouse Gas Reduction Act 2010.
38 AEMO, Draft 2022 Integrated System Plan, December 2021, p. 8
39 AEMO, Draft 2022 Integrated System Plan, December 2021, p. 11

Figure 1-4: ISP projects underway or subject to regulatory approval



Projects delivered or in progress

1 QNI Minor Upgrade

This involves a minor upgrade to the existing QNI interconnector, boosting interstate transmission capacity and increasing power flow on existing lines. It enhances network reliability ahead of the forecast closure of Liddell power station.

2 Project EnergyConnect

This involves constructing new 330kV double circuit transmission lines, with approximately 800 MW transfer capacity that will connect SA and NSW, with an added connection to north-west Victoria.

5 VNI Minor Upgrade

This is the NSW component of works to upgrade the existing VNI interconnector. It is essential to manage the risk of reliability standard breaches during extreme heat conditions in Victoria, following the closure of Liddell power station[40] The project is also expected to support the development of renewable generation and incorporates the use of SmartValves' technology that enables dynamic control of power flows.

Projects subject to regulatory approvals

3 HumeLink

This involves new 500kV lines in an electrical 'loop' between Maragle, Wagga Wagga and Bannaby. It will open up additional capacity for new generation (primarily renewable generation) in southern NSW, increase the transfer capacity between Victoria and NSW and reduce customers' final electricity bills by improving wholesale market competition.

4 VNI West (via Kerang)

This involves a new high capacity 500kV double-circuit transmission line to connect the Western Victoria Transmission Network Project (north of Ballarat) with Project EnergyConnect (at Dinawan) via Kerang. This project will increase access to Snowy 2.0's deep storages and support new renewable energy sources particularly in the Murray River and western Victoria REZs. It will also provide system resilience to address projected coal closures and enable sharing of geographically diverse renewable energy.

In the 2023–28 period, we will deliver projects identified in AEMO's ISPs and the NSW Electricity Infrastructure Roadmap as they are approved, in accordance with the automatic contingent project provisions in the Actionable ISP Rules and the NSW EII Regulations. We will consult with our customers and other stakeholders about these projects during their delivery phases and as they progress through their regulatory approvals. As discussed in Chapter 2, we are establishing a Major Projects Monitoring Committee for all major ISP and NSW Electricity Infrastructure Roadmap projects. Approvals are required from AEMO, the NSW Government and the AER before we include any costs of these projects in our transmission prices.

Our forecast capex does not include the costs that we may incur if we are required to ready our network for 100 per cent renewables by 2025.[41] We are currently examining the nature and scope of these costs and will work closely with AEMO, our industry peers and our customers to understand and quantify the investment required to facilitate an orderly transition towards this future state. Subject to this work, we propose either to include the forecast costs, or a further cost pass through event, in our Revised Revenue Proposal.

40 AEMO, 2019 Electricity Statement of Opportunities (ESOO), p. 5.
41 AEMO, NEM Engineering Framework Initial Roadmap, December 2021. This finds by 2025 the NEM could reach up to 100 per cent instantaneous renewables at times.

1.1.6 Our customers and other stakeholders

Customers are the 'end-users' of electricity who ultimately pay for our services. This includes residential households and small businesses as well as large directly connected customers and generators. Our customers and communities are diverse, with differing interests and priorities. We also have many other stakeholders.

End use customers

Our customers are diverse, living and working in regional, rural and metropolitan areas, and all rely on a safe, reliable and affordable supply of electricity. We plan and operate our network to meet their present and future needs.

Directly connected customers

We directly connect some customers into our transmission network. Our directly connected customers include large electricity generators including solar, wind, pumped-hydro, gas and coal generators, large energy users such as smelters and mines, neighbouring transmission networks through our interconnectors, and distribution networks. Our directly connected customers are generally medium to large businesses.

Communities and landowners

Our network stretches over 13,000 kilometres through NSW and the ACT, and almost 17,000 landowners across the state have our assets or easements on their property. We acknowledge also that our network traverses the traditional lands of many First Nations' people whose rights we acknowledge and respect.

We have ongoing relationships with these landowners, traditional and otherwise, and communities given the long life of our assets. These communities and landowners expect us to operate and maintain our assets to the highest standards to ensure their safety and to minimise our impact on them. In developing and operating our network we will seek to maximise employment and other economic opportunities for all our communities whilst minimising our impact on environmental and cultural values of the land on which we operate.

1.1.7 Our transmission revenues

Our transmission revenues comprise 7 to 8 per cent of indicative residential household and small business bills in NSW and ACT. The cost of our transmission services is only one component of the total retail bill that customers pay. The other bill components include generation, distribution and retail costs.

Table 1-1: Indicative breakdown of total retail bill – residential and small business customers

Electricity supply chain	Proportion of total bill %	
	Residential	Small business
Generation	29	28
Transmission	**8**	**7**
Distribution	28	28
Retail and other	27	28
Environmental policies	9	10

Source: ACIL Allen, Transgrid TUOS as a proportion of residential and small business electricity bills, 29 November 2021. Note: the proportion of total bill % is assumed to apply to typical annual bills for 2021–22. These may differ from those expected for 2022–23.

1.1.8 Our services

We provide prescribed transmission services under the Rules,[42] relying on, amongst other things, our licences that are issued under the Electricity Supply Act 1995 (NSW) and the Utilities (Technical Regulation) (Electricity Transmission Supply Code) Approval 2016 (ACT). These services include:

- shared transmission services which are provided to directly connected customers and distribution networks (prescribed Transmission Use of System (TUOS) services)
- connection services for large customers and Distribution Network Service Providers (DNSP) who are connected to our transmission network (prescribed exit services)
- grandfathered connection services provided to generators and customers directly connected to the transmission network that were in place on 9 February 2006 (prescribed entry and exit services), and
- services required under the Rules or to comply with jurisdictional electricity legislation that are necessary to ensure the integrity of the transmission network, including through the maintenance of power system security and quality (prescribed common transmission services).[43]

The quality, reliability and security of supply of the prescribed transmission services we provide are established in the Rules, our licences as well as in customer connection and access agreements.

Our forecast expenditure in this Revenue Proposal relates to prescribed transmission services only. The allocation of costs to these services is in accordance with our Cost Allocation Methodology (CAM).[44]

Expenditure has been allocated to capex and opex in accordance with our Expenditure Capitalisation Standard. A copy of this standard is provided as an attachment to this Revenue Proposal.[45]

42 Chapter 6A and 10 of the NER.
43 These services are services are provided in bulk to AEMO
44 Transgrid, Cost Allocation Methodology, 17 January 2022.
45 Transgrid, Expenditure Capitalisation Standard, November 2021

1.2 Our Revenue Proposal

1.2.1 Structure of this Revenue Proposal

Our Revenue Proposal is structured as follows:

Part A

> **Introduction** covers the context for and development of this Revenue Proposal, an overview of what we have delivered over the current regulatory period, our engagement with customers and other stakeholders and our acceptance of the AER's positions in its Framework and Approach (F&A) paper

Part B

> **Building Blocks** explains our forecast expenditure and proposed building blocks which the AER will assess to determine our Maximum Allowed Revenue (MAR) in the 2023–28 regulatory period. It also details:

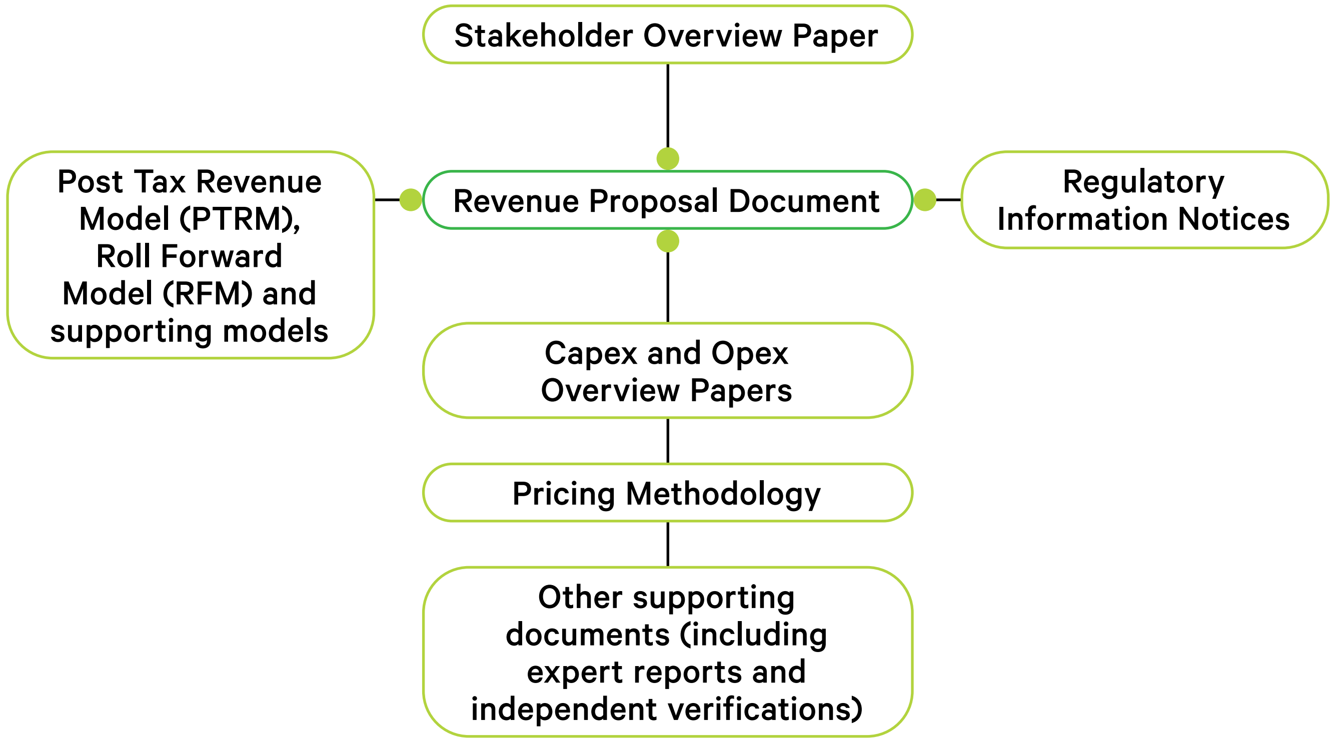
- the AER's incentive schemes which encourage us to deliver our services efficiently
- how we would recover the costs of particular uncertain events that may occur in the 2023–28 regulatory period
- our contingent projects for the 2023–28 regulatory period and their trigger events
- our revenue from shared assets over the 2023–28 regulatory period
- our proposed pricing methodology for the 2023–28 regulatory period.

Part C

> **Other matters** provides information on our approach to confidential information and the assurance and certification we must provide, including the key assumptions supporting our expenditure forecasts.

Our Revenue Proposal comprises the attachments and models illustrated in Figure 1-5 as well as other supporting documents. This Revenue Proposal references these attachments, models and other supporting documents and should be read in conjunction with them.

Figure 1-5: Revenue Proposal document structure



1.2.2 Next steps and on-going consultation

We welcome customers and other stakeholders' views on this Revenue Proposal. Please share your views with us by:

- Email us at: revenue.reset@transgrid.com.au
- Calling us on: 02 9284 3431

Figure 1-6: Next steps

1.2.3 Conventions

In this Revenue Proposal, unless otherwise specified:

- historical and forecast expenditure is presented in end-year (to 30 June) real 2022–23 dollars
- all dollars for regulatory years:
  - up to and including 2020–21 are actuals
  - 2021–22 and 2022–23 are estimates, and
  - 2023–24 onwards are forecasts.
- negative figures are presented in brackets, and
- our revenue building-blocks from the post tax revenue model (PTRM) are presented in end-year (to 30 June) nominal dollars.

Totals presented in tables may not add due to rounding.

All figures and tables have been prepared from material sourced by us, unless otherwise specified.

1.3 Supporting documentation

The following documents support this Chapter and accompany our Revenue Proposal.

Name
2023–28 Revenue Proposal Stakeholder Overview
Document Register
2021 Transmission Annual Planning Report
ACIL Allen, Transgrid TUOS
Cost Allocation Methodology
Expenditure Capitalisation Standard

2. What we have heard from our customers and other stakeholders

This Chapter overviews our engagement approach, activities and what we have heard from our customers and other stakeholders. More detail about our engagement is provided in our attached '2023–28 Stakeholder Engagement Report' and Forethought's 'Revenue Reset Stakeholder Engagement – Executive Report'.

Key messages

> Customers are the 'end-users' of electricity who ultimately pay for our services. This includes residential households and small businesses as well as large directly connected customers and generators. We also have many other stakeholders, including First Nations people and their elders and traditional owners, other landowners, other community and environmental groups, governments, regulators, financiers, trade unions and industry bodies.

> The development and operation of our network are geared to meeting our customers and other stakeholders' needs. Engaging them is therefore integral to our operations to ensure that we understand and address their priorities and preferences in the rapidly changing energy system.

> Our 2023–28 Revenue Proposal engagement builds on, and extends, our business-as-usual engagement activity.

> We developed engagement objectives for our Revenue Proposal, and a Stakeholder Engagement Plan, which we have used to determine our engagement activity and have enabled our customers to assess the effectiveness of our engagement to date.

> Customers and other stakeholders have told us that they want an affordable, safe, secure, reliable and sustainable energy supply. This Revenue Proposal addresses these priorities for the 2023–28 regulatory period.

> We will continue to engage our customers and other stakeholders over the coming 15 months as the AER reviews our Revenue Proposal, including through a joint program with TAC members.

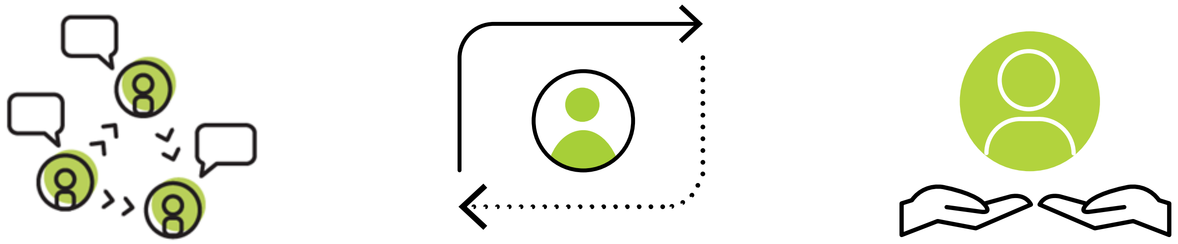
2.1 Our engagement objectives

The development and operation of our network are geared to meeting our customers' needs. This is increasingly important given the rapid changes in the energy system and our role in the energy transformation.

Figure 2-1 overviews our engagement objectives for our 2023–28 Revenue Proposal. To achieve these objectives our engagement has focused on:

- building awareness of who we are, our role in the energy system, and our emerging key challenges
- understanding the broad range of customer and other stakeholders' priorities and preferences, and
- addressing customer and other stakeholders' priorities and preferences in our Revenue Proposal so we continue to deliver the services they want, need and are willing to pay for in the rapidly changing energy system.

Figure 2-1: Revenue Proposal engagement objectives



1. Understand and address customers' priorities and preferences

- Broaden TAC to hear different customer voices
- Monthly TAC meetings
- Independent customer research
- Published Preliminary Revenue Proposal (on 5 October 2021)

2. Customer centric operations

- Facilitated by Executive and Leadership team
- TAC shaped independent research design
- TAC determined engagement topics

3. Being open and transparent

- Responsive and unbiased approach
- Clarified scope of Revenue Proposal and other avenues (e.g. actionable ISP process)
- Involved regulators – AEMO, AEMC and AER

Our engagement objectives:

- framed the engagement activity on our Revenue Proposal, and
- enabled customers to assess the effectiveness of our engagement activities.

Our approach addressed the AER's feedback on our engagement activity from the 2018–23 Revenue Proposal, including by incorporating more structured review and measurement mechanisms.

Following our final TAC meeting in December 2021, we asked our TAC to provide feedback on whether our engagement meets our engagement objectives. Most TAC members agreed or strongly agreed that our engagement on our 2023–28 Revenue Proposal:

- was open and transparent
- was supported by our Executive and Leadership team, and
- covered matters that are most important to them.

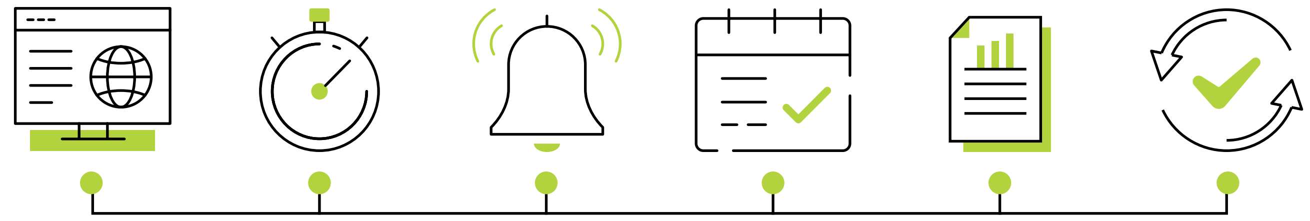
Most of our TAC members also agreed or strongly agreed that our Revenue Proposal reflects our customers' priorities and preferences. Our TAC suggested ways that we could further improve our engagement including by:

- starting earlier – we accept this feedback and note that what we have undertaken is only the first phase of our engagement. We will continue to engage our customers over the next 15 months, as the AER reviews our Revenue Proposal
- establishing a reset working group, based on a sub-set of the TAC – we will establish a TAC working group in the second phase of our engagement as we prepare our Revised Revenue Proposal, and
- undertaking more deep dives – we will hold regular deep dives with the TAC working group to discuss in detail key matters to inform our Revised Revenue Proposal.

2.2 Our engagement framework

Figure 2 2 sets out our overall engagement framework to achieve meaningful and well-informed engagement with our customers and other stakeholders to inform this 2023–28 Revenue Proposal. This approach is consistent with the AER's Customer Engagement Guidelines and the International Association of Public Participation Spectrum (IAP2 Spectrum)[46].

Figure 2-2: Our reset engagement framework



Consultation processes should be easily accessible	Stakeholders should be given adequate opportunity to participate in regulatory development, implementation and review	Stakeholders should be adequately notified of proposed consultation	Adequate time should be given for stakeholders to participate in consultation	Outcomes of consultation should be reported back to stakeholders	Consultation processes should be evaluated

2.3 Our engagement activity

Our 2023–28 Revenue Proposal engagement builds on and extends our ongoing business-as-usual engagement. We developed our 2023–28 Revenue Proposal engagement activity having regard for:

- lessons learned from, and feedback on, our 2018–23 Revenue Proposal engagement
- best practice engagement principles from leading authorities including the IAP2.[47] We designed our engagement to move up the IAP2 spectrum to involve and collaborate
- the AER's engagement framework for the Victorian DNSPs 2021–26 regulatory period, the AER's Better Resets Handbook and previous AER decisions. We have completed a self-assessment against the AER's Better Resets Handbook, which is set out in section 2.5, and
- input from our customers on our draft Stakeholder Engagement Plan.[48] In May 2021, we provided our draft Stakeholder Engagement Plan, which provided a high-level overview of our proposed consultation approach to our TAC for their review and input. We published our final Stakeholder Engagement Plan on our website in June 2021. Customers supported our Stakeholder Engagement Plan, subject to tailoring matters for discussion to those identified by the TAC, which we addressed in our final plan.

46 The AER's Consumer Engagement Guideline for network service providers suggests adopting an engagement framework like the IAP2 Spectrum when developing customer engagement strategies and processes.
47 https://iap2.org.au/.
48 Transgrid, 2023–28 Stakeholder Engagement Plan, 28 June 2021

2.3.1 Business-as-usual engagement

Engagement is integral to our business' operations to ensure we continue to provide services tailored to suit our customers' needs in a rapidly changing energy system.

Our business-as-usual engagement has focussed on all aspects of our business including our Energy Vision and ISP Projects, particularly Project EnergyConnect, QNI Minor, VNI Minor, HumeLink and VNI West. Examples of our business-as-usual engagement are:

Energy Vision[49] – to better understand what our energy future could look like we partnered with independent experts, CSIRO, ClimateWorks Australia and The Brattle Group to model the implications of a range of scenarios on the evolution of our energy system, resulting in our "Energy Vision: a clean energy future for Australia". We engaged with the TAC in developing our Energy Vision to ensure that it reflects customers' priorities and preferences – we met with the TAC five times before we finalised our Energy Vision. Together with the TAC, we explored global energy trends, the current network and energy drivers and the scenario planning outcomes. Our TAC provided valuable insight into the development of, and supported, our Energy Vision. We also met with many other stakeholders including AEMO, the NSW Government and the Clean Energy Council in developing this document.

Customer feedback

- 'I enjoyed the context of the Energy Vision which set up the context for the reset and particularly the need for the ISP'.
- 'The work Transgrid has done on the vision is outstanding.'
- 'Great piece of work! Many thanks for taking the time to present to the ENA team on the Transgrid Vision'.

Regulatory Investment Test – we follow the RIT-T requirements for all projects greater than $7 million[50], which includes consultation on the potential solutions to meet the identified needs. Since 2018, we have consulted on over 30 projects through the RIT-T process to identify, evaluate and implement the prudent and efficient solutions. Most RIT-Ts do not attract significant public input, however a limited number do. One example of a RIT-T that did attract significant public input concerns our Repex investment in maintaining compliance with performance standards of our Broken Hill substation secondary systems. We received a submission from the Public Interest Advocacy Centre (PIAC) on our Project Assessment Draft Report (PADR) and then met with them to better understand their concerns and provide further details on our assessment. PIAC asked us to describe further the credible options, including their expected benefits and the economic assessment, and sought greater clarity about why our preferred option was the most efficient and prudent solution. We addressed these matters in our Project Assessment Conclusions Report (PACR).

Transmission Annual Planning Report (TAPR)[51] – the TAPR is the key mechanism through which we communicate emerging constraints and highlight opportunities for the market to identify potential demand management solutions. The TAPR is based on information shared with AEMO and our network partners with whom we conduct joint planning. Projects in the TAPR are included in our capex forecast for the 2023–28 period.

Energy Charter annual performance – we are a founding and active participant in the Energy Charter. Our business is committed to becoming a more customer-centric organisation. In preparing our annual Disclosure Statement, we are guided by recommendations from the Charter's Independent Accountability Panel.

49 Transgrid, Energy Vision – A clean energy future for Australia, October 2021
50 In accordance with the AER's applicable cost threshold review for the RIT-T and the AER's RIT-T application guidelines
51 Transgrid, NSW Transmission Annual Planning Report, 2021

Major Projects – we engage with our customers and other stakeholders on Major Projects. We established a Stakeholder Monitoring Committee for Powering Sydney's Future and meet with the Committee regularly to keep them informed about our progress and seek their input. We also engaged with a broad range of customers on Project EnergyConnect including large energy users, generators, residential and business customers, First Nations people, primary producer groups and landowners and local communities impacted by the interconnector route. Our engagement activities included extensive consultation on the route and the costs of the project. Our Stakeholder Engagement Overview Paper for Project EnergyConnect addresses the feedback we received and how we responded to it.[52]

Customer feedback

PSF Monitoring Committee is 'a great example of good engagement – designs were presented to TAC, there was pushback and response by both stakeholders and Transgrid, there were changes to structuring and sequencing of projects in response to feedback.'

Customer feedback

'Engagement on Major Projects should address:

- The project need, objectives and alternatives
- Customer issues including impacted communities.

Bringing in critics such as NSW Farmers Federation and environment organisations early will help smooth project delivery in the end.'

Our TAC has told us that they would like regular discussions on Major Projects to share knowledge and provide them with a greater opportunity to participate in decision making, where possible. We are working with the TAC to establish a Major Projects' Monitoring Committee that covers all major ISP and NSW Electricity Infrastructure Roadmap projects – whether they are in their delivery phase or are progressing through the regulatory approvals process – including Project EnergyConnect, HumeLink and VNI West. We are currently seeking TAC members' input on our engagement approach and topics for Major Projects in 2022.

Regulatory policy matters – we discuss key policy reforms and issues with the TAC. TAC members provide valuable input into our decision making and inform our positions on key policy matters. We have discussed with the TAC significant policy issues such as the AER's review of the Rate of Return for network businesses and the AEMC's Transmission Investment Review to ensure that we understand and incorporate, where possible, stakeholders' priorities and preferences.

2.3.2 Engagement on our 2023–28 Revenue Proposal

In addition to our business-as-usual engagement, we have undertaken specific engagement on this Revenue Proposal. This has involved:

- monthly meetings with our TAC, some of which were targeted deep-dive workshops[53]
- independent customer research led by Forethought, and
- the publication of our Preliminary Revenue Proposal, which set out our draft positions and proposals.

In parallel, we engaged closely with the AER, including through its attendance and participation at our monthly TAC meetings.

52 Transgrid, Stakeholder Engagement Overview Paper – Contingent Project Application for Project EnergyConnect, 30 September 2021
53 These workshops were open to a broader range of stakeholders than our TAC, such as generators and battery owners / providers

Transgrid Advisory Council

Our TAC is the primary forum for engagement on our Revenue Proposal. We expanded the TAC's membership in 2021 to include a broader range of stakeholder organisations to capture more diverse views. New members included:

- AEMO – to provide insight and content for investments that we will deliver over the 2023–28 period through the ISP and the NEM's transition to renewable sources of generation
- Commonwealth Bank of Australia – to provide insight into financeability and other issues that debt providers consider when assessing debt finance for infrastructure service providers
- ERM Advisory and the Clean Energy Council – to bring insights, as independent energy advisors, about new technology, and
- Professor Andrew Blakers from the Australian National University (ANU) – to provide independent advice on future development needs within Australia's energy markets.

Our TAC members in 2021 were:

- AEMO
- Australian Industry Group
- Professor Andrew Blakers
- City of Sydney Council
- Clean Energy Council
- Commonwealth Bank of Australia
- Energy Consumers Australia
- Energy Users Association of Australia
- ERM Advisory
- Ethnic Communities Council NSW
- Goldwind
- Public Interest Advocacy Centre
- Snowy Hydro Ltd.
- St Vincent de Paul Society
- Tesla
- Tomago Aluminium Co.

The TAC met monthly from June to December 2021 to address topics nominated by TAC members. Industry experts presented on matters such as transmission pricing and the Actionable ISP process. These meetings were facilitated by our Executive and Leadership team to ensure customer and other stakeholders' views were shared broadly across our business. Members of our Board attended many of the meetings as observers to receive the feedback from our TAC members.

The AER attended and participated in our TAC meetings, and so responded directly to TAC members' questions, where relevant.

After each TAC meeting, we spoke to all TAC members to invite feedback and reflections. This helped us to tailor subsequent meetings to areas reflecting their priorities and preferences.

Materials for all TAC meetings and deep-dive sessions are available on our website.

Independent customer research

We partnered with Forethought to research our customers' priorities and preferences and to test key elements of our Preliminary Revenue Proposal, which was published on 5 October 2021. This research focused on customers' immediate and likely future priorities and preferences. This is important to inform our investment decisions to support the changes to Australia's energy system.

Our research comprised a three-phase program as illustrated in Figure 2-3. It included formal quantitative and qualitative research through online discussion boards, surveys and focus groups. The quantitative research involved a survey of 1,480 customers to understand what is most important them regarding their relationship to energy. The outcomes of this survey were used to prioritise initiatives to be included in this Revenue Proposal.

Figure 2-3: Three-phase study design

Forethought's 'Revenue Reset Stakeholder Engagement – Executive Report' accompanies this Revenue Proposal.

Published our Preliminary Revenue Proposal

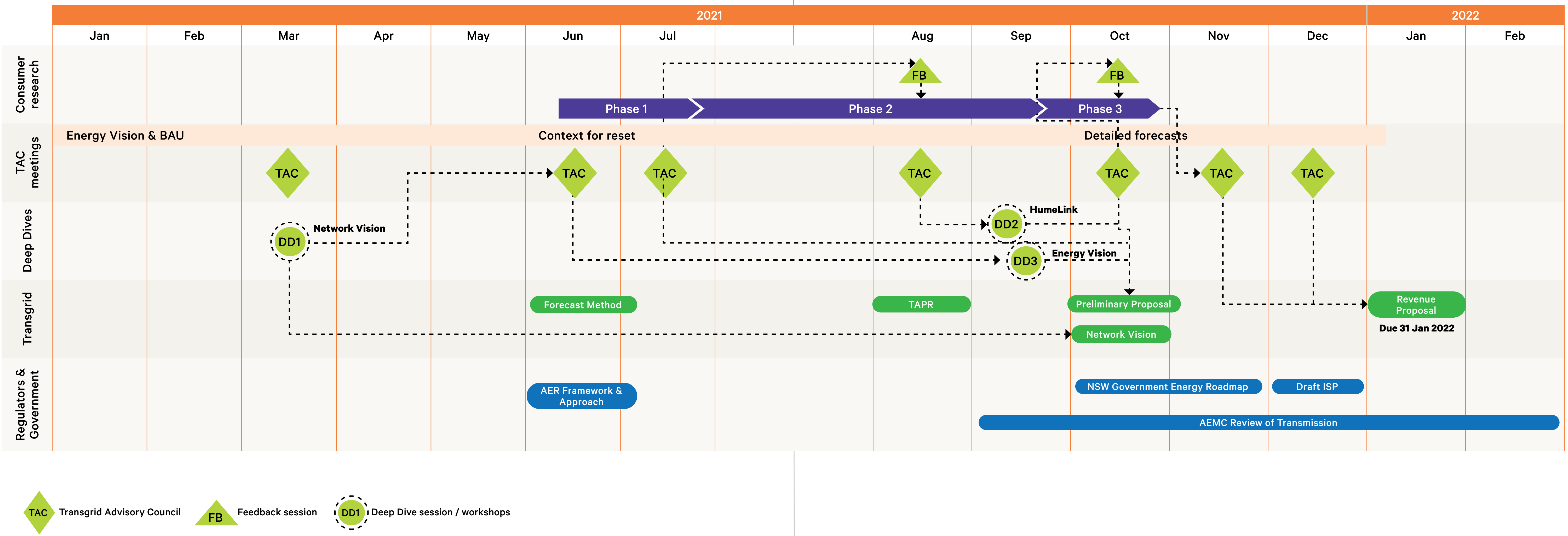
On 5 October 2021, we published our Preliminary Revenue Proposal, which set out our draft positions and proposals and invited feedback from our customers and other stakeholders to inform this Revenue Proposal.

We met with the TAC on 5 October 2021 to discuss our Preliminary Revenue Proposal and then again on 2 November 2021 to receive members' considered views and positions. Generally, TAC members supported our proposals, including our capex and opex forecasts.

We also received feedback on the Preliminary Revenue Proposal through the online qualitative research phase of Forethought's three-phase engagement program, which occurred in late October and early November 2021.

Figure 2-4 shows the feedback loops that occurred in relation to our customer research, the Energy Vision, our Preliminary Revenue Proposal published on 5 October 2021, and this Revenue Proposal.

Figure 2-4: Overview of engagement activity on this Revenue proposal



2.4 Customers' feedback and our response

Our independent customer research from Forethought indicates that customers want an affordable, safe, secure, reliable and sustainable energy supply. Our TAC members supported these outcomes, noting that they are broadly consistent with the findings of studies undertaken by our peers and other industry organisations. We have summarised customers' priorities and preferences below, which should be read in conjunction with Chapter 5 – what we will deliver in 2023–28.

2.4.1 Affordability

Customer feedback

Our independent customer research found that the price of electricity was still a major concern for residential and small business customers and that they want us to prioritise investment that improves electricity affordability, particularly in the next four years.

In particular, our research found that:

- investment to improve electricity affordability was prioritised by all customer segments, who want investment to be frontloaded in the next four years
- customers largely supported the level of savings in our Preliminary Revenue Proposal, however they felt the savings were small in the context of their overall energy bills, therefore many customers would prefer to re-invest the savings in projects that delivered longer-term climate-related benefits, and
- affordability is the primary driver for customers to invest in technology such as PV and batteries in homes and business.

TAC members are concerned about three key issues relating to affordability:

- the treatment of risk and uncertainty. Members wanted to understand whether our expenditure forecasts included risk costs, including costs associated with climate resilience
- equity in pricing, particularly between generators and other customers. Many TAC members consider that generators should pay more for investment to relieve network congestion and address the operational complexity of maintaining network stability and security given the rapid change in the mix and location of generation. TAC members also raised concerns about who will pay for system strength services, and
- the whole customer bill impact including the outcome of both the Revenue Proposal and Actionable ISP projects. TAC members expressed concern that the capex forecasts do not include the costs of future Actionable ISP projects such as HumeLink and VNI West, which could materially impact transmission prices within the period. Members requested greater transparency on the potential impact of transmission bills from Actionable ISP Projects and NSW REZ projects being approved in the 2023–28 period.

Our response

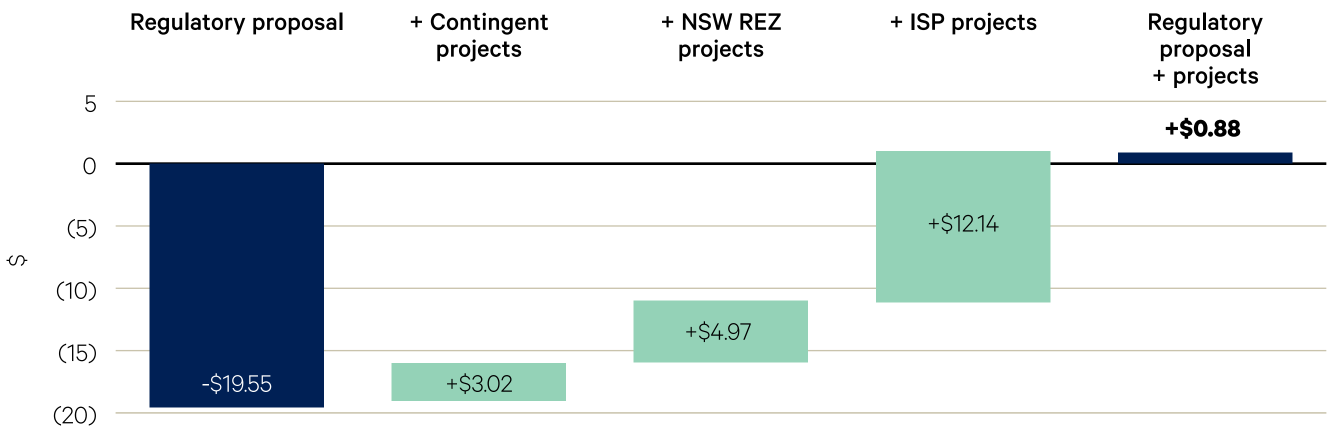
Our Revenue Proposal will deliver a safe, secure and reliable energy supply at the most affordable possible price for all customers. Based on this proposal, from 30 June 2023 to 30 June 2028, we expect to deliver transmission cost savings of $19.55 per annum for residential customers and $73.05 per annum for small business customers, which in both cases is a 13.4 per cent reduction over this period. Delivering these savings will depend on the outcome of this revenue determination process.

Section 5.1 details how we have achieved these savings.

In relation to concerns raised by our TAC:

- Uncertainty and risk – we have used the AER's uncertainty mechanisms, and the actionable ISP rules, to deal with any additional capex that becomes necessary during the period. This ensures that customers only pay for these projects if the AER and AEMO determine that they are needed. This is discussed in section 5.1. We have not included a specific allowance for replacing assets with more resilient alternatives. Rather, we will pursue climate-resilient alternatives through our condition-based replacement so that our network withstands more frequent, climate-driven extreme weather events.
- Equity in pricing – the current pricing arrangements are determined by the existing Rules' framework, which we must apply in this Revenue Proposal. Members of the TAC recognise that changes to the existing framework would require a Rule change. On 1 December 2021, the AEMC attended our TAC meeting to address questions on pricing and explain how members could progress a proposed Rule change. We are required under the new System Strength Rules to provide system strength as a service – the costs of these services will be recovered through a pass through or contingent project. This is discussed in section 5.2.
- The whole customer bill impact – we responded to TAC members' requests for more bill transparency by providing the indicative impact on the transmission component of the residential and small business customers' bills if the following are approved by the AER during the 2023–28 regulatory period:
  - Contingent projects – we have included four projects undergoing a RIT-T and eight standard contingent projects in this Revenue Proposal at a total estimated cost of $1.9 billion. These projects are discussed in Chapter 17.
  - NSW REZ projects – there are five NSW REZ projects in the following regions – New England, South West NSW, Central West Orana, Hunter-Central Coast and Illawarra region. We have not included these as contingent projects in this Revenue Proposal because we expect that they will be regulated under the NSW EII Regulations[54] rather than the NER. The total indicative cost of these projects is $4.2 billion.
  - Actionable and future ISP projects – subject to regulatory approvals and securing the necessary land access and environmental and heritage approvals, we will deliver four actionable and future ISP projects – HumeLink, VNI West, Sydney Ring (reinforcing Sydney, Newcastle and Wollongong supply) and QNI connect. The total indicative cost of these projects in the 2023–28 period is $6.4 billion. These projects are also discussed in Chapter 17.

Figure 2-5: Residential bill impact – transmission component ($, Real 2022–23)[55]

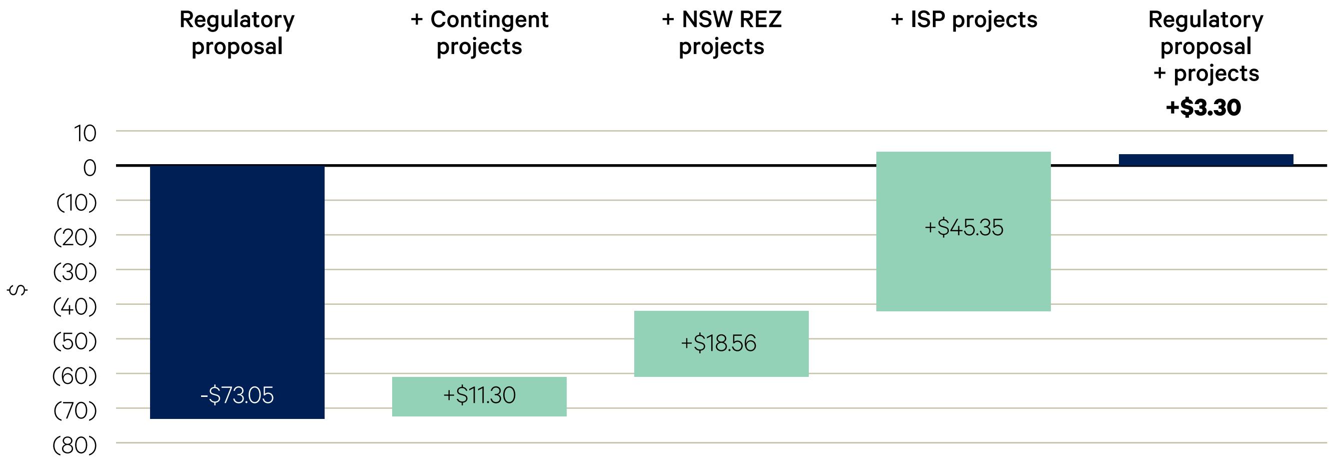


Notes: 1. The values do not sum exactly due to impact of equity raising costs. 2. The estimated impact of adding the contingent, NSW REZ and ISP projects is indicative. 3. Values are estimated annual bills for residential customers.

54 The NSW Electricity Infrastructure Investment Act 2020 (EII Act) establishes a NSW-specific cost recovery route for transmission investments associated with the Electricity Infrastructure Roadmap.

55 Capex for ISP projects is projected to be incurred earlier than for NSW REZ projects. As a consequence, the ISP projects would impact revenue and prices sooner.

Figure 2-6: Small business customers bill impact – transmission component ($, Real 2022–23)



Notes: 1. The values do not sum exactly due to impact of equity raising costs. 2. The estimated impact of adding the contingent, NSW REZ and ISP projects is indicative. 3. Values are estimated annual bills for small business customers.

Figure 2-5 and Figure 2-6 show that the expected cost savings from this Revenue Proposal will largely off-set the potential future transmission costs arising from investments in contingent projects, Actionable and future ISP projects and NSW REZs. Delivering these savings will depend on the outcome of this revenue determination process.

Importantly, in accordance with the regulatory framework, these projects will only proceed if they deliver net benefits to customers such that the expected savings in wholesale costs outweigh the increase in the transmission costs. This means that any increase in the transmission component of the bill will be more than offset by a reduction in the wholesale component. AEMO's Draft 2022 ISP finds that the net market benefits of investment in transmission returns 2.5 times its cost and therefore these investments are 'low cost and low regrets for customers'.[56]

AEMO also indicates that it intends to include its assessment of the likely impact on customer bills, including the transmission network component, arising from transmission projects on the optimal development path. This analysis will include the expected wholesale price reduction, and will be published in June 2022 in AEMOs final 2022 ISP.

2.4.2 Safety, security and reliability

Customers have told us they are satisfied with current reliability levels. Our independent customer research indicates that customers consider the primary benefit of transmission networks to the community is a reliable and affordable electricity supply, with over half of customers seeing investment in the future of energy as a benefit. Customers expressed a strong preference for investment to facilitate renewables but also to increase safety. Small to medium business customers, particularly those businesses who manufacture products and rely on constant, reliable energy supply to maintain their productivity, expect us to maintain our strong performance and high levels of reliability.

Customers support our proposed step changes in insurance premiums and cyber and physical security given their importance in maintaining a safe, secure and reliable supply. They also support our capex to build a safe and reliable network for the future. In particular, our customer research found:

- customers support increased investment in cyber security. Some customers questioned whether the proposed expenditure was sufficient considering the importance of system security
- customers support funding the increase in insurance premiums, once they understood the level of risks that need to be insured, even if they were initially surprised at the cost increase, and
- customers support investing in capex, however, they requested more information about how the investment would be linked to reliability, resilience and emissions reduction in future.

56 AEMO, Draft 2022 Integrated System Plan, December 2021, pp. 8, 11, 57 (return on investment ratio) and 97

Customer feedback

- 'Hearing about cyber in the news, it feels like money well spent.'
- 'It's a fact, insurance premiums are always going up.'

Our response

As discussed in section 8.1, around 80 per cent of our capex forecast is focused on maintaining safety, security and reliability in the next regulatory period. We will achieve this by:

- investing in the long-term condition of our assets to maintain our network risk and reliability performance
- replacing assets with more climate-resilient alternatives, where efficient to do so, through our condition-based replacement methodology
- enhancing our cyber and physical security capability to meet the Australian and NSW Governments' new obligations, and
- ensuring our non-network assets, including property, fleet, plant and equipment, continue to support our core services as we deliver an increasing capital program including major ISP projects.

We have also included two opex step changes – insurance premiums and cyber and physical security – which will maintain safety, security and reliability. These are discussed in section 7.5.4.

2.4.3 Rapid localised demand growth

Our independent customer research found that all customer segments want the energy industry to invest in infrastructure and technologies that cater for future demand, which is increasing. This increase is due to new residential and commercial developments, major transport projects and data centres, and mining and industrial developments in regional NSW.

Our response

As discussed in Chapter 5, we will undertake network investments in western Sydney, north west Sydney, North West Slopes and central and far west NSW. These investments will address load growth and enable compliance with mandated voltage stability and thermal limits and reliability standards.

2.4.4 Energy transition

Our independent research found that the environment and climate change are customers' most important priorities when they think about the future. Customers want the energy industry to reduce emissions and to invest in infrastructure and technologies that promote renewables as well as safety and capacity to cater for future demand. More than half of residential and small to medium business customers indicated they would pay more on their quarterly/monthly bills to reduce emissions:

- 57 per cent of residential customers would pay $25 or more on top of quarterly bills, and
- 50 per cent of small to medium business customers would pay $40 to $50 on top of monthly bills.

Many customers indicated that they would prefer to re-invest the cost savings included in our Preliminary Revenue Proposal in projects that deliver longer-term climate-related benefits.

Members of the TAC agreed with these findings noting that they are broadly consistent with the findings of studies undertaken by our industry peers and other organisations.

Some members of the TAC highlighted the importance of us engaging with the communities impacted by the construction of new transmission lines, including HumeLink and VNI West that are part of AEMO's ISP optimal development path to net zero emissions and Australia's Long Term Emissions Reduction Plan. They consider that this is critical to maintaining our social licence to operate by ensuring impacted communities benefit from these projects. Suggestions included:

- grant programs for local community groups
- neighbourhood improvement schemes, and
- more transparent compensation system for landholders.

Some members of the TAC also highlighted the importance of ensuring that the costs of these projects allow for biodiversity off-set costs.

Our response

We are committed to working with Governments to achieve net zero. As Australia's largest electricity transmission network, our infrastructure is vital to achieving Australia's net zero emissions target and providing customers with access to low cost renewable generation sources. Our Energy Vision provides insights into what that transformation could look like over the next 30 years and how we can plan for a range of future scenarios.

Section 5.4 explains that in the 2023–28 regulatory period, we will:

- invest in maintaining network stability and security in response to the rapidly changing mix and location of generation, as the energy system transitions to renewable technology, and
- deliver projects in accordance with AEMO's ISPs and the NSW Electricity Infrastructure Roadmap, as they are required.

In relation to our social licence and biodiversity off-set costs, these matters are a focus of our Major Projects consultation and the associated contingent project application process through which we recover the costs of these projects, which are separate to this Revenue Proposal. As discussed above, we are working with the TAC to establish a Major Project Monitoring Committee and will agree the topics for consultation and the overall engagement program with the members of the TAC.

We agree with AEMO that substantially expanded community engagement programs are needed to explore the social licence for transmission investments.

2.4.5 Technology and innovation

Our independent research found that customers' perception was that Australia lagged other countries in combating climate change and investing in research and innovation. Customers told us that they expected more investment in research and innovation across all industries to maintain competitiveness and a high standard of living. Customers promoted technological innovation to mitigate climate change and make energy more affordable. Our independent research found that the savings offered as part of our Preliminary Revenue Proposal would be better invested in innovation to facilitate the energy transition to renewables.

Members of the TAC also supported innovation to facilitate the transition and promote affordability.

Our response

Innovation activities are embedded across our business and are part of the way we operate. As discussed in section 5.5, we have reflected the benefits of successful recent innovations in our revenue forecasts. We have not included specific innovation expenditure in our forecasts at this stage, however we will continue to engage with customers and other stakeholders about innovation initiatives and whether they should be reflected in our Revised Revenue Proposal.

2.5 Addressing the AER's Better Resets Handbook

In its Better Resets Handbook, the AER sets out its expectations for customer engagement on a principles-basis, covering:

- the nature of engagement
- the breadth and depth of engagement, and
- clearly evidenced impact of this engagement.

We have used these principles to assess our engagement approach and outcomes in Table 2-1, albeit noting that the AER's Handbook does not formally apply to this reset process.

Table 2-1: Self-assessment against the AER's framework for customer engagement

	AER principles	Our self-assessment
Nature of engagement	Sincerity of engagement: • High level 'buy-in' from network businesses extending from Board level • Openness to new ideas and a willingness to change • Ongoing conversation with customers about outcomes that matter to them, which allows customers to 'set the agenda'	Our CEO chairs the TAC and during the development of our revenue proposal board members were regular observers to TAC meetings. We have shown a willingness to listen to advice and guidance from TAC members. We amended our research program on the advice of TAC members and reduced our forecast opex and capex in response to customer feedback on our Preliminary Revenue Proposal. The TAC is an established vehicle for customer engagement that has been in place since 2016. TAC meeting agendas were specifically designed to address issues of concern raised by TAC members both at TAC meetings and during one-on-one follow-up discussions.
Breadth and depth of engagement	Accessible, clear and transparent engagement • Set out plans and objectives, topics, areas of influence	We set a clear plan for engagement with TAC at the beginning of the process. The process itself responded to TAC members request to streamline members' time commitment. A monthly meeting schedule was published with topics to be covered at each meeting at the start of the process. Other meetings were scheduled to address issues raised by the TAC when requested and were attended on an opt-in basis with most TAC members attending. TAC agendas allow time for discussion of issues following presentations and respond directly to issues raised.
	Consultation on outputs, then inputs • customers should be seen to guide development of proposals i.e. consumers consulted on what they want and how they want businesses to engage • customers guide consultation on individual components of a proposal.	We consulted TAC members on how they wanted to be engaged prior to the reset engagement process. TAC reset engagement began with discussion of the energy transition and results of analysis in our Energy Vision. Discussions continued throughout the reset consultation process on the content of the regulatory proposal and its context, specifically the major projects likely to be triggered by the 2022 ISP including the price implications for customers. TAC feedback in November 2021 supported our opex step-changes and capital forecasts.
Clearly evidenced impact of engagement	Proposal links to customer preferences Independent customer support for the proposal	Our Revenue Proposal reflects the balance between customers' priorities for an affordable and reliable energy supply and their priority for a sustainable energy supply in future. The proposal provides savings for customers and is driven almost entirely by compliance ranging from safety to cyber security requirements, thus minimising the cost burden on customers.

2.6 Engagement in 2022

We intend to continue to engage with our customers and other stakeholders throughout 2022 in a program to be developed jointly with TAC members.

On 26 November 2021, we proposed the draft schedule, including topics for discussion at our TAC meetings in 2022. TAC members were supportive of the topics identified, which will be refined based on input from members in 2022.

As discussed in section 2.1 above, we will address feedback from our TAC on how we could further improve our engagement by adopting the following in the second phase of our engagement:

- establish a revenue reset working group based on a sub-set of the TAC
- undertake more deep dives to discuss key issues relevant to our Revised Revenue Proposal, and
- establish a Major Project Monitoring Committee that covers all major ISP and NSW Electricity Infrastructure Roadmap projects.

2.7 Supporting documentation

The following documents support this Chapter and accompany our Revenue Proposal.

Name
2023–28 Stakeholder Engagement Report
Forethought, Revenue Reset Stakeholder Engagement – Executive Report

3. Our key operational challenges

The continued transformation of the power system presents unique challenges for our network operations. This Chapter identifies the key operational challenges that we will face in 2023–28.

Key messages

> **Safety, reliability and security** – we will address the following challenges to ensure we continue to deliver a safe, reliable and secure electricity supply:

- Our network assets are ageing and declining in condition. To maintain the reliability and security of our network we will continually renew and replace assets in poor condition or which are technically obsolete
- The Australian and NSW Governments are introducing new obligations that we will address to ensure that our network is protected against cyber and physical infrastructure threats, and maintain the security and reliability of our network expected by our customers, and
- The frequency, intensity and duration of climate-driven extreme weather events are increasing. We will continue to adapt the way we plan, operate and maintain our network to maintain our safety, security, reliability and quality of supply.

> **Rapid localised demand growth** – economic growth is forecast to return to trend levels over the next decade although there will be pockets of strong maximum demand growth in some regions, including the North West Slopes, central west NSW and western Sydney.

> **Energy transition** – the transition to a new energy market is happening quickly, as renewable costs fall, technology advances and governments commit to decarbonisation. The change in the generation mix is increasing the operational complexity of maintaining network stability and security. This is causing:

- more widespread network congestion
- shortfalls in system strength and inertia, and
- decreasing minimum demand.

These challenges have also been highlighted by our customers and other stakeholders as key priorities they would like us to focus on for the 2023–28 regulatory period.

3.1 Safety, security and reliability

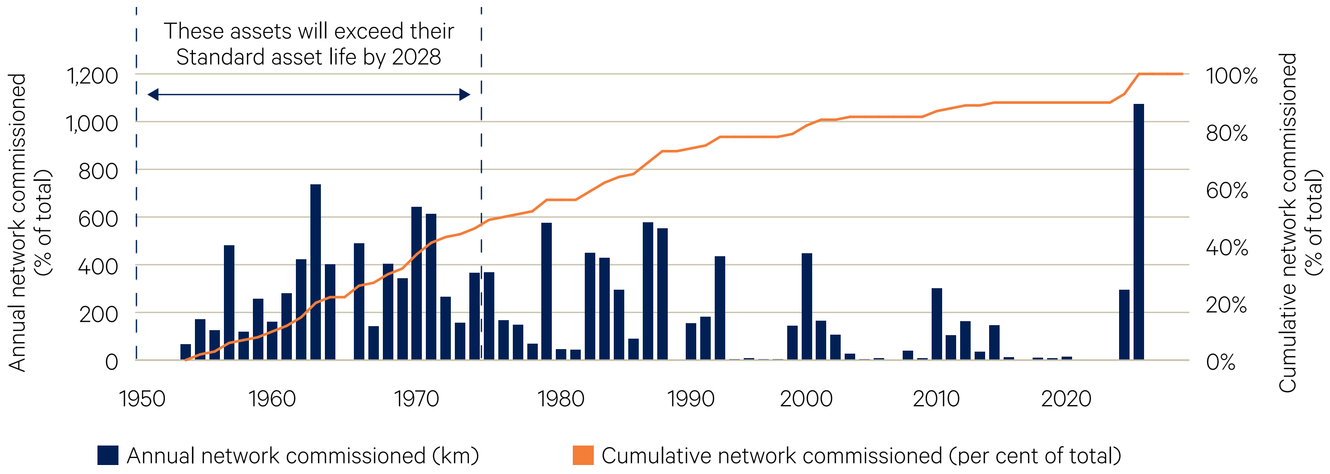
3.1.1 Ageing assets

Our network assets are ageing and declining in condition, as evidenced by the increase in our fault outage rates, particularly our transmission lines and digital infrastructure. Condition related asset failures are exacerbated by more frequent and damaging extreme weather events. We will maintain the long-term condition of our assets in order to manage our network risk and maintain our performance.

We manage our assets under our ISO 55001 certified asset management system in accordance with good industry practice and to comply with our safety and reliability obligations, delivering a safe and reliable network to our customers.

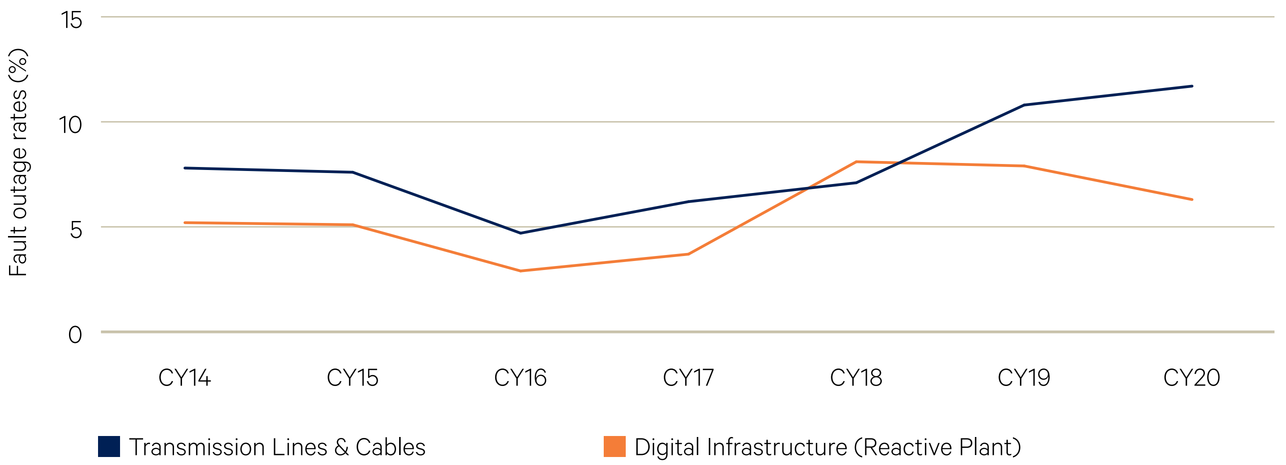
While we replace our assets based on their condition, asset age provides a long-term proxy for condition. Figure 3-1 shows that large portions of the transmission network installed in the 1950s, 1960s and 1970s will reach end of life[57] by the end of the next regulatory period (2028).

Figure 3-1: Transmission network age profile



The increasing number of assets reaching end of life is becoming evident through observed increases in fault outage rates, particularly for transmission lines and digital infrastructure as shown in Figure 3-2, which are the asset classes we are focusing most of our Repex on in the current 2018–23 period. While fault outage rates declined slightly in 2015–16 there has since been an increasing trend for transmission lines and digital infrastructure, consistent with the challenges presented by an ageing asset base and declining asset condition.

Figure 3-2: Fault outage rates



To maintain long term asset condition we will continue to renew and replace assets in poor condition or that are technically obsolete.

57 Assuming a 50 year standard asset life.

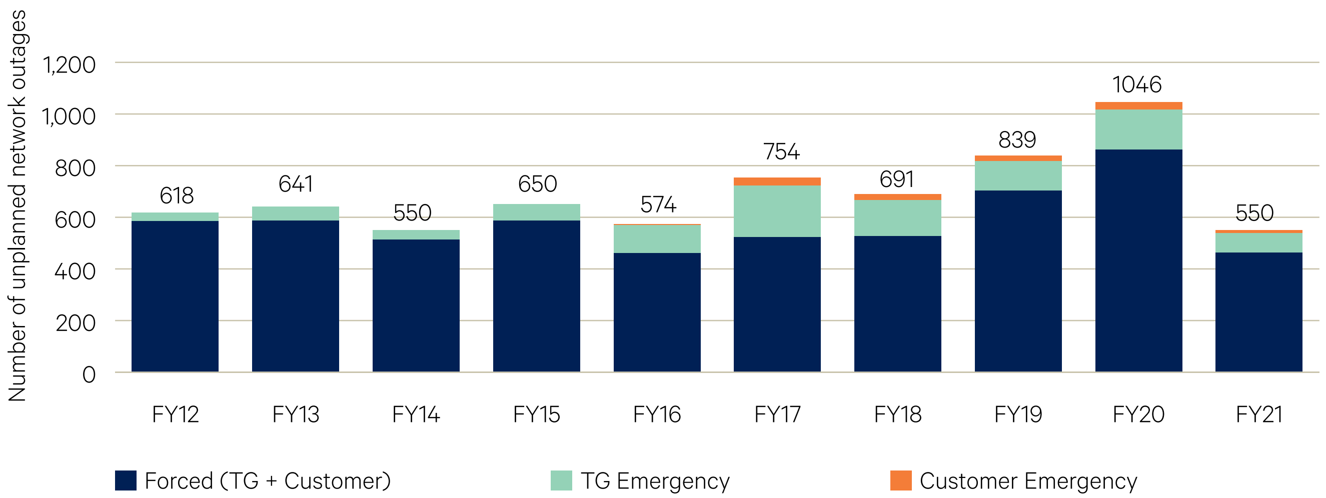
3.1.2 Climate change and network resilience

The frequency, intensity and duration of climate-driven natural disaster events are increasing.[58] Our transmission network will need to become more resilient to the impacts of climate-driven events so that we can continue to deliver the safe and reliable transmission services our customers require.

Over the current regulatory period, we experienced a marked increase in the number of climate-driven natural hazard events impacting our network, including bushfires, storms and extreme winds and floods. These are discussed in Chapter 4.

Figure 3-3 shows the increase in unplanned network outages, which is driven in part by more frequent extreme weather events. The significant increase in unplanned outages in 2019–20 is due to the impact of the 2019–20 bushfires. The lower than average unplanned outages in 2020–21 were due to very mild temperatures and high rainfall resulting in significantly less bushfire and heat related failures relative to earlier years.

Figure 3-3: Unplanned network outages



We need to continue to adapt the way we plan, operate and maintain our network to maintain our safety, security, reliability and quality of supply. We are already responding to climate change by replacing assets with more resilient alternatives when we undertake planned condition-based replacements, such as replacing deteriorated timber poles with concrete or steel poles.

GHD's independent climate change adequacy review of our network found that we are leaders in assessing and implementing options to improve our network resilience to climate change.

3.1.3 Increasing cyber security threats to critical infrastructure

The Australian Government is introducing new obligations that we need to comply with in the next regulatory period to:

- ensure that our network is protected against cyber and physical infrastructure threats, and
- maintain the security and reliability of our network expected by our customers.

These obligations are set out in various current or prospective legislative instruments:

- the Security of Critical Infrastructure Act 2018 (CI Act), which introduces obligations on the electricity, gas, water and ports sectors to ensure the physical and electronic security of Australia's critical infrastructure
- the Australian Government Security Legislation Amendment (Critical Infrastructure) Act 2021, assented to in December 2021, with a second part anticipated in 2022. Together, these extend the scope of the CI Act to cover critical infrastructure including in the energy sector
- the Australian Government is considering a proposal to introduce an enhanced regulatory framework that increases the security and resilience requirements for critical infrastructure. This builds on work completed by AEMO, in collaboration with industry and government stakeholders including the Australian Cyber Security Centre, Critical Infrastructure Centre, and the Cyber Security Industry Working Group, to develop the Australian Energy Sector Cyber Security Framework (AESCSF), and
- the Energy Legislation Amendment Act 2021, assented to in November 2021. This introduces obligations for managing cyber security risks and responding to cyber security incidents.

58 NSW Treasury 2021 Intergeneration Report TTRP – An indicative assessment of four key areas of climate risk for the 2021 NSW Intergenerational Report, April 2021

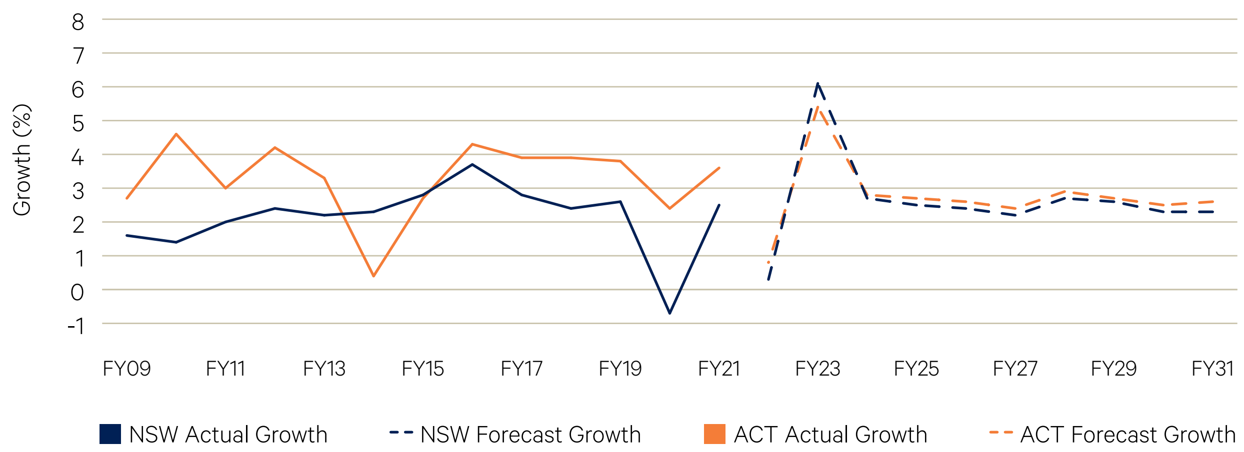
We expect that we will need to reach the highest level of maturity of the AESCSF framework – SP3[59] – by the end of 2026. This will require us to spend more on people, systems, processes and solutions to monitor, identify and respond to cyber security attacks.

3.2 Rapid localised demand growth

Electricity consumption is closely related to economic activity, which captures factors including population growth and industrial production. Economic growth in NSW and the ACT are forecast to return to trend over the next decade although pockets of strong maximum demand growth are expected in some regions of NSW.

Figure 3-4 is based on updated forecasts from Deloitte Access Economics and shows that the NSW economy is expected to grow by 0.3 per cent in 2021–22, 6.1 per cent in 2022–23 and return to the trend rate of growth later in this decade. Similarly, the ACT economy is expected to grow by 0.8 per cent in 2021–22, 5.4 per cent in 2022–23 and return to the trend rate of growth later in this decade.

Figure 3-4: NSW and ACT region Gross State Product (GSP)

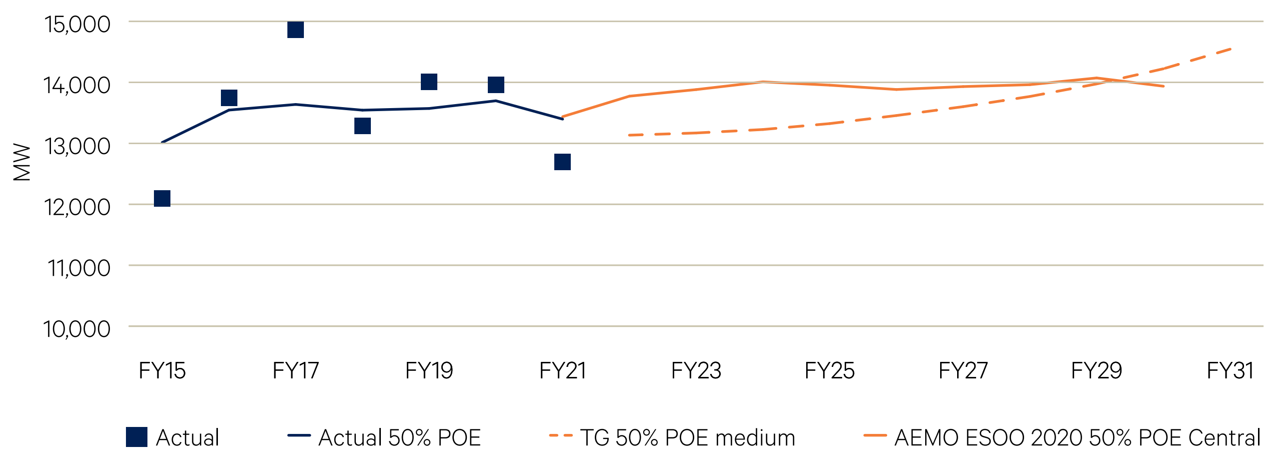


Source: Deloitte Access Economics, Business Outlook

The COVID-19 related lockdown and restrictions on economic activity caused the NSW and ACT economies to contract in 2019–20. Over the next five years, electricity demand is forecast to return to trend as a result of post-COVID economic recovery and new loads from mining in regional NSW, urban development, industrial precincts and data centres. This is despite changes in downstream energy usage (e.g. energy efficiency initiatives) and production (e.g. distributed solar and battery systems).

Figure 3-5 shows that our forecast of NSW NEM region summer maximum demand is consistent with AEMO's forecast. Our demand forecast starts below AEMO's but reaches a similar level by 2030.

Figure 3-5: Transgrid's 2021 demand forecast compared to AEMO's ESOO 2020 summer maximum for NSW



Source: AEMO and Transgrid

59 There are two measures for cyber security capability and maturity in the AESCSF, with different timing expectations of when each level is compiled with: Maturity Indicator Level (MIL) – there are four MILs, MIL-0 through MIL-3; and Security Profile (SP) – there are 3 alternate groupings of SP-1 to SP-3. For each SP a number of identified MILs must be achieved.

Pockets of strong maximum demand growth are expected in some regions, including western Sydney, due to urban growth development, major transport projects and data centres, leading to increases in connected distribution loads. This increase in demand is strengthened by significant development of mining and industrial precincts in regional NSW, including the North West Slopes and central west areas. Together, these developments are driving growth in existing spot loads and the connection of new spot loads.

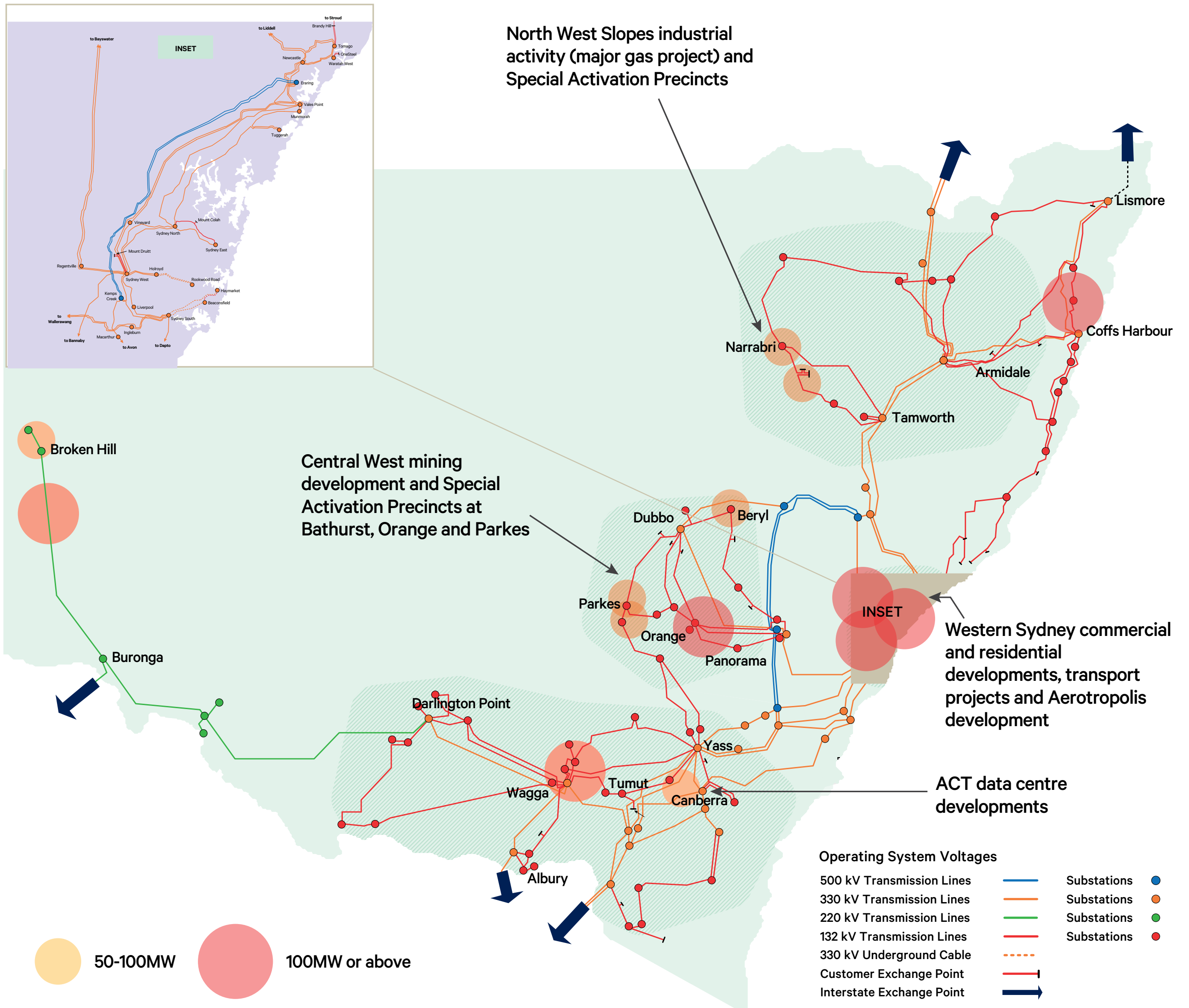
Figure 3-6 shows future spot load growth in NSW. Our proposed investments will address this load growth to comply with mandated voltage stability, thermal limits and reliability standards.

In several of these areas the growth in demand is coupled with anticipated changes in the pattern of power flows, due to changes in the generation mix discussed above. This also impacts our compliance with NER voltage stability and thermal limits. Major projects in the 2023–28 period to meet these obligations include:

- supply to Western Sydney Priority Growth area – this is included in our Augex forecast
- supply to the North West Slopes project (covering Tamworth, Narrabri and Gunnedah) – this is a contingent project because it is undergoing a RIT-T, and
- supply to Bathurst Orange and Parkes (stage 1) – this is also a contingent project and is undergoing a RIT-T.

These projects are discussed in Chapter 8 and our Augex Overview Paper.

Figure 3-6: Future spot loads in NSW



3.3 Energy transition

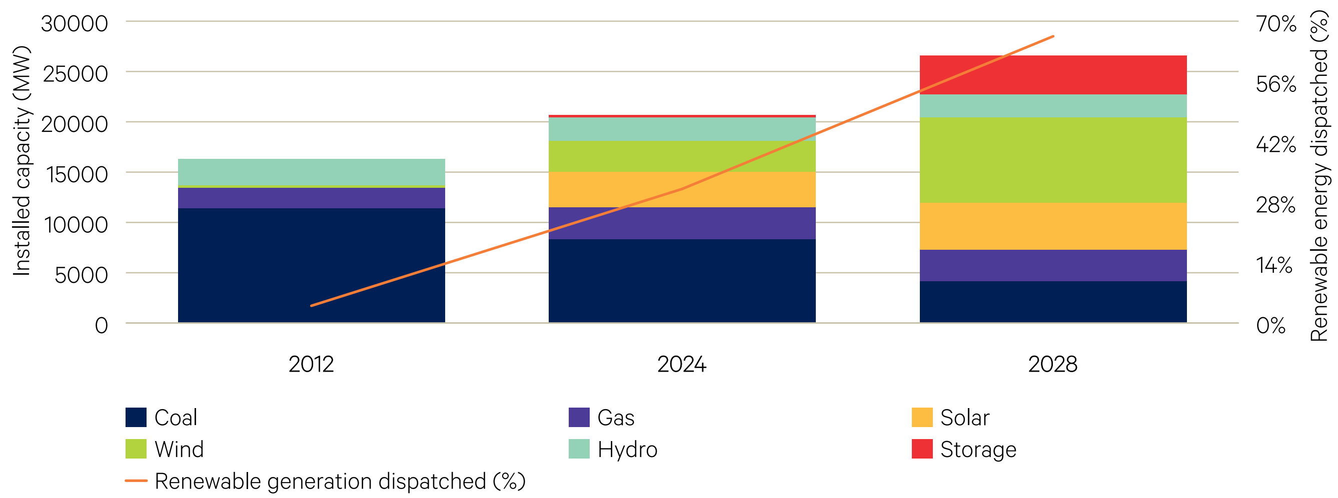
Addressing climate change is essential for environmental sustainability,[60] low cost energy and economic and job growth. In support of this, the NSW[61] and ACT[62] Governments have adopted a 2050, or sooner, goal of net zero emissions. The NSW Government has also recently committed to reducing emissions by up to 50 per cent below 2005 levels by 2030.[63] The ACT Government has also committed to reducing emissions by 50 to 60 per cent below 1990 levels.[64]

Government policies supporting decarbonisation, technology advances and renewable energy costs reductions have led to the transition to renewable generation occurring quickly. The change in the generation mix is increasing the operational complexity of maintaining network stability and security. This includes increased power transfers leading to voltage management issues, more widespread network congestion, increasing fault levels in southern NSW and decreasing minimum demand due to increased solar generation. Our network will need to adapt in the 2023–28 period to address these issues.

Figure 3-7 shows the change in generation mix over time based on AEMO's actual and forecast data. This shows that:

- In 2012, coal was the largest contributor to NSW generation capacity, comprising 11,384 MW or 70 per cent of installed capacity. Hydro comprised 2,619 MW or 16 per cent and gas comprised 2,029 MW or 12 per cent.
- By 2024, coal is expected to reduce to 8,330 MW or 40 per cent of installed capacity, gas is expected to increase to 3,129 MW or 15 per cent and other grid scale energy sources are expected to emerge, so that:
  - solar comprises 3,548 MW or 17 per cent
  - wind comprises 3,113 MW or 15 per cent, and
  - dispatchable storage comprises 290 MW or 1 per cent.
- By 2028, AEMO forecasts that:
  - coal will reduce to 4,130 MW or 15 per cent of installed capacity
  - gas and hydro will remain largely in line with their 2024 levels (3,129 MW and 2,285 MW respectively)
  - wind will increase to 8,493 MW or 31 per cent of installed capacity
  - solar will increase to 4,674 MW or 17 per cent of installed capacity, and
  - storage will increase significantly to 3,855 MW or 14 per cent of installed capacity.

Figure 3-7: NSW installed generation capacity and proportion of dispatched renewables (grid scale only)



Source: AEMO. Forecast based on draft 2022 ISP, Step Change Scenario, CDP12.

60 Meet the 1.5°C global warming target in the Paris Agreement.
61 NSW Government – Department of Planning, Industry and Environment (DPIE) Net Zero Plan Stage 1: 2020–2030
62 The targets, set under the Climate Change and Greenhouse Gas Reduction Act 2010
63 NSW Minister for Energy and Environment, NSW set to halve emissions by 2030, 29 September 2021
64 ACT Government, ACT Climate Change Strategy 2019-25, 2019, p. 1

3.3.1 Government policy changes and decarbonisation commitments

The Australian Government's policies and initiatives include:[65]

- achieving net zero emissions by 2050 through the long-term emissions reduction plan[66]
- climate change strategies, including investing in new technologies that will lower emissions and support jobs and growth and encouraging customers to reduce emissions, and
- growing Australia's hydrogen industry.

The NSW Government's electricity market priorities include:

- achieving a 50 per cent reduction in emissions in NSW by 2030 compared to 2005 levels and net zero emissions by 2050
- enabling renewable energy sources, such as solar and wind generation including through the development of REZs[67]
- promoting the adoption of new technologies that reduce emissions, such as electric motor vehicles, and
- supporting the early adoption of new technologies by NSW businesses so that they remain globally competitive and create new market opportunities.

The ACT Government's commitments include:[68]

- maintaining 100 per cent renewable electricity supply
- reducing emissions by 50 to 60 per cent below 1990 levels by 2025 and achieving net zero emissions by 2045
- improving energy performance and climate change resilience requirements for new buildings and rental dwellings, and
- encouraging zero emissions vehicles.

Government climate change-related policies are encouraging and supporting investment in large-scale renewable electricity generation and the transmission investment that will be needed to deliver the energy transition. These policies include:

- the NSW Electricity Infrastructure Roadmap, which is a coordinated framework to deliver a modern electricity system for NSW that is cheaper, cleaner and more reliable. It is underpinned by the Electricity Infrastructure Investment Act 2020 (NSW), which identifies five REZs in the Central West Orana, New England, South West, Illawarra, and Hunter-Central Coast regions of NSW. These REZs are expected to deliver network capacity of at least 12GW and will help the NSW Government deliver on its ambitions to reach net zero emissions by 2050 or sooner
- the development of AEMO's ISP, and the supporting regulatory changes to make the ISP actionable. The ISP identifies the optimal development path for eastern Australia's power system to facilitate the transformation of the energy market. It identifies the necessary investments, taking into account a range of potential future outcomes, and recommends essential actions (actionable and future ISP projects) to optimise customer benefits, and
- the ESB's post-2025 market review, which is the key energy market reform identifying how energy market arrangements will need to evolve to continue to be fit-for-purpose in light of the changing generation mix. The ESB has recommended changes to support the development of REZs and has identified the new services and markets that will be needed to support the transition to renewables.

We support the transition to the new energy market and the delivery of projects identified in AEMO's ISP and the NSW Electricity Infrastructure Roadmap, which will facilitate the uptake of new low cost renewable generation. In the current period, we have delivered, or are in the process of delivering, three actionable ISP projects:

- the Queensland – New South Wales Interconnector (QNI) minor upgrade
- the Victoria – New South Wales interconnector (VNI) minor upgrade, and
- Project EnergyConnect

These projects are discussed in sections 1.1.5 and 4.3.

We will deliver additional projects in accordance with AEMO's ISP and the NSW Electricity Infrastructure Roadmap, although the associated capex for these other projects is not reflected in this Revenue Proposal.

65 Australian Government, Department of Industry, Science, energy and Resources, Policy Initiatives – Emissions Reduction
66 https://www.industry.gov.au/data-and-publications/australias-long-term-emissions-reduction-plan.
67 Both small scale and grid-scale solar generation.
68 ACT Government, ACT Climate Change Strategy 2019-25, 2019, p. 1

Our customers and other stakeholders strongly support the energy transition and support investment that delivers on the objectives of lowering emissions in our economy. More than half of residential households and small to medium businesses surveyed indicated they would pay more on their quarterly/monthly bills to reduce emissions.

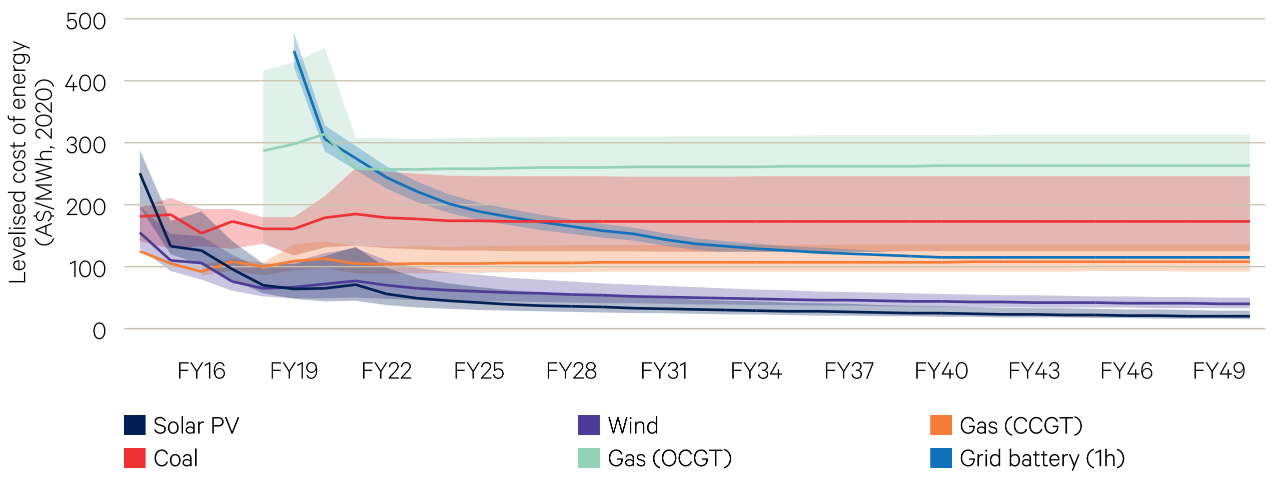
3.3.2 Declining costs of renewable generation

Figure 3-8[69] shows that renewable generation currently provides the lowest cost source of energy generation, and is expected to continue to be the lower cost source of energy in the future.

Since 2009, the cost of solar PV has declined by 87 per cent and the cost of wind generation has reduced by 63 per cent. Since 2013, the cost of battery storage has reduced by 80 per cent.[70] Figure 3-8[71] shows that further cost reductions are expected over the next 30 years to 2050, with the cost of:[72]

- solar PV expected to reduce by a further 70 per cent
- wind generation expected to reduce by a further 50 per cent, and
- grid-scale batteries expected to reduce by a further 60 per cent.

Figure 3-8: Projections of the levelised cost of energy in Australia[73]



Source: BloombergNEF, 1H 2021, Levelised Cost of Energy Data Viewer

3.3.3 Impact of the change in generation mix on our transmission network

The change in the generation mix is increasing the operational complexity of maintaining network stability and security in a number of ways including:

- more widespread network congestion
- shortfalls in system strength and inertia
- increasing fault levels in southern NSW, and
- decreasing minimum demand.

More widespread network congestion

The rapid change in the mix and location of generation in weaker parts of our network is increasing network congestion. In order to maintain a secure and stable power system, AEMO's market dispatch engine (NEMDE) must curtail generation to maintain power flows within safe and stable limits. This prevents customers from fully benefitting from low cost and low emission sources.

69 CSIRO GenCost 2020–21 and BloombergNEF, 2020, Levelised Cost of Energy Data Viewer
70 Global cost reductions. BloombergNEF, 1H 2021, Levelised Cost of Energy Data Viewer
71 CSIRO GenCost 2020–21 and BloombergNEF, 2020, Levelised Cost of Energy Data Viewer
72 Projections of Australian cost reductions. BloombergNEF, 1H 2021, Levelised Cost of Energy Data Viewer
73 BloombergNEF, 1H 2021, Levelised Cost of Energy Data Viewer. Shaded area represents the minimum and maximum cost projections, cost converted to Australian dollars with a 2020 average conversion rate of 0.69

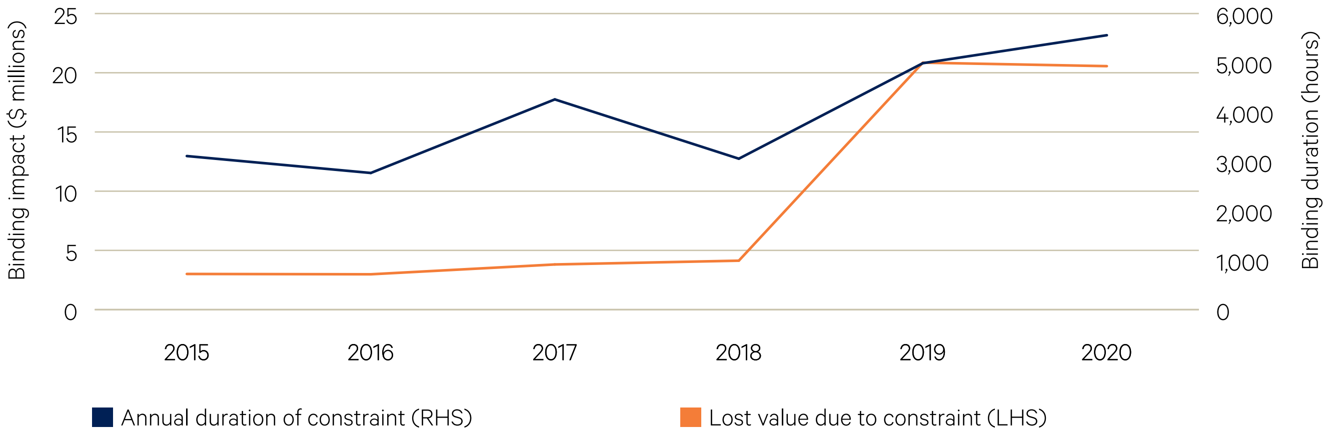
The Energy Security Board has acknowledged the issue of network congestion, which if not addressed will be a limiting factor in the transition of the energy market:

> Increasing levels of penetration means more curtailment of those [wind and solar energy] resources because of network congestion and insufficient services like frequency control system strength, voltage control, or flexibility (ramping). Without further action, the maximum instantaneous penetration of renewable resources would be limited to between 50 and 60 percent.[74]

Congestion also limits the timeframes within which we can schedule planned outages to undertake capital works and maintain the network.

Figure 3-9 shows the increasing duration and financial impact of network congestion in NSW.

Figure 3-9: Network Congestion in NSW



Source: AEMO NEM Constraint Report 2020

Shortfalls in system strength and inertia

As traditional synchronous generators in NSW, including Liddell, Vales Point and Eraring Power Stations, retire or move to flexible operation and we transition to non-synchronous generation from intermittent renewables, there is a need to provide services such as system strength and inertia. These services are essential to maintain stability and security of the power system:

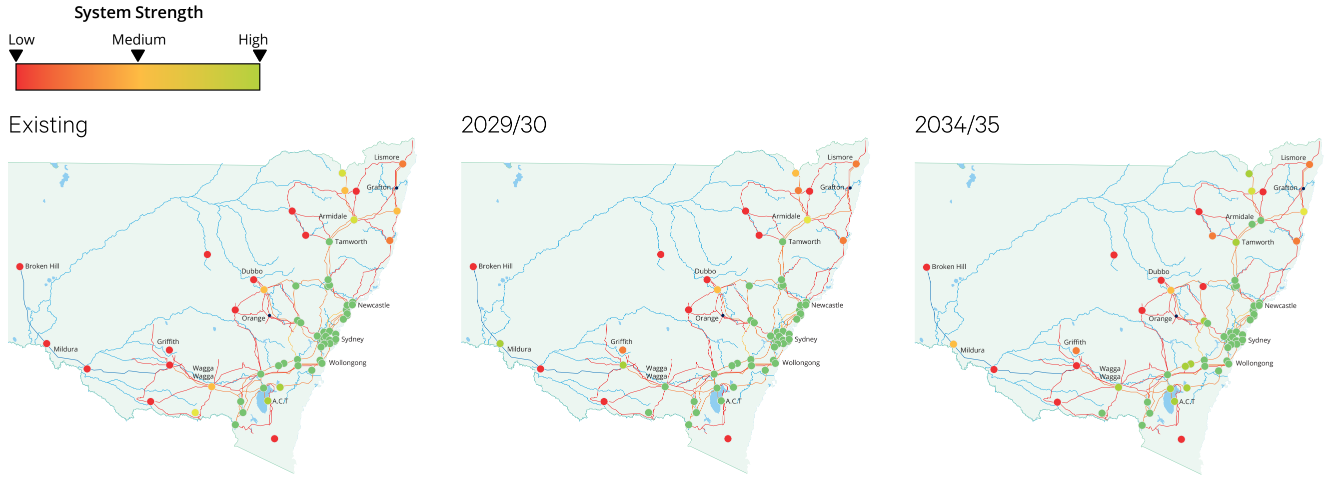
- **System strength** is the power system's ability to temporarily provide high energy to manage disturbances while maintaining voltage control,[75] and
- **Inertia** is the power system's ability to 'ride through' disturbances without significant frequency variation.

We will provide system strength and/or inertia services where AEMO declares that there is a projected system strength gap or an inertia gap.[76]

Figure 3-10 shows that system strength is expected to continue to decline in the 2023–28 regulatory period and beyond. AEMO is expected to declare a 'system strength' gap in NSW during the next regulatory period, following the retirement of Vales Point Power Station.

74 Energy Security Board, 2021, Post 2025 Market Design Options – A paper for consultation Part A
75 System strength has historically been supplied by coal and gas generators. The transition to renewable generators has reduced the supply of system strength.
76 Under NER Clause 5.20B.4 (a), as the inertia service provider we are obliged to provide inertia network services if an inertia shortfall has been identified by AEMO. Similarly, under NER Clause 5.20C.3 (a), as the system strength service provider we are obliged to provide system strength services if an inertia shortfall has been identified by AEMO.

Figure 3-10: System strength outlook: Existing and future projections at 2029–30 and 2034–35



Source: AEMO interactive map for system strength

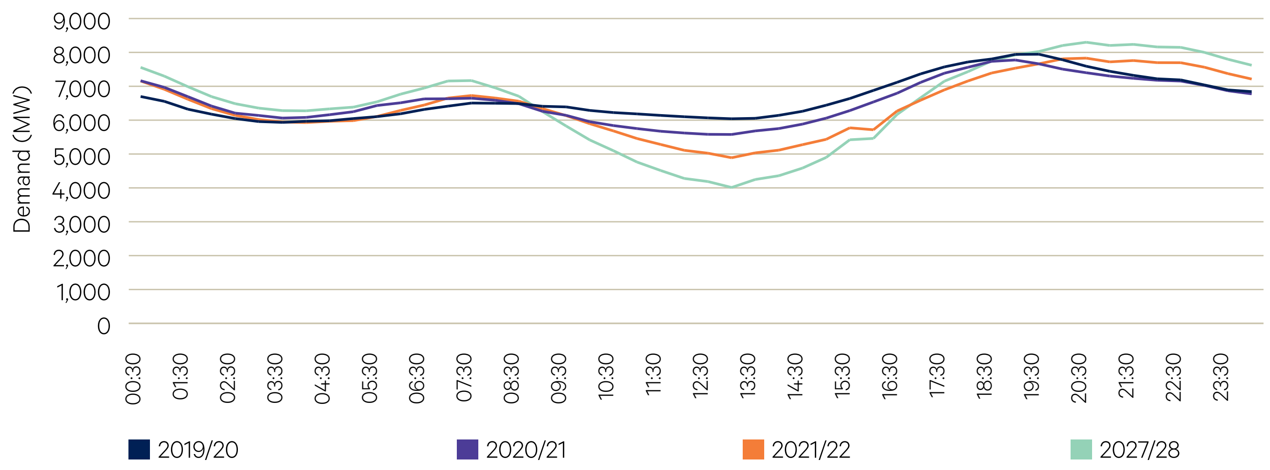
Closing non-renewable generation may also lead AEMO to declare an inertia shortfall.

In October 2021, the AEMC published its rule change for the efficient management of system strength on the power system. The rule change has established us as the system strength service provider in NSW and the ACT. We will therefore plan and design our network to meet AEMO's projected system strength requirements. As discussed in Chapter 17, we have included a contingent project in this Revenue Proposal to cater for any investments which may be required, and we will rely on the pass through and automatic contingent project provisions in the NER to ensure that we provide the necessary system strength services to meet our obligations.

Decreasing minimum demand

Over the next regulatory period NSW minimum demand throughout the day is forecast to decline predominately due to solar PV generation from households which is reducing daytime demand below the minimum demand that previously occurred overnight. This is shown in Figure 3-11.

Figure 3-11: Minimum demand – NSW daily load curve



The forecast decline in minimum demand is expected to lead to high voltages in certain parts of the network requiring the installation of reactors[77] to maintain voltage levels within prescribed limits. We have included compliance related projects to maintain voltage levels in our Augex forecast.

77 Reactive power equipment

3.4 Supporting documentation

The following documents support this Chapter and accompany our Revenue Proposal.

Name
Augex Overview Paper
Repex Overview Paper
Energy Vision
2021 Transmission Annual Planning Report
BIS Oxford Economics, Labour Cost Escalation Forecast to 2027–28
GHD, Demand Driven Augex Forecast Review
GHD, Climate change and extreme weather event resilience

4. What we delivered in 2018–23

This Chapter details the outcomes we have delivered in the 2018–23 regulatory period for the matters that customers have told us that they value most – an affordable, safe, secure, reliable and sustainable energy supply.

Key messages

In the 2018–23 regulatory period, we have delivered the outcomes our customers value most – affordable, safe, reliable and secure energy supply, while supporting the transition to net-zero emissions:

> **Affordability** – we have:
  – delivered opex efficiencies that have allowed us to spend below the AER's base year allowance. These efficiencies result in a $59.6 million savings to our customers in the 2023–28 period (compared to our base year allowance)
  – spent below the AER's capex allowance. This means that our Regulatory Asset Base (RAB), which was adjusted to include three ISP projects, is lower than the AER projected
  – delivered projects on AEMO's optimal development path which will significantly reduce customers' total electricity bills by delivering wholesale market savings, and
  – maintained our opex productivity performance. The AER's opex benchmarking, and the independent analysis that we have commissioned from HoustonKemp, show that we are efficient.

> **Safety, reliability and security** – we have:
  – maintained our network risk in line with the risk index at the start of the regulatory period
  – maintained a consistently high level of reliability by delivering Powering Sydney's Future (PSF) and building a new 330/132kV substation at Stockdill in the ACT
  – achieved strong safety performance. We are below the industry benchmark for Lost Time Injury Frequency Rate (LTIFR) and have improved our Critical Risk Injury Frequency Rate (CRIFR)
  – responded to emergencies, including the 2019–20 bushfires which were the worst in NSW history, floods and extreme winds, and COVID-19, to keep the community and our people safe and minimise disruptions to our transmission services.

Key messages (continued)

> **Energy transition** – we have supported the transition to a low carbon future through our investments in major transmission projects which underpin AEMO's ISP optimal development path including Project EnergyConnect, HumeLink, QNI minor and VNI minor.

> **Technology and innovation** – In collaboration with industry partners, contracting suppliers and other third parties, we have invested in new technology and innovation which will provide future benefits for our customers including by placing downward pressure on transmission prices and improving safety and climate outcomes.

4.1 Affordability

In the 2018–23 regulatory period, we have delivered value for money transmission services by undertaking efficient opex and capex, which is reflected in strong benchmark performance outcomes.

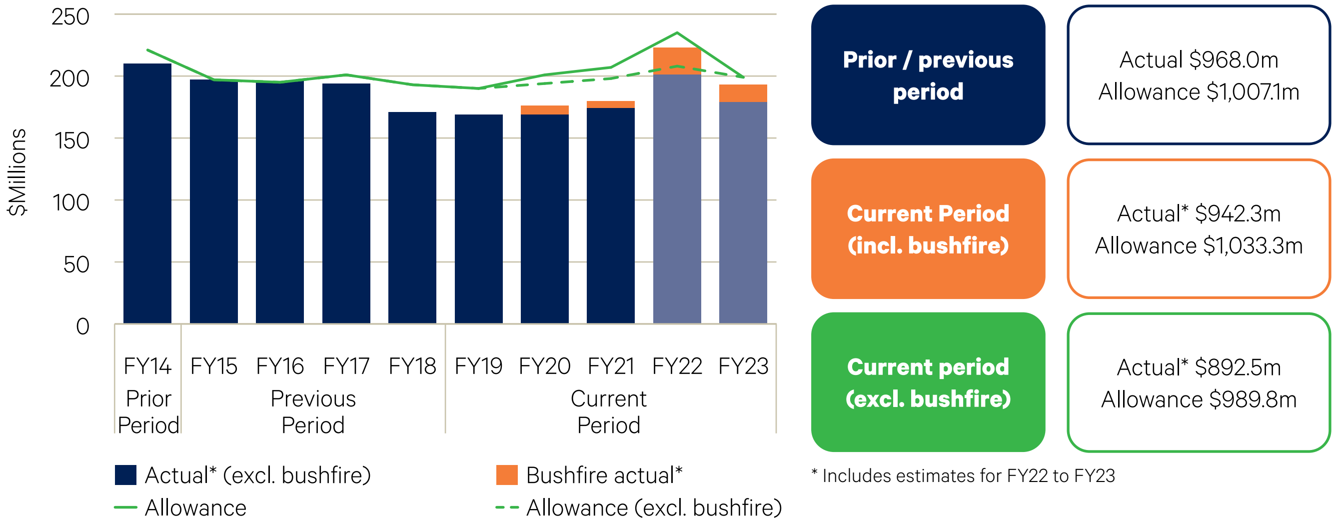
4.1.1 Efficient opex

We have made cost savings in the current regulatory period so that we expect to underspend the AER's opex allowance. This results in lower forecast cost, and therefore reduces our revenue requirements in the 2023–28 period.

Figure 4-1 compares our actual and estimated opex to the AER's allowance over the previous and current regulatory periods. It shows that over the current regulatory period, we expect our actual opex of $942.3 million[78] to be $91.0 million, or 8.8 per cent below the AER's allowance[79] of $1,033.3 million including the Bush Fire Allowance (BFA) and excluding debt raising costs. This shows that we are responding appropriately to the incentives under the AER's Efficiency Benefit Sharing Scheme (EBSS).

We are using 2021–22 opex as the basis of our opex forecast in the next period and have removed expenditure on bushfires from this base year. Over the 2023–28 regulatory period this equates to a saving of $59.6 million to our customers.[80]

Figure 4-1: Actual / estimated opex for FY14 to FY23 vs AER allowance ($M, real 2023)



78 Including bushfire remediation expenditure and excluding debt raising costs.
79 Adjusted for AER approved cost pass through – 2019–20 Bushfire season bushfire allowance of $49.8m (nominal $). Transgrid incurred/expects to incur the costs in FY20, FY21 and FY22 and be compensated for them in FY23, FY24 and FY25. For the purposes of meaningful comparison we have aligned the adjustment to the 2018–23 AER opex allowance of the pass through costs to when they have been / expected will be incurred by us.
80 Calculated as $11.9 million underspend projected for 2021–22 multiplied by 5 years.

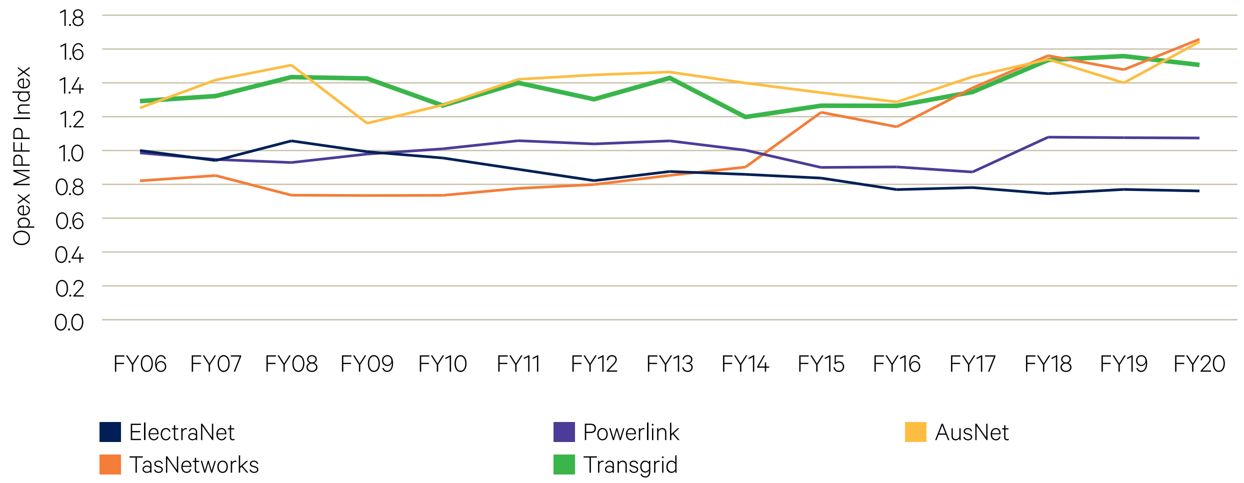
We achieved opex reductions in the current regulatory period by:

- achieving more effective labour utilisation
- replacing manual HR and procurement processes with streamlined transaction management process. We also transformed our Information Technology support functions by implementing the outcomes from a Strategic IT Sourcing Review undertaken in 2018. This included on-boarding a new lower cost vendor for telecommunication and managed services
- changing our operating model to allocate functions, people and resources to streamlined management structures
- continually adapting our labour force to ensure it meets our ongoing needs
- implementing risk-based, reliability-centred maintenance practices to optimise the intervals by which we perform routine inspections and maintenance activities, and
- improving planning and scheduling to ensure that work is completed safely, on time, within budget to meet customers' expectations.

Our opex benchmarks strongly against our peers. The AER's multilateral partial factor productivity (MPFP) index measures opex productivity over time, based on a ratio of a business's inputs and outputs. Figure 4-2 shows that:

- we are efficient in both absolute and trend terms, with our productivity performance ranking in the middle in comparison with our peers, and improving over time
- our improvement in productivity over time demonstrates that we are responding to the incentives under the regulatory framework to improve our efficiency, and
- our current level of opex productivity has improved relative to our opex incurred in 2016–17, which the AER deemed to be an efficient level of opex in its final determination on our 2018–23 revenue proposal.

Figure 4-2: Opex multilateral partial factor productivity (MPFP) 2005–06 to 2019–20

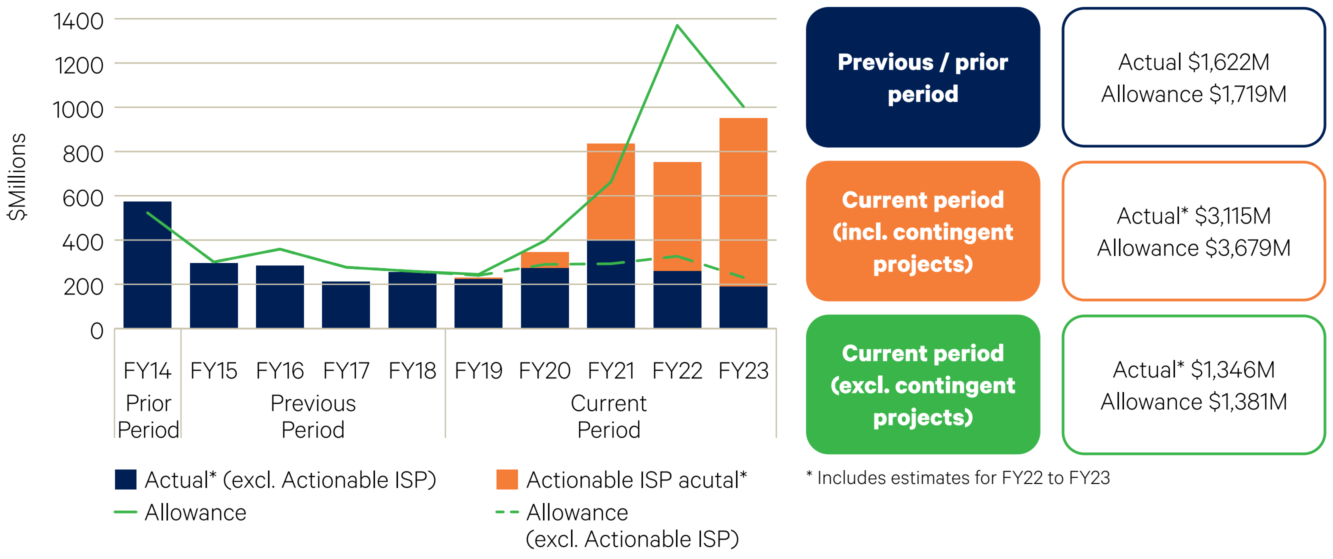


Source: Economic insights TNSP MTFP Tables and Charts, August 2021

4.1.2 Efficient capex

Figure 4-3 shows that our capex in the current regulatory period is below the AER's allowance, which was adjusted to include three ISP projects including Project EnergyConnect, VNI minor upgrade and QNI minor upgrade. This means that our RAB is growing slower than the AER's and customers' expectations.

Figure 4-3: Actual/estimate capex versus AER allowance over 2014–2024 ($M, Real 2022–23)



Our capex over the current regulatory period has enabled us to:

- maintain network performance, as discussed in sections 4.2.1 and 4.2.2
- deliver Powering Sydney's Future project to continue to meet reliability requirements for load in the inner Sydney area, which is expected to cost $235.2 million. This is $19.4 million or 7.6 per cent below the AER's allowance due to savings from innovative cable technology and construction practices. We also expect to deliver this project by mid 2022, which is ahead of the December 2022 scheduled completion date.
- deliver three ISP projects (Project EnergyConnect, VNI minor upgrade and QNI minor upgrade), as discussed in section 4.3, and
- respond to external emergencies, as discussed in section 4.2.3.

We have achieved these outcomes in line with the AER's allowance by reprioritising our capex to reflect circumstances, as discussed in section 4.2.1, and by implementing our capital efficiency program. This is a multi-phased transformation program aimed at ensuring our increased capital work program maximises capital efficiency and improves the end-to-end capital delivery processes. This program comprises:

- a rolling 24-month projects work plan
- a capital portfolio performance framework
- a new delivery strategy and model
- a new operating model for capital planning, allocation and delivery value chain
- redesigned end-to-end process for capital planning, allocation and delivery, and
- streamlined governance and oversight of the capital work plan, which is underpinned by change management initiatives.

4.1.3 Wholesale market cost reductions

Coordinated transmission investment based on AEMO's ISP will reduce customers' final electricity bills by helping to share reliable generation resources across the NEM, improve wholesale market competition, open-up the development of REZs and facilitate the development of large scale storage.

As discussed in section 1.1.5, we are delivering three nationally significant actionable ISP projects identified in AEMO's optimal development path that are critical to enabling the energy market transition and are expected to significantly reduce customers' overall electricity bills through delivering wholesale market cost savings:

- Project EnergyConnect – this project is expected to deliver approximately $201 million in net benefits.[81] FTI Consulting has estimated that this project will reduce average annual total customer bills for NSW residential customers by up to $64 per year over the 2020 to 2040 period[82]
- QNI Minor Upgrade – this project is expected to deliver approximately $170.0 million in net benefits, which will contribute to total residential and business electricity bill reductions,[83] and
- VNI Minor Upgrade – this project is expected to deliver approximately $268.0 million in net benefits, which will contribute to total residential and business electricity bill reductions.[84]

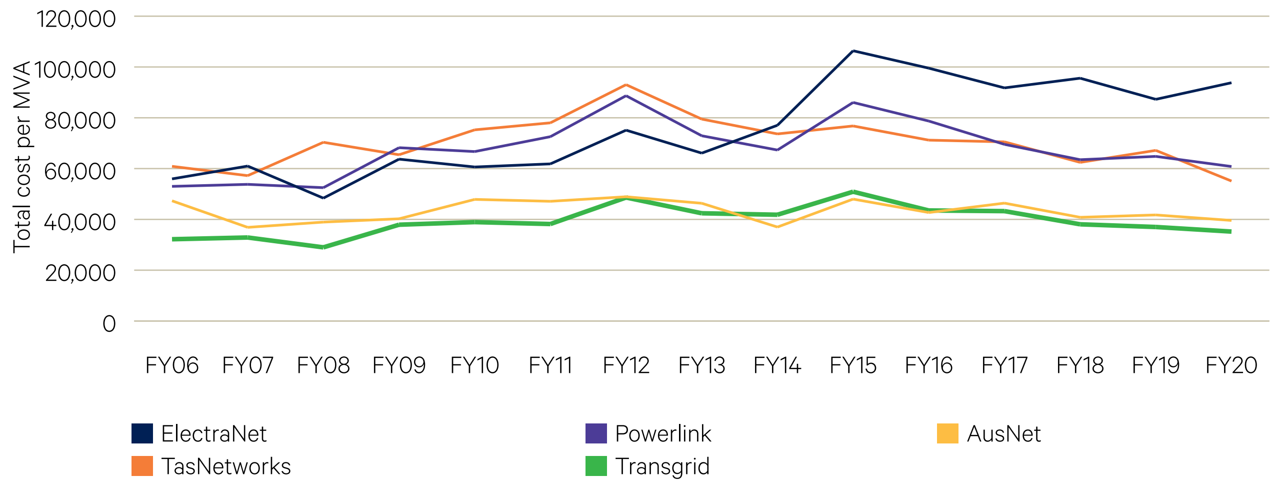
Lower generation costs, which will more than offset the increases in our transmission costs and our investment in the transmission network, is the most cost-effective way to reduce emissions and to provide customers with access to lower cost renewable generation sources.[85]

4.1.4 Strong benchmarking performance outcomes

We benchmark strongly against our peers. The AER's benchmarking, and the independent analysis that we have commissioned from HoustonKemp, show that we are amongst the most efficient TNSPs on a state-by-state basis on a range of measures. We rank:[86]

- first – the lowest cost – in total cost per MVA of maximum demand served
- second lowest cost in total cost per end user and our costs on this measure are 3.6 per cent lower than they were in 2006
- second lowest cost in total cost per circuit length (per kilometre), and
- lowest cost alongside AusNet on total cost per MWh of energy transported. Our costs on this measure have trended down since 2014–15 and our cost per MWh of energy has decreased by 19 per cent since 2014–15.

Figure 4-4: Total cost per MVA of demand served



81 ElectraNet, Project EnergyConnect Updated Cost Benefit analysis, September 2020.
82 FTI Consulting, Assessing the benefits of interconnectors, a report for TransGrid (Wider Benefits Report), September 2020. This analysis assumes: (i) wholesale price changes; (ii) the cost of EnergyConnect; and (iii) the effect of the Project on existing interconnector residues, are fully passed on to customer retail bills, and average annual household consumption figures remain constant over time.
83 Transgrid and PowerLink, Project Assessment Conclusions Report, Expanding NSW-QLD transmission transfer capacity, 20 December 2019, p. 4. Net benefits are calculated over the period to 2044–45 (in NPV terms).
84 AEMO, Victoria to New South Wales Interconnector Upgrade, Project Assessment Conclusions Report, February 2020, p.6. Net benefits are calculated over the period to 2044–45 (in NPV terms).
85 Grattan Institute, Go for Net Zero – A practical plan for reliable, affordable, low emissions electricity, April 2021, section 2.
86 AER, Annual benchmarking report electricity transmission network service providers, November 2021, section 4.2.

Figure 4-5: TNSP total cost per end user

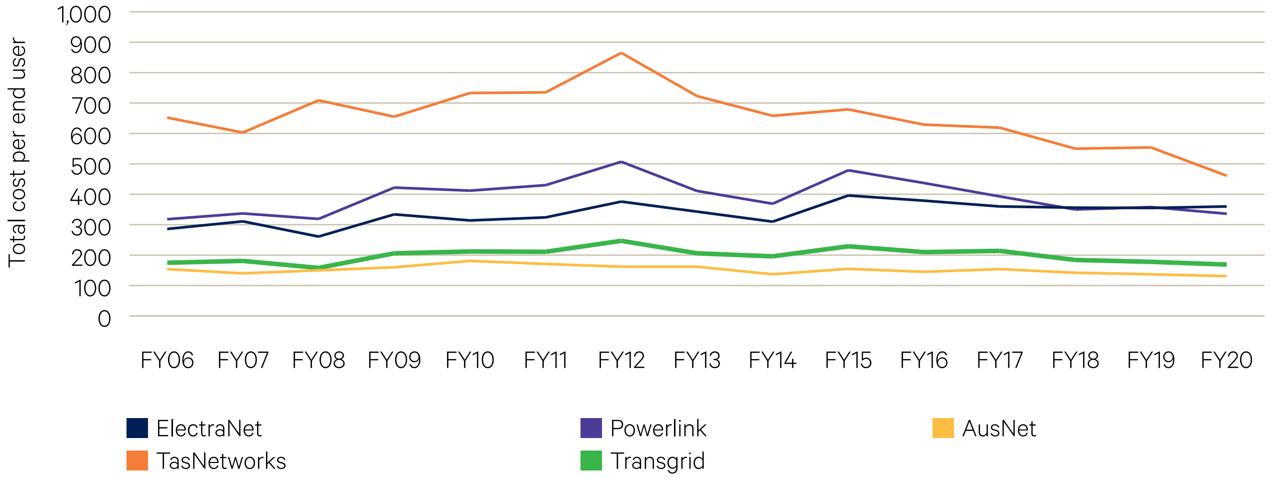


Figure 4-6: Total cost ($) per circuit length (per km)

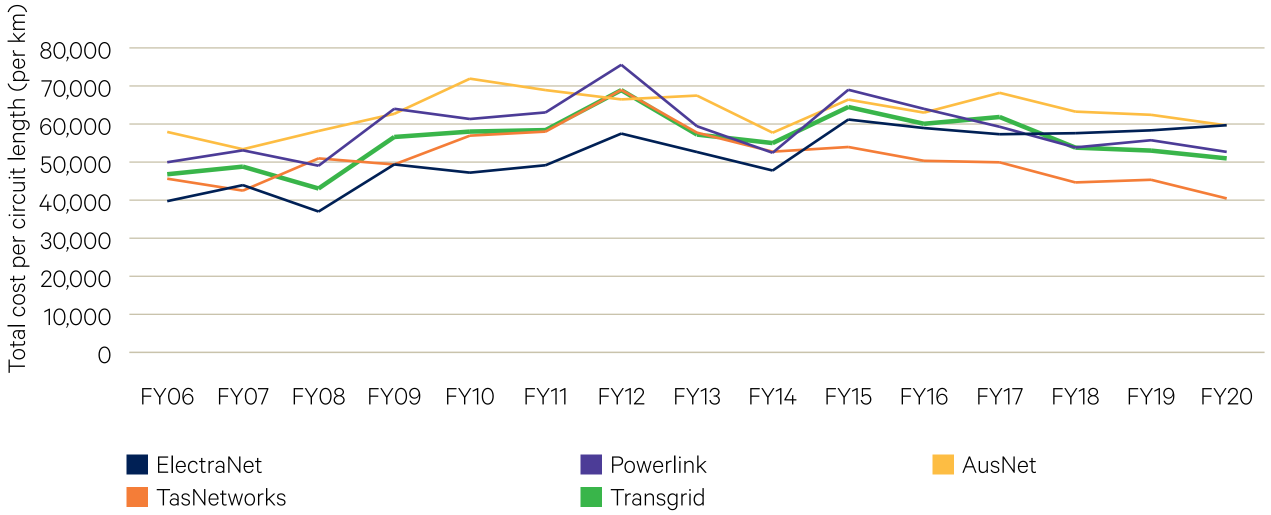
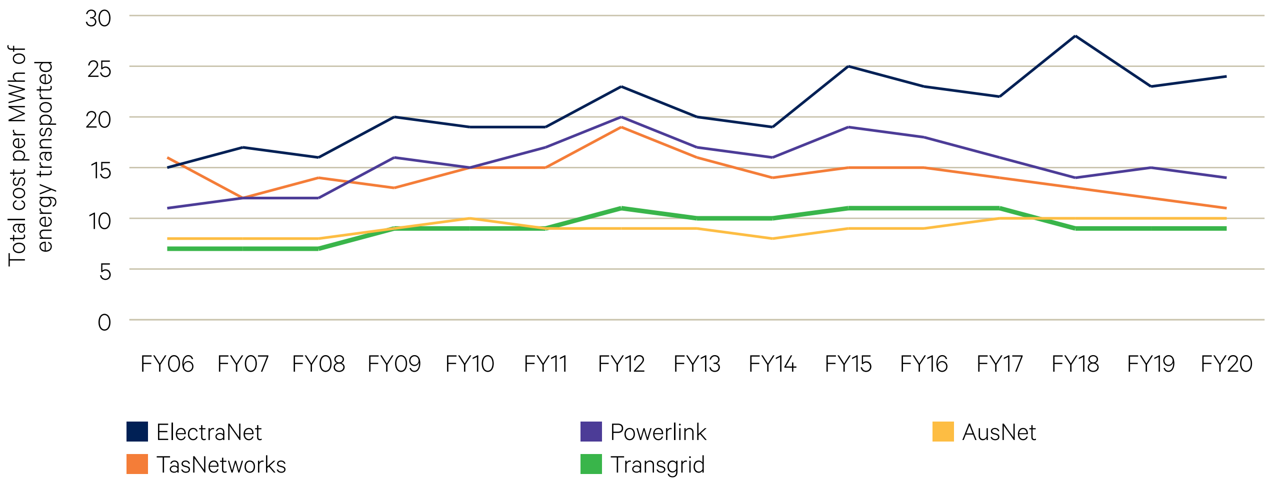


Figure 4-7: TNSP total cost per MWh of energy transported



Source: AER, Annual benchmarking report electricity transmission network service providers, November 2021. Dollars converted from $2020 to Real$2023.

4.2 Safety, security and reliability

In the 2018–23 regulatory period, we have maintained network risk at an acceptable level, met network security and reliability requirements and responded to network emergencies.

4.2.1 Maintain network risk at an acceptable level

The safety of our communities, customers, employees and delivery partners is our top priority. By maintaining our network to an acceptable risk level we have continued to deliver our strong network, safety and reliability performance. Our customers, particularly small businesses, have also indicated they place a high priority on the reliability of the network.

We measure our total network risk in the form of a 'risk index', which is a multi-dimensional measure for safety, environmental, bushfire and reliability risk. The risk index is the sum of the residual risk of each individual asset, which is then baselined, so that we can monitor relative changes in network risk over time. A higher risk index represents a relative increase compared to the 2018–19 baseline risk and a lower risk index represents a relative decrease compared to the 2018–19 baseline risk.

The risk index measures the effectiveness of our capital works program to mitigate network risk, taking into account:

- asset condition data collected through inspections and online monitoring systems
- probability of failure curves
- consequences of a failure from a community perspective, considering all of our statutory, regulatory and legal obligations and the consequences for safety, bushfire, environmental and reliability outcomes. This considers:
  - value of Statistical Life
  - value of Customer Reliability as estimated by the AER
  - bushfire and safety consequence, as required to meet the requirements set out in IPART licence obligations and Electricity Supply (Safety and Network Management) Regulation 2014, and
  - other regulatory and statutory obligations
- the inherent asset risk, applying risk treatments (our asset management strategies and plans) to calculate the residual asset risk.

Figure 4-8 shows that by the end of the current period, we expect our network risk index to be in line with the risk index at the start of the regulatory period. We are achieving this by continually reviewing and reprioritising our expenditure and works programs to focus on the delivery of key projects driven by our compliance obligations. In particular:

- we prioritise the replacement of deteriorated wood poles and refurbishing steel towers on transmission lines in high risk areas (including high bushfire risk) to meet our network safety obligations. The total cost of these investments are expected to be $334.5 million in the current regulatory period
- we focus on replacing substation transformers, switchgear and instrument transformers to mitigate safety and network reliability risks. The total cost of these investments is expected to be $199.7 million in the current regulatory period, and
- we invest in replacing control and protection systems which are critical to maintaining the safety, reliability and security of the network. The total cost of this investment is expected to be $263.4 million in the current regulatory period.

Figure 4-8: Network Risk Index

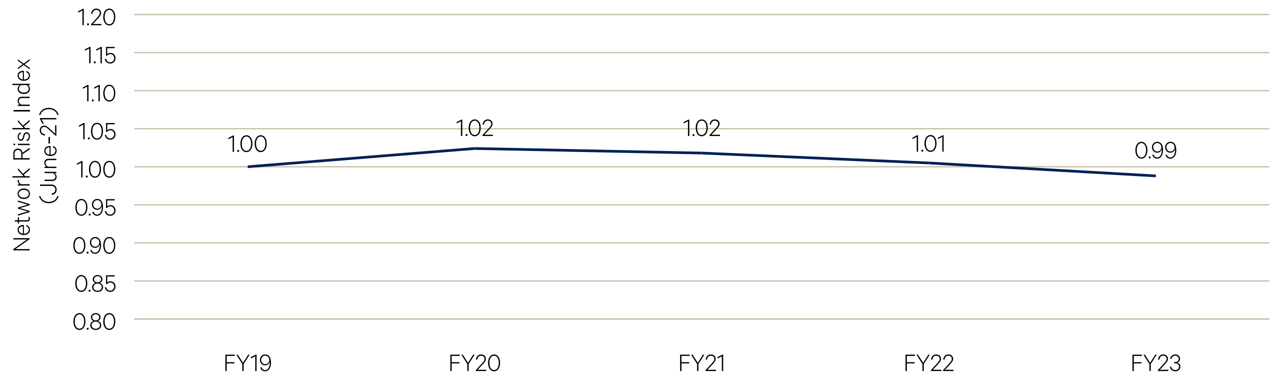
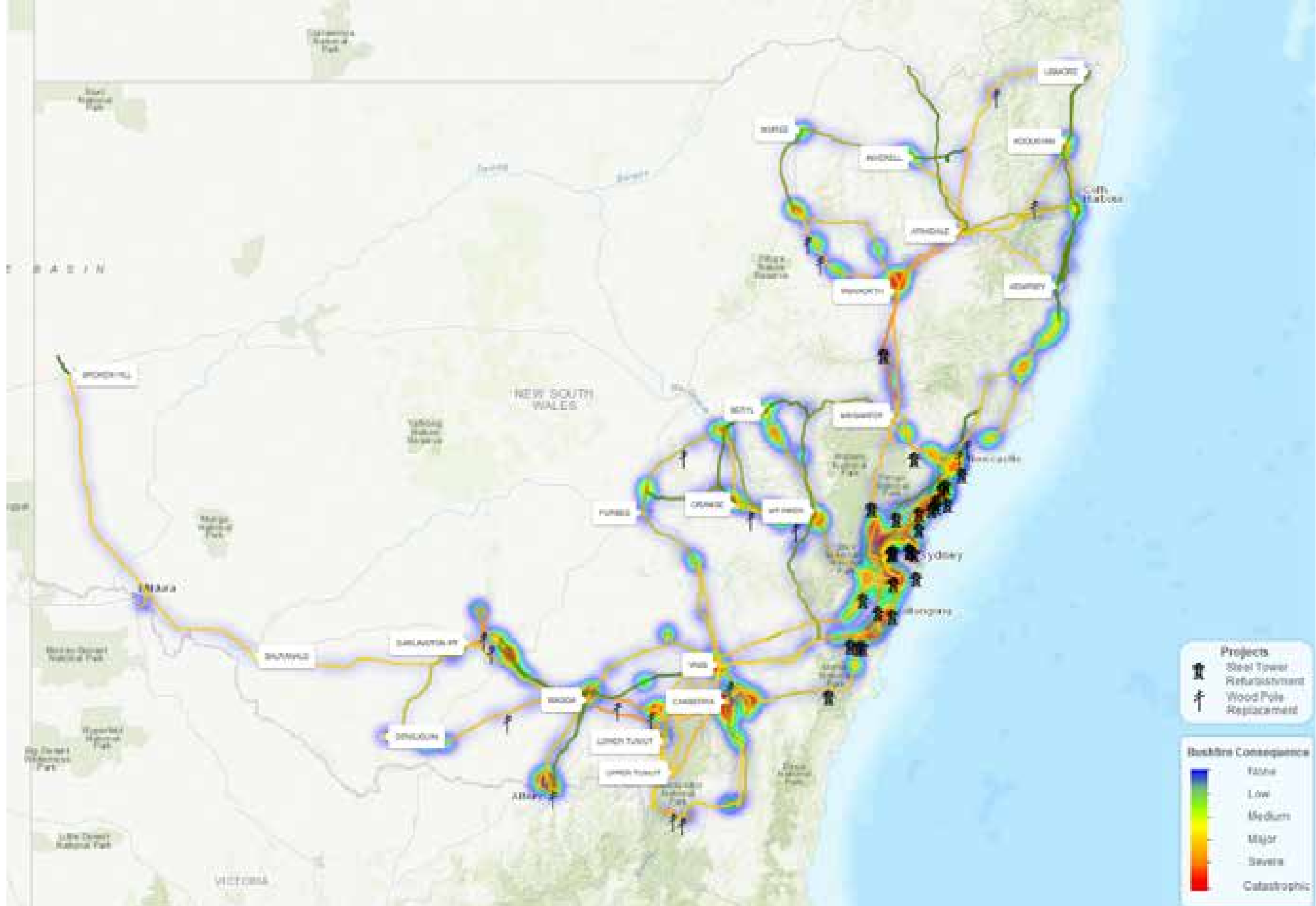


Figure 4-9 is a heat map showing our transmission line bushfire consequence and the icons identify our investments in steel tower refurbishment and wood pole replacement to maintain our risk index in the current regulatory period.

Figure 4-9: Transmission line investments in 2018–23



4.2.2 Meet network security and reliability requirements

We are managing the stability of the power system to ensure the safe, reliable and secure delivery of electricity to homes and businesses across NSW and the ACT in accordance with our licence conditions.

In NSW, our reliability and performance standards are set out in our licence,[87] issued under the Electricity Supply Act 1995 (NSW). This standard specifies two reliability criteria for each Bulk Supply Point (BSP):[88]

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

We are also subject to the *Electricity Transmission Supply Code July 2016*[89] under our transmission licence in the ACT.[90] This requires:

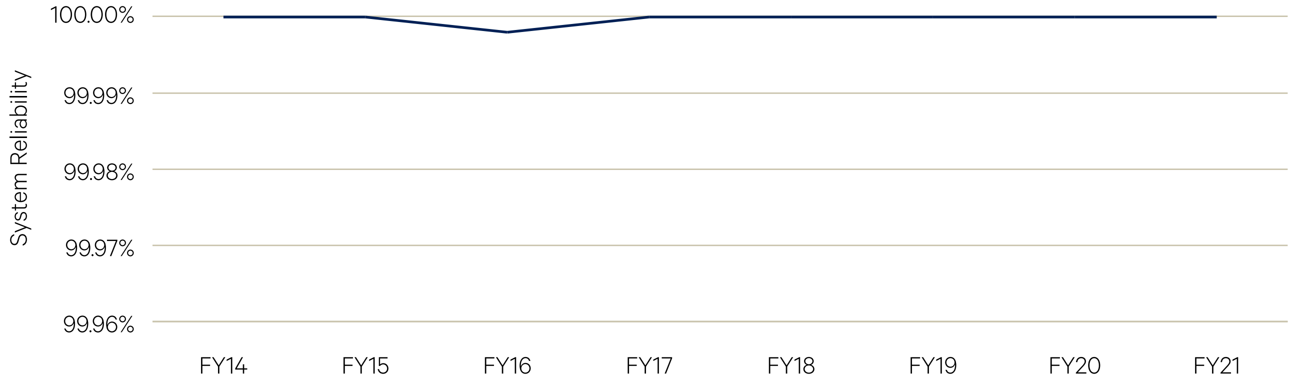
- two or more geographically separate points of supply at 132 kV or above, and
- a continuous electricity supply at maximum demand to the ACT network at all times, including following a single credible contingency event.

The Canberra, Stockdill, Williamsdale and Queanbeyan Substations currently supply the ACT load from our network.

87 Transmission operator's licence under the Electricity Supply Act 1995 (NSW)
88 NSW Electricity Transmission Reliability and Performance Standards 2017
89 Utilities (Technical Regulation) Electricity Transmission Supply code, 2016
90 Independent Competition and regulatory Commission (ICRC), Licence to provide electricity transmission and connection services under the Utilities Act 2000 (ACT)

We analyse the unserved energy at each of our BSPs to ensure we deliver energy within our allowable unserved energy allowance in our licences and are compliant with our licence requirements. When we have an event resulting in unserved energy, this reduces our reliability below 100 per cent based on the quantum and duration of unserved energy at that BSP. We aggregate this across all BSPs to a whole of network reliability measure shown in Figure 4-10, which demonstrates that we have maintained a consistently high level of reliability over the current regulatory period.

Figure 4-10: Annual network reliability FY14 to FY21

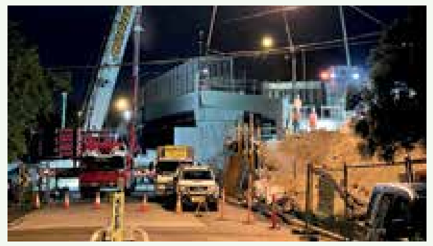


We are achieving our network performance by investing in traditional infrastructure and new technology, including:

- investing in the Powering Sydney's Future (PSF) project, which is a major component of our capex. PSF has been driven by the need to continue to meet reliability requirements for load in the inner Sydney area. PSF involved the installation of a new underground 330 kV cable to greatly enhance the reliability of supply for the 800,000 people working and living in Sydney's CBD and surrounding suburbs. A key benefit to customers of PSF is the reduction in expected unserved energy. The project is nearing completion and is expected to cost $235.2 million (Real 2022–23).
- building a new 330/132kV substation at Stockdill to ensure continued compliance with our ACT licence requirements after 31 December 2020, through providing a new second supply source to Williamsdale and Canberra substations. This achieves compliance with the Electricity Transmission Supply Code for two fully independent supply points. This project was completed in 2020–21 at a total cost of $40.7 million (Real 2022–23).
- undertaking investments to meet our network regulatory obligations and other compliance requirements, in light of load increases driven by economic growth, as well as the impact of changes in the generation mix. The most substantial of these projects include:
  - the installation of a new 330/66 kV transformer at the Macarthur Bulk Supply Point (BSP) to meet demand growth in the Greater Macarthur area (at a cost of $8.2 million), and
  - the installation of new capacitor banks at our Panorama and Orange substations (at a cost of $3.9 million), to ensure NER voltage requirements continue to be met, given load growth in the area which is driven by mining activity.

Case Study 1: Powering Sydney's Future

PSF has delivered a new underground electricity cable, and upgrades to three substations. This will ensure the 800,000 people living and working in Sydney's CBD and surrounding suburbs have a reliable energy supply into the future. The new 330kV cable will replace 50 year old cables which are now reaching the end of their serviceable life.



Despite the challenges of COVID-19 and completing construction works through some of Australia's most densely populated areas, we expect to deliver the project according to schedule. We have consulted and engaged with the community extensively through both the planning and construction phases of the project through our Stakeholder Monitoring Committee and Community and Stakeholder Reference Group. This has provided transparency and enabled ongoing community participation in delivery of the project.

As part of the project, we will provide community benefits by delivering a new cycleway to Sydney's inner west, which was co-funded by the NSW Government. The cycleway has been constructed as part of a new cable bridge for the project, which crosses the rail corridor at St. Peters. The cycleway will relieve congestion for customers and make the bridge safer for all road users.

4.2.3 Strong safety performance

Safety is a non-negotiable element of our business operations. People are at the heart of our organisation and we strive towards a safety citizenship culture to deliver a beyond harm workplace.

We are proud of our strong safety performance over the current regulatory period. Figure 4-11 and Figure 4-12 show that we are below the industry benchmark for Lost Time Injury Frequency Rate (LTIFR) and have improved our Critical Risk Incident Frequency Rate (CRIFR).

Figure 4-11: LTIFR (Transgrid & Delivery partners)

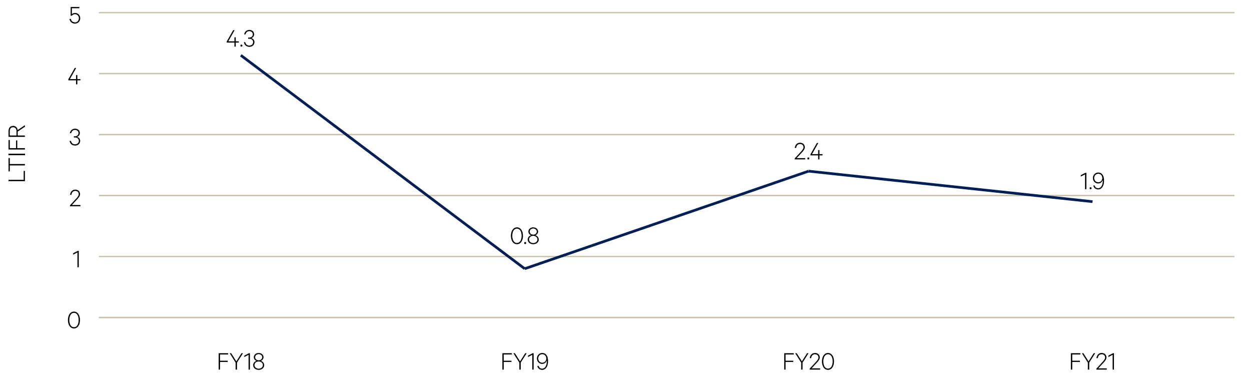
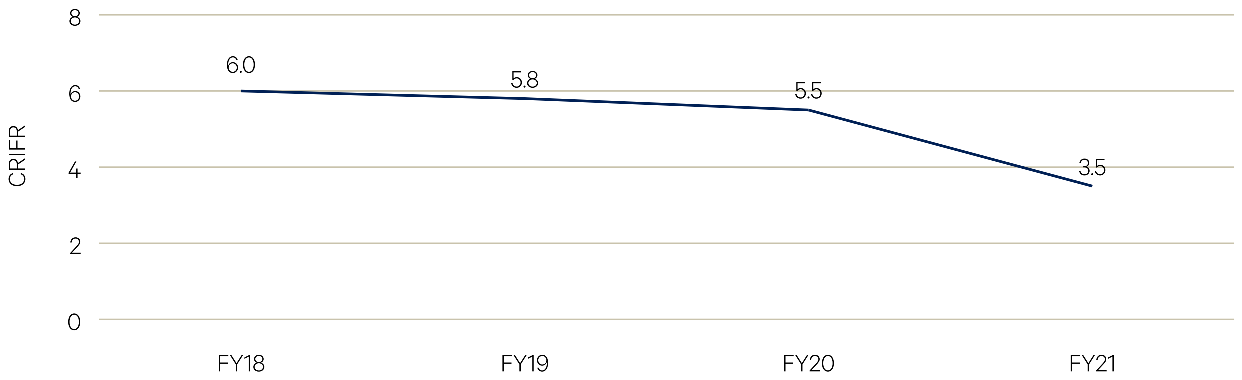


Figure 4-12: CRIFR (Transgrid & Delivery partners)



Our forward looking and proactive risk management approach has significantly lifted our performance in risk awareness through lead indicators such as our industry best hazard identification program where we identify, report and control hazards.

4.2.4 Respond to emergencies

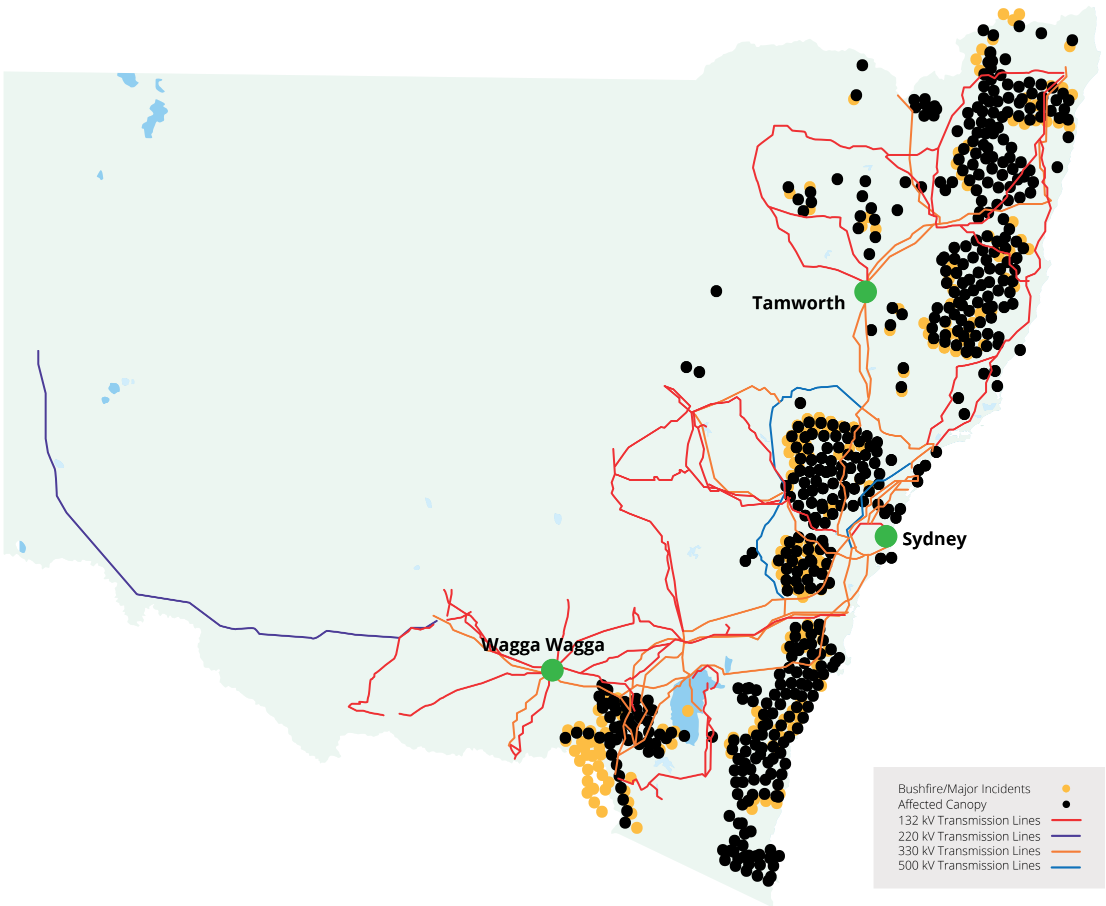
We experienced a number of emergencies in the current regulatory period, including bushfires, floods and extreme winds, as well as COVID-19. We kept the community and our people safe, minimised disruptions to our transmission services and provided financial relief to customers by deferring charges and providing rebates to certain customers.

Climate change contributed to these emergencies by increasing the frequency and severity of extreme weather events which impacts our network security. In response, we are replacing assets with more resilient alternatives when they become due for replacement, such as replacing deteriorated timber poles with concrete or steel poles. We have reflected the outcomes of an independent climate change adequacy review[91] into our capex forecasts for the 2023–28 regulatory period.

Bushfires

We experienced unprecedented network damage as a result of the 2019–20 bushfires, which were the worst in NSW history. This included damage to 999km of transmission line route length and 2,681 transmission line structures in bushfire impacted zones, the extent of which is shown in Figure 4-13. We undertook extensive condition assessment of bushfire damaged components of our network and continued ongoing remedial works to ensure the continued safe operation of the network. Due to the scale and severity of the damage, the AER approved a cost pass through allowance to ensure we are able to undertake the necessary repair works to keep the community safe and to maintain the reliability of the network.

Figure 4-13: 2019–20 bushfire zones



Source: RFS, DPIE and Transgrid

91 AECOM, Transgrid Network Climate Change Adaptation Strategy, 2019

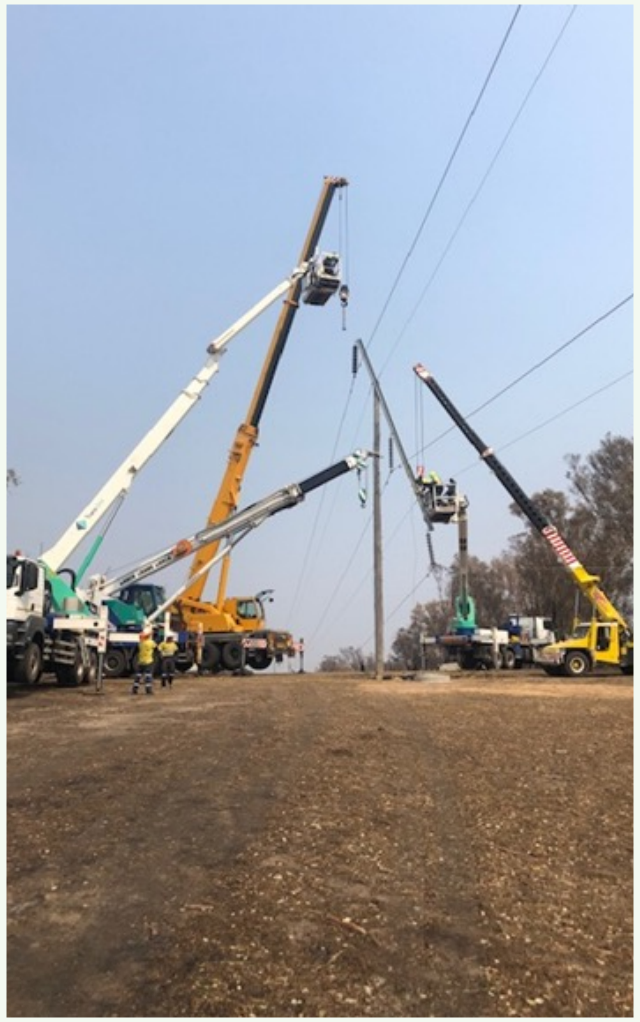
Case Study 2: Impact of the 2019–20 bushfires

The 2019–20 NSW Black Summer bushfires caused unprecedented damage to our network. Our staff worked tirelessly through the 2019–20 summer, coordinating with the Energy Utilities Functional Area Coordinator and NSW Rural Fire Service (RFS), to undertake emergency repairs in difficult, hot, dusty and smoky conditions. This helped us to ensure damaged but critical transmission network assets could be returned to service safely and quickly, as we supported the community by maintaining the supply of electricity.

For example, on 4 January 2020, southern NSW faced extreme fire danger conditions with many fires burning at emergency warning levels. The intensity and scale of the fires in this area caused extensive network damage resulting in the separation of the NEM between NSW and Victoria. This fire damage caused the collapse of a wood pole transmission line resulting in a loss of supply to the Tumut area, where towns in the area were under threat from bushfires. The collapsed poles also dropped wires over the Snowy Mountains Highway. This closed safe-access along the highway which was a critical access route for the RFS at the time.

Our crews immediately responded with the support of the RFS to access the fire zone, undertaking emergency works to restore supply and allow the highway to be reopened to RFS crews. This critical work supported the community and our customers at a time of emergency.

When undertaking condition-based replacement of our wood poles, we replace these with modern resilient alternatives (steel or concrete).

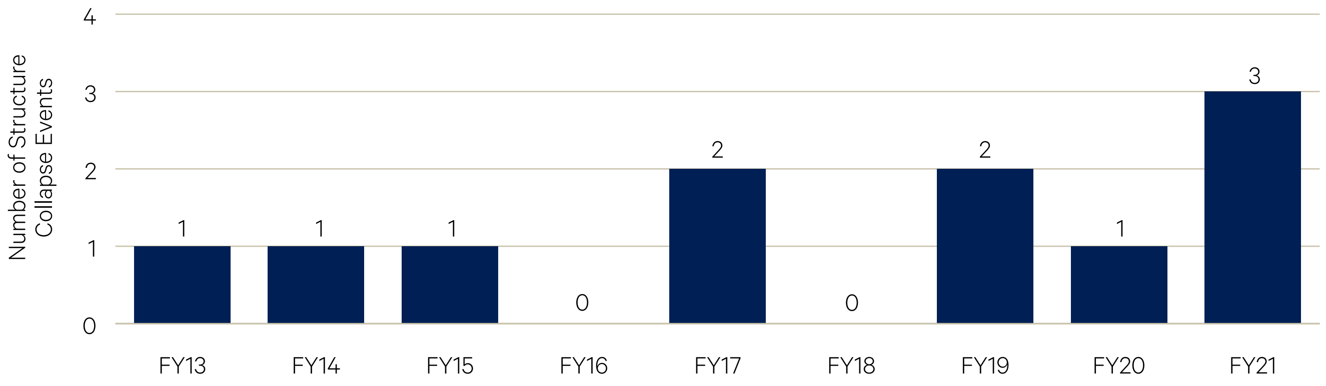


Floods and extreme winds

Figure 4-14 shows an increasing trend in transmission line structure collapse events during storms and extreme winds.

There were six separate events from 23 March 2019 to 28 December 2020 when our transmission structures collapsed due to extreme winds. We restored these structures, including by rebuilding an entire 5.6 kilometre section of transmission line damaged in a storm on 1 December 2020. We reprioritised our works programs to perform these works in order to maintain the security and reliability of our network expected by our customers.

Figure 4-14: Structure collapse events



In March 2021, extreme rainfall led to widespread floods in NSW including Sydney, which experienced the worst flooding in 60 years.[92] The then NSW Premier, Gladys Berejiklian, described the event as 'one in 100-year' flooding. Many of our assets were affected by the flood waters. We responded to this by inspecting the assets to ensure public safety once the flood waters receded and performing repair works.

Figure 4-15: Worst flooding in NSW in 60 years

92 Jose, Jill Gralow, Renju, Australia to rescue thousands as Sydney faces worst floods in 60 years 22 March 2021

COVID-19 pandemic

The COVID-19 pandemic has, and continues, to present challenges for us, our business partners and supply chains, our customers and other stakeholders.

Our highest priority during the pandemic has been the health, safety and wellbeing of our communities, customers, employees and delivery partners.

The COVID-19 pandemic has impacted the cost and availability of equipment needed to deliver our projects. There have been, and continue to be, delays in manufacturing and delivery of equipment as shipping and land freight are affected by COVID-19 related restrictions. We have responded by changing our business practices and finding new innovative approaches to deliver our projects and programs on time and on budget.

We provided financial relief to customers impacted by COVID-19 during April – June 2020 in the following circumstances:

- rebates for small business customers who experienced financial stress and whose businesses were mothballed
- rebates for residential customers of small retailers who defaulted, and
- deferred charges for residential customers of large retailers who went on payment plans or hardship arrangements.

4.3 Energy transition

AEMO's 2020 ISP identifies the optimal development path for the NEM. The ISP is a whole-of-system plan to deliver the lowest cost energy solutions for customers consistent with an electrified, low carbon future.

As discussed in section 1.1.5, in the 2018–23 regulatory period, we are delivering three nationally significant actionable ISP projects identified in AEMO's optimal development path – Project EnergyConnect, QNI Minor Upgrade and the VNI Minor Upgrade. These projects are critical to ensuring the security and reliability of the NEM as well as enabling the energy market transition. We will also deliver HumeLink and VNI West subject to receiving regulatory approvals from AEMO and the AER and the necessary land access and environmental and heritage approvals.[93]

In October 2021, we published our Energy Vision to better understand what our energy future could look like. We partnered with independent experts, CSIRO, ClimateWorks Australia and The Brattle Group to model the implications of a range of scenarios on the evolution of our energy system over multiple regulatory periods.

Our Energy Vision explores six possible futures for our energy system to 2050 by comparing them against their level of decarbonisation, decentralisation and the underlying electricity consumption in 2050. In all future scenarios, our modelling shows that renewable energy will supply the vast majority of Australia's electricity production by 2050. AEMO's NEM Engineering Framework Initial Roadmap, finds that by 2025 the NEM could reach up to 100 per cent instantaneous renewables at times.[94]

Our transmission system is a key enabler of Australia's energy transformation. It is essential for connecting new, low-cost, renewable generation as coal retires and supporting the uptake of electric vehicles and renewable energy adoption by industry.[95] AEMO's Draft 2022 ISP finds that transmission projects on its optimal development path will 'add $29 billion in value while enabling the transformation' and that these investments return '2.5 times' their investment value.

More information on our Energy Vision can be found on our website.

As discussed in Chapter 2, our customers strongly support the energy transition and investment that delivers on the objectives of lowering emissions in our economy.

93 We published the Project Assessment Conclusions Report (PACR) on 29 July 2021. We will shortly submit our feedback loop request to AEMO in accordance with the new ISP Rules and subject to AEMO confirming that HumeLink remains on the optimal development path, we will submit our initial Contingent Project Application to the AER.
94 AEMO, NEM Engineering Framework Initial Roadmap, December 2021.
95 Industry is the largest user of energy in Australia, and around two thirds of that energy is used to produce heat for industrial and other processes. Electrification of industry will occur as coal and gas fired industrial boilers are converted to electricity. Electrification of industry and the economy provides material emissions reduction toward meeting Australia's net zero target ARENA.

4.4 Technology and innovation

Innovation is critical to help us increase productivity and improve customer outcomes. We have established strategic partnerships with industry partners, contracting suppliers and other third parties to identify projects and approaches that improve affordability and safety and address climate change.

In the current period, amongst other things, we:

- partnered with ARENA to deliver the Sydney West battery at Wallgrove, which is the first grid-scale battery in NSW. We are trialling the use of batteries to provide synthetic inertia, which could be a lower cost solution to meet future inertia shortfalls in the NEM, driving down costs for customers.
- installed a non-network solution – SmartValve modular power flow converters (MPFC) at Stockdill and Yass – to increase network capacity and reduce congestion. SmartValve MPFC is proprietary technology that was identified as forming part of the preferred option for the VNI minor upgrade under the RIT-T, which is an open process that allows all potential proponents of alternative solutions to participate
- will use guyed towers to significantly reduce our delivery costs for Project EnergyConnect. This approach was identified through the competitive procurement process
- are installing synchronous condensers to assist with system strength on our network[96]
- implemented our industry leading digital substation strategy to develop and install IEC 61850 digital technology at new and existing substations. By reducing the amount of cabling and panels required at the sites this results in improved safety and lower costs, and
- retro-fitted a low sag high temperature conductor on one of our transmission lines. This is the first time this particular conductor has been used in Australia, to allow increased renewable generation and provide market benefits without the need to rebuild the transmission line.

We have reflected the benefits of these successful recent innovations in this proposal. We will continue to pursue a range of innovation initiatives, although at this stage we have not proposed any specific innovation expenditure for the 2023–28 period. We will continue to engage with customers and other stakeholders about innovation initiatives and whether they should be reflected in our Revised Revenue Proposal.

We have included projects under the AER's NCIPAP and DMIAM schemes as discussed in Chapters 14 and 15.

As discussed in Chapter 2, all customer segments have indicated strong support for investment in innovation and research, particularly to support the energy transition and improve affordability

4.5 Supporting documentation

The following documents support this Chapter and accompany our Revenue Proposal.

Name
Augex Overview Paper
Repex Overview Paper
Non-network ICT Overview Paper
Non-network Other Overview Paper
Energy Vision
HoustonKemp, Efficiency of Transgrid's Base Year Operating Expenditure
HoustonKemp, Assessment of Transgrid's benchmarking performance

96 System strength is required to keep the power system stable. It has historically been supplied by coal and gas generators. The transition to renewable generators has reduced the supply of system strength

5. What we will deliver in 2023–28

This Chapter details the outcomes we will deliver in the 2023–28 regulatory period for the matters that our customers have told us that they value most – an affordable, safe, secure, reliable and sustainable energy supply.

Key messages

In the 2023–28 regulatory period, we will meet our customers' priorities by:

> **Affordability** – based on this proposal, from 30 June 2023 to 30 June 2028, we expect to deliver transmission cost savings of $19.55 per annum for residential customers and $73.05 per annum for small business customers, which in both cases is a 13.4 per cent reduction over this period. Delivering these savings will depend on the outcome of this revenue determination process.

> **Safety, security and reliability** – we will:

- maintain the long-term condition of our assets, particularly our transmission lines and digital infrastructure, in order to maintain our network risk and reliability performance
- replace assets with more climate-resilient alternatives, where the opportunity arises, through our condition-based replacement, such as replacing deteriorated timber poles with concrete or steel poles
- enhance our cyber and physical security capability to meet the Australian and NSW Governments' new obligations, and
- ensure our non-network assets, including property, fleet plant and equipment, continue to support our core services as we deliver an increasing capital program including major ISP projects.

> **Rapid localised demand growth** – we will undertake network investments in western Sydney, north west Sydney, North West Slopes and central and far west NSW. These investments will address load growth and enable compliance with mandated voltage stability and thermal limits and reliability standards.

> **Energy transition** – we will invest in maintaining network stability and security in response to the rapidly changing mix and location of generation, as the energy system transitions to renewable technology. We will deliver projects in accordance with AEMO's ISPs and the NSW Electricity Infrastructure Roadmap, as they are required. The costs of these projects are therefore not included in our expenditure forecasts and customers will only pay for these projects if AEMO and the NSW Government determine that they are needed.

Key messages (continued)

> **Technology and innovation** – innovation activities are embedded across our business and are part of the way we operate. We have reflected the benefits of successful recent innovations in our revenue forecasts although at this stage have not included any specific innovation expenditure in our 2023–28 forecasts. We will continue to engage with customers and other stakeholders about innovation initiatives and whether they should be reflected in our Revised Revenue Proposal, and

> These priorities have been developed through extensive stakeholder engagement and consultation in the development of this Revenue Proposal.

5.1 Affordability

Based on this proposal, from 30 June 2023 to 30 June 2028, we expect to deliver transmission cost savings of $19.55 per annum for residential customers and $73.05 per annum for small business customers, which in both cases is a 13.4 per cent reduction over this period. Delivering these savings will depend on the outcome of this revenue determination process.

In support of these cost savings, we:

- propose capex forecasts that are broadly in line with our expected capex for the current period, but particularly focus on delivering a safe and reliable network as our assets age and condition-related issues increase. Except for $39.6 million of capex to relieve generator constraints and improve operational response, this Revenue Proposal includes no discretionary or uncertain capex and does not include capex for major projects currently under-going a RIT-T, identified in AEMO's ISP or the NSW Electricity Infrastructure Roadmap. We will:
  - use the AER's uncertainty mechanisms, and the actionable ISP rules, to deal with any additional capex that becomes necessary during the period, and
  - include in our Revised Revenue Proposal the costs of major projects once their RIT-T has been completed.
- propose opex forecasts based on the base-step-trend forecasting method. This reflects:
  - savings arising from using the 2021–22 opex as the base-year. We expect our 2021–22 opex will be $11.9 million below the AER's allowance for that year, which results in savings of $59.6 million to our customers in the 2023–28 period (compared to our base year allowance),[97] and
  - savings of $14.3 million in 2023–28 by using a 0.5 per cent per annum productivity adjustment.
- have not at this stage included:
  - a real increase in materials costs in our expenditure forecasts, although we note that in October 2021, Infrastructure Australia forecast that renewable energy and transmission construction will significantly add to steel and concrete demand.[99] This is likely to lead to real materials costs increases. In December 2021, AEMO's Draft 2022 ISP also forecast that the acceleration in global infrastructure and energy investment over the next two decades will significantly increase demand for expertise, materials, and equipment, putting pressure on costs for transmission projects.[98] In our Revised Revenue Proposal, we will revisit this matter in consultation with our customers and other stakeholders, and
  - any cost impacts associated with the long-term effects of the COVID-19 pandemic given that the economic effects are still highly uncertain.
- are efficient in terms of cost and service performance compared to our peers. The AER's November 2021 'Annual Benchmarking Report for Electricity Transmission Network Service Providers' shows that we are efficient in both absolute and trend terms, with our productivity performance ranking in the middle in comparison with our peers, and improving over time, and
- have incorporated the benefits of successful recent innovation activity. We will continue to pursue a range of innovation initiatives across our network and business, although at this stage we are not proposing any specific innovation expenditure allowance for the 2023–28 regulatory period.

97 Calculated by multiplying the base year underspend of $11.9 million by five years ($11.9 million x 5 years = $59.6 million).
98 Infrastructure Australia: Market capacity for electricity generation and transmission projects, October 2021 report.
99 AEMO, Draft 2022 Integrated System Plan, December 2021, p. 15.

5.2 Safety, security and reliability

Safety, security and reliability are fundamental to our service offering in an increasingly complex operating environment. We will:

- renew and replace deteriorated and obsolete network assets to maintain the long-term condition of our assets. This represents most of our Repex, which comprises more than half of our total capex
- use condition-based assessments to replace assets with more resilient alternatives so that our network withstands more frequent, intense and longer climate-driven extreme weather events. This helps to deliver affordability by minimising our capex requirements and is consistent with GHD's independent finding that our network is currently resilient, however climate change has the potential to erode this resilience
- align with the Australian and NSW Governments' new cyber and physical security obligations through:
  - network related digital infrastructure (operational technology equipment)
  - cyber security ICT investments
- rollout new ICT and continue to refresh or replace legacy applications and systems at the end of their lives that support our core business
- deliver safe, compliant and productive offices and depots that support the increase in network operations activity as we deliver an increasing capital program including major ISP projects
- provide fit for purpose fleet, plant and equipment that allows us to access and undertake work on our network, and
- improve our operational response to contingency events through special control and protection schemes.

Managing the risk of deteriorating wood pole condition on Line 86 (Tamworth to Armidale) will be a key project in the 2023–28 regulatory period and is critical to maintain safety, reliability and security of our network. This project is currently subject of RIT-T. We will update our capex forecasts for the preferred option, as appropriate, in our Revised Revenue Proposal. This project is discussed further in our Augex Overview Paper.

Figure 5-1 shows that we expect to maintain our network risk index over the 2023–28 regulatory period. The risk index returns to baseline levels in 2028–29 once the risk reduction benefits from works commissioned in 2027–28 are realised, noting that benefits start to be realised the year after commissioning.

Figure 5-1: Network risk index 2023–28 regulatory period

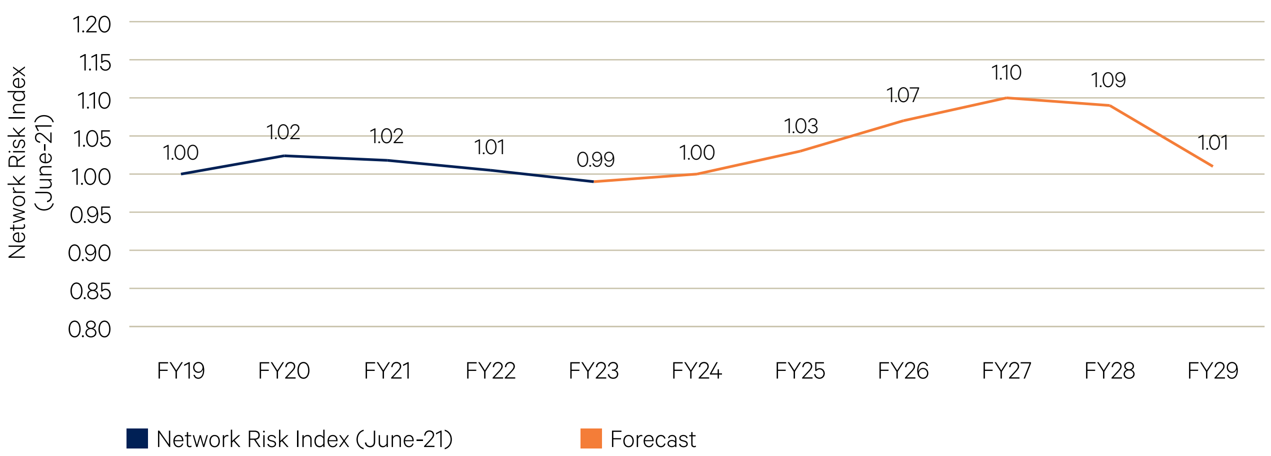
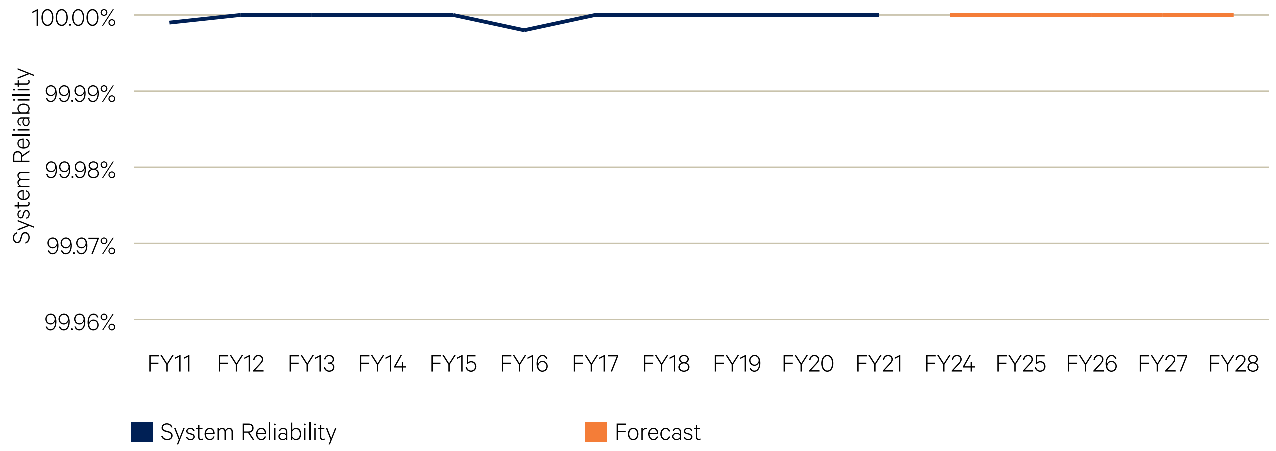


Figure 5-2 shows that based on our 2023–28 capex program, we expect to maintain a consistently high level of reliability over the next regulatory period.

Figure 5-2: Expected annual network reliability 2023–28 regulatory period



5.3 Rapid localised demand growth

We will meet rapid growth to serve strong maximum demand growth in regions such as western Sydney (Western Sydney Priority Growth area), north west Sydney (Vineyard), North West Slopes (Tamworth, Gunnedah and Narrabri), central west NSW (Bathurst, Orange and Parkes as well as Beryl) and far west NSW (Broken Hill). Our proposed investment will address this load growth and to comply with mandated voltage stability and thermal limits and reliability standards. This is discussed further in Chapters 3 and 8 of this Revenue Proposal and in our Augex Overview Paper.

The projects to supply the North West Slopes and central west NSW are currently the subject of RIT-Ts. We have therefore not included the costs of these projects in our capex forecasts, because the preferred option has not yet been identified. We will update our capex forecasts for the preferred options, as appropriate, in our Revised Revenue Proposal. The Transgrid Advisory Council (TAC) supports this approach, as it delivers on the affordability imperative by only including known costs that will be incurred in our capex forecast.

5.4 Energy transition

As discussed in Chapter 3, a key operational challenge in the 2023–28 regulatory period is maintaining network stability and security due to the rapidly changing mix and location of generation, as the energy system transitions to renewable technology. We will address:

- more widespread network congestion, as renewables connect in the weaker parts of our network. This is illustrated in Figure 5-3.
- NER compliance obligations relating to:
  - maintaining voltage stability within prescribed limits. The rapid uptake of household solar PV is causing voltage levels to exceed these limits as minimum demand reduces
  - increasing fault levels in southern NSW, as we undertake major ISP projects, including Project EnergyConnect, HumeLink and VNI West, and connect new renewable generator connections, including Snowy 2.0, and
  - system strength and inertia, as we will provide services where AEMO declares that there is a projected system strength gap or an inertia gap.

In response, our 2023–28 capex forecasts include:

- $22.1 million to relieve network congestion and enable additional generation from low cost and low emission sources to support our customers' sustainability and affordability objectives. This expenditure includes:
  - increasing capacity of 132 kV busbars at Wagga Wagga Substation ($5.2 million)
  - increasing capacity for generation in Wagga north area ($10.3 million), and
  - increasing capacity for generation in the Molong to Parkes area ($6.6 million). This is discussed in Case Study 3.
- $34.7 million in voltage control devices in southern NSW (Kangaroo Valley, Darlington Point and Buronga), north west NSW (Moree and Inverell) and Greater Sydney (Beaconsfield).

Case Study 3: Lower costs through innovation

Central west NSW is an area that has seen a rapid increase in solar generation since 2017. 340 MW of solar generation has already connected in the Molong and Parkes area and another 270 MW of solar generation is expected to connect in the next three years. Constraints in transmission network capacity in this area currently result in the curtailment of 130 GWh per annum of this low-cost renewable generation.

We have identified an opportunity to alleviate this network congestion and provide market benefits by increasing the capacity of a 132kV transmission line between Molong and Orange north. This upgrade will utilise an innovative 'high temperature low sag' conductor technology to replace the existing conductor. This will unlock the extra capacity at a cost that is up to five time lower than the traditional approach of rebuilding the transmission line, providing net economic benefits of $43 million over the life of the asset.

We have also included the following as contingent projects to:

- manage increased fault levels in Southern NSW – $51.1 million to comply with the NER fault levels in southern NSW, as new generators connect and we invest in ISP projects in southern NSW
- meet the NSW system strength requirement (for the transitional period until the new rules are in full effect), and
- meet the NSW system inertia requirement.

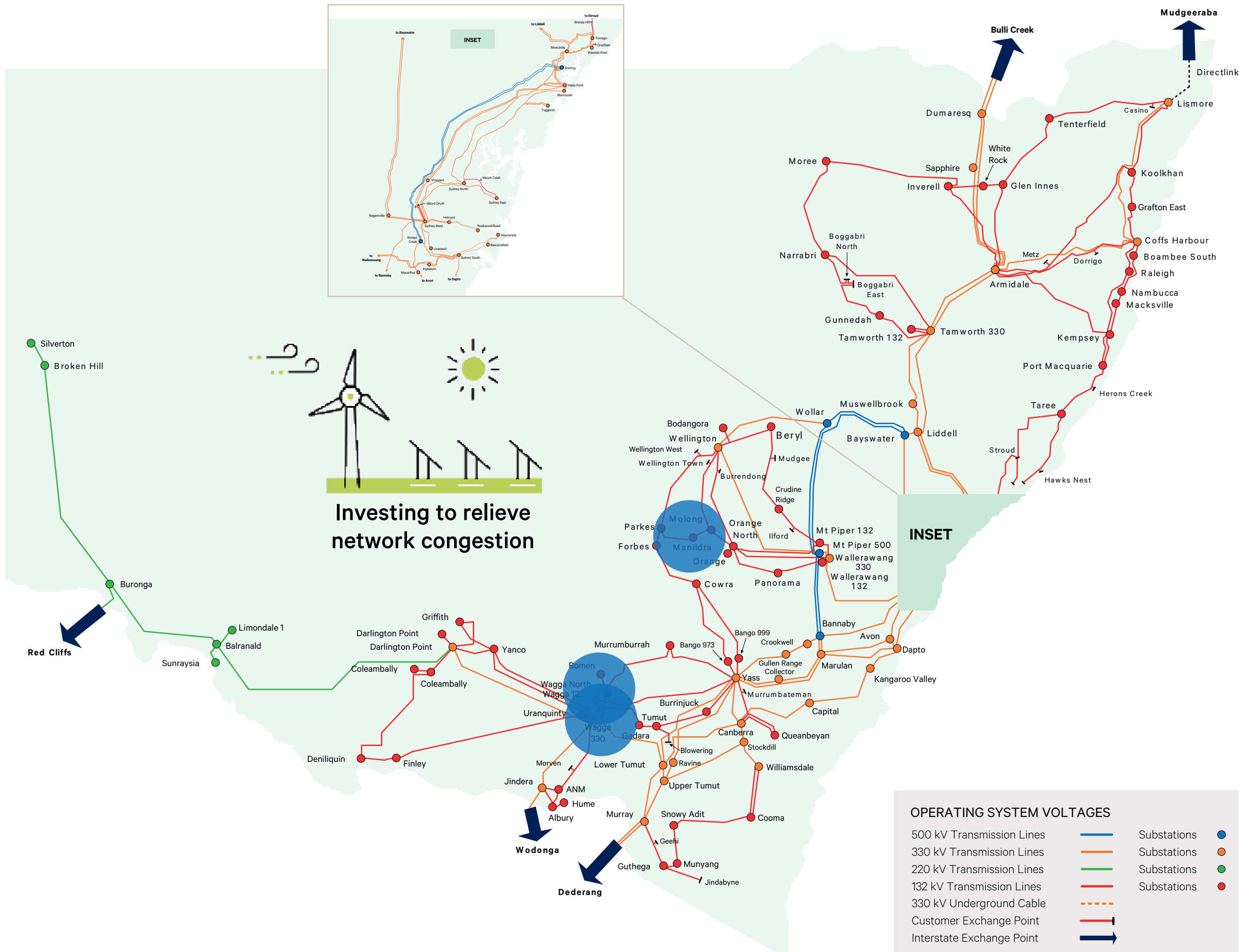
We have treated these as contingent projects (rather than included the costs in our Augex forecast) given their uncertainty. Both the system strength and inertia projects would be triggered if AEMO declares or forecasts a shortfall in either, noting that:

- shortfalls in system strength can be met by additional new generation (either synchronous or with grid forming inverters), greater interconnection, synchronous condensers or grid forming batteries, and
- a secure level of inertia may be achieved using traditional plant such as synchronous condensers with flywheels or through emerging technology such as synthetic inertia and fast frequency response devices, such as the grid-scale battery we are currently piloting in western Sydney.

These investments are discussed in Chapter 8 and our Augex Overview Paper.

We will deliver projects in accordance with AEMO's ISPs and the NSW Electricity Infrastructure Roadmap, as they are required, which will facilitate the uptake of new low cost renewable generation. We will adhere to the NER automatic contingent project provisions for Actionable ISP projects and the EII Regulations for NSW Electricity Infrastructure Roadmap projects. The costs of these projects are therefore not included in our expenditure forecasts and customers will only pay for these projects if, after public consultation, AEMO and the NSW Government determine that they are needed and their costs have been assessed as prudent and efficient by the AER.

Figure 5-3: More widespread congestion



5.5 Technology and innovation

Innovation activities are embedded across our business and are part of the way we operate. We have reflected the benefits of successful recent innovations in our revenue forecasts although at this stage we are not proposing specific innovation expenditure for the 2023–28 regulatory period. We will continue to engage with customers and other stakeholders about innovation initiatives and whether they should be reflected in our Revised Revenue Proposal.

In the 2023–28 regulatory period, we will continue to:

- work closely with customers and other stakeholders, including through the RIT-T process, to help identify low-cost non-network alternatives to traditional network options
- improve our external collaboration including with suppliers, universities, industry bodies and other organisations to accelerate the identification and development of new technologies. Our aim is to identify feasible ideas that can move into the generation of pilot projects
- continue to develop our innovation culture including through collaboration across the organisation, improved problem solving skills, promoting diversity and inclusion and strengthen employee engagement
- use our Startup Garage,[100] which we plan to establish in 2022–23, to collaborate closely with innovators to share our technical expertise and knowledge to make their solution development successful and customise it to our needs, and
- where there are net benefits, undertake pilot projects to test latest technologies as a basis for longer-term roll-out as solutions across the energy network (e.g. similar to the NSW Grid Battery project).

As discussed in Chapters 14 and 15 we will identify projects for inclusion in:

- the AER's Network Capability Incentive Parameter Action Plan (NCIPAP), which encourages low cost one-off projects that improve network capability at times when it is most needed and provide value for money to customers, and
- the AER's Demand Management Innovation Allowance Mechanism (DMIAM), which encourages new demand management solutions that have the potential to reduce long-term network costs by reducing ongoing or peak demand.

5.6 Supporting documentation

The following documents support this Chapter and accompany our Revenue Proposal.

Name
Augex Overview Paper
Repex Overview Paper
Non-network ICT Overview Paper
Non-network Other Overview Paper
Forethought, Transgrid Revenue Reset Stakeholder Engagement – Executive Report
HoustonKemp, Efficiency of Transgrid's Base Year Operating Expenditure

100 A start-up garage enables us to identify ideas early and leverage the insights from working with the start-ups to minimise risks and allocate investments better. Feasible ideas identified will move into the generation of pilot projects

6. Response to Framework and Approach Paper

Key messages

> We accept the AER's final Framework and Approach (F&A) paper and have reflected its positions in our Revenue Proposal.

> We note the AER's intention to review our service classification as part of its Draft Decision on our Revenue Proposal.

> We accept the AER's proposed positions on the application of incentive schemes, including the:

- Service Target Performance Incentive Scheme (STPIS)
- Efficiency Benefit Sharing Scheme (EBSS)
- Capital Expenditure Sharing Scheme (CESS)
- Small Scale Incentive Scheme (SSIS)
- Demand Management Innovation Allowance Mechanism (DMIAM).

> We note the AER intends to review the current version of its STPIS, EBSS and CESS in light of the concerns that we and other TNSPs have raised. We look forward to participating in the AER's review of these schemes and understand that the updated versions will be published in the second half of 2022 and will be reflected in the AER's Final Decision on our 2023–28 Revenue Proposal.

> We note the AER's intention to:

- forecast depreciation to determine the Regulatory Asset Base (RAB) at the start of the subsequent period
- work with us to develop a 'sandbox' waiver process
- apply its expenditure forecast assessment guideline to assess our capex and opex forecasts for the next regulatory period, and
- apply its framework for customer engagement when assessing our Revenue Proposal.

6.1 Introduction

On 30 July 2021, the AER published its F&A for our 2023–28 regulatory period.[101] The F&A is the first step in the Revenue Determination process and sets out the AER's proposed approach in relation to the application of incentive schemes and other guidelines, as well as its approach to calculating regulatory depreciation.

We support the AER's Final F&A paper and have reflected its positions in this Revenue Proposal. Our primary concern is ensuring that the incentive schemes that apply in the 2023–28 regulatory period remain relevant and fit-for-purpose.

We outline below our response to the F&A paper together with our consideration of incentive schemes.

6.2 Service classification

On 27 April 2020, we submitted a Rule change proposal to the AEMC seeking confirmation that system strength services are a prescribed transmission service. System strength is a critical service that supports Inverter Based Resources (IBR), such as wind and solar generation, as well as batteries, which are rapidly becoming a key part of the NEM generation mix.

On 29 April 2021, the AEMC published a draft decision[102] requiring system strength to be provided by TNSPs and has made a final rule determination in October 2021.

In its F&A paper, the AER has advised that it will review our service classification in light of the outcomes from the AEMC's final Rule determination as part of its Draft Decision on our Revenue Proposal.

6.3 Incentive schemes and mechanisms

The NER provides incentive schemes to encourage maintaining and improving service levels, capex and opex efficiencies and demand management. We accept the AER's proposal to:

- apply the STPIS,[103] EBSS,[104] CESS,[105] and DMIAM, and
- not apply the SSIS because we did not propose a detailed scheme developed in conjunction with our customers.

We have previously raised concerns about certain aspects of the expenditure incentive schemes.[106] In particular, that:

- in relation to the EBSS, we are concerned that the recent falls in the discount rate have reduced the target sharing ratio compared with the 30 per cent applying under the CESS, and
- in relation to the Market Impact Component (MIC) of the STPIS, we are concerned that the growth in renewable generation is materially increasing the number of constraints on our network. This means we are not able to achieve our targets, which are based on historical data and do not reflect expected future outcomes.

The AER has acknowledged our concerns, and similar concerns raised by other TNSPs and advised that it intends to shortly commence a broad review the CESS, EBSS and STPIS to ensure that they remain relevant and fit-for-purpose. We look forward to participating in the AER's review of these schemes and understand that the AER is aiming to finalise its review in the second half of 2022 and the updated versions of these schemes will be incorporated in the AER's Final Decision on our 2023–28 Revenue Proposal.

Chapters 12, 13, 14 and 15 detail how we have applied the EBSS, CESS, STPIS, and DMIAM in this Revenue Proposal.

101 AER, Framework and Approach Transgrid – Regulatory control period commencing 1 July 2021, 30 July 2021
102 AEMC, Draft Rule Determination – Efficient management of system strength on the power system, 29 April 2021
103 Version 5 of the STPIS
104 Version 2 of the EBSS
105 Version 1 of the CESS
106 Transgrid, Request for an updated or replacement Framework and Approach, 30 October 2020

6.4 Regulatory depreciation to establish the RAB for subsequent periods

We note and support the AER's intention to apply forecast depreciation to determine our RAB at the start of the subsequent regulatory period, commencing on 1 July 2028. We agree that, in combination with the proposed application of the CESS, this approach will maintain incentives for us to pursue capex efficiencies. Our proposed approach to determining the regulatory depreciation building block for the next regulatory period is set out in Chapter 9.

6.5 Regulatory sandbox arrangements

We note the AER's intention to work with us to develop a sandbox waiver process within which participants can test innovative concepts in the market under relaxed regulatory requirements at a smaller scale, on a time-limited basis and with appropriate safeguards in place.

We look forward to working with the AER to develop a sandbox waiver process that is focussed on supporting a better process for reform in the long-term interests of customers.

6.6 Expenditure Forecast Assessment Guideline

We note the AER's intention to apply its Expenditure Forecast Assessment Guideline to assess our capex and opex forecasts for the 2023–28 regulatory period. We have had regard to this guideline in preparing our opex and capex forecasts in Chapters 7 and 8 of this Revenue Proposal.

6.7 Approach to stakeholder engagement

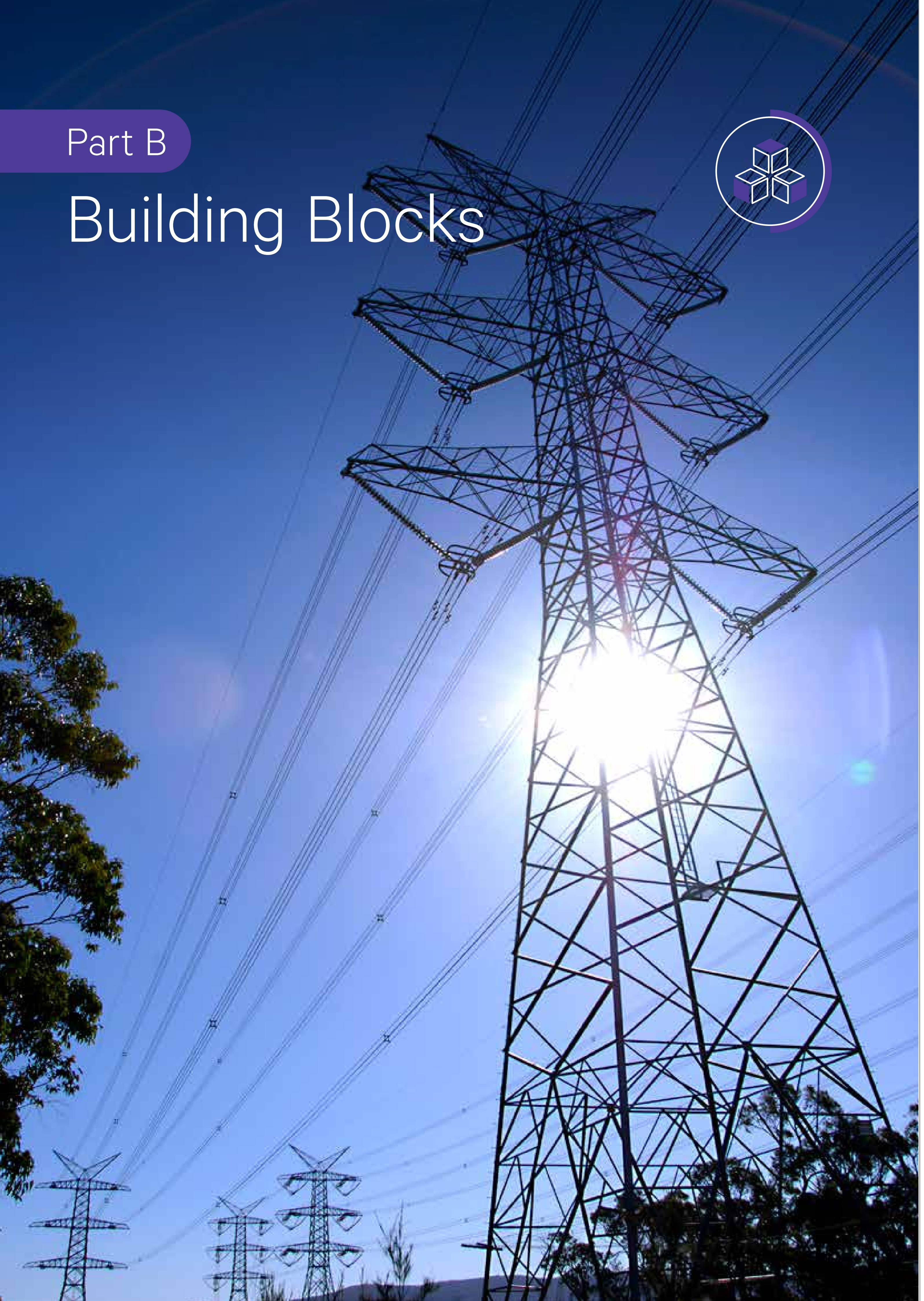
The AER provided guidance on how it will assess whether we have genuinely engaged with our customers and other stakeholders in the development of our 2023–28 Revenue Proposal.

Chapter 2 explains how we have engaged with our customers and other stakeholders, and the changes we have made to the positions and proposals in this Revenue Proposal based on the feedback we have received. Chapter 2 also explains how we have addressed each aspect of the AER's customer engagement framework.

6.8 Supporting documentation

The following documents support this Chapter and accompany our Revenue Proposal.

Name
Expenditure Forecasting Methodology
Request for an updated or replacement Framework and Approach



7. Opex forecasts

Key messages

> We have applied the base-step-trend method to forecast our opex, which is the AER's preferred forecasting method.

> We benchmark strongly against our peers. The AER's benchmarking, and the independent analysis that we have commissioned from HoustonKemp, shows that our historical opex is efficient and that we are continuing to respond to the incentives in the regulatory framework to further improve our opex productivity over time.

> We are using 2021–22 opex as the base year opex. We expect our base year opex to be $11.9 million below the AER's opex allowance for that year reflecting the operational efficiencies we have achieved. This will result in savings of $59.6 million to our customers in the 2023–28 period (compared to our base year allowance).

> We have included step changes in our opex forecast for externally driven costs that we will incur that are not in our base year opex and are too material for us to absorb costs in the 2023–28 regulatory period. These step changes are supported by our customers and relate to:

- insurance premiums
- cyber and critical infrastructure security, and
- ISP preparatory activity.

> We have included a productivity growth improvement of 0.5 per cent per annum, which reduces our total opex by around $14.3 million in the 2023–28 period.

> Our total forecast opex for the 2023–28 regulatory period is $1,015.0 million (including debt raising costs). This is $47.1 million, or 5.0 per cent higher than our actual opex in the 2018–23 regulatory period, due to:

- the externally-driven step changes, and
- the growth in our network from delivering major ISP projects.

7.1 Overview

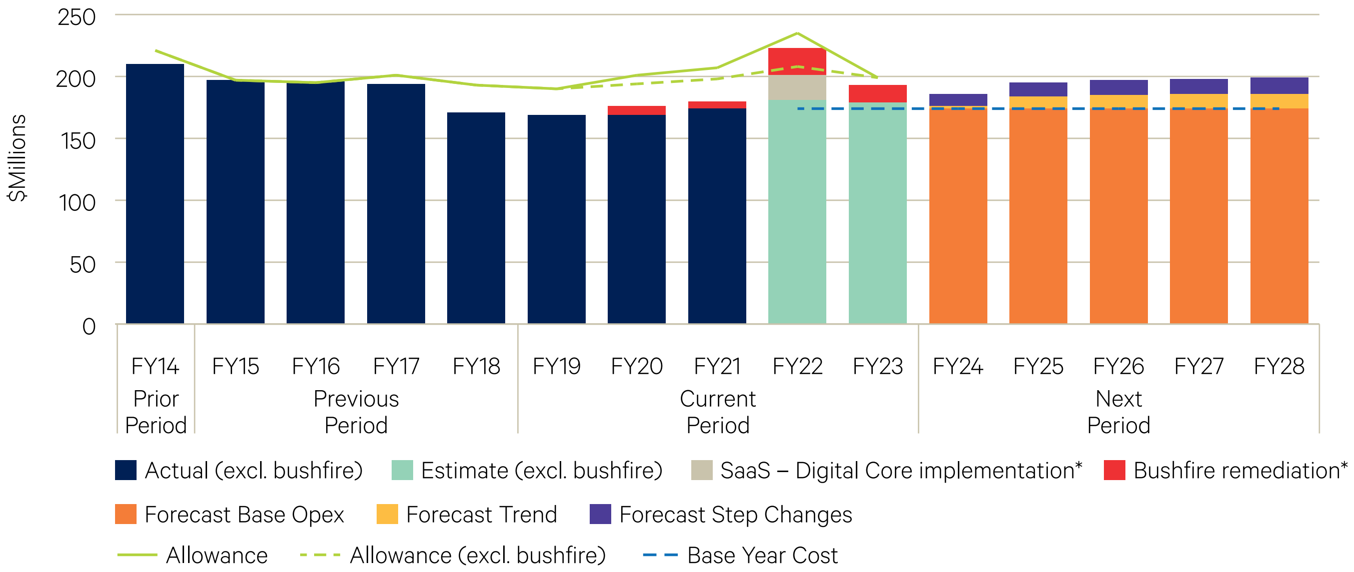
Our opex includes expenditure on inspections, asset maintenance and management, network operations, insurance, rates and (non-income and GST) taxes and corporate support functions that we need to incur to provide our prescribed transmission services to our customers.

This Chapter explains and justifies our opex forecast for our prescribed transmission services for the 2023–28 regulatory period. Our opex must comply with the Rules' requirements to submit an efficient opex forecast that is consistent with maintaining the quality, reliability and safety of supply. These objectives are supported by our licence requirements, a range of regulatory obligations and our customers' reasonable expectations that we should maintain supply quality, reliability and security.

We have used a base-step-trend approach to prepare our opex forecast for the 2023–28 regulatory period. Our opex forecasts include only opex that is properly allocated to prescribed transmission services in accordance with our Cost Allocation Methodology (CAM).

Figure 7-1 shows our actual and estimated opex for each year of the 2014–18, 2018–23 and 2023–28 regulatory periods compared to the AER's allowance. It shows that we expect our 2018–23 opex of $942.3 million, including bushfire remediation expenditure and excluding debt raising costs, to be $91.0 million (or 8.8 per cent) below the AER's allowance of $1,033.3 million, including the Bush Fire Allowance (BFA) and excluding debt raising costs.[107,108] Our efficiency savings relative to the AER's allowance show we are responding appropriately to the incentives under the regulatory framework, including the AER's EBSS. Our 2023–28 opex forecast will result in transmission costs savings of $59.6 million to our customers (compared to our base year allowance).[109]

Figure 7-1: Historical and forecast opex, $M, Real 2022–23, excludes debt raising costs[110]



* Includes estimates for FY22 to FY23

107 Adjusted for AER approved cost pass through – 2019–20 Bushfire season bushfire allowance of $49.8 million (nominal). Transgrid incurred/expects to incur the costs FY20, FY21 and FY22 and be compensated for them in FY23, FY24 and FY25. For the purposes of meaningful comparison we have aligned the adjustment to the 2018–23 AER opex allowance of the pass through costs to when they have been / expected will be incurred by us.

108 We expect our 2018–23 opex of $892.5 million, excluding bushfire remediation expenditure and debt raising costs, to be $97.3 million (or 9.8 per cent) below the AER's allowance of $989.8 million, excluding the BFA and debt raising costs..

109 Calculated by multiplying the base year underspend of $11.9 million by five years ($11.9 million x 5 years = $59.6 million).

110 This figure excludes allowed, actual and forecast debt raising costs. We discuss our debt raising cost forecasts in section 7.5.3.

As discussed in Chapter 4, we achieved opex efficiencies in the current regulatory period by:

- replacing manual process and systems, including for procurement and HR
- changing our operating model to streamlined management structures
- continually adapting our labour force to ensure it meets our ongoing needs
- improving our maintenance practices and activities, and
- improving planning and scheduling of work.

Table 7-1 compares our actual opex in the current and previous period with AER's allowance.

Table 7-1: Opex comparison ($M, Real 2022–23, excludes debt raising costs)

Opex	2014–18	2018–23	Difference $	Difference %
AER allowance	1,007.1	1,033.3	26.2	2.6
Actual	968.0	942.3	(25.8)	(2.7)

Table 7-2 compares our Revenue Proposal opex with the opex included in our Preliminary Revenue Proposal discussed with stakeholders, and the outcome from the current regulatory period. This shows that our opex forecast has reduced since our Preliminary Proposal because we have:

- applied the AER's latest productivity adjustment factor of 0.5 per cent per annum, which is an increase from 0.3 per cent that we applied in our Preliminary Revenue Proposal, and
- removed non-recurrent Digital Core costs from our 2021–22 opex base year.

Table 7-2: Opex comparison ($M, Real 2022–23, excludes debt raising costs)

Opex	Value	% change over 2018–23	% change over Preliminary Revenue Proposal
2018–23 actual	942.3	N/A	N/A
Preliminary Revenue Proposal	1,085.9	15.2	N/A
Revenue Proposal	989.3	5.0	(8.9)

7.2 Our customers and other stakeholders' input

In developing our opex forecast for the 2023–28 regulatory period, we have considered the priorities and preferences of our customers and other stakeholders outlined in Chapter 2 and explained in Forethought's Final Report[111].

On 5 October 2021, we published a Preliminary Revenue Proposal to invite feedback from our customers and other stakeholders on our key proposals and positions for the 2023–28 regulatory period. Overall, they supported our approach to forecasting opex, the drivers of our step changes and the level of our forecast opex. In particular, as discussed in Chapter 2, customers and other stakeholders support our proposed step changes in insurance premiums and cyber and physical security given their importance in maintaining a safe, secure and reliable supply.

Consistent with our customers' focus on affordability we reduced our forecast opex following consultation on our Preliminary Revenue Proposal.

111 Forethought Revenue Reset Stakeholder Engagement, Final Report (Phases 1 to 3), December 2021.

7.3 Key opex assumptions

Table 7-3 details the key assumptions underpinning our opex forecasts. Our Directors have certified the reasonableness of these key assumptions in accordance with clause S6A.1.2(5) of the NER, as discussed in Chapter 21 of this Revenue Proposal.

Table 7-3: Opex key assumptions

Key assumption	
1. Legislative and regulatory obligations	Our opex forecasts are based on our current legislative and regulatory obligations and our licence requirements.
2. Network reliability	Our opex forecast will maintain, but not improve, service outcomes consistent with clause 6A.6.6(a)(3)(iii) of the NER.[112]
3. Cost allocation and capitalisation	Our opex forecasts reflect our expenditure capitalisation policy and our CAM, which provides an appropriate basis for attributing and allocating costs to, and between, our prescribed transmission and other services.
4. Efficient opex base year	Our 2021–22 opex provides a reasonable basis for our opex forecasts and is representative of our requirements to sustainably provide our services
5. Opex trend assumptions	Our forecast changes in input costs, output growth and productivity are reasonable and appropriately reflect the trend in our future opex, given our (adjusted) opex base year and expected growth in RAB
6. Cost escalations	The cost escalations that we have applied in developing our opex forecasts are representative of the increased costs that we will incur in the next period[113]
7. Inflation	The inflation that we have has applied in developing our opex forecasts is representative of the inflation-related costs that we will incur in the next period and is consistent with the AER-preferred inflation forecasting method[114]
8. Cost pass throughs and contingent projects	The AER will approve our nominated pass through events and contingent projects

112 NER clause 6A.6.6, total forecast opex is required to maintain the quality, reliability and security of supply of prescribed transmission services
113 Real labor cost escalators are based on BIS Oxford Economic forecasts
114 AER, Regulatory Treatment of Inflation, Australian Energy Regulator, December 2020

7.4 Opex benchmarking

We support the AER's use of benchmarking as part of its framework for assessing TNSPs' efficient opex requirements.

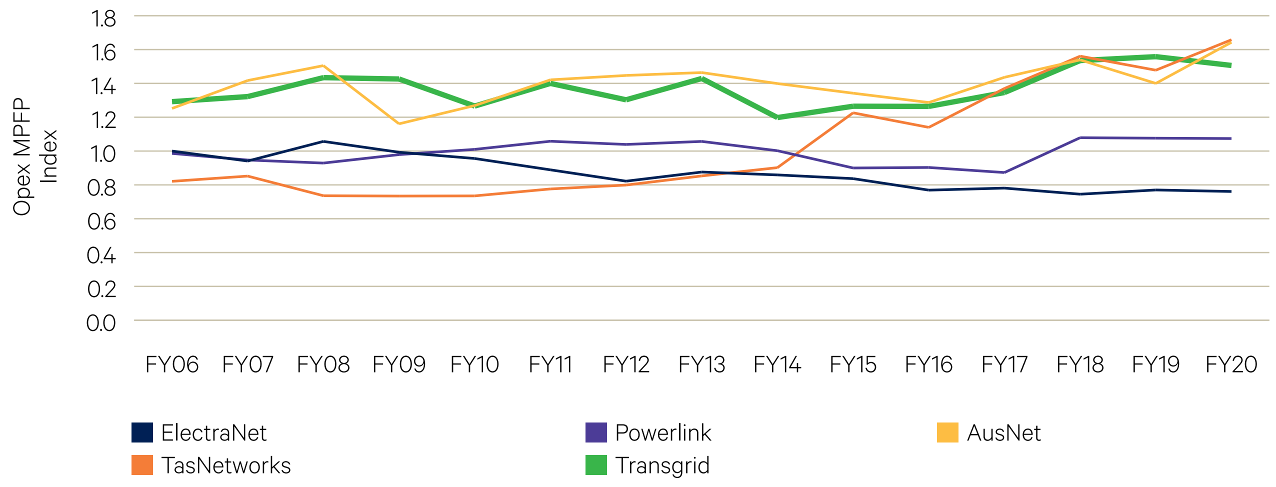
The AER uses economic benchmarking as one of several factors it considers in assessing and amending TNSPs' expenditure proposals. The AER recognises that the conclusions which can be drawn from TNSP benchmarking are limited, in part due to the limited sample size and the relatively early stage of development of benchmarking for TNSPs. The AER describes its use of benchmarking for TNSPs as important for a 'first pass' assessment to identify whether there are areas that may warrant further review. The AER's approach has been to assess a TNSP's response to the incentives under the regulatory framework to determine whether actual opex reflects efficient levels.

The AER uses multilateral partial factor productivity (MPFP) analysis to examine the productivity of a TNSP's use of opex. A MPFP index is a measure of productivity over time, formed as a ratio of a business's inputs and outputs. Figure 7-2 shows that:

- we are efficient in both absolute and trend terms, with our productivity performance ranking in the middle in comparison with our peers, and improving over time
- our improvement in productivity over time is consistent with us responding to the incentives under the regulatory framework to improve our efficiency, and
- our current level of opex productivity has improved relative to our opex incurred in 2016–17, which the AER deemed to be an efficient level of opex in its final determination on our 2018–23 revenue proposal.

It should be noted that TasNetworks' improved index value is unlikely to be reflective of an increase in the productivity for an efficient stand-alone TNSP as the data reflects outcomes of a combined distribution and transmission business.

Figure 7-2: Opex Multilateral Partial Factor Productivity (MPFP) 2005–06 to 2019–20



Source: Economic insights TNSP MTFP Tables and Charts, August 2021

As noted above, we commissioned independent analysis from HoustonKemp to assess our benchmarking performance having regard for the AER's benchmarking analysis.

HoustonKemp's analysis supports the AER's view that our historical opex is efficient in absolute terms and that we are continuing to respond to the incentives in the regulatory framework to further improve our opex productivity over time.

The AER's Benchmarking Report and HoustonKemp's analysis, including its category benchmarking analysis, find that we are efficient and have sustained this efficient performance over many years and are responding to the incentives that the regulatory regime presents.

7.5 Our opex forecasting approach

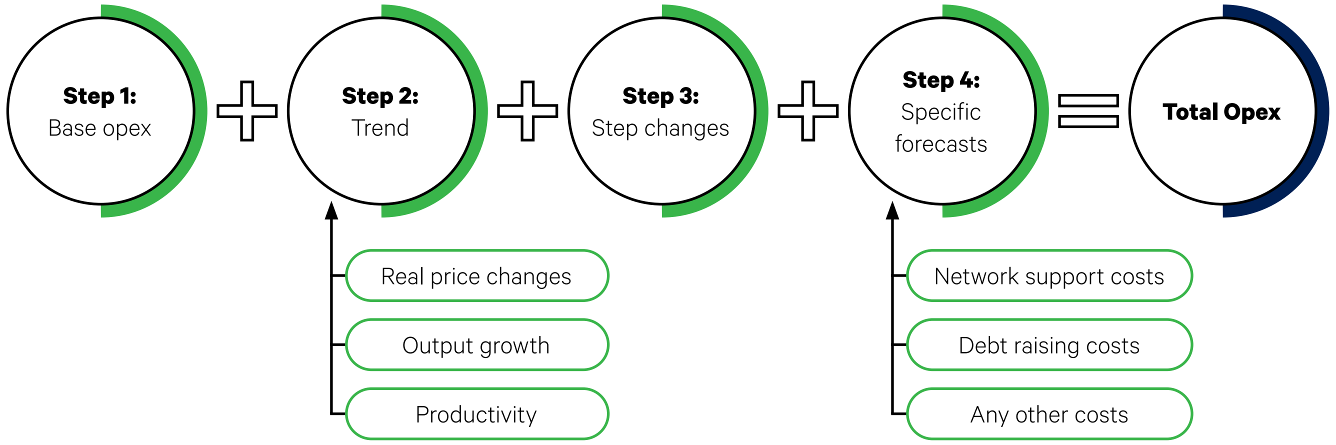
We have used a base-step-trend approach to forecast our opex for the 2023–28 regulatory period, except for our debt raising costs and network support costs. This is consistent with the approach that we proposed in our Expenditure Forecasting Methodology[115] submitted to the AER on 29 June 2021 and the AER's preferred approach for forecasting opex, as detailed in its Expenditure Forecast Assessment Guideline.

The base-step-trend approach involves a forecast developed at an aggregate level, rather than for each of the opex categories detailed in the AER's Economic Benchmarking Regulatory Information Notice (RIN).

Figure 7-3 overviews the four steps in the base-step-trend approach:

- Step 1 – nominate the efficient revealed cost base year (base opex). This includes applying adjustments to remove non-recurrent expenditure from the base year
- Step 2 – apply rate of change adjustments, which comprises three elements:
  - real price change in labour and non-labour prices
  - growth in output, and
  - productivity improvements
- Step 3 – add or subtract step changes, and
- Step 4 – add specific forecasts for any other costs that were not included within steps 1–3.

Figure 7-3: Opex forecasting approach



This approach reflects the AER's view that:[116]

- total opex is relatively stable and follows a predictable path over time, and
- the incentives to improve efficiency that arise from the various incentive schemes in the regulatory framework mean that, for a business that is responsive to those incentives, actual past opex should be a good indicator of future efficient opex.

115 Transgrid, 2023–28 Expenditure Forecasting Methodology, 30 June 2021
116 AER, *Expenditure forecast assessment guidelines for electricity transmission*, November 2013, p 22

7.5.1 Base year

We are using 2021–22 as the base year for our 2023–28 opex forecast. We have chosen 2021–22 opex because it represents a realistic expectation of the efficient and sustainable on-going opex that will provide our prescribed transmission services in the 2023–28 regulatory period:

- it continues the well-accepted regulatory practice of using the penultimate year in the current regulatory period, which is the most recent year for which audited data is available by the time of the final Transmission Determination, and
- we have achieved substantial efficiencies over the 2018–23 regulatory period through operational improvements and continually adapting our workforce to ensure it meets our ongoing needs. We expect our actual opex in our 2021–22 base year to be $11.9 million below the AER's opex allowance, reflecting the operational efficiencies we have achieved. Over the 2023–28 regulatory period this equates to transmission cost savings of $59.6 million (compared to our base year allowance).[117]

We have relied on our 2021–22 board approved budget opex for this Revenue Proposal, as actual data is not available at this time. We will update our base year opex to reflect our actual 2021–22 opex in our Revised Revenue Proposal which is due to the AER in November 2022.

SaaS implementation costs are now included as part of our base year opex

Due to recent changes in accounting standards, our 2021–22 base year includes $25.0 million associated with cloud computing arrangements, which are commonly referred to as Software as a Service (SaaS). Prior to April 2021, we capitalised certain SaaS costs associated with the implementation of software (e.g. customisation and configuration costs). In April 2021, the International Financial Reporting Interpretations Committee (IFRIC) published guidance which clarifies that these costs should be expensed rather than capitalised. We consulted with the AER on this change to accounting standards and the AER advised us that we should apply this change in the 2018–23 regulatory period. We have therefore revised our capitalisation policy for SaaS-related costs and expensed (rather than capitalised) these costs in our 2021–22 opex base year. However, not all of the $25.0 million SaaS costs we incurred in 2021–22 are recurrent, as some relate to one-off costs to replace our previous enterprise management system, Ellipse, which is approaching end of life. From 2022, Ellipse will no longer be supported by the service provider, ABB. We have therefore replaced Ellipse with a modular SaaS-based Enterprise Resourcing Planning (ERP) solution stack. We refer to this as our 'Digital Core' initiative. We have therefore made a negative base year adjustment of $20.2 million to remove the non-recurrent 'Digital Core' initiative costs for the purposes of forecasting our opex in the 2023–28 regulatory period.

Base year adjustments

We have made the following adjustments to our base year opex consistent with the AER's preferred approach and its recent transmission determinations:

- removed movements in provisions
- removed costs for bushfire remediation incurred in 2021–22, which are not expected to be recurring costs
- removed network support costs, and
- removed the non-recurrent component of SaaS costs, which were one-off costs relating to our 'Digital Core' initiative to replace our previous enterprise resource planning system, Ellipse, which is approaching end of life.

These adjustments are consistent with our customers' priority on affordability and are detailed in Table 7-4.

117 Calculated by multiplying the base year underspend of $11.9 million by five years ($11.9 million x 5 years = $59.6 million)

Table 7-4: Opex base year adjustments ($M, Real 2022–23)

Base year expenditure adjustment	Total $M, Real 2022–23	Reason for exclusion
FY22 opex budget	223.5[2]	
Less movements in provisions	(5.0)	AER established approach to remove movements in provisions
Less budgeted cost for bushfire remediation	(22.4)	Non-recurrent expenditure that was approved by the AER as part of its Final Cost pass through decision on 2019–20 bushfire event[118]
Less budgeted network support costs	(1.6)	Avoid any future double-counting with category specific forecast. It will not be necessary to make this deduction from 'total opex' as reported in the RIN
Less Digital Core (SaaS) costs	(20.2)	Remove non-recurrent SaaS costs related to the implementation of our 'Digital Core' initiative to replace our enterprise management system, Ellipse.[119]
Proposed base year opex	174.3[1]	

Notes: 1. The proposed based year opex of $174.3 million (Real 2022–23) matches that in HoustonKemp's report[120]. 2. 2021–22 budgeted opex does not include debt raising costs or yet-to-be capitalised operating expenditure associated with the Network Capability Incentive Parameter Action Plan, which will similarly not be included in the level of 'total opex' reported in the RIN.

Table 7-5 shows that our 2018–23 opex, adjusted for non-recurrent bushfire remediation and Digital Core costs, is relatively stable across the period. In particular, our 2021–22 opex base year is in line with our actual expenditure in 2020–21 and our forecast opex in 2022–23. The slight increase in opex between 2019–20 and 2020–21 relates to the preparation costs for our Revenue Proposal and an increase in our insurance premiums in this year.

Table 7-5: Opex profile over 2018–23 ($M, Real 2022–23)

	2018–19	2019–20	2020–21	2021–22	2022–23
Total opex (i.e. unadjusted budget for 2021–22)	169.3	175.8	180.4	223.5	193.2
Less bushfire remediation costs	–	(10.1)	(6.3)	(22.4)	(13.8)
Less Digital Core (SaaS) costs	–	–	–	(20.2)	–
Net opex	**169.3**	**165.7**	**174.2**	**180.9**	**179.5**
% year on year change		-2.1%	5.1%	3.9%	-0.8%

We commissioned HoustonKemp to review the efficiency of our 2021–22 base year opex.[121] HoustonKemp has based its assessment on the relative efficiency of our:

- actual opex in 2019–20, and
- 2021–22 budget opex and forecast output measures.

118 AER, Decision Cost Pass through: Transgrid' 2019–20 bushfire natural disaster event, May 2021
119 This adjustment was calculated by comparing our estimated SaaS costs in FY22 of $25 million to average expected SaaS costs over the 2023–28 period (of $4.9 million).
120 HoustonKemp, Efficiency of Transgrid's base year operating expenditure, December 2021.
121 HoustonKemp, Efficiency of Transgrid's base year operating expenditure, December 2021.

HoustonKemp found:

- that our 2019–20 opex is efficient, and
- that our opex MPFP score in 2021–22 excluding one-off bushfire costs is not materially different from our opex score in 2019–20, based on actual opex. This reflects that the increase in our 2021–22 budgeted opex is expected to be accompanied by a commensurate increase in outputs.

In its assessment of our benchmarking performance,[122] HoustonKemp notes that the AER's economic benchmarking analysis also found that our actual 2019–20 opex is efficient.[123]

Give this, Houston Kemp concludes that our 2021–22 budget opex is efficient[124] and that no adjustments are required. This confirms that the base-step-trend approach to forecast our 2023–28 opex is appropriate.

7.5.2 Rate of change

The rate of change is applied to our base year opex for each year of the 2023–28 regulatory period. It captures the year-on-year change in efficient expenditure due to forecast changes in output levels, prices and productivity. In line with the AER's Expenditure Forecast Assessment Guideline, the rate of change is calculated according to the following formula:

$$\text{Rate of change} = \text{output growth} + \text{real price growth} - \text{productivity growth}$$

Each component of the rate of change is discussed below.

Rate of change – output

Our base year opex reflects our current outputs. Output growth is the expected change in network output over the 2023–28 regulatory period. We have included an allowance in our opex forecast for the impact of output growth in the 2023–28 regulatory period, consistent with the AER's standard approach. This reflects the fact that delivering greater outputs is associated with an increase in underlying infrastructure and activities, which costs more to operate and maintain.

We have applied the output change measures and respective weightings that are detailed in the AER's 2021 Annual Benchmarking Report for TNSPs.[125] The four output growth measures are detailed in Table 7-6.

122 HoustonKemp, Assessment of Transgrid's benchmarking performance, December 2021.
123 The AER identified no evidence that our actual 2019–20 opex is materially inefficient
124 On the basis that there is no evidence to suggest that it is materially inefficient
125 AER, Annual Benchmarking Report – Electricity transmission network service providers, November 2021

Table 7-6: Output change factors

Output measure	Description	Weighting (%)[1]
Energy throughput	Forecast growth of delivered energy within NSW and the ACT plus energy delivered through interconnectors to / from Queensland (QNI), Victoria (VNI) and SA (Project EnergyConnect). This information is sourced from our 2021 Regulatory Information Notice (RIN) as the base and growth rates applied in accordance with our 2021 TAPR. In 2023–28, energy throughput in NSW is forecast to increase by 0.6 per cent.	14.9
Ratcheted maximum demand	Ratcheted maximum demand is the ratcheted non-coincident maximum demand. Non-coincident maximum demand is the maximum demand of each individual connection point in a year measured in MVA. This information is sourced from the highest historical value from our RINs, and being a non-coincident figure is not anticipated to increase. In 2023–28, the maximum demand in NSW is forecast to remain within the historical maximum for non-coincident demand.	24.7
Customer numbers	This is based on the aggregate number of customers sourced from AER TNSP Partial Performance Indicator Analysis August 2020 for NSW DNSPs Endeavour Energy, Essential Energy and Ausgrid) and ACT DNSP (Evo Energy) as well as our directly connected customers, forecast into the future using linear regression. Based on this approach, customer numbers are forecast to increase by 6.7 per cent, over the 2023 28 regulatory period.	7.6
Circuit line length	Circuit length is the total transmission line circuit length measured in kilometres sourced from our 2021 RIN. Our circuit length over the 2018–23 regulatory period was increased to reflect the delivery of Project EnergyConnect.[126] We have forecast 1,368 km overall increase in circuit length over the 2023–28 regulatory period. This reflects our estimated circuit length increase associated with Project EnergyConnect.	52.8

Notes 1. Currently, weightings are based on Economics Insights report prepared for the AER for the 2021 benchmarking report for TNSPs.[127]

Table 7-7 shows the annual output growth factors for the 2023–28 regulatory period, as well as the total output growth based on the weightings from the AER 2021 Benchmarking Report and supporting expert report from Economic Insights. The last two years of the current regulatory period are shown for completeness.

Table 7-7: Forecast output growth over 2023–28

Output measure (%)	2021–22	2022–23	2023–24	2024–25	2025–26	2026–27	2027–28
Energy throughput	(0.3)	0.1	(0.5)	0.0	–	0.4	0.7
Ratcheted maximum demand	(2.2)	0.3	0.5	0.7	1.0	1.0	1.2
Customer numbers	1.4	1.3	1.3	1.3	1.3	1.3	1.3
Circuit line length	–	0.2	2.2	7.7	–	–	–
Total output growth	(0.5)	0.3	1.3	4.4	0.4	0.4	0.5

Rate of change – price

Our base year opex reflects the current prices of our cost inputs. The base-step-trend adjusts the base year opex for forecast real changes in input costs (labour and materials) over the 2023–28 regulatory period.

126 Note that QNI and VNI have no additional circuit length contribution
127 Economic Insights, Economic Benchmarking Results for the Australian Energy Regulator's 2020 TNSP Annual Benchmarking Report, 12 November 2021, p.2

We commissioned BIS Oxford Economics (BISOE) to forecast real labour escalators for the 2023–28 regulatory period.[128] BISOE found that the average increase in the NSW Gas, Water and Waste Services (EGWWS 'Utilities') sector, expressed in Wage Price Index (WPI) terms, is forecast to average 0.7 per cent per annum over the period 2023–28, inclusive of the impact of the increase to the Superannuation Guarantee (SG) over the five years from 2021–22 to 2025–26.

Table 7-8 details the forecast average annual change in labour costs for each year of the 2023–28 regulatory period.

Table 7-8: Forecast real labour price growth 2023–28 – including impact of proposed superannuation increase (%)

Real labour price growth (%)	2023–24	2024–25	2025–26	2026–27	2027–28	Average
EGWWS WPI – NSW	0.46	0.76	0.90	0.82	0.62	0.71

We have applied the labour cost escalators in Table 7-8 using the AER's preferred input price weights of 70.4 per cent and 29.6 per cent for labour and non-labour respectively, as reflected in the AER's recent draft decision for AusNet Services' transmission business.[129] Real labour costs add approximately $12.9 million to forecast opex over the 2023–28 regulatory period.

Table 7-8 show that BISOE forecast utilities wages to increase by more than the national average over the forecast period. This is due to a range of factors including:

- demand for skilled labour is expected to strengthen with the high levels of investment in the utilities sector over the period 2023–24 to 2027–28. This will also be a key driver of wages going forward, and
- employees in the utilities sector have higher skill, productivity and commensurately higher wage levels than most other sectors

BISOE notes that:

> With strong competition for similarly skilled labour from the mining and construction industries, firms in the utilities sector will need to raise wages to attract and retain workers. In other words, the mobility of workers between the EGWWS, mining and construction industries means that demand for workers in those industries will influence employment, the unemployment rate and hence spare capacity in the EGWWS labour market. Businesses will find they must 'meet the market' on remuneration in order to attract and retain staff and we expect wages under both individual arrangements and collective agreements to increase markedly over the FY24 to FY26 period

The scale of investment in the energy sector that is expected to occur in NSW over the next regulatory period under AEMO's ISP and the NSW Electricity Infrastructure Roadmap is substantial. These projects represent a material increase in the expected volume of work and are expected to put upward pressure on real wages over the 2023–28 regulatory period. [130]

Materials escalation

Materials' costs comprise a range of cost categories, including materials, motor vehicle expenses, media and marketing costs, as well as land and building leases.

At this stage we have not included a real increase in materials costs in our expenditure forecasts, although like Infrastructure Australia and AEMO we forecast that the cost of materials will increase at a rate faster than CPI:

- in October 2021, Infrastructure Australia forecast that renewable energy and transmission construction will significantly add to steel and concrete demand.[131] This is likely to lead to real materials costs increases, and
- in December 2021, AEMO's Draft 2022 ISP forecast that the acceleration in global infrastructure and energy investment over the next two decades will significantly increase demand for expertise, materials, and equipment, putting pressure on costs for transmission projects.[132]

128 BISOE, Labour escalation forecast to 20-27/28 – prepared by BIS Oxford Economics for Transgrid, December 2021.
129 AER, AusNet Services Transmission Determination 2022 to 2027, Attachment 6 Operating expenditure, June 2021
130 We are in the process of finalising our next Enterprise Agreement.
131 Infrastructure Australia: Market capacity for electricity generation and transmission projects, October 2021 report.
132 AEMO, Draft 2022 Integrated System Plan, December 2021, p. 15.

In our Revised Revenue Proposal, we will revisit this matter in consultation with our customers and other stakeholders.

Rate of change – productivity

As discussed in Chapter 2, we have delivered substantial opex efficiency savings in the 2018–23 regulatory period.

The AER's productivity growth factor represents its estimate of the shift in the 'efficiency frontier' of the transmission industry. This means that it is the industry productivity that is relevant for calculating the productivity growth factor, rather than the changes in productivity of any given individual TNSP. The AER calculates the opex productivity factor as the slope of the 'line of best fit' to the industry opex MPFP over time.

Consistent with the AER's preferred methodology we have included a forecast productivity improvement of 0.5 per cent per annum in our forecast opex. The forecast growth in productivity reflects the annual productivity growth rate that the transmission industry has been able to achieve over the long term and as such is a reasonable estimate of productivity growth in the upcoming regulatory period.

Productivity growth improvement will deliver transmission cost savings by reducing our overall opex by around $14.3 million in the 2023–28 period.

Table 7-9: Rate of change – productivity growth ($M, Real 2022–23)

Rate of change – productivity	2023–24	2024–25	2025–26	2026–27	2027–28	Average / Total
Productivity change %	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
Productivity change ($)	(0.9)	(1.9)	(2.8)	(3.8)	(4.8)	(14.3)

As discussed above, the incentives provided by the design of the ex-ante regulatory framework including the EBSS, provide a continuous incentive for us to make efficiency gains over time and can be expected to drive further efficiencies in the next regulatory period, which would be shared with customers in future periods.

7.5.3 Specific or category forecasts

Category specific forecasts relate to opex that meets the criteria for efficient opex, however is not appropriate for inclusion in base opex and is not included as a step change. These costs are separately forecast (a category specific forecast) and are then added to the opex forecast determined using the base-step-trend approach.

We have two category specific forecasts, being debt raising costs and network support costs.

Debt raising costs

Debt raising costs are the transaction costs incurred each time debt is raised or refinanced as well as the costs for maintaining the debt facility. These costs may include underwriting fees, legal fees, company credit rating fees and other transaction costs.

We engaged an independent expert Frontier Economics (Frontier) to estimate the level of benchmark debt raising costs for the 2023–28 regulatory period consistent with the AER's accepted estimation methodology. The AER's methodology uses Bloomberg data to estimate the arrangement fee[133], and Chairmont's estimates of all other components of debt raising costs.

We engaged Frontier to estimate our benchmark debt raising costs because actual debt raising costs in our base year are not necessarily representative of future costs and may not reflect benchmark costs. Frontier has determined our debt raising costs for 2023–28 consistent with the approach used by the AER in its most recent decisions and in line with Chairmont's recommendations to the AER in 2019[134]. Our approach to debt raising costs is explained and justified in section 10.6.

133 The AER has concluded that relying on Bloomberg data to estimate arrangement fees, which are the most material direct debt raising transaction cost is more transparent that relying on the Chairmont approach, which is based on informal discussions with several bond market participants.
134 This amortises upfront debt raising costs over nine rather than 10 years.

Network support costs

Network support costs relate to non-network solutions used as an efficient alternative to network solutions, including demand side response, local generation and co-generation.

We currently have three network support contracts in place in connection with the Powering Sydney's Future (PSF) project, which are expected to total $1.6 million in the 2021–22 base year. These contracts are due to expire prior to the 2023–28 regulatory control period and, at present, we do not have any network support contracts in place for the 2023–28 regulatory period. As discussed in section 7.5.1, we have removed the expected network support costs from our 2021–22 base year. We have therefore included zero value for network support in the 2023–28 regulatory period.

We are currently actively exploring network support options in a number of areas, to defer or supplement network investment.[135] We will seek to recover any network support costs as pass through event in accordance with the network support cost pass through provisions under the Rules[136] should they arise during the period.

7.5.4 Step changes

We have included an allowance in our opex forecast for a range of step changes for events or obligations that will cause us to incur additional costs over and above the efficient base year in the 2023–28 regulatory period.

In its Expenditure Forecast Assessment Guideline, the AER indicated that step changes should relate to either changes in regulatory obligations or capex-opex trade-offs. Table 7-10 details our proposed opex step changes and their associated drivers. These step changes are explained and justified in our Opex Step-change Overview Paper.

Table 7-10: Opex step changes ($M, Real 2022–23)

Step changes	Description	Preliminary Forecast
Insurance premiums	Our insurance premiums are forecast to increase in the next regulatory period. Since 2018, the global insurance market has experienced significant volatility, with ongoing premium increases and a contraction in available insurance cover capacity. This is placing upward pressure on premiums.	30.0
Cyber and critical infrastructure security	We will incur additional opex to meet new cyber security obligations under the Australian Government's Critical Infrastructure 2021 Act (including Part 2 anticipated in 2022) and the NSW Government's Energy Legislation Amendment Act 2021. This comprises: • ICT Cyber Security $18.6 million • OT Security $3.5 million • Physical infrastructure security $2.8 million	25.0
ISP preparatory activity	We will incur additional opex to undertake preparatory activities[137] for future ISP projects as determined by AEMO in its ISPs, which it issues every two years. We are required to undertake these activities in accordance with the Actionable ISP Rules.	2.9

135 For example, through our on-going RIT-T processes relating to the Broken Hill, Bathurst, Orange, Parkes and North West Slopes supply areas.
136 In accordance with Rule 6A.7.2
137 NER rule 5.10.2.

7.6 Our opex forecast

Table 7-11 details our base-step-trend forecast opex over the 2023–28 regulatory period, which is a summation of the above components.

Table 7-11: Forecast opex, 2023–28 regulatory period, ($M, Real 2022–23)

	2023–24	2024–25	2025–26	2026–27	2027–28	Total
2021–22 base opex	174.3	174.3	174.3	174.3	174.3	**871.7**
Adjustment to 2022–23	2.6	2.6	2.6	2.6	2.6	**13.0**
Output growth	2.3	10.2	10.9	11.8	12.8	**48.1**
Price growth	0.6	1.5	2.7	3.7	4.5	**12.9**
Productivity growth	(0.9)	(1.9)	(2.8)	(3.8)	(4.8)	**(14.3)**
Step changes	9.9	10.8	12.2	11.7	13.2	**57.8**
Total excluding debt raising costs	**188.9**	**197.6**	**199.9**	**200.3**	**202.6**	**989.3**
Debt raising costs	5.0	5.2	5.2	5.2	5.1	**25.7**
Total including debt raising costs	**193.8**	**202.8**	**205.2**	**205.5**	**207.7**	**1,015.0**

7.7 Supporting documentation

The following documents support this Chapter and accompany our Revenue Proposal.

Name
Expenditure Forecasting Methodology
Forethought, Transgrid Revenue Reset Stakeholder Engagement - Executive Report
Opex Forecast Model
Opex Step Change Overview Paper
KMPG, Memorandum on SaaS Product Accounting
Critical Infrastructure Security Costs
Cost Allocation Methodology
BIS Oxford Economics, Labour Cost Escalation Forecast to 2027-28
HoustonKemp, Efficiency of Transgrid's Base Year Operating Expenditure
HoustonKemp, Assessment of Transgrid's benchmarking performance
Frontier Economics, Benchmark Debt Raising Costs
AON, Insurance Premium Cost Forecast

8. Capex forecasts

Key messages

> Our forecast capex for the 2023–28 regulatory period balances affordability and safety, security and reliability, while supporting the energy transition. Our capex forecast reflects our key operational challenges and the priorities identified by our customers, including:

- our ageing assets, which require replacement due to their condition, deterioration and obsolescence, climate-related extreme weather events and new cyber and physical security obligations. These challenges impact our network's safety, security and reliability.
- pockets of strong maximum demand growth in some regions from mining in regional NSW, urban development, industrial precincts and data centres, and
- increased operational complexity of our network from large-scale variable renewable generation connecting to the NEM as part of the energy transition. This includes more widespread network congestion and decreasing minimum demand due to increased solar generation.

> Our forecast 2023–28 capex of $1,368.5 million (excluding pre-approved forecast capex) is $23.0 million or 1.7 per cent higher than our estimated capex of $1,345.6 million for the 2018–23 regulatory period.

> Our Repex forecast of $797.6 million is the largest component (58.3 per cent) of our total capex forecast and will increase slightly (3.6 per cent) above our 2018–23 expenditure to deliver a safe and reliable network as our network ages and condition-related issues increase. We will also:

- invest to enhance our cyber and physical security capability and respond to the changing generation mix, and
- focus on climate change and network resilience to maintain our network safety, reliability and security during extreme climate events.

> Our Augex forecast of $253.6 million contributes 18.5 per cent of our proposed total capex and is about 16.9 per cent lower than our estimate for 2018–23, excluding capex on ISP projects. The key drivers of our 2018–23 Augex (excluding capex on ISP projects) were reliability and compliance related projects including PSF and constructing a new sub-station at Stockdill. These projects will be completed in the 2018–23 period.

> The key drivers of our lower Augex in the 2023–28 period are:

- addressing rapid localised load growth and spot loads in certain regions including central west NSW, western Sydney, and north west Sydney which if not addressed, will lead to the network in those areas not complying with NER voltage stability and thermal limits and IPART's reliability standards, and

Key messages (continued)

  - maintaining compliance with voltage stability which is being impacted by decreasing minimum demand as household solar PV generation increases.

> Our ICT capex forecast of $86.9 million is 29.1 per cent higher than our estimate for the current period, and will enable us to rollout new technology and continue to refresh or replace legacy applications and systems at the end of their lives.

> Our non-network other capex forecast of $71.4 million is 22.1 per cent higher than our estimate for the current period as we continue to provide safe, compliant and productive offices and depots to support the increase in our network operations activity and invest to maintain the suitability and safety of our fleet, plant and equipment.

> Our capitalised overheads forecast of $159.0 million is 10.2 per cent higher than our estimate for the current period to enable us to deliver a larger capital works program.

> Our forecast capex does not include costs that we may incur if we are required to ready our network for 100 per cent renewables by 2025. We are currently examining the nature and scope of these costs and will work closely with AEMO and our industry peers to understand and quantify the investment required to facilitate an orderly transition towards this future state.

> Our 2023–28 forecast capex has been independently reviewed for consistency with good industry practice. These reviews support our forecast capex as being prudent and efficient.

8.1 Overview

Our 2023–28 forecast capex comprises pre-approved and new forecast capex.

8.1.1 Our pre-approved forecast capex for 2023–28

In May 2021, the AER published its Determination for Project EnergyConnect, which approved total capex of $2,008.0 million[138] for the 2018–23 regulatory period. Project delays mean that this Project's delivery date is now anticipated to be 2024–25. As a result we expect to spend $532.8 million of the approved capex for this project (pre-approved forecast capex) in the 2023–28 period. We will add this pre-approved capex to our forecast for the first two years of the 2023–28 period. We are committed to delivering this Project in line with the total approved capex allowance of $2,008.0 million and are not seeking any additional capex for this Project EnergyConnect in this Revenue Proposal.

138 Excluding equity raising costs

8.1.2 Our new forecast capex for 2023–28 (excluding pre-approved forecast capex)

Our forecast capex balances affordability and safety, security and reliability, while supporting the energy transition. Our forecast capex for the 2023–28 regulatory period is $1,368.5 million, excluding the above pre-approved forecast capex.[139] Figure 8-1 details the breakdown of our 2023–28 forecast capex by sub-category, excluding pre-approved capex. This shows that Augex and Repex are the largest capex categories – together they comprise about 77 per cent of our total capex, excluding pre-approved capex.

Our 2023–28 forecast capex has been independently reviewed for consistency with good industry practice. These reviews support our forecast capex as being prudent and efficient.

Our forecast capex does not include the costs that we may incur if we are required to ready our network for 100 per cent renewables by 2025.[140] In December 2021, AEMO published its NEM Engineering Framework, which states:[141]

> Exceptional change is required to enable the National Electricity Market (NEM) to securely and efficiently transition to new operational conditions. The instantaneous penetration of renewables is increasing rapidly and, with appropriate preparation, could reach up to 100% at times by 2025. Urgent and extensive industry collaboration and effort is needed to engineer the power system to meet these new conditions in a timely and orderly manner, with positive consumer outcomes at the heart of all decision-making.

We are currently examining the nature and scope of these costs and will work closely with AEMO, our industry peers and our customers to understand and quantify the investment required to facilitate an orderly transition towards this future state. Subject to this work, we propose either to include the forecast costs, or a further cost pass through event, in our Revised Revenue Proposal.

Figure 8-1: 2023–28 forecast capex by subcategory, excluding pre-approved forecast capex[142]

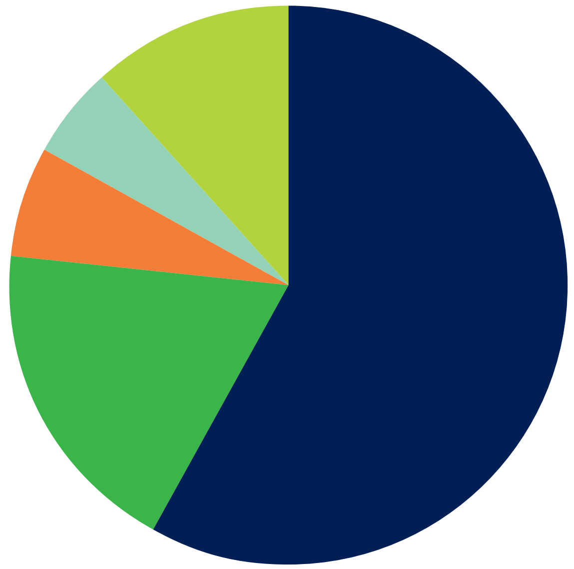


Figure 8-2 shows our actual and estimated capex for each year of the 2014–18, 2018–23 and 2023–28 regulatory periods compared to the AER's allowances. As noted above, our 2023–28 forecast capex excludes pre-approved capex for Project EnergyConnect and it also excludes capex for projects identified in AEMO's ISP (including HumeLink and VNI West) and the NSW Electricity Infrastructure Roadmap. As discussed in Chapters 5 and 17, these projects will be progressed under the Actionable ISP Rules and the NSW EII Regulations as they arise during the 2023–28 period. To aid comparison, we have also excluded our expenditure of $1,769.2 million on actionable ISP Projects approved by the AER as contingent projects for the 2018–23 regulatory period (i.e. Project EnergyConnect, QNI minor and VNI minor), which is discussed in Chapter 4.

Figure 8-2 and Table 8-1 show that:

- over the 2018–23 regulatory period, we expect our actual capex of $1,345.6 million, excluding ISP Projects, to be slightly below the AER's allowance of $1,380.7 million, and
- our forecast 2023–28 capex of $1,368.5 million, excluding pre-approved forecast capex, is $23.0 million or 1.7 per cent higher than our estimated capex of $1,345.6 million for the 2018–23 regulatory period.

139 Related to Project EnergyConnect
140 AEMO, NEM Engineering Framework Initial Roadmap, December 2021. This finds by 2025 the NEM could reach up to 100 per cent instantaneous renewables at times.
141 AEMO, NEM Engineering Framework Initial Roadmap, December 2021, p. 6
142 Excluding pre-approved forecast capex for Project EnergyConnect.

Figure 8-2: Capex trends compared to the AER allowance, excluding pre-approved capex, ISP Projects and the NSW Electricity Infrastructure Roadmap projects ($M, Real 2022–23)

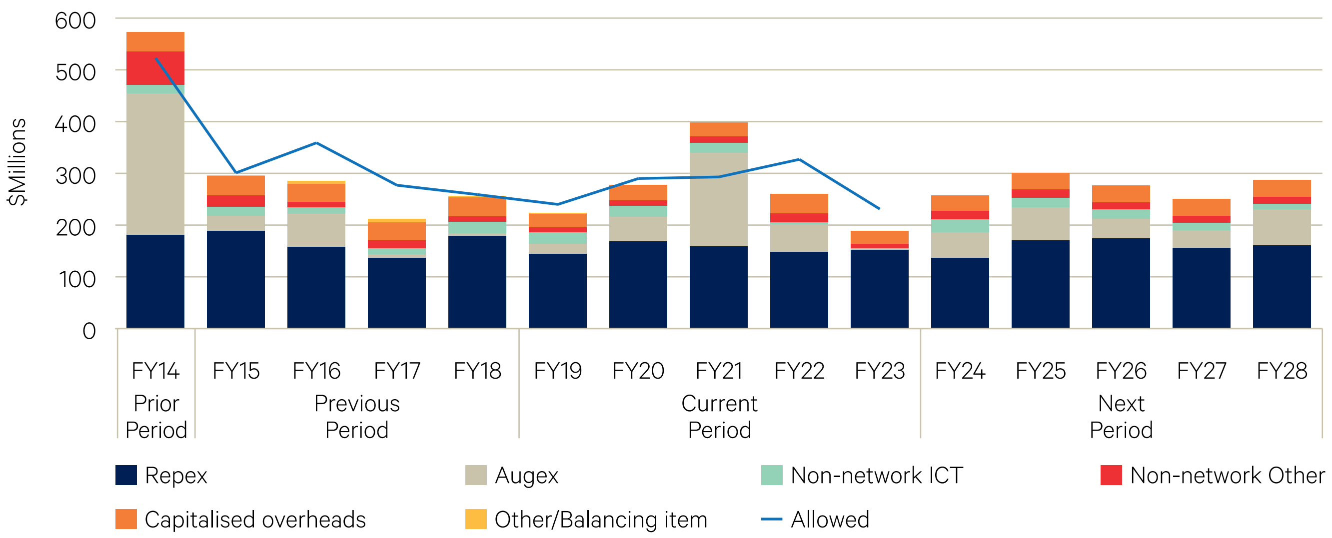


Table 8-1: Comparison: 2018–23 actual and 2023–28 forecast capex, excluding pre-approved forecast capex, ISP Projects and NSW Electricity Infrastructure Roadmap projects ($M, Real 2022–23)

Capex by sub-category	Total 2018–23	Total 2023–28	2023–28 % of total	Difference $	Difference %
Repex	770.2	797.6	58.3	27.4	3.6
Augex	305.4	253.6	18.5	(51.7)	(16.9)
Non-network ICT	67.3	86.9	6.4	19.6	29.1
Non-network Other (Property)	15.3	22.8	1.7	7.5	48.7
Non-network Other (Fleet, plant and equipment)	43.2	48.6	3.6	5.5	12.7
Capitalised overheads	144.3	159.0	11.6	14.7	10.2
Total	**1,345.6**	1,368.5	100.0	23.0	1.7

Table 8-2 sets out our total forecast capex for 2023–28 by sub-category and year both excluding and including pre-approved capex for Project EnergyConnect. There are no other ISP or NSW Electricity Infrastructure Roadmap project costs in our forecasts.

Table 8-2: Forecast 2023–28 capex, including pre-approved forecast capex but excluding ISP and the NSW Electricity Infrastructure Roadmap projects ($M, Real 2022–23)

Capex by sub-category	2023–24	2024–25	2025–26	2026–27	2027–28	Total
Repex	136.6	169.5	174.5	156.0	161.0	797.6
Augex	48.5	64.3	37.5	34.0	69.2	253.6
Non-network ICT	25.0	19.2	18.3	13.7	10.7	86.9
Non-network Other (Property)	6.5	5.8	3.8	3.8	3.0	22.8
Non-network Other (Fleet, plant and equipment)	9.3	9.9	9.7	10.2	9.6	48.6
Capitalised overheads	30.2	32.4	32.0	31.6	32.7	159.0
Total[143] (excluding Pre-approved Project EnergyConnect)	256.0	301.1	275.9	249.3	286.2	1,368.5
Pre-approved Project EnergyConnect capex	457.2	75.6	–	–	–	532.8
Total (including Pre-approved Project EnergyConnect)	713.3	376.7	275.9	249.3	286.2	1,901.4

143 This excludes pre-approved capex for Project EnergyConnect of $532.8 million that will be incurred in the first two years of the 2023–28 regulatory period

Sections 8.6 to 8.11 explain and justify our 2023–28 forecast capex by category.

Figure 8-3 provides a breakdown of how our capex forecast relates to the customer and other stakeholder priorities for the 2023–28 regulatory period discussed in Chapter 5. It shows that:

- Almost 80 per cent of our capex will support delivering a safe, secure and reliable network
- 15 per cent of our capex will support localised maximum demand growth, and
- The remaining 6 per cent will support the energy transition.

This Chapter provides a high level explanation and justification of our expenditure forecasts. We have provided Expenditure Overview Papers with this Revenue Proposal that provide further information on each capex category.

8.2 ISP and NSW Electricity Infrastructure Roadmap Projects

We support the transition to the new energy market and the delivery of projects in AEMO's ISP and the NSW Electricity Infrastructure Roadmap as they are approved. As discussed in Chapter 1:

- AEMO's ISP identifies the necessary transmission network investments, taking into account a range of potential future outcomes, and recommends essential actions (actionable and future ISP projects) to optimise customer benefits. The 2020 ISP was published on 30 July 2020[144]. Under the NER, AEMO must update the ISP every two years.[145] On 10 December 2021, AEMO published its Draft 2022 ISP with the final 2022 ISP expected to be published by 30 June 2022.
- the NSW Electricity Infrastructure Roadmap sets out the 'NSW Government's plan to transform our electricity system into one that is cheap, clean and reliable'. It is expected to deliver five REZs which will contribute at least 12GW of new transmission capacity.

As noted above, we will deliver projects in accordance with the automatic contingent project provisions in the Actionable ISP Rules and the NSW EII Regulations. The costs of these projects are therefore not included in our expenditure forecasts. Approvals are required from AEMO, the NSW Government and the AER before we include any costs of these projects in our transmission prices.

We have included an opex step change to undertake preparatory activities[146] for future ISP projects as determined by AEMO in its ISPs. We are required to undertake these activities in accordance with the Actionable ISP Rules. This is discussed in Chapter 7.

Figure 8-3: Breakdown of capex by customer outcome ($M, Real 2022–23)

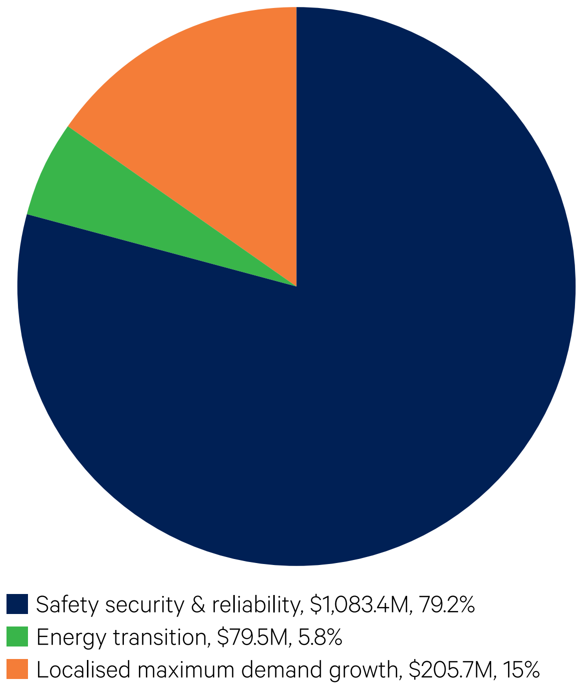


Table 8-3 identifies the actionable and future ISP projects set out in AEMO's 2020 Draft ISP expected to be delivered in the 2023–28 regulatory period.

144 AEMO, 2020 ISP, 30 July 2020
145 NER Clause 5.22.1 AEMO must publish an ISP every two years by 30 June
146 NER rule 5.10.2. preparatory activities include activities to design and investigate the costs and benefits of actionable and future ISP projects including detailed engineering design, route selection, easement assessment, cost estimation, stakeholder engagement and assessment of environmental and planning approvals

Table 8-3: Actionable and future ISP projects based on Draft AEMO's 2022 ISP ($M, Real 2022–23)

ISP Projects	Description	2023–28 Forecast ($M)	Total estimated cost ($M)
Actionable ISP			
HumeLink	HumeLink strengthens the transmission network between southern and central NSW providing access for Snowy 2.0 renewable generation in southern NSW, and imports from Victoria and South Australia to NSW major load centres.	3,618.9	3,618.9
VNI West[1]	VNI West is a large new interconnector between Victoria and NSW. It will enable high transfer between New South Wales and Victoria and provide access to renewable generation in Murray River, central north Victoria and western Victoria REZs.	1,696.7	3,090.9
Sydney Ring (Reinforcing Sydney, Newcastle, and Wollongong Supply)	Sydney Ring strengthens the transmission network to supply the Sydney, Newcastle and Wollongong load centres once coal-fired generators around Newcastle retire.	924.5	924.5
Future ISP			
QNI Connect[2]	QNI Connect involves the development of a new interconnector to increase the transfer capability between northern NSW and southern Queensland.	159.2	1,316.4
Total		**6,399.4**	**8,950.8**

Notes: 1. Includes NSW and VIC components. 2. Includes NSW and QLD components.

8.3 The nature and drivers of our capex

Table 8-4 details the categories of capex that support the delivery of our prescribed transmission services and the key drivers for each category. Our 2023–28 capex forecast is our response to these drivers so that, together with our opex forecast, we will maintain a reliable, safe and resilient network that supports the changing energy system, at the lowest sustainable cost to customers. Our forecast capex has also been guided by our customers' priorities, in terms of supporting the energy transition, meeting load growth, maintaining a safe reliable and secure supply and promoting technology and innovation, while maintaining affordability.

Table 8-4: Nature and drivers of expenditure by category of capex

Category	Nature	Drivers
Repex	Investment to replace or refurbish our existing assets that are approaching technical end of life to ensure the continued safety (bushfire, public and workforce, environment) and reliability and security of the network	Key drivers are: • continuing delivery of a safe and reliable network, as assets in our network age and condition-related issues continue to grow. This includes maintaining asset condition, risk and performance at current levels though investment to address asset failure and deteriorating asset condition • managing emerging issues in the external environment including: – increasing cyber and physical security threats to critical infrastructure – climate change and resilience to more frequent extreme weather events – increasing renewable generation and change in the generation mix resulting in higher utilisation of some assets due to the location of new renewable generation, and – meeting our legislative and regulatory obligations and commitments as a business.

Category	Nature	Drivers
Augex	Investment to augment the existing transmission network to: • meet or manage the expected demand for prescribed transmission services, • comply with all applicable regulatory obligations or requirements • maintain the quality, reliability and security of the transmission network, in circumstances where the current network is no longer sufficient, and • address transmission constraints preventing the dispatch of lowest cost generation.	Key drivers are: • economic conditions resulting in: – increases in peak electricity demand associated with underlying load growth at some connection points, and – the development of major new spot loads and connections (such as new mining load and data centres) (i.e. locational demand). • increasing renewable generation and the changes in the generation mix from thermal to renewables. Changes to the generation mix impact power system stability, which results in the power system becoming more complex, and – increases the need for compliance-related Augex[147] to address voltage stability gaps, and – presents market-benefit investment opportunities to relieve network congestion, where benefits exceed costs
ICT	• Non-network investment needed to support the business in providing its prescribed transmission services	Key drivers are: • refreshing or replace legacy applications and systems at the end of their lives • developing, maintaining and modernising our bespoke application • transitioning to cloud-based solutions • complying with new cyber security obligations
Non-network other (Property, fleet, plant and equipment)	Property – offices and regional depots including workshops, warehouses, office floors Fleet, plant and equipment – light commercial motor vehicle and mobile plant, such as trucks, trailers, cranes and elevated work platforms	Key drivers are: • Property – continuing to provide safe, compliant and productive workspaces at our offices and depots, and • Fleet, plant and equipment – maintaining the suitability and safety of our current fleet.
Capitalised overheads	• corporate overheads – corporate support and management services that cannot be directly attributed to specific services • network overheads – network control and management services that cannot be directly attributed to specific services	The key driver is growth in our overall capital program

147 To ensure compliance with NER obligations

8.4 Our customers and other stakeholders' input

In developing our capex forecast for the 2023–28 regulatory period, we have considered the priorities and preferences of our customers and other stakeholders outlined in Chapter 2 and explained in Forethought's Final Report.[148]

Our customers support capex to meet load growth and promote a safe, secure and reliable supply while enabling the energy transition including through the use of technology and innovation. Reliability and supporting the energy transition were the highest priorities for small business customers and residential customers respectively, while all customer segments supported investment to promote affordability.

We have reduced our forecast capex in response to customer feedback on our Preliminary Revenue Proposal to deliver on affordability – our customers' highest priority.

Customers expressed a strong preference for investment to facilitate renewables but also to increase safety.

8.5 Key capex assumptions

Table 8-5 details the key assumptions underpinning our capex forecasts. Our Directors have certified the reasonableness of these key assumptions in accordance with clause S6A.1.1(5) of the NER, as discussed in Chapter 22 of this Revenue Proposal.

Table 8-5: Capex key assumptions

Key assumption	
1. Legislative and regulatory obligations	Our capex forecasts are based on our current legislative and regulatory obligations and our licence requirements.
2. Network reliability	Our capex forecast will maintain, but not improve, service outcomes consistent with clause 6A.6.7(a)(3)(iii) of the NER.
3. Demand forecasts	Our forecasts are required to meet DNSPs' connection point demand forecasts (published in our TAPR) reconciled to AEMO's forecasts.
4. Value of customer reliability (VCR)	Our capex forecasts reflect AER's VCR, which represents the monetary value different types of customers place on having access to a reliable electricity supply. The VCR is a key input into how we determine when to replace assets on our network.
5. Unit rates and project costs	The unit rates and project costs that we have applied in developing our capex forecasts are representative of the costs that will be incurred in the next regulatory period.
6. Cost allocation and capitalisation	Our capex forecasts reflect our capitalisation policy and our CAM, which provides an appropriate basis for attributing and allocating costs to, and between, our prescribed transmission and other services.
7. Cost escalations	The cost escalations that we have applied in developing our capex forecasts are representative of the increased costs that we will incur in the next period
8. Inflation	The inflation that we have has applied in developing our capex forecasts is representative of the inflation-related costs that we will incur in the next period and is consistent with the AER-preferred inflation forecasting method
9. Cost pass throughs and contingent projects	The AER will approve our nominated pass through events and contingent projects

148 Forethought Revenue Reset Stakeholder Engagement, Final Report (Phases 1 to 3), December 2021.

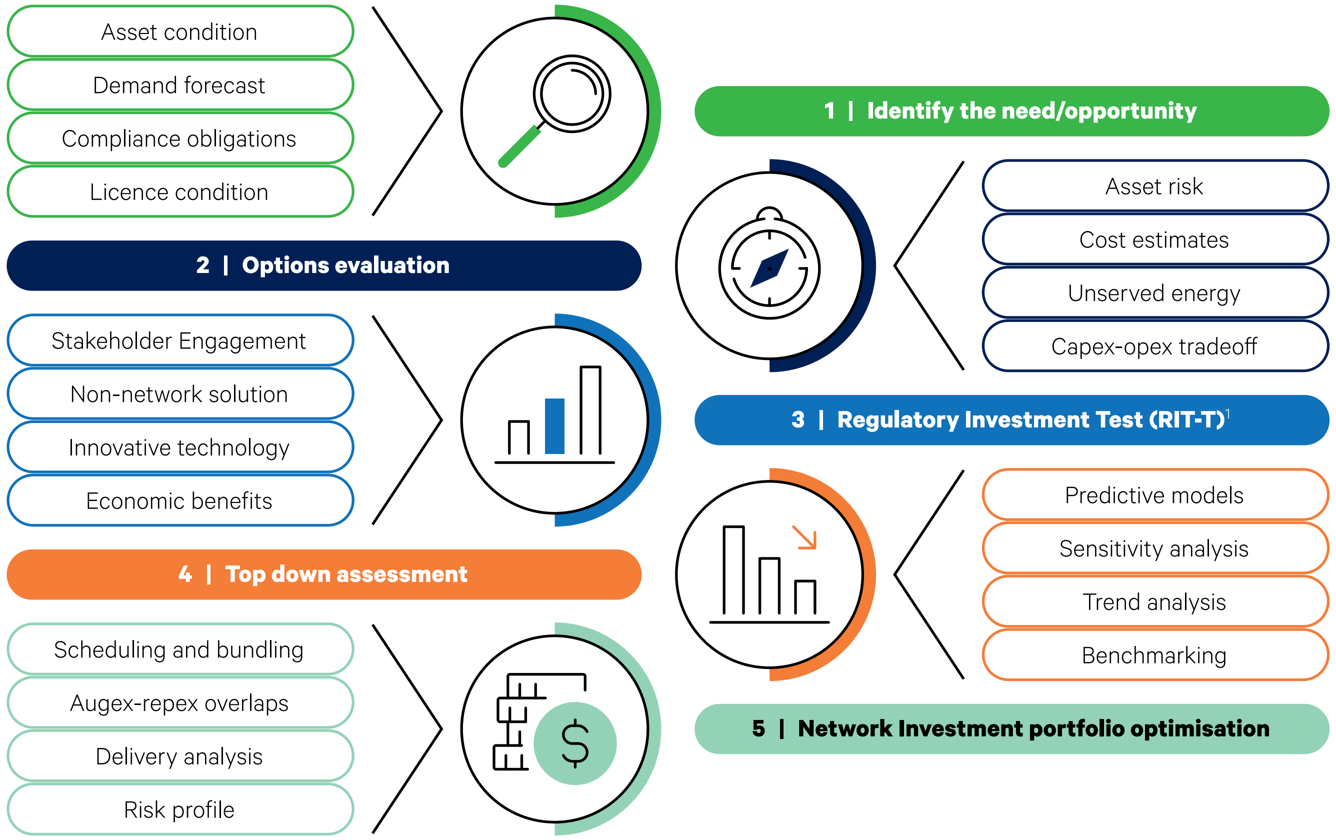
8.6 Our expenditure forecasting methods

Our Expenditure Forecasting Methodology, provided to the AER in June 2021, sets out our capex forecasting methodology that we have used to develop our capex program on a project by project basis that meets our network requirements, customer expectations and community needs.

This general approach is illustrated in Figure 8-4 and includes the following steps:

- **Identify the need / opportunity** – identify investment needs and opportunities that efficiently support the continued delivery of a safe, reliable and secure power system. We consider both traditional infrastructure and new and innovative technologies, processes and systems to ensure we continue to provide value for money and environmentally sustainable services to meet customers' needs.
- **Options evaluation** – evaluate options to address each need and opportunity. For Repex and Augex we assess the expected benefits, such as risk reduction, to our customers and the costs for each feasible option in an economic cost benefit analysis business case. For Non-network Other capex, we assess the business support need for the investment to proceed on a case by case basis. Where the preferred option requires an investment or delivers net benefits, it is added to the investment portfolio.
- **Regulatory Investment Test for Transmission (RIT-T)** – for projects with a cost greater than $8 million apply the RIT-T to identify the credible option, including consulting for non-network options, that maximises the present value of net economic benefit to the market of our proposed investments.[149] Through this process, we engage with stakeholders to identify and assess non-network and new technology innovations that can assist in maximising the net economic benefit to the market. The timing of the RIT-T process varies in accordance with the timeframe to address the identified need and only certain projects in our Capex Forecast are subject to, or will commence, the RIT-T at the time we submit this Revenue Proposal.
- **Top down assessment** – test and challenge our capex program (investment portfolio) using top down assessments including predictive models and benchmarking
- **Network investment portfolio optimisation** – identify optimisation opportunities by considering the deliverability of the portfolio, appropriate scheduling and bundling of works.

Figure 8-4: Capex forecasting process



Notes: 1. RIT-T will commence based on expected project timing. Not all projects will commence a RIT-T prior to Step 5.

149 Where the identified need is for reliability corrective action, the preferred option may have negative net economic benefit

We forecast the costs of our Augex and Repex projects and programs using our MTWO estimating database.

Our MTWO cost estimating database reflects actual outturn costs built up over more than 10 years from:

- period order agreement rates and market pricing for plant and materials
- labour quantities from recently completed project, and
- construction tender and contract rates from recent projects.

The costs of some unitised Repex programs are based on historical actual costs for similar work.

Our MTWO estimating database is reviewed annually to reflect the latest outturn costs and confirm that our estimates are within their stated accuracy range and represent the most likely expected cost of delivery (P50 costs). As part of this annual review, we benchmark the outcomes against independent estimates provided by various engineering consultancies.

We forecast the costs for our non-network capex (ICT, property and fleet, plant and equipment) based on contract rates, service agreements and independent estimates.

8.7 Repex

Our 2023–28 Repex forecast of $797.6 million is 3.6 per cent above our estimated 2018–23 Repex of $770.2 million and will deliver a safe and reliable network as our network ages and condition-related issues continue to grow. We will replace and upgrade deteriorated and obsolete assets using a risk-based approach to maintain asset condition and risk. Our investment will also improve the security of our digital and physical network infrastructure to meet new requirements, which are expected to become mandatory during the next regulatory period.

We will continue to address climate change and promote network resilience to maintain our network safety, reliability and security, as we experience more frequent extreme climate-driven natural hazard events. We will also continue to adopt innovation-driven practices and approaches to our Repex, to ensure our costs reflect efficient levels of investment.

8.7.1 Our Repex profile

Figure 8-5 shows Repex trends compared to the AER's allowance over the 2014–18, 2018–23 and 2023–28 regulatory periods. This shows that our 2023–28 Repex forecast of $797.6 million is $27.4 million or 3.6 per cent higher than 2018–23 estimated Repex of $770.2 million and is slightly lower, by $45.4 million or 5.4 per cent, than our outturn Repex for the 2014–18 regulatory period.

Figure 8-5: Repex trends compared to the AER allowance ($M, Real 2022–23)

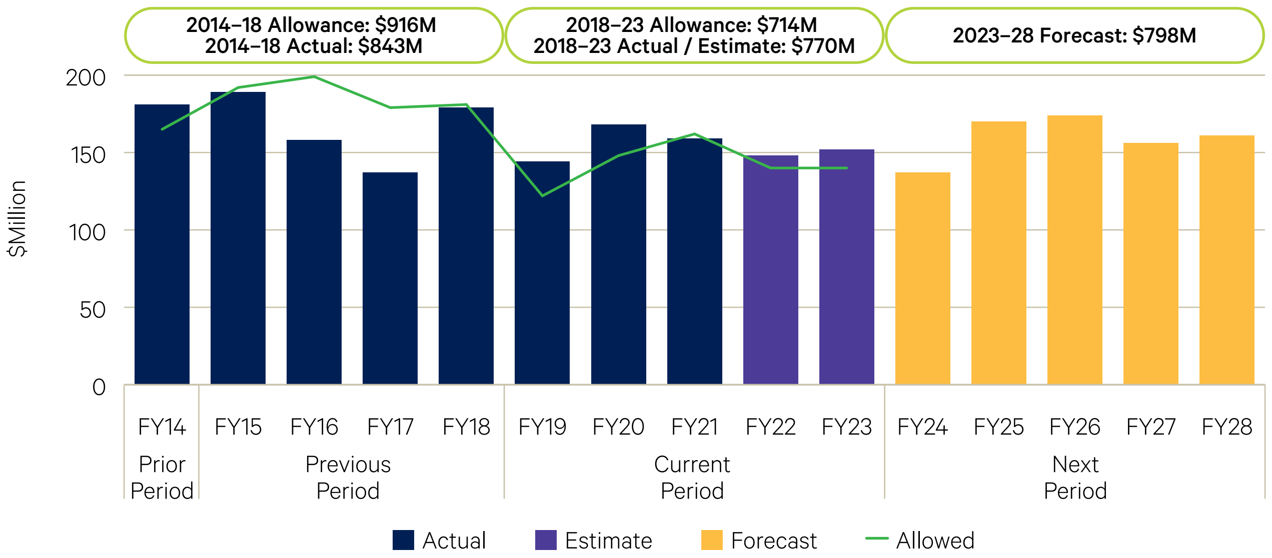
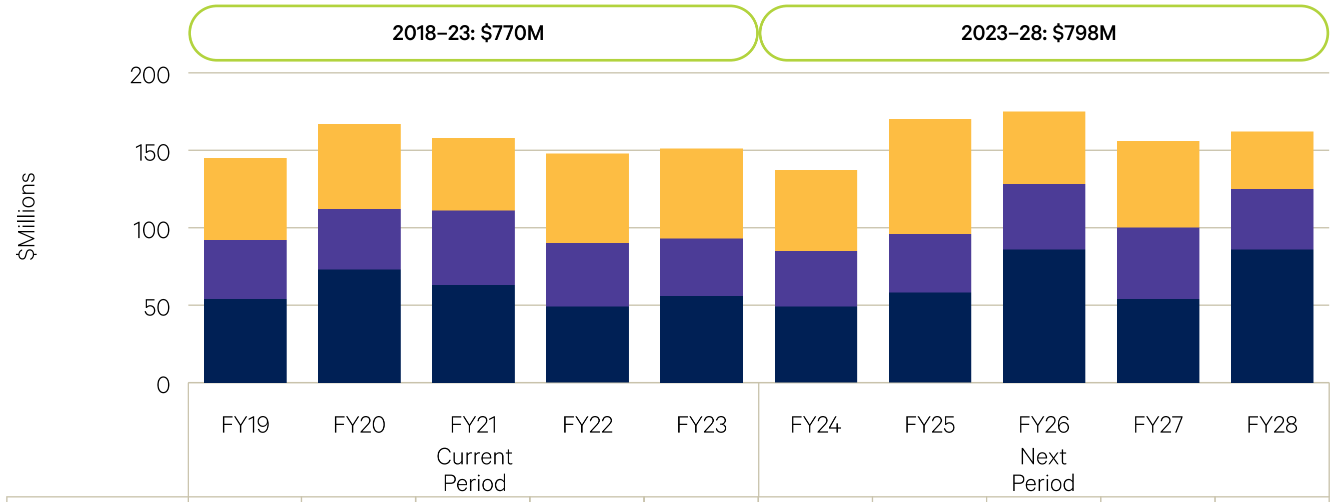


Figure 8-6 shows our 2018–23 and 2023–28 Repex by subcategory – transmission lines, digital infrastructure and substations.

Figure 8-6: Comparison of Repex by sub-category in current and next regulatory period ($M, Real 2022–23)



	FY19	FY20	FY21 Current Period	FY22	FY23	FY24	FY25	FY26 Next Period	FY27	FY28
Digital Infrastructure	53	55	47	58	58	52	72	47	56	37
Substations	37	39	48	41	37	36	38	42	46	39
Transmission Lines	54	73	63	49	56	49	60	86	54	86
Total	**144**	**168**	**159**	**148**	**152**	**137**	**170**	**174**	**156**	**161**

The volumes of each category of Repex – transmission lines, digital infrastructure and substations – are determined using condition based risk modelling which is informed by:

- asset condition, performance and attribute data for the asset
- component failure modes of the overall asset class fleet and the expected probability of failure for each asset, and
- consequence values from each of the consequence models (bushfire, worker and public safety, environment, and reliability).

The output of the condition analysis is an effective asset age used to determine the probability of failure. The asset probability of failure is then combined with the consequence (criticality) values for each asset, to calculate the asset risk. This allows the optimum intervention strategy to be determined through an economic cost-benefit analysis.

Our forecasting approach is consistent with AER's asset replacement planning application note. The projects and programs included in our capex forecast will result in positive net benefits, except where strict compliance requirements exist, and are optimally timed to maximise this benefit.

The following sections 8.7.2 to 8.7.4 explain the nature and drivers of our 2023–28 Repex by category.

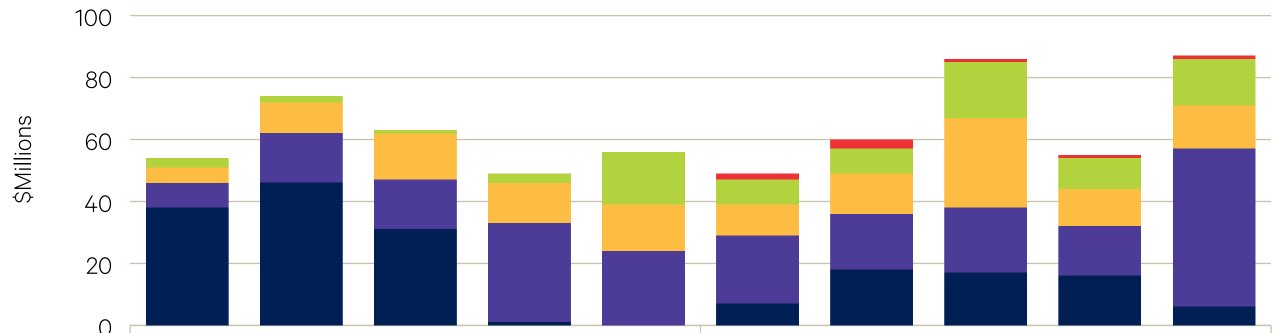
8.7.2 Transmission lines

Our 2023–28 forecast for transmission lines is $334.5 million and comprises around 41.9 per cent of our total 2023–28 Repex forecast. Our transmission line and cable network is made up of assets dating back to the 1950s, with a significant share of lines being commissioned in the 1960s and 1970s.

Our 2023–28 Repex forecast for these assets will maintain the safety and reliability of the network to meet our compliance obligations as the condition of our transmission line assets deteriorates due to age. This Repex will promote network resilience in response to extreme weather events and asset ageing.

Figure 8-7 shows that the key sub-categories for transmission lines relate to replacement or refurbishment of transmission towers, transmission poles, insulators and conductors and cable.

Figure 8-7: 2023–28 forecast Repex – Transmission lines ($M, Real 2022–23)



	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28
			Current Period					Next Period		
TL - Underground cables	0	0	0	0	-	2	3	1	1	1
TL - Overhead conductors	3	2	1	3	17	8	8	18	10	15
TL - Insulators	5	10	15	13	15	10	13	29	12	14
TL - Transmission Towers	8	16	16	32	24	22	18	21	16	51
TL - Transmission Poles	38	46	31	1	–	7	18	17	16	6
Total	**54**	**73**	**63**	**49**	**56**	**49**	**60**	**86**	**54**	**86**

Transmission towers

Steel lattice towers are critical assets in our network and are used to support conductors on overhead transmission lines. Our 2023–28 forecast capex for these assets is $128.1 million, which is largely driven by safety and bushfire management.

We will replace 102 steel towers which are at end of life across coastal transmission Line 11 (Dapto to Sydney South – Picnic Point) between Sydney and the Illawarra as well as Line 23 (Munmorah to Vales Point) at the Central Coast. These steel towers have experienced the highest rates of steel corrosion on the network and present some of the highest bushfire and public safety risks. We will also invest to refurbish 266 steel towers to address specific issues identified in our condition assessments.

We will also address safety and compliance issues on our steel towers, including removing asbestos containing paint from 727 towers and replacing or modifying 2,733 climbing deterrent devices to align with the latest industry guidelines.

Transmission poles

Wood poles are used to support conductors on overhead transmission lines. Our 2023–28 capex forecast to replace and refurbish these assets is $63.9 million, which is largely driven by safety, reliability and bushfire management. Over the 2023–28 regulatory period, we will replace 468 wood pole structures with either steel or concrete pole structures to mitigate the risk of failure.

Insulators

Insulators are critical in safely attaching the high voltage conductors to transmission line structures. Our 2023–28 forecast capex for these assets is $78.2 million and is largely driven by safety and bushfire management. Over the 2023–28 regulatory period, we will replace up to 1,746 insulator sets, over multiple steel tower/pole and wood pole refurbishment/replacement projects.

We will also rectify low ground clearances on specific transmission lines, partly arising due to the changing generation mix. Renewable generator connections are increasing asset utilisation in some areas of our network, resulting in remediation requirements for low ground clearance conductors to comply with standards and maintain public safety. Our forecast capex for low ground clearances is $30.3 million.

Case study 4: Managing bushfire and safety risk

In the 2023–28 regulatory period, we will replace end of life steel towers on our 330kV transmission line between Dapto and Sydney South at a forecast cost of $56.4 million. This is our largest Repex program in the 2023–28 period. Being near to the coast, the majority of this transmission line is in a high corrosion area, with towers, conductors, insulators and attachment fittings all subject to corrosion. Corrosion increases the risk of a critical element of the transmission line failing, creating the potential for a conductor-drop event. This transmission line crosses major motorways, public spaces and bushland on the urban fringe. The safety and bushfire consequences of a failure event could be catastrophic and presents one of the highest risks on our network.

Our economic and risk assessment is supported by:

- detailed visual and ultra high-resolution condition assessment data
- field sampling and lab testing of key components, and
- bushfire propagation modelling and mobile phone based human movement data to assess the likely consequences of a failure

The serious potential consequences of failure of a single component of a transmission line were highlighted in 2018 in California, USA, when an attachment fitting failed causing the Camp Creek Road fire to ignite. This fire destroyed 18,804 structures and resulted in 85 fatalities, with billions of dollars in damages attributed to the network operator, Pacific Gas & Electric.

Our proactive and advanced condition assessment techniques mean that we can identify these critical issues and intervene before a failure event occurs, which is particularly important in these high consequence locations

Overhead conductors

Conductors are used to transmit electrical energy across distances. Our 2023–28 capex for this asset is $57.8 million, which is largely driven by safety and bushfire management. This is based on asset condition monitoring using innovative new technology – ultra-hi-res photos coupled with artificial intelligence. Our forecast capex will replace:

- 138 km of conductor which have reached end of life due to various factors including corrosion, annealing due to bushfire exposure, fretting and fatigue due to Aeolian vibration, and
- 208 km of steel earth wire due to corrosion related deterioration.

Underground cable

Monitoring systems such as cable temperature and oil sensors support the safe operation of underground cable. Our 2023–28 capex for these assets is $6.4 million and is largely driven by reliability and managing environmental risk. Over the 2023–28 regulatory period we will replace condition monitoring systems and procure spares to enable the continued safe and reliable operation of these cables.

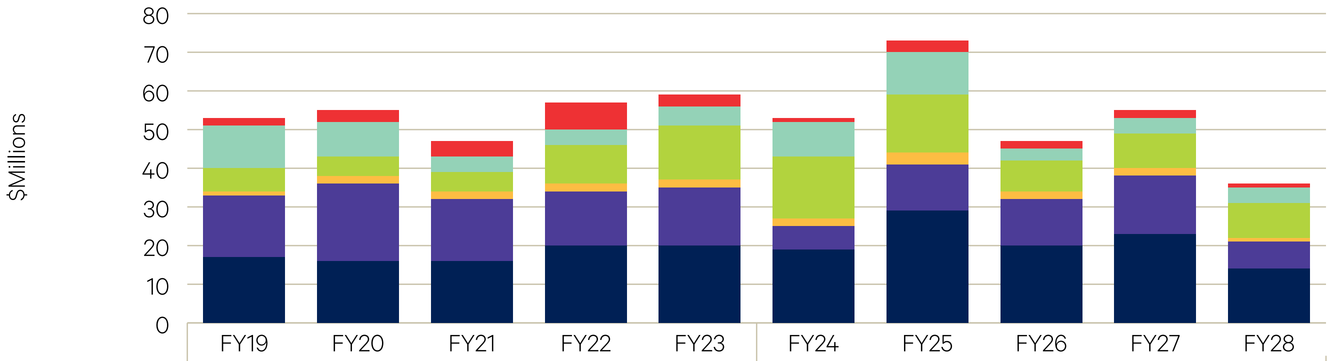
8.7.3 Digital infrastructure

Our 2023–28 forecast for digital infrastructure is $263.4 million and comprises 33.0 per cent of our total Repex forecast. Digital infrastructure assets include protection and control equipment, communications and metering equipment, and their associated power supplies.

These assets monitor each network element and take automatic action in the event of faults and other events. They also provide real time monitoring and remote operation capability allowing us to efficiently operate our network. Our 2023–28 Repex forecast for these assets will maintain the safety and reliability of the network as operational complexity of the network increases, technology changes and new legislative requirements for cyber and physical security are introduced.

Figure 8-8 shows that the key sub-categories for digital Infrastructure technology relates to protection systems, network building and security and communications systems.

Figure 8-8: 2023–28 forecast Repex – Digital Infrastructure ($M, Real 2022–23)



	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28
	Current Period					Next Period				
DI - AC/DC and Auxiliary Systems	2	3	4	7	3	1	3	2	2	1
DI - Communications Systems	11	9	4	4	5	9	11	3	4	4
DI - Network Property	6	5	5	10	14	16	15	8	9	9
DI - Market Metering Systems	1	2	2	2	2	2	3	2	2	1
DI - Control Systems & SCADA	16	20	16	14	15	6	12	12	15	7
DI - Protection Systems	17	16	16	20	20	19	29	20	23	14
Total	**53**	**55**	**47**	**58**	**58**	**52**	**72**	**47**	**56**	**37**

Protection systems

Protection system devices:

- ensure electrical faults are cleared within compliance timeframes under the Rules
- mitigate potential grid destabilising events, and
- prevent life-ending failures of high voltage assets.

Our 2023–28 capex for these assets is $105.3 million and is largely driven by reliability and safety. Over the 2023–28 regulatory period we will replace 962 protection relays at end of life with new schemes, which will also help to manage the increasingly complex generation mix.

Case Study 5: Upgrading critical protection relay network devices

Digital infrastructure assets include network control and protection systems which ensure that our equipment operates reliably, and unsafe situations are avoided or power is quickly switched off if they occur. Many of these assets are reaching the end of their serviceable lives as they become obsolete and operate less reliably.

In January 2021, one of these protection relays approaching end of life, mal-operated and disconnected the northern NSW town of Tenterfield from the network, causing a 1.8MW loss of supply to the entire town of approximately 4,000 people.

These events have also occurred internationally. In 2019, a protection relay did not operate as designed on ConEdison's network causing an outage to over 70,000 people in New York City, USA.

Our forecast capex includes $105.3 million to renew critical protection relay network devices in the 2023–28 period so we can maintain a reliable network. This includes $1.9 million for our Tenterfield substation.

Network property

Network Property comprises assets such as operational buildings, fire systems, physical security systems, HVAC systems, which are critical for housing secondary systems equipment, physically securing nationally significant assets, and providing a safe working environment for all parties working at our sites. Our 2023–28 capex for these assets is $56.1 million, which is largely driven by reliability, safety and compliance requirements. Over the 2023–28 regulatory period we will refurbish 332 items of substation property buildings (CCTV, access control and motion detection) and fire systems due to deteriorating condition. This investment will enhance no longer fit-for-purpose physical security systems on the network.

Communications systems

Communications systems provide essential communication paths for high speed protection services, operational data and telephony, and other bulk carrier services. Our 2023–28 capex for these systems is $31.1 million and will meet security, reliability and compliance obligations. Over the 2023–28 regulatory period we will replace 320 obsolete telecommunication systems.

Control systems & SCADA

Control systems are critical to the operation of our SCADA Control Room and monitoring unstaffed substations and switching stations throughout our network as well as collecting status and condition information. SCADA provides real-time visibility of network statuses and measurements. Our 2023–28 capex includes $51.5 million to meet security, reliability and compliance requirements. Over the 2023–28 regulatory period, we will replace 124 substation controllers. We will also replace operational technology equipment to align with cyber security requirements under new legislation. This investment will enhance cyber security maturity levels.

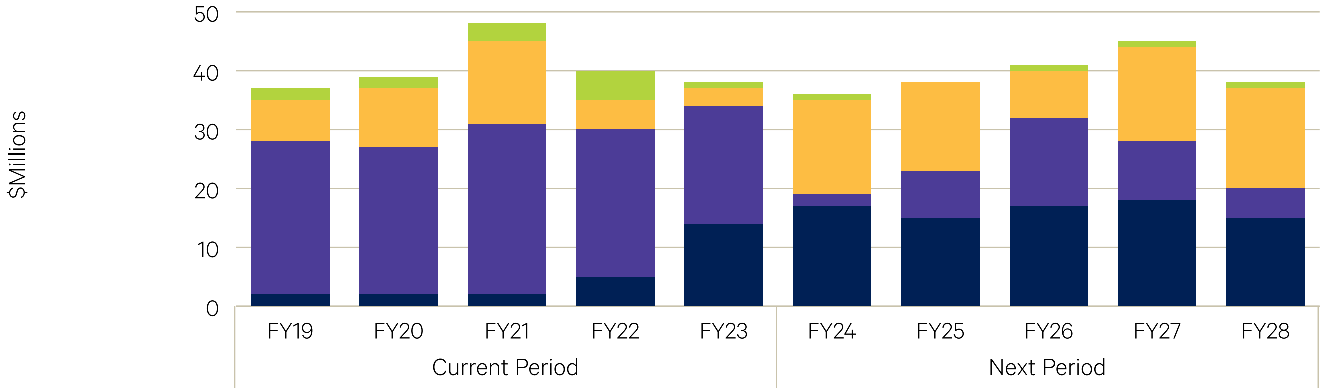
Metering & Auxiliary systems

Market metering systems are essential to accurately measuring the flow of energy across the NEM. Auxiliary systems provide vital support for the core protection, control and high voltage equipment at each substation. Our 2023–28 capex for these assets is $19.4 million and is largely driven by obsolescence, reliability and safety requirements. Over the 2023–28 regulatory period we plan to replace 152 metering and 79 auxiliary systems, which are at end of life or technologically obsolete.

8.7.4 Substations

Our 2023–28 forecast for substations is $199.7 million and comprises around 25.0 per cent of our total 2023–28 Repex forecast. Our Repex forecast for substations is necessary to maintain the safety and reliability of the network, as condition-related issues and the average age of the legacy assets continues to grow. Our substation Repex is supported by asset condition data, quantified risk assessments and economic evaluations.

Figure 8-9: 2023–28 forecast Repex – Substations ($M, Real 2022–23)



	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28
Substation – Reactive Plant	2	2	3	5	1	1	0	1	1	1
Substation – Switchbay Equipment	7	10	14	5	3	16	15	8	16	17
Substation – Power Transformers	26	25	29	25	20	2	8	15	10	5
Substation – Site Establishment and Supporting Assets	1	2	2	5	14	17	15	17	18	15
Total	**37**	**39**	**48**	**41**	**37**	**36**	**38**	**42**	**46**	**39**

Site establishment and supporting assets

Our site establishment and supporting assets are critical to performance outcomes of our substation assets. Our 2023–28 forecast for these assets is $82.2 million, which is largely driven by reliability and safety risk management. Over the 2023–28 regulatory period we plan to refurbish corroded gantry steelwork at 5 substations where improved asset condition monitoring has identified significant steelwork corrosion indicating that asset have reached end of life and have an increased risk of failure.

Case study 6: Installation of substation monitoring devices

Our high voltage transformers and reactors can fail when the bushing internal insulating material degrades and fails. As these devices are filled with large volumes of oil, an insulation failure can result in an explosion, fire and release of oil. This can destroy the equipment, cause damage to surrounding assets and the environment and pose a safety risk for people. It can also result in a loss of electricity supply.

We have installed real time monitoring devices on many of our transformers and reactors to continuously monitor for degradation, allowing us to respond prior to a catastrophic failure occurring. In 2019, the monitoring system detected an issue on a reactor at our Sydney South substation allowing us to intervene prior to failure. Had the asset failed, it may have reduced supply capacity to the Sydney CBD for up to 9 months.

Our 2023–28 capex forecast for site establishment and supporting assets includes $4.7 million to install more of these monitoring devices on our transformers and reactors in the 2023–28 period.

Switchbay Equipment

Switchbay equipment includes high voltage circuit breakers (CBs), current transformers (CTs) and voltage transformers (VTs) that are essential for safe access to, and clearing electrical faults from, the network. Our 2023–28 forecast for these assets is $71.7 million, which is largely driven by reliability and safety risk management. Over the 2023–28 regulatory period we will replace 708 switchbay equipment units.

A small amount of expenditure, $0.4 million, relates to the replacement of circuit breakers with non-SF6 alternatives. This will enable early trials of this technology which, if proven, will contribute to the achievement of lower emissions targets in future regulatory periods.

Power Transformers

Power transformers are vital to our network as they change the voltage and current of electricity supplied to customers. Our 2023–28 forecast capex for these assets is $40.6 million, which is largely driven by network reliability, noting that the performance of these assets is a key driver of reliability. Over the 2023–28 regulatory period we will replace 10 power transformers.

Reactive plant

Reactive plant – capacitor banks and shunt reactors – enable us to operate the transmission network within the defined voltage limits under the NER. Our 2023–28 forecast capex for these assets is $5.2 million, which is largely driven by voltage limit requirements under the Rules, as the probability of failure of these assets increases. Over the 2023–28 regulatory period we will replace of 5 reactive plant based on our quantified risk methodology, which considers condition analysis and the probability and consequence (criticality) of failure.

8.8 Augex

Our 2023–28 Augex forecast of $253.6 million[150] will maintain a reliable, safe and resilient network that supports the changing energy system. Our 2023–28 forecast capex is about 16.9 per cent below our estimated 2018–23 Augex of $305.4 million (excluding capex on ISP projects), which was driven by two key projects, PSF and the new Stockdill sub-station, which will be completed in the 2018-23 period.

Our lower Augex in the 2023–28 regulatory period will:

- support rapid load growth driven by new spot loads including data centres and large commercial and residential developments in western Sydney (Western Sydney Priority Growth area). Peak demand increases are also forecast for the Beryl, Vineyard (north west Sydney) and Broken Hill areas
- meet our compliance obligations relating to voltage levels, as the minimum demand for NSW is forecast to decline over the next regulatory period, predominantly due to solar generation on the power system. This will trigger the need to undertake a program of installing reactors to ensure continuing voltage stability, and
- realise economic benefits by alleviating network congestion and reduce generator curtailment to enable additional generation from low cost and low emission sources.

8.8.1 Our Augex profile

Figure 8-10 shows Augex trends compared to the AER's allowance over the 2014–18, 2018–23 and 2023–28 regulatory periods. Overall, our Augex forecast of $253.6 million for the 2023–28 regulatory period, excluding pre-approved Project EnergyConnect capex, is $51.7 or 16.9 per cent lower than our expected Augex in the current period, excluding capex on ISP projects.

150 Excluding pre-approved 2023–28 capex.

Figure 8-10: Augex trends compared to the AER allowance excluding ISP and the NSW Electricity Infrastructure Roadmap projects ($M, Real 2022–23)

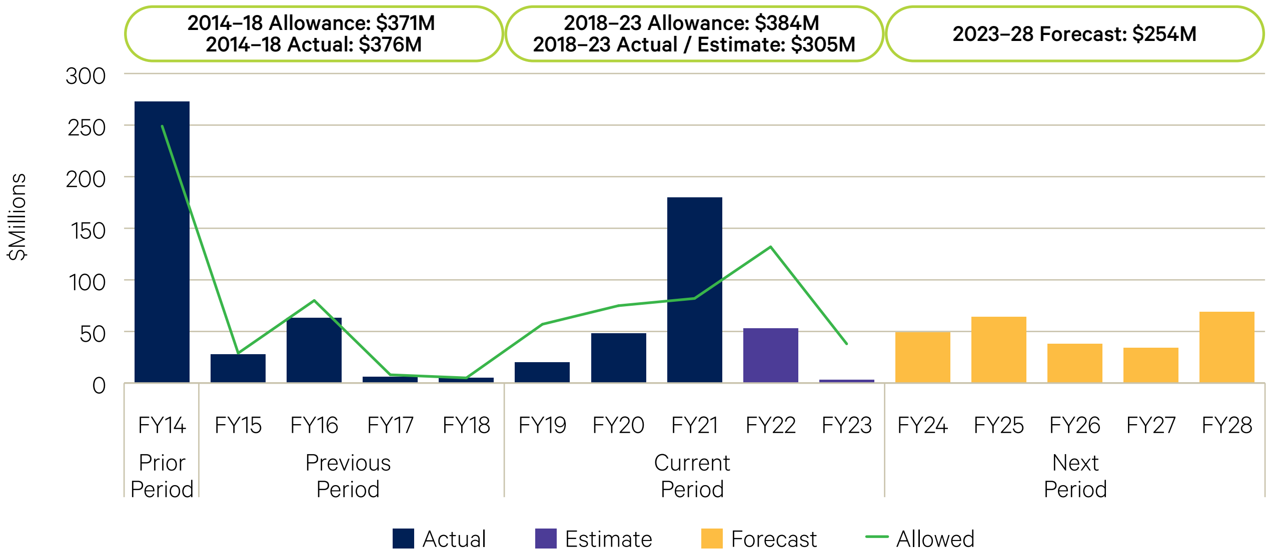


Figure 8-11 and Table 8-6 show our Augex in the 2018–23 and 2023–28 regulatory periods. These show that the key drivers of the increase in Augex in the 2023–28 regulatory period are anticipated Major Projects (non-ISP Augex projects greater than $40 million) and demand,[151] which comprise around [redacted] million and $85.2 million respectively of total Augex (or [redacted] per cent).

Figure 8-11: Comparison of Augex by driver in current and next regulatory period, excluding pre-approved forecast capex, ISP and the NSW Electricity Infrastructure Roadmap projects ($M, Real 2022–23)

[redacted]

Notes: Capex in FY22 and FY23 does not include costs for SaaS that are required under the recent changes to International Financial Reporting Standards (IFRS) to be expensed. The changes in accounting standards are discussed in section 7.5.1.

151 Augex projects expected to cost more than $40 million.

Table 8-6: 2023–28 Augex by category and year ($M, Real 2022–23)

Augex	Total 2018–23	2023–24	2024–25	2025–26	2026–27	2027–28	Total 2023–28	2023–28 % of total
Major Projects	275.9	[redacted]						
Strategic Property	–	[redacted]						
Base Augex (excluding major projects)	14.8	31.3	63.6	33.9	20.4	12.5	161.6	63.7
Compliance	2.7	4.8	11.6	18.2	0.5	1.8	36.9	14.5
Demand	8.0	22.9	33.4	7.6	13.9	7.3	85.2	33.6
Economic Benefits	4.2	3.6	18.6	8.1	6.0	3.3	39.6	15.6
Connections	14.7	–	–	–	0.6	2.3	2.9	1.1
Total Augex (excluding pre-approved Project EnergyConnect and NCIPAP)	305.4	48.5	64.3	37.5	34.0	69.2	253.6	100.0
Pre-approved Project EnergyConnect	n.a	457.2	75.6	–	–	–	532.8	n.a
Total including pre-approved Project EnergyConnect	305.4	505.8	139.9	37.5	34.0	69.2	786.5	n.a
NCIPAP	32.8	2.6	9.0	4.6	0.0	–	16.2	n.a

The majority of the projects included in our Augex forecasts have been identified using the following three step approach:

- identify network constraints using demand forecasts and power system simulation
- calculate the expected risk of unserved energy, the inability to connect new load or not meet our compliance obligations. In the case of economic benefits projects, we consider the lost opportunity cost of constraining generation which leads to higher energy costs, and
- compare the avoided risk cost or economic benefits against the cost of the credible options using an economic cost-benefit evaluation.

In the case of strategic property, we have adopted the following approach in developing our forecast:

- identify long term supply needs to meet future network reliability requirements
- determine efficient future locations in close proximity to the load centres and near to existing assets
- assess the property to determine its availability to procure in the future and future cost, and
- compare the risks and net economic benefits between early and later procurement using an economic cost-benefit evaluation.

Sections 8.8.2 to 8.8.4 explain the nature and drivers of each Augex sub-category.

8.8.2 Major Projects (non-ISP)

Major Projects are non-ISP Augex projects greater than $40.0 million. These projects are detailed in Table 8-7 and comprise around [redacted] million or [redacted] per cent of our forecast Augex. They are primarily required to respond to locational load growth, which if not addressed will lead to non-compliance with the NER voltage limits and IPART's reliability standards due to voltage stability and thermal limitations.

Load growth projects are supported by business cases that quantify the risk of expected unserved energy resulting from future demand forecasts and our network capacity to meet this demand. These investments will deliver net benefits and the preferred option will be subject the regulatory investment test for transmission (RIT-T) process, which will also explore the potential for non-network options to defer network investment.

Our demand forecasts are based on forecasts we receive from DNSPs and have been reconciled against AEMO's connection point forecasts. These demand forecasts are published in our 2021 TAPR.

Table 8-7: 2023–28 Augex Major Projects – included in Augex forecast ($M, Real 2022–23)

Augex Major Projects	Description
Supply to Western Sydney Priority Growth area **Forecast capex:** [redacted] million **Driver:** Locational demand	Driven by substantial increase in spot load in the Western Sydney Priority Growth area around the Western Sydney Aerotropolis, metro train lines, data centres and large commercial and residential developments and the need to maintain the reliability and supply capability to Endeavour Energy's Western Sydney distribution network.

Case study 7: Supporting growth in Western Sydney

The NSW Government has established the Western Sydney Priority Growth area, which includes the Western Sydney Employment area and Western Sydney Aerotropolis, contributing up to 200,000 new jobs for the region. As this part of Sydney develops into a 'thriving economic centre', electricity demand will increase rapidly and far exceed the current transmission network capacity in the area.

We have forecast two projects to respond to this growth in a staged approach. The first project will increase the supply capacity at our existing Sydney West substation as described in section 8.8.4 (Supply to Sydney West area). The second project will establish a new substation and supply point near our existing Kemps Creek substation, as described in section 8.8.2 (Supply to Sydney West Priority Growth area). These investments, which must meet IPART's connection point reliability standards, will support and enable the economic growth in the region.

We are forecasting a total of [redacted] million for these two projects to power the growth in Western Sydney.

Major Projects undergoing a RIT-T

We have not included the following load growth projects in our Augex forecast at this stage because they are currently undergoing RIT-T. We will include the preferred option identified through the RIT-Ts in our Augex forecast in our Revised Revenue Proposal.

Table 8-8: 2023–28 Augex Major Projects – undergoing RIT-T ($M, Real 2022–23, not included in Augex forecast)

Augex Major Projects	Description
Supply to the North West Slopes project[152] **Indicative cost:** $168.4 million **Driver:** Locational demand	Driven by increased spot load resulting from the connection of new industrial loads (i.e. Narrabri Gas) and underlying demand growth in Narrabri and Gunnedah. If not addressed, this load increase will lead to non-compliance with NER voltage limits[153] and IPART reliability standards due to thermal limitations. The RIT-T can be found here.
Supply to Bathurst Orange and Parkes (stage 1).[154] **Indicative cost:** $117.4 million **Driver:** Locational demand	Driven by increased spot load due to the expansion of a mine at Orange, connection of new mines in the Bathurst and Parkes areas and industrial load expansion at the Parkes special activation precinct. If not addressed, this load increase will lead to non-compliance with NER voltage stability limits[155]. Stage 1 investment may involve the installation of dynamic reactive power support devices at Parkes and Panorama substations. The RIT-T can be found here.
Managing risk on Transmission Line 86 (Tamworth – Armidale) **Indicative cost:** $331.1 million **Driver:** Economic benefits	Driven by the deteriorating condition of wood poles on the transmission line, which forms part of the Queensland – New South Wales Interconnector (QNI) path. There is an opportunity to address the condition issues through an Augex solution which is expected to deliver material market benefits. The RIT-T can be found here.

8.8.3 Strategic Property

Strategic property relates to the acquisition of easements for future investments to meet expected load growth and deliver future ISP Projects, which would support the transition to renewable generation. These projects are detailed in Table 8-9 and comprise [redacted] million or [redacted] per cent of total Augex.

Table 8-9: 2023–28 Strategic Property – included in Augex forecast ($M, Real 2022–23)

Strategic Property	Description
Strategic property acquisition for Western Sydney Priority Growth Area **Forecast capex:** [redacted] million	A new Western Sydney BSP will be needed to supply the growing Western Sydney demand. Land south of the existing Kemps Creek 500/330 kV Substation is a suitable site with its access to the 330 kV and 500 kV network and its close-proximity to the load centre. There is a window of opportunity to secure the land south of Kemps Creek Substation while it is still available, prior to the surrounding land in the area being built out, which is currently occurring rapidly. Alternate locations for the BSP are likely to be higher-cost solutions because they will be a further distance from the existing Kemps Creek 500/330 kV Substation, requiring additional underground 330 kV cable connections back to Kemps Creek or another close-by substation.

We have not included the strategic property project set out in Table 8-10 in our Augex forecast. At this stage, we have included it as a contingent project and will reassess its status for our Revenue Proposal once we understand how AEMO is treating this project in its 2022 ISP.

152 The Project Specification Consultation Report (PSCR) was published in April 2021. The Project Assessment Draft Report (PADR) is expected to be published in early 2022.
153 Schedule 5.1.4 of the NER requires us to plan for voltage control to maintain voltage levels within 10 per cent of normal voltage.
154 The PSCR was published in March 2021. The PADR is expected to be published in early 2022.
155 Schedule 5.1.4 of the NER requires us to plan for voltage control to maintain voltage levels within 10 per cent of normal voltage.

Table 8-10: 2023–28 Strategic Property – included as contingent project ($M, Real 2022–23)

Strategic Property	Expenditure description
Strategic easement acquisition for supply to Sydney from the south **Indicative cost:** $252.2 million	This easement will provide a corridor for a future 500 kV double circuit transmission line to be installed from South Creek (in the western suburbs of Sydney) to Bannaby (in the Southern Highlands of NSW). It is needed for the 'Sydney Ring (Sydney, Newcastle and Wollongong Supply)' project, which is an Actionable project in AEMO's Draft 2022 ISP.

8.8.4 Base Augex

Base Augex investments support compliance, demand and economic benefits. This investment comprises $161.6 million or 63.7 per cent of total Augex. We are projecting an increase in these three categories of our Base Augex over the 2023–28 regulatory period. We have not yet commenced a RIT-T for any of these investments.

Table 8-11: 2023–28 Base Augex ($M, Real 2022–23)

Base Augex	Expenditure description
Compliance ($36.9 million)	The change in the generation mix is expected to lead to various voltage level issues through the NSW network, requiring additional compliance-driven projects to maintain power quality. In addition, the minimum demand for NSW is forecast to decline over the next regulatory period, predominantly due to solar PV generation from households. This is expected to require the installation of reactors to maintain voltage stability. Key compliance related projects included in our Base Augex are: • improve voltage control in Southern NSW area ($21.0 million) • maintaining voltage in Greater Sydney area ($9.0 million).
Demand ($85.2 million)	Anticipated load growth is also driving an increase in Base Augex, outside of the Major Projects, including to: • maintain voltage in the Vineyard area ($38.4 million) • maintain voltage in the Beryl area ($20.9 million) • supply to Sydney west area ($17.4 million) • supply to far west NSW ($8.4 million).
Economic benefits ($39.6 million)	The increase in renewable generation across the network is leading to increases in generator constraints in some areas. Investment to relieve these constraints will reduce generator curtailment and provide an economic benefit by enabling additional generation from these low cost and low emission sources. The most substantive economic benefits projects included in our Base Augex are: • increase capacity of 132 kV busbars at Wagga Wagga Substation ($5.2 million), and • increase capacity for generation in Wagga Wagga north area ($10.3 million) • Manage multiple contingencies in Sydney north west area ($10.1 million).

We are examining other potential Augex projects, which we may include in our Revised Revenue Proposal in consultation with our customers and other stakeholders.

8.9 ICT

Our 2023–28 ICT forecast of $86.9 million is $19.6 million, or 29.1 per cent, higher than our estimated 2018–23 capex of $67.3 million. Our 2023–28 ICT forecast will:

- refresh or replace legacy applications and systems which are at the end of life
- enhance our data analytics and reporting capability
- continue our transition to cloud-based platforms
- modernise our IT platforms to align with the changing requirements of our network and technology trends, and
- meet our obligations under new cyber security legislation.

8.9.1 Our ICT profile

Figure 8-12 shows ICT capex trends compared to the AER's allowance over the 2014–18, 2018–23 and 2023–28 regulatory periods.

Figure 8-12: ICT capex trends compared to the AER allowance ($M, Real 2022–23)*

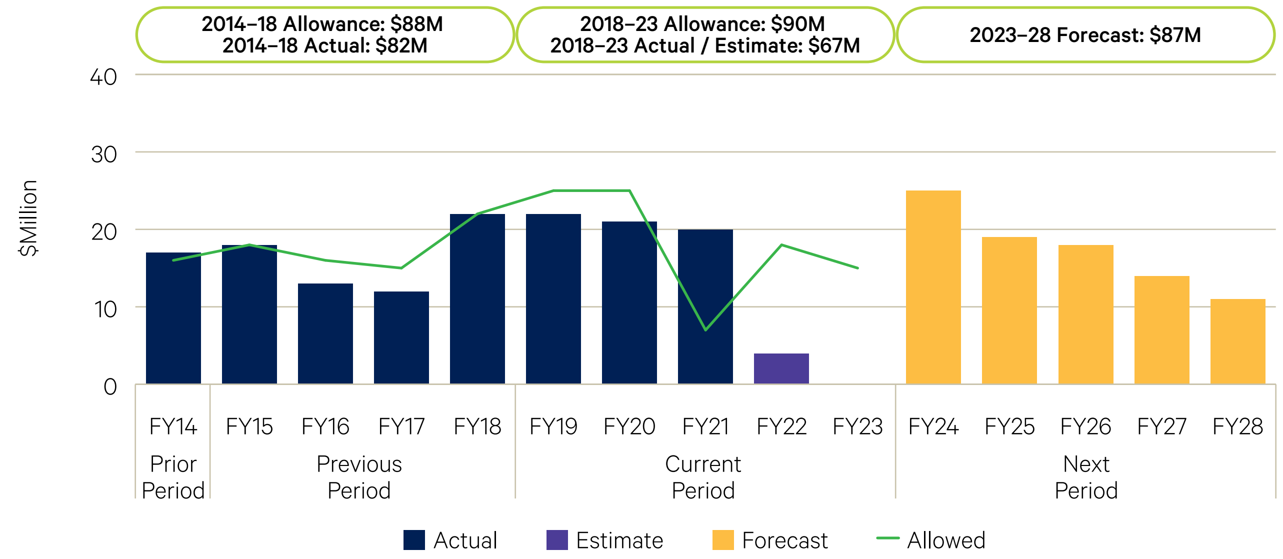
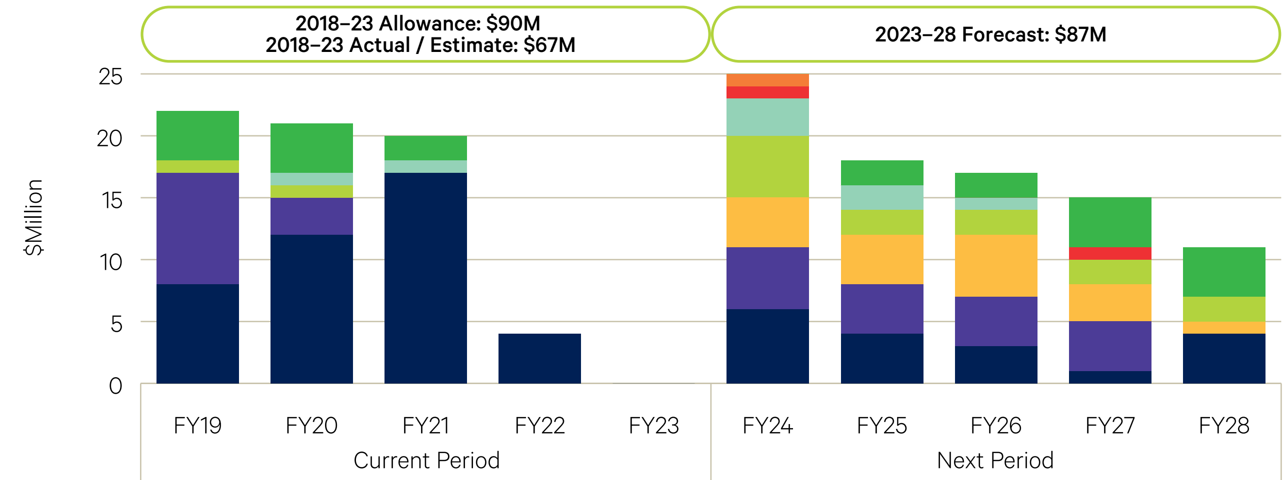


Figure 8-13 shows our ICT investment in the 2018–23 and 2023–28 regulatory periods. We expect to underspend our ICT allowance in the current period as a result of changes to the accounting standards, described in Section 7.5.1. These changes require that from regulatory years 2021–22 onwards, we must expense costs for configuration or customisation in cloud computing arrangements, whereas these costs were treated as capex prior to 2021–22.

Figure 8-13: Comparison of ICT capex in current and next regulatory period ($M, Real 2022–23)*



	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28
Customer Safety and Support	–	–	–	–	–	1	0	–	–	–
Employee Enablement	1	1	(0)	–	–	5	2	2	2	2
Data and Decisioning	0	1	1	–	–	3	2	1	–	–
Cyber Security	4	4	2	–	–	0	2	2	4	4
Application Maintenance	8	12	17	4	0	6	4	3	1	4
Bespoke Applications	0	0	–	–	–	4	4	5	3	1
Operational Evolution	–	0	0	–	–	1	0	0	1	–
Infrastructure and Network	9	3	0	–	–	5	4	4	4	0
Total	**22**	**21**	**20**	**4**	**0**	**25**	**19**	**18**	**14**	**11**

* Notes: Capex in FY22 and FY23 does not include costs for SaaS that are required under the recent changes to International Financial Reporting Standards (IFRS) to be expensed. The changes in accounting standards are discussed in section 7.5.1.

Table 8-12 sets out our ICT capex forecast for the 2023–28 periods by package:

Table 8-12: 2023–28 ICT by category and year ($M, Real 2022–23)

ICT package	Expenditure description
Application Maintenance **$18.3 million**	This investment will update or replace around 93 specialised software applications either due to obsolescence or end of vendor support. These applications consist of commercial off the shelf (COTS), which have a five year average lifecycle, and cloud-based applications. As we replace the COTS applications, we plan to leverage the latest software features that are increasingly only being provided as a cloud-based service.
Infrastructure and Network **$17.8 million**	This investment involves a cyclical refresh of our Corporate Data Network (CDN) and Data Centre (DC) to extend their asset lives. This technology change is driven by our critical IT infrastructure, which supports our core business, reaching end of life and the transition to a hybrid IT environment as services increasingly move to cloud based solutions.
Bespoke Applications **$17.5 million**	This investment involves refreshing our bespoke applications with a modern code base and implementing a secure development environment for all applications. We currently have 18 legacy bespoke applications that have been developed over the course of the last 15 years to address the shortcomings in capabilities offered in COTS applications. The technology supporting these applications is no longer supported by vendors and will need to be replaced to remain secure.
Employee Enablement **$12.2 million**	This investment will maintain our current End User Services and migrate to supported versions of Microsoft Products. It also involves replacing the soon to be decommissioned Integrated Services Digital Network (ISDN) telephony solution with a Session Internet Protocol (SIP) solution.
Data and Decisioning **$6.3 million**	This investment will address gaps in our core data capabilities to meet the Critical Infrastructure Act 2021 requirements. These proposed changes will also streamline reporting requirements to reduce compliance risks around financial reporting
Operational Evolution **$1.9 million**	This investment will replace our Project and Portfolio Management (PPM) system with a hybrid cloud-based solution that incorporates the industry standards system. This evolution in Project Management capability is necessary in order to accommodate our business activities going forward in delivering major ISP projects. We also intend to expand our Digital Core capabilities to help us better manage our inventory, assets and workforce.
Customer Safety and Support[156] **$1.0 million**	This investment will upgrade our Customer Relationship Management (CRM) system to support multi-channel engagement that will allow stakeholders self-service access to real time, tailored information.
Cyber Security **$11.9 million**	This investment will meet new and expected cyber security and critical infrastructure compliance obligations under: • the Critical Infrastructure Act 2021 • the Energy Legislation Amendment Act 2021, and • AEMO's Australian Energy Sector Cyber Security Framework (AESCSF). We expect this will come into effect by the end of 2021 for full compliance in 2025–26.

156 The application is expected to be fully delivered in FY26.

8.10 Non-network Other – Property

Our 2023–28 Property forecast of $22.8 million will enable us to continue to provide safe, compliant and productive offices and depots that support the increase in network operations activity as we deliver an increasing capital program including major ISP projects.

We undertake an independent condition audit of our offices and depots every five years as part of our detailed site inspection cycle. The outcomes from the audit are reviewed by an independent third party to advise on options for prioritising addressing the audit recommendations.

Our 2023–28 Property forecasts are based on the outcomes our most recent condition audit (2020 Audit),[157] which assessed the electrics, external areas and façade, internal areas, fire safety, roof condition, hydraulic and mechanical functionality of each asset.

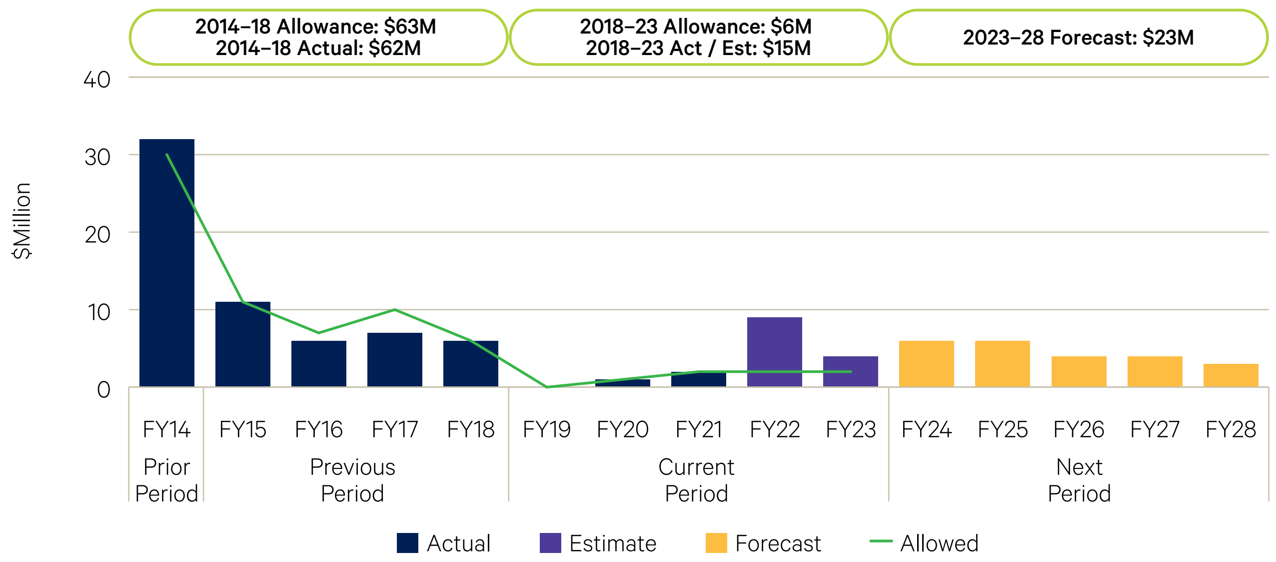
The 2020 audit found that some assets, including Waratah West, are now in poor condition and:

- present increased Workplace Health and Safety (WHS) and operational risks, and
- some components of the buildings are at end of life must be replaced.

8.10.1 Our Property profile

Figure 8-14 shows Non-network Property capex trends compared to the AER's allowance over the previous, current and next regulatory periods. This shows that our 2023–28 capex forecast of $22.8 million is $7.5 million or 48.7 per cent higher than 2018–23 actual/estimated capex of $15.3 million.

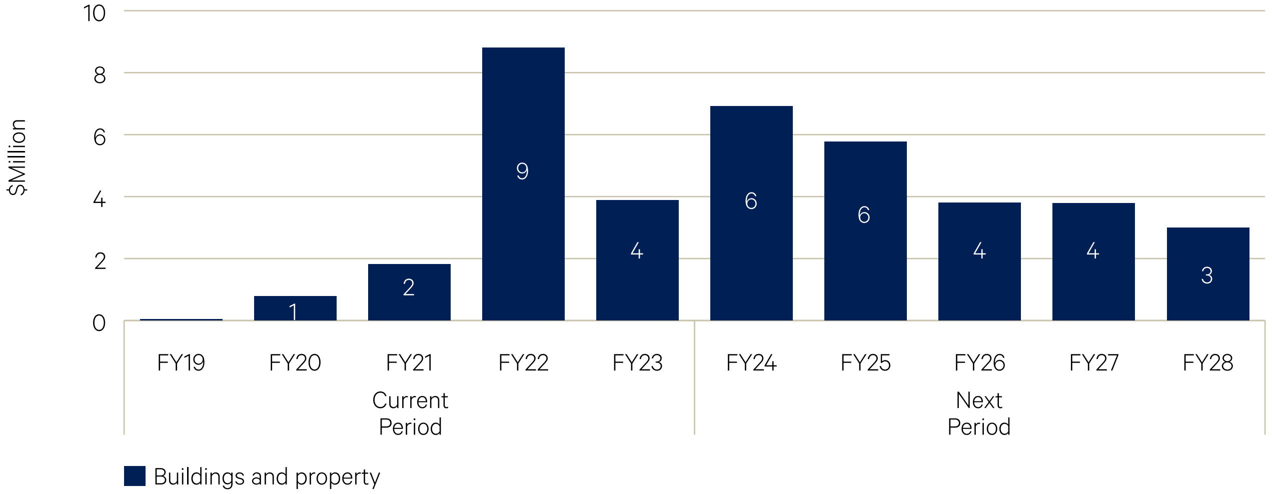
Figure 8-14: Non-network property capex trends compared to the AER allowance ($M, Real 2022–23)[158]



157 Undertaken by Nutbrook. We engaged Aptness to peer review Nutbrook's recommendations
158 In its 2018–23 Revenue Determination, the AER did not break provide a break-down of Non-Network Other in terms of Fleet, Plant and Equipment and Property. We have allocated the AER allowance across the sub-categories based on actual results for FY19, FY20 and FY21, and used FY21 as a proxy for FY22 and FY23.

Figure 8-15 shows our Non-network Property capex in the 2018–23 and 2023–28 regulatory periods.

Figure 8-15: 2023–28 forecast Non-network – Property ($M, Real 2022–23)



In the 2023–28 regulatory period, we will undertake the following investments to ensure that we maintain our six depots to a safe and compliant standard:

- roof repairs and replacement
- electrical work including life cycle replacement and addressing electrical non-conformances at the Orange, Wallgrove, Waratah West and Yass depots
- mechanical works including end-of-life and/or make-safe mechanical chillers, roller-doors, pumps and general fixtures
- lighting replacement with LED lights and solar PV systems to meet our sustainability initiatives
- internal office and depots façade works, including replacing and or repairing ceiling sub-structures, car park entry doors, walls, steel structures around lifts, common areas and amenities, and
- tarmac and concrete resurfacing and repairs.

8.11 Non-network Other – Fleet, plant and equipment

Our 2023–28 fleet, plant and equipment capex forecast of $48.6 million is critical for safe access to our network and the continued reliable, secure and safe delivery of prescribed transmission services. Providing fit for purpose equipment allows us to safely access network sites and undertake work on our network.

During the 2023–28 regulatory period the key drivers of our fleet, plant and equipment forecast are to maintain the suitability and safety of our current fleet plant and equipment. We apply an established risk management framework to determine our fleet, plant and equipment forecasts, which optimises cost, risk and performance while meeting our regulatory compliance obligations.

8.11.1 Our fleet, plant and equipment profile

Figure 8-16 shows fleet, plant and equipment trends compared to the AER's allowance for the 2014–18, 2018–23 and 2023–28 regulatory periods. This shows that our 2023–28 forecast of $48.6 million is $5.5 million or 12.7 per cent higher than 2018–23 actual/estimated capex of $43.2 million.

Figure 8-16: Fleet, plant and equipment trends compared to the AER allowance ($M, Real 2022–23)

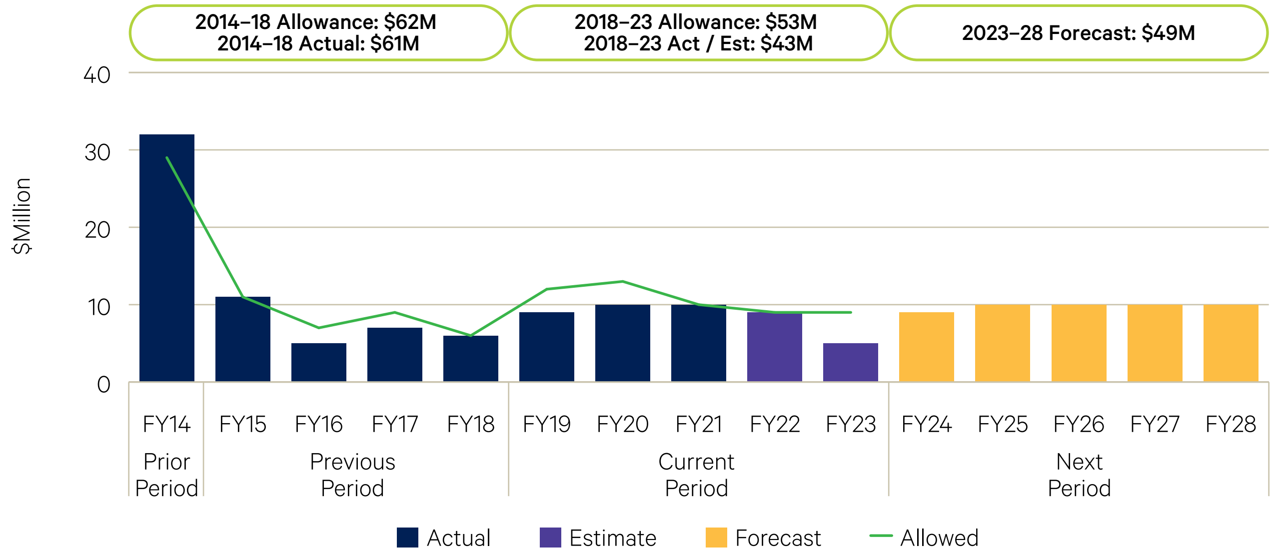
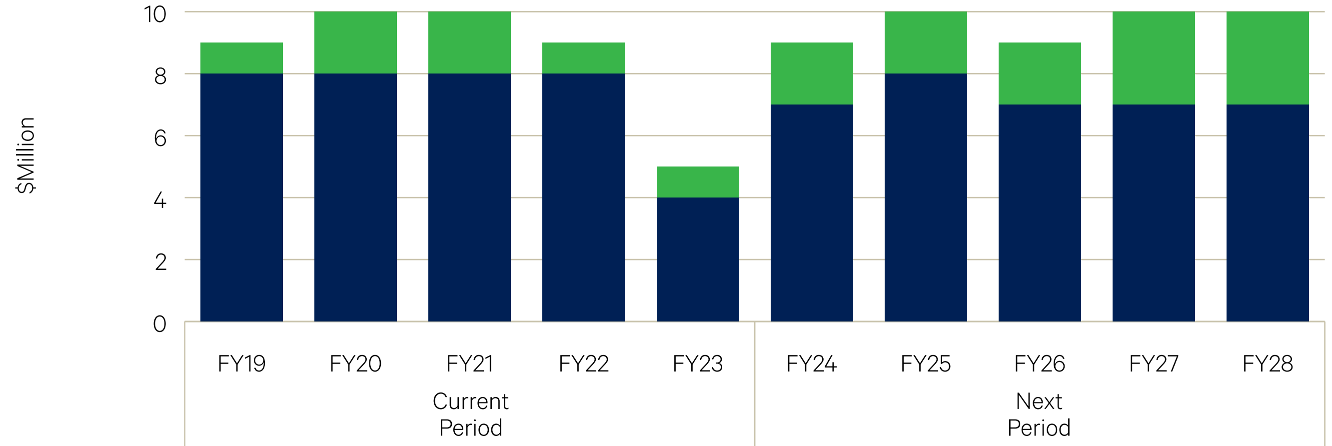


Figure 8-17 details our fleet, plant and equipment capex in the 2018–23 and 2023–28 regulatory periods.

Figure 8-17: 2023–28 forecast Non-network – fleet, plant and equipment ($M, Real 2022–23)



	FY19	FY20	FY21	FY22	FY23	FY24	FY25	FY26	FY27	FY28
Plant and equipment	1	2	2	1	1	2	2	2	3	3
Fleet	8	8	8	8	4	7	8	7	7	7
Total	**9**	**10**	**10**	**9**	**5**	**9**	**10**	**10**	**10**	**10**

In the 2023–28 regulatory period, we will undertake the following investments to ensure our fleet, plant and equipment remain fit for purpose to support the continued safe and reliable access to our network and delivery of prescribed transmission services:

- providing fleet capabilities consistent with our Motor Vehicles and Mobile Plant Renewal and Maintenance Strategy, to effectively support network operations and deliver major ISP transmission projects
- electrifying our fleet vehicles by continuing to transition our pool car fleet to full electrical vehicles (EVs) and commence the transition of our light commercial vehicles when commercially available, and
- improving our equipment utilisation in order manage our construction and maintenance costs. In particular, we plan to purchase an additional 60 meter elevated work platform to replace a 46 meter unit, and replace two 35 meter elevated work platforms that will reach end of life.

8.12 Capitalised Overheads

Overhead activities support the delivery of our capital program. They include corporate support and management costs not directly incurred in producing output, and shared costs that we cannot directly allocate to a particular business activity or cost centre.

We have forecast our overhead costs using the AER's default approach based on:

- 75 per cent of capitalised overheads are fixed based on the most recent available year of actual capex (i.e. 2021–22), and
- 25 per cent of capitalised overheads vary with direct capex.[159]

The AER has reflected its default method in its standard capex model for electricity distribution that it is currently consulting on and is expected to apply this method in its Revenue Determination for our 2023–28 regulatory period.[160]

Figure 8-18 shows capitalised overhead trends compared to the AER's allowance for the 2014–18, 2018–23 and 2023–28 regulatory periods. This shows our 2023–28 forecast of $159.0 million is $14.7 million or 10.2 per cent higher than 2018–23 estimated capex of $144.3 million to enable us to deliver a larger capital works program.

Figure 8-18: Capitalised overheads trends compared to the AER allowance ($M, Real 2022–23)

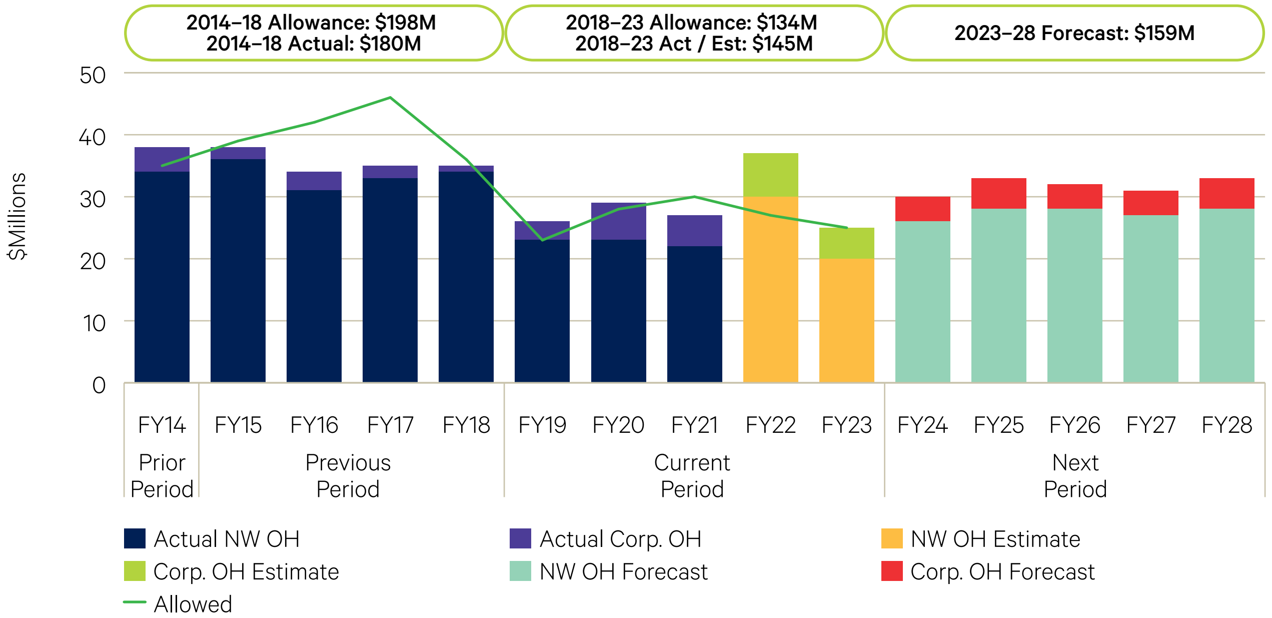


Table 8-13 shows our capitalised overheads at a total level and by subcategory in the 2018–23 and 2023–28 regulatory periods.

Table 8-13: Capitalised overheads – comparison between current and next regulatory period ($M, Real 2022–23)

Capitalised overheads	Total 2018–23	Total 2023–28	2023–28 % of total	Difference $	Difference %
Capitalised Network Overheads	118.0	136.8	86.0	18.8	16.0
Capitalised Corporate Overheads	26.3	22.2	14.0	(4.1)	(15.6)
Total	144.3	159.0	100.0	14.7	10.2

159 This approach was adopted by the AER in its April 2021 decisions for the Victorian electricity distribution networks.
160 AER Standardised SCS Capex model

8.13 Supporting documentation

The following documents support this Chapter and accompany our Revenue Proposal.

Name
Expenditure Forecasting Methodology
Forethought, Transgrid Revenue Reset Stakeholder Engagement - Executive Report
Capex Model
Cost Allocation Methodology
Expenditure Capitalisation Standard
Repex Overview Paper
Augex Overview Paper
Non-network ICT Overview Paper
Non-network Other Overview Paper
GHD, Demand Driven Augex Forecast Review
Aurecon, Point Load Study
GHD, Climate change and extreme weather event resilience

9. RAB and depreciation

Key messages

> We have used the AER's Roll Forward Model (RFM) to calculate an opening RAB at 1 July 2023 of $8,713.0 million (nominal).

> Our RAB will increase over the 2023–28 period by $1,212.9 million (nominal) from $8,713.0 million (nominal) to $9,925.8 million (nominal).

> The key drivers of the increase in our RAB over the 2018–2028 period are:

- new capex of $5,083.7 million (nominal) which includes Project EnergyConnect, VNI Minor and QNI Minor
- indexation of $1,809.7 million (nominal), and
- offset by straight-line depreciation of $3,338.6 million (nominal).

9.1 Overview

Our RAB reflects the value of assets used to deliver prescribed transmission services. The RAB is the accumulation of past capex net of depreciation of assets in each period based on the standard economic lives which range from short life assets, such as communications assets (with a 10-year life) to long life assets such as transmission lines (with a 50-year life). The land and easements we own are not depreciated.

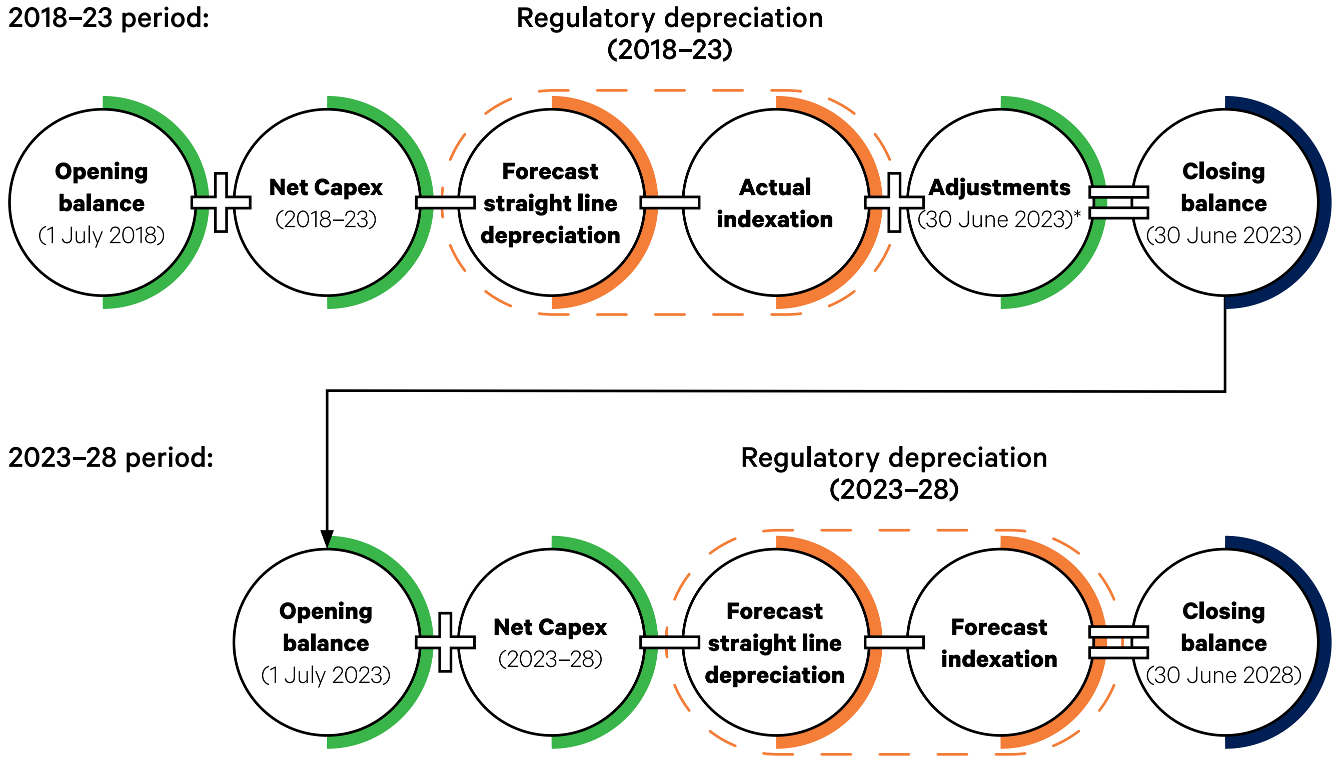
The RAB value is used to calculate the revenue required to recover our efficient costs associated with the return on capital and depreciation.[161] The value of the RAB is calculated (or rolled-forward) over the 2018–23 and 2023–28 periods consistent with the NER and the AER's models. The RAB value is adjusted each year to reflect:

- increases due to inflation (indexation)
- increases due to new capex net of any contributions from customers or proceeds from any asset sales
- deducting straight line depreciation.[162]

Our RAB value has increased significantly since the start of the 2018–23 period largely due to expenditure to deliver Powering Sydney's Future and projects included in AEMO's ISP, namely Project EnergyConnect, VNI Minor and QNI Minor.

161 The RAB is also used to calculate debt raising costs, which forms part of the operating expenditure building block.
162 Other adjustments are sometimes made to the RAB, such as truing up for the difference between actual and estimated net capex.

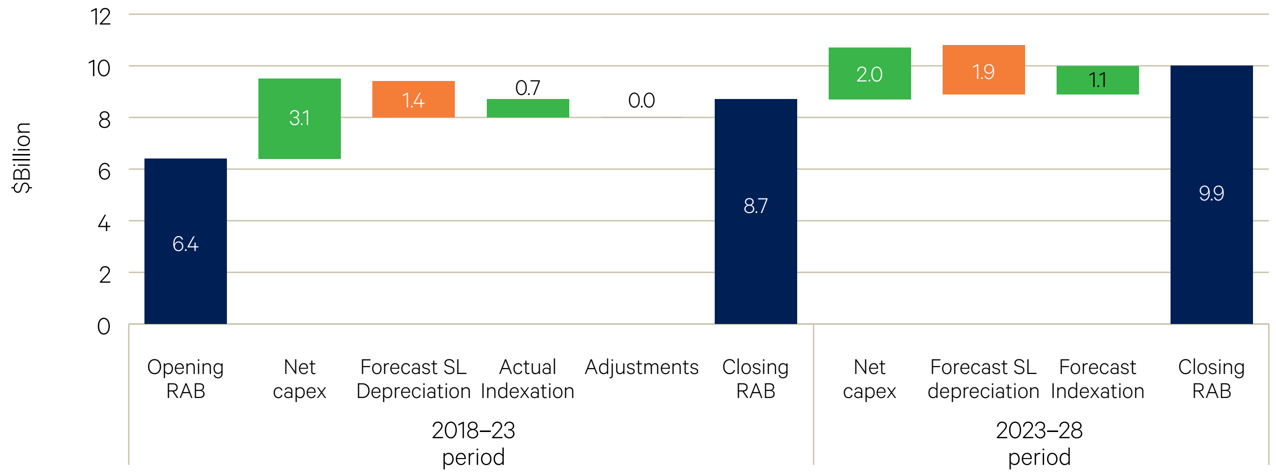
Figure 9-1: How the RAB changes over time



Note: * The adjustment is to replace estimated net capex for 2017–18 included in the opening balance with actual net capex and to remove any penalties or rewards associated with the difference between the two.

We expect our RAB will increase by $1,212.9 million (nominal) over the 2023–28 regulatory period from $8,713.0 million (nominal) at 1 July 2023 (opening RAB) to $9,925.8 million (nominal) at 30 June 2028 (closing RAB). If further ISP projects are approved then our RAB is likely to grow further in the 2023–28 period.

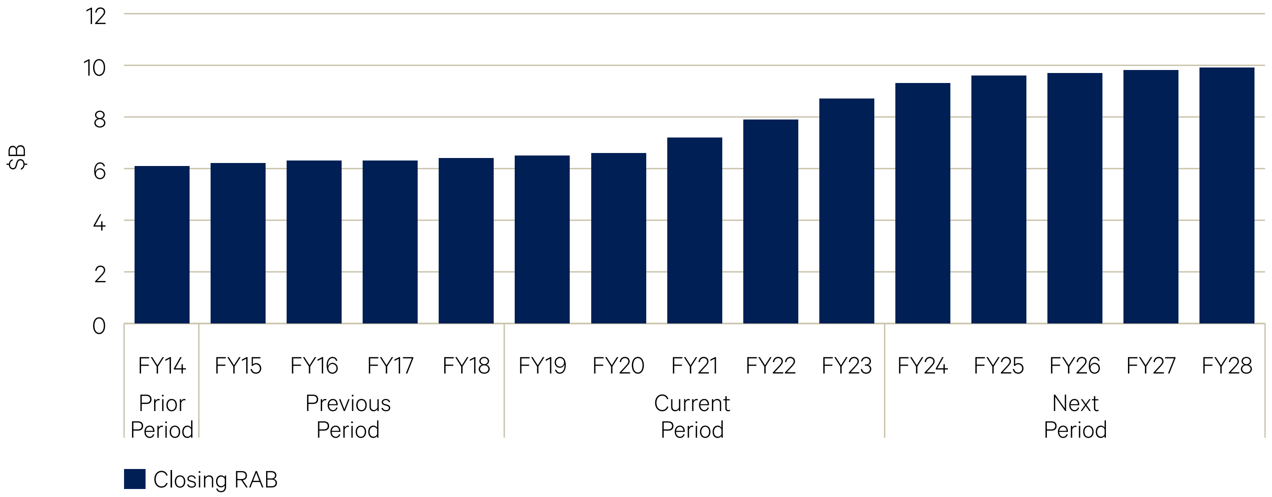
Figure 9-2: Our RAB roll-forward including approved ISP projects (nominal)[163]



163 Approved ISP projects are VNI Minor, QNI Minor and Project EnergyConnect

Figure 9-3 shows our actual and projected RAB value by year over the 2014–18, 2018–23 and 2023–28 periods.

Figure 9-3: Our RAB roll-forward including approved ISP projects (nominal)[164]



9.2 Establishing the opening RAB at 1 July 2023

Table 9-1 sets out the opening RAB as at 1 July 2023 calculated in accordance with clause 6A.6.1 and schedule 6A.2 of the NER and using the AER's roll forward model (RFM).

The opening value as at 1 July 2023 is estimated to be $8,713.0 million (nominal) based on an opening value at 1 July 2018[165] of $6,371.2 million (nominal) set by the AER in its 2018–23 Revenue Determination. Table 9-1 summarises the calculations. The completed RFM is provided as an attachment to this Revenue Proposal. We will update our inflation forecast and capex for actual 2021–22 inflation and capex in our Revised Revenue Proposal, which is due to the AER in November 2022.

Table 9-1: RAB roll-forward over the 2018–23 period ($M, nominal)

	2018–19	2019–20	2020–21	2021–22	2022–23
Opening value (1 July)	6,371.2	6,463.9	6,638.7	7,201.1	7,888.2
Actual indexation	113.7	119.0	57.1	234.0	177.5
Net-capex[1]	235.0	330.9	795.2	744.6	963.3
Forecast Straight line depreciation	(256.0)	(275.1)	(290.0)	(291.5)	(315.9)
Adjustments	–	–	–	–	(0.2)
Closing value	**6,463.9**	**6,638.7**	**7,201.1**	**7,888.2**	**8,713.0**

Note: 1. Net capex is gross capex less any asset disposals and capital contributions.

Indexation

Consistent with the approach used in our control mechanism, we calculate indexation of our opening RAB value for each year by applying the actual annual December to December All Groups CPI, Weighted Average of Eight State Capital Cities (published by the Australian Bureau of Statistics) with a one-year lag.

164 Approved ISP projects are VNI Minor, QNI Minor and Project EnergyConnect
165 1 July 2018 is the start of the 2018–23 period.

Capex

The RAB value is increased by our net capex, based on:

- our actual capex for the first three years (2018–19 to 2020–21) of the current period as reported in our 2020–21 regulatory accounts[166], and
- forecast capex for the last two years of the 2018–23 period (because actual capex is not available). As noted above, we will provide actual capex for the 2021–22 year in our Revised Revenue Proposal and may revise our forecast for the 2022–23 to reflect updated information.

Under the NER,[167] the AER may exclude capex from being added to our RAB if they determine that we:

- inefficiently overspent our capex allowances (adjusted for approved pass-through amounts)[168]
- paid inflated margins to our related parties, and
- capitalised expenditure previously classified as opex.

The relevant period for this review is 1 July 2016 to 30 June 2021 (the review period).[169] Over this period:

- our capex was less than the AER allowance when ISP projects are included and only marginally higher ($36.8 million or less than 2.0 per cent) if ISP projects are excluded[170]
- there were no related party margins in our capex, and
- we did not change our capitalisation policies.

We have therefore included our actual capex over the review period in the RAB and our estimate of capex for the period 1 July 2021 to 30 June 2023 in the RAB, noting that the capex for these years will form part of the review period at the next reset.

Depreciation

Consistent with the AER's 2018–23 Revenue Determination, we have rolled-forward the RAB using the forecast depreciation approved by the AER for the 2018–23 regulatory control period, updated as appropriate to reflect the AER's decisions on the VNI Minor, QNI Minor and Project EnergyConnect contingent projects and the bushfire pass-through.[171]

9.3 Forecast RAB over the 2023–2028 regulatory period

Table 9-2 sets out our forecast RAB value for each year of the 2023–28 period. We have derived the RAB values consistent with the NER and using the AER's PTRM. Only actual and estimated capex attributable to the provision of prescribed transmission services in accordance with our cost allocation methodology has been included in the RAB. As discussed in Chapters 8 and 17, our 2018–23 forecast capex does not include the costs of Contingent or ISP Projects. Customers will only pay for these projects if, and when, after public consultation the AER and AEMO determine that they are needed, their triggers have been satisfied and their costs have been assessed as prudent and efficient.

We have adjusted the opening RAB value of $8,713.0 million (nominal) at 1 July 2023 (the closing RAB value at 30 June 2023)[172] by:

- adding forecast indexation, which we have calculated based on the AER's December 2020 final decision on the treatment of expected inflation,[173] which is also reflected in the AER's PTRM. This is discussed in Chapter 10.
- adding forecast net-capex, which is discussed in Chapter 8, and
- deducting straight-line depreciation, as discussed in section 9.4.

166 We have relied on our 2020–21 regulatory accounts because they have restated capex in our 2018–19 and 2019–20 Regulatory Account so as to include capex for Project EnergyConnect and QNI Minor (which was not included in our 2018–19 and 2019–20 regulatory accounts)
167 NER clause S6A.2.2A.
168 Clause 6A.6.7(c) – Capex Criteria.
169 S6A.2.2A(a1) of the NER. The review period for such exclusions is the last two years of the 2015–2018 period and the first three years of the 2018–23 period (i.e., 2013–14 to 2017–18).
170 Our actual capex, excluding ISP projects, is $4 million above the AER's allowance
171 On 13 November 2020, we submitted a bushfire cost pass through application to the AER for our incremental bushfire remediation capex and opex. In May 2021, the AER's Decision approved incremental costs of $40.2 million (Real 2017–18) comprising opex of $39.4 (Real 2017–18) and capex of $0.8 million (Real 2017–18). Our forecast depreciation reflects the AER Decision on incremental capex. 168
172 The opening value for the 2023–28 period is set equal to the closing value for the 2018–23 period
173 AER, Final position – regulatory treatment of inflation, December 2020.

Table 9-2: RAB roll-forward over the 2023–28 period ($M, nominal)

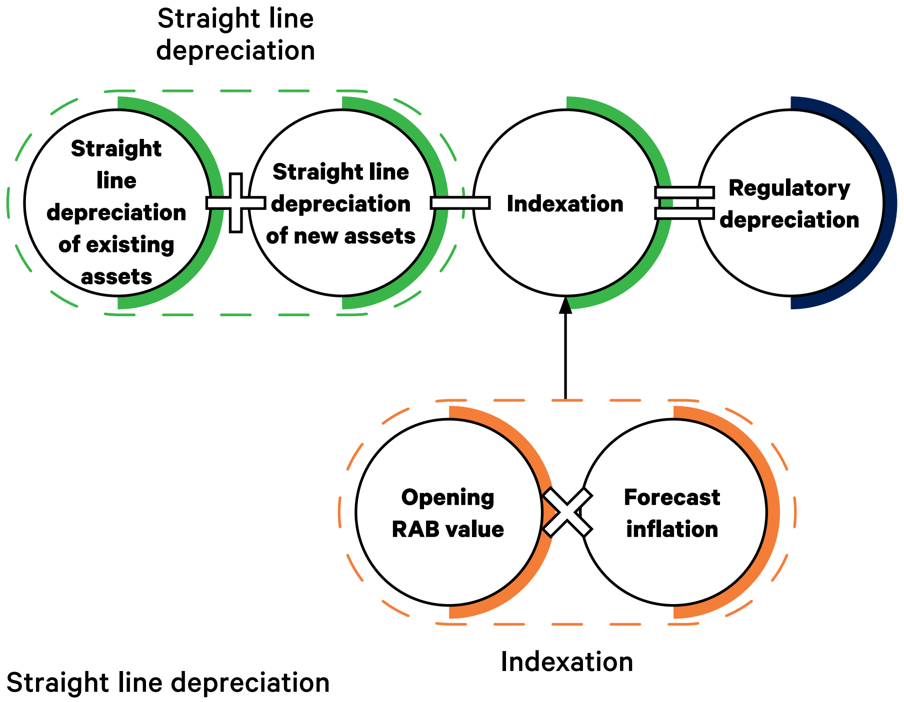
	2023–24	2024–25	2025–26	2026–27	2027–28
Opening RAB	8,713.0	9,335.5	9,594.8	9,717.6	9,805.3
Forecast indexation	204.8	219.4	225.5	228.4	230.4
Net-capex[1]	733.8	394.5	294.4	271.8	320.2
Forecast straight-line depreciation	(316.1)	(354.5)	(397.0)	(412.5)	(430.0)
Closing RAB	9,335.5	9,594.8	9,717.6	9,805.3	9,925.8

Note: 1. Net capex is gross capex less any asset disposals and capital contributions.

9.4 Depreciation methodology

Depreciation is the mechanism through which we recover our expenditure on our network investments over the economic life of the assets. Figure 9-4 shows the AER's approach to regulatory depreciation, which is to subtract forecast indexation (which increases the RAB) from straight line depreciation (which reduces the RAB).

Figure 9-4: How regulatory depreciation is calculated



Straight line depreciation

We have calculated straight line depreciation of our existing assets (as at 30 June 2023) over the 2023–28 period using the AER's depreciation model, which applies the year-on-year tracking method. Straight line depreciation of new assets forecast for the 2023–28 period is calculated within the AER's PTRM using the same method. Table 9-3 sets out our proposed standard asset lives. We propose to use the same asset classes and standard asset lives approved by the AER in it 2018–23 Revenue Determination, with the exception of a new asset class for Leasehold Land and Property. We have included this in light of an accounting standards change to AASB 116, that came into effect in 2019–20, which requires operating leases for fleet and buildings to be capitalised rather than expensed.[174] An offsetting reduction to our lease operating costs is reflected in our opex, ensuring that these costs are only recovered once.

174 We note that the asset classes used over the 2018–23 regulatory period all include the extension '(2018–23)', implying that they apply just to that period. As we intend to continue using these same asset classes for the 2023–28 period, we have adjusted the names in the PTRM to instead include the extension '(2018 onwards)'.

Table 9-3: Standard asset lives

Asset class	Remaining asset lives in years (at 1 July 2018)	Standard asset lives in years
Transmission Lines (pre 2004–05)	14.1	N/A
Underground Cables (pre 2004–05)	26.3	N/A
Substations including Buildings (pre 2004–05)	12.5	N/A
Transmission Lines (2004–09)	40.1	N/A
Underground Cables (2004–09)	32.4	N/A
Substations including Buildings (2004–09)	29.8	N/A
SCADA and Communications (2004–09)	4.8	N/A
Transmission Lines & Cables (2009–14)	44.6	N/A
Substations (2009–14)	34.2	N/A
Secondary Systems (2009–14)	29.5	N/A
Communications (2009–14)	29.4	N/A
Minor Plant, Motor Vehicles & Mobile Plant (2009–14)	2.2	N/A
Transmission Lines (2014–18)	49.6	N/A
Underground Cables (2014–18)	43.1	N/A
Substations (2014–18)	38.3	N/A
Secondary Systems (2014–18)	13.6	N/A
Communications (short life) (2014–18)	9.1	N/A
Business IT (2014–18)	3.1	N/A
Minor Plant, Motor Vehicles & Mobile Plant (2014–18)	6.7	N/A
Transmission Line Life Extension (2014–18)	24.0	N/A
Residual – other	1.0	N/A
Transmission Lines (2018 onwards)	N/A	50.0
Underground Cables (2018 onwards)	N/A	45.0
Substations (2018 onwards)	N/A	40.0
Secondary Systems (2018 onwards)	N/A	15.0
Communications (short life) (2018 onwards)	N/A	10.0
Business IT (2018 onwards)	N/A	4.0
Minor Plant, Motor Vehicles & Mobile Plant (2018 onwards)	N/A	8.0
Transmission Line Life Extension (2018 onwards)	N/A	35.0
Land and Easements	N/A	N/A
Synchronous Condensers (2018 onwards)	N/A	40.0
Leasehold Land and Property	N/A	10.0
Buildings – capital works	N/A	40.0
In-house software	N/A	15.0
Equity raising costs	32.6	15.9

Indexation

Indexation for a given year is calculated by multiplying the opening RAB value by forecast inflation. As discussed in section 10.5, in December 2020, the AER published its updated approach to estimating expected inflation, which is also reflected in its PTRM.[175]

We have applied the AER's updated approach to estimating expected inflation in this Revenue Proposal. However, we note that the current approach to indexation can have two undesirable effects:

- firstly, the deduction of forecast inflation from regulatory depreciation can defer the recovery of revenue to later in an asset's life, which can increase the cost of financing new investment above the regulated return (because credit metrics cannot be maintained and/or additional equity is required which is higher cost than the return on debt provided), and
- secondly, if the actual indexation differs from the forecast indexation, it could result in windfall gains or losses to investors and customers as more or less value is added to the RAB than was taken out. This is because the AER uses forecast inflation to roll-forward the projected RAB at the start of each regulatory period whereas actual inflation is used to roll-forward the actual RAB at the end of the period. This means that differences in forecast and actual inflation result in NSPs either under or over recovering their efficient costs for no other reason than an error in the forecast.

Addressing both issues is likely to require rule changes. The AEMC is considering indexation as part of its Transmission Planning and Investment Review.[176] The outcome of this review may impact how our RAB is indexed and therefore our forecast revenues and prices. We are actively participating in this review and would welcome the opportunity to work with the AER and the AEMC, in consultation with our customers and other stakeholders, to resolve this matter.

We note that whilst the second issue has been largely addressed by the AER's improved method for forecasting inflation, the lost value to Transgrid during the 2018–2023 regulatory period arising from the error in the forecast of expected inflation will be substantial. In the 2018–23 regulatory period, estimated inflation will be 2.4 per cent on average over the period whereas actual inflation is estimated to be 2.0 per cent on average over the period. This has led to an under recovery of our efficient costs by $152.9 million (real $2017–18).[177] If actual inflation had been higher than the AER forecast, consumers would have paid too much.

Regulatory depreciation

The calculation of the forecast straight line depreciation, indexation, and regulatory depreciation is presented in Table 9-4.

Table 9-4: Forecast regulatory depreciation ($M, nominal)

	2023–24	2024–25	2025–26	2026–27	2027–28	Total
Forecast straight line depreciation	316.1	354.5	397.0	412.5	430.0	1,910.2
Less forecast indexation	(204.8)	(219.4)	(225.5)	(228.4)	(230.4)	(1,108.4)
Regulatory depreciation (nominal)	111.3	135.1	171.6	184.2	199.6	801.8
Regulatory depreciation ($Real 2022–23)	108.8	129.0	160.0	167.8	177.7	743.3

9.5 Roll-forward over the 2023–28 period

We propose to use forecast depreciation to roll-forward the RAB to the start of the regulatory period starting 1 July 2028. This is the same treatment as applied to the 2018–23 period and is consistent with the AER's framework and approach paper.[178]

175 AER, Final position – regulatory treatment of inflation, December 2020
176 AEMC, Transmission Planning and Investment Review. This review is underway.
177 This value is the change in allowed building block revenues, in Real $2017–18, which arises over the 2018–23 period if forecast inflation of 2.00% is used instead of 2.45 per cent. This was calculated using the PTRM published with the AER's decision on Project EnergyConnect. The 1.93 per cent is estimated as the geometric mean of actual inflation for the years to December 2017 through to December 2020, and the RBA's most recent forecast inflation to December 2021.
178 See section 6. See also: AER, Framework and Approach – Transgrid – Regulatory Control Period commencing 1 July 2023, July 2021, pp.26–28,

9.6 Supporting documentation

The following documents support this Chapter and accompany our Revenue Proposal.

Name
Roll-forward model
Depreciation model
Post-tax revenue model

10. Rate of return, inflation, debt and equity raising costs

Key messages

> We estimate a rate of return of 4.7 per cent for the 2023–28 regulatory period, using the AER's binding 2018 Rate of Return Instrument (RORI) and recent observable market data. The final rate of return will be calculated using updated market data and the AER 2022 RORI, which the AER is currently consulting on. The AER will reflect the outcomes of the 2022 RORI in its Final Decision on our 2023–28 Revenue Proposal. We do not consider the current level of returns are adequate and have set out our positions in the AER's RORI review process, which we are actively participating in.

> We estimate forecast inflation of 2.3 per cent using the method included in the AER's PTRM. This inflation forecast is used to index the RAB over the 2023–28 regulatory period. The AER will update the inflation forecast in its final decision to reflect the latest available forecasts published by the Reserve Bank of Australia (RBA).

> The PTRM also allows for debt and equity raising cost to compensate for efficient capital raising costs. Whilst we don't seek to recover any equity raising costs, we estimate debt raising costs of $25.7 million for the 2023–28 regulatory period.

10.1 Overview

Under the NER, our return on capital allowance is calculated by multiplying the rate of return or the weighted average cost of capital (WACC) and the value of our opening Regulatory Asset Base (RAB) in each year of the regulatory period.

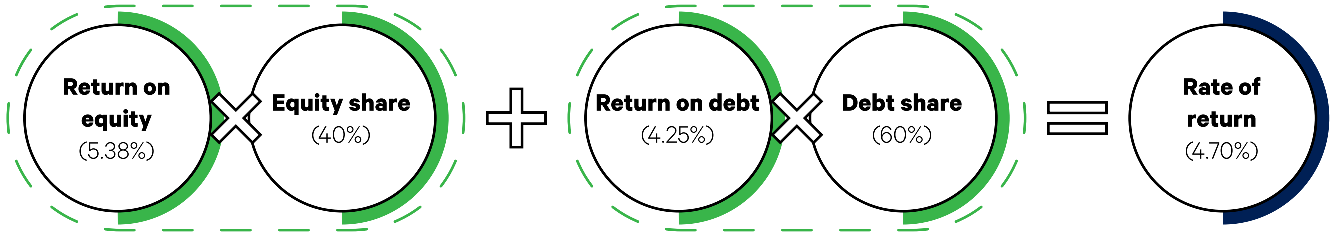
Under the NEL, the AER's RORI, which is binding on both us and the AER, sets out how the AER calculates the rate of return.[179] Under the NEL, we are required to use the prevailing 2018 RORI when calculating our return on capital allowance in this Revenue Proposal.[180,181] The AER is currently reviewing the 2018 RORI and is expected to publish its 2022 RORI in December 2022. We do not consider the current level of returns is adequate and have set out our views on this in the AER's RORI review process.

The rate of return represents the average cost of debt and equity an efficient firm would incur to raise funds from a range of investors and capital markets to finance investments in our network. It is the return required by debt and equity investors on invested capital (the RAB), and is compensation for the risks and opportunity costs those investors bear when committing capital to the business.

The rate of return is estimated as a weighted average of the return on equity and the return on equity as shown in Figure 10-1.

179 NEL, section 18H – Rate of return instrument is binding on AER and network service providers
180 NEL – section 18T – 'A rate of return instrument remain in force until the day it is replaced under section 18U'
181 NER, Chapter 10, defines 'applicable rate of return instrument' as follows – 'for a regulatory year means the rate of return instrument in force when the network revenue or pricing determination for the Network Service Provider for the regulatory control period to which the regulatory year belongs is made (disregarding any determination made in substitution for an earlier determination for the Network Service Provider for that regulatory control period)'.

Figure 10-1: Our proposed rate of return[182]



As required under the NEL and the NER, we have applied the AER's 2018 RORI and recent observable market data to derive a rate of return estimate of 4.7 per cent (nominal, vanilla) for the first year of the 2023–28 period. This is shown in Table 10-1.

Table 10-1: Forecast return on capital ($M, Real 2022–23)

	2023–24	2024–25	2025–26	2026–27	2027–28	Total
Opening RAB	8,512.9	8,911.7	8,949.0	8,855.4	8,730.2	
Rate of return (%)	4.70%	4.70%	4.70%	4.70%	4.70%	
Return on capital	400.4	419.1	420.9	416.5	410.6	2,067.6

Our rate of return estimates shown in Table 10-1 are placeholder estimate only that will be updated by the AER in its Final Determination based on its 2022 RORI, which must be finalised in December 2022. Given that the 2022 RORI is not yet finalised we have calculated the rate of return estimate presented in this proposal using the AER's 2018 RORI.

10.2 Return on equity

The return on equity is the return required by equity investors to provide equity capital.

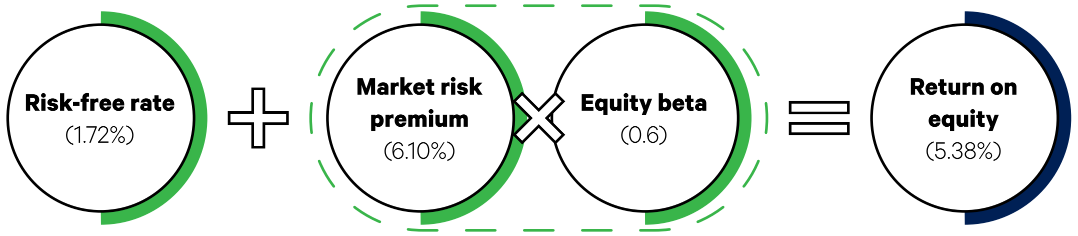
We propose a rate of return of 5.38 per cent calculated in accordance with the 2018 RORI. In particular, we have used the Sharpe-Lintner Capital Asset Pricing Model, which, as shown in Figure 10-2, combines a risk-free rate parameter with the product of the market risk premium and equity beta.

We have adopted the value in the 2018 RORI for market risk premium (6.1 per cent) and equity beta (0.6). We have estimated the risk-free rate parameter using yields on Commonwealth Government Securities observed over the 20 trading days to 30 October 2021 to be 1.72 per cent.

This is a placeholder estimate of the risk-free rate for the purpose of this Revenue Proposal. The AER will calculate our actual risk-free rate using the method outlined in Clause 4 of the 2018 RORI (or equivalent in the 2022 RORI) as well as our nominated averaging period, which is provided as an attachment to this Revenue Proposal.

182 We used a placeholder averaging period of the 20 trading days to 31 October 2021 to estimate the market parameters needed to calculate the returns on equity and debt. The return on debt and rate of return values shown are for the first year of the 2023–28 period. The equity and debt shares are detailed in the 2018 RORI.

Figure 10-2: Our proposed return on equity[183]



10.3 Return on debt

The return on debt is the return required by debt investors for lending funds to invest in new assets and continue financing existing assets.

As required by the 2018 RORI, the return on debt is calculated as a trailing average of past return on debt observations. The AER's 2013 Rate of Return Guideline required that we transition to a full trailing average over a 10-year period. This approach was maintained by the AER in its 2018 RORI.

Our 2018–23 rate of return allowance was determined based on the AER's 2013 Rate of Return Guideline and we therefore commenced the 10-year transition to the full trailing average in 2014–15. By the commencement of the 2023–28 regulatory period, we will have completed the 10-year transition.

Our estimate of the return on debt for the first year of the 2023–28 period is 4.3 per cent and has been calculated using the methodology in the AER 2013 Rate of Return Guideline for the 10th year of the 10-year transition to the full trailing average. The 2022–23 observation is a placeholder until actual market data becomes available for the averaging period approved by the AER in its final decision for the 2018–23 period.

In line with the 2018 RORI, the 2023–24 observation is to be calculated using corporate bond data published by Bloomberg, the Reserve Bank of Australia, and Thomson Reuters.

10.4 Averaging periods

We must propose averaging periods that the AER will use to update the market observable parameters used to estimate the return on equity and return on debt. Our proposed averaging periods are included in as an attachment to this Revenue Proposal.

10.5 Forecast inflation

Forecast inflation is used to calculate the depreciation building block and to convert real dollar values to nominal dollar values.[184]

We have calculated forecast inflation based on the AER's December 2020 final decision on the treatment of expected inflation,[185] which is also reflected in the AER's PTRM. This is based on the geometric mean of:

- two years of forecast inflation published by the RBA in its most recent Statement on Monetary Policy, and
- three years transitioning to the midpoint of the RBA's inflation target, of 2.5 per cent.

As shown in Table 10-2, we have forecast inflation of 2.3 per cent per annum by applying this method and using the RBA's November 2021 Statement on Monetary Policy. Our rate of return and PTRM models provided as attachments to this Revenue Proposal sets out the detailed calculations of forecast inflation.

183 The risk-free rate will be updated to reflect the future averaging period that we proposed in confidential Nominated Averaging Period attachment to the Revenue Proposal.
184 There is also a link to the return on capital building block because the nominal rate of return implicitly includes an allowance for forecast inflation. That allowance is then netted off allowed revenues as a negative adjustment to the depreciation building block and instead added to the RAB as indexation.
185 AER, Final position – regulatory treatment of inflation, December 2020

Table 10-2: Proposed inflation forecast

	2023–24	2024–25	2025–26	2026–27	2027–28
	RBA Forecast		Linear transition to 2.5		
Inflation forecast (%)	2.3	2.3	2.3	2.4	2.5
Geometric average (%)	**2.3**				

Notes 1. The geometric average is calculated by adding one to each inflation forecasts and multiplying them together to get a 5year inflation projection, and then converting that projection back to a compound annual growth rate.

10.6 Debt and equity raising costs

Debt and equity raising costs reflect the costs we incur when raising debt and equity capital from external investors, and include agency, placement, arrange, legal, credit rating, and registration fees, and roadshow costs.

We have adopted the AER's preferred approaches and parameters to estimate these costs for a benchmark efficient business (rather than our actual costs), as described in Table 10-3. Our PTRM provided as an attachment to this Revenue Proposal sets out the detailed calculations of our debt and equity raising costs.

Table 10-3: Debt and equity raising cost estimation approaches and assumptions

Component	Approach and assumptions
Debt raising costs	Debt raising costs are calculated for each year of the 2023–28 period by multiplying the opening RAB value for the year by a unit rate. We propose adopting a unit rate of 9.5 basis points per annum, which is the value estimated by Frontier Economics.. The approach used by Frontier Economics to estimate efficient debt raising costs is consistent with the approach used by the AER in its most recent decisions and in line with Chairmont's recommendations to the AER in 2019,[186] Frontier Economics has amortised upfront debt raising costs over nine rather than 10 years.
Equity raising costs	Equity raising costs are estimated in two steps: • first, the PTRM calculates the share of earnings paid out and then reinvested and the uses these values – along with forecast cash flows – to determine how much additional equity is needed to maintain a 60 per cent leverage ratio. • second, the PTRM calculates the costs of the various funding sources, namely retained earnings, reinvested dividends, and equity offerings. To apply this method, we propose adopting the parameters that the AER used for the 2018–23 period: • imputation payout ratio (or earnings payout ratio) – of 90 per cent per dollar of income generated • dividend reinvestment plan take up – of 30 per cent of each dollar paid out as dividends • subsequent equity raising cost – of 3 per cent per dollar of equity raised in a subsequent equity raising, and • dividend reinvestment plan cost – of 1 per cent per dollar of equity reinvested.

Applying these approaches and assumptions gives the debt and equity raising cost forecasts set out in Table 10-4. Consistent with recent AER decisions, we treat debt raising costs as opex and equity raising costs as capex.

Table 10-4: Forecast debt and equity raising costs ($M, Real 2022–23)

	2023–24	2024–25	2025–26	2026–27	2027–28	Total
Debt raising costs	5.0	5.2	5.2	5.2	5.1	**25.7**
Equity raising costs	–	–	–	–	–	**–**

186 Chairmont, *Debt raising costs*, 29 June 2019.

10.7 Supporting documentation

The following documents support this Chapter and accompany our Revenue Proposal.

Name
Rate of return model
Post-tax revenue model
Nominated averaging period
Frontier Economics, Benchmark Debt Raising Costs

11. Estimated cost of corporate income tax

Key messages

- We have calculated our income tax allowance using the AER's revised approach to the treatment of regulatory tax published in 2018 and subsequently reflected in its PTRM. The approach applies the corporate tax rate of 30.0 per cent less the value of imputation credits (gamma) of 58.5 per cent of forecast tax payable set out in the 2018 RORI.
- The key changes in the AER's revised treatment of regulatory tax are:
  - adopting an NSP's actual practice in immediately expensing capex, and
  - applying a diminishing value depreciation method when calculating tax depreciation to most asset classes rather than the straight line method.
- Our forecast tax allowance for the 2023–28 period is $65.7 million compared to $181.6 million for the prior period.

11.1 Forecast income tax allowance

This Revenue Proposal includes an allowance for tax costs consistent with the AER's revised method for the regulatory treatment of tax as reflected in the PTRM and the value of imputation credits (0.585) in the AER's 2018 RORI.[187]

Under clause 6A.6.4 of the NER, the AER sets out the expected statutory income tax. We have applied the statutory income tax rate of 30.0 per cent in the AER's PTRM.

In 2018, the AER revised its regulatory treatment of tax. The key changes are the immediate expensing of certain capex for tax purposes consistent with the practice of a NSP and the use of diminishing value method to calculate tax depreciation for most asset classes.

We have calculated our income tax allowance for the 2023–28 period using the AER's PTRM.

Figure 1-11 shows the calculation of the corporate tax allowance which multiplies forecast taxable income by the statutory corporate tax rate and then deducting the assumed value of imputation credits.[188]

Forecast taxable income is calculated as revenue including capital contributions less taxable expenses. Taxable expenses include the forecast operating costs (outlined in Chapter 7[189]) less forecast tax depreciation less interest costs. Interest costs are based on the cost of debt discussed in Chapter 10.

187 AER, Final Report Review of regulatory tax approach, December 2018. This approach is reflected in the AER's PTRM and is consistent with NER clause 6A.6.4.
188 As noted in section 10 with regards to the rate of return, the assumed value of imputation credits may be revised when the 2022 RORI is finalised.
189 Although in practice there can be differences between opex reported for financial purposes and that used to calculate taxable expenses, the AER's PTRM treats these the same for regulatory purposes

Figure 1-11: How the tax allowance is calculated

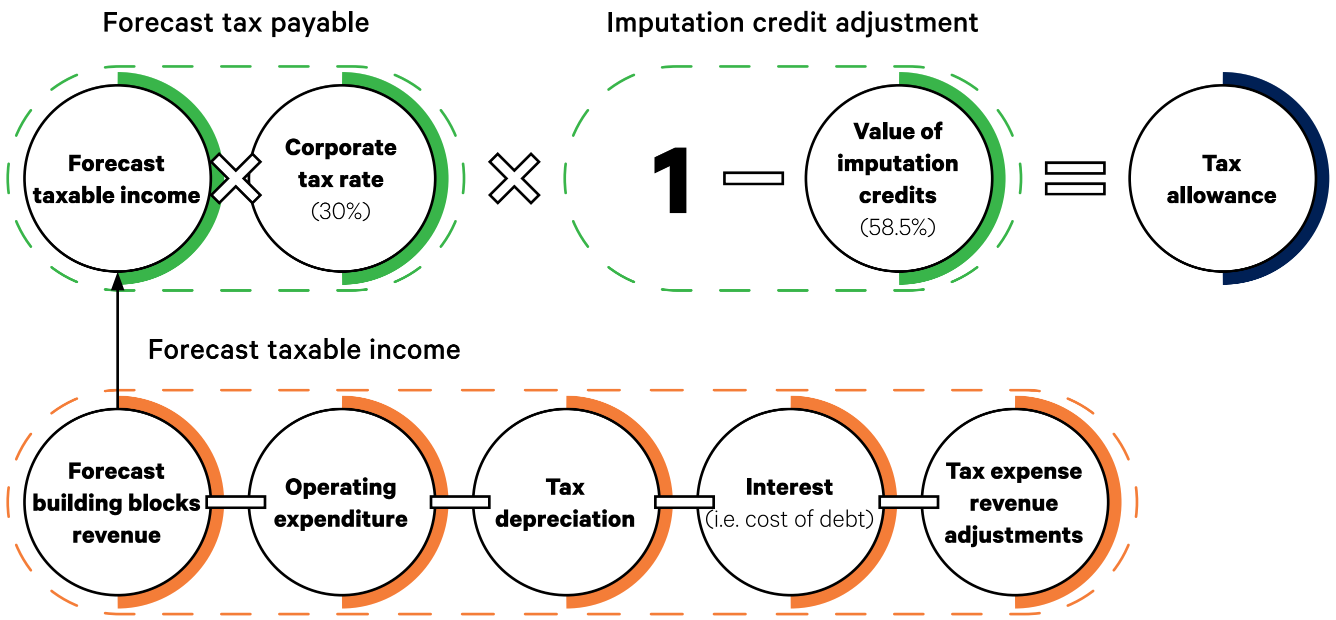


Table 11-1 sets our forecast tax allowance for the 2023–28 period calculated using the AER's PTRM.[190] Our forecast tax allowance comprises 1.7 per cent of our total building block costs.

Table 11-1: Forecast tax allowance ($M, Real 2022–23)

	2023–24	2024–25	2025–26	2026–27	2027–28	Total
Building blocks revenue	741.3	768.3	790.6	795.6	829.2	3,925.1
(–) Operating expenditure	(193.8)	(202.8)	(205.2)	(205.5)	(207.7)	(1,015.0)
(–) Tax depreciation	(181.8)	(229.6)	(286.7)	(265.8)	(263.2)	(1,227.1)
(–) Interest (i.e. cost of debt)	(217.2)	(227.4)	(228.4)	(226.0)	(222.8)	(1,121.8)
(–) Tax expense revenue adjustments	(22.6)	(4.4)	4.8	7.3	(18.6)	(33.5)
Taxable income	**125.8**	**104.1**	**75.2**	**105.7**	**117.0**	**527.7**
(x) Corporate tax rate (%)	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%
Tax payable	**37.7**	**31.2**	**22.6**	**31.7**	**35.1**	**158.3**
(–) Value of imputation credits (58.5%)	(22.1)	(18.3)	(13.2)	(18.5)	(20.5)	(92.6)
Estimated cost of corporate income tax	**15.7**	**13.0**	**9.4**	**13.2**	**14.6**	**65.7**

190 The AER's PTRM (version4) includes its preferred approach to calculating corporate income tax based on its 2018 Review.

11.2 Forecast tax depreciation

Forecast tax depreciation is an input to calculating forecast taxable income, which is calculated within the AER's PTRM. The regulatory calculation of tax depreciation depends on:

- the value of the regulatory tax asset base (TAB) as at the commencement of the 2023–28 regulatory period (1 July 2023). Table 11-2 shows the opening regulatory TAB at 1 July 2023, which is established by rolling forward the opening regulatory TAB at 1 July 2018 using a combination of actual and estimated capex, disposals and straight-line depreciation over the 2018–23 period[191]
- immediately expensed capex.[192] The AER's 2018–23 determination did not adjust the regulatory TAB roll-forward over the 2018–23 period for immediate expensing of capex. We have reflected this approach in the 2018–23 RFM, and
- standard and remaining tax lives. Table 11-3 presents our standard and remaining tax lives as at 1 July 2023 for existing asset classes in the 2018–23 regulatory period.

Unlike the RAB, the regulatory TAB includes the value of capital contributions (which are expected to be small). These contributions attract a tax liability that we will pay, as well as tax expenses that we can claim over the life of the assets.

Table 11-2: Opening tax asset base at 1 July 2023 ($M, nominal)

	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Opening TAB (1 July)	3,911.6	4,045.3	4,102.1	4,142.4	4,540.9	4,895.4
Gross capex	274.3	211.1	203.9	563.8	544.9	
Asset disposals	(4.2)	(2.2)	(3.8)	(4.3)	(4.3)	
Immediate expensing of capex[193]	–	–	–	–	–	
Straight-line depreciation	(136.5)	(152.1)	(159.8)	(161.1)	(186.1)	
Final year asset adjustments	–	–	–	–	–	
Closing TAB (30 June)	**4,045.3**	**4,102.1**	**4,142.4**	**4,540.9**	**4,895.4**	

Table 11-3: Tax asset lives

Asset type	Standard lives in years as at 1 July 2023	Remaining lives in years as at 1 July 2023
Transmission Lines	50.0	49.0
Underground Cables	45.0	44.9
Substations	40.0	38.6
Secondary Systems	15.0	13.3
Communications (short life)	10.0	8.6
Business IT	4.0	2.6
Minor Plant, Motor Vehicles & Mobile Plant	8.0	5.7
Transmission Line Life Extension	35.0	33.4
Land and Easements	n/a	n/a
Synchronous condensers	30	–
Leasehold Land and Property	10	9.4

191 We have used actual capex and disposals for 2018–19 to 2020–21 as reported in our 2020–21 regulatory accounts and forecast capex and disposals for 2021–22 and 2022–23. We will provide actual capex for the 2021–22 year in our Revised Revenue Proposal.
192 This allows for inputs of certain capex to be immediately expensed when estimating the benchmark tax expense.
193 The AER's determination for the 2018–23 regulatory period did not adjust the TAB roll-forward over that period for immediate expensing of capex. We have reflected that in the Roll-Forward Model covering the same period.

Asset type	Standard lives in years as at 1 July 2023	Remaining lives in years as at 1 July 2023
Buildings – capital works	40	–
In-house software	5	–
Equity raising costs	5	6.7

Table 11-4 shows the forecast regulatory TAB for the 2023–28 period including the impact of the AER's changes to immediately expense capex based on past practice[194] and apply diminishing value depreciation to all asset classes, except for equity raising costs, in-house software and buildings. We have continued to use the weighted average remaining lives (WARL) method to calculate the remaining lives of for these asset classes in the regulatory TAB.

Table 11-4: TAB roll-forward over the 2023–28 period ($M, nominal)

	2023–24	2024–25	2025–26	2026–27	2027–28
Opening value	4,895.4	5,620.5	6,916.4	6,937.1	6,886.8
Gross capex	915.6	1,541.0	332.8	246.3	432.5
Immediate expensing of capex	–	–	–	–	–
Asset disposals	(4.5)	(4.6)	(4.7)	(4.8)	(4.9)
Depreciation[195]	(186.1)	(240.5)	(307.4)	(291.7)	(295.6)
Adjustments	–	–	–	–	–
Closing value	5,620.5	6,916.4	6,937.1	6,886.8	7,018.8

11.3 Supporting documentation

The following documents support this Chapter and accompany our Revenue Proposal.

Name
Post-tax revenue model

194 The PTRM was updated to require TNSPs to input the share of forecast capex that is expected to be expensed immediately for tax purposes. This expenditure is treated as depreciation in the year incurred.
195 This reflects the diminishing method for asset classes, except for equity raising costs in-house software and buildings. We have continued to use the WARL for these asset classes.

12. Efficiency Benefit Sharing Scheme

Key messages

> We support the continued application of the EBSS as proposed in the AER's F&A. The EBSS encourages us to pursue opex efficiency improvements which deliver lower costs to customers over the long term.

> As discussed in Chapter 2, our improvement in productivity over time demonstrates that we are responding to the incentives under the regulatory framework to improve our efficiency. Our opex efficiencies in the 2018–23 period will result in opex savings of $59.6 million in the 2023–28 period relative to costs incurred in the 2018–23 period.

> Based on our operational efficiencies in the 2018–23 period, we estimate a positive EBSS carryover amount of $34.9 million.

> As noted in Chapter 6, we have raised concerns with the AER about the EBSS including the impact of the decline in the discount rate on the sharing ratio. We look forward to participating in the AER's review of its incentive schemes, including the EBSS which is expected to commence shortly.

12.1 The Efficiency Benefit Sharing Scheme

The EBSS provides us with a continuous incentive to pursue opex efficiency improvements and share these with our customers. The intent of the EBSS is that we retain approximately 30 per cent of efficiency gains (or losses) and customers receive 70 per cent in each year of the regulatory period. This sharing ratio is dependent on the discount rate (i.e. the regulatory WACC) such that we retain a higher proportion of the efficiency gains or losses when the discount rate is high and a lower portion when the discount rate is low.

The EBSS is intrinsically linked to the base-step-trend opex forecasting approach, where our forecast opex is based on our actual opex from a recent nominated base year. The EBSS addresses two potential incentive problems arising from this forecasting approach:

- the incentive to increase base year opex, and
- the incentive to delay efficiency improvements beyond the base year.

The use of the base-step-trend forecasting approach combined with the EBSS creates a continuous incentive to pursue efficiency improvements by allowing us to retain efficiency gains for a total of six years, regardless of the year in which it was made.

Prior to the commencement of the next regulatory period, the AER calculates our carryover amounts for opex efficiency gains (or losses) made in the current regulatory control period, and adds (or subtracts) these to (or from) our annual revenue requirements.

We note the AER intends to review the current version of EBSS in light of the concerns that we and other TNSPs have raised in relation to the sharing ratio.[196] We are concerned that the substantial decline in the WACC since the EBSS was developed, means that the share of the EBSS gains or losses that we retain has substantially fallen and is lower than the share of capex gains or losses retained under the current CESS. We welcome the AER's review to ensure that the sharing ratio is maintained.

We look forward to participating in the AER's review of its incentive schemes and understand that the updated versions will be published in the second half of 2022 and will be reflected in the AER's Final Decision on our 2023–28 Revenue Proposal.

196 Transgrid, Request for Revised Framework and Approach Paper, 30 October 2020

12.2 Carryover amount from 2018–23 regulatory period

The EBSS (version 2) currently applies to our 2018–23 regulatory period.[197] Under the EBSS, our MAR for the 2023–28 period is adjusted for a portion (30 per cent) of the efficiency gains or losses accrued during the 2018–23 regulatory period (the carryover amount).[198]

As discussed in Chapter 7 we have achieved operational efficiencies in the 2018–23 period including by upgrading our process and systems, changing our operating model, adapting our labour force and improving planning and scheduling of work.

We expect our 2018–23 opex will be around 8.8 per cent below the AER's allowance[199] and that our opex in our 2021–22 base year will be $11.9 million below the AER's opex allowance in this year reflecting the operational efficiencies we have achieved. The lower opex will flow through to our forecast opex for the 2023–28 period.

Table 12-1 shows that we are forecasting a positive EBSS carryover of $34.9 million based on our operational efficiencies in the 2018–23 period. Our EBSS model, provided as an attachment to this Revenue Proposal, sets out the detailed calculations of the proposed EBSS carryovers.

Table 12-1: Proposed EBSS carryovers[200]

	2023–24	2024–25	2025–26	2026–27	2027–28	Total
Carryover	19.3	5.3	(3.8)	(6.1)	20.2	34.9

12.3 EBSS for the 2023–28 period

The AER's F&A proposes to apply version 2 of the EBSS.[201] However, the AER indicated that the application of the EBSS is contingent on using the base-step-trend forecasting approach, which in turn, depends on the efficiency of our base year.

As discussed in Chapter 7, we have forecast our 2023–28 opex using the base-step-trend approach and have used our 2021–22 opex as the base year. Our opex base year estimate is below the efficient opex forecast determined by the AER for the 2018–23 period and the AER and HoustonKemp's benchmarking shows that our opex base year is efficient.

We support the following adjustments and exclusions consistent with version 2 for the EBSS in the 2023–28 period:[202]

- approved pass through amounts or opex for contingent projects
- capitalisation policy changes
- categories of opex not forecast using a single year revealed cost approach. For the 2023–28 regulatory control period, we propose to exclude debt raising, network support costs, NCIPAP costs and DMIA, and
- inflation.

197 AER, *Efficiency Benefit Sharing Scheme for Electricity Network Service Providers* (EBSS – Version 2), November 2013
198 AER, EBSS Version 2, section 1.3
199 Adjusted for AER approved cost pass through – 2019–20 Bushfire season bushfire allowance of $49.8 million (nominal). Transgrid incurred/expects to incur the costs FY20, FY21 and FY22 and be compensated for them in FY23, FY24 and FY25. For the purposes of meaningful comparison we have aligned the adjustment to the 2018–23 AER opex allowance of the pass through costs to when they have been / expected will be incurred by us.
200 The carryover amounts for a given year over the next period reflects the total of amounts carried over from the 2018–23 regulatory period that apply to that year. For instance, the amounts carried over to 2023–24 combine the gains from 2018–19 ($13.9 million), 2019–20 ($9.1 million), 2020–21 ($2.3 million), 2021–22 (-$26.2 million), and 2022–23 ($20.2 million). This gives a carryover amount for that year of $19.3 million.
201 AER, Framework and Approach Transgrid – Regulatory control period commencing 1 July 2021, 30 July 2021.
202 AER, EBSS Version 2, section 1.4

Table 12-2 shows our proposed opex for the EBSS for the 2023–28 regulatory period.

Table 12-2: Proposed EBSS target ($M, Real 2022–23)

	2023–24	2024–25	2025–26	2026–27	2027–28	Total
Opex	193.8	202.8	205.2	205.5	207.7	**1,015.0**
Adjustments						
Debt raising costs	(5.0)	(5.2)	(5.2)	(5.2)	(5.1)	**(25.7)**
Network support costs	–	–	–	–	–	–
Expensed NCIPAP	–	–	–	–	–	–
capitalised opex that has been excluded from the RAB	–	–	–	–	–	–
movements in provisions	–	–	–	–	–	–
EBSS target	**188.9**	**197.6**	**199.9**	**200.3**	**202.6**	**989.3**

12.4 Supporting documentation

The following documents support this Chapter and accompany our Revenue Proposal.

Name
Efficiency Benefit Sharing Scheme Model

13. Capital Expenditure Sharing Scheme

Key messages

- We support the continued application of the CESS as proposed in the AER's F&A. The CESS encourages us to pursue capex efficiency improvements and share these with customers.
- As discussed in Chapter 8, due to the change in circumstances, the anticipated project delivery date for Project EnergyConnect is now 2024–25. Given this, we have deferred $532.8 million of pre-approved capex for this project to the 2023–28 period. As a result, we expect to underspend our capex allowance for the 2018–23, including ISP projects. We have adjusted the CESS carryover amount to exclude this deferral so that we do not earn an efficiency gain for this underspend.
- We forecast a positive CESS carryover amount of $5.1 million, which reflects the financing costs for Project EnergyConnect that we have already recovered during the 2018–23 period.

13.1 The Capital Expenditure Sharing Scheme

The CESS provides a consistent incentive for us to spend capex efficiently over the regulatory period by rewarding or penalising us for capex efficiency gains or losses respectively. Similar to the EBSS, the sharing ratio means that we retain 30 per cent of the cumulative underspends (or overspends) and customers receive 70 per cent. The AER's forecast capex is used as a proxy for efficient capex, and differences between forecast and actual capex approximate efficiency gains and losses.

The CESS also encourages more efficient substitution between capex and opex.

Prior to the commencement of the next regulatory period, the AER calculates our carryover amounts for capex efficiency gains (or losses) made in the current regulatory control period, and adds (or subtracts) these to (or from) our annual revenue requirements.

13.2 CESS outcomes from 2018–23 regulatory period

The CESS (version 1) currently applies to our 2018–23 regulatory period. As discussed in Chapter 8, our expected 2018–23 capex including on ISP projects (VNI, QNI and Project EnergyConnect) of $3,114.8 million is $564.0 million below our allowance of $3,678.8 million. This is largely due to a change in circumstances which means the anticipated project delivery date for Project EnergyConnect is now 2024–25. Given this, we have deferred $532.8 million of pre-approved capex for this project to the 2023–28 period. As a result, we expect to underspend our capex allowance for the 2018–23, including ISP projects. We have adjusted the CESS carryover amount to exclude this deferral so that we do not earn an efficiency gain for this underspend.

Table 13-1 sets out our carryover for the 2023–28 period. We are forecasting a positive CESS carryover amount of $5.1 million, which reflects the repayment of the financing costs that we received for Project EnergyConnect in the 2018–23 period, given the project is partially deferred.

Our CESS model provided as an attachment to this Revenue Proposal sets out the detailed calculations of the proposed CESS carryovers.

Table 13-1: Carryover amounts ($M, Real 2022–23)

	2023–24	2024–25	2025–26	2026–27	2027–28	Total
Carryover	1.0	1.0	1.0	1.0	1.0	**5.1**

13.3 2023–28 regulatory period

The AER's F&A paper for the 2023–28 regulatory period proposes to apply version 1 of the CESS to Transgrid.[203] We support the AER's position at this stage, although we look forward to participating in AER's proposed review of this scheme.

13.4 Supporting documentation

The following documents support this Chapter and accompany our Revenue Proposal.

Name
Capital Expenditure Sharing Scheme Model

203 AER, Framework and Approach Transgrid – Regulatory control period commencing 1 July 2021, 30 July 2021.

14. Service Target Performance Incentive Scheme (STPIS)

Key messages

> We support the continued application of the STPIS as proposed in the AER's F&A. The STPIS encourages us to maintain and improve our service performance for the benefit of customers.

> Our strong performance in the 2018–23 period has delivered value to our customers through the three components of STPIS:

- maintaining or improving network reliability through the service component,
- maximising availability of the network to allow lowest cost generation dispatch though the market incentive component, and
- reducing transmission congestion by implementing innovative solutions through our network capability incentive parameter action plan (NCIPAP) as part of the network capability component.

> We have calculated our service and market incentive component targets for the 2023–28 period consistent with the AER's STPIS (version 5), however we have set the service component large loss of supply events parameter at 0.15 system minutes so that our target for 2023–28 is 1 event to reflect our recent improvements in network reliability. This ensures that we have an incentive to improve our performance over the period.

> We have proposed priority projects as part of our NCIPAP, which have been endorsed by AEMO and will deliver benefits to the market and customers.

14.1 The STPIS

The STPIS provides a financial incentive for us to maintain or improve service performance, maximise network availability and address network constraints to maximise the dispatch of the lowest cost generation. The STPIS is important to counter-balance our expenditure incentives including the EBSS, which, is discussed in Chapter 12 and the CESS, which is discussed in Chapter 13.

The STPIS (version 5) has three components:[204]

1. the service component (SC) – this provides a reward or penalty of +/- 1.25 per cent of the MAR for the relevant calendar year to improve network reliability by focussing on unplanned network outages and prompt restoration in the event of unplanned outages that cause supply interruptions. It also encourages us to identify and address potential network reliability issues.
2. the market incentive component (MIC) – this provides a reward or penalty of up to +/- 1 per cent of the MAR for the relevant calendar year to minimise the impact of transmission outages that can impact the spot price and wholesale market outcomes. Performance is measured based on the number of five-minute dispatch intervals (DIs) constrained when an outage constraint binds with a marginal value greater than $10/MWh.
3. the network capability component (NCC) – this provides pro-rata incentive payment of up to 1.5 per cent of MAR for completion of low cost one-off opex or capex projects that improve network capability at times when it is most needed and provide value for money to customers. As required under Version 5 of the STPIS, we have provided a NCIPAP, which has been endorsed by AEMO as an attachment to this Revenue Proposal.

204 In accordance with the AER's STPIS version 5 (corrected) (October 2015)

As discussed in Chapter 6, the AER intends to review its incentive schemes including the STPIS in light of the concerns that we and other TNSPs have raised.[205] We are concerned that aspects of the STPIS, in particular the MIC, should be adjusted to ensure it remains fit for purpose given the significant changes to the energy system.

Since 2015 when the MIC was last reviewed, the energy system has experienced significant change as it transitions quickly to a low carbon future. As discussed in Chapter 2, the energy transition is resulting in widespread network congestion across our network from the connection of large-scale variable renewable generation. In 2020, almost 2 GW of large scale solar and wind generation capacity was added to the NEM, a further 8 GW is under construction, and a pipeline of 55GW proposed.[206] Much of this growth involves connection to weaker parts of the transmission network. As large baseload generators continue to retire, congestion in remote locations will continue to grow.

In light of these changes we consider that the MIC is no longer an effective incentive mechanism because targets set by reference to historical performance do not reflect the future market conditions. A new method that sets MIC targets that reflect expected market conditions over a regulatory period rather than historical performance is required in order for it to continue to provide meaningful incentives in the 2023–28 regulatory period.

We look forward to participating in the AER's review and working with the AER to develop an alternative method for calculating MIC target. We understand that the updated versions of the schemes will be published in the second half of 2022 and will be reflected in the AER's Final Decision on our 2023–28 Revenue Proposal.

14.2 Our 2018–23 STPIS performance

To date during the 2018–23 period, we have provided our customers with strong service outcomes under the STPIS.

Table 14-1 overviews our performance in 2018 to 2020, which is reported on a calendar year basis. This shows our continued improvement over the period, with the exception of our SC parameters for transmission lines and reactive plant fault outages and our MIC performance.

Table 14-1: 2018–23 regulatory period STPIS performance

Parameter	Unit of measure	2018–23 target	Calendar year 2018	2019	2020
Service component					
Unplanned outage circuit event rate					
Lines event rate – fault	Rate	13.30	18.02	12.25	18.65
Transformer event rate – fault	Rate (%)	13.80	12.86	6.74	11.84
Reactive plant event rate – fault	Rate (%)	10.30	17.72	13.67	11.97
Lines event rate – forced	Rate (%)	17.60	8.54	7.07	11.19
Transformer event rate – forced	Rate (%)	26.50	7.83	6.74	9.58
Reactive plant event rate – forced	Rate (%)	22.10	8.12	10.07	9.15
Loss of supply events frequency					
Loss of supply events > 0.05 (x) system minutes	Count	3	1	3	1
Loss of supply events > 0.25 (y) system minutes	Count	1	0	0	1

205 Transgrid, Request for Revised Framework and Approach Paper, 30 October 2020
206 Transgrid's Transmission Annual Planning Report 2021

Parameter	Unit of measure	2018–23 target	Calendar year		
			2018	2019	2020
Average outage duration					
Average outage duration	Minutes	104	58.20	69.82	45.17
Proper operation of equipment					
Failure of protection system	Number	17	20	12	11
Material failure of Supervisory Control and Data Acquisition (SCADA) system	Number	3	0	0	0
Incorrect operational isolation of primary or secondary equipment	Number	7	6	3	6
Market Impact Component					
MIC	Number of Dispatch Intervals	1,348	4,937	1,252	14,881
Network Capability Component					
NCIPAP	Priority projects completed and in-progress: • Replacing HV Plant at Wagga 132kV Substation to increase the rating of a transmission line element • Dynamic Line Monitoring to improve the rating and allow additional renewable generation transfer on a transmission line • Installing SmartWires on Upper Tumut – Yass 330kV Line to increase power transfer capability • Implementation of Transfer Tripping Scheme at Gadara, Tumut and Burrinjuck to prevent generator constraints • Dynamic Ratings for Darlington Point Transformers to improve transfer capacity between NSW and Victoria • Replacing HV Plant on Mt Piper to Wallerawang 330kV Lines to increase the rating of two transmission line elements • Armidale Capacitor Transfer Tripping Scheme to avoid constraints on the Queensland New South Wales Interconnector • Replacing Wavetraps and Varying the CT Ratio at Wagga to increase the rating of a transmission line element • Installation of a 330kV 100MVAr Shunt Capacitor Bank at Wagga 330 kV Substation to improve the NSW to Victoria power transfer limit • Replace metering and control equipment on Wollar to Wellington 330kV line to increase the rating of a transmission line element • Replace conductor on Coleambally to Darlington Point 132kV line with high temperature low sag conductor to improve the rating and allow additional renewable generation transfer • SmartWires on Wagga – Jindera 330kV Line to improve the NSW to Victoria power transfer limit				

14.2.1 Service component

Over the 2018–23 period, we expect our overall performance under the SC to consistently exceed the AER's targets for forced outage rates, loss of supply events and average outage duration. This has, and will continue to minimise the impact of short notice outages and loss of supply on our customers. However, we have experienced challenges with our fault outage rates for transmission lines and reactive plant.

The following sections overview our performance against the three parameters which have a SC weighting[207] – unplanned outage circuit event rate, loss of supply events frequency and average outage duration.

Unplanned outage circuit event rate

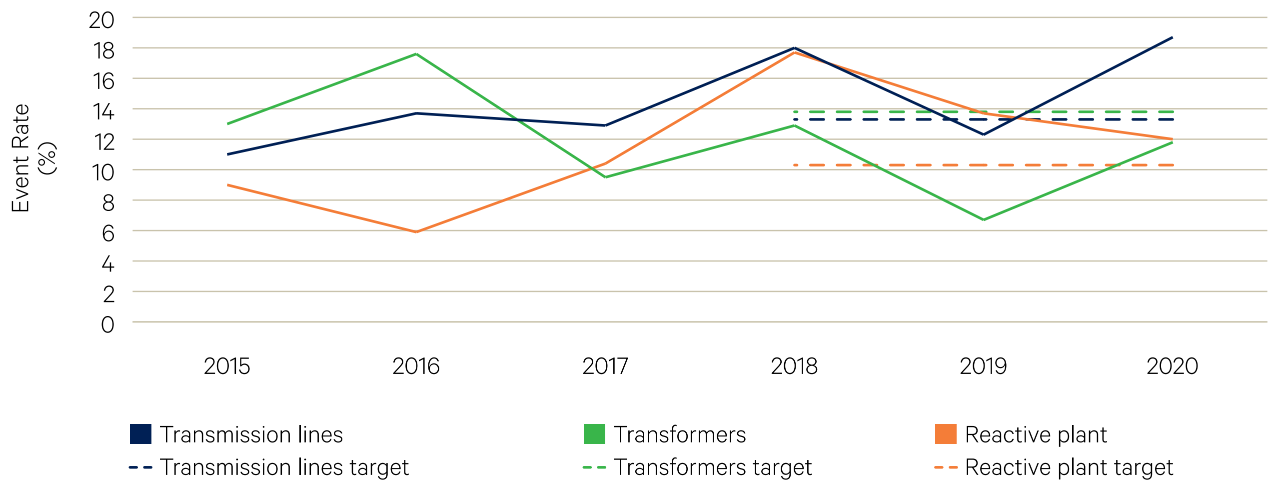
Unplanned outage events occur when a network element is unavailable for an unexpected reason and are categorised into one of two categories, fault outages or forced outages. This parameter is measured by taking a total count of unplanned outage events each year across the transmission line, transformer and reactive plant network element types, and expressing this as a percentage of the total number of network elements.

Fault outages

Fault outages occur when a network element is unexpectedly switched off by the automated control and protection systems. For example, an asset failure will trigger the protection system to switch off the asset, resulting in a fault outage event.

Our historical performance for the fault outage rate is shown in Figure 14-1. It shows that our fault outage rate for transformers has consistently improved (i.e. decreased) since 2016 and we have outperformed the target so far in the 2028–23 period (our performance is below the target). This is largely because we have renewed our transformer fleet and have installed condition monitoring devices to allow us to detect issues before a fault occurs. Figure 14-1 also shows that our fault outage rate for transmission lines and reactive plant has an increasing trend (our performance has declined). The reactive plant fault outage rate has decreased in 2019 and 2020 due to recent investments that have improved asset performance, however, the overall increasing trend in fault outages is expected to continue in the future. This reflects the challenges of our ageing asset base discussed in Chapter 3.

Figure 14-1: Fault outage event rate historical performance



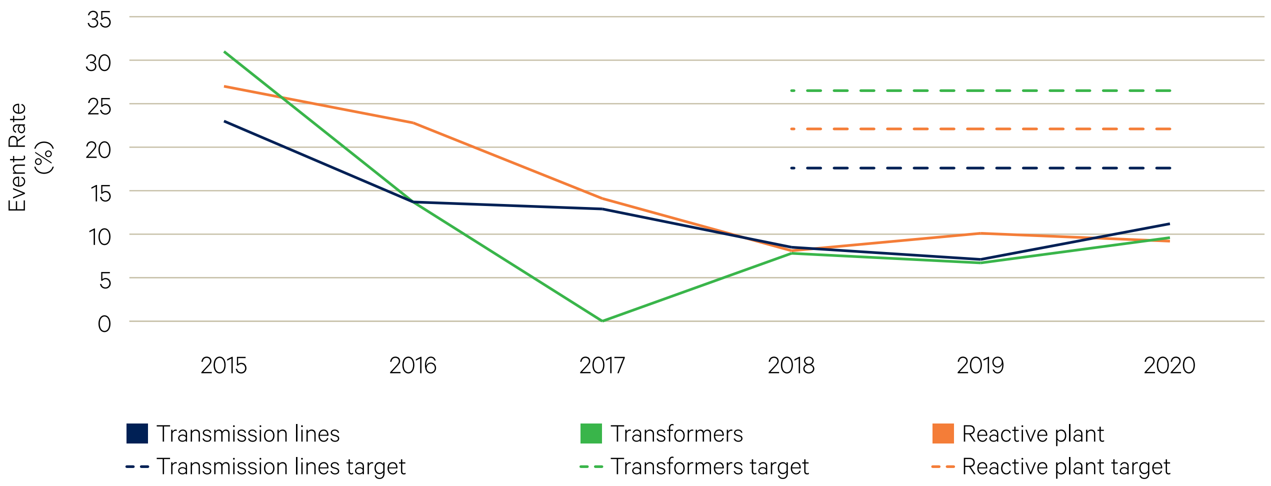
207 We also consistently exceeded the AER's target for the Proper operation of equipment parameter, but we have not discussed this in detail as it presently has zero weighting towards to the SC in the AER's STPIS version 5.

Forced outages

Forced outages occur when an urgent outage is taken unexpectedly (within 24 hours) through manual intervention to switch off the network element. For example, an urgent safety issue requires a network element to be switched off while it is resolved, resulting in a forced outage event.

Our historical performance for the forced outage rate is shown in Figure 14-2. It shows that our forced outage rate across all network elements has improved (i.e. declined) and that we have significantly outperformed the target (i.e. our performance is below the target) so far in the 2018–23 period. This is due to our improved outage planning and delaying our response to non-urgent issues, improving the outcome to our customers and other stakeholders impacted by the outages.

Figure 14-2: Forced outage event rate historical performance



Loss of supply events frequency

Loss of supply events occur when we have an unplanned outage causing a supply interruption. We report these events against two targets, a moderate event target (loss of supply greater than 0.05 system minutes) and a large event target (loss of supply greater than 0.25 system minutes).

Figure 14-3 shows that we have minimised loss of supply events in the 2018–23 period to date and outperformed our targets in most years to ensure our customer receive a reliable supply. Figure 14-4 shows that we perform favourably when compared with our peers.

Figure 14-3: Loss of supply events frequency – historical performance

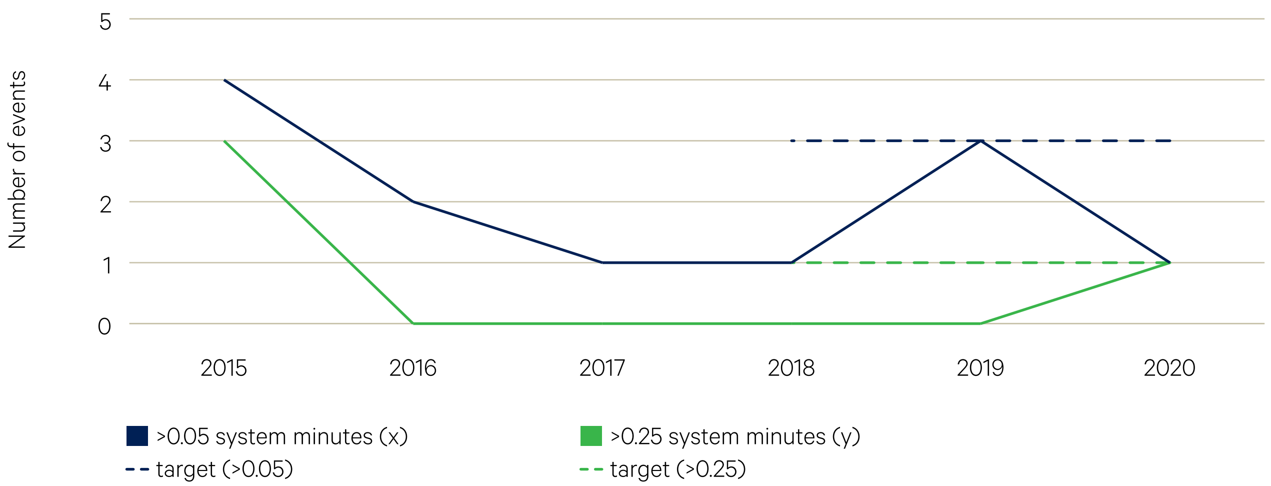
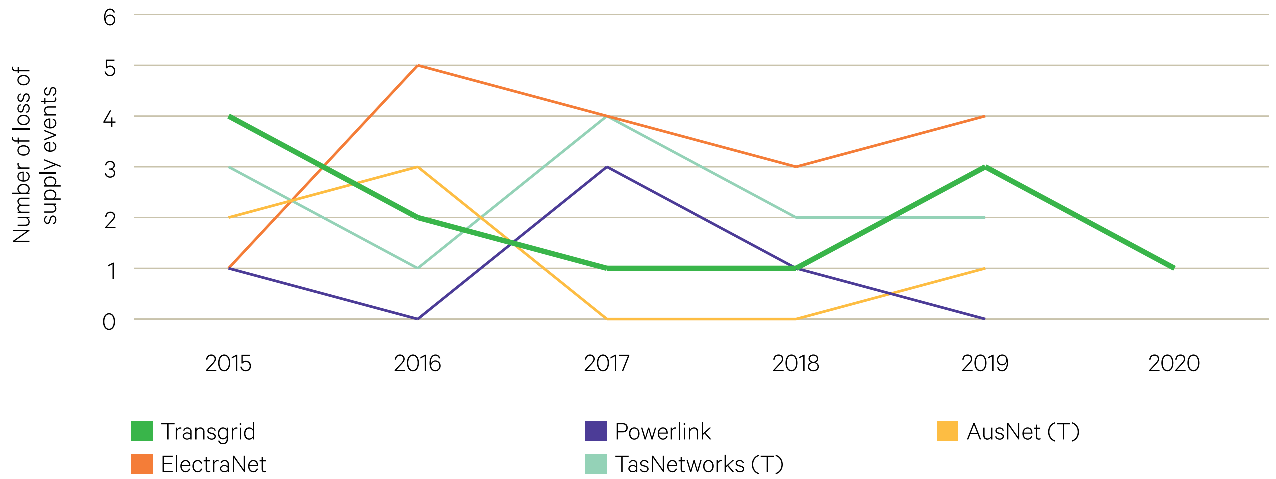


Figure 14-4: Loss of supply event frequency for TNSPs



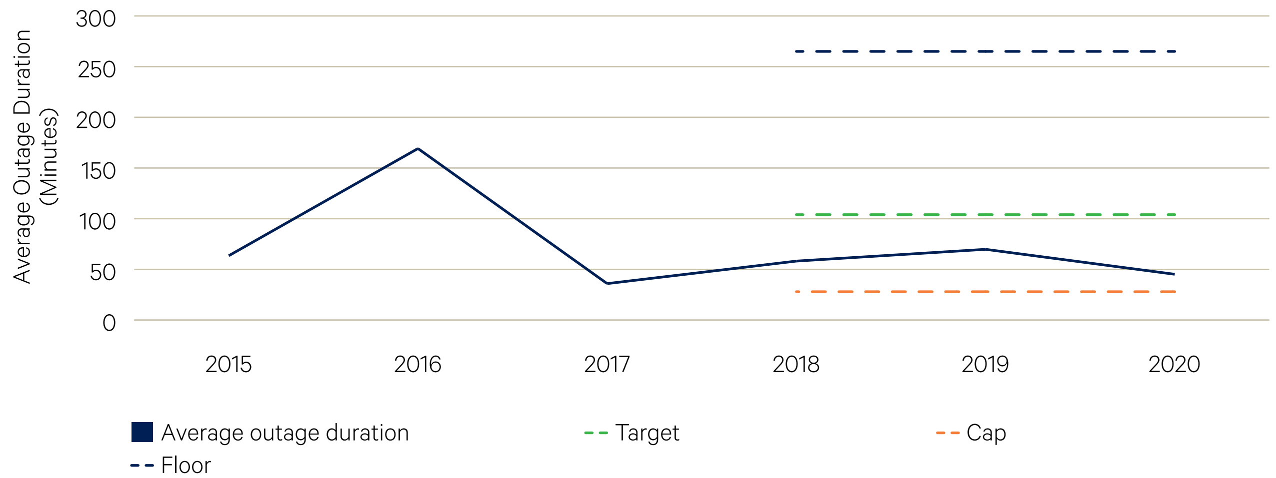
Source: AER Electricity TNSP Operational performance data 2006–2020

Average outage duration

The average outage duration measures the average time is take to restore a supply interruption. It is calculated by taking the total duration of all unplanned outages with a loss of supply in a year and dividing it by the total number of these events.

Figure 14 5 shows that our historical performance has been relatively steady and we have outperformed the target in the 2018–23 period to date. This means that we have improved our supply restoration times to customers after interruptions.

Figure 14-5: Average outage duration historical performance



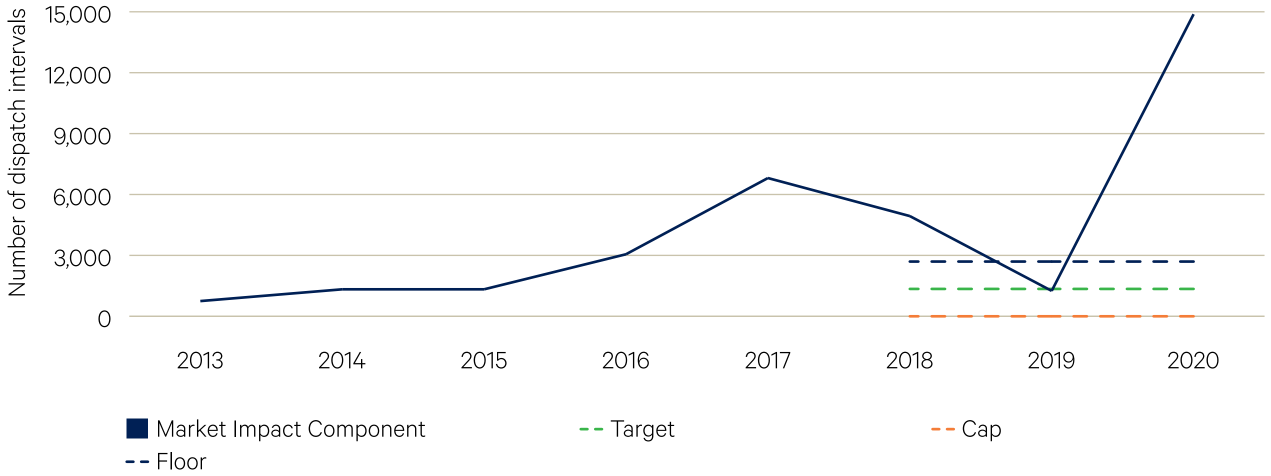
14.2.2 Market Impact Component performance

The Market Impact Component is the number of dispatch intervals where an outage on our network results in a network constraint which increases the cost of producing electricity. It is measured as a count of dispatch intervals where the network constraints causes the change in cost of producing electricity (marginal value) to be greater than $10/MWh.

As the energy mix changes and new generation connects to parts of the network which did not traditionally have generation connections, network constraints are occurring more frequently. We work closely with our customers, actively plan outages, and reschedule planned outages to minimise the market impact.

However, due to the challenges arising from the energy transition discussed in section 14.1 and the delivery of network upgrades as part of our delivery of ISP projects, and in particular the QNI Minor upgrade, our performance dramatically declined in 2020 after strong improvement in the previous two years as shown in Figure 14-6.

Figure 14-6: Market Impact Component historical performance



14.2.3 Network Capability Component performance

Figure 14-7: Dynamic line rating weather station

Our NCC projects delivered as part of our NCIPAP have allowed us to deploy innovative technologies and solutions to deliver benefits to our customers by alleviating transmission network constraints and allowing the lowest cost generation to be dispatched.

The NCC incentivises us to undertake low cost projects which improve the capability of the transmission system, typically by alleviating transmission constraints and providing additional transmission capacity.

So far in the 2018–23 regulatory period, we have delivered four projects and expect to deliver an additional eight projects by the end of the period. These projects involved innovative technologies such as:

- dynamic line rating systems – this involves the installation of weather stations to monitor real time conditions which influence the ratings of transmission lines. During favourable weather conditions (e.g. cool or windy conditions), this system is used to dynamically increase the available capacity of the transmission line. This benefits our customers by allowing more low cost generation to be dispatched or through using the additional capacity to avoid supply interruptions. Weather stations are installed near our transmission lines, as shown in Figure 14-7, and the data is transmitted to our control room where an algorithm calculates the dynamic real time rating.
- SmartWires power flow controllers – this involves installing power flow converters on two transmission lines to improve power transfer capacity between NSW and Victoria. These innovative devices, installed where the transmission lines connect at the substation, can uniquely and dynamically increase or reduce power flows across transmission lines to help optimise the network. This will benefit customers by allowing more generation to be shared across the states, delivering market benefits.
- high temperature low sag conductors – this involved the replacement of a traditional transmission line conductor with a high temperature low sag conductor. We were the first NSP to install this conductor in Australia. This project provided market benefits to customers from the increased dispatch of low cost renewable generation in Southern NSW.

Figure 14-8: Installation of high temperature low sag conductor in Southern NSW

14.3 Proposed 2023–28 STPIS values

In the 2023–28 period,[208] the STPIS Version 5 will continue to apply and we have proposed parameters, targets and plans for each of the three STPIS components[209]:

1. the service component (SC),
2. the market impact component (MIC), and
3. the network capability component (NCC).

Our STPIS values for the 2023–28 period are based on the historical date ranges required by the AER in its Reset RIN.

14.3.1 Service Component

Our SC proposed values of caps, targets and collars have been calculated in line with STPIS version 5 and are based on historical five-year data (2016 to 2020). This is consistent with the approach used to determine our 2018–23 STPIS targets.

The caps and floors were determined by using probability distribution fitting on the performance data. The targets were determined using the arithmetic mean of the five years of performance data. Table 14-2 details our proposed caps, targets, floors, best fit distribution and corresponding weighting. Our STPIS Service Component – Probability Distribution Fitting document provided as an attachment this Revenue Proposal provides further details on probability distribution assessment.

Our strong outperformance on the large loss of supply event frequency parameter target will see us reach the performance frontier in the 2023–28 regulatory period, whereby our target would reduce to zero events. This would mean we no longer have an incentive to improve our performance. We therefore propose to set the SC large loss of supply events parameter at 0.15 system minutes so that our target for 2023–28 is 1 event. This ensures that we have an incentive to improve our performance over the period. This is discussed below.

Table 14-2: Proposed performance parameters

Service component (+/- 1.25% MAR)	Cap	Target	Floor	Distribution	Weighting (% MAR)
Unplanned outage circuit event rate (+/- 0.75% MAR)					
Lines event rate – fault	11.30%	15.12%	19.96%	Pearson5	0.2
Transformer event rate – fault	6.15%	11.70%	18.72%	Dagum	0.2
Reactive plant event rate – fault	5.28%	11.92%	18.46%	Dagum	0.1
Lines event rate – forced	6.71%	10.69%	15.44%	Erlang	0.1
Transformer event rate – forced	3.12%	12.57%	23.84%	Rayleigh	0.1
Reactive plant event rate – forced	7.52%	12.85%	22.15%	Dagum	0.05
Loss of supply events frequency (+/-0.3% MAR)					
Loss of supply events > 0.05 (x) system minutes	0	2	4	Poisson	0.15
Loss of supply events > 0.15 (y) system minutes	0	1	2	Poisson	0.15
Average outage duration (+/- 0.2% MAR)					
Average outage duration	33.12	75.60	159.81	Dagum	0.2
Proper operation of equipment (+/- 0% MAR)					
Failure of protection system	9	15	21	Poisson	0
Material failure of supervisory control and data acquisition (SCADA) system	0	1	3	Geometric	0
Incorrect operational isolation of primary or secondary equipment	2	5	9	Poisson	0

208 In accordance with the AER's Framework & Approach July 2021. We have been subject to STPIS version 5 since 2018–19.
209 In accordance with the AER's STPIS version 5 (corrected) (October 2015)

Alternate target setting – Loss of supply events (y) system minutes

Our strong recent performance for the loss of supply events >0.25 (y) system minutes parameter results in a target and cap of zero for the 2023–28 period.[210] Setting both the target and cap to zero means that there is no positive incentive outcome for this measure, which we consider is inconsistent with clause 6A.7.4 (b)(1)(i) of the NER, which requires the STPIS to *'provide incentives for each Transmission Network Service Provider to… provide greater reliability'*.

To ensure this parameter continues to provide an incentive to improve reliability, we are propose to reduce (i.e. tighten) system minutes[211] from 0.25 to 0.15 minutes[212]. Table 14-3 shows that this would increase our target from zero to one event in the 2023–28 period thereby providing an incentive if we have zero events in any given year.

Table 14-3: Count of events at 0.25 to 0.15 system minutes

Count of events	2016	2017	2018	2019	2020	Average
Loss of Loss of supply events > 0.25 (y)	0	0	0	0	1	0
System minutes supply events > 0.15 (y) system minutes	1	0	1	1	1	1

The AER may approve a performance target based on an alternative methodology proposed by a TNSP if it is satisfied by the considerations described in Table 14-4. Table 14-4 also explains how our proposed approach satisfies these requirements.

Table 14-4: Alternate target setting considerations for loss of supply events (y) system minutes

AER STPIS Consideration[213]	Comment
the methodology is reasonable	Our proposed approach results in the symmetric operation of this parameter with the cap, target and collar being distinct. As the cap, target and collar have been calculated based on actual network performance data for the revised threshold (0.15 system minutes), there is an incentive associated with improved service performance and a penalty associated with a reduction in service performance.
the TNSP's performance as measured by the relevant parameter has been consistently very high over every calendar year of the previous five years	The count of events for this measure has been consistently low for every calendar year for the past five years, resulting in a target of zero.
it is unlikely that the TNSP will be able to improve its performance during the next regulatory control period (or any potential improvement would be marginal), or any further improvements are likely to compromise the TNSP's other regulatory obligations	We cannot be rewarded for an improvement in performance with a target of zero and Y threshold of 0.25 system minutes. Changing the Y threshold to 0.15 will result in a performance target of one, which would result in the symmetrical and fair operation of the scheme.
where applicable, the TNSP's proposed performance targets are not a lower threshold than the performance targets that applied to an identical parameter in the previous regulatory control period	Our proposed cap and target have the same values as for the current 2018/23 regulatory control period. The proposed collar is one count tighter at 2, compared to the current value of 3 for the 2018/23 regulatory period.
the proposed methodology is consistent with the objectives in clause 1.4 of the scheme	Our proposed approach is consistent with the AER objectives of STPIS: • National Electricity Objective – promotes efficient network operation with respect to the reliability as it provides incentive to maintain the reliability of supply. • NER 6A.7.4 (b) – provides a greater incentive to improve reliability – maintaining the same cap and target while reducing the trigger threshold corresponds to improved reliability. • Transparency – transparent approach to determine the target using historical network performance data to ensure the scheme continues to incentivise reliability outcomes for customers.

210 Based on the best probability distribution fit of Poisson,
211 The 'y' threshold
212 We have fit a probability distribution to the recent performance data for this threshold to determine integer values for the cap, target and floor which provide the opportunity to achieve an incentive which corresponds to an improvement in reliability
213 AER STPIS version 5 (corrected) (October 2015), section 3.2 (i)

14.3.2 Market Incentive Component

For this proposal we have calculated indicative MIC performance values for the 2023–28 regulatory period in accordance with STPIS version 5, which is consistent with the approach used to calculate the values for the 2018–23 period:

- Seven years of performance data ranging from calendar years 2014 to 2020 were used to determine the target.
- An interim unplanned outage event limit was calculated using 2011 to 2017 performance data. This interim unplanned outage limit was used to determine the adjusted performance counts for the 2014 to 2017 years. The unplanned outage event limit published in the 2018–23 regulatory period determination was used for 2018 to 2020.
- An average of the medial five years of adjusted performance counts within the 2014 to 2020 window was used to determine the performance target, with the lowest (2014) and highest (2020) performance counts excluded from the calculation.
- The cap was set to zero and the collar to be twice the performance target.
- The unplanned outage event limit was calculated by multiplying the performance target by 0.17.

Table 14-5 details our adjusted performance counts and Table 14-6 details our proposed MIC parameters for the 2023–28 regulatory period.

Table 14-5: MIC Adjusted performance counts

Performance Year	Adjusted Performance Count	Historical Unplanned Event Limit
2014	698	230
2015	1329	230
2016	3056	230
2017	6365	230
2018	4717	229
2019	1252	229
2020	14881	229

Table 14-6: MIC Proposed performance parameters

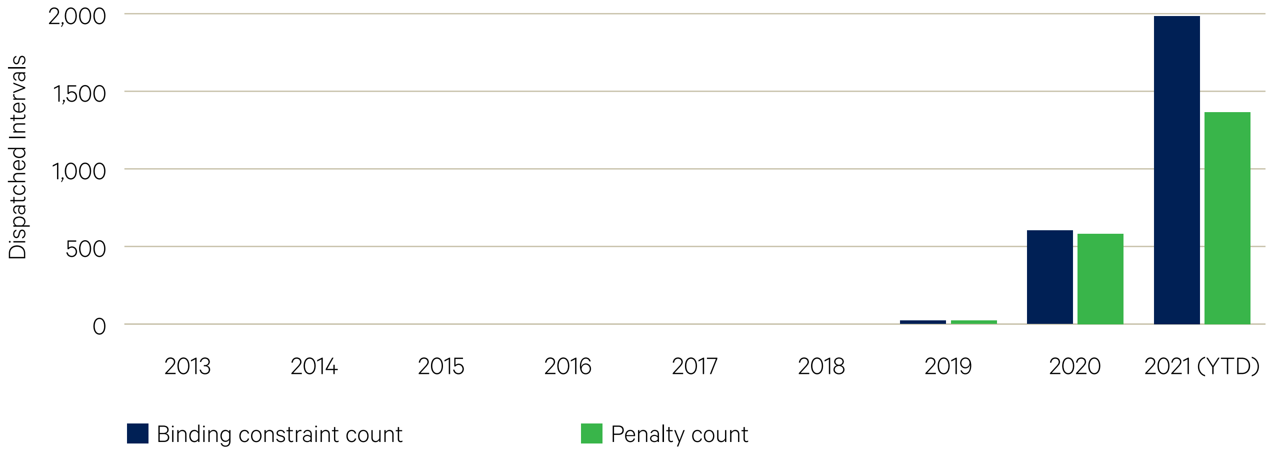
Parameter	Proposed dispatch interval count
Cap	0
Target	3344
Collar	6688
Unplanned outage event limit	568
Dollar per dispatch interval	2,731[214]

As discussed in section 14.1, the energy transition is resulting in widespread congestion across our network and so historical performance does not reflect future market conditions. Many elements of our network, which were not previously constrained now require new outage constraints to ensure the network operates securely and safely. To date during the 2018–23 period, we have accumulated 1,342 market penalties[215] due to new thermal outage constraints, which did not exist when our targets were set. As shown in Figure 14-9 these new constraints were not accounted for in our 2018–23 MIC target, which was calculated based on historical data prior to their existence.

We consider that an alternative method for calculating the MIC is required in order for it to continue to provide a meaningful incentive over the 2023–28 regulatory period. We look forward to participating in the AER's review to develop an alternative method for calculating MIC target that we expect this new methodology will be applied in the AER's Final Decision on our 2023–28 Revenue Proposal.

214 Based on 2022–23 MAR of $913.4 million, the $ per dispatch interval = CY23 ($) MAR * 1% / 3344. An alternative MAR value (e.g., once updated for inflation) will lead to a different $ per dispatch interval.
215 From 1st July 2018 to 20th May 2021.

Figure 14-9: Binding Constraints and Market Penalty Trend due to New Generation



* The CY 2021 values in the graph are year to date as at 20th May 2021.

14.3.3 Network Capability Component

AEMO[216] has endorsed our NCIPAP[217], which will continue delivering material benefits through the NCC for our customers in the 2023–28 regulatory period. Table 14-7 lists our proposed NCIPAP projects, which are explained in our Augex Overview Paper provided as an attachment to this Revenue Proposal.

Table 14-7: Proposed NCIPAP projects 2023–28 ($M, Real 2022–23)

Proposed NCIPAP project	Estimated cost ($ Million)
1. Increase capacity for generation between Darlington Point and Wagga	4.0
2. Darlington Point 330/220 kV transformer tripping scheme	0.3
3. Increase capacity for generation X5 voltage stability constraints	5.2
4. 94T line dynamic ratings.	0.4
5. Yass 330/132 kV transformer dynamic ratings	1.5
6. Maintain capacity during Climate Change – install dynamic line ratings on multiple lines	4.8
Total	**16.2**

14.4 Supporting documentation

The following documents support this Chapter and accompany our Revenue Proposal.

Name
STPIS Service Component Probability Distribution Fitting
2023–28 NCIPAP Projects
AEMO, NCIPAP Endorsement Letter

216 Refer to AEMO NCIPAP endorsement letter, provided as an attachment to this Revenue Proposal.
217 Included in Schedule 7.9 of our Regulatory Information Notice and 2023–28 NCIPAP Projects, provided as an attachment to this Revenue Proposal.

15. Demand Management Innovation Allowance Mechanism

Key messages

> We support the application of the AER's Demand Management Innovation Allowance Mechanism (DMIAM) in the 2023–28 regulatory period.

> The AER published its first demand management scheme - the DMIAM - for TNSPs in May 2021.

> The DMIAM will provide funding for research and development in demand management projects that have the potential to reduce long-term network costs by reducing ongoing or peak demand.

> We estimate a DMIAM allowance of $4.1 million for the 2023-28 regulatory period and will use this to promote innovation in non-network solutions to improve affordability and address climate change.

15.1 The DMIAM

In May 2021, the AER published its DMIAM, which is the first demand management scheme to apply to TNSPs. This was in response to a rule change request by the Energy Networks Australia (ENA) for the AER to develop a demand management scheme to apply to TNSPs, noting that a similar scheme already applies to DNSPs.

The DMIAM provides TNSPs with research and development funding to trial new demand management solutions that have the potential to reduce long-term network costs by reducing ongoing or peak demand.

The AER's F&A paper confirmed its position to apply its DMIAM in our 2023–28 regulatory period.[218] We support this decision and are committed to identifying and implementing demand management projects to improve affordability and address climate change.

The DMIMA provides a fixed upfront allowance, which if not spent during the regulatory period, is returned to customers via lower tariffs in the future. This allowances is based on:

- a fixed allowance for the costs of independent assessment, plus
- 0.1 per cent of our total annual building block revenue requirement.

The DMIAM establishes:

- project eligibility requirements that we must satisfy in order for projects to be funded under the DMIAM, and
- annual compliance reporting requirements to assist the AER in assessing whether projects meet the eligibility requirements and promote sharing of research outcomes and knowledge across the industry.

218 AER, Framework and Approach Transgrid – Regulatory control period commencing 1 July 2021, 30 July 2021.

15.2 DMIAM for the 2023–28 regulatory period

Using the AER's PTRM, we estimate an allowance of $4.1 million under the AER's DMIAM for the 2023–28 regulatory period based on:[219]

- $200,000[220] fixed allowance for the costs of independent assessment, plus
- 0.1 per cent of our total annual building block revenue requirement for the 2023–28 regulatory period,[221] which is discussed in Chapter 19.

Figure 15-1 shows how the DMIA is calculated.

Figure 15-1: How the DMIA is calculated

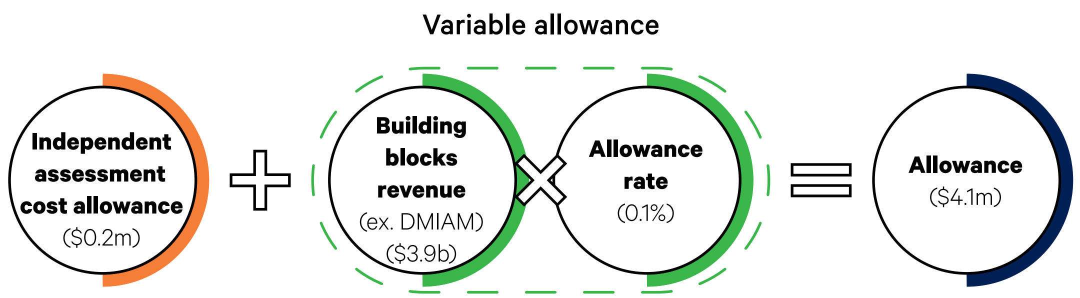


Table 15-1 sets out our 2023–28 DMIAM allowance.

Table 15-1: DMIAM allowance ($M, Real 2022–23)

	FY24	FY25	FY26	FY27	FY28	Total
Allowance	4.1	–	–	–	–	4.1

We intend to engage with industry stakeholders about how best to utilise DMIA funding and are considering the following potential DMIA projects in the 2023–28 regulatory period:

- Technology trialling projects – using existing technology in innovative ways to shift demand from existing network elements (transmission lines and transformers), including:
  - distributed energy resource management systems trial
  - fast runback demand response trial
  - behavioural demand response program
  - electric vehicle fleet charging trials
  - commercial HVAC demand response trials and chilled water storage
- Collaboration – engaging with industry stakeholders about how best to utilise DMIA funding, and
- Market understanding and research – understanding how future demand will evolve in a decarbonised world and its effect on transmission. We will collaborate with leading researchers to study future sources of demand and develop strategies to manage their effects on the grid, including:
  - increased load flexibility study
  - integration with Virtual Power Plants (VPPs)
  - partnerships with external academics and international experts.

219 AER, *Demand management innovation allowance mechanism, Electricity transmission network service providers*, May 2021.
220 This is dollars at 30 June 2021. We have adjusted this by inflation using actual CPI
221 The allowance is calculated using building blocks excluding the allowance to avoid circularity.

16. Cost pass through events

Key messages

> In addition to the prescribed pass through events in the NER, we are nominating the following pass through events and definitions over the 2023–28 regulatory period. These events currently apply in our 2018–23 regulatory period and we have updated them to reflect changes made by the AER in its recent decisions:
> - an insurance coverage event
> - insurer's credit risk default event
> - natural disaster event
> - terrorism event

> We are currently examining the nature and scope of costs that we may incur if we are required to ready our network for 100 per cent renewables by 2025. Subject to this work, we propose to either include the forecast costs, or a further cost pass through event, in our Revised Revenue Proposal.

16.1 Overview

Our operating environment is unpredictable and events beyond our control can substantially change our expenditure within a regulatory period. We exclude some high cost low probability events from our expenditure forecasts to ensure that customers only pay for them if and when they actually occur.

The NER includes a 'cost pass through' provisions so that we can recover (or pass through) costs of defined, unpredictable, high cost events that are not included in the expenditure and revenue forecasts in the AER's Final Decision. The AER determines the efficient costs of these events as they occur during the period.

For example, in the 2018–23 regulatory period we experienced unprecedented network damage as a result of the 2019–20 bushfires, which were the worst in NSW history. The AER approved a cost pass through allowance to ensure we can undertake the necessary repair works to keep the community safe and to maintain the reliability of the network. There is a need for similar provisions for the next regulatory period to deal with nominated pass through events.

16.2 Our nominated pass through events

The Rules[222] recognises the following defined pass through events:

- regulatory change event
- service standard event
- tax change event
- insurance event
- any other event specified in a transmission determination as a pass through event for the determination (nominated pass through event).

222 NER rule 6A.7.3(a1) (1) to (4)

In addition to these defined events[223], we propose the following four nominated pass through events for the 2023–28 regulatory period:

- insurance coverage event
- insurer's credit risk default event
- natural disaster event
- terrorism event

Sections 16.3 to 16.6 outline our proposed nominated pass through events and their respective definitions for the 2023–28 regulatory control period. These events are consistent with the nominated pass through events approved by the AER in the current 2018–23 Transmission Determination. However, we have updated the definitions to be consistent with the AER's most recent regulatory determinations.

None of our nominated pass through events are covered by any of the categories of pass through events specified in clauses 6A.7.3(a1)(1) to (4) of the NER. In addition, we consider that the nature and type of the events can be clearly identified at the time the AER's determination is made.

16.3 Insurance coverage event

An insurance coverage event is a prudent and efficient way to mitigate the risk of liability losses that exceed our insurance coverage.

Given the current volatility in the insurance liability market, this event covers potential insurance gaps in relation to insurance caps and the possibility of withdrawn capacity or uneconomic increases in premiums in the future.

Our proposed definition of an insurance coverage event is largely consistent with our current insurance cap event amended to include 1(b) and 2(b) consistent with the AER's recent regulatory decisions.[224]

223 In accordance with NER rule 6A.6.9(a)
224 AER final decisions for the Victorian DNSPs, April 2021, and AER draft decision, AusNet Services Transmission 2022–27, Attachment 13, Pass through events, 30 June 2021.

16-1: Insurance coverage event

Insurance coverage event

1. Transgrid:

(a) makes a claim or claims and receives the benefit of a payment or payments under a relevant insurance policy or set of insurance policies; or

(b) would have been able to make a claim or claims under a relevant insurance policy or set of insurance policies but for changed circumstances; and

2. Transgrid incurs costs:

(a) beyond a relevant policy limit for that policy or set of insurance policies; or

(b) that are unrecoverable under that policy or set of insurance policies due to changed circumstances; and

3. The costs referred to in paragraph 2 materially increase the costs to Transgrid in providing prescribed transmission services.

For the purposes of this insurance coverage event:

'changed circumstances' means movements in the relevant insurance liability market that are beyond the control of Transgrid, where those movements mean that it is no longer possible for Transgrid to take out an insurance policy or set of insurance policies at all or on reasonable commercial terms that include some or all of the costs referred to in paragraph 2 above within the scope of that insurance policy or set of insurance policies.

'costs' means the costs that would have been recovered under the insurance policy or set of insurance policies had:

– the limit not been exhausted, or

– those costs not been unrecoverable due to changed circumstances.

A relevant insurance policy or set of insurance policies means an insurance policy or set of insurance policies held during the regulatory control period or a previous regulatory control period in which Transgrid was regulated.

Note: In assessing an insurance coverage event through application under Clause 6A.7.3 of the Rules, the AER will have regard to:

– the relevant insurance policy or set of insurance policies for the event;

– the level of insurance that an efficient and prudent Network Service Provider (NSP) would obtain, or would have sought to obtain, in respect of the event;

– any information provided by Transgrid to the AER about Transgrid's actions and processes; and

– any guidance published by the AER on matters the AER will likely have regard to in assessing any insurance coverage event.

Our nominated insurance coverage event satisfies the AER's considerations for nominated pass-through event as follows:

- The aim of an insurance coverage event is to cover us if an insurer is not able to pay all, or part, of a large, or catastrophic, event that could have a financially significant impact on us.
- We invest, operate and maintain our network within our risk framework to reasonably withstand events outside our control. We set our insurance limits based on a level of insurance cover that is commensurate with the scale and size of our operations and the risks associated with our operations, as well as industry standards and practices.
- In some cases the cost of insurance to mitigate the risk is too high given the probability of the event occurring. This has been made more difficult in recent times given that the volatility of the global insurance industry since 2019, resulting from the increased frequency of extreme weather events and bushfires. These factors have driven up the cost of insurance premiums as providers exit the market or reassess the liability cover they are willing to provide. This is outside our control and may mean it is no longer possible to take out an insurance policy (or set of insurance policies) at all, or on reasonable commercial terms over the 2023–28 regulatory period.

- Self-insurance would not be appropriate because the cost impact of the event is far too high and would require substantial reserves for us to cover the potential liability.
- Our insurance coverage is based on reasonable commercial terms. Based on professional insurance broker advice, we set our insurance limits based on credible risk based scenario analysis and what the potential loss could be. We consider it would not be efficient to obtain additional insurances beyond these limits of cover and would unnecessarily increase the costs of our prescribed transmission services to our customers.

16.4 Insurer's credit risk default event

An insurance credit risk event mitigates the risk of an insurer becoming insolvent and of us consequently being forced to insure with another provider and incurring substantial additional costs, through higher premiums, or a lower claim limit or higher deductible.

Our proposed definition of an insurance coverage event is largely consistent with our current credit risk event and the AER's recent regulatory decisions.[225]

16-2: Insurer's credit risk default event

Insurer's credit risk default event

An insurer credit risk event occurs if an insurer of Transgrid becomes insolvent, and as a result, in respect of an existing or potential claim for a risk that was insured by the insolvent insurer, Transgrid:

(a) is subject to a higher or lower claim limit or a higher or lower deductible than would have otherwise applied under the insolvent insurer's policy, or

(b) incurs additional costs associated with funding an insurance claim, which would otherwise have been covered by the insolvent insurer.

Note: In assessing an insurer credit risk event pass through application, the AER will have regard to, amongst other things:

- Transgrid's attempts to mitigate and prevent the event from occurring by reviewing and considering the insurer's track record, size, credit rating and reputation, and
- in the event that a claim would have been covered by the insolvent insurer's policy, whether Transgrid had reasonable opportunity to insure the risk with a different provider.

Our nominated insurance credit risk event satisfies the AER's considerations for nominated pass-through event as follows:

- If an insurer was unable to pay all, or part, of a large or catastrophic event claim it could have significant financial implications for our ability to deliver prescribed transmission services. We minimise this risk through using an insurance broker to obtain our insurance coverage. Our insurance broker:
  - selects insurance providers based on a robust assessment of financial viability, geographical spread and international reputation
  - mitigates insurer counterparty risk by regular monitoring and reporting, and
  - ensures that insurers meet a minimum financial standard set by external rating agencies. Where possible, we seek to insure with providers that have a Standard & Poor rating of A- or better (or equivalent with another recognised rating agency).
- It is outside our control that one or more of our insurers become insolvent.
- Self-insurance would not be appropriate because the cost impact of the event is far too high and would require substantial reserves for us to cover the potential liability.

225 AER final decisions for the Victorian DNSPs, April 2021, and AER draft decision, AusNet Services Transmission 2022–27, Attachment 13, Pass through events, 30 June 2021.

16.5 Natural disaster event

Natural disaster such as floods, earthquakes, bushfires and major storms are entirely beyond our control. The recent Intergovernmental Panel on Climate Change (IPPC) report on the global climate[226] indicates such events will become more common. A natural disaster event mitigates the risk of not being able to obtain insurance coverage on reasonable commercial terms and materially increasing our efficient costs that we are not otherwise able to recover.

Our proposed definition of a natural disaster event is consistent with our current natural disaster event, adjusted to include cyclones as per the AER's recent regulatory decisions.[227]

16-3: Natural disaster event

Natural disaster event

Natural disaster event means any natural disaster including but not limited to cyclone, fire, flood or earthquake that occurs during the 2023-28 regulatory control period that changes the costs to Transgrid in providing prescribed transmission services, provided the cyclone, fire, flood, earthquake or other event was:

(a) a consequence of an act or omission that was necessary for Transgrid to comply with a regulatory obligation or requirement or with an applicable regulatory instrument, or

(b) not a consequence of any other act or omission of Transgrid.

Note: In assessing a natural disaster event pass through application, the AER will have regard to, amongst other things:

- whether Transgrid has insurance against the event;
- the level of insurance that an efficient and prudent NSP would obtain in respect of the event.

Our nominated natural disaster event satisfies the AER's considerations for nominated pass-through event as follows:

- Our risk based approach to managing our assets aims to minimise and mitigate the consequences of exposure of our transmission network to natural disasters. Our mitigations include technical preventative measures, asset monitoring and maintenance activities, supplemented by insurance cover. However, some areas as insurers no longer offer coverage resulting in insurance premiums becoming unsustainable for certain events and / or assets over the 2023–28 regulatory period. For example:
  - we are no longer able to obtain coverage of towers and lines outside of a terminal station boundary and have to self-insure these assets, and
  - our insurance broker has advised that a significant amount of global capacity for bushfire liability risks has left the marketplace because of the perception of inadequate pricing, increasing volatility and insufficient returns. Given existing and emerging trends in the international insurance market, it is likely there will be withdrawal of capacity from the market which may require us to purchase lower levels of cover.
- Where insurance becomes unavailable on reasonable commercial terms, it may be more prudent and efficient to reduce or remove the level of insurance coverage for a natural disaster event. Justification for this approach will need to balance the long-term interests of customers against rising insurance premiums and the likelihood of an event occurring.
- Self-insurance would not be appropriate given the need to develop credible self-insured risk quantifications for very low probability events. The resulting cost impact of the event is likely to be far too high and would require substantial reserves for us to cover the potential liability.

226 IPCC, Global Warming of 1.5 degrees C, 2018
227 AER final decisions for the Victorian DNSPs, April 2021, and AER draft decision, AusNet Services Transmission 2022–27, Attachment 13, Pass through events, 30 June 2021

16.6 Terrorism event

A terrorism event mitigates the risk of liability of deliberate damage caused to our network and our ability to deliver our prescribed transmission services.

Our proposed definition of a terrorism event is largely consistent with our current definition and the AER's recent regulatory decisions.[228]

16-4: Terrorism event

Terrorism event

Terrorism event means an act (including, but not limited to, the use of force or violence or the threat of force or violence) of any person or group of persons (whether acting alone or on behalf of or in connection with any organisation or government), which:

(a) from its nature or context is done for, or in connection with, political, religious, ideological, ethnic or similar purposes or reasons (including the intention to influence or intimidate any government and/or put the public, or any section of the public, in fear), and

(b) changes the costs to Transgrid in providing prescribed transmission services.

Note: In assessing a terrorism event pass through application, the AER will have regard to, amongst other things:

- whether Transgrid has insurance against the event;
- the level of insurance that an efficient and prudent NSP would obtain in respect of the event; and
- whether a declaration has been made by a relevant government authority that a terrorism event has occurred.

Our nominated terrorism event satisfies the AER's considerations for nominated pass-through event as follows:

- In response to cyber security and critical infrastructure concerns, we have new obligations[229] over the 2023–28 regulatory period to ensure the physical and electronic security of our transmission network. We have set out in Chapters 7 (opex step changes) and 8 (Digital Infrastructure repex and ICT capex) our expenditure needed to meet these new obligations which should minimise the risk of a cyber-terrorism event occurring.
- Even with new security measures in place over the 2023–28 regulatory period, an act of terrorism could significantly impact on the cost of maintaining or restoring reliable supply of our prescribed transmission services.
- Our insurance broker has advised that the global insurance market landscape for cyber risk is evolving at a rapid pace and is likely to adversely impact upon the level, terms and availability of future cyber insurance cover. Consequently, we may not be able to secure future insurance cover for cyber risk on reasonable commercial and economic terms.
- We consider it appropriate to share the residual risk of an act of terrorism occurring with our customers by including a nominated Terrorism event pass-through event.
- Self-insurance would not be appropriate given the very low frequency of a terrorism event and potentially very high cost impact, which would require substantial reserves to cover the potential liability. Calculating the amount of self-insurance premium required would also be complex and subjective.

228 Ibid.
229 The Security of Critical Infrastructure Act 2018 (CI Act) and Bill amendment, and AEMO's Australian Energy Sector Cyber Security Framework (AESCSF).

17. Contingent Projects

Key messages

- Our rapidly changing operating environment means that the need, timing and cost of a number of projects remain uncertain at the time of submitting this Revenue Proposal.
- We are proposing to treat these uncertain projects as contingent projects so that customers only pay for them if and when they proceed. The costs of these contingent projects are not included in our capex forecast and are therefore not reflected in our forecast revenues or prices.
- We have two categories of contingent projects:
  - Projects undergoing a RIT-T – these are projects that are currently undergoing a RIT-T, but where we expect the outcome to be known prior to submitting our Revised Regulatory Proposal to the AER in November 2022. Currently we are conducting RIT-T assessments on 4 projects that have an indicative cost in the 2023-28 regulatory period of $741.9 million and a total estimated cost of $792.2 million. We will include the preferred option identified through the RIT-Ts in our revised capex forecast.
  - Standard contingent projects – we have identified 8 projects under the NER that have an indicative cost in the 2023-28 regulatory period of $1,175.9 million and a total estimated cost of $2,142.3 million. The key drivers of these projects are:
    - system inertia and strength requirements
    - increased fault levels
    - expected demand growth, and
    - expected new generation connection.
- As requested by stakeholders, for transparency we have listed future or Actionable ISP projects although these are automatic contingent projects under the Actionable ISP Rules, and therefore do not require AER approval.
- We have not included NSW REZ as contingent projects because these projects will be regulated under the NSW regulatory framework, being the NSW EII Regulations, rather than the NER.

17.1 Nominated contingent projects

As explained in Chapter 3, in the 2023–28 regulatory period our network will be challenged by:

- pockets of strong maximum demand growth in some regions from mining in regional NSW, urban development, industrial precincts and data centres, and
- increased operational complexity from the rapid change in the mix and location of generation as ageing coal-fired generation retires and large-scale variable renewable generation connects to the NEM.

Given these operational challenges, the need, timing and cost of a number of projects remain uncertain at the time of submitting this Revenue Proposal. We are proposing to treat these projects as contingent projects so that customers only pay for them if and when they proceed. The costs of these projects are not included in our capex forecast and are therefore not reflected in our revenue forecast or prices.

As discussed in Chapter 8, for the purpose of this Revenue Proposal we have also treated projects currently undergoing a RIT-T as contingent projects where we expect the outcome of the RIT-T to be identified prior to submitting our Revised Regulatory Proposal to the AER in November 2022.

We have two categories of nominated contingent projects:

- projects undergoing a RIT-T, which will be completed prior to November 2022 and
- standard contingent projects under the NER.

17.1.1 Projects undergoing a RIT-T

We have included projects currently undergoing a RIT-T as contingent projects where the RIT-T is expected to be completed before we submit our Revised Revenue Proposal to the AER in November 2022. These projects are listed in Table 17-1. We will include the costs of the preferred network options in our capex forecast in our Revised Revenue Proposal.

Table 17-1: 2023–28 Augex Major Projects undergoing a RIT-T ($M, Real 2022–23)

Major Projects – undergoing RIT-T	2023–28 estimated cost	Total estimated cost	Project commencement	Expected completion
Managing risk on Line 86 (Tamworth – Armidale)	331.1	331.1	2023–24	2026–27
Improving stability in south western NSW	127.1	175.3	2022–23	2024–25
Supply to North West Slopes	166.3	168.4	2023–24	2027–28
Supply to Bathurst, Orange and Parkes Stage 1	117.4	117.4	2023–24	2026–27
Total	**741.9**	**792.2**		

Table 17-2 sets out the key milestones in the RIT-T process for these projects, which shows that we expect to complete the RIT-T process for all projects by July 2022. We will consult with customers and other stakeholders throughout the RIT-T process and on the outcomes of the RIT-Ts and the expected costs of the preferred options over the period July to November 2022.

Table 17-2: Key milestones in the RIT-T process

Proposed contingent project	PSCR Published	PADR Published / Expected	PACR Expected
Managing risk on Line 86 (Tamworth – Armidale)	December 2021	May 2022	July 2022
Improving stability in south-western NSW	July 2020	September 2021	March 2022
Supply to North West Slopes	April 2021	February 2022	June 2022
Supply to Bathurst, Orange and Parkes Stage 1	March 2021	February 2022	June 2022

17.1.2 Standard Contingent Projects

Table 17-.3 lists our proposed standard contingent projects under the NER. We have identified 8 standard contingent projects, with an indicative total cost of $2,142 million of which we expected to incur $1,176 million in the 2023–28 regulatory period. The key drivers of these projects are:

- system inertia and strength requirements
- increased fault levels
- expected demand growth, and
- expected new generation connection

The timing and costs of these projects will be determined through the RIT-T process. Subject to the preferred option being confirmed via the RIT-T process and the trigger events being satisfied, we will seek to recover the costs of these projects through the contingent project application process as they arise during the 2023–28 regulatory period.

Further detail on our contingent projects is set out in Chapter 8 and our Augex Overview Paper.

Table 17-3: Standard contingent projects for 2023–28 regulatory period ($M, Real 2022–23)

Proposed contingent project	2023–28 estimated cost	Total estimated cost	Expected completion	Proposed trigger
1. Meeting NSW system inertia requirement	105.1	262.7	2030–31	(a) Notice by AEMO under NER clause 5.20B of the existence of an inertia shortfall in the New South Wales region, and (b) Successful completion by Transgrid of a RIT–T that demonstrates that transmission investment is the preferred option (or part of the preferred option).
2. Meeting NSW system strength requirement	283.7	640.9	2025–26	(a) Notice by AEMO under NER clause 11.143.14 of the existence of a system strength shortfall in the NSW region, (b) Unless the system strength project is not subject to the RIT-T under clause NER 11.143.16, then successful completion of a RIT–T that demonstrates that transmission investment is the preferred option (or part of the preferred option).
3. Supply to Bathurst, Orange and Parkes Stage 2	94.6	404.9	2030–31	(a) One or more of the following: (i) Total demand in the Orange area exceeds 355 MW, or (ii) Total demand in the Parkes area exceeds 155MW, and (b) Successful completion of a RIT-T demonstrating that increasing capacity of the network in the Bathurst, Orange and Parkes areas is the option or part of the option that maximises positive net economic benefits.
4. Improve capacity of Southern NSW lines for renewables	275.8	394.0	2029–30	(a) New generation of more than 1,000 MW is committed in Southern and/or South western NSW (b) Successful completion of a RIT-T demonstrating that increasing capacity of the network in southern NSW is the option or part of the option that maximises positive net economic benefits
5. Supply to ACT network capability	71.4	94.6	2028–29	(a) One or more of the following: (i) Combined demand between Canberra to Williamsdale exceeds 890 MW (ii) The ACT Utilities (Technical Regulation) (Electricity Transmission Supply Code) makes a change to the agreed maximum demand under a special contingency event, and (b) Successful completion of a RIT–T that demonstrates that transmission investment is the preferred option (or part of the preferred option)
6. Moree Special Activation Precinct	42.0	42.0	2027–28	(a) Moree total demand forecast exceeds 50 MW (b) Successful completion of a RIT–T that demonstrates that transmission investment is the preferred option (or part of the preferred option)
7. Manage increased fault levels in Southern NSW	51.1	51.1	2026–27	(a) Successful completion of a RIT–T that demonstrates that transmission investment in the HumeLink Project is the preferred option (or part of the preferred option) (b) Contingent Project Application approval for the HumeLink Project
8. Strategic Easement acquisition for supply to Sydney from the south	252.2	252.2	2025–26	(a) Inclusion of Southern 500 kV Ring (supply to Sydney, Newcastle and Wollongong future ISP project, southern section) in optimal development path in 2022 (or subsequent) ISP, and (b) Rezoning of land along the proposed easement between South Creek and Greendale from rural to residential, commercial or industrial.
Total	**1,175.9**	**2,142.3**		

17.2 Actionable and future ISP projects

We support the transition to the new energy market and the delivery of projects identified in AEMO's ISP, which identifies the optimal development path for eastern Australia's power system to facilitate this transition. We will deliver projects in the 2023–28 period in accordance with AEMO's ISPs, as they are required.

We have not included these projects as contingent projects because these projects are, or will be, 'automatic' contingent projects under the new NER automatic contingent project provisions for Actionable ISP projects.[230] Under the NER automatic contingent project provisions:

- AEMO assesses the net benefits of these projects through the feedback loop process which involves confirming whether:
  - the project addresses the need and aligns with the optimal development path in the most recent ISP, and
  - the cost of the preferred option does not change the status of the project as part of the optimal development path, and
- subject to AEMO's confirmation, us submitting a contingent project application and the AER assessing the prudence and efficiency of the costs and making a revenue determination.

AEMO's Draft 2022 ISP identifies the following actionable and future ISP projects to be delivered in the 2023–28 regulatory period.

230 NER rule 6A.8.A1(b)

Table 17-4: Actionable and future ISP projects ($M, Real 2022–23)

ISP Projects	2023–28 estimated cost	Total estimated cost	Project commencement	Expected completion
Actionable ISP				
HumeLink	3,618.9	3,618.9	2023–24	2026–27
VNI West[1]	1,696.7	3,090.9	2023–24	2030–31
Sydney Ring (Reinforcing Sydney, Newcastle, and Wollongong Supply)	924.5	924.5	2023–24	2027–28
Future ISP				
QNI Connect[2]	159.2	1,316.4	2027–28	2032–33

Notes: 1. Includes NSW and VIC components. 2. Includes NSW and QLD components

17.3 Supporting documentation

The following documents support this Chapter and accompany our Revenue Proposal.

Name
Augex Overview Paper

18. Shared Assets

Key messages

> We forecast that our unregulated revenue from our shared assets will exceed 1 per cent of our forecast MAR in the 2023–28 period.

> We propose to reduce our forecast 2023–28 MAR by $10.6 million consistent with the AER's shared asset guideline so our customers benefit from the shared use of those assets.

> We will continue to look for opportunities to generate shared asset revenue to deliver cost savings to customers.

18.1 Shared Assets

Shared assets are those assets in the RAB that are used to provide both regulated and unregulated services. Our total expected annual maximum allowed revenue (smoothed revenue) (MAR) must be reduced when our annual unregulated revenues from the use of shared assets are expected to exceed 1 per cent of our annual expected MAR for that regulatory year. If this materiality threshold is exceeded, then 10 per cent of forecast unregulated revenue from shared assets is deducted from our annual expected MAR to ensure that we do not recover more than our efficient costs.[231]

There are five broad categories of commercial activities that generate unregulated revenue from the use of our regulated assets. These are:

- fibre optic communications systems that utilises the transmission lines and tower assets of our regulated transmission network
- radio communication sites that utilises transmission lines and tower assets of our regulated transmission network
- property leases that make use of the property and land where our transmission network is sited,
- operation and maintenance (O&M) services provided to services provided to other third parties than Lumea (e.g. Endeavour Energy), and
- O&M services provided to our ring-fenced commercial arm Lumea, that employs use of our regulated fleet plant and equipment.

The unregulated services are branded under Lumea, which we established as a separate, ring-fenced entity in May 2021 to provide non-regulated services. For historical legal reasons, Transgrid remains the legal entity responsible for the first four services, but does so under the Lumea brand (i.e. two brands one company).

In respect of the fifth category of O&M services, Lumea contracts with generators and other connectees for provision of unregulated contestable services and is the counterparty to those contracts. Transgrid provides O&M services to Lumea on a commercially negotiated, arms-length, market standard O&M contract. In this fifth category, Lumea procures O&M services from Transgrid as a third-party provider for relevant asset management services for its connection projects. We have allocated a share of the unregulated revenue paid to Transgrid under the O&M contracts by Lumea to reflect the use of regulated assets in providing those services. The regulated assets used to provide O&M services are ICT, fleet and mobile plant. We have identified the portion of revenue that relates to these asset using the account codes for these assets and have treated the associated revenue as shared asset revenue.

Lumea provides other unregulated contestable services, in addition to the above five services, which do not involve the use of shared assets. Lumea's activities are financed by its own balance sheet on a fully arms' length basis from Transgrid.

231 AER, *Shared asset guideline*, 29 November 2013. A 'shared asset' is an asset whose costs were initially allocated to prescribed transmission services that is now also used to provide unregulated services.

In addition, we ensure that there is no cross subsidisation of the unregulated services by Transgrid by:

- ensuring that the O&M service contracts between Lumea and Transgrid are all arms' length, commercially negotiated arrangements
- maintaining separate accounts for our prescribed business (being Transgrid) and an amalgamated set of accounts for our entire business, and
- applying our cost allocation method (CAM) to allocate costs between prescribed and other services.

This ensures that customers do not pay for the costs of providing other unregulated services.

18.2 2023–28 regulatory period

In the 2023–28 period, we expect to earn unregulated revenue from shared assets including:

- fibre optic communications systems – telecommunications services agreements for services including ethernet, wavelength and data
- radio communications sites – licences to third parties for the use of towers, buildings and ground spaces
- property – grazing leases and tenancies to third parties
- ICT and fleet, plant and equipment – operations and maintenance service contracts for third parties other than Lumea, and
- ICT and fleet, plant and equipment – operations and maintenance service contracts for Lumea.

Table 18-1 shows that we forecast our revenue from shared assets to increase by 48.9 per cent from $71.3 million in 2018–23 to $106.2 million in 2023–28. This is largely driven by the expected increase in revenue from fibre optic communications data services[232] and radio communications site leases,[233] which comprise around [redacted] per cent of our 2023–28 shared asset revenue. This is due to the forecast growth in customers and the number of services offered over this period.

The forecast growth in fibre optic communications data services is largely due to:

- an increased focus on services provision in regional and rural areas as wholesale businesses and government agencies commit to providing the same level of internet and mobile phone connectivity in regional, rural and metro areas to 'bridge the digital divide'
- the increasing demand for our above ground fibre. This differentiates us from other optical fibre providers whose optical fibre is below ground. Above ground optical fibre provides a reliable and secure service and has lower risk of being impacted by extreme weather events such as fires and floods, and
- improvements in the backbone network for data services which increases the communications network capacity to more locations.

The forecast growth in radio communications site leases is driven by:

- the changes in technology, including the 4G and 5G mobile roll out. Mobile network operators are increasingly requesting to install their equipment on our communications towers, particularly in regional and rural areas as this is a more cost effective alternative to building new sites
- improvements to our processes such as 3D mapping of communication sites, which increase the speed at which customers can access new site leases, and
- the rural and regional presence of our network offers communications access in remote areas where the services are required by growing wholesale and government markets.

The forecast growth in operations and maintenance services is driven by:

- the rapid growth in renewable energy projects which we are connecting to the transmission network
- Lumea providing connection services which include long-term operations and maintenance of the assets

Property leases is expected to remain steady largely due to existing grazing leases and tenancies being maintained and no growth in this offering is expected.

232 Data services includes the use of fibre optic cores on Transgrid's transmission line optical ground wire network.
233 Communications site leases includes the installation of third party services at Transgrid's radio repeater site towers/poles and on transmission line towers/poles.

We will continue to look for opportunities to generate shared revenue to deliver cost savings to customers.

Table 18-1: Shared asset revenue forecast ($M, Real 2022–23)

	2018–23 Total	2023–24	2024–25	2025–26	2026–27	2027–28	2023–28 Total	% of 2023–28 total
Radio communications site leases	[redacted]							
Fibre optic communications data services	[redacted]							
Property leases	1.3	0.3	0.3	0.2	0.2	0.2	1.2	**1.2**
O&M services for third parties other than Lumea	3.1	0.3	0.3	0.3	0.3	0.3	1.6	**1.5**
O&M services for Lumea	[redacted]							
Total	**71.3**	**17.9**	**19.1**	**20.5**	**23.0**	**25.7**	**106.2**	**100.0**

Our forecast growth in revenue from shared assets in the 2023–28 regulatory period is consistent with the growth we have experienced in the 2018–23 period, where our actual revenue is expected to be materially higher than our forecast revenue. This is due to the rapid growth in our telecommunications services to renewable energy projects in Australia, including renewable energy zones and special activation projects. New customers include: Water NSW, NSW Records, SunTop Solar Farm, +ES, Newcastle Connect, Greenlight Contractors and St Paul's College. Optus also purchased additional services from us to boost their own network resilience based on the resilience of our assets in recent extreme weather events including storms and floods.[234]

Table 18-2: Comparison for our 2018–23 forecast and actual shared asset revenue ($M, Real 2022–23)

	2018–19	2019–20	2020–21	2021–22	2022–23	Total
Forecast	6.6	7.4	8.0	8.2	8.4	**38.5**
Actual	11.9	13.1	14.5	15.3	16.4	**71.3**
Difference	**5.3**	**5.7**	**6.5**	**7.2**	**8.0**	**32.8**

We forecast that our unregulated revenue from our shared assets will exceed one per cent of our forecast MAR, having regard to the shared asset principles and the AER's Shared Asset Guideline. We therefore propose to reduce our MAR so that our customers benefit from the shared use of those assets.

Table 18-3 compares our annual MAR for the 2023–28 period to our forecast unregulated revenue of $106.2 million from shared assets over this period. We forecast a total reduction in our 2023–28 MAR of $10.6 million for shared asset revenue in accordance with the AER's Share Asset Guideline.

We have deducted this from MAR in the PTRM, which is provided as an Attachment to this Revenue Proposal.

234 Transgrid, Annual Review FY21, p.39

Table 18-3: Shared asset revenue reduction ($M Real 2022–23)

	2023–24	2024–25	2025–26	2026–27	2027–28	Total
MAR prior to shared asset reduction	781.1	781.2	781.4	781.6	806.9	3,932.2
Threshold (1% of MAR)	7.8	7.8	7.8	7.8	8.1	39.3
Forecast unregulated revenue from shared assets	17.9	19.1	20.5	23.0	25.7	106.2
Threshold met[235]	Yes	Yes	Yes	Yes	Yes	Yes
Revenue adjustment (10% of shared asset revenue)	1.8	1.9	2.0	2.3	2.6	10.6
Smoothed MAR adjusted for shared asset reduction	779.3	779.3	779.3	779.3	804.3	3,921.6

235 The guideline requires that the *average* shared asset revenue (i.e. $21.2 million) is compared to the threshold for each year.

19. MAR, X factors and price path

Key messages

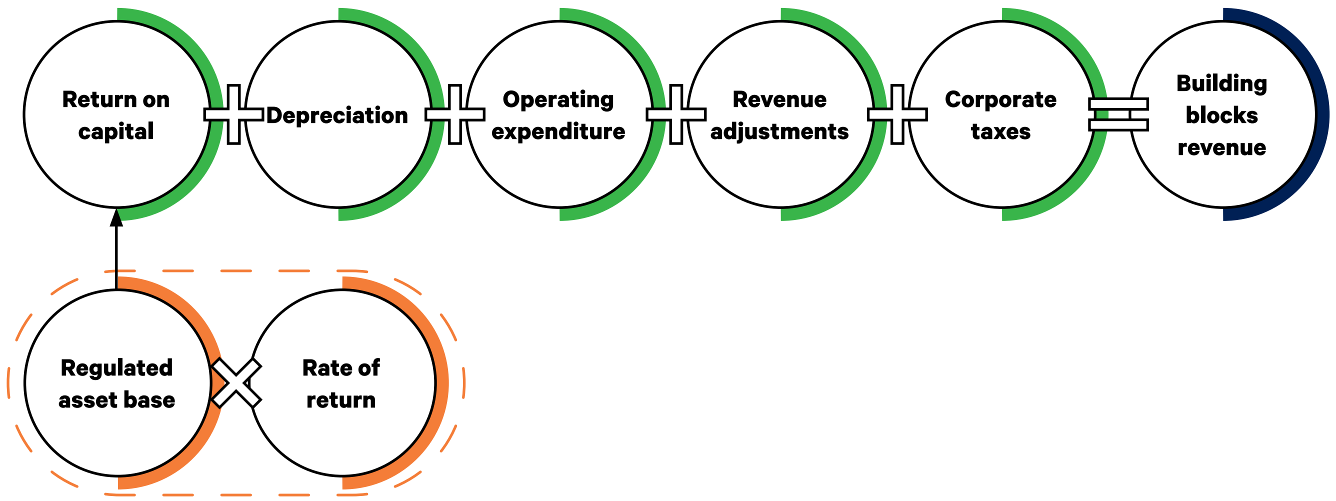
- Our total annual building block revenue requirement (ABBRR) for the 2023–28 regulatory period is $3,925.1 million. This is $168.9 million or 4.1 per cent less than our expected ABBRR in real terms for the 2018–23 period. Our total ABBRR is our unsmoothed revenue.
- Our expected 2023–28 Maximum Allowed Revenue (MAR), which is our smoothed revenue, is $3,921.6 million and includes a 14.7 per cent reduction in our revenue in 2023-24 relative to 2022–23. This supports our customers' affordability priority by front-ending cost savings.
- Based on our forecast MAR, we expect the transmission component of indicative residential household and small business bills, which comprises 7 to 8 per cent of these bills, to reduce over the 2023–28 period by $19.55 and $73.05 per annum respectively. Delivering these savings will depend on the outcome of this revenue determination process.

19.1 Overview

Under the NER, our total ABBRR is calculated using a building block approach which estimates our revenue as the sum of the efficient costs to provide our prescribed transmission services. The building blocks include:

- return on capital – this is discussed in Chapter 10
- regulatory depreciation (or return of capital) – this is discussed in Chapter 9
- operating expenditure – this is discussed in Chapter 7
- revenue adjustments – this is discussed in Chapter 12 and 13 (expenditure sharing schemes), 14 (STPIS), 15 (DMIA) and 18 (shared assets)
- corporate income tax (net of imputation credits) – this is discussed in Chapter 11.

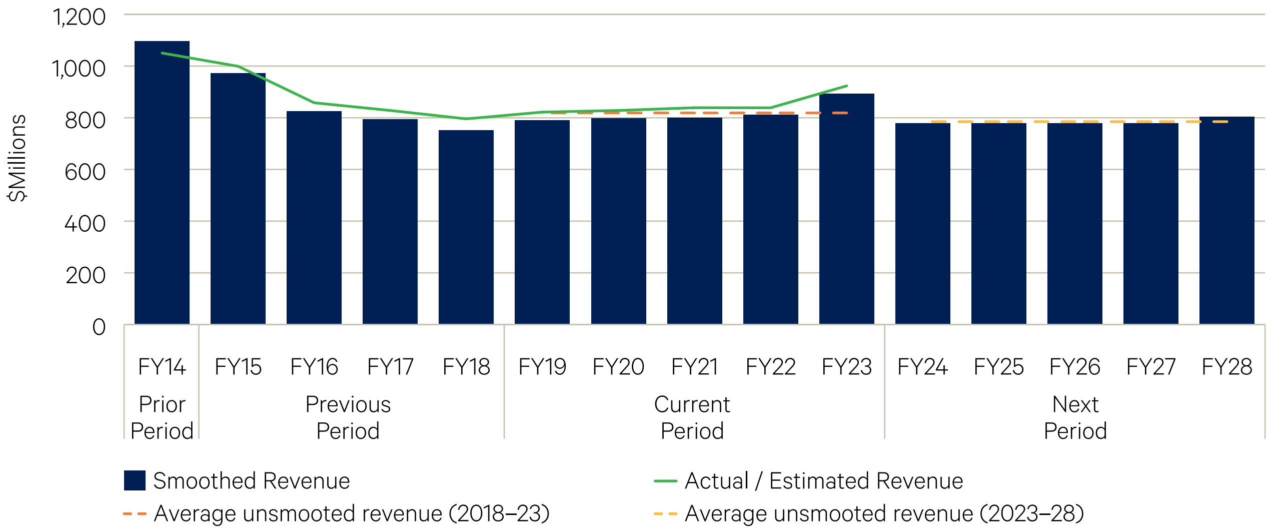
Figure 19-1: Calculation of total annual building block revenue requirement



Our ABBRR is calculated in the AER's PTRM for each year of the regulatory period. These requirements are then smoothed over the period to reduce significant variations in revenue (and ultimately transmission prices) from year to year. This smoothing is made using X-factors, so that the total ABBRR and MAR are equal (in NPV terms) over the period.[236]

Figure 19-2 shows the trend in our revenue over the 2014–18 and 2018–23 and 2023–28 period.

Figure 19-2: Our proposed revenue ($M, Real 2022–23)[1]



Notes: 1 Our proposed revenue reflects our forecast expenditure as well as approved ISP projects including VNI Minor, QNI Minor and Project EnergyConnect. It does not reflect ISP projects that have not yet been approved such as HumeLink and VNI West.

19.2 Building blocks revenue (unsmoothed revenue)

We have estimated our 2023–28 ABBRR using the AER's PTRM.

Table 19-1 shows the building blocks that make up our total ABBRR of $3,925.1 million for the 2023–28 period. Figure 19-3 shows the trends in our ABBRR over the 2014–18, 2018–23 and 2023–28 periods and that our estimated 2023–28 ABBRR is $168.9 million or 4.1 per cent less than our expected ABBRR for the 2018–23 period in real terms.

The key drivers of this difference are:

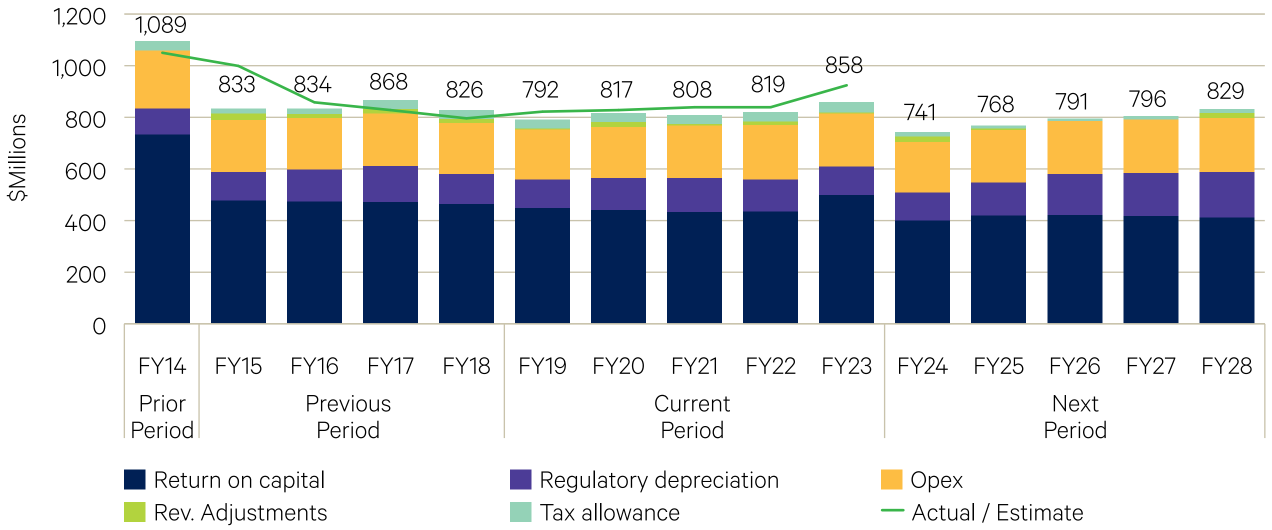
- a lower rate of return due to lower return on equity parameters and observed bond yields
- lower forecast inflation (which reduces indexation)
- lower projected corporate income tax due to calculation changes that factor in a higher value of assumed imputation credits, immediate expensing of expenditure, and diminishing value tax depreciation, and
- lower EBSS and CESS carryover amounts and negative shared asset revenue adjustments.

236 Smoothing involves first calculating the net present value of the annual building block revenue requirements for the period and then calculating a smoothed revenue profile that has the same net present value. The smoothed revenue starts with an estimate of revenue for 2022–23 and then projecting out to 2027–28 using forecast inflation and a series of real price movements, referred to as 'X factors'.

Table 19-1: Annual building block revenue requirements ($M, Real 2022–23)

	Total 2018–23	2023–24	2024–25	2025–26	2026–27	2027–28	Total 2023–28
Return on capital	2,254.2	400.4	419.1	420.9	416.5	410.6	2,067.6
Depreciation	601.2	108.8	129.0	160.0	167.8	177.7	743.3
Opex	1,009.1	193.8	202.8	205.2	205.5	207.7	1,015.0
Revenue adjustments[237]	47.9	22.6	4.4	(4.8)	(7.3)	18.6	33.5
Corporate income tax	181.6	15.7	13.0	9.4	13.2	14.6	65.7
ABBRR (unsmoothed revenue)	4,094.0	741.3	768.3	790.6	795.6	829.2	3,925.1

Figure 19-3: Annual building block revenue requirements ($M, Real 2022–23)[238]



19.3 Maximum allowed revenue (smoothed revenue)

Table 19-2 details the ABBRR, X-factors and MAR for the 2023–28 regulatory period.

As required by the Rules[239], the unsmoothed and smoothed revenue are equivalent in NPV terms and the difference between them of 3.0 per cent in the final year of the 2023–28 regulatory period is minimal.

Table 19-2 shows that we estimate an annual real reduction of 14.7 per cent in our 2023–24 smoothed revenue (i.e. from 2022–23). In the remaining years of the period our annual revenue is forecast to remain constant in real terms until slightly increasing in the final year. Overall, our total expected MAR for the 2023–28 period is 4.3 per cent lower than our total expected MAR for the 2018–23 regulatory period.

Over the 2023–28 period, our MAR will be updated each year to reflect:

- actual inflation
- return on debt observations
- any STPIS adjustments, and
- any cost-pass throughs or contingent projects.

237 Revenue adjustments include carryover amounts from the EBSS and CESS, a negative adjustment for shared asset revenue, and the DMIA.
238 The values shown on the figure are the total building blocks revenue. This differs from the actual / estimated revenue dotted line shown.
239 NER, clause 6A.6.8(c).

Table 19-2: Maximum allowed revenue ($M, Real 2022–23)

	2023–24	2024–25	2025–26	2026–27	2027–28	Total	NPV
ABBRR (unsmoothed revenue)	741.3	768.3	790.6	795.6	829.2	3,925.1	3,663.9
X-factors (%)	14.68	–	–	–	(3.21)	N/A	N/A
MAR (smoothed revenue)	779.3	779.3	779.3	779.3	804.3	3,921.6	3,663.9

19.4 Indicative household and small business bills

Our transmission revenues comprise 7 to 8 per cent of indicative residential household and small business bills in NSW and ACT, as shown in Table 19-3.

Table 19-3: Residential and small business – transmission costs as a proportion of total bill

Electricity supply chain	Proportion of total bill %	
	Residential	Small business
Generation	29	28
Transmission	**8**	**7**
Distribution	28	28
Retail and other	27	28
Environmental policies	9	10

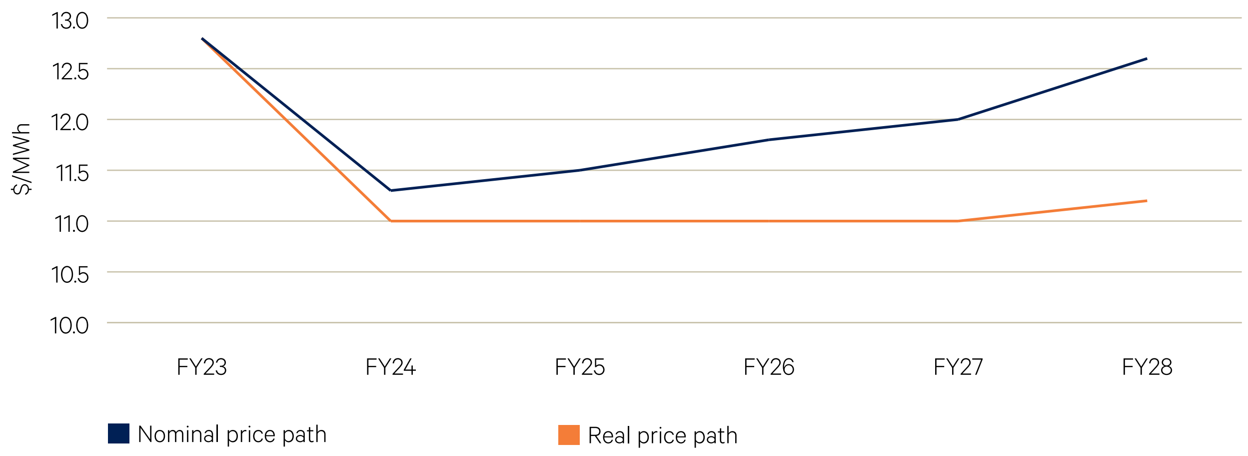
Source: AcilAllen, Transgrid TUOS as a proportion of residential and small business electricity bills, 29 November 2021. Note: the proportion of total bill % is assumed to apply to typical annual bills for 2021–22. These may differ from those expected for 2022–23.

We calculate our annual prescribed transmission charges consistent with our approved Pricing Methodology, discussed in Chapter 20, which complies with the Rules and the AER's Pricing Methodology Guidelines for transmission networks.[240]

We set our transmission prices each year to recover our MAR. To illustrate the indicative impact on average transmission prices in the 2023–28 period, we divide our expected MAR by forecast energy delivered in NSW and the ACT in each year of the 2023–28 period. This is shown in Figure 19-4.

240 Electricity Transmission Network Service Providers: Pricing Methodology Guidelines, Australian Energy Regulator, July 2014.

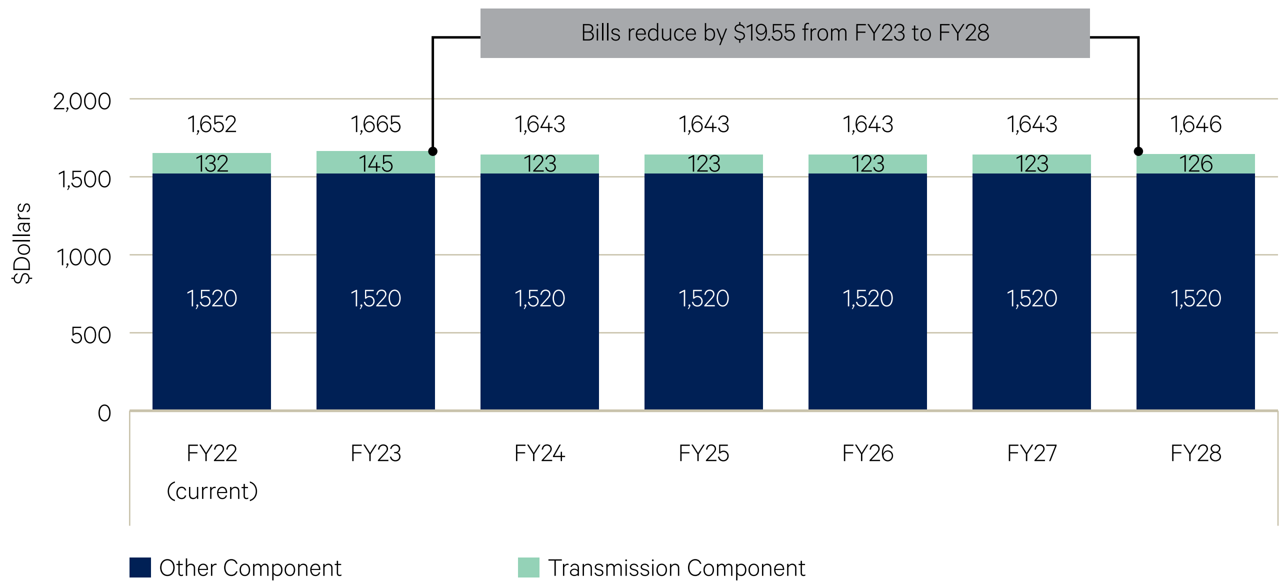
Figure 19-4: Indicative transmission price path from 2022–23 to 2027–28



Based on our forecast MAR, from 30 June 2023 to 30 June 2028, we expect to deliver transmission cost savings of $19.55 per annum for residential customers and $73.05 per annum for small business customers, which in both cases is a 13.4 per cent reduction over this period.[241] Delivering these savings will depend on the outcome of this revenue determination process.

Figure 19-5 shows the indicative household bills and Figure 19-6 shows the equivalent for small business bills over the 2023–28 regulatory period.

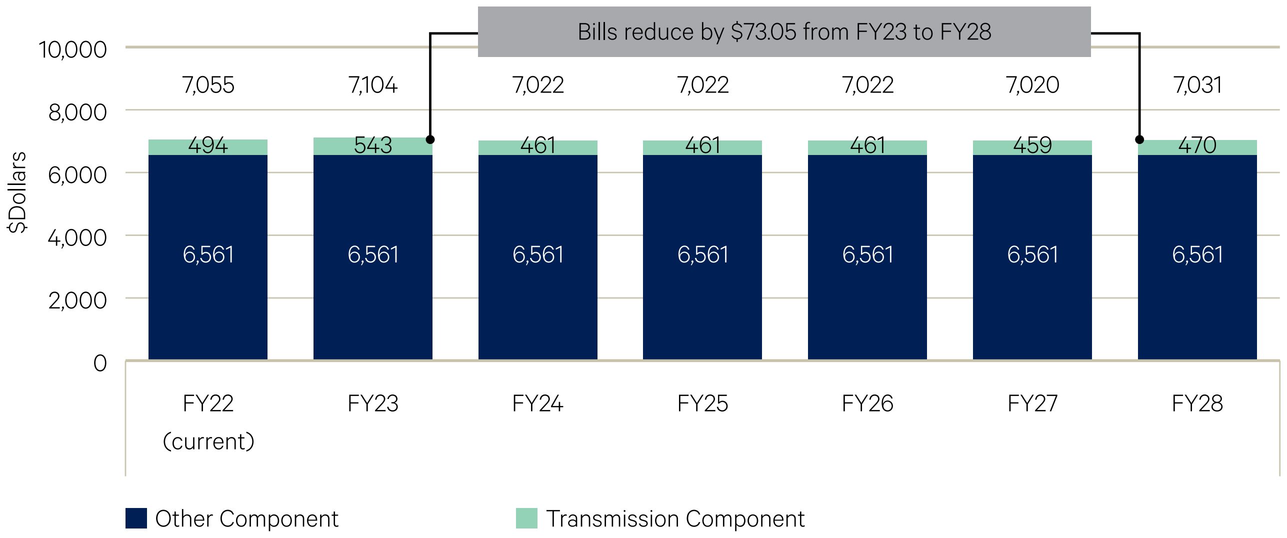
Figure 19-5: Indicative household bill ($, Real 2022–23)



Notes 1. The indicative bill uses average bill information published by the AER and the AEMC and assumes that the non-transmission components of the bill stay constant in real dollars.

241 We converted our proposed MAR into indicative household bills using the approach used by the AER in its decision on our Project EnergyConnect contingent project application. This converted forecast revenue into indicative household bills using forecast energy throughput and typical household bill information, such as the typical bill size and the share of NSW residential bills attributed to transmission charges.

Figure 19-6: Indicative small business bill ($, Real 2022–23)



The estimated impact of our forecast MAR on the transmission component of average annual electricity bills in each year of the 2023–28 period is outlined in Table 19-4. The final year of the current regulatory period is included to show the change in the first year of the next regulatory period.

Table 19-4: Indicative electricity price impacts ($ Real 2022–23)

	2022–23	2023–24	2024–25	2025–26	2026–27	2027–28	2023–28 Total
Residential annual bill (transmission component)	145.4	123.3	123.3	123.3	122.8	125.9	N/A
Annual change		(22.1)	(0.0)	–	(0.5)	3.0	(19.6)
Small business annual bill (transmission component)	543.3	460.9	460.7	460.7	458.9	470.2	N/A
Annual change		(82.4)	(0.1)	–	(1.9)	11.4	(73.1)

19.5 Supporting documentation

The following documents support this Chapter and accompany our Revenue Proposal.

Name
Post-tax revenue model
ACIL Allen, Transgrid TUOS

20. Pricing Methodology

Key messages

> Our Pricing Methodology describes how we allocate our aggregate annual revenue requirement (AARR) to the various categories of prescribed transmission services and transmission network connection points and determines the structure of our prescribed transmission prices.

> Our proposed 2023–28 Pricing Methodology is consistent with the Pricing Principles in clause 6A.23 of the NER and the AER's Pricing Methodology Guidelines.

> Our proposed 2023–28 Pricing Methodology includes limited changes from that approved for the 2018–23 regulatory period to address the following matters:

- changes to National Transmission Planner costs
- allocation of settlement residue adjustments for dedicated network asset, and
- other minor changes to simplify and clarify our pricing arrangements.

20.1 Overview

We are required[242] to submit with this Revenue Proposal a proposed Pricing Methodology for prescribed transmission services. Our Pricing Methodology must address:

- the Pricing Principles under clause 6A.23 of the NER, and
- the AER's Pricing Methodology Guidelines.[243]

In accordance with the NER, our pricing methodology provides 'a formula, process or approach' to:

1. allocate the AARR to each category of prescribed transmission services
2. set out the manner, and sequence, of adjustments to the annual service revenue requirement (ASRR) and allocate the ASRR to transmission network connection points, and
3. determine the structure of the prices for each category of prescribed transmission services.

20.2 Our Proposed Pricing Methodology

20.2.1 Our customers and other stakeholders' input

In developing our proposed Pricing Methodology for the 2023–28 regulatory period, we have considered the priorities and preferences of our customers and other stakeholders outlined in Chapter 2 and explained in Forethought's Final Report.[244]

As discussed in Chapter 2, affordability is our customers' highest priority. Members of our TAC raised concerns about equity in pricing particularly between generators and other customers. Members of the TAC recognised, however, that the current pricing arrangements are determined by the existing NER framework, which we must apply in this Revenue Proposal and that a NER change is required to address pricing issues.

242 NER clause 6A.10.1.
243 NER clause 6A.25 and AER AER, Pricing Methodology Guidelines, 2014.
244 Forethought Revenue Reset Stakeholder Engagement, Final Report (Phases 1 to 3), December 2021.

20.2.2 Pricing methodology objectives

The objectives underpinning our proposed 2023–28 Pricing Methodology are the same as those for our approved 2018–23 Pricing Methodology. These are detailed in Table 20 1 and were developed in consultation with our customers and other stakeholders.

Table 20-1: Pricing methodology objectives

Objective	Description
Price Stability	Minimise customer price variation and moderate price signals to avoid inefficient usage decisions.
Price Signals	Provide price signals to customers to encourage efficient use of the network.
Responsiveness	Enable customers to understand how transmission prices are set and to respond to price signals.
Equity	Ensure transmission prices reflect customers' use of the transmission system and allocate costs equitably between customers.
Efficiency	Ensure transmission prices reflect the efficient costs of providing network services.

20.2.3 Key changes to our Pricing Methodology

Our proposed 2023–28 Pricing Methodology includes limited changes from that approved for the 2018–23 regulatory period. The changes address the following matters:

National Transmission Planner Costs

The Integrated System Planning Rules (ISP Rules),[245] which commenced in July 2020, require that costs incurred by AEMO for its National Transmission Planner (NTP) function to be recovered from market customers. As a result, from 1 January 2021, AEMO's NTP function fees were reallocated between us and other TNSPs. Our estimated NTP fees for 1 July 2021 to 30 June 2022 are \$9.6 million.[256] This will increase transmission costs in 2021–22 for residential customers by \$0.82 per annum and small business customers by \$2.29 per annum.

The ISP Rules[247] require that the non-locational component of prescribed TUOS is adjusted for the NTP function fees advised by AEMO[248]. These fees do not form part of this Revenue Proposal and we therefore have not included any adjustment to our forecast opex to account for these additional fees.

This amendment is reflected in section 6.2 of our proposed 2023–28 Pricing Methodology.

Intra-regional residues for dedicated asset

In July 2021, the AEMC made its Final Determination on Connection to Dedicated Connection Assets (DCA)[249]. This Rule change resulted in significant amendments to the NER, including for the calculation of prescribed transmission prices.

In particular, the Rule change amended the description of the process to adjust the non-locational component of prescribed transmission prices by applicable settlements residue. The amendment provides that the settlements residue adjustment should not include amounts that accrue on designated network assets[250] and must instead be distributed or recovered from the owner of each designated network asset.[251]

We have reflected this change in section 6.2 of our proposed 2023–28 Pricing Methodology

245 The cost recovery arrangements were modified through two Rule changes, namely the Integrated System Planning Rule, July 2020 and the Reallocation of National Transmission Planner Costs Rule, 29 October 2020.
246 AEMO, National Transmission Planner Charges – 1 July 2021 to 30 June 2022, 15 February 2021
247 NER clause 2.11.3(ba).
248 NER clause 6A.23.3(e)(6).
249 National Electricity Amendment (Connection to dedicated connection assets) Rule 2021, AEMC, No. 7, Australian Energy Market Commission, July 2021.
250 NER clause 6A.23.3(e)(2).
251 NER clause 3.6.2B(f).

Other minor changes to simplify and clarify our pricing arranges

We have made minor editorial changes to our proposed 2023–28 Pricing Methodology to simplify and clarify our pricing arrangements.

In particular, for consistency with the AER's Pricing Methodology Guidelines, we have clarified that maximum demand-based charges for non-locational and common services charges must be calculated by 'multiplying the maximum demand based price by the current metered maximum demand offtake if the historical metered maximum demand offtake is significantly different to the current metered maximum demand offtake'[252].

We have included this clarification in section 7.3 of our proposed 2023–28 Pricing Methodology, which concerns 'non-locational charges'.

20.3 Supporting documentation

The following documents support this Chapter and accompany our Revenue Proposal.

Name
2023–28 Pricing Methodology

252 AER, Pricing Methodology Guidelines, 2014, clause 2.4.

Part C

Other matters

21. Other Matters

21.1 Confidential information

In accordance with clause 6A.10.1 (f)(2) of the NER and the AER's Confidentiality Guideline, we have completed a confidentiality template as an Attachment to this Revenue Proposal that details the matters for which we are claiming confidentiality.

21.2 Certifications

21.2.1 Certification statement

Schedules 6A.1.1(5) and 6A.1.2(5) and of the NER require our directors to certify the key assumptions that underlie our capex and opex forecasts. Our key assumptions for:

- opex are set out in section 7.3, and
- capex are set out in section 8.5.

Our certification statement is provided as an Attachment to this Revenue Proposal.

21.2.2 Statutory declaration by Chief Executive

The AER's Reset RIN requires an officer of Transgrid to make a statutory declaration attesting to the information provided in response to that notice. The statutory declaration made by our Chief Executive Officer is provided as an Attachment to this Revenue Proposal.

21.2.3 Compliance checklist

We have completed compliance checklists, which demonstrates how we have complied with the requirements of the NER and the AER's Reset RIN. These are provided as Attachments to this Revenue Proposal.

21.3 Supporting documentation

The following documents support this Chapter and accompany our Revenue Proposal.

Name
Confidentiality claims
Key capex and opex assumptions certification
NER compliance checklist
Regulatory Information Notice compliance checklist
2023–28 Revenue Proposal Statutory Declaration

22. Abbreviations

The following abbreviations are used in this Revenue Proposal.

Acronym/Abbreviation	Meaning
2018–23 regulatory period or period	The regulatory control period commencing 1 July 2023 and ending 30 June 2028
$Real 2022–23	These are dollar terms as at 30 June 2023
$Nominal	These are nominal dollars of the day
2018–23 approved contingent projects	Project EnergyConnect, QNI Minor and VNI Minor
AARR	Annual Aggregate Revenue Requirement
ABBRR	Annual Building Block Revenue Requirement
ACT	Australian Capital Territory
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AESCSF	Australian Energy Sector Cyber Security Framework
ANU	Australian National University
ASRR	Annual Service Revenue Requirement
Augex	Augmentation capex
BFA	Bush Fire Allowance
BISOE	BIS Oxford Economics
BSP	Bulk Supply Point
CAM	Cost Allocation Methodology
Capex	Capital expenditure
CBs	Circuit Breakers
CDN	Corporate Data Network
CESS	Capital Expenditure Sharing Scheme
CI Act	Critical Infrastructure Act 2018
COTS	Commercial off the Shelf
CRIFR	Critical risk injury frequency rate
CRM	Customer relationship management
CTs	Current transformers
DC	Data centre
DCA	Dedicated connection assets
DMIAM	Demand management innovation allowance mechanism
DNSP	Distribution network service providers
EBSS	Efficiency benefit sharing scheme
EII Regulations	NSW Electricity Infrastructure Investment Regulations

Acronym/Abbreviation	Meaning
ENA	Energy Networks Australia
ERP	Enterprise Resourcing Planning
ESOO	Electricity Statement of Opportunities
EV	Electric vehicles
F&A	Framework and Approach
GSP	Gross State Product
IAP2 Spectrum	International Association of Public Participation Spectrum
IBR	Inverter based resources
ICT	Information and communication technology
IFRIC	International Financial Reporting Interpretations Committee
IFRS	International Financial Reporting Standards
IPPC	Intergovernmental Panel on Climate Change
ISDN	Integrated Services Digital Network
ISP	Integrated System Plan
Km	Kilometre
LTIFR	Lost Time Injury Frequency Rate
M	Million
MAR	Maximum Allowed Revenue
MIC	Market Impact Component
MPFC	Modular Power Flow Converters
MPFP	Multilateral Partial Factor Productivity
MWh	Megawatt hour
NCC	Network Capability Component
NCIPAP	Network Capability Incentive Parameter Action Plan
NEL	National Electricity Law
NEM	National Electricity Market
NER or Rules	National Electricity Rules
Non-network Other capex	Property, fleet, plant and equipment
NPV	Net Present Value
NSP	Network Service Provider
NSW	New South Wales
NSW Electricity Infrastructure Roadmap	NSW Government's Electricity Infrastructure Roadmap
NTP	National Transmission Planner
opex	Operating expenditure
PADR	Project Assessment Draft Report
PIAC	Public Interest Advocacy Centre
PPM	Project and Portfolio Management

Acronym/Abbreviation	Meaning
Pre-approved forecast capex	AER approved capex for Project EnergyConnect
PSF	Powering Sydney's Future
PTRM	Post tax revenue model
QNI Minor	Queensland to New South Wales Interconnector Minor
RAB	Regulatory asset base
RBA	Reserve Bank of Australia
Repex	Replacement capex
REZs	Renewable Energy Zones
RFM	Roll forward model
RFS	Rural fire service
RIN	Regulatory Information Notice
RIT-Ts	Regulatory Investment Tests for Transmission
RORI	Rate of Return Instrument
SaaS	Software as a Service
SC	Service Component
SG	Superannuation Guarantee
SIP	Session Internet Protocol
SSIS	Small Scale Incentive Scheme
STPIS	Service Target Performance Incentive Scheme
TAB	Tax Asset Base
TAC	Transgrid Advisory Council
TAPR	Transmission Annual Planning Report
TUOS	Transmission Use of System
VCR	Value of Customer Reliability
VNI Minor	Victoria to New South Wales Interconnector Minor
VPPs	Virtual Power Plants
VTs	Voltage Transformers
WACC	Weighted Average Cost of Capital
WARL	Weighted Average Remaining Lives
WHS	Workplace Health and Safety
WPI	Wage Price Index

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