Ausgrid's Regulatory Proposal

1 JULY 2019 TO 30 JUNE 2024

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CEO Foreword

It is with pleasure that we submit the Ausgrid 2019–2024 Regulatory Proposal (the Proposal) to the Australian Energy Regulator (AER). Ausgrid is the largest distributor of electricity on Australia's east coast. We bring power to 1.7 million households and businesses across 22,275 square kilometres covering Sydney, the Central Coast and the Hunter Valley. Ausgrid plays a key economic role both nationally and in New South Wales (NSW), with our distribution network supplying electricity that powers the creation of 20% of our national and 59% of NSW's Gross Domestic Product.

I believe our Proposal captures the significant progress Ausgrid has made so far to become a more customer centric organisation. Our customers want Ausgrid to provide network services which are affordable, reliable and sustainable.

I want to recognise and thank our customers and stakeholders who have contributed both time and effort to helping the development of this proposal over the past two years. Your input has been influential in determining the final approach to our strategy, investment and the programs that are incorporated in the Proposal.

Close engagement with our customers has underscored that affordable energy is particularly important. We understand that high energy prices are negatively impacting households and businesses alike. We have made inroads in addressing this and by 1 July 2018, Ausgrid's network component of our customer's bills will have reduced by 30% since July 2013. Specifically in relation to affordable energy supply, our Proposal will result in:

- **lower prices**, with a 6% reduction in our prices within the network component of residential customer bills from 1 July 2019;
- **fairer prices**, with changes to pricing that reflect the actual costs of network usage and measures to protect vulnerable customers; and
- **zero** real growth in the value of the assets we use to provide our services on a per customer basis.

This is only the start, as we will continue to keep downward pressure on our costs to support lower prices for customers.

We are also committed to maintaining a reliable service to customers, whilst recognising that customers are often struggling under cost of living pressures. We will keep investment to a minimum, by only replacing ageing assets where there is no alternative and only augment to support targeted growth areas. We will continue to support growth in our economy with targeted infrastructure investment, for example in the Rozelle area to support transport growth and in Macquarie Park to support growth in the Information and Communication Technology sector.

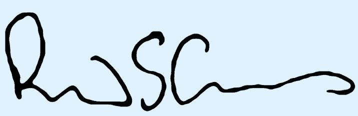
Additionally, rather than simply planning for more network infrastructure, we are looking first at where new technology, innovation (including demand management) and partnering with other companies and our customers will deliver supply at a lower cost.

Our customers have also told us that they are interested in adopting more sustainable sources of energy and expect us to take action to facilitate the transition to a lower carbon economy. In response, our Proposal includes investments in a new technology platform that will support the transformation of our network from a passive one way distribution network to a smart grid that will more easily allow us to incorporate distributed energy resources and deliver the tools to better operate the network in real-time.

I look forward to continuing to drive the company to achieve its vision over the coming regulatory period to be 'a leading energy solutions provider, recognised both locally and globally' and commit Ausgrid to continuing to work with our customers and stakeholders to deliver on this vision. We know from experience that we can only achieve our goals and purpose by working closely together.

Your feedback on our Proposal is very welcome.

Yours sincerely,



Richard Gross

Chief Executive Officer
Ausgrid

Ausgrid's Proposal at a glance

Meeting our customers' needs

AFFORDABLE

Lower prices

6%

reduction in our component of network costs in residential bills from 1 July 2019

Fairer

Updated price structures

More efficient

Operating cost savings (pa)

$100m

Benefit per customer

$76pa

RELIABLE

Replacing ageing assets

$335m pa

investment in renewing the grid

+

Investing in technology

$43m pa

including cyber security

SUSTAINABLE

Flexible network

$58m

to deliver the '**future grid**' sooner by trialling technologies that enable sustainable customer choices

Smart

$41m

additional investment in an **Advanced Distribution Management System** following an initial investment of $35m in the current period

Powering our economic growth

15% of Australia's population

16% of Australia's jobs

1.5m Homes

20% of Australia's GDP

105 Hospitals

37% of Australia's ICT industry

37% of Australia's financial services industry

15% of Australia's construction industry

Our electricity supply chain

The different cost components of a typical customer bill.

GENERATION	TRANSMISSION	AUSGRID NETWORK Distribution and dual function assets	RETAILER	STATE AND FEDERAL GOVERNMENT ENVIRONMENTAL POLICIES
48%	5%	33%	9%	5%

Source: Ausgrid analysis for FY17/18, based on standing offer in Ausgrid's network, Ausgrid's network charges (including NSW Government Climate Change Fund costs) and Australian Energy Market Commission data for wholesale generation costs and other Federal and State Government Environmental policies.

Reliability and growth investment

Replacement investment

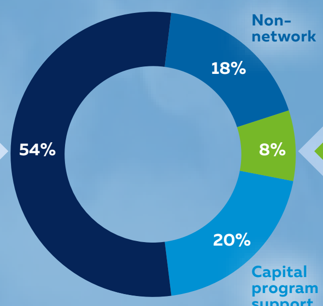
$1,673m

Including:

- Fluid and gas cables
- Switchboards
- Overhead poles
- Low voltage cables
- Control and protection systems
- Overhead conductors
- Service lines
- Transformers
- Monitoring and control systems
- Substation assets
- Reactive program

Total investment

$3.08b



Growth investment

$241m

Macquarie Park investment

$28.1m

increasing capacity for new data centre and telecommunication customers, together with potential expansion of education facilities.

Rozelle substation investment

$17.5m

increasing capacity for anticipated growth in the area including transport projects such as WestConnex.

01

About this Proposal

01

About this Proposal

1.1 Overview

Ausgrid is the largest distributor of electricity on Australia's east coast, providing electricity to 1.7 million connected customers. Our core business is to provide distribution network services. We do this by building and operating assets and delivering non-network solutions to ensure our customers have safe and reliable access to electricity at an efficient and reasonable price.

This 2019–2024 Regulatory Proposal (the Proposal) is prepared for the Australian Energy Regulator (AER), and outlines how Ausgrid will achieve these customer outcomes for the five-year period from 1 July 2019 to 30 June 2024. It sets out how much we need to invest so we can deliver affordable, reliable and sustainable electricity supply – safely – now and in the future.

To help us make the right choices, we have been talking to our customers – from major industrial users to households – about their priorities. Our Proposal takes into account both what customers and stakeholders have told us directly, our business planning and our regulatory obligations. Section 2 explains how we consulted with our customers and how our Proposal reflects their views. We also welcome further feedback on our Proposal.

An easy to read summary of this Proposal is also available. It explains the key components of our Proposal and how our investment in the network will benefit our customers.

1.2 Our regulatory obligations

In our role as a Distribution Network Service Provider (DNSP), we provide our customers with a range of electricity distribution services, which are regulated by the AER under the National Electricity Rules (NER or the Rules). Periodically, the AER assesses the efficiency of our proposed expenditure plans as well as the proposed structure of our prices.

Our current regulatory period ends on 30 June 2019. Ausgrid proposes that the next regulatory control period be for a term of five years, commencing on 1 July 2019 and ending on 30 June 2024 (the 2019–24 regulatory period or next regulatory period).[1]

Ausgrid proposes to build and operate distribution network assets and deliver non-network solutions to ensure our customers have safe and reliable access to electricity at an efficient and affordable price.

1 NER clause S6.1.3(13) requires Ausgrid to propose the commencement and length of the regulatory control period.

The objective of the regulatory framework is to promote the efficient operation and use of electricity services for the long-term interests of consumers of electricity with respect to:

- price, quality, safety, reliability and security of electricity supply, and
- reliability, safety and security of the national electricity system.

We intend to meet these obligations with expenditure plans that address our customers' requirements for affordable, reliable and sustainable network services that are provided safely. This Proposal will:

- ensure Ausgrid supports the most cost effective transition to a lower carbon future,
- reduce prices in a sustainable manner, so that the choices we make do not cause unnecessary price increases in the future,
- keep downward pressure on costs, while maintaining network reliability and security, and managing the transition to more renewable and distributed energy sources, and
- move towards fairer pricing structures appropriate for the future grid, but do this in a way that manages the impact on vulnerable customers.

This document and its supporting attachments sets out our Proposal and addresses all matters in line with the requirements under the Rules.

Our Proposal also meets other regulatory requirements specified in the Regulatory Information Notice (RIN) and the Expenditure Forecast Assessment Guideline. Further details on the Expenditure Forecast Assessment Guideline can be found on the AER's website.

Certain parts of the Proposal and our response to the RIN have been redacted on the grounds of confidentiality.[2] This information primarily relates to:

- market-sensitive cost inputs which, if disclosed, could affect Ausgrid's ability to obtain competitive prices in future transactions, and
- commercially sensitive information about our suppliers.

See Attachment 1.01, Confidentiality claims, for a detailed explanation of why we have made claims for confidentiality.

For regulatory purposes, the AER classifies our services into: standard control, alternative control, negotiated and unclassified services. Service classification is important because it determines the extent of regulation that applies to the services we provide to our customers. Our approach in this Proposal largely adopts the AER's proposed classification, which is set out in its Framework and Approach paper (F&A). Further details on our service classification are provided in Chapter 11.

1.3 Feedback on this Proposal

Ausgrid welcomes feedback on this Proposal from customers, stakeholders and the wider community.

You can send us feedback directly by:

- Emailing us at yoursay@ausgrid.com.au

Alternatively, you can also provide comments on our Proposal to the AER (www.aer.gov.au).

2 NER clause 6.8.2(c)(6) requires Ausgrid to identify the parts of the Proposal that we claim to be confidential and want suppressed from publication.

1.4 How to read our Proposal

Our 2019–24 Regulatory Proposal comprises this document and the attachments as set out in the following table. The body of this document outlines the key elements of our Proposal. Further detail and supporting information is provided in the attachments.

Table 1.

Structure of our Proposal

CHAPTER	CONTENT	SUPPORTING ATTACHMENTS
1. About this proposal	• Provides an overview of our approach to developing the proposal • Sets out the structure of the Proposal	1.01 Confidentiality claims 1.02 National Electricity Rules (NER) compliance table
2. Ausgrid and our customers	• Describes our customers, what they've told us and how we've engaged with them • Describes who we are • Sets out our track record	2.01 Extended Stakeholder Consultation Report 2.02 Customer and stakeholder engagement prior to December 2017
3. Our role in a changing market	• Describes the changing policy environment and technology landscape • Explains what Ausgrid is doing to meet the evolving expectations of our customers	3.01 Strategic Innovation Portfolio
4. Annual revenue requirement	• Provides an overview of our proposed: – Annual revenue requirement – Corporate income tax – Regulatory depreciation – Regulatory asset base	4.01 Roll Forward Model (RFM) for distribution 4.02 Post Tax Revenue Model (PTRM) for distribution 4.03 Capital Efficiency Sharing Scheme (CESS) calculation 4.04 RFM for transmission 4.05 PTRM for transmission 4.06 Control mechanism for Standard Control Services (SCS) and Alternative Control Services (ACS)

CHAPTER	CONTENT	SUPPORTING ATTACHMENTS
5. Forecast capital expenditure	• Provides an overview of the capital expenditure (capex) program, drivers and major programs • Outlines replacement capex and growth capex • Explains our forecasting approach • Outlines our key assumptions • Describes our Information & Communications Technology (ICT) Benchmarking study • Outlines our Non-network Plan: – Information Technology (IT) & Property • Explains how the NER requirements have been met	5.01 Ausgrid's proposed capital expenditure 5.02 Master list of Ausgrid forecast capex projects and programs 5.03 Business Planning Consolidation (BPC) description 5.04 Prioritisation Investment Plan (PIP) process description 5.05 Investment Governance Framework 5.06 Unit cost methodology 5.07 2017 electricity demand forecasts report 5.08 GHD Review of demand and customer forecasts 5.09 Cost benefit analysis for planning 5.10 GHD Review of cost benefit analysis methodology 5.11 Key assumptions and Director's certification of key assumptions 5.12 Resourcing and Delivery Strategy for 2019–24 period 5.13 Project justification for replacement and duty of care programs 5.14 Project justification for 11kV switchgear, 33kV switchgear and sub-transmission cables replacement 5.15 Nuttall review of repex 5.16 Project justification for augmentation major projects 5.17 Connection Policy 5.18 ICT Technology Plan for 1924 period 5.19 ICT Project Justifications (excluding ADMS) 5.20 Non-network property plan 5.21 Non-network property business cases 5.22 Capitalisation Policy
6. Forecast operating expenditure	• Provides an overview of our forecast method (base step trend) • Outlines key assumptions • Explains how the NER requirements have been met	6.01 Ausgrid's proposed operating expenditure (opex) 6.02 Opex model 6.03 Network maintenance opex plan 6.04 Proposed opex base year – AER method 6.05 Demand management cost benefit assessment
7. Allowed rate of return	• Explains our proposed rate of return parameters, including: – Cost of equity – Cost of debt – Value of imputation credits	7.01 Ausgrid's rate of return 7.02 Averaging period for cost of equity and debt

CHAPTER	CONTENT	SUPPORTING ATTACHMENTS
8. Alternative control services	• Describes our approach to alternative control services, including: – Public lighting – Metering services – Ancillary network services (ANS)	8.01 Ausgrid's metering services 8.02 Metering RFM 8.03 Metering PTRM and pricing model 8.04 Independent appraisal of economies of scale 8.05 Ausgrid's ancillary services 8.06 ANS pricing models 8.07 Ausgrid's public lighting services 8.08 Public lighting – Pre 2009 'Fixed Charge' model FY20–24 8.09 Public lighting – Post June 2009 Annuity Prices FY20–24 8.10 Public lighting – Opex cost build up model FY20–24 8.11 Public lighting investment plans (capital and opex) 8.12 Public lighting price list
9. Incentive schemes and pass through events	• Explains our approach to the following: – Efficiency Benefit Sharing Scheme (EBSS) – Capital Expenditure Sharing Scheme (CESS) – Service Target Performance Incentive Scheme (STPIS) – Demand Management Innovation Allowance (DMIA) – Demand Management Incentive Scheme (DMIS) – Nominated pass through events	9.01 Application of incentive schemes 9.02 Nominated cost pass through events
10. Pricing structures and policies	• Outlines our proposed: – Tariff Structures Statement – Indicative pricing schedules – Pricing policies and procedures	10.01 Tariff Structure Statement 10.02 Procedure for assigning customers to a tariff class 10.03 Long Run Marginal Cost (LRMC) model 10.04 LRMC methodology report 10.05 Tariff model (SCS) 10.06 ES7 network Price Guide 10.07 Price elasticity 10.08 Transmission pricing methodology 10.09 Methodology for avoided TUOS charges 10.10 Indicative pricing schedule – DUOS charges 10.11 Indicative pricing schedule – TUOS 10.12 Indicative pricing schedule – ACS 10.13 Indicative pricing schedule – Climate Change Fund 10.14 Pricing directions: a stakeholder perspective
11. Classification proposal and negotiation framework	• Sets out our service classification and control mechanisms • Addresses the negotiated services framework and criteria	11.01 Ausgrid's classification proposal 11.02 Proposed negotiating framework

RIN SUPPORTING ATTACHMENTS

RIN01	RIN Response
RIN02	RIN Schedule 1 response table
RIN03	List of proposal documents
RIN04	Regulatory models review final report
RIN05	Repex model description
RIN06	Demand Management Standard NIS420
RIN07	Demand Side Engagement Document
RIN08	Agreement 2012
RIN09	Cost escalation report
RIN10	Vegetation compliance audit
RIN11	Regulatory Determination
RIN12	New Category Analysis
RIN13	Recast Category Analysis
RIN14	EBSS
RIN15	CESS
RIN16	Ausgrid's Basis of Preparation
RIN17	RIN audit reports
RIN18	RIN statutory declaration

02

Ausgrid and our customers

02

Ausgrid and our customers

What did we achieve in 2014–19?

We have fundamentally redesigned the way we engage with stakeholders and customers.

- We developed a Stakeholder and Customer Consultation Program to better understand our customers and their needs. To date, we have engaged with more than 2,500 customers through our targeted research program, and we continue to have regular consultation with key energy consumer stakeholder organisations.

  Key elements:

  - Customers at the Centre research project – a multi-phase project, incorporating customer focus groups, deliberative forums and a quantitative survey of 2,360 customers. This research has given us a better understanding of customers' priorities, for us to deliver network services that are affordable, reliable and sustainable.
  - Reformed our Customer Council and created a new Customer Consultative Committee (CCC) to provide oversight and advice on Ausgrid's plans, policies, service and engagement with customers. We created a CCC sub-group, called the Reset Working Group (RWG), to enable us to consult more effectively on the detailed technical aspects of our Proposal.

We focused on delivering better outcomes for our customers.

- We invested in a new **digital customer strategy**, including new systems and a website rebuild to make it easier for customers to communicate with us via their individually preferred channels. Today, digital maps show customers where network outages are and allow faults to be reported. Customers can also report street light outages online, thereby shortening repair times.
- We are **reducing red tape** for customers who want to connect their solar systems to the network by fast-tracking certain connection applications and removing the need to conduct a detailed technical assessment for others.
- **Life Support Customers** (LSC) research was also undertaken following the CCC's suggestion that we should better understand LSC's communication expectations and preferences.
- We improved information on load shedding on our website in response to concerns raised in the CCC meetings.
- We are specifically targeting our research to better understand needs and preferences of **Culturally and Linguistically Diverse** (CALD) communities.

What outcomes will we deliver in 2019–24?

We intend to deliver value to our customers in terms of an affordable, reliable, and sustainable network, while also delivering services safely.

Affordable energy is particularly important for our customers. It has been made clear to us that high energy prices are negatively impacting households and businesses alike. In developing this Proposal, we specifically focused on offering households real relief from rising energy prices.

Our Proposal will reduce our component of customer bills by 5.7% in real terms. We are also proposing specific measures to protect vulnerable customers by, for example, introducing a transitional safeguard price.

Reliable energy supply is important to our customers, with customers expecting very infrequent supply interruptions and prompt return to service following an interruption (particularly on high demand hot summer days). In response, we will continue to operate and invest in our network (now and into the future) to meet reliability requirements and respond to incidents in a timely manner. To meet these objectives, in the next regulatory period, we will invest in replacing older assets on the network (approximately $1.7 billion) and on IT systems ($216 million, including investments in cyber security).

Sustainable sources of energy supply are increasingly of interest to our customers and Ausgrid is looking to provide services to support them. In this Proposal, we are seeking to continue the transformation of our network from a passive to an active distribution network. We are proposing to invest $41 million in an Advanced Distribution Management System (ADMS) , which will enable this transformation. Our transformation will also be supported by a $58 million commitment to trials and new technology in order to deliver the future grid sooner.

In the future, our network will more easily incorporate distributed energy resources and allow us to operate and optimise the network in real-time, further helping us to deliver on the affordable, reliable and sustainable objectives our customers expect.

How are we responding to our customers' feedback?

Overall, the feedback from our customers and stakeholders indicates that we can improve how we engage with customers.

In response, Ausgrid is working to embed a customer-focused approach across our entire business from customer connections to responding promptly to customer outages, to deep engagement on our Proposal and beyond. Having customer-focused operations across our entire business will ensure daily decisions always include real consideration of the customer's perspective. It will also keep our stakeholders both informed and heard, so they can continue to influence our strategic priorities.

Our approach is guided by our Reset Engagement and Empowerment Framework (the naming of which was co-created by our stakeholders and Ausgrid). The framework ensures we are:

- **Customer focused** – so our primary focus is on the long-term interests of consumers, with the best possible customer service we can deliver
- **Accountable and transparent** – so key decisions are supported by robust evidence, with an open and transparent process and stakeholders' views clearly taken into account
- **Respectful and collaborative** – so relevant stakeholders are consulted and involved at each key stage in respectful two-way conversations, with necessary information provided simply.

Stakeholders have advised that Ausgrid needs to build on the engagement it has undertaken to date and embed greater levels of trust by delivering on commitments. Ausgrid will be meeting with the CCC in May 2018 to map out our further consultation program following the publication of this Proposal.

2.1 Background

2.1.1 Our business and our network

Ausgrid is the largest distributor of electricity on Australia's east coast, connecting 1.7 million large industrial, business and residential customers.

The origins of Ausgrid go back more than 100 years, when we were the first company to electrify Sydney. Since then, the Sydney electricity network has expanded to provide the essential power that makes our lives work.

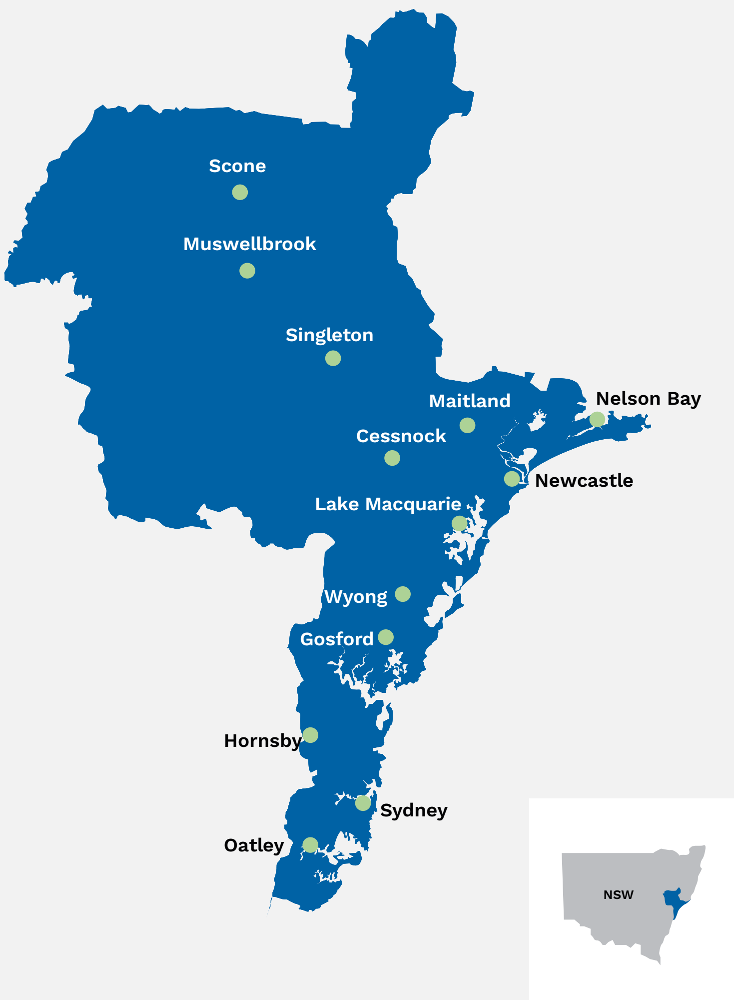
Our core business is to provide distribution network services to customers. We do this by building and operating assets and delivering non-network solutions on behalf of our customers to ensure safe and reliable access to electricity at an efficient and reasonable price.

Our network area (shown in the figure below) is made up of large and small substations connected through high and low voltage powerlines, underground cables and power poles spread across more than 22,275 square kilometres. Our network extends from Waterfall in Sydney's South, to Auburn in inner western Sydney, to the Central Coast and Hunter Region. Our service area also includes some of Australia's most densely populated areas, as well as the fastest growing areas of NSW including, Greater Sydney.

Day-to-day, we are responsible for operating, maintaining, repairing and building our network. Long term, our job includes making sure that this network is ready for a future where renewables and demand management play a major role in the power supply mix, and households and businesses can generate their own electricity and sell it back to the grid.

Figure 1.

Ausgrid's network map



Customers
1.7 million

Area
22,275 km²

Number of power poles
500,000

Length of powerlines and underground cables
50,000 kms

Large electricity substations
230

Small distribution substations
30,000

Employees
3,600

2.1.2 Our customers

The 1.7 million customers connected to the Ausgrid network have a diverse set of needs and preferences. Our customers range from small residential households consuming about 5 megawatt hours (MWh) per year, through to large industrial customers consuming more than 40 gigawatt hours (GWh) per year.

Residential customers make up 89% of our customer base, but businesses account for 66% of energy consumption.

Over a quarter of our residential customers speak a language other than English at home. In some Sydney suburbs, this is true for more than half the household occupants.

Our customers also have a wide range of income levels and household characteristics. Approximately 30% rent their homes and, in some parts of our network, many customers live in apartments or units.

2.1.3 Our owners

In December 2016, the NSW Government commenced a 99-year lease of a 50.4% share of Ausgrid's assets to IFM Investors (IFM) and AustralianSuper, who now have operating control. This change of ownership accelerated the transformation journey we had already embarked on to respond to the disruption in the energy sector and our customers' changing wants and needs.

> IFM and AustralianSuper have jointly leased a 50.4% share of Ausgrid's assets. The NSW Government continues to hold a 49.6% interest.

IFM

- **Funds under management** – $101 billion (as at December 2017)
- **Members represented** – More than five million (Australia) and more than 15 million (global)
- **Key Australian assets** – Port of Brisbane, Port Botany, Port Kembla, Adelaide Airport, Brisbane Airport, Melbourne Airport, NT Airports, Perth Airport, Eastern Distributor and Interlink Roads
- **Investment philosophy** – IFM manages funds across four asset classes: infrastructure, debt investments, listed equities and private equity. The focus is on delivering strong, consistent performance over the long term with a patient and strategic approach to investment management.

IFM is an Australian, investor-owned global fund manager with over A$101.0 billion in assets under management across listed equities, private capital, debt investments and approximately A$43.0 billion in direct infrastructure investments as at 31 December, 2017.

AustralianSuper

- **Funds under management** – $130 billion (as at December 2017)
- **Members represented** – 2.2 million
- **Key Australian assets** – Port Botany, Port Kembla, Perth Airport and Transurban Queensland
- **Investment philosophy** – AustralianSuper's strategy is to invest in meaningful core infrastructure assets with a focus on transport, regulated utilities and contracted assets.

As Australia's largest superannuation fund, AustralianSuper has more than 2.2 million members (including more than 650,000 in NSW) and over $130 billion of members' savings (as at 31 December 2017). The Fund invests across the globe and in most major asset classes, including infrastructure, property, listed equities, private equity and debt, to generate the best possible sustainable returns over the long-term for our members in retirement. AustralianSuper is one of Australia's largest infrastructure investors, with more than $13 billion invested in infrastructure, and a strategy to invest in meaningful core infrastructure assets with a focus on transport, regulated utilities and contracted assets.

2.1.4 Our strategic priorities

Ausgrid's strategic priorities help guide our decisions to achieve our vision of becoming a leading energy solution provider, recognised locally and globally. Our strategic priorities are:

- **Strengthen safety** – to minimise potential risks to customers and employees,
- **Become more customer focused** – to know our customers and earn their respect, so we can deliver services that meet their preferences and needs. This will be measured by our Customer Satisfaction Index and the Service Target Performance Incentive Scheme (STPIS),
- **Continue cultural change** – to be a business of the future, not of the past, and
- **Deliver our transformation program** – to provide better value for our customers.

Our strategic priorities are consistent with delivering safe, reliable and efficient network services in accordance with our statutory obligations and Rules requirements. Importantly, these strategic priorities also focus our attention on addressing our customers' preferences efficiently and prudently, as discussed in the next section and throughout the remainder of this Proposal.

2.1.5 Safety

At the heart of health and safety at Ausgrid are people. We ensure that they all have the right tools and knowledge to manage their own safety, as well as the safety of their workmates. We integrate health and safety systems into everything we do, so customers can be served safely. Safety is paramount for us. We strive to live safely, call out, speak out, stop, think and look after ourselves and each other.

To manage health and safety and to prevent incidents, we use a systematic approach designed to deliver a safer work environment and achieve continuous improvement. This is underpinned by our Health and Safety policy and management systems, which set out the requirements for managing the impacts of our operations and projects on employees, contractors, customers and the public. Our metrics include leading indicators to measure and assess performance, so we improve continuously. We support and develop our people to manage health and safety.

To keep our customers and employees safe, we are:

- maintaining and replacing assets to manage the safety of our network,
- installing, operating, maintaining and disposing of our assets safely,
- helping customers manage bushfire risks on their properties and providing information on our website,
- providing free safety resources, developed in collaboration with other NSW DNSPs, for emergency services and construction workers to keep them safe when working around assets,
- undertaking timely communications and campaigns to educate customers and the community about potential risks, such as at the start of bushfire season or during do-it-yourself activities, where we offer a 'dial before you dig' service,
- maintaining an ongoing commitment to teach primary school children how to stay safe around electricity during Electricity Safety Week, and
- responding to emergencies promptly.

Ausgrid's focus on improving safety in the work place resulted in our Work Safe, Live Safe Reform Strategy and Safe Journey Map, developed in collaboration with staff from across the business. The Map builds on our existing frameworks and provides a clear plan to deliver an organisation where people:

- **Act** – safely, responsibly, respectfully and united,
- **Feel** – safe, proud and empowered, valued and respected and connected and supported, and
- **Are** – leaders in safety, trusted, clear with our communications, trained and capable, tech enabled and partners with our service providers.

We have 14 initiatives currently underway to deliver our Work Safe, Live Safe approach. This is all about continual improvement where health and safety are a natural part of everything we do. Our improvement initiatives are focused on using technology, simplification, agility and upskilling people to lift Ausgrid's health and safety performance.

2.2 Consultation with our customers and stakeholders

2.2.1 Our new approach

In the past, Ausgrid has not engaged with customers as effectively as we should. Although we have made considerable progress in the last two years, we are aware there is more work to be done. With the help of our stakeholders, we will continue to work to put customers at the centre of our business.

We have a Stakeholder and Customer Consultation Program in place. The overarching aim of this program is to help us align our business planning, policies and practices with our customers' expectations.

Through the program, Ausgrid is working to embed a customer-focused approach across our entire business from customer connections to responding promptly to customer outages, to deep engagement on our Proposal. Having customer-focused operations across our entire business will ensure daily decisions include real consideration of the customer's perspective. It will also keep our stakeholders both informed and heard, so they can continue to influence our strategic priorities.

With our stakeholders, we developed a new approach to guide the way we work together. It was agreed to call this approach the Reset Engagement and Empowerment Framework, which is shown in the table below.

Table 2.

Ausgrid Reset Engagement and Empowerment Framework

Customer focused	Primary focus on long-term interests of customers, with the best possible customer service we can deliver
Ethical and responsible	Safety never compromised, environmentally and socially responsible, always an ethical, responsible employer
Optimal solution	Delivering reliability and risk management with optimal revenue, investment levels and affordability. Incorporating market/policy trends, technology and innovation
Fair and reasonable	Proposals for reliability, investment levels, revenue and pricing are seen as fair and reasonable by customers and stakeholders
Accountable and transparent	Key decisions supported by robust evidence, with an open and transparent process, and customers' and stakeholders' views clearly taken into account
Respectful and collaborative	Relevant stakeholders consulted and involved at each key stage in respectful two-way conversation; necessary information provided simply
Stakeholder-supported	Broad support from most stakeholders
Rules and regulation compliant	Meets all legal and regulatory requirements and in line with professional/industry codes

The framework ensures we are:

- **Customer focused** – so our primary focus is on the long-term interests of consumers, with the best possible customer service we can deliver,
- **Accountable and transparent** – so key decisions are supported by robust evidence, with an open and transparent process and stakeholders' views clearly taken into account, and
- **Respectful and collaborative** – so relevant stakeholders are consulted and involved at each key stage in respectful two-way conversations, with necessary information provided simply.

2.2.2 How we sought our customers' views

This Proposal has been subject to higher levels of consultation than Ausgrid has undertaken previously. This reflects not just the regulatory requirements rightly introduced, but also feedback that customers want more quality engagement. In the new energy ecosystem, customers are increasingly empowered to make decisions about their energy consumption, production and storage. We are committed to strong engagement with our customers to help us meet their changing needs and expectations.

To help us achieve our aim of business alignment with customer expectations, we developed a customer insights and research program in order to better understand our customers and their needs. A key initiative of our customer research and insights program was the Customers at the Centre project, which was specifically designed to support the development of our Proposal.

Customers at the Centre was a multi-phase project, incorporating: customer focus groups, deliberative forums and a quantitative survey of 2,360 customers. Participants in the project reflected the diversity of Ausgrid's total customer base, including CALD individuals, older and younger people, the vulnerable and businesses.

To date, we have engaged with more than 2,500 customers through our research program, and we continue to have regular consultation with key energy consumer stakeholder organisations as outlined in Table 3, below.

Table 3.

Customer and stakeholder and input into our Proposal

GROUP	CHANNEL	DESCRIPTION	INPUT INTO OUR PROPOSAL
Reset Working Group	Workshops Individual meetings	Customer advocates Highly informed on regulatory and energy issues	Tested details of the Proposal, capital expenditure (capex) program, operating expenditure (opex) forecasts and Tariff Structure Statement
Customer Consultative Committee	Workshops Individual meetings	Customer advocates Informed on energy policy and regulatory issues	Tested key components of the Proposal and Tariff Structure Statement at a high level
Retail energy businesses	Workshops Individual meetings	Part of the energy ecosystem Highly informed on regulatory and energy issues	Discussed how we plan to structure our prices and how our Proposal might impact businesses and their customers
Local council representatives	Workshops Individual meetings	Customers Informed on local regulations	Vegetation management, street lighting and planning
Customers	Deliberative Forums Focus groups Surveys	General population Equipped with unique insights on customer issues and preference	Explored customer expectations, long-term needs and attitudes to pricing and managing network peaks Explored customer expectations and preferences Tested key issues identified in qualitative research

Customer Consultative Committee

Feedback on previous proposals indicated that customers wanted more quality engagement with us. In response, we fundamentally redesigned the way we engage with stakeholders and customers. We reformed our Customer Council and created a new CCC to provide oversight and advice on Ausgrid's plans, policies, service and engagement with customers. We also created a CCC sub-group, the RWG, to enable us to consult more effectively on the detailed technical aspects of our Proposal.

We provided extensive materials to the CCC/RWG to build members' capacity to test and challenge our Proposal and pricing strategy.

> The Customer Consultative Committee's purpose is to provide oversight and advice to assist Ausgrid in becoming a customer-centric business that is sensitive to the needs and views of its stakeholders.

Local government

We established consultation programs with local government representatives on street lighting and vegetation management. Our consultation on street lighting included two meetings in 2017 with 41 local government councils and several sessions with the Southern Sydney Regional Organisation of Councils (SSROC).

On tree trimming, Ausgrid engaged with 33 councils across Sydney, the Hunter and Central Coast. Our focus was on how we can better align our tree trimming practices with community expectations. In addition to these discussions, Ausgrid conducted risk assessment studies to inform changes in our practices.

Retailers

Retailers are responsible for billing customers and bundling up our network charges along with other costs. In 2017, we met with AGL, EnergyAustralia, Origin Energy and Alinta Energy to discuss how we plan to structure our prices and how our Proposal might impact them.

In early 2018, we continued to engage with retailers to obtain feedback, which has helped shape our Proposal and pricing strategy.

Our response – current period

In response to this feedback, Ausgrid has already made important improvements to becoming more customer focused across our business activities as shown in the figure below.

Figure 2.

Ausgrid's customer focus

The feedback also helped shape our Reset Engagement and Empowerment Framework (described in section 2.2.1), particularly the way in which we consult and involve our stakeholders at key stages in the development of our Proposal and the way in which we make and communicate our decisions.

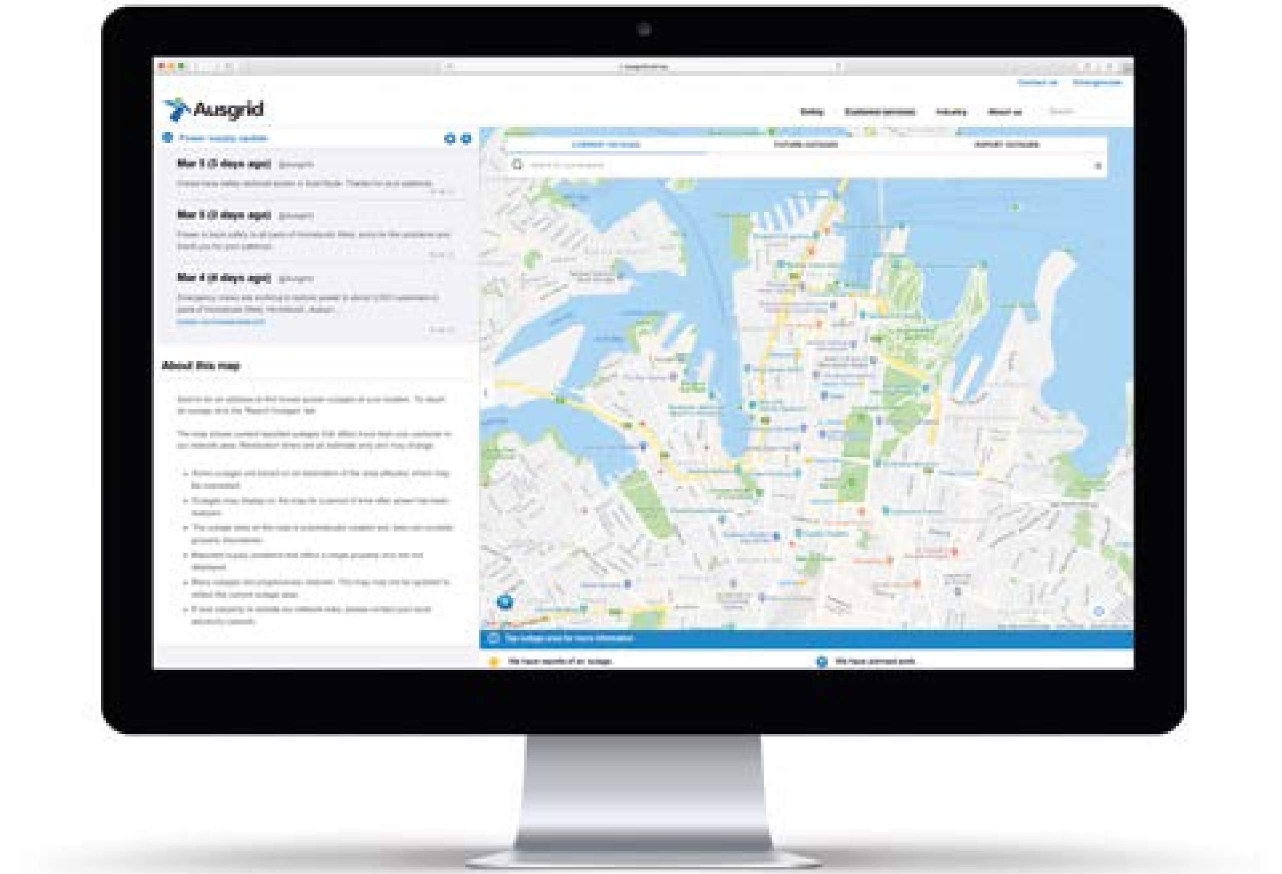
In addition, we have undertaken the following initiatives to improve our customer engagement and customer service:

- **Investing in a new digital customer strategy** – Including new systems and a website rebuild to make it easier for customers to communicate with us via their preferred channel. Digital maps on our website show network outages and allow faults to be reported (see below).
- **Streamlining our complaints handling processes** – Making it easier for customers to notify us of issues and track resolution, and making it easier for us to respond to our customers.
- **Measuring customer service** – We have co-designed with our stakeholders a new customer parameter for the STPIS that is a more meaningful measure of customer service. We will gather data over 2019–24 to enable us to develop targets and apply it in 2024–29. Further details are provided in section 9.3.
- **Servicing our CALD communities** – We specifically targeted our research to better understand the needs and preferences of CALD communities. We are currently developing a strategy to better engage with our CALD customers and we will absorb the increased costs associated with this initiative within our opex allowance.
- **Promoting Energy Literacy** – We are revamping our Energy Literacy material to identify and address any gaps, and to make information easier to access and understand. We will also work with our stakeholders to identify appropriate channels to provide information to different customers.

Customers can now find out about, and report, outages via our website. We also report on outages via our social media pages, such as Facebook as shown below.

Figure 3.

Outage map on Ausgrid's website



Our response – 2019 to 2024

We will continue to focus on our key strategic priority to 'become more customer focused' through our ongoing engagement processes as well as our customer service initiatives.

Specifically, we are investing in modernising and automating our services to customers. For example, we will be investing $30 million in workplace technology to provide a more streamlined and efficient service to our customers. This involves upgrading mobile devices so our field workers can directly access key business applications and corporate data while working in the field away from offices and depots. It will also streamline project planning and work activity in the field.

We are implementing a new digital customer strategy including new systems and undertaking a website rebuild to make it easier for customers to communicate with us via their preferred channel. This will include refinements to our recently launched digital maps that show customers the location of network outages and allow faults to be reported, with improvements to the underlying systems that allow timely and informative updates on outage status to be shared with affected customers.

2.2.3 Extended Stakeholder Consultation program

Stakeholder Consultation Document

After receiving the AER's approval to extend the submission deadline for our Proposal to the end of April 2018, we were able to expand our consultation program to allow an even greater level of community and stakeholder engagement on key aspects of our Proposal.

Our extended consultation program included the release of a Stakeholder Consultation Document designed to:

- enable energy customers and stakeholders to understand the basis of our Proposal and to give further feedback, and
- provide our key stakeholders with clarity on the investments we intend to make and the services they will receive in the next regulatory period, so they can provide detailed feedback.

We sought feedback on our Stakeholder Consultation Document from the CCC, customer advocates and stakeholders including:

- AER Consumer Challenge Panel (CCP)
- AER representatives
- Councils on the Ageing NSW (COTA)
- Energy Consumers Australia (ECA)
- Energy Users Association Australia (EUAA)
- Energy Water Ombudsman NSW (EWON)
- Ethnic Communities Council of NSW (ECCNSW)
- NSW Council of Social Services (NCOSS)
- Public Interest Advocacy Centre (PIAC)
- Retailer representatives
- South Sydney Regional Organisation of Councils (SSROC)
- Total Environment Centre (TEC)
- Urban Development Institute of Australia (UDIA)

Additionally, we invited all customers and members of the general public to provide feedback to us via email to yoursay@ausgrid.com.au. We also worked closely with the AER during the extension period and held the following CCC and deep dive sessions.

Deep dive sessions

The objective of the deep dive program was to share detailed information on our proposed capex projects and pricing strategy with our stakeholders and get their feedback, so we could shape our final capex proposals and price structures.

These sessions allowed stakeholders to raise issues with and ask questions of our technical staff. We invited key stakeholders to these sessions, including AER representatives, ECA, AER CCP, PIAC, NCOSS and TEC.

We convened four deep dive sessions on our capex proposals, a session on the development of our Tariff Structure Statement and a session on operating expenditure (opex). The proposed session on the future of the energy network was deferred until after the submission of the Proposal.

Extended Stakeholder Consultation Report

The key outcomes from the first CCC meeting, the deep dive sessions and any community feedback were compiled into the Extended Consultation Report that was discussed with the CCC. The report highlighted what we heard and how this was used to inform and amend our Proposal.

See Attachment 2.01 and 2.02 for further information on how we engaged with our stakeholders and customers and how we have taken their views into account in this Proposal.

2.3 Key issues for customers and stakeholders

Engaging with our customers and stakeholders has helped us see ourselves in a very different way – not just from a technical or economic perspective. Our customers and stakeholders have challenged us to deal with difficult issues. With their assistance, we now have a better understanding of what's important to our customers and how we can serve them better, which has been taken into account in this Proposal.

To align our business with the feedback we received from customers, our corporate strategy is focused on the three core themes that are most important to our customers:

- Affordable
- Reliable
- Sustainable.

This section addresses each of these themes.

2.3.1 Affordable

What our customers and stakeholders told us

Affordable energy is a key priority for customers, for both the residential and business sectors. Energy bills have risen steeply over the last decade and customers are challenged by rising prices and many have experienced 'bill shock'.

While affordability issues are partly attributable to cost drivers in both the wholesale and retail markets, our network costs have also contributed to pressure on the overall price that customers pay for their electricity.

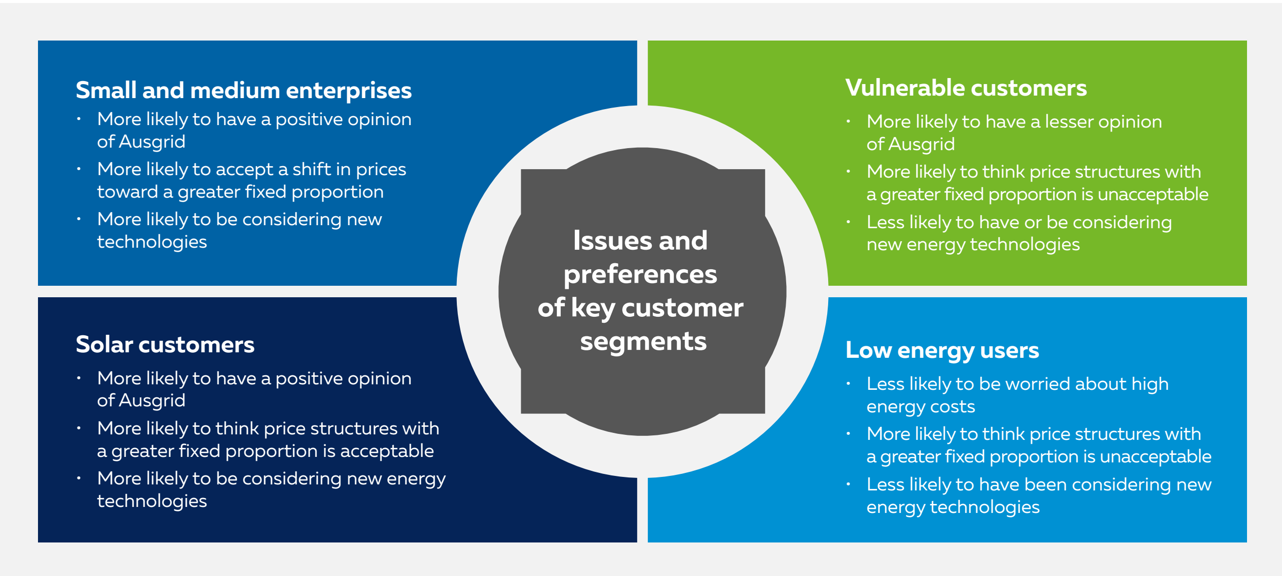
Given that wholesale costs are expected to rise over the next few years due to changes in the generation technology mix and the rising cost of gas, we must take action to reduce network prices as much as possible.

Customers also want assurances that our capital proposals are consistent with a reasonable long-term expenditure profile, to avoid the peaks and troughs of investment which occurred in previous periods. A peak and trough investment profile has direct flow on implications in relation to our prices.

Specifically in relation to pricing, as part of our customer research, we asked customers about their concerns and preferences, as to our proposed price changes as well as demand management programs and the adoption of new technologies. The figure below summarises the feedback we received, which varies significantly across different customer segments.

Figure 4.

Customer views on price changes, demand management and new technologies



Feedback received indicated that, customers and stakeholders broadly support the need for pricing reform to enable more equitable and more efficient price signals. Given our diverse customer base, different customers had different views as to the nature, and extent, of any pricing reforms.

In light of the above feedback, Ausgrid will establish a pricing working group to take on board customer and stakeholder feedback; mitigate unacceptable customer bill impacts; and ensure adequate safeguards are put in place. The proposed working group will be framed with the assistance of customers and stakeholders with a focus on a pricing strategy which fairly and equitably recovers the costs of providing network services, whilst also giving customers price signals that enable them to benefit from more efficient use of the network.

To address concerns of negative customer bill impacts whilst rebalancing prices we are proposing network bill discounts for small and vulnerable customers. We are committed to working with retailers and the pricing working group to automate the identification and assignment of customers eligible to receive network discounts.

Stakeholders broadly did not support any change in Ausgrid's connection policy which would have reallocated connection costs, currently paid for by the connecting party, to the broader customer base resulting in an increase in the regulatory asset base (RAB).

Our response – current period

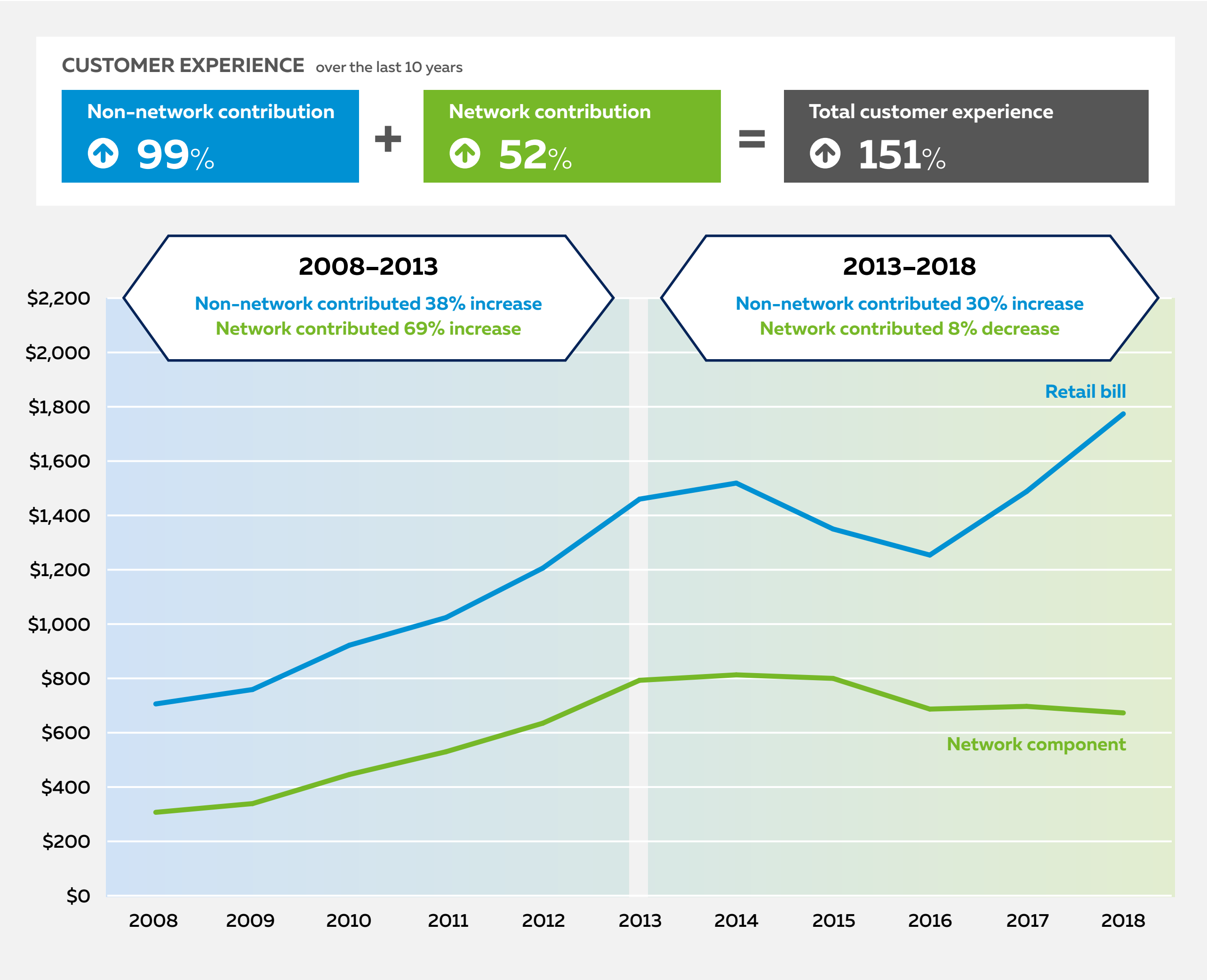
Ausgrid has been working hard to sustainably reduce the cost of providing services to our customers which is a constant priority and whilst we continue to make progress, it remains an ongoing challenge. However, thus far our transformation program has delivered the following benefits:

- Reducing labour costs, which is the biggest component of our opex. This includes improving the productivity of our internal labour force through better scheduling and more efficient labour practices, such as integrated crew services and greater use of automation.
- A blended and more flexible work delivery approach that allows us to operate more efficiently.
- Incorporating our cost-benefit analysis into our forecasting methods to defer the timing of major projects where the cost saving outweighs the risk to customers.
- Exploring a greater variety of options to resolve network issues, resulting in lower cost solutions. In particular, we managed to avoid 'like for like' replacement of major infrastructure by using spare capacity on neighbouring parts of the network. We also considered demand management solutions to defer replacement capex.

Our transformation program has already significantly reduced our operating costs, by about 19% – around $100 million – per year in real terms. This has contributed to the significant decrease from 2013/14 to 2017/18 in the overall network costs borne by Ausgrid customers. Over the same period the non-network component of a customer's bill (which includes electricity generation, green schemes and retailer margin costs) has increased. This can be seen in the figure below.

Figure 5.

Comparison of retail bill and network component of bill 2007/08–2017/18 ($, nominal)



Source: Ausgrid analysis, based on regulated or standing offer retail prices. Non-network contribution includes electricity generation, green schemes and retailer margin.

Table 4.

Retail bill and network components of bill ($, nominal)

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Retail Bill (total customer bill)	($)	706	759	922	1,024	1,206	1,460	1,519	1,350	1,254	1,488	1,774
Network component	($)	307	339	446	530	635	793	813	800	687	697	673
Network % of Total		43	45	48	52	53	54	53	59	55	47	38

The network component of a typical customer bill reached a peak of 59% in 2015 but has now dropped to 38% of the total bill.

Our response – 2019 to 2024

During the forthcoming regulatory period we have focused on improving the affordability of our network services through the following measures:

- Focusing on only replacing assets on an as needs basis and identifying opportunities to better utilise existing network capacity in response to changes in demand.
- Rather than simply building more infrastructure, we will look first at where new technology, innovation and partnering with other companies and our customers will solve the network issues at a lower cost.
- Maintaining downward pressure on our expenditure plans and driving further efficiency improvements over time.
- Adopting our stakeholder's preference for Australian Energy Market Operator's (AEMO) lower value of customer reliability in our major project cost benefit assessments, which results in reduced levels of capex.
- Providing greater support for low consumption and vulnerable customers through transitional arrangements (a safeguard price) as we rebalance fixed and variable charges to provide more cost-reflective prices. Our Proposal aims to fairly and equitably recover the costs of providing network services, while giving customers price signals that enable them to benefit from more efficient use of the network. Chapter 10 presents our price proposals, with further detail including breakdowns contained in the Tariff Structure Statement.
- Sharing the benefits of efficiency savings in capex from the previous period with customers in accordance with the regulatory framework.

If the AER accepts our Proposal, we will:

- **Reduce our component of prices by 5.7% in 2020 in real terms**

  Our Proposal means that our component of prices will reduce by 5.7% in 2019/20 in real terms and then remain unchanged in real terms over the next four years to 2023/24. In other words, our component of prices will increase by less than inflation over the five-year period.

- **Lock in operating expenditure savings**

  Our opex proposal embeds a $100 million per annum saving that we have achieved from transforming our business. This saving is equivalent to approximately $76 per customer, per year. We will continue to put downward pressure on opex by:

  – continuing to look for and make changes that will make us more efficient,
  – being more innovative in the way we use new technology and work with other businesses and our customers, and
  – streamlining our internal processes.

- **Zero real growth in the value of the grid (our 'regulated asset base') on a per customer basis**

  To improve affordability in the long term, our network planning approach should enable us to meet the changing needs of customers without needing more assets per customer. We will do this by:

  – supporting and encouraging customers to manage peak demand, and
  – being more efficient in the way we spend capital.

- **Change the pricing structure to minimise bill shock and increase efficiency**

  Our new pricing strategy will lay the foundations for a future energy system that meets our customers' needs at the lowest sustainable cost. It is designed to lower overall system costs by rewarding customers who use the network more efficiently.

- **Not adjust our connections policy**

  At the start of the extended stakeholder consultation program, we set out a revised connections policy for the next period which allocated a larger proportion of shared connection costs to the broader customer base, reducing costs for the connecting party.

  While Ausgrid set out the equity benefits of the revised cost allocation under the new connections policy, stakeholders' view was that Ausgrid, to the extent practicable, should avoid any change in connections policy which results in an increase in the RAB.

  We will therefore not effect this change at this time and will retain our existing policy. We will work with the AER to develop a common set of principles for setting connections policy for all DNSPs and may seek to review our policy in light of this. As a result of this decision, our RAB will be $27 million lower compared to our original proposal.

- **Invest $548 million on IT, property and fleet over five years**

  We are investing to modernise the way we do business to deliver improvements in our customer service. At the same time, we will maintain the significant savings we have achieved in our fleet, which has been reduced by approximately 50% in the last five years.

  We are implementing a new digital customer strategy including new systems and undertaking a website rebuild to make it easier for customers to communicate with us via their preferred channel. This will include refinements to our recently launched digital maps that show customers the location of network outages and allow faults to be reported, with improvements to the underlying systems that allow timely and informative updates on outage status to be shared with affected customers.

  The majority of our IT investment relates to updating the systems that support our business-critical functions, and on continuing our transition to cloud based services. We are also investing in modernising and automating our services to customers. For example, we will be investing $30 million in workplace technology to provide a more streamlined and efficient service to our customers. This involves upgrading mobile devices so our field workers can directly access key business applications and corporate data while working in the field away from offices and depots. It will also streamline project planning and work activity in the field.

  We will invest $208 million over five years on replacing and upgrading five of our 19 primary depots as well as upgrading offices. In most cases, these properties are over 50 years old and are at risk of not meeting basic workplace standards. In some cases, replacement of corporate property will result in surplus land which will be sold and used to lower the RAB to the benefit of our customers.

In summary, we consider that our capex plans provide the best price-service outcome for our customers, both now and for subsequent regulatory periods.

2.3.2 Reliable

What our customers and stakeholders told us

Our customers have told us that they highly value the reliable and secure supply of electricity to both their businesses and their homes. However, in a price sensitive environment, customers are also keen to make sure that we balance out network investment to meet reliability requirements against the value provided to customers.

Our stakeholders also advised they are looking for more clarity on our load shedding practices. Communities and councils are looking for a better balance between network safety and reliability needs and the local community's aesthetic expectations for trees in their neighbourhoods.

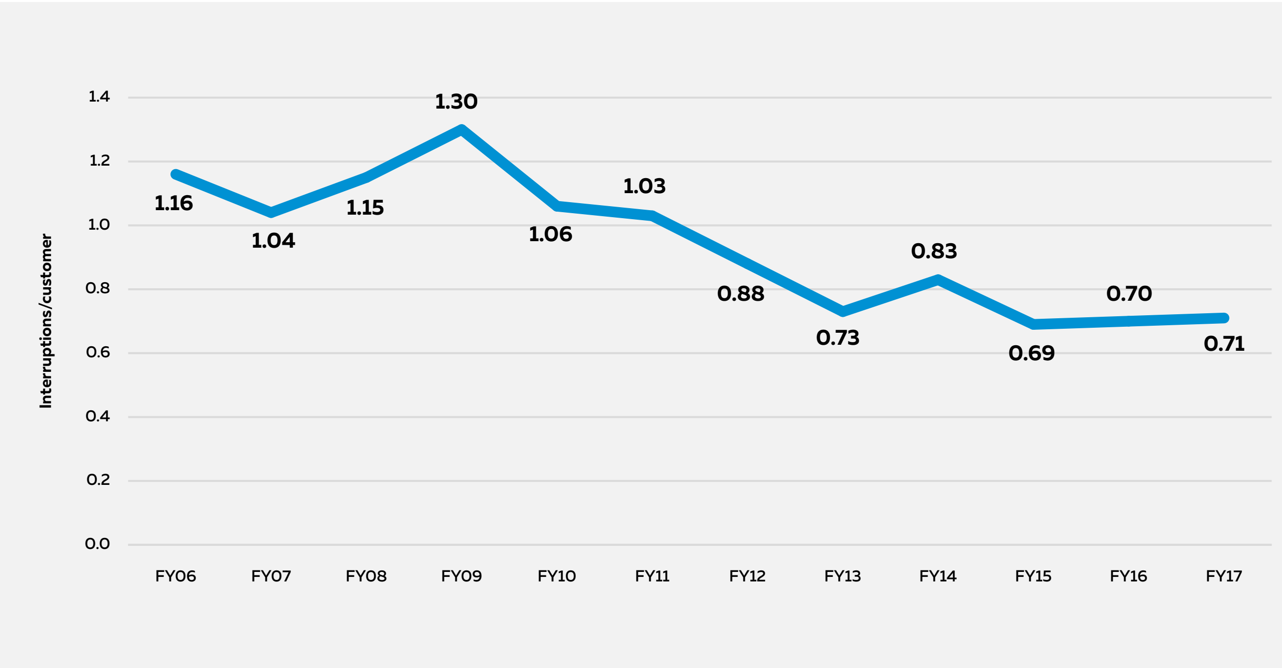
Our response – current period

Ausgrid recognises that reliability and security of supply are critical to business and residential customers, underpinning our economy and quality of life. We are also required to meet reliability and security-related licence conditions imposed by the NSW Government, with additional incentives through the STPIS to meet or exceed reliability targets.

As a result, reliability is a key performance indicator for our business, which is regularly reported to the Board. In the last decade, we have invested significantly in our transmission and sub-transmission networks and our zone substations. This investment has helped strengthen the reliability and security of Ausgrid's network upstream, improving reliability since 2009, with a minor reduction in reliability in the last two years, as shown in the figures below.

Figure 6.

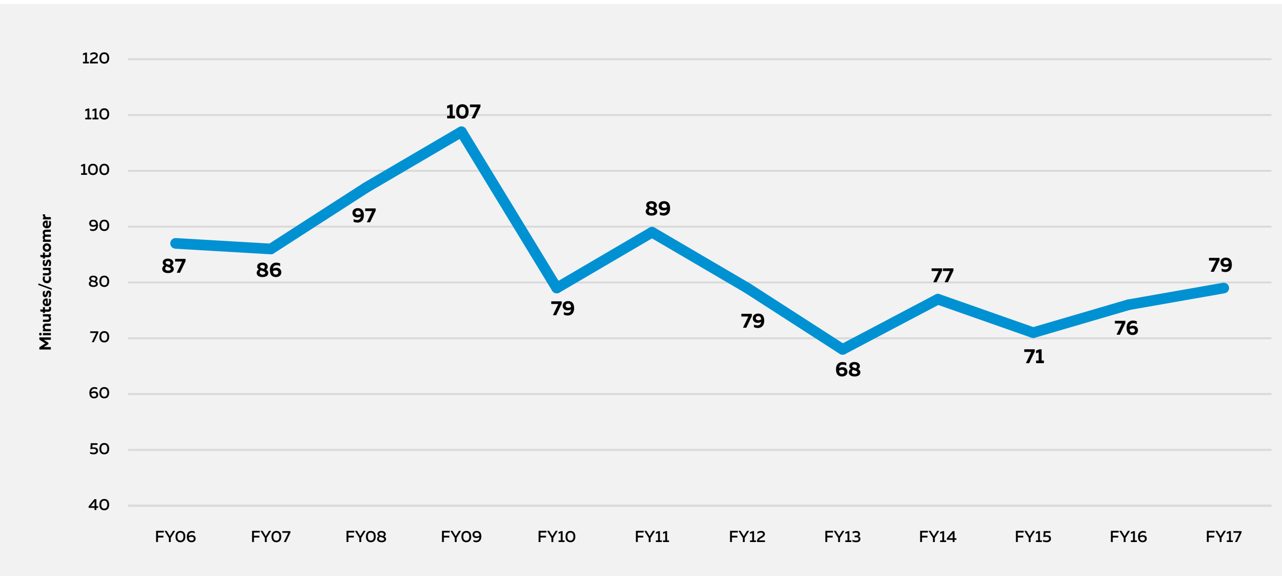
Frequency of outages per customer 2005/06–2016/17



Source: Ausgrid analysis.

Figure 7.

Duration of outages per customer 2005/06–2016/17 (minutes)



Source: Ausgrid analysis.

We are now well placed to manage peak electricity demand days, such as the one that occurred on 10 February 2017. On that day, higher than forecast summer temperatures contributed to a peak demand of 14,181 megawatt (MW) across NSW. While challenging our network infrastructure, Ausgrid's network was able to adequately meet the increased demand placed on it.

Given the tight supply/demand conditions on that day, AEMO also directed TransGrid to reduce demand at the Tomago Aluminium smelter. In light of this experience, the CCC raised questions about how Ausgrid approaches load shedding. In response, we have improved our website to ensure customers have clear and timely information on why and how load shedding occurs.

Ausgrid also has an excellent track record in restoring power quickly and safely following natural disasters. For example, in April 2015, Ausgrid's network area was hit with a 'super storm' that resulted in 22 local government areas being declared national disaster areas. The storm damage caused widespread power outages that affected 369,000 (almost a quarter) of our customers. In an exceptional response in adverse weather conditions, within five days we had restored power to almost all of our customers.

To provide a better balance between network safety and reliability needs and the local community's aesthetic expectations for trees in their neighbourhoods, we have developed a new network standard that defines cutting clearances, amongst other things. In non-bushfire areas, trimming clearances have been reduced from one metre to 50 centimetres and in the case of Aerial Bundled Cables, vegetation will be able to grow within 10 centimetres of the asset. These changes will allow less severe trimming and better canopy cover without compromising reliability or safety.

We have also developed a Grant Scheme with councils which will allow us to co-fund projects which would not ordinarily proceed based on strictly technical grounds. For example, undergrounding of electricity wires can improve reliability but usually not at an acceptable cost. However, when combined with the community and environmental benefits of allowing trees to remain in place, the project may be justifiable. The scheme allows councils and Ausgrid to both contribute to projects where there are both reliability and community benefits.

Our response – 2019 to 2024

We are targeting our expenditure plans to maintain current levels of reliability and where possible, shifting load and reconfiguring the network to ensure that we utilise the existing network effectively.

Of our $3.1 billion in total capex, $1.7 billion will go towards replacing ageing and poor condition assets, which is an increase of 3% compared to the current period. Almost a quarter of our assets are more than 50 years old. We will need to replace them based on asset condition and risk in order to continue to provide the reliability our customers want.

We are also investing in a new Advanced Distribution Management System (ADMS), which will enable us to monitor the network in real time and identify exactly when and where an outage occurs, rather than having to send out a crew to locate the fault. In the long term, the ADMS will therefore enable us to put downward pressure on the costs of maintaining reliability.

We are implementing our new network standard for vegetation clearances to allow less severe trimming and better canopy cover without compromising reliability or safety.

We consider that our capex plans provide the best price-service outcome for our customers, both now and for subsequent regulatory periods.

2.3.3 Sustainable

What our customers and stakeholders told us

In the past, the electricity network was a one-way transport system that moved electricity from remote, large-scale generators to industrial, commercial and residential customers.

Looking forward, our customers have told us that they want to continue to be able to produce and consume electricity, when and how they choose, including, for example, being able to feed electricity back into the grid.

Both customers and stakeholders support solar and renewables, with most believing Ausgrid should be actively involved in the shift to renewable energy sources. More generally, customers and stakeholders expect energy companies to support the transition to a lower carbon economy.

Local councils also told us that they would like to implement options to reduce carbon emissions and reduce costs via accelerated replacement of street lighting to light emitting diode (LED) technology for residential roads and main roads. Local councils also requested that Ausgrid provide a detailed business case to enable informed decisions whether to proceed with an accelerated replacement program.

Our response – Current period

In the current period, we have focused on reducing barriers to the connection of renewable energy generation. For customers who want to connect their solar power or battery storage systems to the network by fast-tracking all applications for single phase systems under 10kW and three-phase systems under 30kW. These systems can now be connected without the need to conduct a detailed technical assessment.

For street lighting, we finalised our LED street lighting pricing for residential roads based on our stakeholders' preferred option and provided detailed information to each customer to inform decision making as to the costs and benefits of accelerated replacement. We have also commenced trialling of main road LEDs and smart controls for lighting systems.

Our response – 2019 to 2024

Going forward, we are playing a greater role in developing the grid to support the energy mix of the future.

We are prudently investing in the transformation of our network to more easily allow us to incorporate distributed energy resources and optimise the network in real time. Through these initiatives, we are playing our part in implementing the Electricity Network Transformation Roadmap developed by Energy Networks Australia and CSIRO.

For the next regulatory control period, we are investing $58 million in innovation projects to deliver this 'future grid' sooner. We are also investing an additional $41 million in an ADMS. Although the primary driver of this investment is to replace our outdated system, the new system will allow us to optimise orchestrated demand management solutions, such as partnering with customers to enable smart control of batteries and appliances and, in future, potentially enabling peer-to-peer trading.

In the shorter term we are continuing to make it easier for residential customers to install solar panels and batteries by streamlining our connection processes.

We are also implementing demand management solutions to incentivise solar and battery uptake and encourage investment in energy efficiency where it reduces the need for network investment.

In response to councils' desire to reduce energy bills and carbon emissions, we are progressively installing energy efficient LED lighting. We have given councils a list of options, so they can select a charging structure that best suits their needs. Further details are provided in section 8.1 Public Lighting.

Ausgrid has an important role to play in encouraging customers to invest in renewable technologies and developing the grid for the energy mix of the future. Our track record on this issue, and how our Proposal will help us transition towards the grid of the future, is discussed in Chapter 3.

03

Our role in a changing market

03

Our role in a changing market

What did we achieve in 2014–19?

We recognise the future is not a 'one size fits all' grid system and that increasingly, customers want to generate their own power, store it and manage their own energy needs through demand management.

We have begun trialling assets with the capacity to meet customer needs, including battery storage, home energy management, demand response and distributed energy resource solutions.

We explored the ability of residential batteries and fuel cells to reduce customer bills and network demand.

We have lowered the cost of connecting solar and batteries and reduced red tape by making the process faster and simpler for our customers.

We tested the charging infrastructure, vehicle performance, behaviour and grid impacts from electric vehicles.

We surveyed residential and business customers about solar, batteries and energy efficiency to better understand their motivations and preferences for installing new technology and willingness to partner with Ausgrid to reduce demand.

We implemented the innovative CoolSaver program, where we partnered with 150 residential customers to reduce peak demand from air conditioners using new power saving technology.

We worked with Energy Networks Australia and CSIRO to develop the Electricity Network Transformation Roadmap, which sets out a path for managing transformational change to maximise benefits to customers.

What outcomes will we deliver in 2019–24?

Improve demand management – our plans include partnering with customers to reduce the need to build more network infrastructure by using batteries, smart meters, smart appliances and offering innovative rebates. We will also conduct innovative projects to refine demand management solutions, including identifying the optimal mix of solar, batteries, energy efficiency and embedded generation to help us defer replacing network assets.

Invest in the transition to a modern grid – we are proposing to invest an additional $41 million in ADMS. This new technology investment will replace the end of life existing system and form the foundation for our modern grid. The ADMS will allow us to operate the grid safely, reliably and efficiently as more and more customers adopt distributed energy resources (DER). Our initial investment will provide the core platform to deliver customer benefits in the future, by: enabling us to isolate faults remotely; facilitating peer-to-peer trading; and partnering with customers to operate batteries and use smart appliances to lower their bills.

We are working to **support emissions reduction** and manage system demand by supporting and encouraging customers to take up solar, batteries and smart meters, and investing in grid technologies that enable all stakeholders to maximise the value from these investments. Ausgrid also supports the Energy Security Board's proposed National Energy Guarantee that we believe is important to ensure a reliable and stable electricity sector and help Australia meet its international obligation to reduce emissions.

How are we responding to our customers' feedback?

Affordable

We know that not everyone can or wants to adopt new technology, but we know all are concerned about affordability. We are changing our price structures to ensure the prices customers pay are fair, regardless of their technology choices, while we focus on our core service of providing safe and affordable electricity for all our customers. Our innovation trials and adoption of new grid technology will allow us to explore how to deliver our future grid services more affordably.

Additionally we will be conducting a detailed research program, with the input of customers and stakeholders, to enable the accelerated adoption of network prices/incentives. To promote the sustainable use of the network and deliver value to customers by reflecting the costs of providing network services and the value of demand side participation.

Reliable

We know that most of our customers value their current level of reliability but would like to see that delivered at a lower cost. Over time, our investments in new grid technology, including ADMS, our Network Insight program, expanded self-healing network trials, online condition monitoring and line fault indicator trials will improve our outage management, so we are able to maintain reliability at lower cost.

Sustainable

We received clear guidance from customers that we should be actively involved in the shift to renewables, and demonstrate more innovation in our investment mix. As a result we are undertaking a range of targeted new technology trials to accelerate the transition to an affordable lower carbon future grid. These trials include: a suite of demand management and information sharing initiatives, our trial of Distribution System Operator (DSO) capabilities, and a number of stand-alone power system, grid battery and electric vehicles (EV) charging trials.

The environment in which Ausgrid operates is fundamentally changing. Customers want new services that enable them to connect their rooftop solar PV and battery storage system and charge their electric vehicle, while others will simply wish to continue to access affordable and reliable power. These services must be provided at a price that reflects efficient costs and delivers value for all our customers.

3.1 The policy environment is changing

Recent events and high profile reviews of the energy sector have led to a debate about appropriate policy settings to address the 'energy trilemma' of affordability, reliability and sustainability. The most prominent of these, the Finkel Review[1], was an independent review into the future security of the electricity market triggered, in part, by the blackout in South Australia in September 2016 and by high electricity prices across the country.

The Energy Security Board has been established based on the outcomes of this review and its proposed National Energy Guarantee is an important step to addressing the energy trilemma.

More recently the House of Representatives Standing Committee on the Environment and Energy released the bi-partisan 'Powering our future' Inquiry into modernising Australia's electricity grid. This review has put forward a suite of recommendations that are likely to inform further policy development on key topics for distribution businesses, including subsidies and incentive schemes, customer value of reliability, edge of grid optimisation, energy efficiency, grid cost recovery, and the rollout of smart meters.

As the policy environment continues to evolve over the course of the 2019–24 regulatory period, we will contribute to the consultation processes and implement any new obligations that relate to us. At this stage, we do not anticipate any policy developments that will affect our regulatory obligations or expenditure plans.

3.2 The technology landscape is changing

The electricity industry is undergoing what very well might be a once in a century transformation. For over 100 years, power has largely only flowed one-way from remote fossil fuel generators, through high voltage transmission lines and distributed to households and businesses across lower voltage distribution lines. During this time, applications for storing electrical energy have been relatively limited.

Increasingly, households, businesses and communities are generating, and storing, their own electricity and selling their surplus power back into the energy market or to their neighbours via the distribution network resulting in two-way flows. As a result, the distribution network, and its pricing structures, need to adapt to accommodate the new ways in which customers expect to be able to use the grid if we are to continue to improve affordability while maintaining reliability, safety and security.

Technological developments and improvements in the economics of renewable generation and storage, as well as smarter energy management systems and controls, are accelerating the pace of change. Combined with the anticipated increased penetration of advanced metering technology, these developments will give consumers more choice and control over their energy supply and the services they receive.

While solar adoption on Ausgrid's network has been slower than in other parts of Australia, due largely to our high proportion of apartments and rental properties, we have already seen a material uptake in rooftop solar across our network. As the installed cost (and size) of solar and solar+battery systems continues to fall, and they are supported by new and innovative business models that allow customers to get more value out of their investments, these technologies will become more attractive and accessible to a greater number of customers.

1 Finkel et al, Independent Review into the Future Security of the National Electricity Market, Blueprint for the future, June 2017.

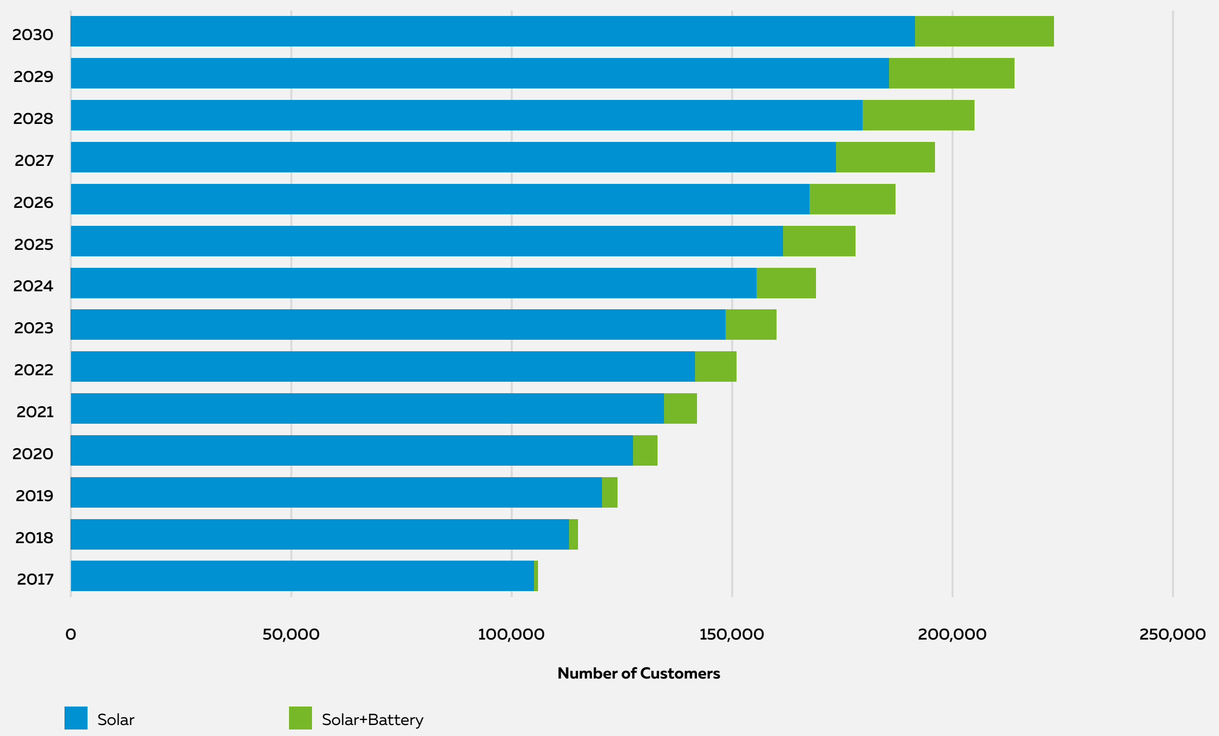
As the installed cost (and size) of solar and solar+battery systems continues to fall, and they are supported by new and innovative business models that allow customers to get more value out of their investments, these technologies will become more attractive and accessible to a greater number of customers. We are also seeing increased interest in community scale solar and storage solutions which provide a further benefit to customers in terms of economies of scale and accessibility (e.g. for those without physical space to install themselves). It is Ausgrid's responsibility to invest in our network and adjust our prices to give customers the choice and control to take full advantage of these new opportunities.

By 2030, we expect the number of customers on the Ausgrid network with solar and solar+battery systems to double. We will conduct trials to see if these technologies can help defer capex and explore new ways to deliver services more affordably.

The figure below shows our forecast growth in the number of customers with solar and solar+battery systems, which are expected to almost double over the next 10 years.

Figure 8.

Number of customers with small-scale solar+battery systems (2016/17–2029/30)

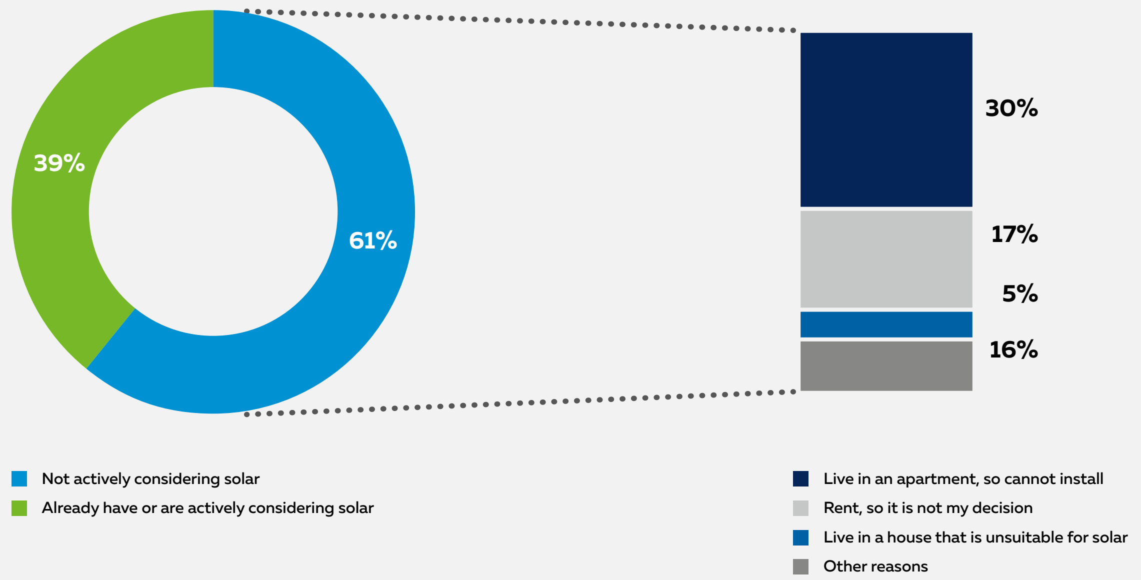


Source: Ausgrid forecasts.

However, we also recognise that many customers – particularly household customers – do not currently have access to some of these new technologies, either for financial or practical reasons. We have surveyed our customers to understand factors that affect their investment decisions. Our findings are summarised below.

Figure 9.

Our customer's interest in, and ability to install, solar panels



Source: Ausgrid analysis of Newgate Research, Customers at the Centre Phases Three and Four: Customer Survey and Advanced Analytics Research (commissioned by Ausgrid). Customers were able to select multiple reasons on why they were not actively researching or considering buying solar panels for their home. Analysis included evaluation of most likely primary reason for citing no interest in solar, with apartment living figures aligned to survey demographics.

This knowledge has been instrumental in the planning of our innovation portfolio for the FY19–24 period, and has led us to have an increased focus on pricing reform and community scale trials that can mitigate or alleviate the inequalities surrounding access to new technology. In structuring our business to cater for new and evolving energy products and services, we will always remain focused on our core service of providing safe, reliable and affordable access to electricity for all our customers. We want to let our customers choose how they use our network, so we play our role in the new technological environment while still serving all customers' needs.

3.3 The way we manage the network is changing

Ausgrid is transforming itself to be more proactive in delivering the services our customers want at a competitive price while improving reliability.

The cost of our future network depends on the investment decisions we make today, which will have a significant impact on the future costs of the services we provide. These decisions consider when and how we should invest to keep down the cost of maintaining and operating our assets, almost a quarter of which are more than 50 years old.

In this context, we should take advantage of new technologies that may offer more cost-effective solutions than traditional network investments.

Ausgrid already considers non-network solutions in our business as usual planning processes. We use a single planning tool for network and non-network solutions, to ensure we consider demand management options for all major projects, not just where we have a regulatory requirement to do so. Rather than building more infrastructure, we are looking first at where new technology, innovation and partnering with other companies and our customers will solve the problem at a lower cost.

In relation to demand management, Ausgrid has a long history of partnering with customers to ensure the grid is utilised efficiently. For decades we have used mains signalling (ripple control) technology to control residential customers' hot water systems, in return for a lower network price for hot water, to manage peak demand. Approximately half a million customers participate in this scheme, saving an average of $200–$400 per year on their electricity bills.

In the future, as explained below, our customers are likely to have a stronger interest in participating in demand management trials which use new technological capabilities as well as eliciting benefits of any pricing reforms.

Figure 10.

Customer feedback on their participation in demand management programs

Our customers are interested in participating in demand management programs

We asked our customers if they were interested in participating in a number of different demand management programs, including:

Peak Time Rebates

Leverage smart meters and other energy monitoring technologies to allow customers to shift their energy in return for network support incentives.

90% Very or quite appealing

79% Likely to participate

Ausgrid's CoolSaver Program

Ausgrid customers receive incentives to reduce peak electricity demand from their air conditioner using the in-built power saving modes of modern air conditioners.

83% Very or quite appealing

71% Likely to participate

Appliance Replacement Rebates

Aimed at reducing customer electricity demand by replacing old, inefficient air conditioners with modern, energy-efficient alternatives.

84% Very or quite appealing

66% Likely to participate

In the future, as new technology becomes more cost effective and is increasingly adopted by our customers, we will seek new ways to operate our network more efficiently.

While demand management has traditionally been used to reduce the need to build additional capacity, we are looking at how it can be used to defer replacing aged assets, which drives the bulk of our forecast capex program. This includes using the demand management innovation allowance to conduct incentive trials to encourage permanent demand reductions through installation of solar power and energy efficiency measures.

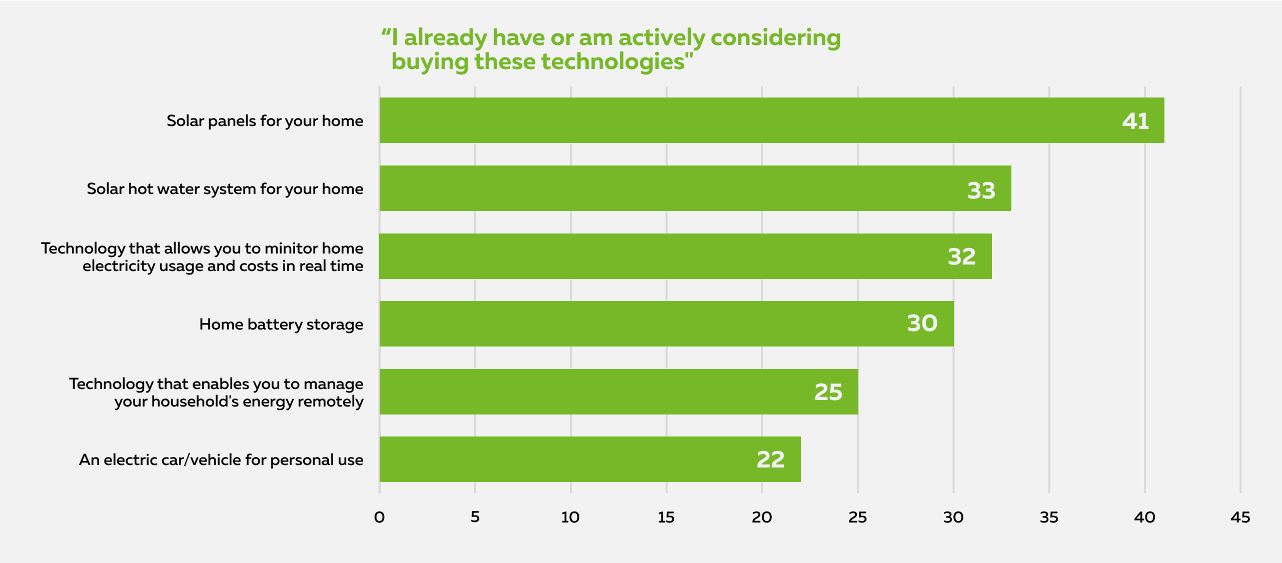
The AER's new demand management incentive scheme will kick-start investments in non-network solutions. This will benefit consumers by reducing the longer-term costs of operating our network. Through this scheme, we will partner with customers to deliver approximately $26 million (real FY19) in demand management projects to reduce demand and provide our customers with savings that would otherwise need to be spent on capital projects.

We also see opportunities to contract with our customers to use the growing number of batteries on our network. A recent survey found 41% of customers with battery storage would consider allowing Ausgrid to operate their battery system in return for a financial incentive.[2]

2 Ausgrid, Household Solar Power and Battery Survey, Interim Report, March 2017, p.44.

Figure 11.

Our customers' preferences for demand management options (%)



Note: Totals exceed 100 as customers were able to select multiple responses.

Source: Newgate Research, Customers at the Centre Phases Three & Four, Customer Survey & Advanced Analytics Research Report, 22 September 2017.

We recognise the importance of responding to technological change and partnering with our customers to find more efficient energy outcomes, consistent with our vision to be a leading energy solutions provider. Equally, the unprecedented scale of the transformational change requires a structured approach to guide Ausgrid and other network companies through the challenges ahead and ensure that the potential benefits from new technology are properly understood and fully captured. For this reason, as explained in the next section, Energy Networks Australia (ENA) and CSIRO developed the Electricity Network Transformation Roadmap.

3.4 Electricity Network Transformation Roadmap

In 2017, the ENA and CSIRO published the Electricity Network Transformation Roadmap (the Roadmap). At the highest level, the ENA and CSIRO explain that with a clear Roadmap, Australia's electricity sector can outperform current abatement targets, keep the lights on and deliver lower costs. However, it also noted that this next decade provides a limited window of opportunity to reposition Australia's electricity system to deliver efficient outcomes to customers.

Ausgrid participated in the development of the Roadmap, which is supported by numerous expert reports and analysis. To assist customers and stakeholders, the ENA has made its report and supporting papers available on its website.[3]

The scale of the transformation is illustrated by the Roadmap's scenario-based modelling, which suggests that by 2050 up to 45% of Australia's electricity supply could be provided by millions of distributed, privately owned generators. Along with significant opportunities, the extent of this transformation provides profound adaptation challenges for the system's architecture, stability and efficiency, given it was originally designed for almost 100% of generation at the transmission end of the system.

The Roadmap is based around five domains:

- customer oriented electricity,
- power system security,
- carbon abatement,
- incentives and network regulation, and
- intelligent networks and markets.

3 http://www.energynetworks.com.au/electricity-network-transformation-roadmap

For each of these domains, the Roadmap lays out a series of milestones and actions to guide an efficient and timely transformation over the 2017–2027 period, including:

- an integrated and sequenced set of actions, outlining time specific milestones to prioritise no regrets outcomes,
- quantitative analysis of the benefits from the proposed actions and transition pathways to 2027 and beyond, and
- strategies for addressing the barriers and constraints that inhibit addressing the priority actions.

The Roadmap provides a systematic and planned approach to addressing the challenges ahead. The following section highlights our initiatives in the next regulatory period, which are consistent with the Roadmap and our customers' preferences.

3.5 Ausgrid's innovation portfolio

We expect that our future grid will need to support an energy mix that includes a high proportion of renewables, both large and small scale. It will encourage customers to help us intelligently manage electricity demand across the grid and reduce their bills by maximising the value and use of their DER.

Our broader innovation portfolio has been developed to align with the Roadmap, specifically targeting delivery against those milestones that will require proactive attention by DNSPs before 2024 if they are to be progressed. Our portfolio covers five main areas:

- **Advanced Distribution Management System** – the initial investment in an ADMS system and the piloting of DSO capabilities (e.g. DER dispatch etc.)
- **Network Innovation Program** – 11 initiatives focused on the trialling or expansion of new grid technologies that improve customer outcomes and allow greater penetration of DER, trials of micro grids, stand-alone power systems, and EV charging systems that will inform the broader scale adoption of these technologies in due course
- **Demand Management Innovation Program** – eight initiatives to improve our understanding of and ability to deploy demand management solutions, funded under the Demand Management Innovation Allowance (DMIA)
- **Planning and Technology Data Usage** – five initiatives enabling greater usage of network data by customers, 3rd parties and the network, to drive increased innovation and reduce prices long term
- **Accelerated Price Reform** – we will be conducting a detailed research program to enable the accelerated adoption of network prices/incentives that promote the sustainable use of the network and deliver value to customers by reflecting the costs of providing network services and the value of demand side participation.

See Attachment 3.01 for information on Ausgrid's innovation projects.

04

Annual revenue requirement

04

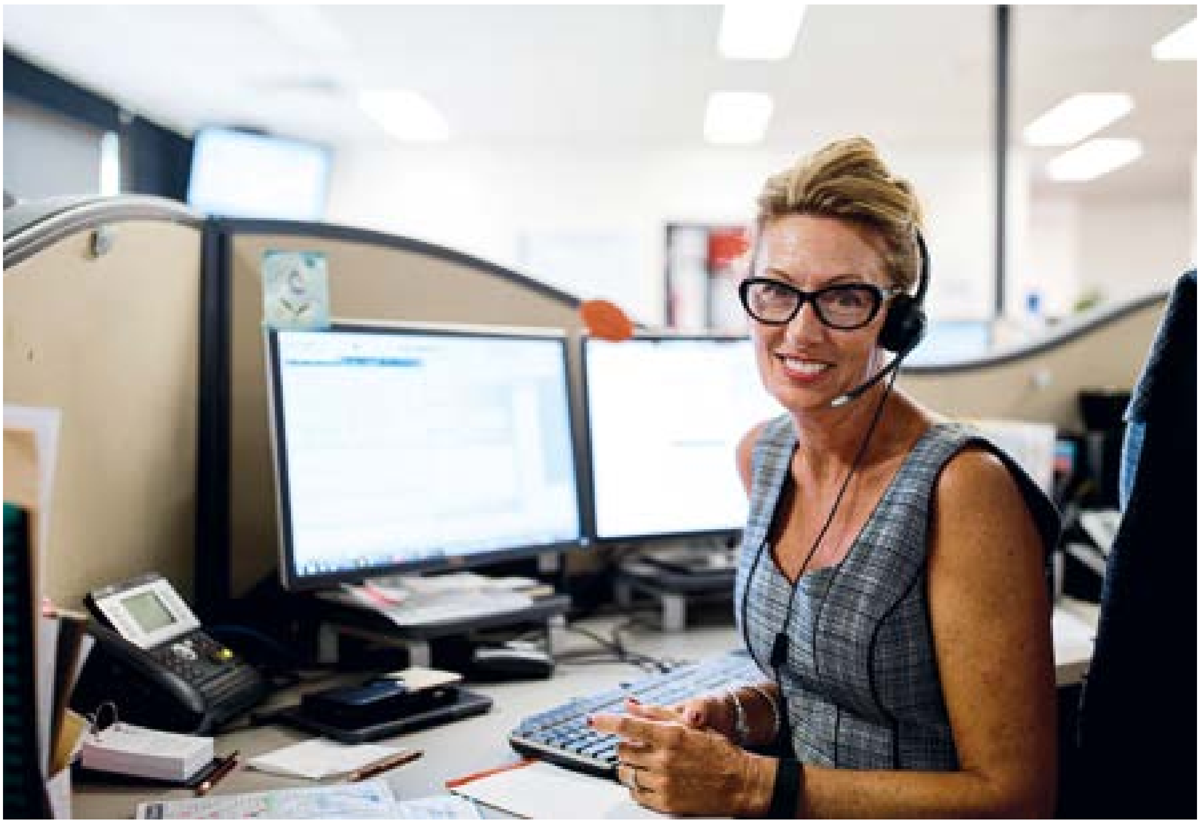
Annual revenue requirement

What did we achieve in 2014–19?

We responded to the significant challenge set by the AER by driving cost efficiencies.

Our opex is now $100 million lower today than five years ago, while capex is 57% below its peak in 2012. These cost reductions, together with lower debt funding costs, have enabled us to reduce our revenue, in real terms, by 33% since 2013–14.

Even though our revenue has declined in real terms, we have still managed to deliver improvements to our reliability performance.



What outcomes will we deliver in 2019–24?

We are committed to reducing network costs in real terms over the 2019–24 regulatory period. Our Proposal means that our component of prices will reduce by 5.7% in 2019/20 in real terms and then remain unchanged in real terms over the next four years to 2023/24. In other words, our component of prices will increase by less than inflation over the five-year period.

Our opex plans will continue to build on the efficiencies achieved so far. For capex, we are focused on delivering sustainable expenditure plans that will not compromise safety or reliability. This follows a period of driving significant reductions to stabilise historically high levels of expenditure. We are also preparing for the future by modernising our grid operating systems through staged investments to replace ageing and old technology systems.

We will minimise as far as practical revenue requested for the following components of our Proposal: the rate of return, tax and depreciation. Our approach is aligned with the AER's current practice, ensuring that the overall impact on prices is fair to our customers while delivering sufficient revenues to support continued investment in the network.

How are we responding to our customers' feedback?

Affordable

Our annual revenue requirement will lead to our component of prices being below current levels in real terms over 2019–24.

Reliable

Our annual revenue requirement will enable us to invest in maintaining network reliability.

Sustainable

The capex and opex strategies underpinning our annual revenue requirement are based on providing a sustainable network by leveraging new technologies and investing in demand management.

4.1 Overview of our building block proposal

Our revenue proposal for 2019–24 is calculated using the AER's post-tax revenue model (PTRM). See Attachments 4.02 and 4.05 for PTRM for distribution and transmission. This model calculates the revenue we require to recover the efficient costs of providing the services our customers have told us they want. The key components of the building block methodology are:

- **Return on capital** – We receive an allowance for return on capital to fund the efficient costs of debt and provide a reasonable return on equity. We calculate the return on capital based on the value of the RAB and the allowed rate of return for each regulatory year.
- **Return of capital** – We receive an allowance to recover the cost of our investments as they depreciate over time. This 'return of capital' or depreciation is calculated using inputs, such as the projected value of the opening asset base as at 1 July 2019 and the remaining lives of assets. Our approach to depreciation is consistent with the AER's standard methodology set out in the AER's PTRM. Depreciation is calculated on a straight line basis, but the revenue allowance we receive in the regulatory period for the return of capital is offset by the indexation of the asset base, which increases the value of the asset base to account for inflation.
- **Operating expenditure** – We receive an allowance to fund the costs of operating and maintaining the network, including corporate support. See Chapter 6 for details of our opex forecasts.
- **Tax** – We receive an allowance to meet our benchmark income tax liabilities, taking into account the benefit that shareholders receive from imputation credits. See section 7.5 for further details of our proposed tax allowance.
- **Other revenue increments or decrements** – We receive a revenue increase or decrease based on penalties or rewards from incentive schemes that applied in the 2014–19 regulatory period. This includes a CESS carryover for capex efficiency over the 2014–19 period and a Demand Management Innovation Allowance (DMIA) amount consistent with the AER's Demand Management Incentive Guideline. An adjustment is also made if we earn revenues above a defined threshold by making use of our regulated assets for non-regulated purposes. In our case, the threshold has not been met and the adjustment therefore does not apply.

Table 5.

Building block components of Ausgrid's proposed annual revenue requirements 2019/20–2023/24 ($ million, nominal)

	2019/20	2020/21	2021/22	2022/23	2023/24	TOTAL
Return on and of capital						
Return on capital	994.5	1,016.5	1,030.5	1,041.6	1,050.7	5,133.7
Return of capital	92.0	120.7	148.0	176.0	175.7	712.5
Operating and tax costs						
Opex[1]	482.9	503.1	526.7	549.8	571.8	2,634.3
Income tax	54.8	61.6	64.4	76.9	72.3	330.1
Other revenue increments or decrements						
CESS revenue	21.4	21.9	22.4	22.9	23.5	112.1
Proposed DMIA revenue	1.4	1.5	1.6	1.6	1.7	7.8
Revenue requirement	**1,647.0**	**1,725.3**	**1,793.6**	**1,868.8**	**1,895.7**	**8,930.4**

Note: Numbers may not sum due to rounding. Regulatory depreciation increases over the regulatory period, this is calculated based on the AER's default method for calculating regulatory depreciation.

Our proposed revenue is to fund the day-to-day network services we provide to our customers, which the AER classifies as Standard Control Services (SCS). These services are central to the supply of electricity that our customers rely on and are subject to a revenue cap set by the AER in five-year regulatory control periods.

1 Includes debt raising cost but excludes proposed DMIA for 2019–24 which is separately disclosed.

In developing our proposed revenue, we have:

- focused on keeping customers' network costs flat or declining in real terms over the next regulatory period,
- sought to limit the revenues we require to provide SCS by reducing our costs, and
- smoothed our revenues for 2019–24 to reduce price volatility. In smoothing our revenues, we have taken into account how forecast energy consumption will impact the prices customers pay over the period.

The proposed revenues do not include any adjustments arising from the remitted 2014–19 decisions on opex and the allowed return on debt. This is the subject of ongoing consultation with the AER and customer groups, and depending on the outcome of this process there may be positive or negative revenue increments applied to our proposed revenues for the 2019–24 regulatory period. Any adjustment amount will reflect the difference between actual revenues recovered over the 2014–19 period and the remade determination revenues for 2014–19.

The remainder of this chapter sets out further information on our RAB, return on capital and return of capital (depreciation).

4.1.1 Dual function assets

Ausgrid has both distribution and dual function (transmission) assets as defined in clause 6.24.2 of the Rules. The AER has decided that part J of Chapter 6A is to apply to the pricing of services provided by dual function assets[2] and therefore must be accounted for separately within our revenue requirements.

Our total RAB is split and separately accounted for between distribution and transmission assets. Similarly, our opex and capex are split between those costs incurred for our distribution and dual function (transmission) assets in accordance with our approved Cost Allocation Methodology (CAM).

2 AER, Framework and Approach Ausgrid, Endeavour Energy and Essential Energy Regulatory control period commencing 1 July 2019, July 2017, p.82.

4.2 Regulatory asset base

Our RAB is an important input to the building block calculation. The value of the RAB during the regulatory period reflects the remaining value of past capital investments and our forecast capex. Our opening and forecast RAB for the 2019–24 regulatory period are set out below.

4.2.1 Opening value of RAB

The estimated value of our RAB (for SCS) as at 1 July 2019 is $15,716 million ($ nominal) as shown in Table 6. This comprises $13,546 million attributable to distribution SCS and $2,170 million attributable to dual function assets. We have calculated these amounts based on clause 6.5.1 and schedule 6.2 of the Rules and the AER's roll forward models. See Attachments 4.01 and 4.04 for the roll forward models for distribution and transmission.

The RAB value of $15,716 million reflects the roll forward of actual capex for 2014/15 to 2016/17 and estimated capex for 2017/18 and 2018/19. It also reflects the use of forecast depreciation as the AER decided in its 2014–19 Determination for Ausgrid.[3]

In addition, the RAB values also reflect $255 million of assets changing classification from Ausgrid dual function assets to Ausgrid distribution assets. These assets no longer meet the definition of a dual function asset under clause 6.24.2 of the Rules and hence classify as distribution assets.

Table 6.

Ausgrid's opening RAB as at 1 July 2014 and 2019 ($ million, nominal)

	$M, NOMINAL
Opening RAB as at 1 July 2014	14,287.4
Add: Actual and estimated capex	2,755.6
Less: Regulatory depreciation	-1,327.3
Adjusted opening RAB as at 1 July 2019	15,715.7
Value of RAB for SCS as at 1 July 2019	
Distribution RAB	13,545.6
Transmission RAB	2,170.2

Note: Numbers may not sum due to rounding.

3 We note the AER's determination of April 2015 was set aside by the Australian Competition Tribunal and the AER is to remake this determination. We do not expect this constituent decision on depreciation method will be different in the remade decision.

4.2.2 Forecast RAB for the 2019–24 regulatory period

The table and chart below summarise the amounts, values and inputs used to derive our distribution RAB value for each year of the 2019–24 regulatory period.

Table 7.

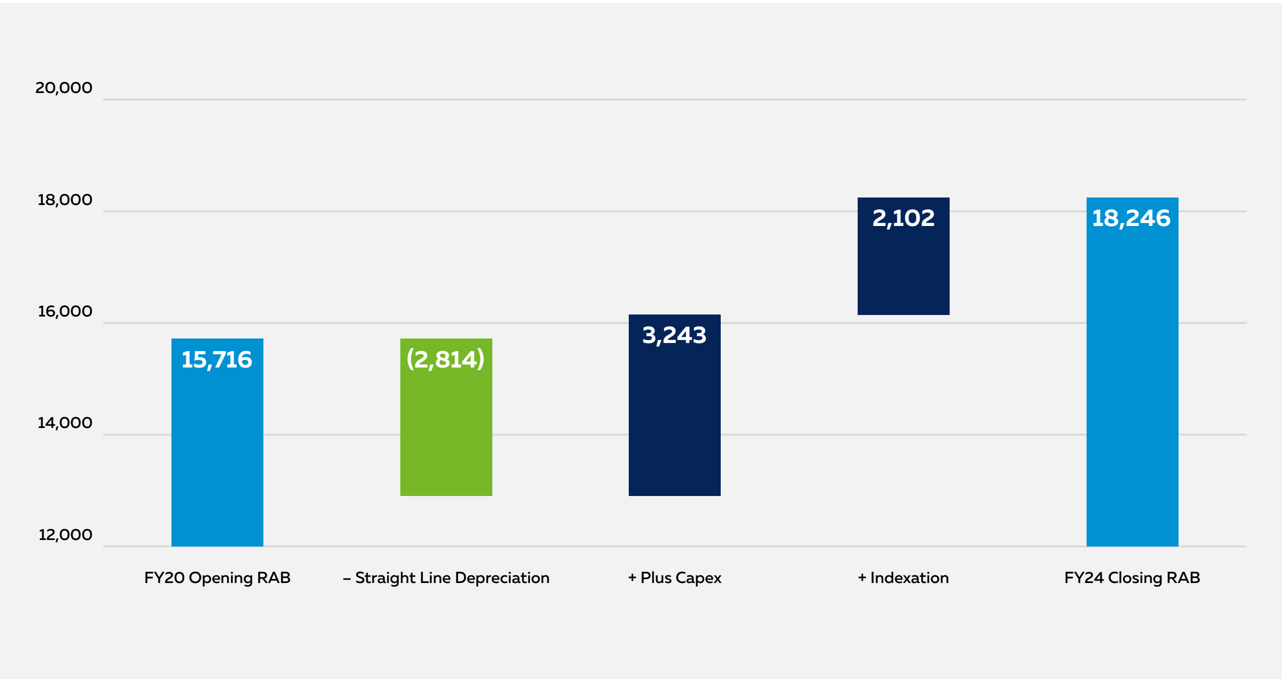
Ausgrid's forecast capex for SCS 2019/20–2023/24 ($ million, nominal, except where stated)

	2019/20	2020/21	2021/22	2022/23	2023/24	2019–24 PERIOD
Start of period RAB	15,715.7	16,341.6	16,856.1	17,341.5	17,810.8	15,715.7
Straight-line depreciation	-484.9	-529.3	-569.4	-609.5	-621.0	-2,814.1
Net capex	717.9	635.2	633.4	645.3	610.9	3,242.7
Inflation on opening RAB	392.9	408.5	421.4	433.5	445.3	2,101.6
RAB (end period)	16,341.6	16,856.1	17,341.5	17,810.8	18,246.0	18,246.0
RAB (end period) – real $ June 2019	15,943.0	16,043.9	16,103.3	16,135.7	16,126.8	16,126.8

Note: Numbers may not sum due to rounding.

Figure 12.

Ausgrid forecast RAB ($ million, nominal)



In accordance with clause S6.2.1(e)(4) of the Rules and the AER approved CAM, the RAB only includes actual and estimated capex properly allocated to the provision of SCS. The nominal capex in the table above excludes capital contributions and is net of asset disposals.

4.3 Rate of return

We propose a rate of return of 6.33% for 2019–20, using a transition to the 10 year trailing average approach to the cost of debt and also adopting the AER's 2013 Rate of Return Guideline parameters for the cost of equity.[4] Although the AER is currently reviewing the 2013 Rate of Return Guideline, Ausgrid is subject to the 2013 guideline for the 2019–24 regulatory period.

We propose a cost of debt for 2019–20 of 5.75%, a cost of equity of 7.20% and a gearing level of 60%. We have assumed the last annual observation to the cost of debt for Ausgrid (i.e. the 2018–19 annual estimate) remains the prevailing cost of debt over the 2019–24 period. Table 8 shows the weighted average cost of capital (WACC) we used to calculate the annual revenue requirement.

Table 8.

Ausgrid's proposed rate of return 2019/20 (%)

RATE OF RETURN PARAMETER	PROPOSED WACC (%)
Overall WACC	6.33%
Cost of equity	7.20%
Cost of debt	5.75%
Gearing	60%
Utilisation of imputation credits	40%

Chapter 7 of this Proposal and associated attachments provide further information in support of our proposed rate of return.

4 We refer to the return on equity and the return on debt in NER as the cost of equity and the cost of debt, respectively.

4.4 Regulatory depreciation (return of capital)

Regulatory depreciation is calculated as straight-line depreciation on the value of the RAB less the indexation of the RAB for inflation.[5]

The straight-line depreciation method charges cost evenly throughout the useful life of an asset. This depreciation method is therefore appropriate where economic benefits from an asset are expected to be realised evenly over its useful life.

The AER's default calculation of depreciation uses a method called the weighted average remaining life approach. This method calculates the remaining lives as at 1 July 2019 by weighting the remaining lives of assets existing as at 1 July 2014 and the remaining lives of assets that are rolled into the RAB during the 2014–19 period (i.e. capex for the current regulatory period) by the depreciated value of those assets in the RAB.

We initially planned to incorporate the year-by-year tracking approach approved by the AER for some other network businesses. This maintains the profile of depreciation more accurately but would result in faster depreciation and higher revenues over 2019–24. However, following consultation with our stakeholders we decided not to propose the year-by-year tracking approach at this time.

The table below sets out the standard lives of our assets, by asset class, for regulatory depreciation purposes. As required by clause S6.1.3(12), Ausgrid's nominated depreciation schedules are provided in Attachments 4.02 and 4.05 for distribution and transmission respectively.

Table 9.

Ausgrid's standard asset lives by asset class – distribution (dx)

ASSET CLASS	STANDARD ASSET LIFE (YEARS)
Sub-transmission lines and cables	46
Cable tunnel (dx)	70
Distribution lines and cables	58
Substations	47
Transformers	46
Low Voltage Lines and Cables	52
Customer Metering and Load Control	25
Customer Metering (digital)	0
Communications (digital) - dx	10
Total Communications	10
System IT (dx)	7
Ancillary substation equipment (dx)	15
Land and Easements	n/a
Emergency Spares (Major Plant, Excludes Inventory)	n/a
Furniture, fittings, plant and equipment	17
Land (non-system)	n/a
Other non system assets	29
IT systems	5
Motor vehicles	10
Buildings	36
Equity raising costs	47

5 NER clauses 6.4.3(b)(1) and S6.2.3(c)(4).

Table 10.

Ausgrid's standard asset lives by asset class – transmission (tx)

ASSET CLASS	STANDARD ASSET LIFE
Transmission & Zone land & easements	n/a
Transmission buildings 132/66kV	60
Zone buildings 132/66kV	60
Transmission transformers 132/66kV	50
Zone transformers 132/66kV	50
Transmission substation equip 132/66kV	45
Zone substation equip 132/66kV	45
Transmission & Zone emergency spares	n/a
Ancillary substation equipment (tx)	15
132kV tower lines	60
132kV concrete & steel pole lines	55
132kV wood pole lines	45
132kV feeders underground	45
Cable tunnel (tx)	70
Network control & com systems	37
Communications (digital) – tx	10
System IT (tx)	7
IT systems	5
Furniture, fittings, plant and equipment	17
Motor vehicles	10
Buildings	36
Land (non-system)	n/a
Other non system assets	29
Equity raising costs	46

To calculate RAB indexation, we used a forecast inflation rate of 2.5% as a placeholder for this Proposal. The inflation rate will be updated in line with latest forecasts at the time of the final determination.

The table below sets out our calculation of regulatory depreciation.

Table 11.

Ausgrid's regulatory depreciation (return of capital)

	2019/20	2020/21	2021/22	2022/23	2023/24	TOTAL
Straight-line depreciation ($ million, nominal)	484.9	529.3	569.4	609.5	621.0	2,814.1
Inflation indexation of the RAB ($ million, nominal)	392.9	408.5	421.4	433.5	445.3	2,101.6
Regulatory depreciation ($ million, nominal)	**92.0**	**120.7**	**148.0**	**176.0**	**175.7**	**712.5**
Forecast inflation on opening RAB (% per annum)	2.5	2.5	2.5	2.5	2.5	2.5

Note: Numbers may not sum due to rounding.

4.5 Other proposed revenue adjustments

The regulatory framework provides incentive mechanisms to encourage network companies to deliver better outcomes for customers in terms of lower costs, improved reliability and innovations in demand side initiatives. To reflect the application of these incentive mechanisms for the 2014–19 period, revenue adjustments are required in the forthcoming regulatory period. The remainder of this section discusses each of these adjustments in turn.

4.5.1 Capital Expenditure Sharing Scheme

The Capital Expenditure Sharing Scheme (CESS) rewards or penalises a network service provider depending on whether actual capex is lower or higher than the approved forecast amount for the regulatory year.

We have applied the CESS scheme outlined by the AER in its determination for the 2014–19 regulatory period.

In its distribution determination for the transitional year (i.e. 2014/15), and consistent with the transitional rules, the AER specified that no CESS would apply in 2014/15. In accordance with the AER's published guidelines, Ausgrid proposes a $104 million (in real 2018/19 terms) CESS benefit to carry into the 2019–24 regulatory period. Our approach to calculating the CESS reward is consistent with the approach set out by regulatory experts Houston Kemp. As per this approach, we have applied a 1/2 nominal WACC adjustment to underspend amounts. However, the financing benefit amount is calculated using the real WACC.

Ausgrid also proposes to apply the AER forecast rate of inflation used in the April 2015 final determination to the nominal WACC figures to calculate the real WACC which applies to the financing benefit amounts. This is because the revenue allowances for 2014–19 were set using the AER forecast rate of inflation (i.e. forecast indexation of the asset base was based on forecast inflation), this assumed indexation was not adjusted for actual inflation rates at the end of the regulatory period.

Our calculation of the CESS reward is based on the AER's original 2014–19 determination capex allowance. The AER is currently remaking its 2014–19 determination debt and opex decisions, and it could remake other components of the 2014–19 determination that are necessary as a result of remaking its debt and opex decisions. In the event that the capex allowance for 2014–19 is adjusted as part of a remade 2014–19 determination, the CESS reward that we have calculated would need to be revisited.

The AER typically also applies an Efficiency Benefit Sharing Scheme (EBSS), which gives network companies incentives to drive opex efficiencies. However, in its 2015 Determination for Ausgrid, the AER did not apply the EBSS. Therefore, we have not adjusted our revenue requirement for the 2019–24 regulatory period to account for the EBSS.

4.5.2 Proposed demand management innovation allowance

The AER recently finalised a new demand management incentive scheme and innovation allowance mechanism. These apply to Ausgrid for the 2019–24 regulatory period, with the innovation allowance to be an ex-ante amount provided as part of the revenue forecast for 2019–24 – see section 9.4 for more detail. Accordingly, Ausgrid proposes an amount of $7.8 million (nominal) as the innovation allowance. This is calculated based on the formula set out in the AER's DMIA guideline as shown in the table below.

Allowance cap = $200,000 (2017) + 0.075% x ARR [6].

Where ARR = Annual Revenue Requirement

Table 12.

Ausgrid's Demand Management Innovation Allowance calculation 2019/20–2023/24 ($ million, real FY19)

	2019/20	2020/21	2021/22	2022/23	2023/24	TOTAL
Real ARR	1,605.4	1,640.7	1,664.1	1,691.6	1,674.0	8,275.9
MAR x 0.075%	1.2	1.2	1.2	1.3	1.3	6.2
Base amount	0.2	0.2	0.2	0.2	0.2	1.0
Total	1.4	1.4	1.5	1.5	1.5	7.2

Note: Numbers may not sum due to rounding.

6 AER, Demand management innovation allowance mechanism, December 2017, p.8.

4.5.3 Proposed shared asset revenue decrement

Shared assets refers to those assets initially wholly captured in the value of the RAB but now used to provide both regulated and unregulated services. The AER may reduce Ausgrid's annual revenue requirement for a regulatory year to share the benefit of using the asset for unregulated purposes with customers. In making this decision, the AER must have regard to:

- **Shared asset principles** – including that a shared asset cost reduction should be applied where the use of the assets, other than for SCS, is material
- **Shared asset guideline** – including reducing a DNSP's annual revenue requirement to reflect the use of shared assets, including defining and calculating materiality. The use of shared assets is material when a DNSP's annual unregulated revenue from shared assets is expected to be greater than 1% of its total smoothed revenue requirement for a particular regulatory year.[7] If this materiality threshold is not met, no shared asset cost reduction applies.[8]

Applying the AER's shared asset guideline, we calculate the materiality of our use of shared assets to earn unregulated revenue as shown in Table 13. The decrease in unregulated revenue between 2019/20 and 2020/21 is due to the end of a property lease in central Sydney which was providing rental income for a period of time.

7 AER, Better Regulation, Shared asset guideline, November 2013, p.8.

8 AER, Better Regulation, Shared asset guideline, November 2013, p.6.

Table 13.

Ausgrid's materiality of shared assets use 2019/20–2023/24 ($ million, nominal)

	2019/20	2020/21	2021/22	2022/23	2023/24	TOTAL
Unregulated revenue from shared assets use	16.1	12.5	12.4	12.6	12.8	66.4
Smoothed revenue (prior to shared assets reduction)	1,696.7	1,739.1	1,782.6	1,827.2	1,872.8	8,918.4
Materiality (%)	0.95%	0.72%	0.70%	0.69%	0.68%	0.74%

Note: Numbers may not sum due to rounding.

The materiality threshold is not met in any year. Consequently, we have not applied a shared asset cost reduction to the proposed annual revenue requirement for the 2019–24 regulatory period.

4.6 Proposed revenue requirements

4.6.1 Proposed building block revenue

The table below shows Ausgrid's annual revenue requirement for both distribution and transmission assets based on the building block calculation.

Table 14.

Ausgrid's proposed 'unsmoothed' annual revenue requirement 2019/20–2023/24 ($ million, nominal)

	2019/20	2020/21	2021/22	2022/23	2023/24	TOTAL
Distribution	1,473.9	1,543.3	1,604.0	1,670.2	1,690.5	7,981.9
Transmission	173.1	182.0	189.6	198.6	205.2	948.5
Total	**1,647.0**	**1,725.3**	**1,793.6**	**1,868.8**	**1,895.7**	**8,930.4**

Note: Numbers may not sum due to rounding.

This revenue forms the basis of the network charges which customers pay to cover the efficient expenditure we need to invest in, to operate, and maintain the network; as well as comply with our regulatory obligations. The revenue also provides a reasonable return on our investment in the network.

4.6.2 Proposed smoothed revenue and X-factors

Annual revenue requirements might fluctuate from year to year over the course of a regulatory period causing price volatility. This volatility can be smoothed by applying X-factors so prices do not fluctuate with the timing of expenditure programs during a regulatory period. The X-factors are calculated so Ausgrid is no better or worse off in net present value terms as a result of the revenue smoothing.

Revenue has been smoothed using only a P0 X-factor. This results in one adjustment to the first year of revenue with only Consumer Price Index (CPI) increases thereafter, keeping revenue constant in real terms. In deciding on the proposed smoothed revenues and the resultant X-factors, we have considered:

- forecast changes in energy consumption over time – energy forecasts remain fairly stable over the regulatory period meaning CPI increases to revenue will result in similar increases to prices,
- our customers' preference for stable prices – revenues used to set prices reduce by 5.7% in 2019–20 and remain stable in real terms over the remaining years, and
- the requirement in the Rules to minimise differences between the annual revenue requirement and smoothed revenue of the last year of the 2019–24 regulatory period, i.e. 2023/24. The difference is 1.2% which falls within the AER's target level of 5%.

The X-factor represents the real percentage reduction in the smoothed revenue for each year of the 2019–24 regulatory period. Revenue for 2018/19, which is used as the reference point to set the X-factor for the first year of the regulatory period 2019/20, is the amount proposed to the AER for the 2018/19 undertaking on 4 April 2018. This will be updated with the amount determined by the AER when it becomes available.

As shown in the table below, we have two sets of X-factors to reflect the separate control mechanisms for services provided by our distribution and dual function assets.[9]

Table 15.

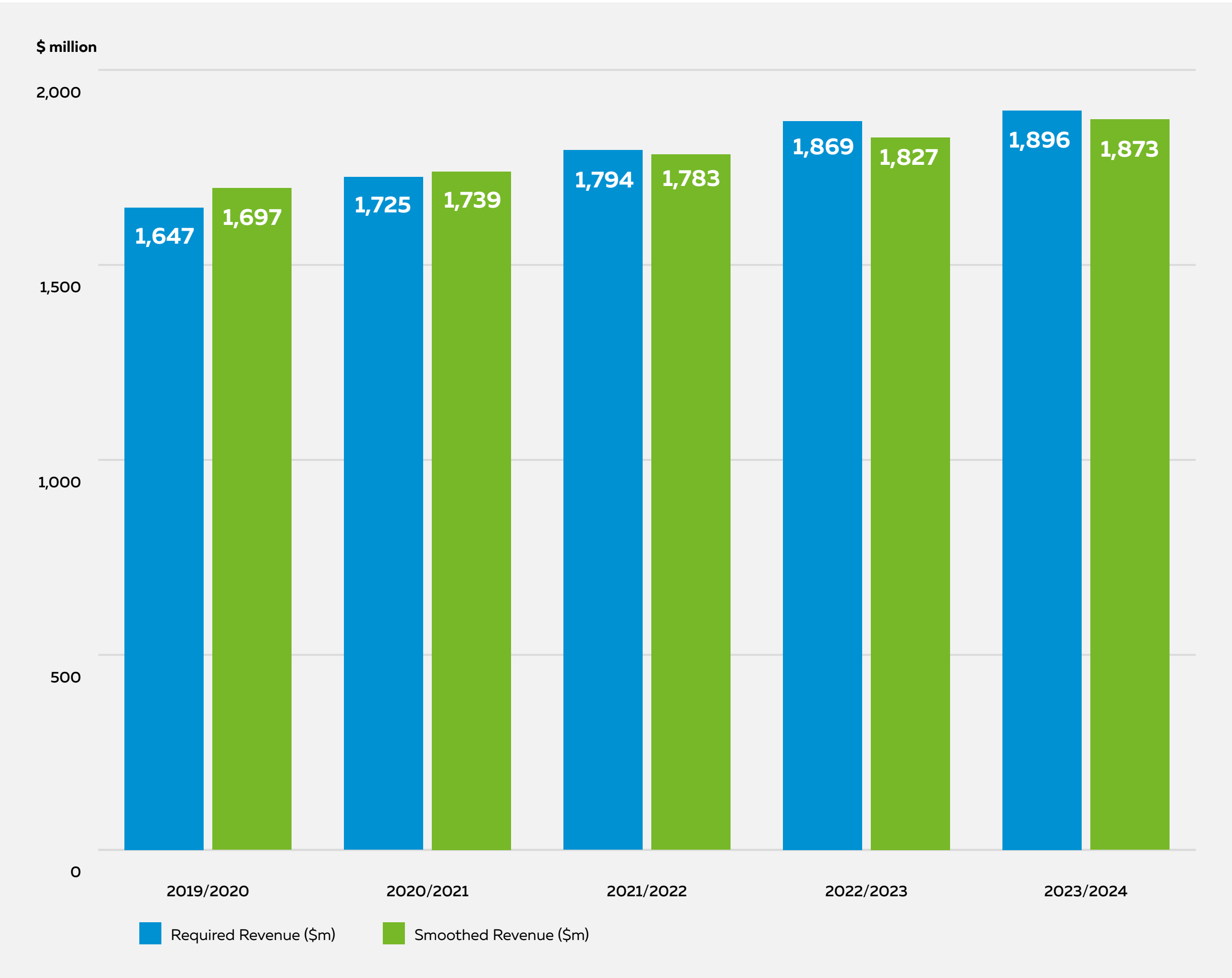
Ausgrid's proposed X-factors for distribution and transmission SCS 2019/20–2023/24 (%)

X-FACTORS (%)[10]	2019/20	2020/21	2021/22	2022/23	2023/24
Distribution	0.9%	0.0%	0.0%	0.0%	0.0%
Transmission	33.0%	0.0%	0.0%	0.0%	0.0%
Weighted average	5.7%	0.0%	0.0%	0.0%	0.0%

The smoothed revenue profile is calculated using the AER's PTRM by making proposed smoothed revenues equal to required (i.e. unsmoothed) revenues in net present value terms. The figure below shows our proposed total smoothed and unsmoothed revenues.

Figure 13.

Ausgrid's forecast required revenue versus smoothed revenue 2019/20–2023/24 ($ million, nominal)



Source: Post Tax Revenue Model for Distribution and Transmission (Attachments 4.02 and 4.05).

9 This is consistent with the AER's final Framework and Approach paper.
10 A positive X factor denotes a price reduction in real terms.

The table below shows our proposed smoothed and unsmoothed revenues for distribution and transmission.

Table 16.

Ausgrid's proposed 'smoothed' annual revenue requirement 2019/20–2023/24 ($ million, nominal)

	2019/20	2020/21	2021/22	2022/23	2023/24	TOTAL
Distribution	1,516.6	1,554.5	1,593.4	1,633.2	1,674.1	7,971.9
Transmission	180.1	184.6	189.2	193.9	198.8	946.5
Total	**1,696.7**	**1,739.1**	**1,782.6**	**1,827.2**	**1,872.8**	**8,918.4**

Note: Numbers may not sum due to rounding.

As discussed further in Chapter 7, we propose an overall allowed rate of return (nominal, WACC), within which, the cost of debt will be annually updated for changes in prevailing debt yields.

We propose to account for the revenue adjustment needed to reflect the updated annual cost of debt through the adjustment of X-factors in the control mechanism formula. This is consistent with the AER's F&A paper[11].

11 AER, Framework and Approach: Ausgrid, Endeavour Energy and Essential Energy, Regulatory control period commencing 1 July 2019 (July 2017), p.54.

05

Capital expenditure

05

Capital expenditure

What did we achieve in 2014–19?

In the 2014–19 period, we improved affordability by **reducing our capex by 57%** in real terms compared to our investment peak in 2012.

We achieved these reductions while also driving reliability improvements. By 2017, we reduced the number of outages per customer by 46% and duration of outages per customer by 27% compared to 2009 levels.

In response to customers' requests, we streamlined connection processes for solar and battery installations, offering customers more choice in how they manage and control their energy needs.

What outcomes will we deliver in 2019–24?

We plan to maintain **reliability performance** and continue to **drive safety improvements**. We will do this while also maintaining **affordability**.

We will invest in a **digital strategy** that gives customers all the information they want when they need it.

We will invest in the **future of the network** to ensure we are ready to offer customers energy solutions such as peer-to-peer trading and support infrastructure for electric vehicles.

We will improve tree trimming through an innovative shared funding model with councils.

How are we responding to our customers' feedback?

Affordable

Forecast total capex of $3.1 billion or $617 million per annum is 1.3% lower (in real terms) compared to the current period. Our forecast expenditure will deliver a lower RAB per customer and help to deliver lower prices for customers. Our Proposal means that our component of prices will reduce by 5.7% in 2019/20 in real terms and then remain unchanged in real terms over the next four years to 2023/24. This is the result of our drive to reduce costs by looking at ways to invest more efficiently and improve affordability for customers.

Reliable

We will continue to maintain network reliability and safety. Our replacement programs carefully target expenditure on assets that ensure the safety of our staff and customers and mitigate reliability risks. We will keep capex to a minimum by only replacing ageing assets where there is no alternative that is more efficient.

Sustainable

Our program will replace only what needs to be replaced, augment just enough and invest on a no regrets basis in light of emerging technologies. Rather than simply building more infrastructure, we are looking first at where new technology, innovation and partnering with other companies and our customers will solve the problem at a lower cost. This includes demand management solutions. We will partner with customers to reduce the need to replace ageing network infrastructure by leveraging batteries, smart meters, smart appliances and innovative rebate offers which support a lower carbon economy.

We are proposing to invest $617 million per year on capex over the next period in real terms. This is a 1.3% decrease from actual capex in the current period. By 2024, we will have reduced capex by 69% since the investment peak in 2012. We have worked hard to balance our customers' need for affordable and reliable services while making sure that the network is safe and secure. We will sustainably renew ageing assets on our network and are investing in new technology to facilitate distributed energy resources and renewables in line with customer feedback and requests.

5.1 Overview

5.1.1 Our proposed capex program

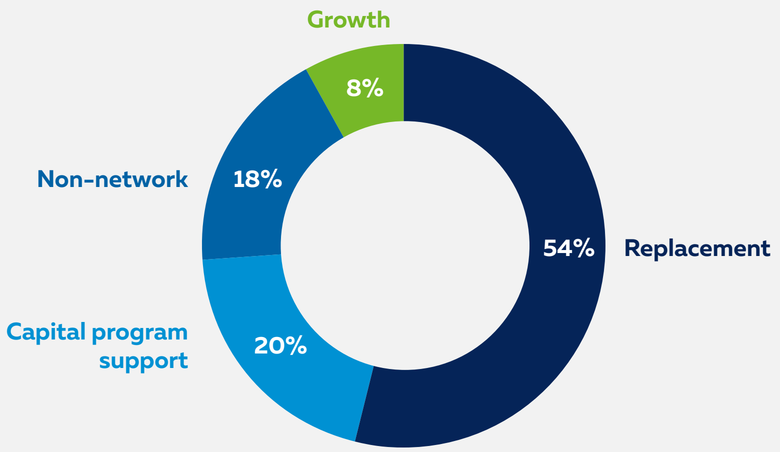
Customers have told us that they want their network service to be affordable, reliable and sustainable. We have listened and adopted these objectives in preparing our capex program for the next regulatory period.

Our proposed capex program supports our objectives of improving affordability for our customers and ensuring that RAB per customer does not increase in real terms. Our investments in 2019–24 will maintain reliability while improving customer service quality through our digital strategy. We are also looking to the long term by maximising our investments in programs that will facilitate our transition to a lower carbon future. We are doing this on a sustainable basis to prevent the swings in investment cycles of previous periods.

The capex program also includes investment in network assets and non-network assets such as ICT, operational technology and innovation projects, property, fleet, plant and capital program support costs. A new component of our ICT program is protecting the network and ICT systems against the new and increasing threat of cyber-attacks. The key drivers of our capex program are shown in Figure 14 below.

Figure 14.

Breakdown of the forecast capex program by driver for 2019–24



Source: Ausgrid.

Our capex program in the 2019–24 regulatory period includes:

- Replacing and renewing network assets in major projects, planned, conditional and reactive programs. Our replacement program is driven largely by assets that are in poor condition and assets that pose a safety risk. We expect to invest $1.7 billion on replacing network assets which represents around 1% per annum of the modern-day replacement value of our 'system' assets.
- Growth-related programs involving connecting new customers and augmenting the network to meet our forecasts of peak demand on the network. We forecast to invest a total of $241 million in growth related expenditure. This represents 8% of the total capital program.
- Programs for non-network assets include investing in ICT, operational technology and innovation projects, property, fleet and plant. These programs are expected to total $548 million with ICT and property making up 18% of the total capex program.
- Capital program support involving the planning, management and supervision of capital projects and programs, scheduling jobs, administrative support and safety. We expect to invest a total of $621 million in capital program support. This represents 20% of the total capex program.

A summary of forecast capex by category for each year of the 2019–24 period is shown in Table 17 below.

Table 17.

Forecast capex by asset driver for 2019–24 period ($ million, real FY19)

	FY20	FY21	FY22	FY23	FY24	TOTAL
Replacement	398.8	345.3	290.0	306.1	332.9	1,673.1
Growth	37.5	64.2	57.2	39.8	42.6	241.3
ICT and innovation	50.2	45.4	40.8	40.0	39.2	215.5
Property	38.3	43.6	46.2	44.1	36.2	208.4
Fleet	18.3	15.2	19.8	23.0	17.7	94.0
Plant	5.4	6.4	6.4	6.4	5.4	30.0
Capital program support	139.1	126.9	119.6	117.0	118.7	621.3
Total forecast capex	**687.7**	**647.1**	**580.0**	**576.3**	**592.6**	**3,083.7**

All the numbers discussed in this chapter are in real 2019 dollar terms unless specified otherwise.

5.1.2 What it means for our customers

Our capital program reflects the feedback we have received from our customers regarding affordable, reliable and sustainable network services. We must continue to meet our safety obligations, while also preparing for the transformational challenges and opportunities described in Chapter 3. The key outcomes from our capex program are summarised below:

- **Affordable** – our capex program will contribute to affordable network services by targeting no growth in our RAB per customer in real terms. We will put downward pressure on expenditure by driving efficiencies in the delivery of our capex program. We have included significantly improved unit rates for delivery when compared to the current period. We are also striving to further improve the efficiency of the way we work and have factored in additional labour productivity improvements of 10% into our forecasts.
- **Reliable** – much of our focus is on ensuring that we meet our customers' preference that reliability should be maintained. Our capex program aims to deliver this outcome at the lowest sustainable cost.
- **Sustainable** – we will avoid major fluctuations in the capex program in the future and prevent any more 'price shocks' for customers. We will achieve these outcomes by smoothing our expenditure profile over successive regulatory periods without compromising network performance or safety.
- **Safe** – maintaining safety of the community, customers and our employees is our priority. We have programs targeting replacement of assets that pose known safety risks.
- **Secure** – we are leading the way in developing programs to mitigate the emerging risk of cyber-attack. We have started a program in the current period and as a critical infrastructure provider, we expect it to be an ongoing part of our capital requirements.
- **Needs based investment** – we will optimise our investment decisions to deliver the best outcome for our customers. It includes utilising spare network capacity by reconfiguring load across our network, and ensuring that we retire assets where they are no longer required and only replace assets that have reached their end of life based on their condition and potential consequences if they fail.
- **Future network** – we are also investing to keep pace with the changing energy landscape, which we described in Chapter 3. To adapt to this future world, we propose to invest in new technology where the replaced asset has reached end of life. This includes investing $41.3 million on the ADMS to replace our current system, which is at the end of its life. The advanced system will help to provide visibility of DER in our network, and the functionality to integrate with management systems to optimise and control DER in the future to enable peer-to-peer trading.
- **Digital strategy** – we will also be investing in ICT programs that automate our work processes, together with a digitalisation strategy that improves our customer's experiences with our services. The shift to digital technologies will enable better decision making for capital investments and introduce safer ways of working. This investment provides better intelligence from data to meet customer expectations of faster response times and real-time information.

The capex program has been developed in close consideration of the network maintenance requirements and supports efficient operating costs (opex) into the future (our opex program is discussed in Chapter 6).

Our assessment is that the proposed capex program strikes the right balance between keeping downward pressure on our costs, maintaining safety and reliability and making investments to prepare for the transformational changes that are already underway. It reflects the prudent and efficient expenditure requirements, consistent with our customers' preferences and the requirements of the Rules.

5.2 Network performance

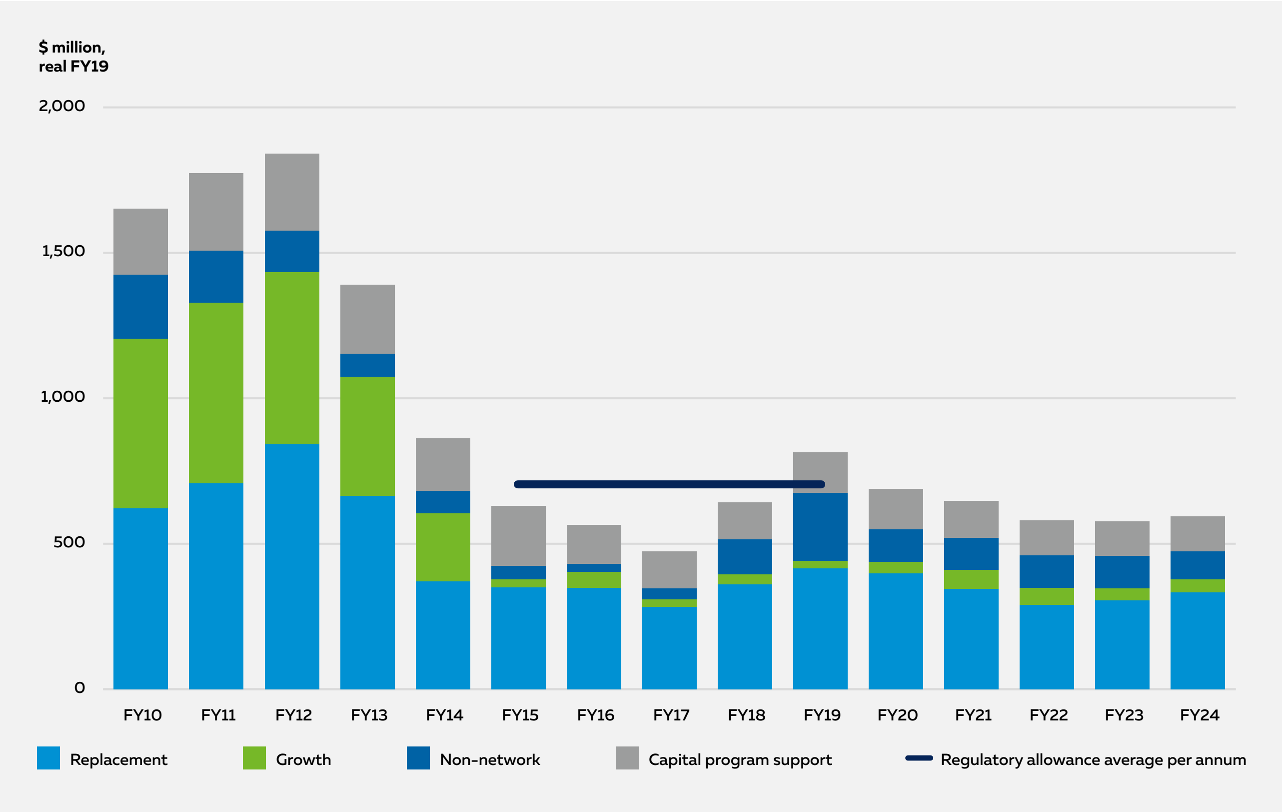
5.2.1 Trends in capex

Our proposed capex program of $617 million per annum is 1.3% lower than the amount we expect to invest in the current 2014–19 regulatory period. From 2012 to 2019 our capex program will have fallen by 57%. By the end of the 2019–24 period, we expect that capex will have fallen by 69% below the peak capex in 2012.

We expect to achieve capex savings in the current period compared to the allowance set by the AER, as shown in Figure 15 below.

Figure 15.

Forecast capex by driver for 2019–24 compared to previous years ($ million, real FY19)



Source: Ausgrid analysis.

Our capex in the current regulatory period is estimated to be around $400 million (or 11%) less than the regulatory allowance. We achieved these reductions through a number of cost saving initiatives, including:

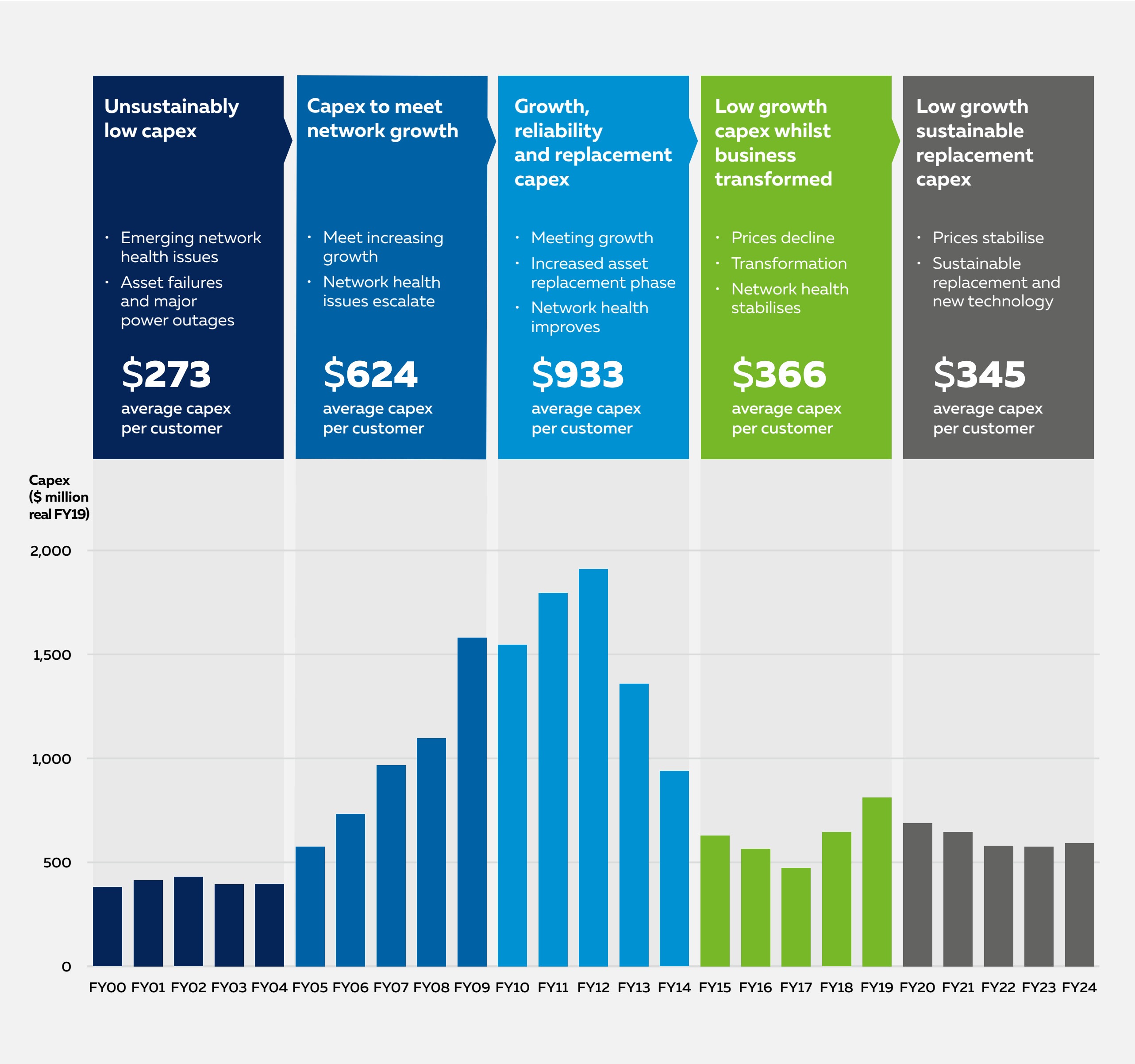
- introducing a more rigorous cost-benefit analysis that deferred major projects where it was efficient to do so,
- avoiding 'like-for-like' replacement of major infrastructure by utilising spare capacity on neighbouring parts of the network,
- increasing our focus on demand management solutions to defer replacement capex,
- outsourcing more of the capital program to external providers where there was a cost advantage of doing so,
- improving the productivity of our internal labour force through better scheduling and more efficient labour practices such as integrated crew services, and
- improving our governance processes to better target our investment and ensure projects are scoped and costed efficiently at each stage of the investment cycle through planning, design and delivery.

These changes will have an enduring impact on improving the efficiency of our capital plans in the 2019–24 period and beyond.

The transformations in our operations reflect our increased focus on customers' affordability. To understand the transformations we have made, it is useful to put our forecast expenditure in a broader historical context, which is provided in Figure 16 below.

Figure 16.

Capex from 2000 to 2024 ($ million, real FY19)



The broader historical perspective illustrates that our capex proposal reflects our focus on sustainable expenditure, following the very substantial reductions achieved in the current period.

Our focus is on delivering efficient and sustainable capex to provide safe and reliable network services consistent with the key preferences expressed by our customers. We will closely monitor the effects of the proposed lower capex to make sure that reliability, safety and security of our service to customers is not adversely affected and meets their expectations.

5.2.2 Network reliability

Reliability to our customers is measured by System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). Many of our major projects and programs are targeted at ensuring that we continue to deliver a reliable and secure service to customers.

Our historic capex program has delivered significant improvements in our reliability performance, measured by SAIDI and SAIFI, as shown in Figure 17 below. Despite a modest deterioration in SAIDI in recent years, our performance remains substantially better than 10 years ago.

Figure 17.

Trends in reliability (SAIDI and SAIFI) from FY07 to FY17

Source: Ausgrid.

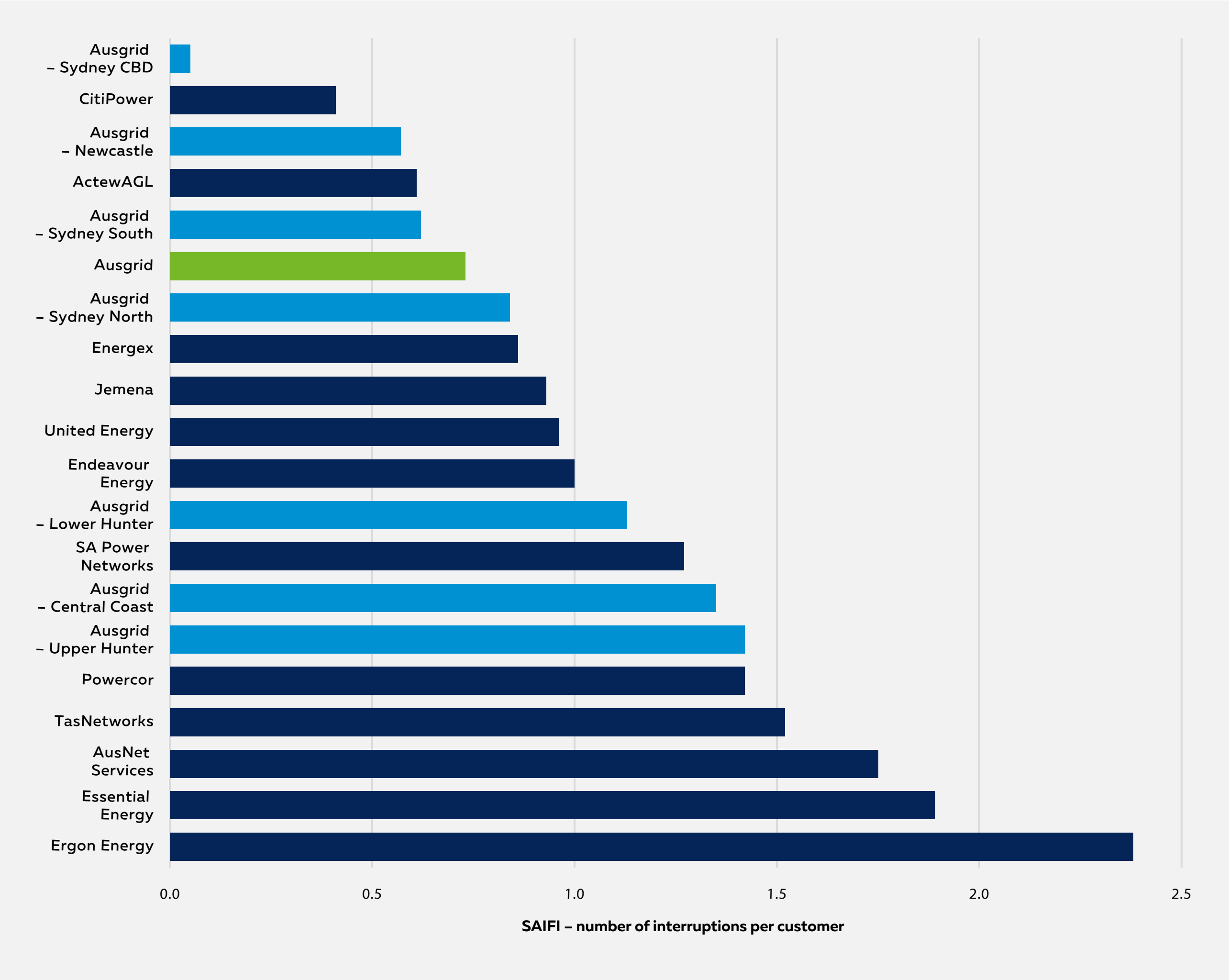
The modest decline in reliability performance in recent years reinforces our Proposal that capex in the next period should remain similar to current levels to ensure we maintain reliability and safety levels as well as avoid the need for capex increases in the future. We will closely watch any further changes in reliability and safety and address them as needed.

Our five-year average SAIFI result of 0.7 outages per customer places us in the top three for reliability performance in the National Electricity Market (NEM). Our results vary by the different regions in our area with the best performance in the CBD and Newcastle. Maintaining high levels of reliability is particularly important in the Sydney CBD as it is the powerhouse of the Australian economy – contributing 7% to GDP.

Our reliability results are shown in Figure 18 below.

Figure 18.

Comparison of average SAIFI by DNSP



Source: Ausgrid analysis using our own and AER data.

Our plans for the next period are to maintain reliability at current levels by avoiding significant interruptions to our customers. This objective is consistent with our customers' preferences and the design of the AER's STPIS.

5.2.3 Trends in capex and RAB per customer

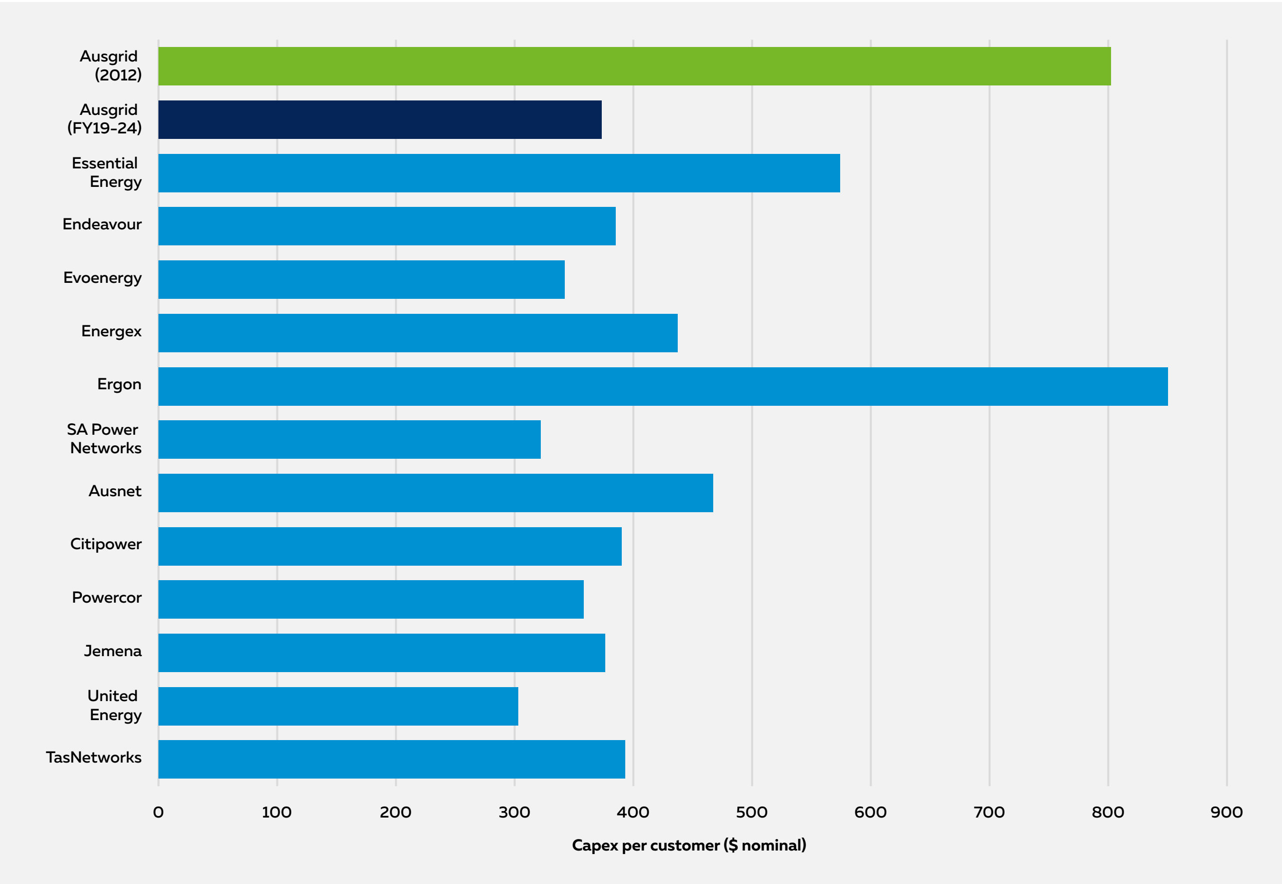
As a result of our transformation, we have improved efficiency. Figure 19 shows Ausgrid's historic five-year average and 2019–24 forecast of capex per customer compared to other DNSPs in the NEM. Our forecast capex for 2019–24 is substantially lower than our five year average capex for the previous regulatory period.

Figure 19 below shows the five-year average capex per final year customer (i.e. customers is not averaged) for Ausgrid compared to other DNSPs. The 2012 Ausgrid entry is also a five-year average (2008–2012) and uses the customer count in 2012.

The figure shows that our capex forecasts for the 2019–24 period would result in average capex just under $400 per customer. This is a substantial reduction from our peak expenditure when we had the second highest capex per customer in the NEM at around $800 per customer. This analysis has been prepared using nominal dollars.

Figure 19.

Ausgrid's capex per customer compared to other DNSPs FY12-17 ($, nominal)



Source: Ausgrid analysis using AER data.

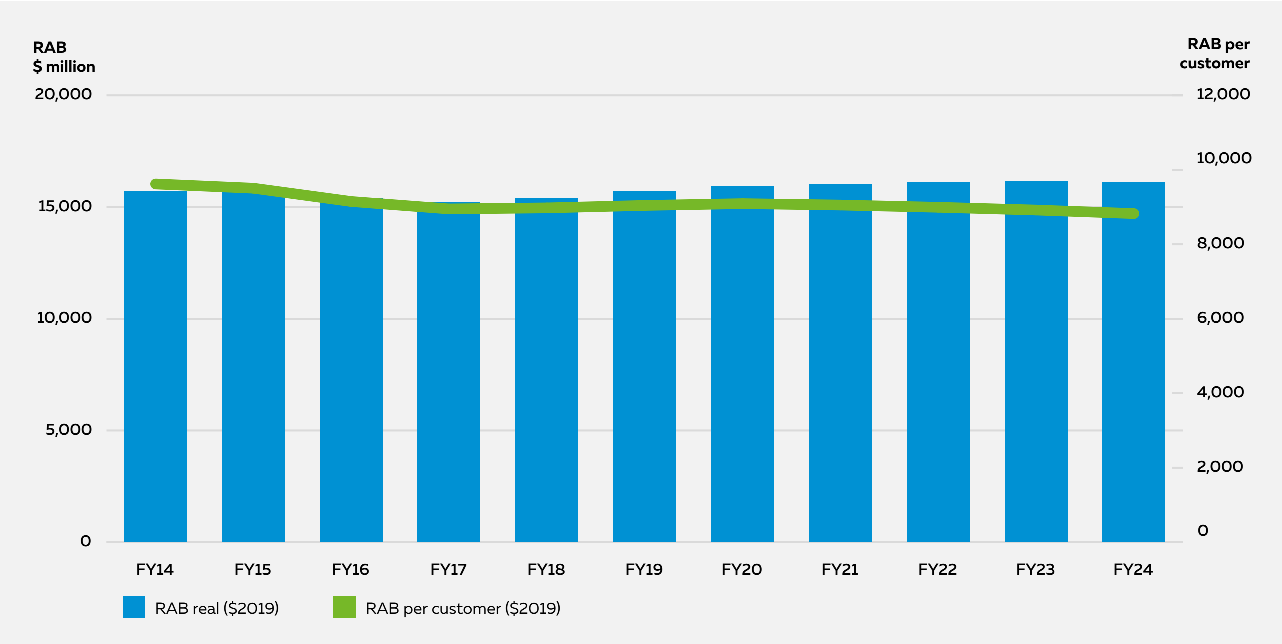
As already noted, our proposed capex for 2019–24 embeds the efficiencies from our transformation program. We have sought to balance the need to renew the network and connect new customers, with the objective of affordability for customers.

We note there are a number of limitations to capex benchmarking results. Nevertheless, the above analysis provides a level of assurance that our proposed capex is at a reasonable level when compared to other DNSPs.

Our program will reduce RAB per customer by 2%, contributing to future price stability. The trend in RAB and RAB per customer is shown in Figure 20 below.

Figure 20.

Trends in RAB per customer ($ million, real FY19/$, real FY19)



Source: Ausgrid.

This downward trend is the result of our concerted effort to make sure that our capex improves affordability in the long term by meeting customers' changing needs with fewer assets per customer.

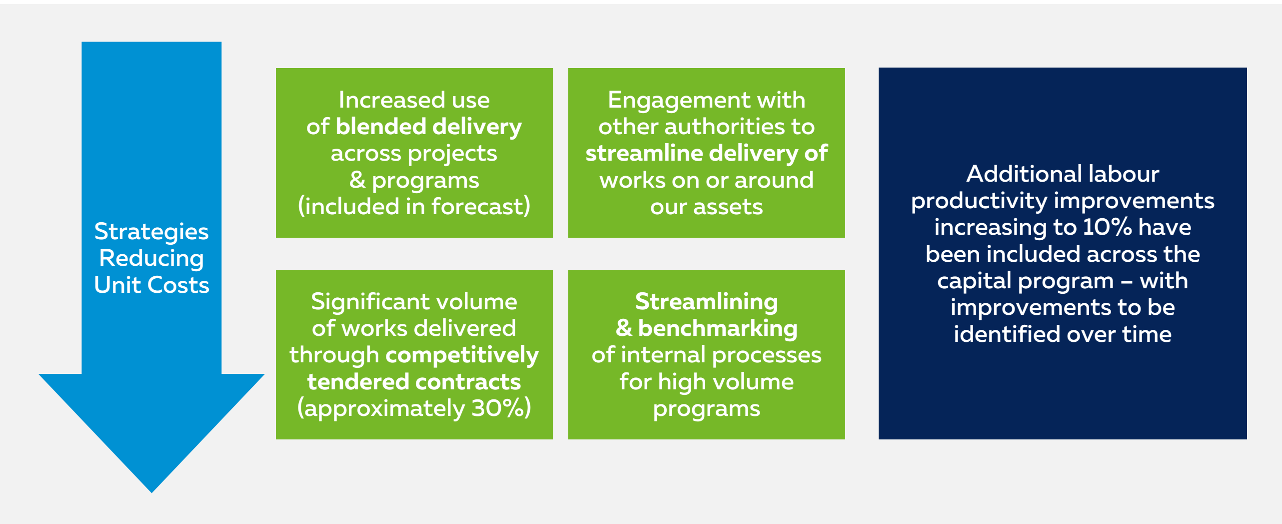
5.2.4 Trends in efficiency

The transformation program which started in the 2014–19 period has seen efficiency improvements in the delivery of our capex program. The transformation program includes more use of external providers procured through competitive tendering, and better engagement and streamlining of processes with telecommunication authorities.

Our strategies to improve unit costs are presented in Figure 21 below.

Figure 21.

Strategies to improve unit costs



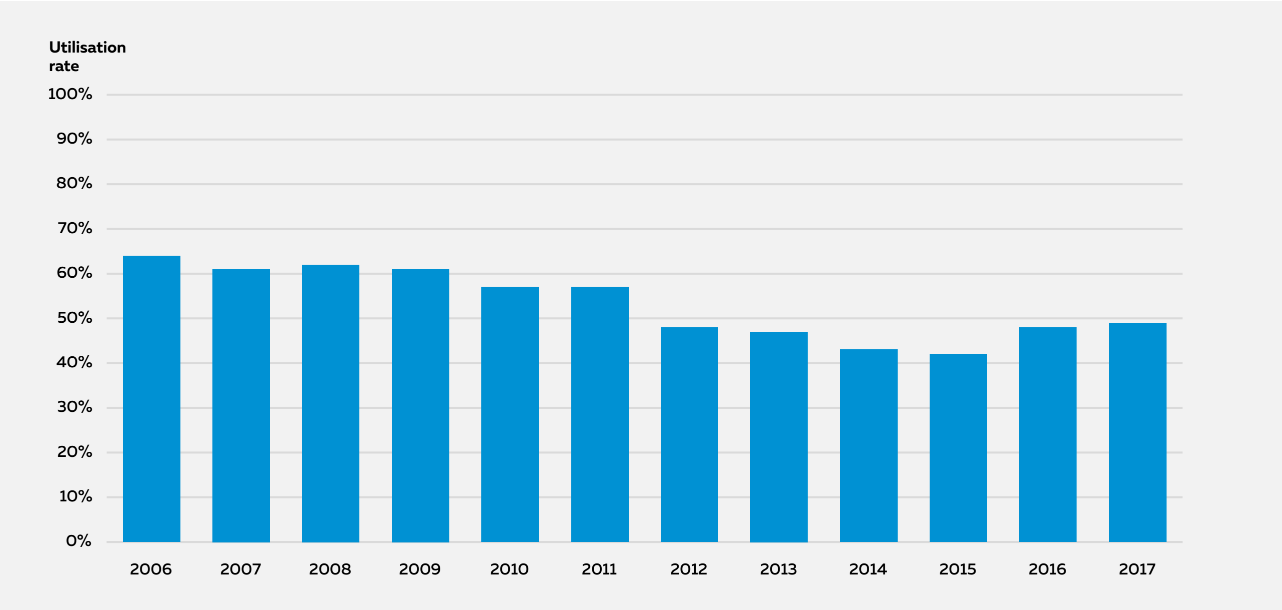
We have built on these improvements and factored in labour productivity improvements into our forecasts for the capex program. By FY24 we expect to achieve a 10% improvement in labour productivity. Further information about the transformation in our unit costs is presented in section 5.4.5.

5.2.5 Trends in capacity utilisation

Ausgrid's capacity utilisation (measured at zone substation transformers) has been improving in the last two years. The trend in Ausgrid capacity utilisation from 2006 to 2017 is shown in Figure 22. It shows that capacity utilisation dipped from 2011 to 2015 (following the peak investment) but improved in 2016 and 2017.

Figure 22.

Trend in Ausgrid capacity utilisation from 2006 to 2017



5.3 Decision-making for network capital expenditure program and forecast

Our proposed capex program for 2019–24 has been guided by feedback we received as part of our stakeholder consultation and research on expectations and preferences. The key messages from customers are centred on affordable, reliable and sustainable network services. Our customers also provided specific feedback on our capex program and the approach we should take in developing our plans.

This feedback is summarised in Box 1 below.

Box 1.

Feedback from customers and stakeholders

Affordable

Feedback

Energy affordability is a critical priority for customers, for both the residential and business sectors. Energy bills have risen steeply over the last decade. Customers are challenged by rising prices and many are experiencing 'bill shock'. Customers also want assurances that our capital proposals are consistent with a reasonable long term expenditure profile, to avoid the peaks and troughs of investment which occurred in previous periods.

Response

Our capex program focusses on replacing assets on an as needs basis and better utilising existing network capacity in response to changes in demand. Rather than simply building more infrastructure, we will look first at where new technology, innovation and partnering with other companies and our customers will solve the network issues at a lower cost.

Reliable

Feedback

Even though outages are rare, reliable supply is a fundamental expectation and is a particular concern for businesses. Notwithstanding, customers are generally happy with current levels of reliability. Customers expect us to maintain reliability and not necessarily improve it unless there is a clear business case which delivers value to customers.

Response

We are targeting our expenditure plans to maintain current levels of reliability and where possible, shifting load and reconfiguring the network to ensure that we utilise the existing network effectively. Almost a quarter of our assets are more than 50 years old. We will need to replace them based on asset condition and risk in order to continue to provide the reliability our customers want. We are also investing in a new ADMS, which will enable us to more cost effectively locate and respond to outages.

Sustainable

Feedback

Looking forward, our customers have told us that they want to be able to produce and consume electricity, when and how they choose. Our customers support solar and renewables, with most believing Ausgrid should be actively involved in the shift to renewable energy sources and to more generally support the transition to a lower carbon economy.

Response

We are prudently investing in the transformation of our network over the longer term from a passive distribution network to a smart grid that will more easily allow us to incorporate distributed energy resources and optimise the network in real time. We are investing $58 million in innovation projects to deliver this 'future grid' sooner. As already noted, we are also investing in a new ADMS. Although the primary driver of this investment is to replace our outdated system, the new system will allow us to optimise orchestrated demand management solutions, and potentially enable peer to peer trading in the future.

In our engagement sessions, customers and stakeholders asked us to demonstrate our forecast capex is sufficient to avoid future increases in capex (and prices). They also wanted us to ensure we are not proposing to renew elements of the network that may not be required in the future due to energy market transformation. In broad terms, our customers and stakeholders have asked us to explain how we ensure that we are investing in the right assets at the right time.

As explained in Chapter 3, the unprecedented transformation across the energy sector is an important driver of our customers' future needs. We recognise that our capex plans must anticipate our customers' changing requirements as we prepare for the challenges and opportunities ahead.

Greater engagement with our customers and stakeholders has meant that we have changed the way we plan the network and demonstrate to customers the value of our proposed investment. Our approach to planning the capital program and developing the forecasts is presented in the remainder of this section.

5.3.1 Our capital planning process

Each year Ausgrid prepares a 10-year forecast of the capital program. The process has been used to develop the proposed capital program and forecast for the 2019–24 period.

In developing the capital program, the first step involved looking holistically at the drivers of capex. We considered the traditional drivers for network assets including the condition of assets, growth in peak demand by location (spatial load) and the number of new customers seeking connection to the network. We also considered the impact of the growth in the number of customers adopting technologies such as rooftop solar PV and battery storage. We have also considered how our investments should cater for the changing energy sector. This approach ensures that the business considers broader factors including, environmental sustainability as well as customer experience and expectations, and that these are incorporated in the development of our forecasts.

We examined the need for non-network investment in ICT, property and fleet. Non-network investment plays an essential support role to enable safe, reliable and efficient delivery of network services to customers.

We prepare strategies – such as network development strategies and asset class strategies – to guide our management of similar groups of assets. These strategies are high level and help to inform development of the detailed replacement projects and programs.

We apply a needs based approach to our investment planning, as shown in Figure 23 below.

Figure 23.

Ausgrid's approach to forecasting capex

STEP 1 – Examine investment drivers at a holistic level

Asset condition	Growth in network	Future grid	Non-network

STEP 2 – Identify projects

	Sub-transmission network plans	Distribution network plans	Non-network plans
Need	Safety, reliability or environmental risk from asset failure or constraint on network related to peak demand increase from existing or new customer		Support activity to meet obligations or improve efficiency
Options	**Timing**: Consider if project can be deferred by taking on risk-based cost-benefit analysis **Solutions**: Consider lowest cost of all feasible options based on net present value		
Costing	Apply unit costs for least cost solution based on historical experience with similar type projects. Apply cost escalators for labour, material and contract work based on economic advice.		

STEP 3 – Develop a prioritised ten-year capex portfolio

a. Top down discipline checks	Apply sense checks (repex model and trend analysis) and Executive and Board challenge
b. Prioritisation	Apply risk ranking tools to prioritise
c. Delivery Check	Examine resource capability

Source: Ausgrid.

The overarching objective of our planning approach is to identify investments that provide the most benefit to customers in terms of affordability, reliability and safety. For our major projects we use a cost-benefit model that quantitatively assesses the reliability, safety and environmental impact to customers from delaying replacement or growth investments.

When assessing a major project we explicitly consider a range of options, including network investments, demand management and non-network solutions that could achieve the desired outcome. Alternative options are assessed using Net Present Value analysis to identify the option that addresses our compliance obligations at least cost or maximises the net economic benefit to our customers. The timing of the preferred option is also optimised, having regard to the costs and benefits of different timeframes.

We apply similar approaches to determine the most efficient program in combination with the application of industry engineering and safety standards for our smaller value network investments.

Unit cost estimates are developed internally and are based on our recent experience with completing similar works, thereby capturing the efficiencies achieved from recent transformations. For major projects, we developed detailed 'site-specific' estimates. For programs containing a large volume of assets, we developed a 'typical' cost based on scope and location. In some cases, we used a trending approach to guide our estimate of expected costs. We also applied real cost escalators to labour, land and contract services and a labour productivity improvement of 2% per annum peaking at 10% in the final year.

Our unit cost methodology identified the regional cost differences in delivering similar projects across our network. Our experience is that the cost of undertaking capital projects in the CBD and inner metropolitan areas of Sydney is significantly higher than in other parts of our network. For example, some of our larger projects require night work and traffic disruption measures when they traverse across major highways and roads in Sydney. By developing costs on this basis, we can provide the AER and stakeholders with more transparent information that assists in understanding any potential cost differences with our peers.

An important step in ensuring that expenditure is prudent and efficient is to consolidate and prioritise the identified projects and programs into a 10-year capex portfolio. We use a SAP based program 'Business Planning and Consolidation' to consolidate our capital projects and programs across the network and non-network portfolio. Consolidating the capex program involves a number of checks and balances to:

- remove any potential overlap in programs,
- test our replacement capex against a top-down age-based assessment, and
- allocate our costs to SCS.

The consolidated program is subject to a prioritisation process. We use a well-established prioritisation process to assess and rank projects according to the level of risk associated with the assets.

A further step in the process is a delivery capability check, which assesses whether our proposed capex program for each region can be delivered efficiently, given the available internal labour and contracting resources. In the past, forecasts have been challenged through normal business planning and Board approval processes. However, since the lease transaction in 2016 Ausgrid has also held regular Regulatory Reset Executive Committee meetings, which have been the main forum for challenging and debating the investment and planning decisions being proposed by the business for the 2019–24 period.

This Committee has contributed to ensuring that the capex plans set out in this Proposal are appropriate, not just in terms of safety, asset age & condition, reliability & performance and risk, but also in the environment of changing technology and the continuing issue of energy affordability. In summary, our forecasting approach combines bottom up analysis with 'top down' reviews by senior executives to ensure that the proposed expenditure is prudent and efficient.

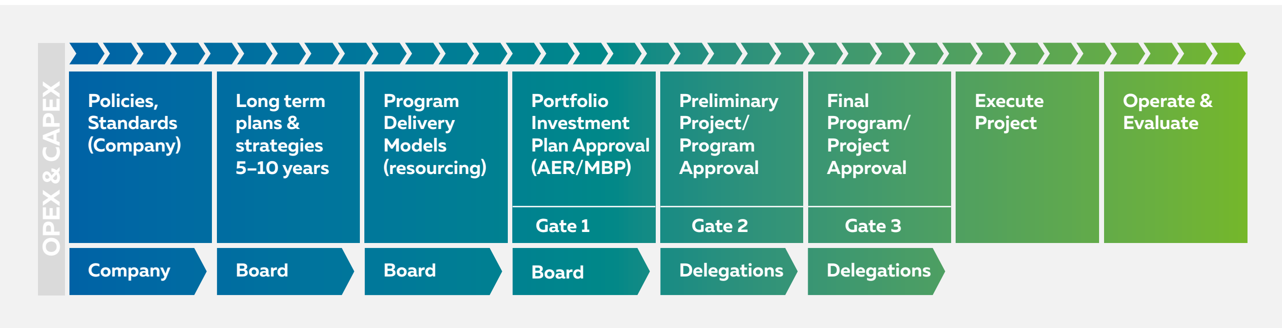
Investment Governance Framework

We maintain an Investment Governance Framework to provide clear guidance and accountability in respect of the development, determination and approval of investments, for both network and non-network assets.

This framework provides the basis for making investment decisions in a transparent and efficient manner by taking into account a full life cycle approach to such investments, and thereby providing assurance to the board and other stakeholders that the investment decisions made are prudent and efficient.

Figure 24.

Network Investment Governance Lifecycle



The key features of the Investment Governance Framework include Board approval of a business plan that delivers sustainable and efficient investments. The Chief Executive Officer (CEO) has the authority and responsibility for approving the governance policy framework. Oversight by the Board and CEO ensures the governance framework permeates throughout the planning process within Ausgrid.

Ausgrid's Executive Leadership Team has the authority and responsibility for complying with and supporting this policy. A robust delegations framework means that we have an appropriate level of ongoing oversight and control in middle management levels. The Investment Evaluation Unit reviews all proposed investments prior to their consideration by the Investment Governance Committee. The Investment Governance Committee is chaired by the Chief Financial Officer and includes an external independent engineering expert, this Committee is tasked with providing independent review and challenge to programs and projects prior to a decision being made as to whether or not to approve them.

The resulting prioritised plan informs forward delivery and resourcing plans.

Our Investment Governance Framework ensures that we are making efficient and prudent investment decisions that address our customers' preferences. The governance process provides confidence that we are:

- making better decisions,
- conducting independent reviews leading to more robust decisions,
- preparing compliance checks with the Rules, and
- driving continuous improvement over time.

Further information about our decision-making process is presented in Attachment 5.01.

5.3.2 Our approach to demand management

Many of our customers and stakeholders sought to understand how we incorporate demand management into our planning process and why there weren't more demand management initiatives.

We recognise that the most efficient way of meeting customers' needs is often through a combination of network investment and non-network solutions such as demand management. Accordingly, as part of our network planning process, we assess demand management options as alternatives to all network capex projects with a cost of over $1 million. Our approach is focused on identifying the most cost-effective way of delivering the services our customers want.

We undertake a cost benefit analysis and probabilistic assessment approach to inform our network capex forecast. For the 2019–24 regulatory period, demand management has been found to be the preferred option for capex projects and a high voltage augmentation program. This will result in deferred capex of around $66.1 million, however, in order to achieve those capital savings, we must spend an additional $26.1 million in opex over the period to procure the required demand response.

In the 2019–24 period, we will complete a demand management trial in Sydney to test whether new solar generation and energy efficiency, together with traditional customer demand response, can manage the load at risk in the event of a network outage.

5.3.3 Our regulatory obligations

Regulatory obligations have a significant impact on our investment drivers and strongly influence the scope of our capex program. As an electricity network service provider, we are subject to a range of industry specific obligations that set out the manner in which we must provide services in the National Electricity Market. The key regulatory instruments include the Electricity Supply Act 1995 (NSW), the National Electricity Law (NEL) and Rules, and the National Energy Retail Law and Rules.

Ausgrid is also subject to more general obligations and requirements which direct the way we design and operate the network. These obligations are mainly concerned with environmental protection, and public and worker safety. These influence our drivers of investment. For example, we may replace an asset if the safety of our workforce or the general public cannot be appropriately mitigated through maintenance. The standards also influence our construction and designs, for instance by adhering to environmental, planning and heritage legislation.

Recent changes to our obligations include:

- requirement by Independent Pricing and Regulatory Tribunal of NSW (IPART) to establish 'Formal Safety Assessments' across key network risk areas (e.g. Bushfire risks), and
- revised ministerial licence conditions including cyber-security and protection of critical infrastructure.

The cyber-security obligations have added $20 million to the ICT capex program for the 2019–24 period.

Further information about our legislative obligations are presented in Worksheet 7.3 of the Reset RIN.

5.3.4 Key assumptions

Our capex forecasts are based on a number of key assumptions which are set out below.

Table 18.

KEY ASSUMPTION	DESCRIPTION	APPLICABILITY
Key assumption 1 – Regulatory obligations	Our forecast capital and operating expenditure for the 2019–24 regulatory period are based on current legislative and regulatory obligations. It is assumed that no new substantive regulatory obligations and/or major change in scope of the current regulatory obligations is anticipated or taken into account.	**Capex and opex**
Key assumption 2 – demand and customer connections	Growth forecasts are based on a set of assumptions regarding spatial peak demand and customer connections over the 2019–24 period, as set out in Attachment 5.07 of the Regulatory Proposal.	**Capex and opex**
Key assumption 3 – TransGrid's Powering Sydney's Future Project	It is assumed that TransGrid will proceed with the 'Powering Sydney's Future' project as outlined in TransGrid's revised regulatory proposal for 2018–23 submitted on 1 December 2017. Based on this assumption, we have not included $239.8 million (real, FY19) of capex to replace 132kV cables on our network. This is based on the premise that the scope of TransGrid's proposed project addresses our network requirements, meaning we can retire rather than replace these assets.	**Capex**
Key assumption 6 – Proposed capex and opex	The reliability and customer outcomes set out in our Regulatory Proposal assume that all components of Ausgrid's 2019–24 Regulatory Proposal, including the capital and operating expenditure forecasts, will be approved by the AER.	**Capex and opex**

Note: Refer to Attachment 5.11 for list of all Key Assumptions.

5.4 Proposed replacement capital expenditure program

5.4.1 Overview of our proposed replacement capex program

Replacement capex is our largest capex category, covering the replacement and renewal of network system assets. It includes any capital activity to replace or renew to extend the life of an asset and also includes new assets installed on our network to enable retirement of end of life assets. The key drivers for replacement capex are:

- ensuring the safety of our customers, our staff and the general public,
- meeting our compliance obligations, and
- maintaining the current level of network reliability.

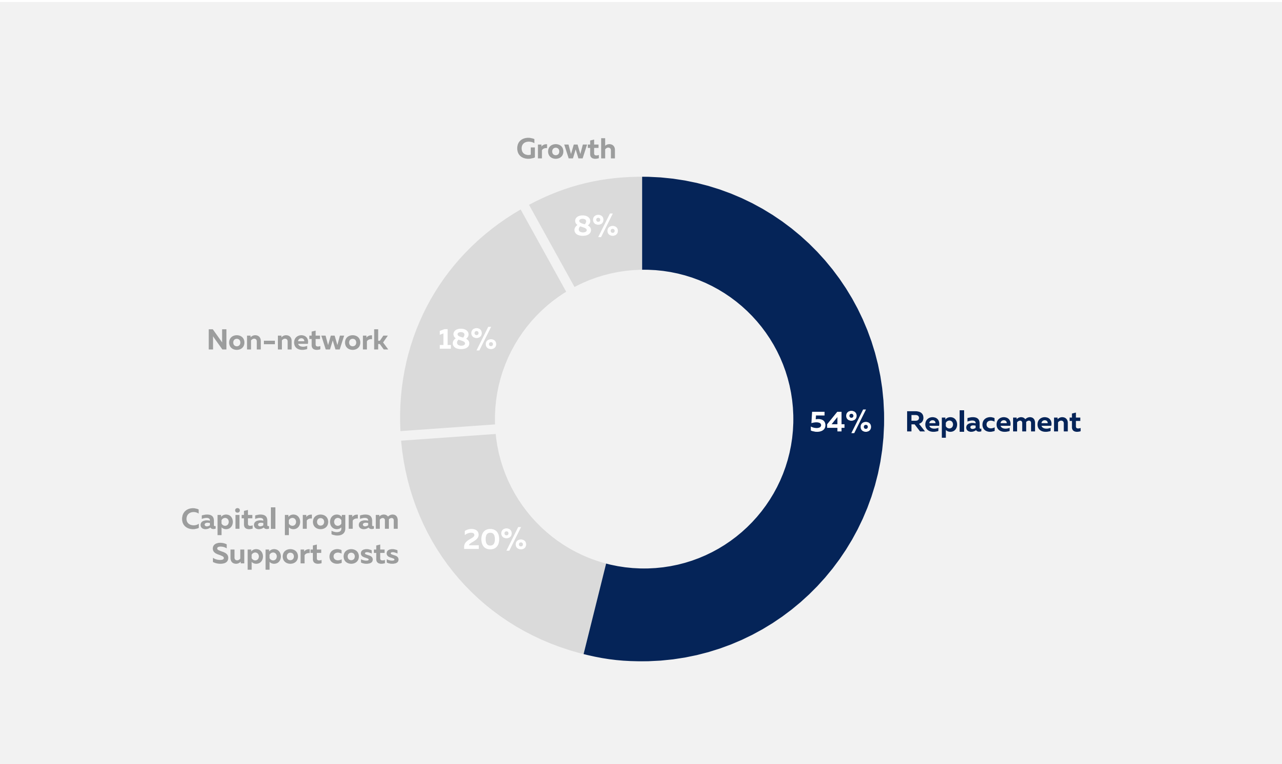
Safety is a key driver in developing replacement programs. We need to meet legislative requirements to eliminate safety risks 'so far as is reasonably practicable'. The replacement capex program has been prepared according to this key principle.

Replacement capex funds key programs to minimise the risk of adverse safety outcomes for customers and electricity workers, adverse environmental outcomes and deterioration of reliability. Ausgrid's replacement program is significant and covers the management of millions of assets with individual characteristics, at different stages of their life cycles and facing a range of condition and design issues.

We propose to invest $1.7 billion on replacement capex for the 2019–24 period ($, real FY19). This represents 54% of the total $3.1 billion capex program as shown in Figure 25 below. The replacement program represents 1% per annum of the $33.8 billion replacement value of our network 'system' asset base (which excludes non-network ICT, innovation, property, fleet and plant).

Figure 25.

Replacement capex as a proportion of total capex program in 2019–24



Our proposed replacement capex program for 2019–24 is $84 million (or 5%) less than the amount we expect to invest in the current period. The difference is the result of lower reliability standards compared to previous years and a strong drive to be more focused on replacing on a needs and no regrets basis. We are mindful that changes in technology mean that the traditional longer term views of investment need to be adjusted. As already noted, replacement capital investment is needed to continue to ensure the safe and reliable operation of Ausgrid's assets in delivering energy to customers. If we do not invest in replacing and renewing assets that are in poor condition and at risk of failing, there is likely to be an increase in the breakdown of assets while they are in service. The consequences of this include:

- Deteriorating safety performance, putting at risk the health and wellbeing of the general public, our customers, our contractors and our staff
- Increased risk of damage to other assets in the event of catastrophic asset failure
- Increased risk of environmental harm – including bushfires – being caused by asset failure
- Deteriorating supply reliability due to an increase in the rate of asset failure.

We will closely monitor reliability, safety and security of our network services to make sure that we meet customer expectations.

5.4.2 Key replacement capex projects and programs

Our network is more than the poles and overhead wires located on the streets. Network assets include substations and underground cables, switchboards and protection equipment and monitoring and management systems such as SCADA and the Distribution Network Management System (DNMS). To manage the performance of these assets we have a number of large replacement programs, many of which span several regulatory periods.

The key replacement projects and programs in our proposed capex program for the next period include:

- **Fluid and Gas Cables** – program to replace a number of sub-transmission fluid filled cable and gas filled cables at a cost of $202 million. Many of these assets were installed in the 1950s to 1980s and are in poor condition. The program targets assets that pose a potential risk to the environment and was developed in consultation with the NSW Environment Protection Authority (EPA). The long-term program will end in 2039.
- **Switchboards** – invest $157 million in replacing switchboards and related equipment in zone substations. This investment is needed to ensure the continuation of safe and reliable delivery of energy to customers. Failure of a switchboard can result in extended outages for between 5,000 and 40,000 customers. Without this investment, large numbers of customers will be exposed to unacceptable reliability risk.
- **Overhead poles** – ongoing program replacing and renewing poles that hold up electrical wires and other equipment. This program targets poles that are non compliant with network standards and are at risk of failing. Poles are in public spaces, so there is a heightened public safety risk in the event of a failure. In rural areas the failure of a pole may lead to a bush fire. We expect to spend $149 million in the next period.
- **Low voltage cables** – invest $111 million on CONSAC and HDPE type low voltage cable replacements. The program will mitigate the risk of electric shock and electrocution due to the degrading condition of the assets. The program is needed to protect the safety of workers and the public.
- **Control and protection systems** – programs to target the replacement of SCADA, relays, modems, batteries and audio frequency load control systems. The need for investment is triggered by degrading and legacy systems that are obsolete and incompatible with new systems. Poor asset conditions are leading to increased level of failure rates and there are limited options to repair. In total, Ausgrid plans to spend $81.8 million on replacing these assets.
- **Overhead conductors** – continue to invest a total of $105 million replacing overhead conductors (including steel mains) to address known risks associated with condition or design issues. These programs aim to ensure safe distribution of electricity from sub-transmission supply points and zone substations to customers and reduce risks of our equipment failure causing a bushfire.
- **Overhead Service lines** – invest $49.5 million on replacing degraded overhead service lines that connect customers' premises to the network. Old technology service lines have known degradation and safety risks that need to be addressed.
- **Transformers** – $33.3 million to replace or refurbish transformers and reactive plant. The program targets some of the oldest transformers on our network, including some in the Sydney Central Business District (CBD) that have an obsolete construction. The average age of these assets is approximately 54 years.
- **Centralised Control System** – replace our end of life network monitoring and control systems, including DNMS with the ADMS. This program has already commenced, with expenditure of $41.3 million planned for the next period to implement a modern 'off-the-shelf' system. This investment will allow for a simplified control system environment, help address emerging cyber security risks and leverage new technologies such as distributed energy resources to better enable a peer-to-peer trading environment.

- **Substation assets** – replace pole top, outdoor enclosures and kiosk distribution substations in capex programs totalling $44.8 million. Programs include replacing ageing and higher risk substations of early era kiosk and outdoor enclosure designs. Pole top substations are being replaced utilising composite poles as they are expected to have a longer life, thus reducing the overall lifecycle cost.
- **Vegetation** – initiate a new scheme to improve the way we manage vegetation near overhead conductors and poles in response to concerns by stakeholder and local councils in urban areas. This proposed program involves working with councils to identify ways to improve our vegetation management to meet community expectations (for example, replacing bare overhead wires with aerial bundled conductors). Ausgrid proposes to invest $18.7 million in the 2019–24 regulatory period to improve our network configuration.
- **Reactive program** – allocate a total of $223 million to fund reactive expenditure during the 2019–24 regulatory period. The reactive program covers situations where assets fail unexpectedly. This forecast has been based on historical trends in actual expenditure. We discuss the way we developed the replacement program in more detail in section 5.4.4 below and Attachment 5.01.

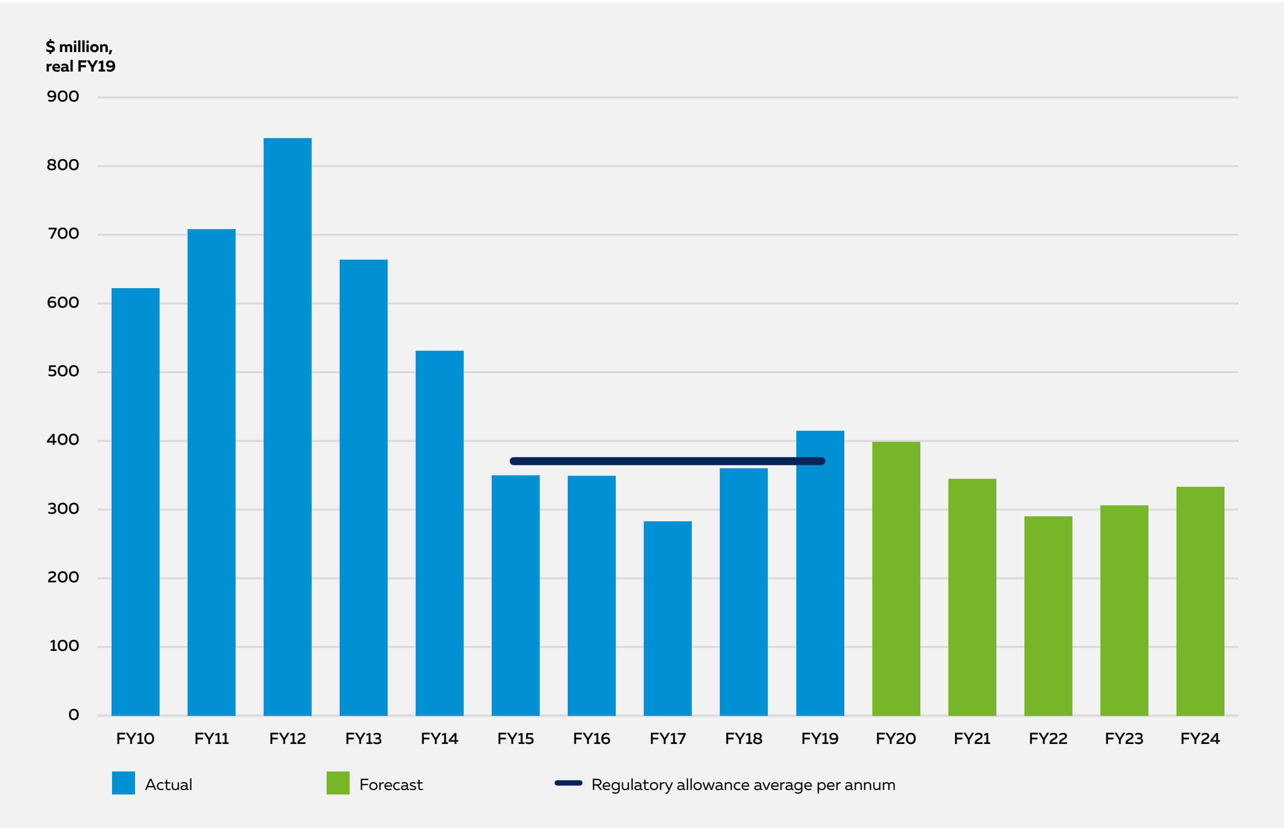
Further information can be found in the program and project justifications for the entire replacement program in Attachments 5.13 and 5.14.

5.4.3 Trends in replacement capex

Our proposed replacement capex program for 2019–24 is broadly in line with the amount we expect to invest in the current period. In the 2019–24 regulatory period we propose to invest $1,673 million on replacing 'system' assets. Expenditure in both periods is significantly lower than the 2009–14 period, when a combination of factors including more stringent licence conditions drove the need for higher levels of expenditure, as shown in Figure 26 below.

Figure 26.

Trends in actual and forecast replacement capex ($ million, real FY19)



Source: Ausgrid analysis.

The above figure also shows the regulatory allowance for replacement capex compared to actual expenditure for 2014–19. Our actual expenditure will be $90 million (or 5%) lower than the allowance. Our proposed replacement capex is $174 million (or 9%) lower than the regulatory allowance for 2014–19. This comparison provides confidence that our proposed expenditure is efficient and prudent, and reflects a positive outcome for customers.

The plateauing of the replacement capex proposed for the next period reflects a concerted effort to carefully target the replacement program where it provides greatest value to customers. We have rigorous maintenance programs that carefully monitor and test assets on the network on a routine basis. By doing this, in some cases we can extend the life of our assets beyond their standard life and lower the level of asset replacement.

As discussed previously we will monitor these expenditure changes to ensure that customer reliability, safety and security is not adversely affected. Ausgrid has strategies in place to act quickly should the reductions lead to unforeseen impacts on network reliability, safety and security.

5.4.4 Developing the proposed replacement program and forecast

We have developed the replacement capex program to enable us to continue to deliver affordable, reliable and safe supply of electricity to our customers. We have taken on board the concerns of our customers and stakeholders and have sought to make the replacement program more sustainable and prevent the expenditure fluctuations of the past.

Safety is the key driver in developing our replacement programs. We need to meet legislative requirements to eliminate safety risks 'so far as is reasonably practicable'. The replacement capex program has been prepared according to this key principle.

The programs achieve these objectives by managing a number of factors as shown in Figure 27 below.

Figure 27.

Objectives and factors driving the replacement capex program

OBJECTIVES	Affordability	Reliability	Safety	Legislative Obligation
FACTORS THE REPLACEMENT PROGRAM SEEKS TO ADDRESS	High cost maintenance	Long duration outages	Public	Require us to eliminate safety risks so far as reasonably practicable and if it is not reasonably practicable to do so, by reducing safety risks to as low as reasonably practicable.
	Operations	Long repair times	Customer	
	Reactive mark-up	Cybersecurity	Worker	
			Environment	

Our asset base is extensive, with millions of pieces of equipment playing a role in delivering energy to customers. The assets on our network are at varying stages of their life cycles, with varying design, technology and material types. They face a range of environmental conditions including extreme weather, bushfires and pollution.

Asset condition is the key input to our replacement expenditure and includes the following considerations:

- measured condition and forecast degradation based on observed trends,
- current asset failure rates and trends of particular asset sub-types,
- consequences of uncontrolled failures on worker safety (for operators and maintainers); public safety; and environmental safety, and
- obsolescence and lack of technical support and spare parts.

The condition of each asset degrades over time based on its technology, its environment and usage. We use the information from our Asset Management System (AMS) to optimise the timing of both maintenance and replacement. The analysis considers risks, costs and customer benefits.

The AMS provides a framework for managing assets on the network. It is an end-to-end system for managing network assets across the life cycle of the asset.

Our AMS has been designed to meet best practice approaches to managing our network including the Reliability Centred Maintenance and Failure Mode Effect and Criticality Analysis. This has helped improve the way we manage assets from a life-cycle perspective which in turn reduces cost. The AMS is explained in more detail in Attachment 5.01.

Our forecasts for replacement capex are validated by age modelling and trend analysis – similar to the replacement expenditure modelling. We discuss the outcome of this validation process later in this chapter.

5.4.5 Transformation in unit rates

Unit rates are a key driver for our capex program. As such, we continually assess our rates to ensure they are efficient and as low as possible. The processes used to assess our rates differ between programs of work and major projects.

While our rates used in our programs have not benchmarked well historically, our performance has been improving in recent years. In particular, we have engaged external advice to prioritise based on our performance against peer DNSPs. Another way we improve rates is through internal benchmarking, whereby the rates for a program of works continually decline as the program is carried out, as efficiencies are uncovered and our ability to deliver the work improves. To continue motivating the business to find further efficiencies we have factored in a 2% per annum decrease in labour costs for each year of the upcoming regulatory period, leading to a 10% reduction in 2024. This efficiency has already been factored in to the capex forecast and it is up to us to ensure this target is met.

The other area of capex affected by unit rates is major projects. These involve capital works that are more bespoke than the programs of work. In putting together the capex forecast, emphasis has been placed on producing accurate estimates as well as achieving efficient rates. An important pressure test for efficiency in this space is the market efficient rate, that is, the competitive external delivery cost.

In 2016 a major review of our ability to deliver projects internally against what the market could provide was carried out for a number of major projects. As a result of this review, we now adopt a blended delivery approach, whereby Ausgrid delivers certain components of projects (so as to retain core competencies within the business and capitalise on existing efficiencies) with other components being outsourced. All major projects are now assessed for blended delivery, resulting in cost savings of approximately 25–30%. We have factored these savings into our capex forecasts.

Further information is provided in Attachment 5.06 Network Unit Cost Methodology.

5.4.6 Testing our replacement capex forecast – age based assessment

We undertook a 'top down' assessment of the outcomes of our analysis using simple aged based comparisons and modelling. The aim was to test the level and sustainability of our capex program. We analysed how much replacement capex would be required to replace today's network. The results of our repex modelling indicates it would cost $34 billion to replace all of our system assets, assuming we embed the efficiencies we have made in the 2014–19 period. While this top-down testing is a useful check, a key issue is that Ausgrid makes replacement decisions based on the condition of assets, rather than age profiles. Further information is provided in Attachment 5.15 Nuttall review of repex.

5.4.7 What happens if we don't invest enough in our assets

Preventing the capex fluctuations of the past was a key issue that our stakeholders wanted us to actively manage from now on. Stakeholders were clear that they didn't want to experience electricity bill shock in the future. Stakeholders also wanted to understand what the consequences were if we don't invest enough.

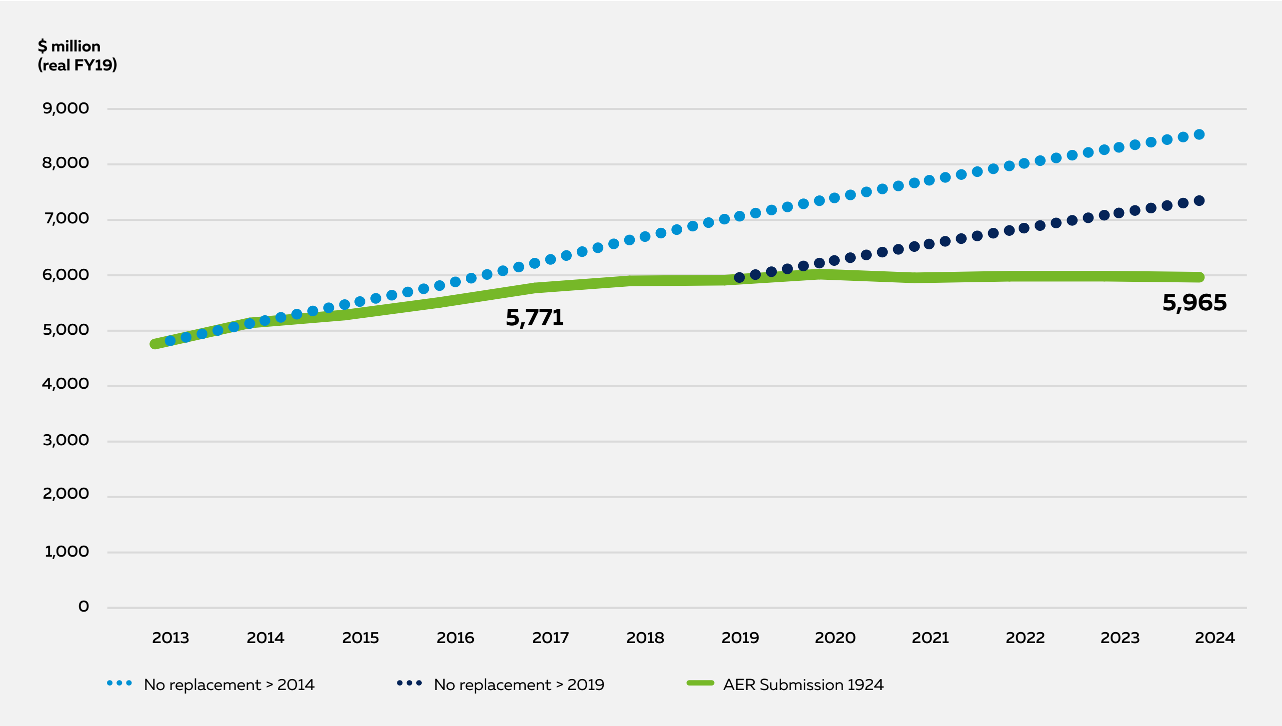
We have taken on board the stakeholder feedback and have sought actively and carefully to manage the risk of assets failing and potentially affecting the reliability and safety of our network service. A key principle in developing the replacement capex program is to manage risk over successive regulatory periods. Each of our replacement programs and major projects reflects this type of assessment.

One way to monitor the balance between risk, reliability and sustainability over successive periods is to assess the weighted value of all our network assets that are over their standard life.

We can apply this approach to 'stress' test various levels of replacement expenditure. The figure below shows that our proposed replacement capex program will lead to a small increase in the value of assets that exceed their standard lives from $5.8 billion to $6 billion by FY24 (real FY19).

Figure 28.

Weighted asset value at risk ($ million, real FY19)



Source: Ausgrid.

We consider that this outcome results in a marginal increase in absolute risk which appropriately balances our customers' preference for affordable, reliable and sustainable network services. Ausgrid undertakes rigorous testing and maintenance programs for all assets which provides early warning of any emerging condition issues, allowing adjustments to our strategy if required. It also means that we can operate some assets beyond their standard life. For example, 42% of our poles are beyond their technical life of 45 years. Poles are inspected on a regular basis and we can treat any problems before they fail.

The chart also shows how the value of assets exceeding their standard lives would increase if there was no investment in replacing assets. This is shown simply for illustration of what 'no investment' would mean. No investment from 2014 onwards would have meant that over $8 billion worth of assets would have been over their standard life in FY24. No investment from the current period would increase value at risk to over $7 billion.

Note this would be an imprudent and inefficient approach to allow an increase in asset risk because it would expose our customers to unacceptable reliability and safety outcomes and potentially much higher costs in future regulatory periods, as the volume of reactive maintenance and backlog works would increase significantly.

5.5 Proposed growth capex forecast

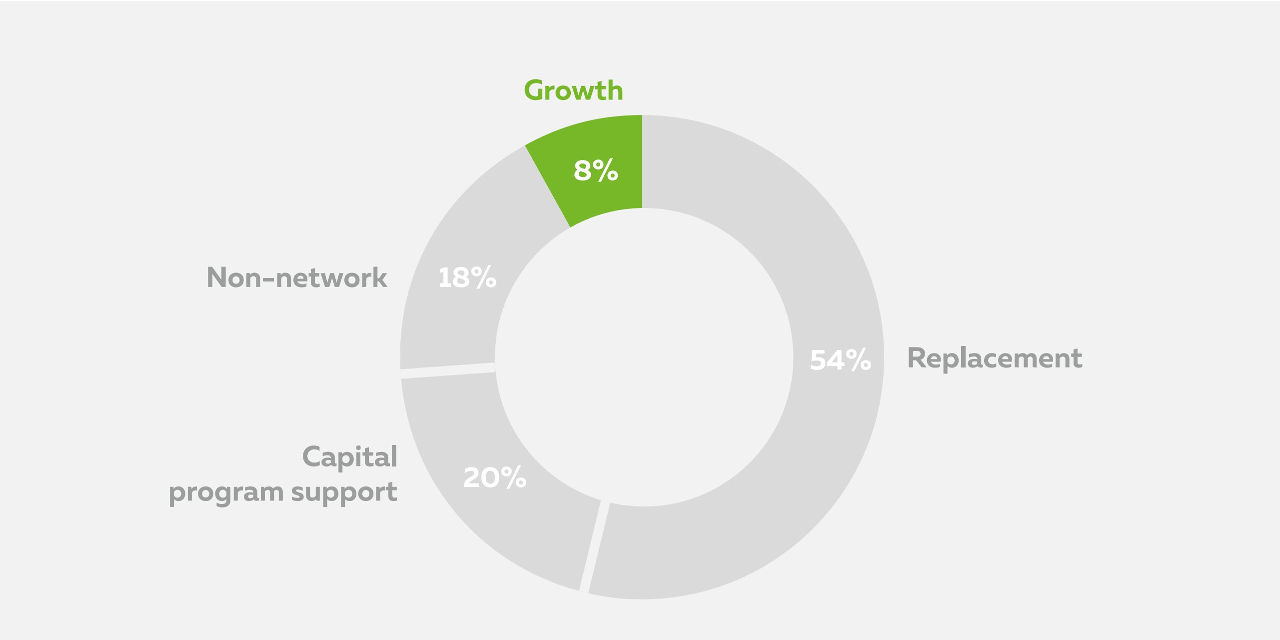
5.5.1 Overview of our proposed growth capex program

Growth capex includes augmentation and customer connection related projects. Augmentation refers to works on our shared network in response to an increase in peak demand. Connection refers to new installations to provide a reliable supply to a customer.

We propose to spend $241 million (or $48 million per annum) (real, FY19) on growth capex in the 2019–24 period. Forecast growth capex is approximately 8% of our total capex program. Our capex program has materially shifted away from growth as a driver. The level of growth capex as a proportion of the total program is shown in Figure 29 below.

Figure 29.

Growth capex as proportion of total capex program in 2019–24



Source: Ausgrid analysis.

Table 19 below shows the breakdown in growth capex by augmentation and connection. These figures exclude capital contributions which we expect to be around $585 million for the 2019–24 period ($ million, real FY19). We discuss the trends in growth capex in section 5.5.3 below.

Table 19.

Forecast growth capex for 2019–24 period ($ million, real FY19)

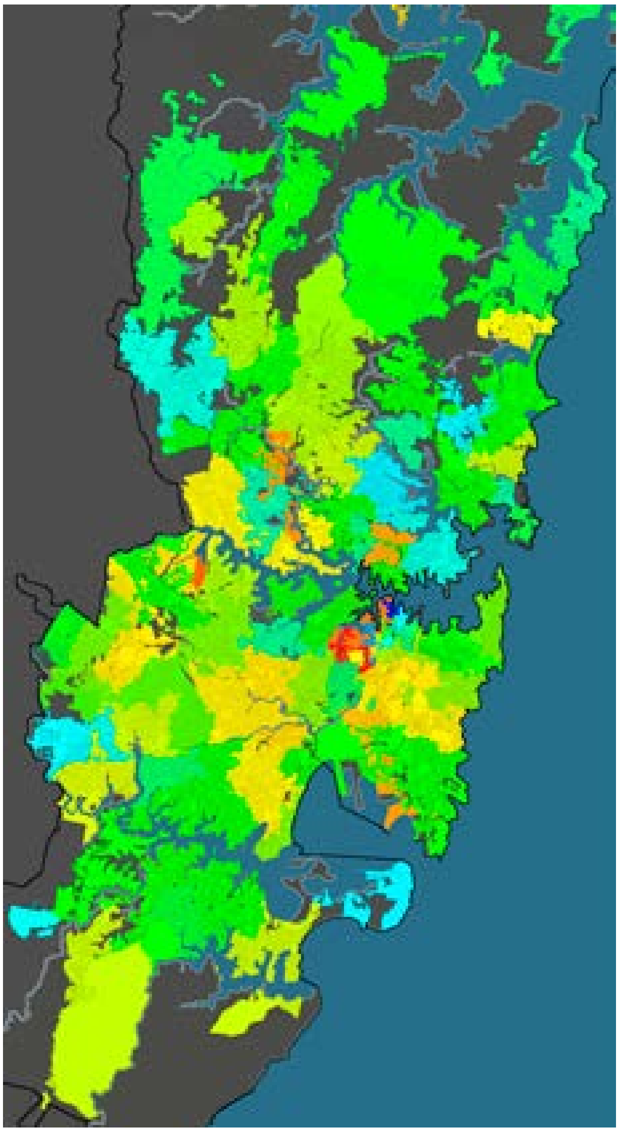
	FY20	FY21	FY22	FY23	FY24	TOTAL
Augmentation	27.0	51.7	46.6	29.8	34.1	189.1
Connection	10.6	12.5	10.6	10.0	8.5	52.2
Total	**37.5**	**64.2**	**57.2**	**39.8**	**42.6**	**241.3**

Modest underlying growth in electricity consumption is being offset by energy efficiency and increases in the adoption of solar by customers.

While we are seeing moderate growth at a system level, some parts of our network are growing quickly due to a rapid increase in large customer connections for transport infrastructure projects, residential high-rise developments and digital infrastructure projects (data centres).

Figure 30.

Load hotspots on our network



This diagram shows load growth on our network. The red and orange areas indicate higher hotspot load growth areas in Sydney.

Source: Ausgrid.

Most of the new asset investments will be on 11kV (high voltage) 'hotspots' on our network. We are experiencing major infrastructure spot loads, particularly in the Sydney region, which is increasing load in these 'hotspots'.

The shift to lower growth capex reflects our drawing on the capacity of past investments to meet new growth. This was shown in the capacity utilisation charts in section 5.2.5 where we are increasing utilisation in 2016 and 2017. We expect the capacity utilisation to continue to increase in the 2019–24 period.

5.5.2 Key growth capex projects

The majority (around 80%) of the proposed growth capex program is for augmentation related projects. To determine forecast capex on the distribution network, we used a model to examine local peak demand and capacity for each area.

The key growth projects are summarised below.

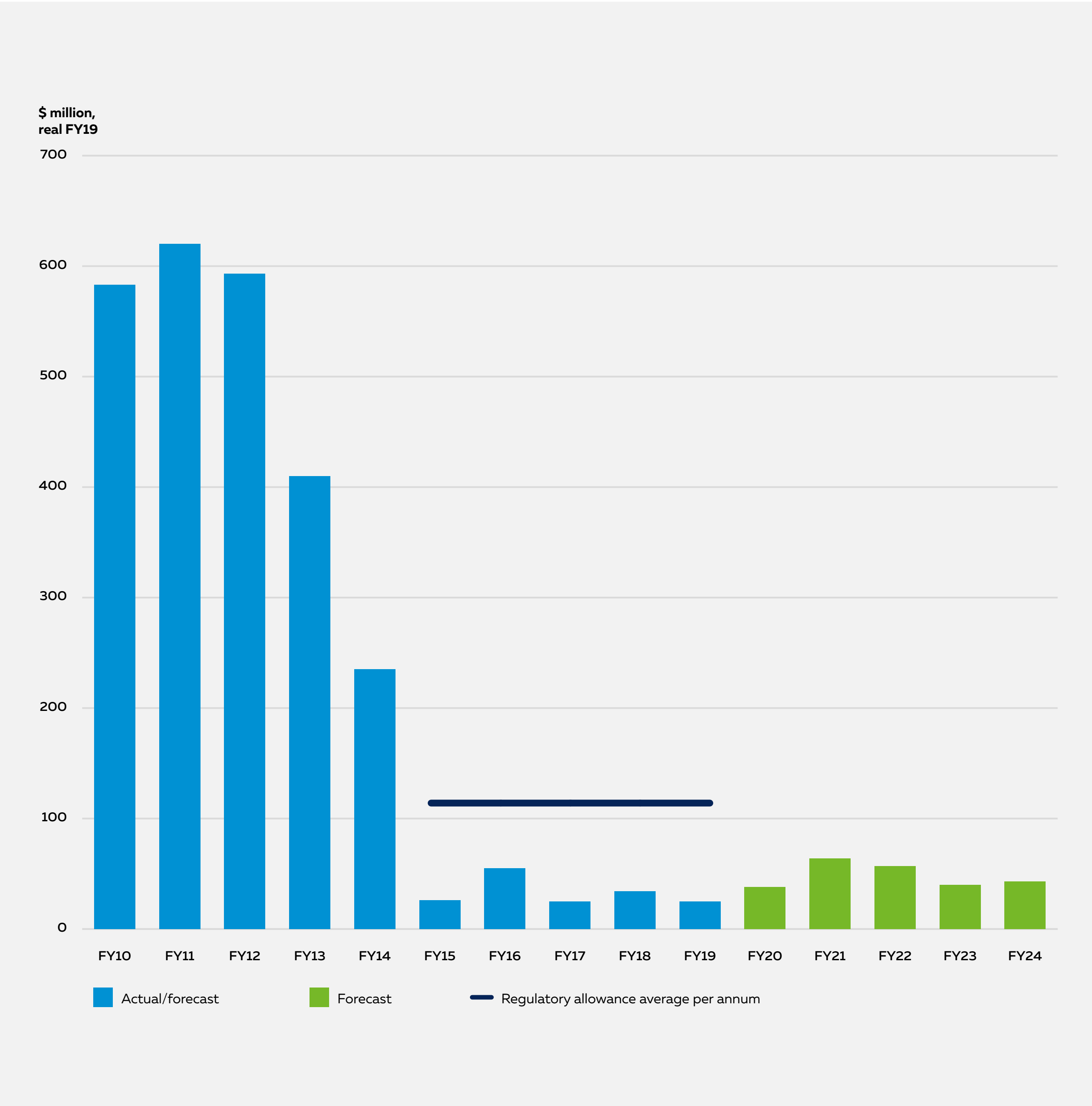
- **Macquarie Park** – provide 33kV supply capacity to the Macquarie Park Precinct in the Carlingford area of Ausgrid's network. The proposed investment will increase capacity to meet new data centre and telecommunication customers, together with potential expansion of education facilities. The preferred option is to establish a new 132/33kV Macquarie Park sub-transmission substation. We have forecast capex of $28.1 million in the 2019–24 period.
- **Rozelle substation** – propose to construct a 33kV busbar and switch room at the Rozelle 132/33kV sub-transmission station in the Inner West region of Ausgrid's network. This will provide a firm, permanent 33kV connection point for part of the WestConnex motorway development. Other large customer connections are anticipated in this area in the future. We have forecast capex of $17.5 million in the 2019–24 period.

5.5.3 Trends in growth capex

We have a relatively low level of growth capex compared to long-term trends as shown in Figure 31 below. Our proposed growth program for 2019–24 represents around 10% of what we invested in 2009–14. The substantial reduction in the level of growth expenditure over time is driven primarily by the relaxation of the NSW licence conditions relating to network reliability standards and lower demand growth.

Figure 31.

Trends in actual and forecast growth capex ($ million, real FY19)



Source: Ausgrid analysis.

Our proposed growth program shows an increase compared to the current period, but the absolute levels of expenditure remain low, with average expenditure of less than $50 million per annum substantially below the expenditure peaks of over $600 million in the 2009–14 period.

5.5.4 Developing the proposed growth program and forecast

Key drivers

Ausgrid has an obligation to connect customers that want to connect to our network. Our objective is to provide the required shared capacity to meet our customers' needs at the lowest total cost.

Determining our growth capex program requires a different approach to forecasting replacement capex program. The growth capex program is largely determined by factors other than the condition of the assets.

The key drivers of need for growth capex are:

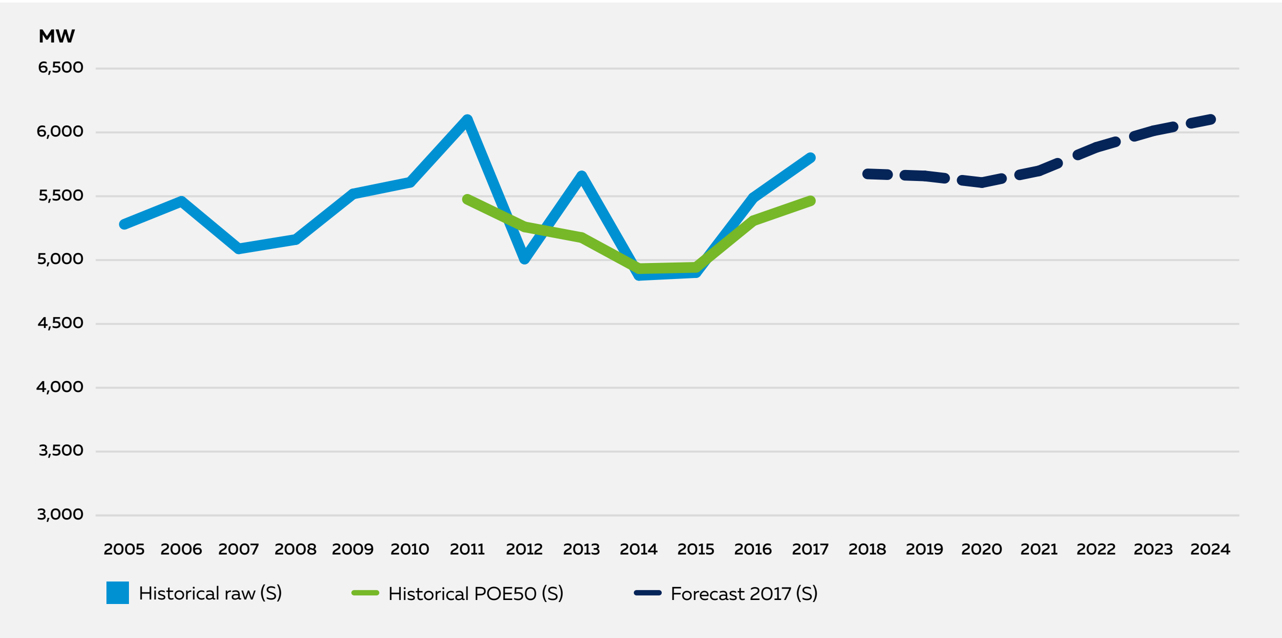
- changes in maximum demand,
- number and size of new customer applications to connect to the network, and
- application of Ausgrid's customer capital contributions policy.

We forecast that maximum (peak) demand will increase by 1.5% per year between 2019 and 2024.

Our forecast growth in summer maximum demand is higher than the 1.4% per annum growth over the FY13 to FY17 period. However, the past few years, growth has been 5.1% per annum with the increase in large customers connecting to the network being a contributing factor.

Figure 32.

Forecast maximum demand for 2019–24 compared to historical



Source: Ausgrid analysis. Note both historical and forecast are weather corrected POE50 values.

Underlying these forecasts, we expect that there will be 20,000 new households connecting to the Ausgrid network each year. We are also forecasting an additional 375MW[1] of demand over 2019–24 from new large customers connecting to the network, especially in the Sydney region.

In NSW, new customers and customers altering their existing connection engage Accredited Service Providers to build their connection to Ausgrid's network and to augment the existing network if additional upstream capacity is required. The connection services provided by Accredited Service Providers are generally referred to as 'contestable services'.

Ausgrid's connection policy and planning framework determines when network augmentation is required and how the augmentation works are funded, for example, as capital contributions by the connecting customer, or as network growth capex. Our connection policy is presented in Attachment 5.17.

In preparing our forecasts we analysed how much (behind the meter) renewable generation and battery storage would be located within our network. We also considered the potential impact of electric vehicles on the network.

1 375 MW refers to large customers connected at 33kV or above. Whilst the 710 MW figure from page 93 refers to all customer connections including those connected at 11kV.

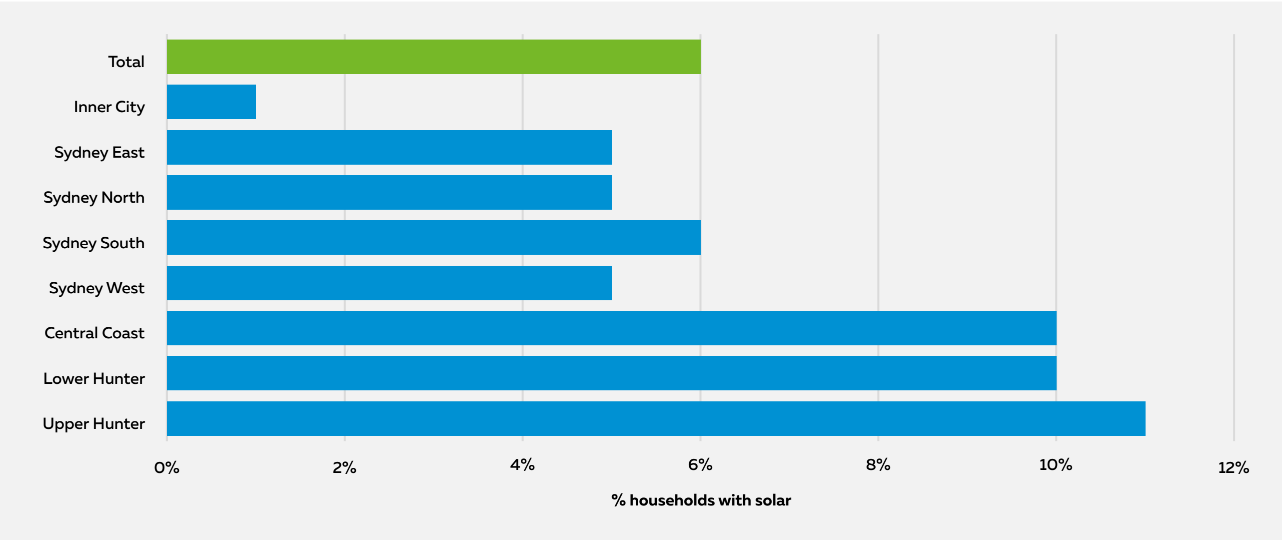
Attachment 5.07 Electricity Demand Forecast Report 2017 sets out all factors included in our internal forecasts, including rooftop solar, solar and battery systems, and electric vehicles.

At present, the penetration of solar and batteries on Ausgrid's network is modest compared to other networks in Australia. This is largely due to the density of our network in the Sydney region, with many apartments and commercial spaces in Sydney not having the conditions or space to install solar technology.

However, in the Hunter region we are seeing a far greater penetration of solar. As Figure 33 shows, we have a high proportion of solar installation among residential customers in the Central Coast and Hunter regions compared with the Inner City and suburbs of Sydney. More renewable generators are also connecting to our network in the Hunter region.

Figure 33.

Solar penetration across Ausgrid's region



Source: Ausgrid analysis.

Our methodology for forecasting maximum demand is presented in the next section.

Forecasting method

Maximum demand forecasts are prepared using inputs from raw data sources such as interval metered demand data, weather data and internal records of changes to network configuration. The forecasts are reviewed by Ausgrid subject matter experts and incorporates inputs from external experts and forecasting data from the AEMO for key variables.

The forecasts we use for assessing options when planning the network are based on a 50% POE. This means that we expect the forecast peak demand to be exceeded one in every two years. We also conduct sensitivity testing using 10% POE and 90% POE levels.

The maximum demand forecasts are prepared for winter and summer for 181 zone substations and 33 sub-transmission substations on Ausgrid's network.

The forecast is developed using a range of key pieces of information:

1. Baseline (underlying) trend in growth
2. Impact of block loads which are new major customer connections
3. Adjustments for the impact of electricity price changes, energy efficiency, rooftop photovoltaic systems, and battery storage systems
4. Upward adjustments for the projected impacts of economic and household incomes growth, population growth, electric vehicles, and customer growth.

Ausgrid's forecast methodology for the 2019–24 period uses an historic trend to project to the near term, econometric modelling for the longer term, and a blend of these two methods to transition between near and long term, as summarised below:

- The baseline trend for each of the target substations uses historic demand data from the substations and weather data from the closest Bureau of Meteorology weather station. Weather normalisation is carried out to smooth out the effects of varying seasonal weather conditions on maximum demand.

- Adjustments are made to the raw data for the historical impact of block loads, load transfers and changes in embedded generation. This approach enables us to develop trends in maximum demand at a spatial level. The historic trend is used for the near term forecast for the first two years, FY18 and FY19, plus an allowance for probability-adjusted block loads.
- The longer term forecast is based on an econometric model to reflect the impact of demand drivers such as household incomes, NSW gross state product and electricity price responses.
- Post-modelling adjustments are made to account for energy efficiency, embedded generation, emerging technologies such as battery storage and electric vehicles, population growth and changes in air conditioner penetration.
- The forecasts for FY20 to FY21 are based on a blend of the baseline trend and the longer term econometric model. The forecasts for FY24 are based on econometric modelling.

Further details about the approach to forecasting maximum demand is provided in Attachment 5.07 Electricity Demand Forecasts 2017.

GHD Advisory reviewed our electricity demand and customer connection forecasts, including methods, processes and assumptions used to prepare those forecasts. GHD found that the overall approach to preparation of Ausgrid's 2017 electricity demand and customer forecasts, the methods used and the data inputs were appropriate – and in some cases innovative – and conducive to the production of reasonably accurate forecasts. The GHD Review of 2017 demand and customer connection forecasts (22 December 2017) can be found at Attachment 5.08.

Impact of new major infrastructure

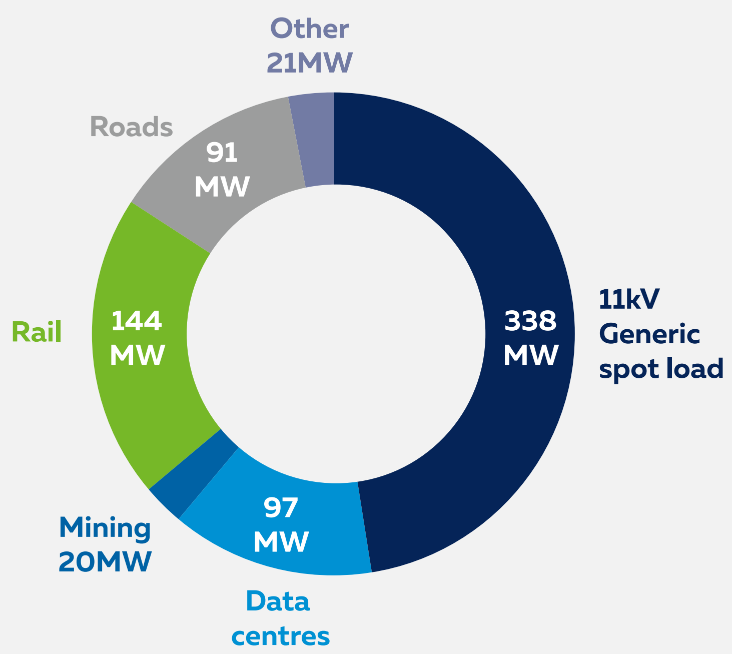
Our connection related component of growth capex program in the 2019–24 period is heavily influenced by large customers including new major infrastructure projects connecting to the network. All new major infrastructure connections are expected to add 710MW of peak demand by 2024 – a 10% increase in peak load over the next seven years.

The majority of peak demand is for rail and road projects in NSW, together with data centres. For example, road infrastructure projects such as the WestConnex motorway currently under construction. WestConnex will consist of close to 30km of underground road and will require a large amount of energy for lighting, water pumps and air ventilation. Generic spot loads at the 11kV level are being driven by high-rise residential development mainly in the Sydney region. An increase in the demand by data centres is also contributing to the increase peak demand.

These major new connections are shown in Figure 34 below.

Figure 34.

Forecast peak demand from major new connections by industry segment 2019/20–2023/24

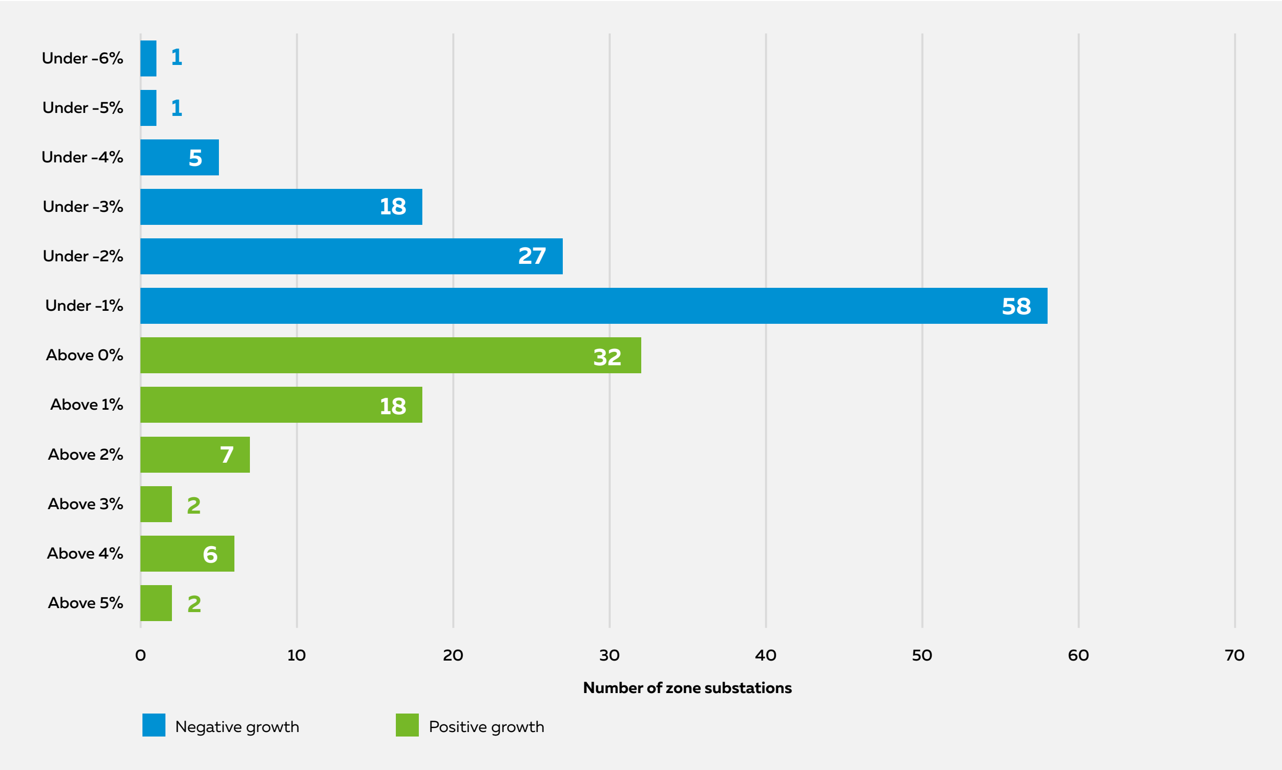


Source: Ausgrid analysis.

Our forecasts of peak demand help us to determine where we need to invest based on whether there is sufficient capacity to meet demand. The figure below shows that only eight zone substations are experiencing growth in excess of 4% per annum.

Figure 35.

Average annual maximum demand growth by zone substation for 2019–2024 period



Source: Ausgrid analysis.

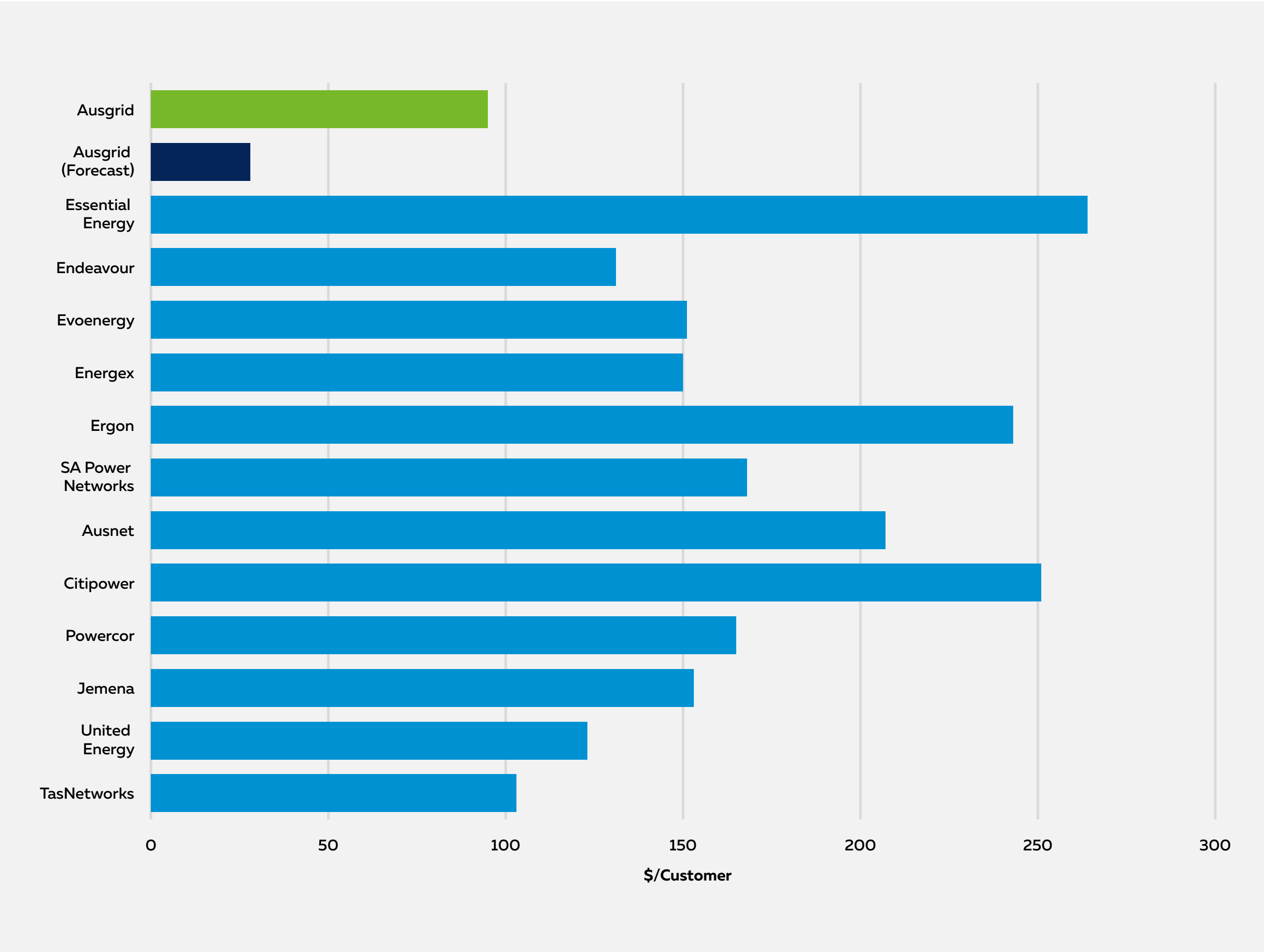
The majority of our substations are expected to experience a modest decline in peak demand, thereby alleviating capacity issues. We address capacity issues by either augmenting the network or, if possible, reconfiguring the assets to transfer load away from highly utilised substations to ones that have spare capacity.

5.5.5 Benchmarking our growth capex forecasts

Ausgrid has the lowest level of growth capex per customer in the NEM. Ausgrid's level of forecast growth capex per customer compared to other DNSP's is shown in Figure 36 below (these are in nominal dollars).

Figure 36.

Growth capex per customer by DNSP five year average ($, nominal)



Source: Ausgrid analysis using AER data.

The main reasons for this include capital planning practices which take advantage of past investment, and the application of a more cost/benefit based approach, along with a continued focus on achieving competitive delivery models and costs. Ausgrid is confident that this combined focus on scope and efficient delivery will allow us to continue to respond to load growth on our network at the lowest sustainable cost to customers.

5.5.6 What happens if we don't invest enough in growth capex

Expenditure on growth capex is driven by external factors such as increases in maximum demand and the number and size of connecting customers. Ausgrid has little control of these factors.

Failure to invest enough in augmenting the network is likely to result in increased unserved energy and lower reliability of the network. However, the low level of proposed growth capex is appropriate given that there is capacity on the network to absorb new load and the low level of growth relative to past periods.

More information about the growth program can be found in Attachment 5.01.

5.6 Delivering the proposed network capital expenditure program

5.6.1 Overview of Resource and Delivery Strategy

Ausgrid has developed a Resource and Delivery Strategy (the Delivery Strategy) to ensure the efficient delivery of the works program (this includes capital and maintenance activities). The Delivery Strategy was developed to demonstrate that we have the capability and capacity to deliver our works program.

The Resource and the Delivery Strategy forms part of Ausgrid's business-as-usual planning. It includes review processes to assess how we are performing.

Ausgrid's capex program involves a mix of distribution and transmission projects. Delivering the capex program requires a broad range of technical skills. These skills are provided by a mix of the internal workforce and external service providers.

Three key aspects of the Delivery Strategy include:

- optimising the efficiency of the internal workforce by increased multi-skilling and competitive tension against external service providers,
- increasing cross-regional sharing of resources, and
- outsourcing work to external service providers where this is the most commercial outcome i.e., feasible and efficient.

The new Enterprise Bargaining Agreement removes defined skills silos and allows for greater performance recognition. The new Agreement will introduce greater flexibility to the way we can use our internal workforce.

The Delivery Strategy has been embedded in our organisation by creating a new Program Delivery Division. This is accountable for implementing the Delivery Strategy, integrating management of capital and maintenance and formation of the Integrated Works Management Office (IWMO) to enforce accountabilities and monitor progress on delivery of the works program.

Figure 37.

Implementation of Resource and Delivery Strategy

Organisational Design

Creation of Program Delivery Division accountable for:

- Developing a single plan for all programmed network activity
- Streamlining end-to-end capital processes including design
- Oversight of the program of works

Integrated Management

Integrated management of capital and maintenance requirements through:

- 'One Plan' – a single, integrated and granular view of supply and demand requirements
- Identification of key constraints and development of associated action plans

Visibility, Collaboration and Accountability

Formation of IWMO to:

- Provide visibility on progress
- Enforce clear accountabilities
- Resolve conflicting priorities

Achieved through:

- Dashboards and key metrics
- Regular 'stand up' meetings with senior management

In April 2017, we implemented the 'One Plan' capital delivery initiative following an investigation into the structural and workforce issues impacting our delivery performance. The investigation identified delivery bottlenecks and opportunities for efficiencies in our delivery performance.

Some of the issues included resource demand-supply imbalances for particular projects, project scheduling, network access and delays in approval of projects.

Our 'One Plan' establishes a series of measures to address these issues. Since its inception, and realisation of benefits from our Phase 1 Transformation initiatives, Ausgrid is now back on track for delivering against the planned work levels, with a smaller and more productive workforce.

5.6.2 Workforce Strategy and Delivery Model

We use the Workforce Strategy and Delivery Model (Model) to continuously review demand and supply of the internal workforce against the requirements of the work program.

The Model uses input from:

- employee numbers and classifications,
- forecast work program, and
- unit costs.

The Model allows us to understand where there is undersupply or oversupply in particular classifications and locations over the medium to long term. The model is used to test sensitivities of our workforce capability using a range of scenarios. This in turn allows us to use a range of levers.

Where there is an undersupply of skills, we consider strategies to ensure that we fill the shortfall. The strategies include moving employees, reskilling existing employees or using external service providers.

Where we forecast an oversupply of skills we look at ways of redeploying or reskilling workers.

5.6.3 Delivery approaches

In recent years, we have become proficient and mature in the use of the external service providers market that may be suitable for delivering projects and programs. This has been driven by a concerted effort to find ways to better manage delivery of our work program.

Our efforts have been rewarded, in part, by the development of a deep market in external service providers. It has become evident that there has been a resultant increase in the availability of competent skills in the market place. Likewise, it is evident that our employees have responded to the competitive environment.

While there are a range of approaches for different types of projects, Ausgrid retains the project management accountability on all projects.

5.6.4 Benefits to customers

The Delivery Strategy will deliver significant benefit to our customers. These include:

- **Greater efficiencies** – We expect to achieve greater efficiencies by the way we deliver our capex program. Multi-skilling our internal workforce will enable us to better allocate and use our existing workforce.
- **Blended approach** – Blended approach allows for greater flexibility in the way we deliver our capex program. We can be more agile in the delivery of the capital works program. This will help to smooth out the delivery of the capex program and avoid under-delivery issues that we faced in the past.
- **Service providers** – Creation of a deep pool of external service providers that can be called on to meet our capital works program requirements. This can help us to create competitive tension in the market place. We seek competitive tenders from a range of potential suppliers.
- **Competitive tension** – Greater competitive tension in the internal workforce by leveraging information about costs offered in the market. We are able to compare costs of undertaking work internally with externally sourced providers.

More information about our approach to delivery and resourcing can be found at Attachment 5.12 Resource and Delivery Strategy for 2019–24.

5.7 Information, Communication and Technology, and Innovation

5.7.1 Overview of ICT capex program

ICT underpins the critical business processes that support the safe and reliable delivery of network services to our customers. Our proposed capex program reflects the efficient level of ICT investment we need to support the continued delivery of network services safely, efficiently and reliably. In addition, the proposed investment for 2019–24 is needed to ensure that:

- there are minimal disruptions to business operations,
- risks of cyber security breaches are managed,
- Ausgrid complies with regulatory requirements and licence conditions including those relating to critical infrastructure,
- we provide customers with improved access to information, and
- we improve our own data-driven decisions.

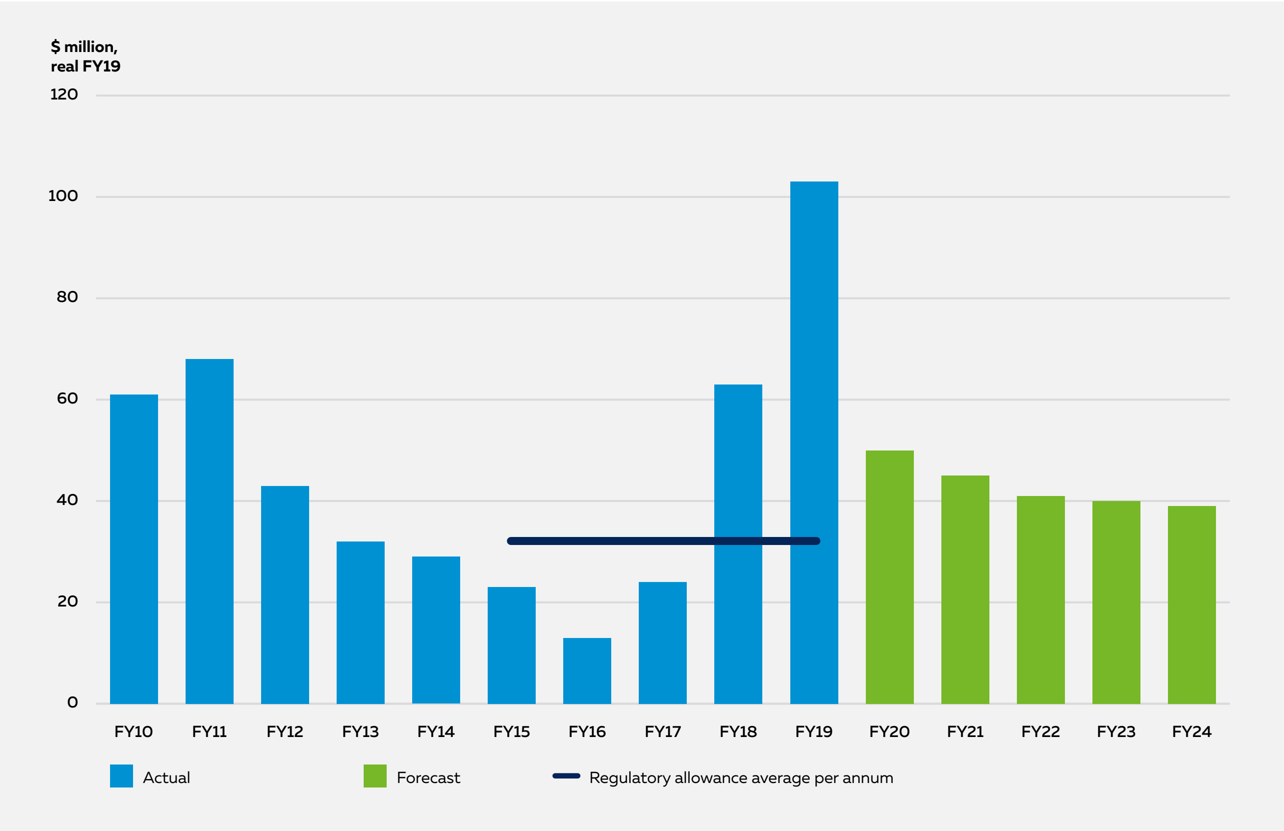
Ausgrid has a complex ICT environment including:

- applications that enable business operations required to run the network,
- security programs and hardware that provide secure links and detect intrusions,
- communications and storage of data, and
- devices to support workplace and field activities.

We forecast that we will invest $216 million on ICT, including non-network operational technology projects and innovation programs (as discussed in Chapter 3) for the 2019–24 period. This includes $157 million for ICT and $58 million for operational technology and innovation. This is slightly less ($16 million or 7%) than the $232 million we expect to invest in the 2014–19 period. Figure 38 illustrates the trend in non-network ICT capex.

Figure 38.

Trends in actual and forecast ICT capex ($ million, real FY19)



Source: Ausgrid.

The large increase in ICT capex towards the end of the 2014-19 regulatory period reflects the fact that critical ICT investment decisions were delayed until after the finalisation of the NSW governments long term lease transaction process. Following the lease transaction, Ausgrid has developed clarity about its ICT investment objectives for the long term, which involves a step up in capex over 2017/18 and 2018/19.

The key drivers of the ICT capex program to:

- maintain safe, reliable and affordable customer service and business operations
- protect the electricity network, our staff and customer information
- comply with licence conditions, laws and regulatory obligations
- adapt Ausgrid's systems and capabilities to improve our data driven customer centric decisions.

We are expecting to spend $232 million in the current period on ICT capex which is $73 million more than the allowance provided by the AER in its 2014–19 final decision. The reasons for this include additional expenditure on cyber security in the current period and the technology maintenance program to bring Ausgrid in line with IT industry practices. The technology maintenance program is a dependency for the delivery of savings that are included in the overall Ausgrid plan.

The benefits for customers from the proposed program include safe, secure and reliable services; increased responsiveness to customer queries and requests; and faster access to better data.

The innovation program is discussed in Chapter 3.

5.7.2 Key ICT programs

Key programs planned for the 2019–24 period include:

- **Application maintenance** – We propose to invest $81 million in an IT Maintenance Program to enable the delivery of safe, reliable and affordable customer service and business operations. The program classifies applications to determine the efficient level of investment, taking into account the criticality of business processes, risk assessments, supplier roadmap timing and application lifecycle. The IT Maintenance Program includes projects to maintain end of life applications. The aim is to ensure that current versions of critical IT applications continue to be vendor supported, and security patches are applied. This will ensure that the technical currency of these applications is maintained, reducing the risk of potential failure and/or unplanned production outages. Without this investment we are exposed to an increase in the risk of vulnerabilities, security breaches and downtime for business operations. A lack of investment would also introduce inefficient work practices and increased operational spend as they would have to revert to manual practices.
- **Cyber security** – In accordance with our licence conditions, and in response to recent global security events, we propose to invest $20 million to reduce the risk of our critical systems being impacted by cyber-attacks. This investment protects our people, our assets and customers from cyber threats. If we do not undertake this program we are exposed to cyber threats which could result in unauthorised access to critical information about our network, our supply of electricity and our customers. There would also be an increased risk of service interruptions to Sydney's financial hub, defence, industry and domestic customers. Further, we would be non-compliant with our licence conditions.
- **Data and Digital Enablement** – We propose to invest $23.5 million into our ongoing Data and Digital Enablement Program to provide the data and digital technologies required to support the efficiencies already built into the proposal, and to meet changing customer expectations. The data and digital enablement program consists of two streams.
  - Digital transformation: Greater automation of our internal processes and expand the capabilities of our existing IT systems to include Robotic Process Automation, wearable technology, intelligent networks and more automation of our customer management platform.
  - Information management: Our proposed Data and Digital Enablement investment will provide better intelligence from data to meet customer expectations of faster response times and access to real time information. If we do not undertake this program, our costs will increase as we will continue to manage using old technologies creating manual processes for both our customers and our employees.

We are also moving more of our IT to the Cloud. Our proposal assumes the Cloud implementation will be completed by FY21 resulting in a capex reduction of approximately $8 million from the investments in the current period. Corresponding opex increases are expected to be minimal.

The proposed ICT program will benefit customers by supporting the safe, efficient and reliable delivery of network services to our customers. More specifically, the program will reduce the impacts of cyber security breaches of the network, thus helping to maintain the security of the network. The program will also help us provide customers with improved access to information, as well as providing data that will help us improve our own decision making.

5.7.3 Developing the ICT program and forecast

Historically ICT non-network investments are refreshed every three to five years. This refresh cycle is in line with industry practice. We are planning to maintain technology in line with ICT industry changes.

The capex program for ICT is based on a needs assessment that evaluates the feasible options that are available to address business requirements over the forecast period. As part of this needs assessment, the state of each IT system is assessed to determine the maintenance, upgrade and patching requirements of each system.

The forecast cost of our ICT investment program has been estimated using bottom-up individual estimates for each project that has been identified as being required during the 2019–24 period. The technology plan and program justification reports for each program are shown in supporting material in Attachments 5.18 and 5.19.

5.7.4 Benchmarking and external verification

Benchmarking ICT capex is challenging because expenditure is often highly cyclical, as the needs of businesses change over time and legacy systems are replaced periodically. The better approach, therefore, is to seek external validation of the ICT strategy and expenditure plans by a suitably qualified expert, who is able to draw on experience across the sector and other industries. [2]

In relation to cyber security, we undertook additional validation to ensure that our proposed expenditure was appropriate, both in the context of the AER's review and in relation to the potential risks. We therefore engaged a number of parties to:

- assess Ausgrid's cyber control maturity using the US Department of Energy developed, Cybersecurity Capability Maturity Model.
- review Ausgrid's cyber security risk landscape to evaluate our cyber security and resilience controls, and existing mitigation strategies. The review produced a costed and executable roadmap of cyber improvement activities we need to undertake, including ongoing continuous improvement. Our forecast of ICT capex includes the efficient cost of executing these improvements over the next regulatory period.
- assist Ausgrid with a strategic review of its cyber security strategy and program. The industry expert (Hakluyt) found the Ausgrid cyber security strategy and program to be 'sound' and identified a number of recommendations incorporated into the Ausgrid cyber security strategy and program.

In addition, the Ausgrid cyber security strategy and program has been reviewed and endorsed by the Critical Infrastructure Centre and Australian Signals Directorate within Federal Government.

Further information on the ICT program is also presented in Attachment 5.01.

2 KPMG undertook an external validation of our ICT strategy.

5.8 Property

5.8.1 Overview of our proposed property program

Our non-network property assets include offices, depots and specialist sites located throughout Ausgrid's distribution area. Capex is required for the consolidation and renewal of depots, and development of offices and specialist supply sites in the right locations that assist in reducing response times in the event of an outage or emergency. The portfolio is ageing with a number of properties not meeting mandatory compliance or environmental requirements.

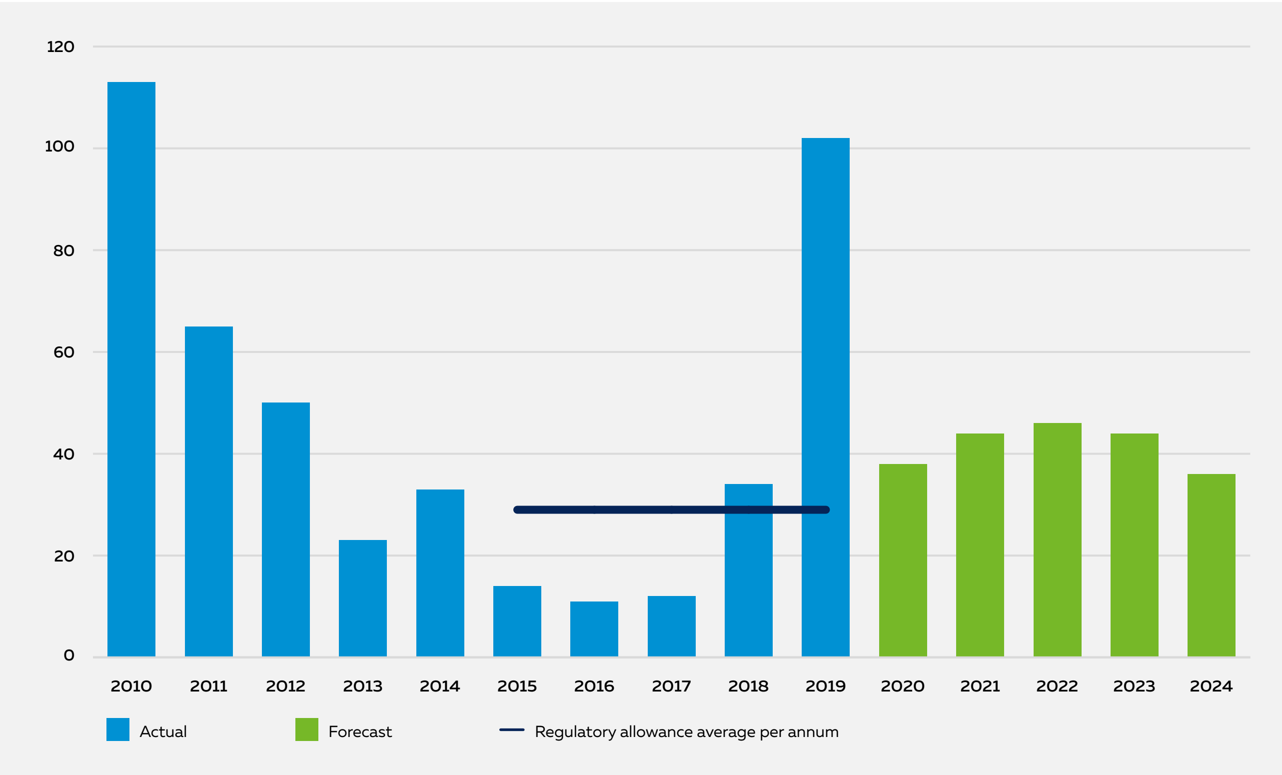
We propose to invest $208 million in capital under our ongoing strategy to consolidate depots and other work places in strategic locations that better assist in servicing the network.

The figure below shows the trend in our recent actual and forecast property capex.

The large increase in Property capex towards the end of the 2014-19 regulatory period reflects the fact that critical property investment decisions were delayed until after the finalisation of the NSW governments long term lease transaction process. Following the lease transaction, Ausgrid has developed clarity about its Property investment objectives for the long term, which involves a step up in capex over 2017/18 and 2018/19.

Figure 39.

Trends in actual and forecast non-network property capex ($ million, real FY19)



Our capex on buildings and property in the 2014–19 period is estimated to exceed the final determination allowance in the current regulatory period by $28 million (real FY19). We expect to dispose of some property during the period which will reduce the value of the RAB. This will result in lower costs to customers over the longer term.

5.8.2 Key property projects

Our proposed program for the 2019–24 period includes two office projects and six depot projects. Each project is summarised below:

- Wallsend office/depot. It is proposed to construct new office accommodation consolidating the Wallsend office and depot operations within the locality to better service the existing and expanding customer base in a strategically located manner and in keeping with the Ausgrid policy of site consolidation to create regional facilities
- Future workplace program. Program of works at various sites to support the cultural transformation by providing a collaborative work environment that sponsors productivity, growth and creativity
- Zetland depot replacement (Alexandria). New green-field development to enable replacement of the existing Zetland depot due to ageing assets, encroachment by residential development and local council infrastructure development
- General depot refurbishment program. Program of works at various minor sites to address ageing assets and compliance requirements
- Homebush depot upgrade. Staged rebuild of the depot facilities at the existing Homebush site to provide fit for purpose facilities and to replace ageing assets
- Hornsby depot replacement. New green-field development to enable replacement of the existing Hornsby depot due to ageing assets
- Oatley depot replacement. New green-field development to enable replacement of the existing Oatley depot due to ageing assets
- Wallsend depot upgrade. Staged rebuild of the depot facilities at the existing Wallsend site to provide fit for purpose facilities and to replace ageing assets.

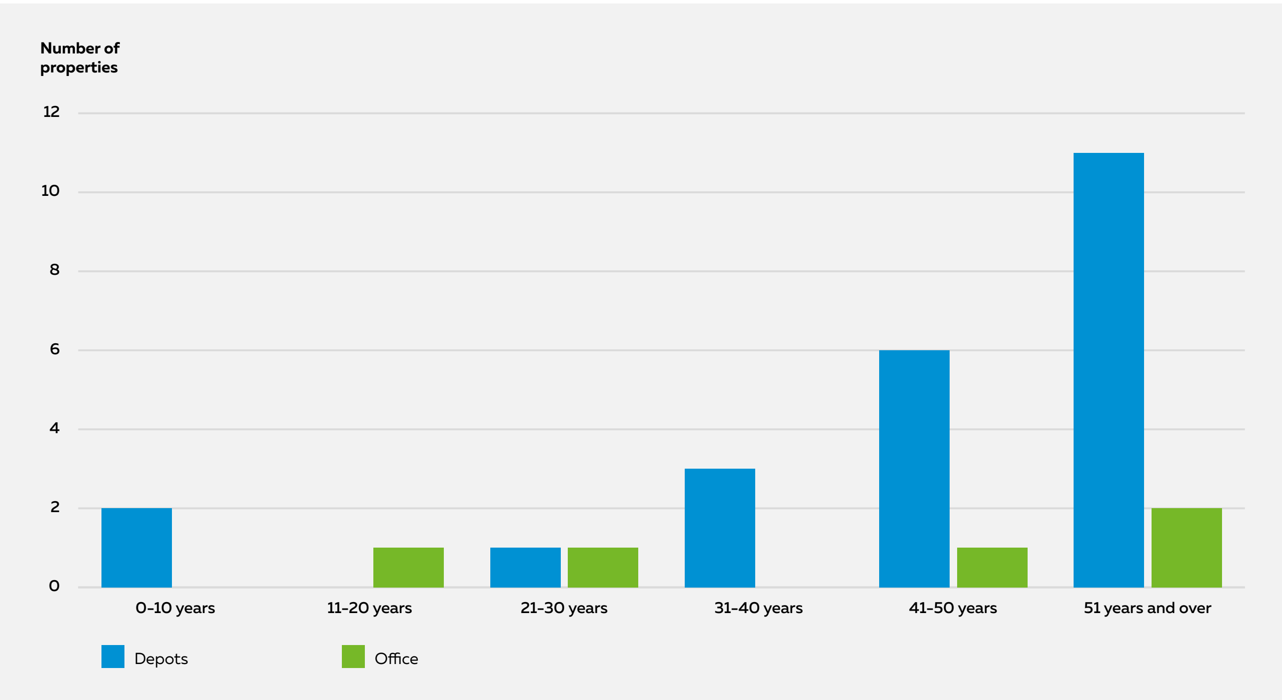
5.8.3 Developing the property program and forecast

The capex program for property and buildings is based on a needs assessment which evaluates the feasible options that are available to address future requirements. Ausgrid conducts annual reviews to assess the state of the property portfolio and how changes in the underlying business environment or external circumstances are likely to drive requirements of the portfolio.

Many of our depots and offices are over 50 years old and in some cases do not meet modern workplace requirements. The age profile of our non-network property is shown in Figure 40 below.

Figure 40.

Age profile of depots and offices



Source: Ausgrid.

The expected service life of depots is 40 years. After this age they cease to comply with relevant codes and modern workplace standards, so they cease to be fit for service. As shown in the above figure:

- 17 depots are currently over the standard age of 40 years, and
- three out of five offices are over 40 years old.

The property program will replace or upgrade a number of these ageing facilities so that they conform with modern standards and provide fit for purpose accommodation for our staff and contractors. The program will deliver benefits through:

- increased proximity of depots to key Ausgrid assets and customers, enabling faster response times in the event of outages and emergencies,
- co-location of offices and depots to bring staff together, enabling greater information sharing between staff, and more collaboration and innovation within the organisation, and
- improved staff morale and wellbeing, leading to productivity increases.

Further information on the non-network property program is also presented in Attachment 5.01.

5.9 Fleet and plant

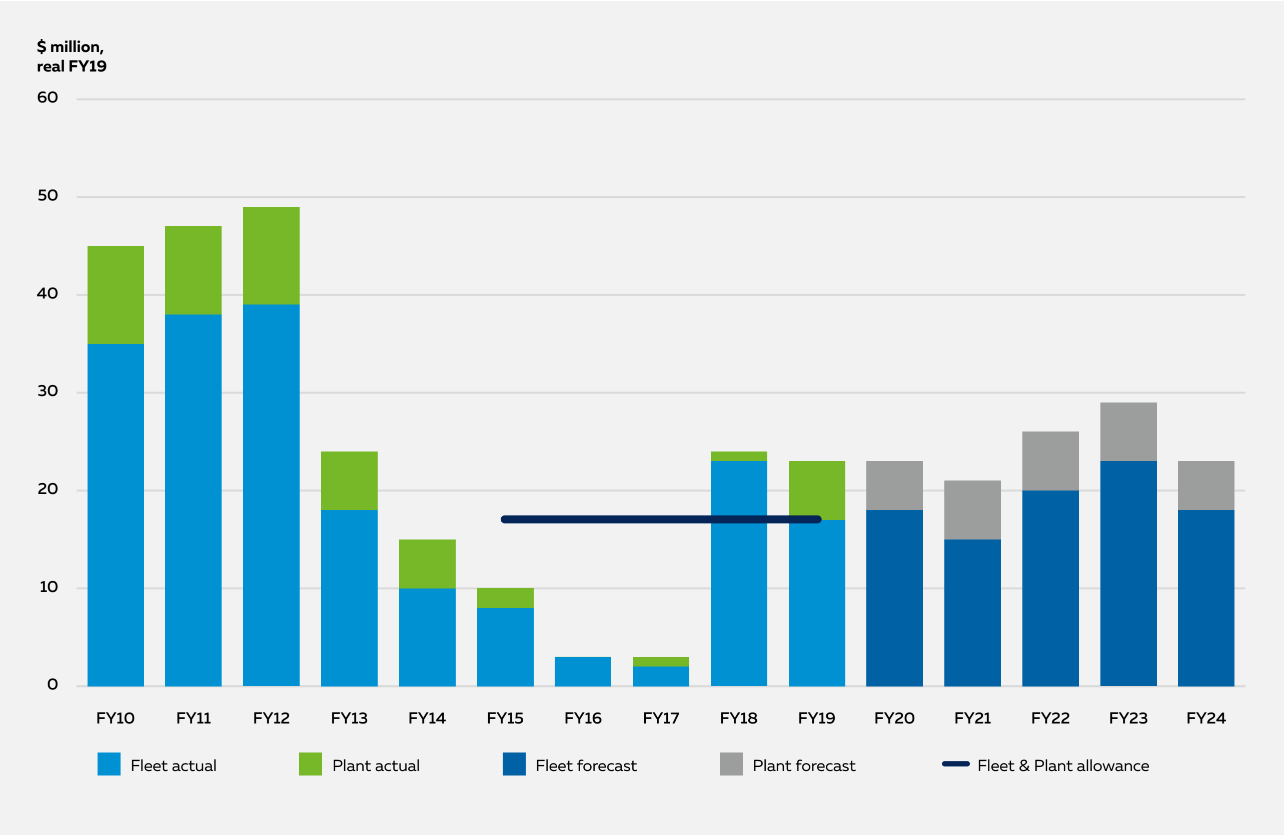
5.9.1 Overview of our proposed fleet and plant program

Ausgrid's fleet of vehicles, trucks, utilities and plant is essential to support our operations in the field and for the efficient delivery of network services.

Ausgrid proposes to invest $124 million (real FY19) in fleet and plant during the 2019–24 regulatory period. This expenditure comprises $94 million for fleet and $30 million for plant as shown in Figure 41 below.

Figure 41.

Trends in actual and forecast fleet and plant capex ($ million, real FY19)



Source: Ausgrid.

Initially in the 2014-19 period, the focus was on reducing the fleet to improve fleet utilisation following the reduction in the capex program. The focus of fleet capex over the 2019-24 period is on fleet replacement. The objective is to reduce opex (maintenance, leasing costs) and optimise the life cycle costs of capex through timely replacement of aged fleet.

Over the course of the next regulatory period we are also seeking to increase the standardisation of our fleet, which should assist in reducing maintenance and replacement costs over the longer term.

Our proposed investment is needed to maintain the safety and efficiency of Ausgrid's fleet of vehicles and plant. This supports the efficient delivery of our capex programs, by providing our workforce with the transport and equipment they need to perform their daily activities safely and efficiently.

5.9.2 Key fleet and plant projects

Ausgrid has a diverse range of fleet and plant to meet the needs of a large multi-functional workforce. The strategic aim of Ausgrid's plan for fleet and plant is to:

- ensure that fleet and plant are safe and reliable,
- ensure that the costs of meeting our needs for fleet and plant are minimised over the life cycle of the assets,

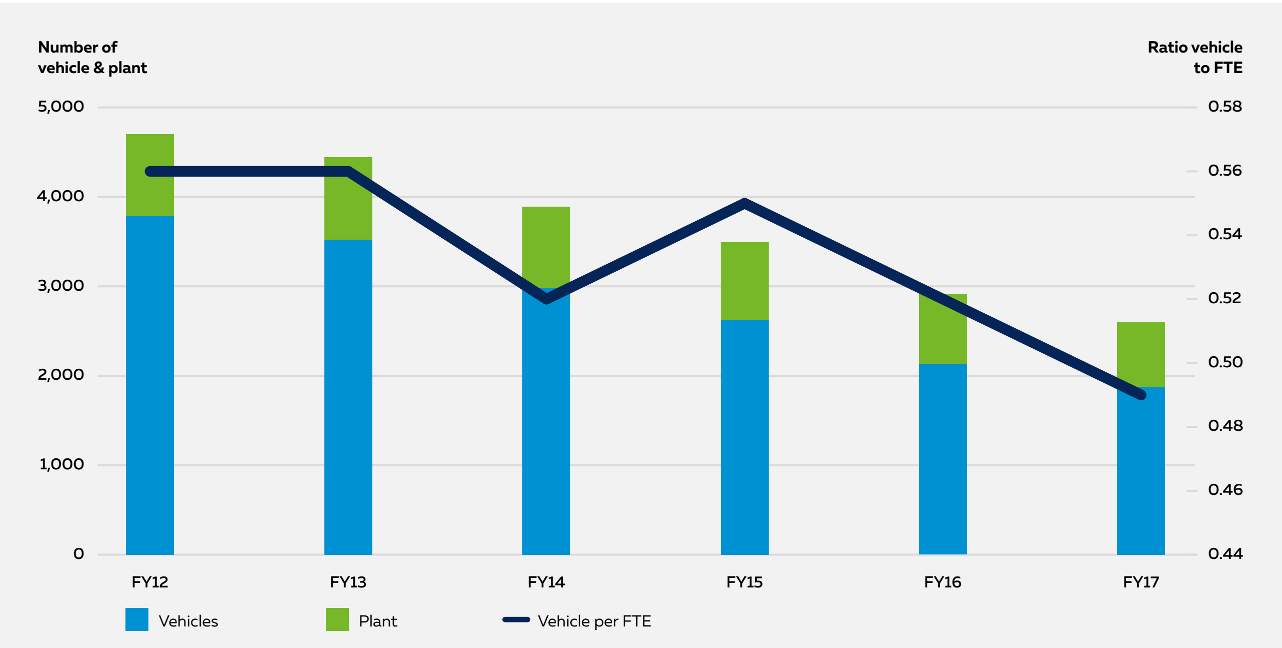
- meet customers' expectations regarding efficient service delivery,
- provide a range of vehicles and plant that promote optimal work practices and productivity of Ausgrid's workforce, and
- meet the requirements of the capex programs.

Key projects include:

- Introducing telematics to allow Ausgrid to monitor driver behaviours and improve fleet utilisation. This provides benefits in workforce safety and operational efficiency.
- Review of elevating work platforms with a focus on moving to smaller, more agile units and more standardisation. This will reduce operational cost, improve efficiency for staff and impact on other road users by having a reduced footprint.
- Fleet renewal. Over the past 2.5 years the fleet plan has focused on fleet reductions and better utilisation (measured by a reduction in vehicles per full-time equivalent (FTE)). The business operating plan is now sufficiently progressed via transformation to support network service delivery with replacement fleet.

Figure 42.

Utilisation of fleet



Source: Ausgrid.

As shown above, we have reduced the number of fleet from 3,783 in FY12 to 1,871 in FY17 (or 50%). The utilisation of fleet has improved from 0.56 to 0.49 vehicles per employee over this same period.

5.9.3 Developing the proposed fleet and plant program and forecast

Capex for fleet and plant was forecast by estimating age-based retirements of existing assets. These forecasts were then adjusted for changes in maximum acceptable asset ages and refurbishment plans and the total requirement for each vehicle/plant type.

The overall objective of our fleet and plant program is to minimise the total lifecycle cost of meeting our efficient requirements. In practice, decisions to replace fleet are primarily driven by vehicle age and our program is based on maintaining the age profile of our assets.

The proposed program will benefit our operations and customers by:

- having a focus on lifecycle costs which will assist in achieving lower overall costs in the longer term, and
- promoting productivity and optimal work practices by providing the workforce with the vehicles and plant that are safe and fit for purpose.

Further information on the fleet and plant program is presented in Attachment 5.01.

5.10 Capital program support costs

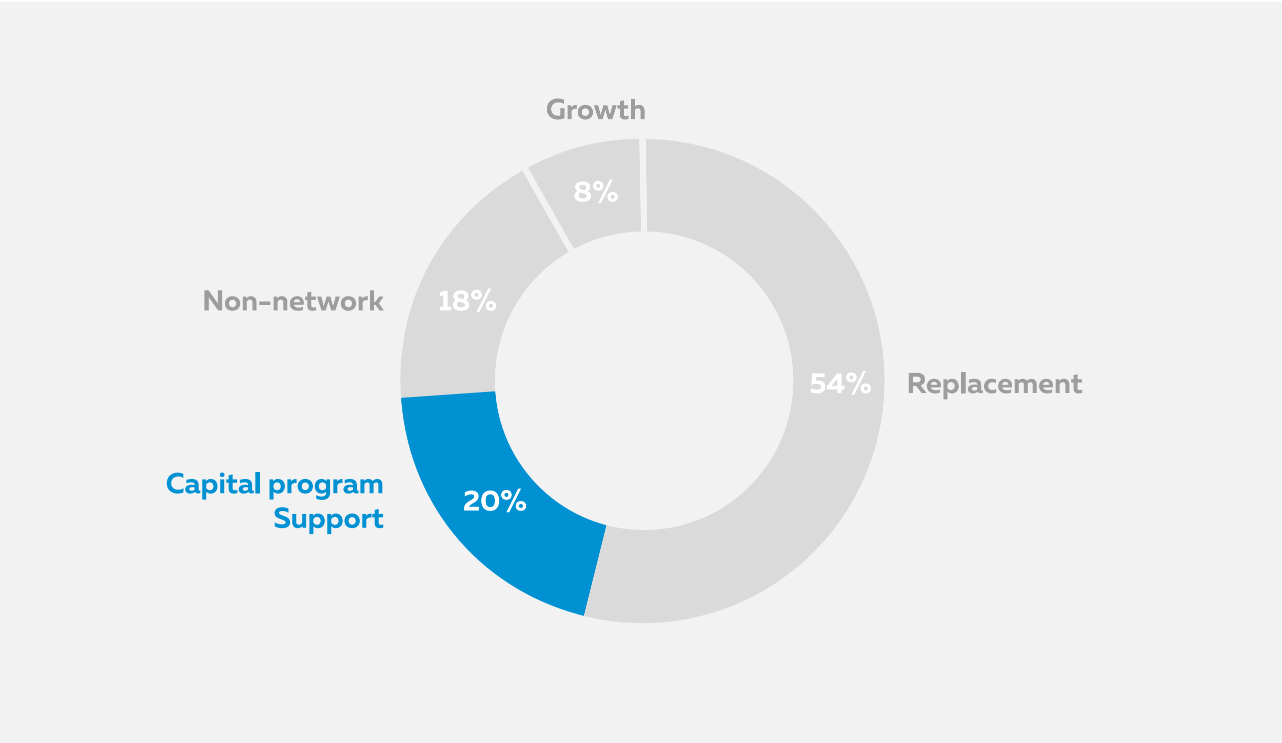
5.10.1 Proposed capital program support costs

Capital program support costs (capitalised overheads) make up the overhead costs that support the efficient delivery of the capital program. These costs are made up of direct costs (network planning) and indirect costs (network divisional management and business support functions; fleet; corporate support functions; logistics, warehousing and procurement; and IT). These are different costs to non-network ICT and fleet.

We forecast that we will require $621 million in capital program support costs in the 2019–24 period. This represents around 20% of the total capex forecast.

Figure 43.

Capital program support costs as proportion of total capital program in 2019–24



Source: Ausgrid.

Our expenditure forecast reflects the efficient level of overhead resources needed to support the efficient delivery of the replacement, augmentation and non-network capital programs.

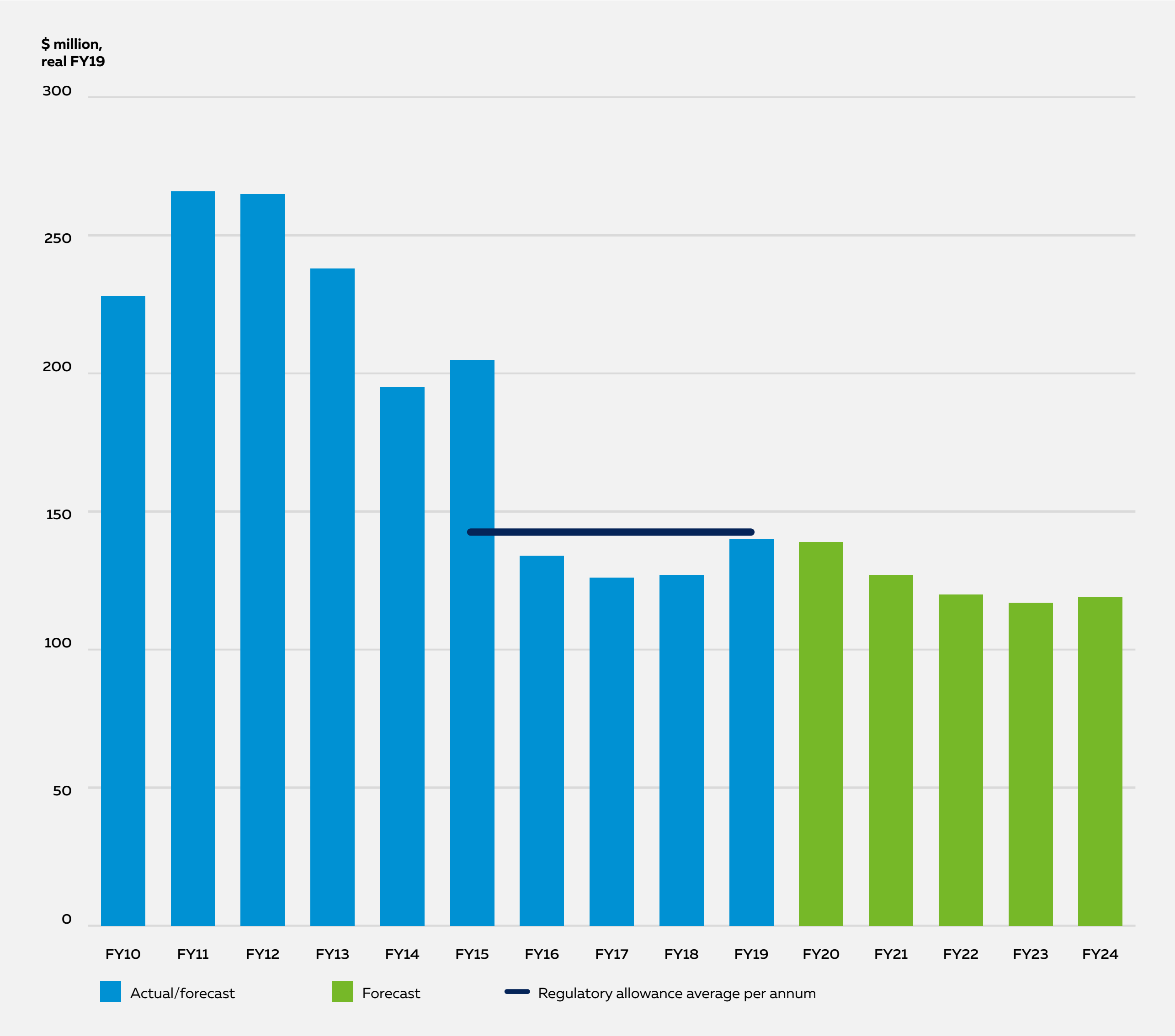
Capital program support costs are allocated to our various capital projects and programs based on direct labour, so they are effectively spread across all asset classes and hence depreciated according to the regulatory depreciation rates for the various RAB asset categories.

5.10.2 Trends in capital program support costs

Capital program support costs have decreased significantly in the current regulatory period, both as a percentage of direct labour and in dollar terms. In the current period (2014–19), we have reduced our capital program support costs by 40% compared to the 2009–14 period. We forecast that we will achieve reductions of a further 9% over the 2019–24 period. The expenditure trend is shown in Figure 44 below.

Figure 44.

Trends in actual and forecast capital program support costs ($ million, real FY19)



Source: Ausgrid.

It is noted that we have reduced our capital program support costs from 74% of direct capex labour in FY10–14, to 64% of direct capex labour in FY18.

These savings reflect sustainable cost reductions, and they have been achieved through Ausgrid's transformation program. Savings we have achieved across our operating and capex programs in the current regulatory period have reduced the total cost pool, resulting in significantly lower indirect support costs being allocated to capital.

5.10.3 Approach to forecasting

These types of costs are indirect costs that support the capital program such as fleet, logistics and procurement and IT. These costs are not directly attributable to any one capital program or project. They are allocated to capital projects in accordance with Australian Accounting Standards and are allocated to standard control services based on Ausgrid's Cost Allocation Methodology (CAM). The CAM is approved by the AER.

Support costs for the FY20–24 period have been forecast based on the current level of support costs to direct capex labour (i.e. a ratio of 64% to forecast direct capex labour).

Further information on the capital support program is presented in Attachment 5.01.

5.11 National Energy Rules compliance

The NER sets out specific requirements in relation to our capex forecasts. In particular, our forecasts must achieve the capex objectives, which include the requirement to provide safe and reliable distribution services to our customers and to comply with our regulatory obligations. The NER also stipulate that our expenditure forecasts should reflect the efficient and prudent costs of achieving the capex objectives.

The NER provides guidance to the AER on the matters that it should consider in assessing our forecasts, which include:

- the AER's most recent annual benchmarking reports,
- the actual and expected capex in previous regulatory control periods,
- the extent to which the forecasts address the concerns of electricity consumers,
- the relative prices of operating and capital inputs,
- the substitution possibilities between operating and capital expenditure,
- whether the forecast is consistent with the applicable incentive schemes,
- whether the forecast reflects arrangements that are not on arm's length terms,
- whether the expenditure forecast includes an amount relating to a project that should more appropriately be included as a contingent project,
- the extent we have considered, and made provision for, efficient and prudent non-network options, and
- any relevant final project assessment report, as required by the regulatory investment test.

For the reasons outlined in this chapter, Ausgrid is confident that the AER will accept our forecast capex. In particular, we note that:

- our capital costs benchmark well against our peers, reflecting our achievement of very substantial savings in the 2014–19 period,
- we have transformed our business to provide a more sustainable cost base and to embed a culture of efficiency, including active consideration of opex-capex trade-offs,
- we have taken account of customers' concerns regarding affordability in preparing our capex forecasts, and
- there will be some capex attributable to a related party (PlusES Partnership) where they undertake metering works (for SCS) in Ausgrid substations. This is subject to an agreement that reflects commercial arm's length terms.

Our proposed capex program for the 2019–24 period is 1.3% lower than the amount we expect to invest in the current 2014–19 regulatory period. This means by 2024 our capex will have fallen by 69% below the peak capex in 2012. We achieved these efficiency savings through initiatives including:

- introducing a more rigorous cost-benefit analysis that deferred major projects where it was efficient to do so,
- avoiding 'like-for-like' replacement of major infrastructure by utilising spare capacity on neighbouring parts of the network,
- increasing our focus on demand management solutions to defer replacement capex,
- outsourcing more of the capital program to external providers where there was a cost advantage of doing so, and
- improving our governance processes to better target our investment and ensuring projects are scoped and costed efficiently at each stage of the investment cycle through planning, design and delivery.

These improvements and efficiency gains are now embedded in the business, and in our capex forecasts for the 2019–24 period. The improvements will reduce ongoing costs and we will make sure that they do not adversely impact on the reliability, security and safety of our services.

In forecasting our capex requirements, we must achieve an appropriate balance between the pressure to reduce expenditure further and the importance of maintaining safety and service performance whilst managing network risks efficiently, both now and in the future. For the reasons set out in this chapter, we believe that we have achieved an appropriate balance.

We are confident that the information presented in this proposal demonstrates that our capex forecasts reflect efficient and prudent costs, in accordance with the requirements of the Rules.

Clause 6.5.7 and Schedule 1 of the NER requires us to provide specific information on our capex forecast.

Additionally, the NER requires us to submit information requested by the AER in a RIN. The AER issued a RIN in January 2018, which consisted of a series of data questions in an Excel worksheet, together with written questions. Further information on our capex program is provided in our response to the RIN which accompanies our Proposal.

5.12 Material to support our capital expenditure proposal

We are submitting 22 documents to the AER to support our capex forecast. We have only included the most relevant documents, to streamline the amount of information submitted. We are open to providing any other information requested by the AER and stakeholders.

Attachment 5.01 provides a comprehensive summary of our capital forecast for 2019–24 including:

- description of our operating environment and state of our network assets
- information on our capex at a high level including our forecast methods, key inputs, benchmarks, and how we addressed the capex objectives, criteria and factors in the NER
- information on our replacement, growth, non-network and capital program support programs.

Each section of Attachment 5.01 refers to key supporting documents to assist the AER and stakeholder assessment. We have made claims to confidentiality in relation to some property information.

06

Operating expenditure


Ausgrid

06

Operating expenditure

What did we achieve in 2014–19?

We invested **$374 million in right-sizing our operations**. This has resulted in significant, sustainable cost reductions without compromising safety or reliability. Our annual opex cost base is now $100 million, or 19%, lower today compared to five years ago.

We embarked on a **transformation program** to reduce costs by:

- embedding a new business model and management structure to streamline decision making and improve accountability and effectiveness, and
- increasing field productivity to reduce overall costs and resources required to deliver our capital and maintenance programs.

Together, these actions have created a sustainable future operating cost base for Ausgrid.

What outcomes will we deliver in 2019–24?

We are **forecasting $2.4 billion of opex over the 2019–24 regulatory period**, $500 million less than we forecast last time. We have embedded the significant and sustainable cost decreases achieved through our transformation program in our forecast. The ongoing benefit of the reduction in our annual opex cost base has benefited each customer by an average of $76 per year.

Our forecast opex compares favourably with other businesses. In the 2019–24 regulatory period, customer affordability concerns and the strength of the AER's incentive framework will provide significant motivation for Ausgrid to continue to pursue **the efficiency frontier**. In addition to focusing on affordability and sustainability, we are seeking to deliver improved customer value.

Although we plan to spend significantly less than historic levels, we will not compromise safety or reliability. We will maintain reliability and improve safety performance where we are able to do so. Additionally, we will undertake trials to use low carbon technologies (such as solar) to support demand management.

How are we responding to our customers' feedback?

Affordable

We will maintain our new lower operating cost base over the 2019–24 regulatory period to sustain **network bill reductions** achieved through our transformation over the 2014–19 regulatory period. Demand management will seek to avoid capex providing positive outcomes for customers.

Reliable

Our demand management program will allow us to use distributed energy resources (such as solar and batteries) to **mitigate the impact of outages** while lowering costs to customers.

Sustainable

In addition to using distributed energy resources in a transition to a lower carbon economy, we are considering ways we can lower the impact of our business on the environment. We will track and identify ways to minimise resource use and **lower our carbon footprint**. We aim to be recognised as an industry leader in sustainability.

In addition to these core themes, we are addressing customers' feedback on vegetation management by seeking a better balance between network safety and reliability needs and the local community's aesthetic expectations for trees in their neighbourhoods.

We are listening to our customers' concerns about affordability and we have delivered. We have invested $374 million in right-sizing our business, streamlining our operations and increasing our productivity. We have lowered operating costs by 19%, or around $100 million per year and will continuously strive to provide greater customer value.

6.1 Overview

Opex makes up around a third of the revenue we recover from customers. It includes the costs of operating and maintaining our physical assets (such as our poles, wires and substations, monitoring and control systems), responding to emergencies (such as fallen trees on our power lines) and undertaking customer-related functions (such as providing call centre services). In general, opex reflects activities and costs that are ongoing and recurrent.

Opex has a direct impact on our prices. In the 2014–19 regulatory period, we addressed customers' concerns regarding affordability by changing our business practices to deliver ongoing opex reductions of more than $100 million per annum, making significant progress in moving to an efficient and sustainable level of opex. This translates into an average saving of $76 to each customer per year.[1] The changes we have made have allowed us to:

- lower costs without compromising safety or reliability, and
- pass on cost savings to customers.

The significant reductions achieved to date provide a sound basis for forecasting our future opex requirements. Consistent with industry best practice, we are using past expenditure (revealed costs) to forecast future opex and applying the AER's EBSS in the next regulatory period. The regulatory framework and our new commercial focus give us strong financial incentives to continually improve our cost efficiency and share these improvements with our customers.

Our opex forecast:

- is calculated using the AER's preferred base-step-trend methodology,
- reflects changes in opex over time from growth in the size of our network and customer numbers and forecast price increases for wages, materials and suppliers, and
- reflects the total opex required to meet Ausgrid's regulatory obligations. Changes in individual components that are not the result of external changes, or an opex/capex trade off, will not be explicitly reflected in the forecast.

In the 2019–24 regulatory period, we have identified a number of cost increases which we are proposing to absorb through efficiency savings, including:

- land tax is expected to increase by approximately 7 per cent annually over the forecast period due to increased land values. This translates to approximately $30 million in additional opex over the 2019–24 period above the amount allowed through the base-step-trend approach,
- costs associated with customer operations activities such as storm readiness campaigns, customer surveys, complaints management, contact centre and customer connections are expected to be approximately $10 million higher than the amount allowed through the base-step-trend approach over the 2019–24 period, and
- IT costs associated with cyber security and data management are expected to be approximately $8 million higher than the amount allowed through the base-step-trend approach over the 2019–24 period.

1 This saving represents the difference between opex per customer in 2012/13 and 2017/18.

In addition to focusing on affordability and sustainability, we are taking initiatives to deliver improved customer value within our opex forecast:

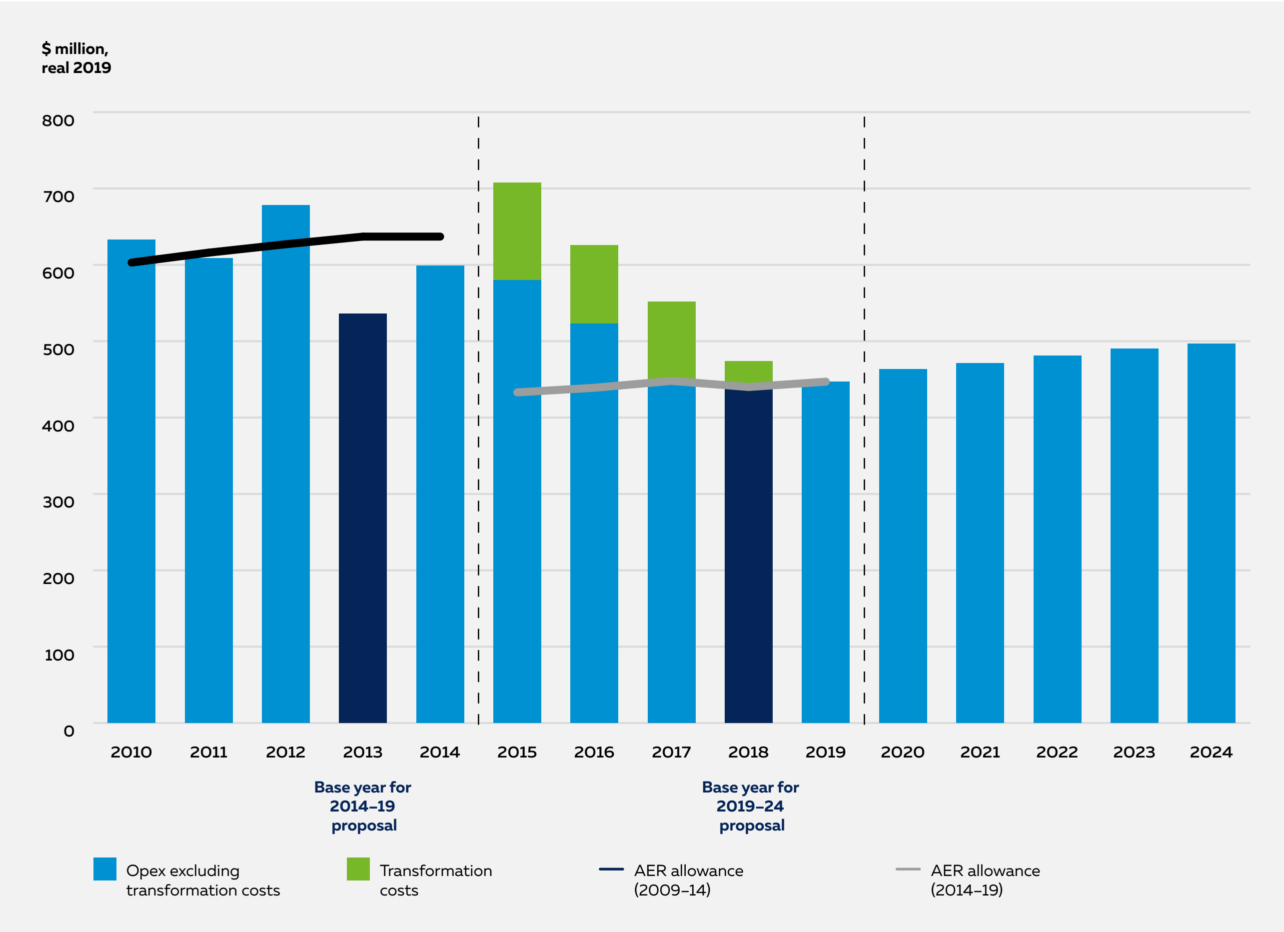
- We have changed our working practices for vegetation management in response to customer feedback. Our new approach of more frequent, less severe tree trimming maximises customer value through increased aesthetics and utility in suburban areas.
- We are implementing an ADMS to enable Ausgrid to take advantage of future industry and technological developments. This will better serve our customers by enabling the modern grid and allowing real-time identification of outages.
- We are increasing our focus on education, developing a strategy to better engage with our CALD customers and revamping our energy literacy material to identify and address any gaps to make information easier to access and understand.

In light of customers' concerns regarding affordability, we are not seeking to pass through any increased operational costs associated with these cost categories. Rather, we will absorb these cost increases and work hard to achieve efficiencies to offset these with reductions.

In the 2019–24 regulatory period, we will maintain the lower cost base achieved in the current period while maintaining reliability and improving safety where it is possible to do so. The figure below shows our forecast opex alongside our actual opex for the current and previous regulatory periods.

Figure 45.

Actual and forecast opex for 2009/10 to 2023/24 ($ million, real FY19)



Note: Opex excluding debt raising costs.

Source: Ausgrid.

Table 20.

Forecast opex 2019/20 to 2023/24 ($ million, real FY19)

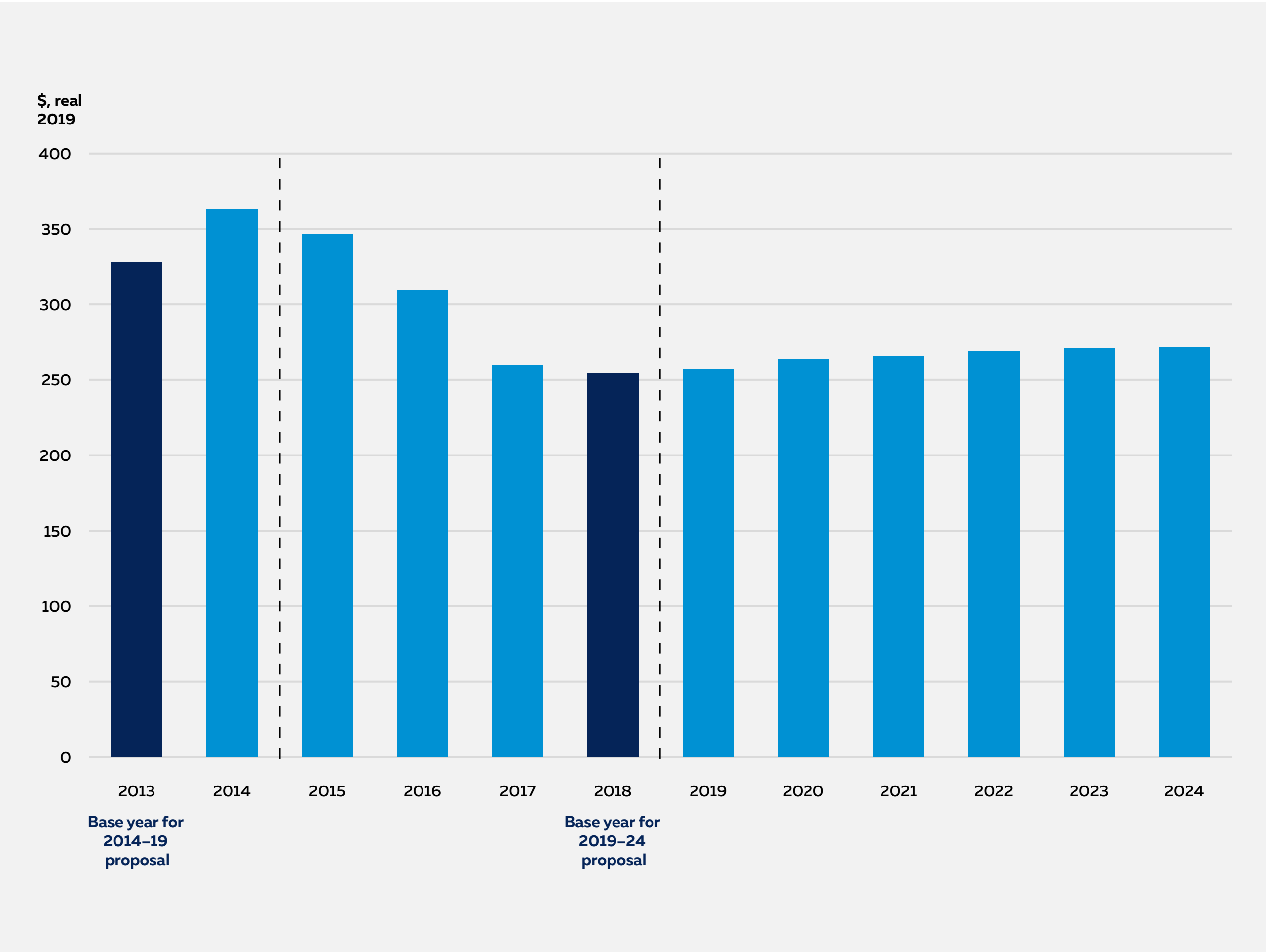
OPEX	2019/20	2020/21	2021/22	2022/23	2023/24	TOTAL
Total	463	471	481	490	497	2,402

Note: Opex excluding debt raising costs.

Overall opex is increasing slightly over the next regulatory period, largely due to growth in our customer numbers and forecast price increases for wages. On a per customer basis, our forecast opex is stable over the next regulatory period, maintaining the savings achieved in the current regulatory period. The figure below shows our forecast opex per customer alongside our actual opex per customer over the period 2012/13 to 2023/24, excluding transformation costs.

Figure 46.

Actual and forecast opex per customer (excluding transformation costs) for 2012/13 to 2023/24 ($, real FY19)



Note: Opex per customer excluding transformation costs and debt raising costs.

Our opex programs are described in the table below.

Table 21.

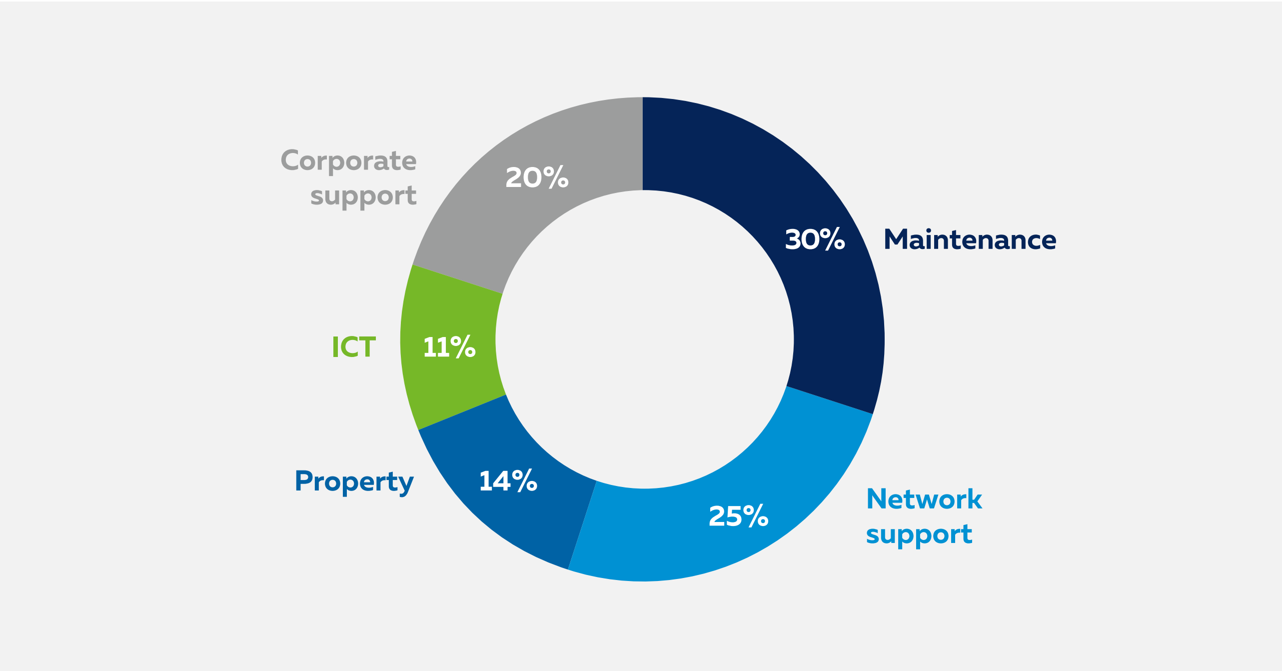
Overview of opex programs

PROGRAM	DESCRIPTION
Maintenance	Inspecting and maintaining our network, to ensure customers, the public and our employees are safe.
Network support	Running the network control centre, undertaking centralised engineering, planning and connection activities and responding to emergencies.
Property	Managing non-network land and buildings, which includes costs such as building maintenance, land tax and municipal rates.
ICT	Running the many IT and telecommunication technologies and systems needed to manage our large network.
Corporate support	Recurrent costs supporting the delivery of network services, including management, human resources, finance, our fleet of vehicles and insurance.

The figure below summarises our allocation of opex to the above program in our base year.

Figure 47.

Forecast opex by program (%, 2017/18)



Source: Ausgrid.

6.2 Performance in the 2014 to 2019 period

In the past, we operated with a higher cost base. Mandated licence conditions, which increased reliability standards, and rising peak demand led to an increase in our operating cost base to support the required rapid increase in capex from 2007 to 2012. Now we are adapting to changes in the energy sector (see Chapter 3) and addressing customer concerns regarding affordability (see section 2.3.1). In response, we have worked hard to reduce our costs to the challenging levels set by the AER for the 2014–19 regulatory period.

The AER's assessment of our past opex performance, and our customers' focus on affordability, made it our top priority to transform our cost base. We have transitioned our business to a more sustainable level of opex through an ambitious program of transformation designed to 'right-size' our workforce and improve our efficiency.

The AER's 2015 Determination set a significantly lower level of opex than we had proposed, which was reflected in a 14% average fall in prices in 2015/16. Since then we have moved as quickly as possible to close the gap between our actual expenditure and our allowance by making sustainable savings.

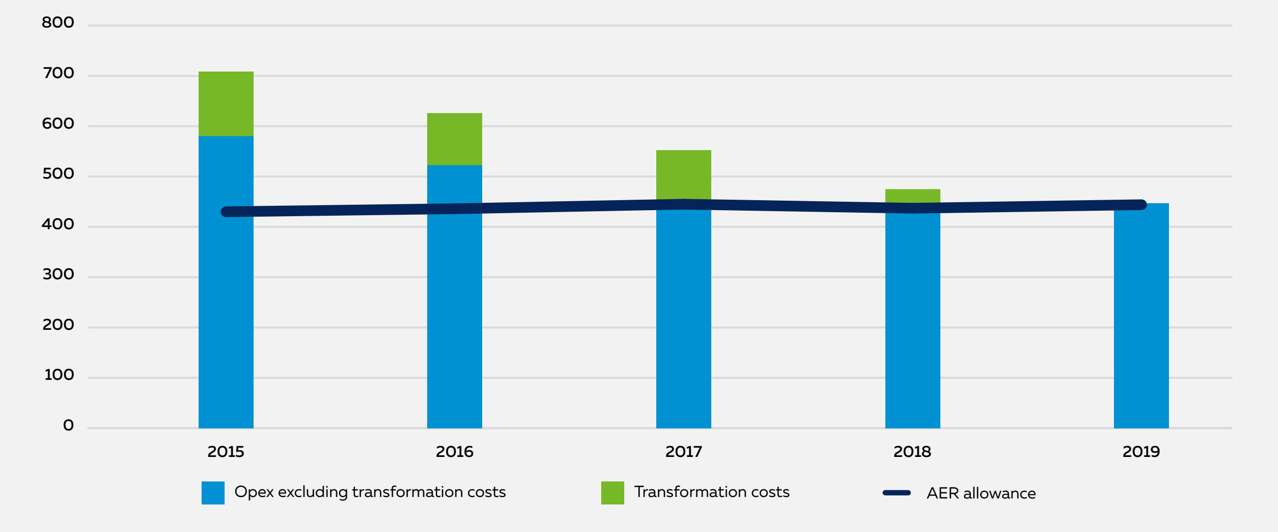
We have worked hard to 'get the fundamentals right'. Our transformation program is delivering sustainable opex reductions.

Stakeholders have asked if we are still meeting our key performance indicators, given the substantially lower levels of expenditure compared to historic levels. As already noted, our transformation program has enabled us to reduce costs without compromising safety or customer outcomes (see Chapter 2). Our achievements have been delivered within our current industrial relations settings, under which any workforce reductions must be achieved through voluntary redundancies.

The figure and table below show our actual and estimated opex for the 2014–19 period compared to the AER's 2015 Determination. As the figure shows, the transformation program has been expansive. However, it is delivering ongoing opex savings that will be sustained in the 2019–24 regulatory period. It is money well spent, both in respectfully managing our people and achieving ongoing reductions in our cost base.

Figure 48.

Opex comparison for 2014–19 ($ million, real FY19)



Note: Opex excluding debt raising costs.

While we have incurred transformation costs in 2017/18, we expect our underlying or recurrent opex in 2017/18 and 2018/19 to be in line with the AER's 2015 Determination allowance.. This is subject to change, depending on circumstances over the rest of this financial year, and to the end of 2018/19.

Table 22.

Opex comparison for 2014–19 ($ million, real FY19)

OPEX	2014/15	2015/16	2016/17	2017/18	2018/19
Actual/Estimated	708	626	553	474	447
AER Allowance	433	439	448	440	447
Difference	275	187	105	34	–

Note: Conversion from nominal to real FY19 terms will depend on the inflation rate used for 2018/19 and 2019/20. For the purpose of the comparison between actual/estimated opex and the AER allowance (shown in this table), we have used a consistent approach to converting our actual/estimated opex and the opex allowance to real FY19 terms. This is different to the approach used in the opex model to calculate the adjustment to base year opex (i.e. incremental opex between 2018/19 and 2019/20). Both approaches to convert to real FY19 terms result in the same adjustment to base year opex.

As part of our effort to improve opex performance over the 2014–19 regulatory period, we regularly measure ourselves against our peers – other Australian distribution businesses. These comparisons show that we have made significant progress over a range of measures, bringing our performance into line with best practice within our industry.

The charts below demonstrate our improved performance, using RIN data from 2016 and 2017. In the first set of charts, the green bar represents our actual performance in 2016/17, and the grey bar indicates our proposed base year 2017/18. As can be seen, our proposed base year represents significant improvement in our comparative opex performance across each measure.

Figure 49.

Opex per customer ($, nominal)

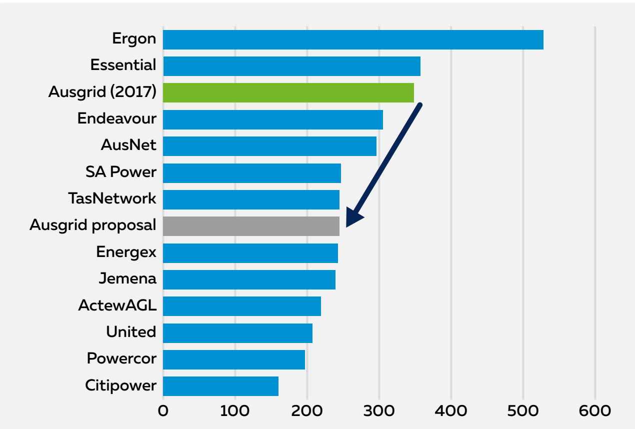


Figure 51.

Opex per km of circuit length ($, nominal)

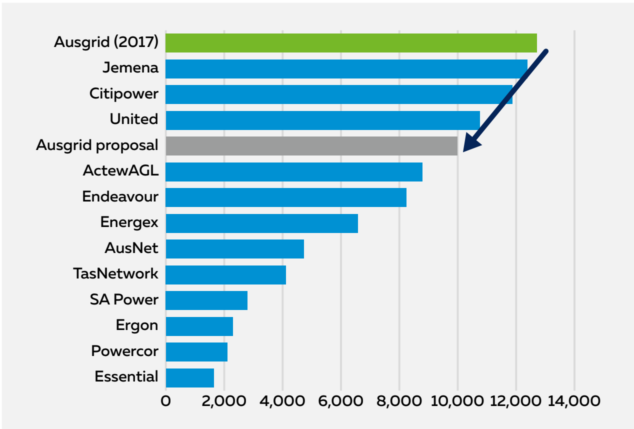


Figure 50.

Opex per GWh delivered ($, nominal)

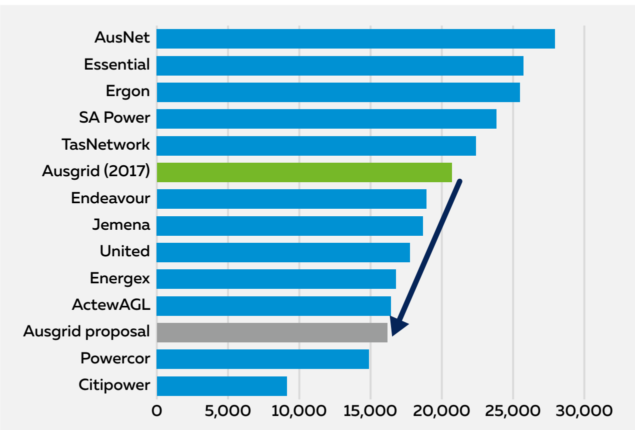
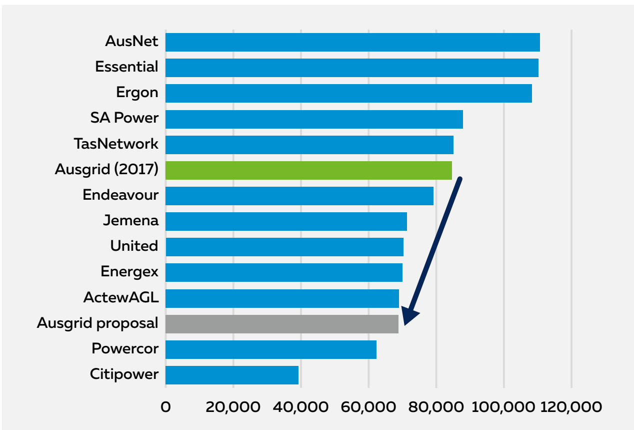


Figure 52.

Opex per MVA of maximum demand ($, nominal)



Source: Regulatory Information Notices available at www.aer.gov.au and Ausgrid analysis.

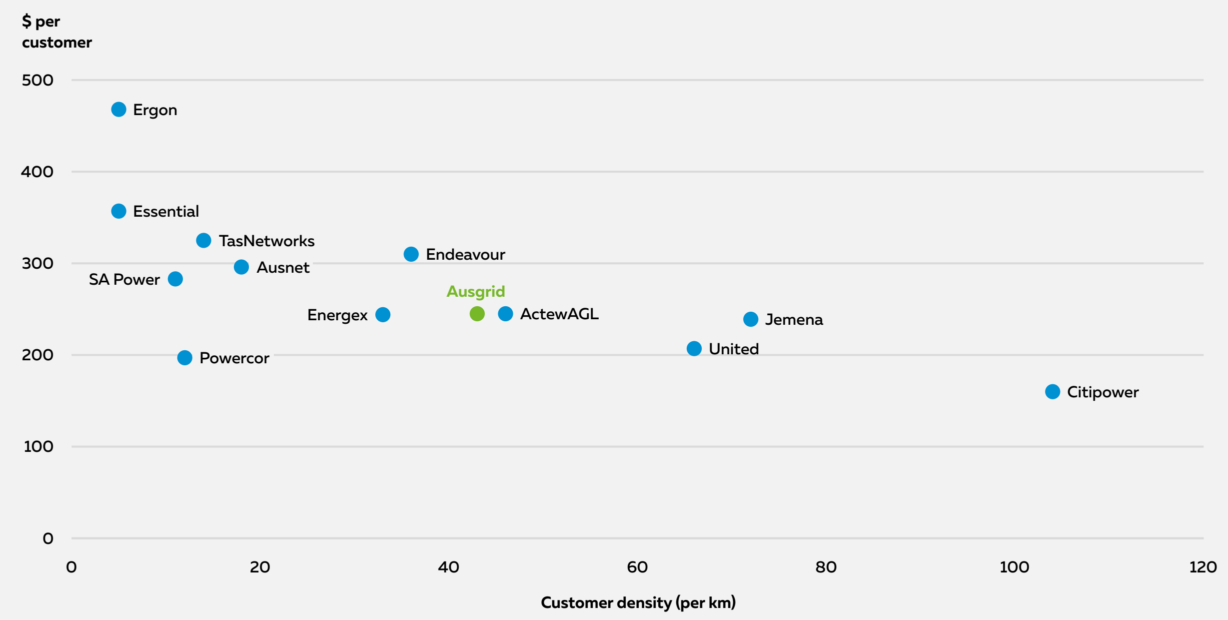
We also assess our performance on three partial efficiency measures (opex per customer, opex per maximum demand, and opex per circuit km) against customer density, estimated as the average number of customers per square kilometre. This is consistent with how the AER presented its benchmarking analysis in 2015. While no single measure can capture all the factors that determine opex, these comparisons highlight the difference between urban network businesses (such as CitiPower) and rural businesses (such as Essential). Ausgrid's service environment is in between these extremes, distributing electricity in the Sydney, Central Coast and Hunter regions.

Our current opex compares favourably with other businesses.

The charts below show the performance of our proposed base year opex (2017/18) on these measures, indicated with the green circles. They indicate that our opex performance is now in line with that of our peers.

Figure 53.

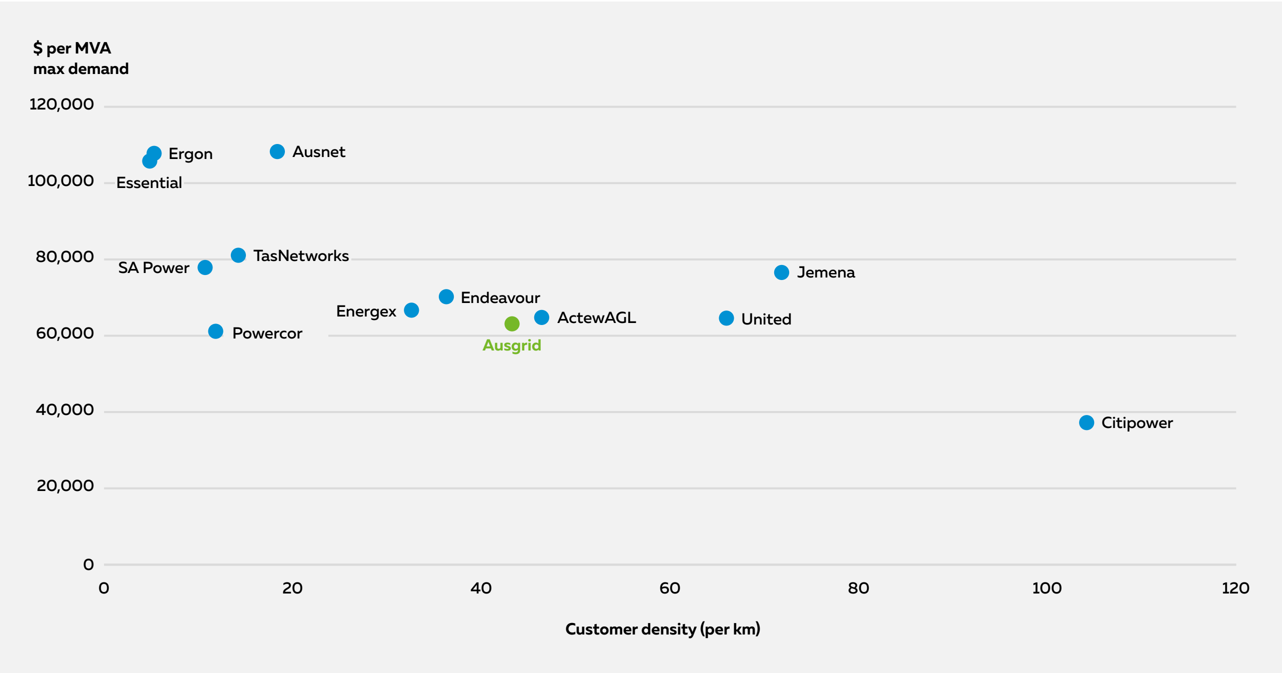
Opex per customer against customer density ($, nominal)



Source: Regulatory Information Notices available at www.aer.gov.au and Ausgrid analysis.

Figure 54.

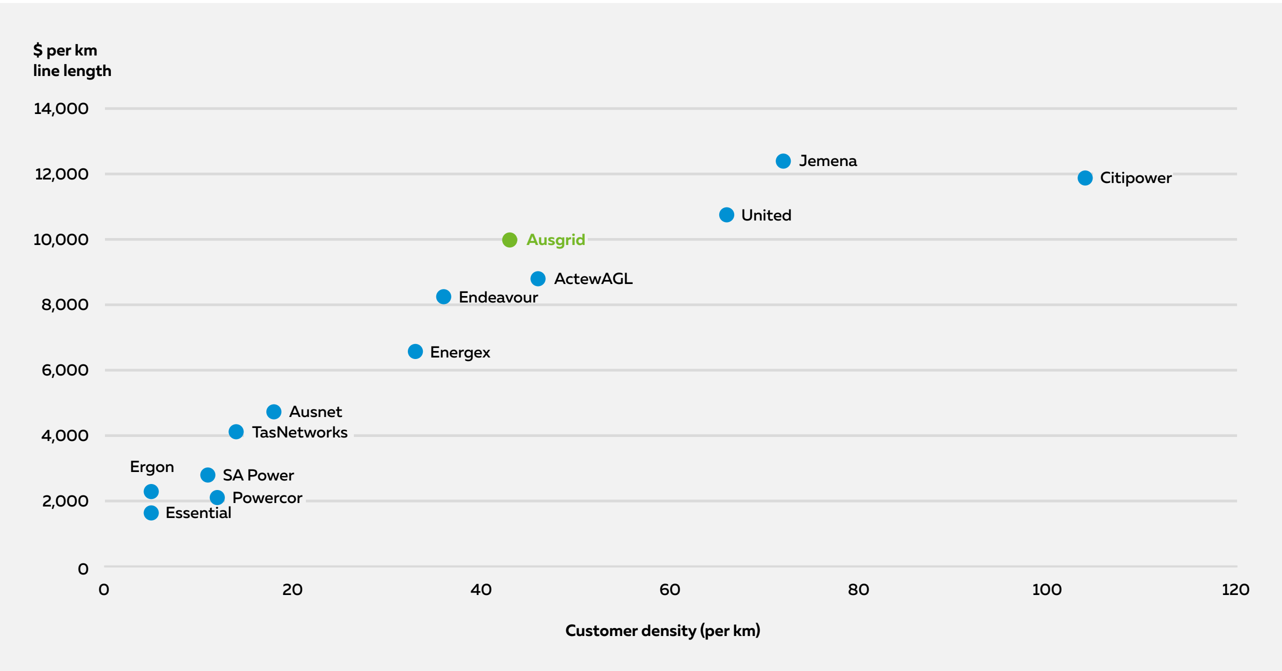
Opex per MVA max demand against customer density ($, nominal)



Source: Regulatory Information Notices available at www.aer.gov.au and Ausgrid analysis.

Figure 55.

Opex per km of circuit length against customer density ($, nominal)



Source: Regulatory Information Notices available at www.aer.gov.au and Ausgrid analysis.

In the AER's 2015 Determination, it used econometric benchmarking techniques to conclude that our opex was not at efficient levels. The AER substituted our proposed base year with its own estimate of efficient costs. Consistent with the improvement in performance shown in the charts above, application of the method applied by the AER to estimate efficient costs shows that our proposed base year for 2017/18 opex would be accepted as efficient.

We tested our proposed base year by comparing it to an alternative opex base year, calculated using the AER's approach in its 2015 determination (further details are included in Attachment 6.01). We firstly reduced average annual opex over the 2006 to 2016 period by the efficiency target generated from Economic Insights' Cobb-Douglas stochastic frontier analysis (SFA) model.[2] This generates an average base year opex value which is then 'rolled forward' to estimate an efficient 2015/16 base year using the difference between the output drivers, undergrounding and technical change between the average for the period and 2016. We then roll forward this estimate to 2016/17 and 2017/18 using the AER's 2015 Determination allowances. The 2017/18 estimate ($454 million in real FY19 terms) acts as a comparison point for our proposed 2017/18 base year opex ($440 million in real FY19 terms). The alternative estimate of opex for 2017/18 is higher than our proposed base year.

The comparison above demonstrates that the AER and our customers can have confidence that our transformation program has achieved levels of opex that are consistent with best practice in our industry, promoting our objective of keeping network bills affordable without compromising network safety or reliability.

2 As outlined in AER, *Annual Benchmarking Report – Electricity distribution network service providers*, p 39, December 2017. We note that, in the AER's 2017 Benchmarking Report, our historical opex still compares poorly to other businesses'. However, it does not necessarily follow that our proposed base year will be found to be inefficient. A number of factors affect the benchmarking results presented in the report, including:

- The report uses data up to 2015/16. Our opex was still relatively high then and includes transformation costs.
- Some techniques used in the report, including the econometric models, estimate an average result over the period 2006 to 2016. It will be some time before our performance improves under these approaches.

6.2.1 Our Transformation Program

Our transformation journey commenced in 2012 with the NSW Government's effort to put downward pressure on electricity prices. However, following the outcomes of the 2015 Determination, which set a significantly lower level of opex than what we had proposed, combined with our customers' focus on affordability, transforming our cost base has become our top priority. Since 2015 we have accelerated our transition to a sustainable level of opex through an ambitious program of transformation.

Phase 1 of the transformation program was launched in 2015 and focussed on laying the foundations for our future success. This was achieved through a series of initiatives to 'right-size' our workforce and increase efficiency and productivity in the field, in order to deliver sustainable reductions in our cost base without compromising safety or reliability.

In December 2016, the NSW Government leased 50.4% of Ausgrid to the private sector for 99 years. Our transformation had already started, but this structural reform provided a further catalyst for improvement.

We introduced phase 2 of our transformation program in 2017 to drive further efficiency and operational effectiveness and to help us meet the AER's opex allowance in order to provide a stable and sound cost base for the future. We implemented additional transformation initiatives to further reduce the size of our workforce, improve the efficiency of our capital investments, improve labour productivity, increase blended delivery, drive efficient network support costs, and streamline back-office operations. We also negotiated a new competitive enterprise agreement, implemented a new management structure and invested in our key capabilities to ensure that the significant cost reductions we have achieved are sustainably embedded within our cost base moving forward.

Figure 56.

Transformation Program

Phase 1

Laying the foundations for our future success

- Commence cultural change
- Significantly improve safety performance and practice
- Re-align structure and capability to meet our future growth and goals
- Rebalance size of office to field resources
- Drive efficiencies and improved prioritisation in the field
- Focus on capex delivery

Phase 2

Driving efficiency, effectiveness and growth

- Roll out new, safer way of working
- Be smarter about what work we do
- Improved efficiency in field, reinvest in capital program delivery
- Deliver better and more consistent customer service
- Continued corporate process and cost efficiency
- Kick off technology investments

Through the transformation program we have been able to drive a significant reduction in costs while continuing to improve operating efficiencies and productivity. Our efforts have allowed us to transform our cost base without compromising safety or reliability, and therefore has resulted in a sustainable reduction in costs and a sound opex base for the future.

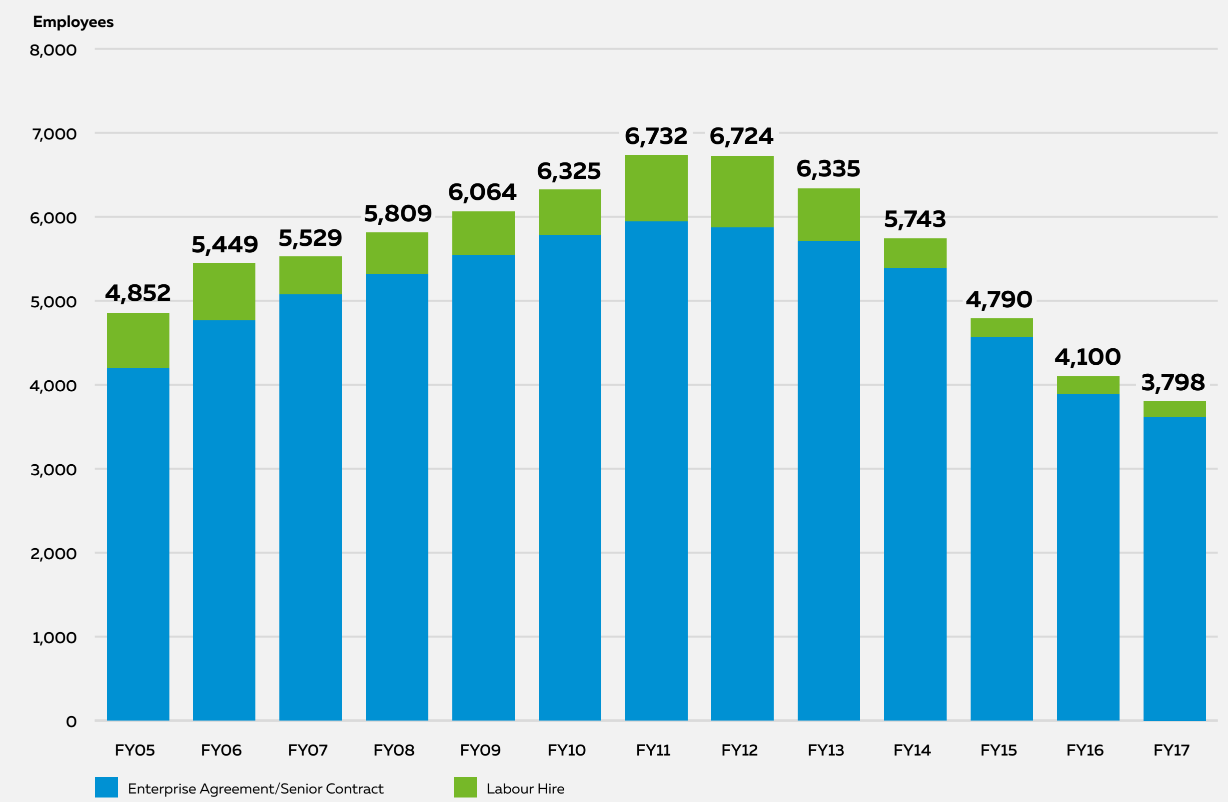
6.2.2 Managing our workforce during the transformation program

Since the peak in 2011, we have reduced our full-time equivalent employees by almost 3,000 without compromising network safety or reliability.

Labour comprises the largest component of our opex. As such, the impact of our transformation program is most easily demonstrated through the workforce reductions shown below.

Figure 57.

Labour force reductions: Ausgrid full time equivalent employees



Note: Figures include Ausgrid employees and labour hire only and exclude third party contracted services reported to IPART in line with obligations under the *Electricity Networks Assets (Authorised Transactions) Act 2015*. These figures also include employees within Ausgrid's retail business up to 1 March 2011, and employees providing retail related services (including customer service, billing, call centre, contract management and data performance management) to the retail business under the transitional services agreement between Ausgrid and TRUenergy (now EnergyAustralia) until March 2015. Over the period FY05 to FY11, the number of FTEs within Ausgrid's retail business fluctuated between 400 and 600 FTE. Between FY11 and FY15, the number of FTEs providing retail related services under the transitional services arrangement decreased from 600 FTE in FY11 to 200 FTE by FY15.

Source: Ausgrid.

We knew that reducing our workforce size would take time and this has proven to be the case. We have been managing our workforce and improving its productivity within the constraints of the 2012 enterprise agreement, which did not allow us to end an employee's employment involuntarily. We are also required to guarantee employment for a minimum number of employees to 30 June 2020 under the *Energy Networks Assets (Authorised Transactions) Act 2015*. We achieved our workforce reductions using voluntary redundancy in tandem with our Career Transition Centre.

Since September 2014, we have worked to reach agreement on a new enterprise agreement to deliver long-term and sustainable wage efficiency (the 2012 agreement reached nominal expiry in December 2014). The partial lease of the business required negotiations on the enterprise agreement to reset in February 2017. In March 2018 we reached agreement on a new enterprise agreement. This will be active from the date the agreement is approved by the Fair Work Commission.

The new agreement delivers employees fair and sustainable wage increases over the next three years, and provides greater workforce flexibility and efficiency outcomes for Ausgrid, including:

- more flexible and broad-banded employee progression through the introduction of the Career, Capability and Remuneration (CCR) framework,
- faster dispute resolution processes, and
- more effective consultation processes that will facilitate business change.

The CCR replaces the existing employee progression and promotion mechanisms in the enterprise agreement, including skill-based progression. The CCR is a simpler, fairer, performance-focused approach to progression, which will create a closer link between an individual's performance and improvements in the business. The CCR framework enables us to recognise individual performance and provide more flexible career paths. Transition to the CCR will occur from December 2018.

The new enterprise agreement delivers improved efficiency and productivity outcomes for Ausgrid and ultimately our consumers from 2018. The efficiency and productivity outcomes expected to be delivered through this new agreement will help us maintain a sustainable opex profile over the 2019–24 period.

6.3 Responding to customer feedback

In developing our opex plans for the 2019–24 regulatory period, we have considered how best to address the feedback we have received from our customers.

Electricity price increases in recent years have created an environment where future prices are a central concern for our customers and therefore for Ausgrid (see section 2.3.1). Our concerted effort to reduce costs during the 2014–19 period has given us a solid base, so we can address customers' concerns regarding affordability, without compromising network safety or reliability.

> Our forecast opex over the 2019–24 regulatory period locks in the ongoing saving of $100 million a year we have made through transforming the business.

During the extended consultation program, stakeholders raised concerns that our forecasting approach for our proposed opex does not adequately capture future efficiency and productivity improvements (see Attachment 2.02).

Through business transformation, we have been able to deliver ongoing and sustainable cost reductions to our customers in the current regulatory period. Our forecast opex locks in the ongoing saving of over $100 million a year we have made through transforming the business, and we will maintain this lower operating cost base, resulting in stable opex on a per customer basis. In the 2019–24 period, we have identified a number of cost increases, which we are not seeking to pass through to customers. Rather, we will absorb these increased costs and work hard to achieve efficiencies to offset them and keep our opex stable. We are also considering other ways we can lower the environmental impact of our business. We will track and identify ways to minimise resource use and lower our carbon footprint. We are keen to be recognised as an industry leader in sustainability.

The regulatory framework and our new commercial focus give us strong financial incentives to continually improve our cost efficiency and share these improvements with our customers. We will continue to work hard to maintain our lower opex cost base during the next regulatory period by:

- continuing to look for and make changes that will make us more efficient,
- being more innovative in the way we use new technology and work with other businesses and customers, and
- streamlining our internal processes.

Productivity or efficiency gains which Ausgrid achieves during the regulatory control period will be shared with customers through the combined effect of:

- establishing a lower base year opex for future forecasts (i.e. beyond 2019-24) where sustained and permanent reductions are revealed during the 2019-24 regulatory period, and
- the operation of the EBSS, which retains the benefits of opex efficiencies achieved for a period of five years.[3]

In addition to focusing on affordability and sustainability, we are taking initiatives to deliver greater customer value within our opex forecasts. Rather than simply building more infrastructure, which drives up opex, we will look first at where new technology, innovation and partnering with other businesses and our customers will provide lower cost solutions. We are also looking at how we can change existing practices to improve customer value.

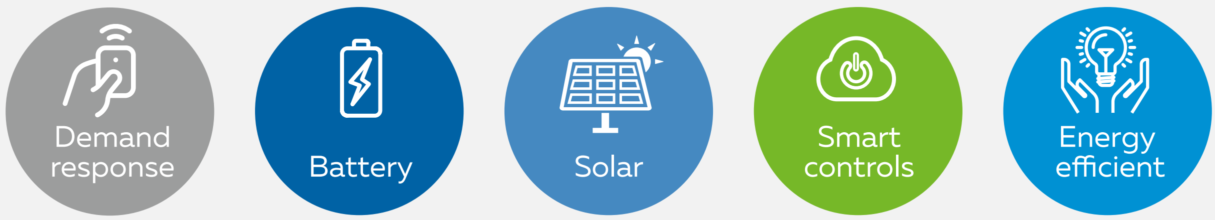
New initiatives will be developed during the next regulatory period. Two areas of focus we can already see delivering additional value to our customers will be:

- demand management, and
- vegetation management.

As explained below, our innovative demand management program, will allow us to use distributed energy resources (such as solar) to mitigate the impact of outages, improving security while lowering prices and transitioning to a lower carbon economy. Our approach to tree trimming will also add considerable customer value by ensuring that suburban areas benefit from an approach that balances costs against aesthetics and utility.

3 It is important to note the EBSS is symmetric, so it also retains the losses resulting from inefficiencies incurred throughout the 2019–24 regulatory period for a period of five years.

6.3.1 Demand management



We plan to partner with customers to better manage demand. Consistent with customer feedback, our opex forecast includes expenditure to further develop our demand management (DM) capabilities in the face of uncertainty over future technologies and energy demand and consumption patterns. For the 2019–24 regulatory period, we are proposing a targeted DM program consisting of six significant projects associated with the replacement or retirement of aged assets and a number of smaller projects associated with local augmentation of the network.

We are also undertaking a large-scale DM trial to refine techniques for an innovative blend of permanent demand reductions from solar and energy efficiency and temporary reductions from demand response solutions such as battery storage, load shifting and dispatchable generation. This solution will help us defer investments related to the replacement or retirement of aged assets and offer customers incentives to invest in energy efficiency solutions that will lower their energy use and bills.

Our proposed non-network DM projects over 2019–24

Customers and stakeholders strongly support Ausgrid's DM activities. Historically, DM opportunities were only assessed where network augmentation was required to address rising demand for electricity. However, such opportunities are limited in the current environment of dampened load growth and a moderation in peak demand, where the dominant driver of capex is ageing assets and the risk of asset failure.

Ausgrid's introduction of advanced asset management techniques to effectively assess the risks related to ageing assets now offers non-network solutions the opportunity to compete with network options in the selection of the least cost solution. In addition, in the assessment of these projects, Ausgrid has quantified an option value to reflect the expected benefit from a delay in network investment that may arise from new future solutions. This benefit might reflect lower future demand or new lower cost options to address the need. Partnering with customers to help manage risk is an effective way to lower network costs in the long term.

In our assessment of around 40 retirement/replacement projects for DM potential, comprising over $500 million in investment, six projects have been identified where DM forms part of the least cost solution. These projects each defer by three years the replacement of aged 11 kV switchgear (SWG) and a 132kV feeder. Opex is paid to customers (either directly or via aggregators) to reduce load or generate additional local supply, lowering the estimated unserved energy in the event of a network failure or spike in demand, so fewer (if any) customers suffer an outage.

6.3.2 Vegetation management

We intend to operate the business within our opex allowance by focusing on customer value – rather than the lowest possible cost. Vegetation management is a specific area where customer value can be increased by changing our working practices. The lowest cost option is to cut trees aggressively to reduce the frequency of work. However, this approach does not maximise the value to our customers, as explained in the box below.

Adding customer value: our approach to vegetation management

Vegetation management is our largest maintenance activity. It includes identifying, scoping and undertaking proactive vegetation cutting to maintain safety clearances from electrical assets. The safety clearance distances are determined by state-wide industry guidelines. However, our crews typically also allow for regrowth to minimise the frequency of cutting to keep our tree trimming costs as low as possible.

Communities have raised concerns about the way in which we trim trees. Between September and November 2015, we sought views from stakeholders such as councils, MPs, community groups and customers. Our stakeholders and customers told us they:

- want us to engage more effectively with communities in relation to tree trimming,
- are concerned about the visual amenity of the tree trimming, and
- want other options that improve visual outcomes while meeting safety requirements.

In response to the feedback received, we entered a more detailed phase of engagement to help us identify how we can better align our tree trimming practices with community expectations. We set up a community stakeholder working group comprising local councils, industry associations, government departments and community groups to review delivery of the vegetation management program and develop a service charter. This includes developing and implementing a strategy that meets the needs of our customers, appropriately manages risks and costs and is mindful of the impact and benefit of trees on our built environment. We have also engaged at senior levels via a workshop with members of our Executive in July 2017.

Outcomes from this engagement include:

- **Development of local precinct plans with councils** – the precinct plans provide a summary of Ausgrid and council priorities, commitments to share data, and planned works within an area to better coordinate and manage vegetation management activities and community expectations. The precinct plans are being developed with all local councils and will be revised annually to reflect changes as required.
- **A new network standard** – this is a technical document for contractors that defines, among other things, cutting clearances. We have changed our standard for vegetation management in non-bushfire areas to better balance network risk and community expectations. In these areas, trimming clearances will be reduced from one metre to 50 centimetres and, in the case of Aerial Bundled Cable (ABC), vegetation will be able to grow within 10 centimetres of the asset. These changes will allow less severe trimming and better canopy cover – a key outcome sought by stakeholders.
- **A tree safety management plan** – this is a broader, community-focused document that provides a comprehensive overview of Ausgrid's management procedures and practices. Consultation with our stakeholders is underway to develop a new plan that better reflects the new way we are engaging with councils.
- **Grant scheme** – we have worked together with councils to design a scheme that allows us to co-fund projects where there is community value in a project, but Ausgrid's prioritisation on strictly technical grounds alone would stop the project from proceeding. For example, ABC or undergrounding electricity wires can improve reliability, but at some cost, and this cannot always be justified on a strictly technical basis. In other words, it is cheaper to keep trimming trees. However, ABC or undergrounding have the significant benefit of allowing trees to remain in place conferring significant community or environmental benefits. Under the scheme, councils and Ausgrid will contribute to projects where there are both community and safety benefits.

6.4 Forecasting methodology

Our opex forecast is based on the AER's preferred method of setting efficient opex for all businesses. This is the base-step-trend approach.

The method underpinning a forecast is important. A sound, robust and well-established method gives our customers confidence that the resulting output is also sound and robust.

Our total opex is forecast using the base-step-trend approach, consistent with our forecasting methodology published in June 2017. We chose this method as it:

- is simple and transparent,
- has been used effectively by the AER and other businesses, and
- locks in the significant and sustainable cost savings we have achieved through our transformation program.

Stakeholders have not expressed any concerns with our forecasting approach.

The base-step-trend forecasting approach projects forwards from efficient opex in the base year. The approach determines the total forecast opex, rather than forecasting an amount for each category of opex.

The significant and sustained cost decreases that we have achieved in our transformation program during the current regulatory period bring our expenditure into line with best practice among Australian distribution businesses. This provides the AER and our customers with assurance that the base-step-trend forecasting approach is appropriate for the 2019–24 regulatory period.

The figure below summarises how we have applied this methodology.

Figure 58.

Our application of the AER's base-step-trend forecasting method

Our application of the AER's base-step-trend forecasting method

1. Start with 2017/18 proposed base year

We start with the expected underlying costs needed to operate and maintain the network in 2017/18, excluding non-recurrent costs.. This is in line with the AER's allowance for 2017/18 and is consistent with the AER's view of efficient costs, as outlined in the AER's 2015 Determination.

2. Included Emergency recoverable works (ERW)

Our base year opex does not include the costs of repairing our network after it is damaged by a liable third party (ERW). These costs will be included from 2019/20 so we have added them to the base year ($5 million, being actual historic costs less what we can recover).

3. Base Year

4. Trend the base forward using the rate of change

We trend base year opex forward by taking into account expected growth in input prices (0.8% per year on average), output (0.8% per year on average) and industry productivity (zero).

5. Add step changes

We have added step changes for costs not included in our base year opex, i.e. demand management projects, (around $5 million per year) and price reform research (a one-off $3 million step change).

6. Add "bottom up" opex

For debt raising costs (around $8 million per year) we have used a specific or bottom up forecasting approach, which better reflects the nature of these costs.

7. Forecast opex for 2019–20 to 2023–24

Note: As part of our approach we have included incremental opex between the base year and the final year of the current regulatory period in line with the AER's 2015 Determination. This has the effect of applying the trend adjustments in the AER's 2015 Determination and is consistent with the approach taken by the AER previously (e.g. TransGrid Draft Determination for the 2018–23 regulatory period). The trend adjustments in step 4 in the diagram are then applied starting from estimated 2018/19 opex.

The table below summarises our approach to forecasting each component of opex and its consistency with the AER's approach to expenditure assessment. We have applied the AER's method of forecasting for all but one component of opex: real labour price growth, where we have adopted an approach that aligns with our internal business planning.

Table 23.

Our approach to forecasting each component of opex

OPEX COMPONENT	OUR METHOD OF FORECASTING	CONSISTENT WITH AER APPROACH?
Base year	Used revealed or underlying costs for 2017/18, i.e. expected expenditure for 2017/18 excluding non-recurrent costs, as we consider this is representative of our efficient recurrent opex in 2017/18.	✓
Base year: Service classification change	Taken into account through an adjustment to base year opex, reflecting net costs of ERW (i.e. costs less receipts from third parties).	✓
Trend: Input cost escalation	Commissioned BIS Oxford Economics to provide forecasts of real labour price growth.	–
	Applied expected labour growth to 59.7% of costs in line with the AER's estimate of labour across all distribution businesses.	✓
Trend: Output growth	Forecast output growth by using Economic Insights' Cobb-Douglas SFA econometric model.	✓
Trend: Productivity growth	Applied no productivity growth as Economic Insights' model indicates a deterioration in productivity over 2006 to 2016.	✓
Step change: Demand management	Bottom up forecast of costs reflecting their non-recurrent nature.	✓
Step change: Price reform research project	Bottom up forecast of costs reflecting their non-recurrent nature.	✓
Other costs: Debt raising	Benchmark debt raising unit rate applied to the debt portion of our RAB.	✓

6.4.1 Base year

For our proposed base year opex, we used our estimated underlying opex for 2017/18. In this way, we exclude non-recurrent costs[4], ensuring prices reflect the ongoing costs we forecast to incur and no more. Our proposed base year opex is set out in Table 24 below.

Our base year opex is in line with the AER's opex allowance for 2017/18 and is consistent with the AER's view of efficient costs, as outlined in the AER's 2015 Determination. We consider this is representative of our efficient recurrent opex requirements for 2019–24.

Our proposed base year reflects the outcome of our transformation program, which has allowed us to significantly reduce our opex. Our opex performance is now in line with best practice among Australian distribution businesses. The AER and our customers can rely on our proposed base year to forecast opex for the 2019–24 regulatory period, and have confidence that it is efficient and contributes to affordable prices.

In 2017/18, ERW was an unregulated service, however, consistent with the AER's Final F&A paper[5], this service will become a regulated distribution service from the beginning of the next regulatory period. In previous determinations, we adjusted the base year costs to reflect changes in the service classification. We have followed the same approach here.

We estimated the adjustment for ERW as the full cost of repairing the damage (based on average historical costs), less the revenue we would expect to recover from third parties found liable for causing damage to our network (based on average historic receipts from third parties). See Attachment 6.01 for further details of how we calculated this adjustment.

4 We have excluded all non-recurrent costs including transformation costs from our proposed base year opex.

5 ERW are defined as emergency works to repair damage following a person's act or omission, for which that person is liable (for example, repairs to a power pole following a motor vehicle accident). The AER proposes to classify ERW as a standard control service (it is currently an unregulated distribution service), so it can be provided by a distribution business without triggering any ring-fencing requirements. We agree with this approach.

The table below shows how we derived our proposed adjusted base year opex.

Table 24.

Adjustment for ERW 2017/18 ($ million, real FY19)

OPEX	2017/18
Proposed base year opex	$440.2
Add adjustment for net cost to Ausgrid of ERW	$5.4
Proposed adjusted base year opex	$445.6

6.4.2 Trend adjustments

We 'trend' our adjusted base year forward to take account of how opex changes over time, reflecting:[6]

- **Real price growth** – to reflect movements in prices that are expected to be different to inflation,
- **Output growth** – to account for changes in how much output we expect to deliver, and
- **Productivity growth** – to reflect expected industry-wide improvements in finding more efficient ways of delivering services.

This approach is in line with current AER practice, with one exception. Although we applied the AER's approach to forecasting output and productivity growth, we deviated slightly when it comes to real price growth, as explained below.

Table 25.

Forecast rate of change (% per annum)

OPEX	2019/20	2020/21	2021/22	2022/23	2023/24
Output	0.75%	0.85%	0.85%	0.85%	0.88%
Price	0.52%	0.82%	1.04%	1.03%	0.80%
Productivity	–	–	–	–	–
Total	**1.27%**	**1.67%**	**1.90%**	**1.89%**	**1.68%**

Real price growth

Our base year opex reflects the costs of providing network services in 2017/18. However, costs change over time, sometimes by more or less than inflation.

As labour makes up most of our operating costs, we rolled our base year cost forward to reflect forecast changes in wages over the next regulatory period. For all other costs, we kept it simple and applied the CPI. This approach is consistent with past AER practice.

It is important to distinguish between labour price changes and labour cost changes. To the extent labour prices increase to compensate workers for increased productivity, labour costs will not increase at the same rate, as less labour is required to produce the same output. Consequently, labour productivity improvements need to be captured in forecasts.

Our approach to adjusting the base year to reflect forecast changes in wages has applied a forecast of labour price increases which is not productivity adjusted. Rather, labour productivity is accounted for in our opex forecast through the productivity measure which we apply to the base year (see below).

To incorporate expected movements in labour prices, we asked BIS Oxford Economics to forecast how much the price of labour will change.[7] We use these forecasts for our internal planning purposes and have aligned our Proposal to these forecasts. We expect to update our opex forecast with the latest forecast change in real labour costs in the revised Proposal. See Attachment RIN01 for the methods and data used to develop the forecasts.

6 As part of our approach, we have included incremental opex between the base year and the final year of the current regulatory period. This has the effect of applying the trend adjustments in the AER's 2015 Determination and is consistent with the approach taken by the AER previously (see e.g. TransGrid Draft Determination for the 2018–23 regulatory period). The trend adjustments are then applied starting from estimated 2018/19 opex.

7 We note the AER's past approach is to use an average of forecasts prepared by BIS Oxford Economics and Deloitte Access Economics. We have adopted BIS Oxford Economics forecasts, to be consistent with our internal planning process.

Table 26.

Forecast change in real labour costs (% per annum)

OPEX	2019/20	2020/21	2021/22	2022/23	2023/24
Labour	0.88%	1.37%	1.74%	1.73%	1.33%

We applied the expected real labour price growth rate to 59.7% of our opex. This is based on the AER's estimate of labour across all distribution businesses and ensures consistency with the AER's preferred benchmarking model (which uses this split[8]) and in turn the output and productivity growth estimates. Our approach of ensuring consistency across all components of the trend is in line with the AER's methodology.

The table below shows the combined effect of the labour cost increases and the assumed CPI increase in the costs of materials.

Table 27.

Forecast real price growth (% per annum)

OPEX	2019/20	2020/21	2021/22	2022/23	2023/24
Price	0.52%	0.82%	1.04%	1.03%	0.80%

Output growth

As we provide more output – for example by adding customers to our network or operating and maintaining more lines – the costs of operating our network increase. Accordingly, we have applied an output growth factor to reflect how our costs change as our output increases.

We deployed the AER's current two-step approach to estimate the impact of output growth.

1. We forecast the expected growth in customer numbers, circuit length and maximum demand, as shown in the table below.

Table 28.

Forecast change in outputs (% per annum)

OPEX	2019/20	2020/21	2021/22	2022/23	2023/24
Customer numbers	0.91%	1.05%	1.03%	1.02%	1.01%
Circuit length	0.42%	0.43%	0.57%	0.58%	0.52%
Ratcheted maximum demand	–	–	–	–	0.38%

2. We estimate how much our opex changes for a 1% increase in each of these outputs, as shown in the table below. To do this, we used Economic Insights' Cobb-Douglas SFA econometric model as preferred by the AER.

Table 29.

Forecast change in outputs

OUTPUT	ESTIMATED CHANGE IN OPEX FOR A 1% CHANGE IN OUTPUT
Customer numbers	0.77%
Circuit length	0.10%
Ratcheted maximum demand	0.13%

We then combined these two steps to get our overall output growth forecast, which is set out below.

8 2017 Economic Insights, Economic benchmarking Results for the Australian Energy Regulator's 2017 DNSP Benchmarking Report, p.2.

Table 30.

Forecast output growth (% per annum)

	2019/20	2020/21	2021/22	2022/23	2023/24
Output	0.75%	0.85%	0.85%	0.85%	0.88%

Productivity

We also adjust our base year opex for forecast changes in the productivity frontier for the industry over the next regulatory period. We applied the AER's approach to measuring a single estimate of productivity growth.

In its latest economic benchmarking report, the AER reported that industry productivity has increased since 2012.[9] We have two comments on these results.

1. This change in productivity is primarily driven by cost reductions in businesses that have transformed. These changes reflect a 'step change' in the level of opex required rather than ongoing productivity improvements within the industry. The productivity performance of businesses that have not undergone transformation programs do not consistently show productivity improvements, which suggests the large productivity gains seen in the data for 2012–16 predominately reflect 'catch-up' efficiency rather than a shift of the efficiency frontier. In addition, those businesses that have significantly reduced opex over this period (e.g. by significantly reducing labour volumes) will have less scope to make further efficiency gains, given the scale of improvements made in recent years. Accordingly, we do not consider that productivity increases over this period could be expected to continue.
2. Productivity is best measured over the long term and ideally from the same position in the business cycle.[10] This is because productivity measures are affected by how much existing assets and capacity are used. For example, when the economy is growing, outputs such as energy throughput may increase without an immediate need to increase inputs. A long-term (e.g., 10 to 15-year) average smooths out any short-term volatility in productivity measures, allowing for a more consistent estimation of productivity over time. A productivity measure calculated over 2012 to 2016 would not be considered a long-term measure.

As with output growth, we used Economic Insights' Cobb-Douglas SFA econometric model to forecast productivity growth, consistent with the AER's forecast expenditure assessment guideline[11] and past practice. This model estimates that productivity has decreased over the period 2006 to 2016, consistent with estimates from the Australian Bureau of Statistics (ABS). Over the same 2006 to 2016 period, the ABS estimated that multifactor productivity and labour productivity decreased by 2.6% and 1.9% respectively for the electricity, gas, water and wastewater sectors.[12]

Given that applying negative productivity growth would increase our opex forecast, we have decided not to do this. Instead, we have applied a productivity growth of zero, equivalent to not applying a productivity factor. We also note that CPI forecasts include economy wide productivity improvements, and there is no evidence to suggest that the utility industry is delivering greater productivity improvements than the wider economy.

Given the significant cost reductions we have achieved in the current regulatory period, and the forecast industry productivity growth, we propose no further productivity adjustment to our opex forecasts. This is consistent with the incentive properties in the AER's framework for assessing opex. We believe this is a reasonable approach.

6.4.3 Step changes

Step changes are increases or decreases in our opex associated with meeting new or changed regulatory obligations or opex-capex trade-offs. As such, the costs of step changes are not captured in the base year expenditure or trend escalation. They must therefore be added separately if the network company is to recover its efficient costs. Our forecast opex includes two step changes in relation to:

1. identified DM projects, which will deliver capex savings, and
2. pricing reform acceptance research project to inform and expedite our transition to more cost reflective pricing as required by the Australian Energy Market Commission's (AEMC) rule change for Distribution Network Pricing Arrangements.

9 2017 AER, Annual Benchmarking Report – Electricity distribution network service providers, p 40. We note that this finding was not based on the Economic Insights' econometric model, but rather total factor productivity analysis, which is not consistent with the approach for output growth.

10 OECD 2011, Measuring Productivity: Measurement of aggregate and industry-level productivity growth, OECD Manual, p.119.

11 2013 AER, Expenditure Forecast Assessment Guideline for Electricity Distribution, pp 23–24.

12 ABS, 5260.0.55.002 – Estimates of Industry Multifactor Productivity, 2015–16, December 2016.

Demand management

We estimate proposed DM expenditure on a case-by-case basis for larger projects at sub-transmission level and on a modelled basis for the smaller projects at 11kV level. For individual projects, a cost benefit assessment is used to assess the cost effectiveness of non-network solutions in comparison with network options over a 20 year time horizon. We assess the net present value of each competing network and non-network option to identify the preferred solution. Where a non-network option is found to offer an equivalent net present value, it is preferred.

For the 2019–24 regulatory period, we assessed around 40 replacement projects (comprising over $500 million in investments) for DM potential. We are proceeding with six of these projects, where the benefits of implementing a DM solution (i.e. the benefits from deferring replacement capex) outweigh its costs. We are also proposing a number of smaller projects associated with local high voltage (HV) augmentation of the network. See Attachment 6.01 for further details on this proposed step change, including the assumptions underlying our project analysis.

Table 31.

Forecast DM opex ($ million, in real FY19 terms)

	2019/20	2020/21	2021/22	2022/23	2023/24	TOTAL
Concord 11 kV SWG Replacement	0.7	0.7	1.3	0.7	1.3	**4.6**
Leightonfield 11 kV SWG Replacement	–	–	0.6	0.6	0.1	**1.3**
Lidcombe 11 kV SWG Replacement	–	–	0.6	0.6	0.6	**1.8**
Mascot 11kV SWG Replacement	1.3	0.7	0.7	1.3	0.2	**4.3**
St Ives 11kV SWG Replacement	–	–	0.6	0.6	1.2	**2.4**
Haymarket–Pyrmont 132 kV Feeder Replacement	1.3	1.4	1.4	1.4	1.4	**6.8**
HV Augmentation	0.3	0.9	1.3	1.4	1.0	**5.0**
Total	**3.7**	**3.7**	**6.5**	**6.6**	**5.7**	**26.1**

Table 32.

Demand management project capex impact ($ million, real FY19)

		2019/20	2020/21	2021/22	2022/23	2023/24	TOTAL
Concord 11 kV SWG Replacement	Pre DM capex	10.7	9.6	1.5	–	–	**21.9**
	Post DM capex	–	0.1	1.1	5.9	13.9	**21.0**
Leightonfield 11 kV SWG Replacement	Pre DM capex	–	–	0.1	0.8	2.2	**3.1**
	Post DM capex	–	–	–	–	–	**–**
Lidcombe 11 kV SWG Replacement	Pre DM capex	–	–	–	–	0.0	**0.0**
	Post DM capex	–	–	–	–	–	**–**
Mascot 11kV SWG Replacement	Pre DM capex	2.4	18.2	22.2	6.7	0.2	**49.7**
	Post DM capex	–	0.1	1.4	2.4	18.2	**22.1**
St Ives 11kV SWG Replacement	Pre DM capex	–	–	–	0.1	1.3	**1.4**
	Post DM capex	–	–	–	–	–	**–**
Haymarket-Pyrmont 132 kV Feeder Replacement	Pre DM capex	–	–	0.6	1.7	15.4	**17.7**
	Post DM capex	–	–	–	–	–	**–**
HV Augmentation	Pre DM capex	9.0	17.9	17.9	17.9	17.9	**80.7**
	Post DM capex	7.7	14.6	15.1	12.2	13.2	**62.8**
Total	**Pre DM capex**	**22.1**	**45.7**	**42.3**	**27.3**	**37.1**	**174.5**
	Post DM capex	**7.7**	**14.7**	**17.6**	**20.5**	**45.3**	**105.9**

Note: We assess the net present value of each competing network and non-network option over a 20 year time horizon to identify the preferred solution. This table presents the capex impact of the DM projects during the current regulatory period only. Further capex savings will be delivered beyond 2023/24.

Price reform research

The driver of this step change is a change to the regulatory obligations for setting network prices, which requires us to transition to cost-reflective network prices and improve the transparency of our pricing information and consult with retailers and customers on the design of network prices. Under this rule change, network prices based on the new pricing objective and pricing principles will be gradually phased in from 2017.[13]

In addition to our proposed pricing reforms (see Chapter 10), we are proposing to simultaneously launch a comprehensive research program, to be developed collaboratively with stakeholders. This research will inform and expedite our transition to more cost reflective pricing in accordance with our regulatory obligations.

This research program will inform potential pricing decisions over the 2019–24 period, and thereafter. In particular, if the research program suggests residential customers will benefit from large-scale assignment to a demand charge, we can fast-track a transition to demand charges using our proposed demand charge (as discussed in Chapter 10).

The appropriate design (and the respective merits/shortcomings) of a residential demand charge is a matter on which there exists significant uncertainty and divergence of opinions. Since the number of customers with an advanced meter is expected to triple to approximately 900,000 over the next five years, the network cost consequences of inappropriately designing and implementing a demand charge are significant.

The price reform research project seeks to understand the attitudes towards energy service pricing amongst customers, community groups, retailers and aggregators (see Attachment 3.01 for further details). The research would help Ausgrid understand and assess:

- the broader range of incentives and pricing structures available to customers for energy services,
- how different customer groups would respond (both in theory and in practice) to alternative cost reflective price arrangements (e.g. critical peak demand charges or rebates, capacity limits, more targeted time of use charges, discounts for controlled load, or locational specific charges etc.) and alternative adoption arrangements (opt in, opt out, mandatory assignment etc.),
- how prices designed for retailers and aggregators would be structured, how they would function, and how those parties can be encouraged to preserve price signals embedded in network charges, and
- price structures suitable for emerging load profiles such as residential with electric vehicles.

13 AEMC rule change for Distribution Network Pricing Arrangements.

A pilot for new pricing models may be conducted. We envisage at least one large scale trial to ensure findings are statistically relevant and applicable across a range of customer demographics.

There will be a once-off $3 million cost to undertake this research program in 2019/20 and 2020/21. This estimate is based on our current expectations of the scope of the research program (to be developed collaboratively with stakeholders) and the cost of previous stakeholder research undertaken by Ausgrid.

Table 33.

Forecast price reform research project opex ($ million, real FY19)

OPEX	2019/20	2020/21	2021/22	2022/23	2023/24	TOTAL
Price reform research project	1.5	1.5	–	–	–	3.0

6.4.4 Bottom up expenditure forecasts

As explained in the description of our forecasting methodology, some expenditure is forecast on a 'bottom up' basis that sits outside the base-step-trend forecasting methodology. It is standard regulatory practice to adopt a 'bottom up' approach to forecasting debt raising costs, which are an unavoidable aspect of raising debt. These costs include: underwriting fees, legal fees, company credit rating fees and other transaction costs.

Ausgrid has adopted the AER's preferred method to forecast this cost, by applying a benchmark debt raising unit rate to the debt portion of our RAB. This is discussed further in Chapter 7.

6.5 Summary of operational expenditure forecast

Our total opex forecast is presented in the table below. As already noted, the base-step-trend forecasting approach determined the forecast at an aggregate level. However, for the purposes of this document, we show how this total opex forecast is split between the opex categories[14].

Table 34.

Total forecast opex ($ million, in real FY19 terms)

	2019/20	2020/21	2021/22	2022/23	2023/24	TOTAL
Maintenance	141.2	143.6	146.3	149.1	151.6	731.8
Network Support	117.0	118.9	123.9	126.2	127.3	613.4
Property	63.5	64.6	65.8	67.1	68.2	329.2
Information Technology	51.8	52.7	53.7	54.7	55.6	268.5
Corporate Support	89.6	91.0	91.2	93.0	94.5	459.4
Total forecast opex (excluding debt raising costs (DRC))	**463.2**	**470.8**	**481.0**	**490.0**	**497.3**	**2,402.3**
Distribution	427.5	434.6	444.0	452.3	459.0	2,217.4
Transmission	35.7	36.2	37.0	37.7	38.3	184.9
Subtotal	**463.2**	**470.8**	**481.0**	**490.0**	**497.3**	**2,402.3**
Other opex (DRC)	7.9	7.9	7.9	7.9	7.9	39.6
Total forecast opex (including DRC)	**471.1**	**478.9**	**489.1**	**498.1**	**505.4**	**2,442.5**

Note: Totals may not add due to rounding.

14 We have derived this split using the categories reported in RIN template 3.2.1, which is based on the categories of forecast spend in the base year (2017/18). The same split has been applied to total opex forecast over the 2019–24 period.

6.6 National Energy Rules compliance

The NER sets out specific requirements in relation to our opex forecasts. In particular, our forecasts must achieve the opex objectives, which include the requirement to provide safe and reliable distribution services to our customers and to comply with our regulatory obligations. The NER also stipulates that our expenditure forecasts should reflect the efficient and prudent costs of achieving the opex objectives.

The NER also provides guidance to the AER on the matters it should consider in assessing our forecasts, which include:

- the AER's most recent annual benchmarking reports,
- the actual and expected opex in previous regulatory control periods,
- the extent to which the forecasts address the concerns of electricity consumers,
- the relative prices of operating and capital inputs,
- the substitution possibilities between opex and capex,
- whether the forecast is consistent with the applicable incentive schemes,
- whether the forecast reflects arrangements that are not on arm's length terms,
- whether the expenditure forecast includes an amount relating to a project that should more appropriately be included as a contingent project,
- the extent we have considered, and made provision for, efficient and prudent non-network options, and
- any relevant final project assessment report, as required by the regulatory investment test.

For the reasons outlined in this chapter and Attachment 6.01, we are confident the AER will accept our forecast opex. In particular, we note:

- our proposed base year benchmarks well against our peers, reflecting our achievement of very substantial savings over the 2014–19 period,
- we have transformed our business to provide a more sustainable cost base and to embed a culture of efficiency, including active consideration of opex-capex trade-offs,
- we have taken account of customers' concerns regarding affordability in preparing our opex forecasts,
- we have committed to demand management initiatives and changes to our vegetation practices that will deliver substantial value to our customers, and
- there will be some opex attributable to a related party (PlusES Partnership) as they provide certain metering related SCS to Ausgrid. The commercial terms and prices for these services are considered to be commercial arm's length terms.

As explained in this chapter, in the past we operated with a significantly higher cost base. The AER's 2015 Determination set a significantly lower opex allowance than we had proposed, which was reflected in a 14% average fall in prices in 2015/16. Since then, we have made a concerted effort to transition to a more sustainable level of opex, through an ambitious program of transformation designed to 'right-size' our workforce, improve our efficiency and reset our cost base.

Over the current regulatory period, we have reduced our annual operating cost base by more than $100 million without compromising safety, reliability or customer outcomes. In the penultimate year (2017/18) of the current period, we expect to have reduced our recurrent opex to the level of the allowance set for us in the AER's 2015 Determination.

Benchmarking shows that we have made significant improvements over a range of measures, bringing our performance into line with our industry peers. Accordingly, the AER and our customers can have confidence that our transformation program has achieved levels of opex that are consistent with good practice in our industry.

In developing our opex forecast for the next regulatory period, we have applied the AER's preferred base-step-trend methodology. Accordingly, our forecasts lock in the ongoing saving of over $100 million a year we have made through transforming the business.

In forecasting our opex requirements, we must achieve an appropriate balance between the pressure to reduce expenditure further and the importance of maintaining safety and reliability while managing network risks efficiently, both now and in the future. For the reasons set out in this chapter and Attachment 6.01, we believe we have achieved an appropriate balance.

We are confident the information in this Proposal demonstrates that our opex forecasts reflect efficient and prudent costs, in accordance with the requirements of the NER.

Clause 6.5.6 and Schedule 1 of the NER require us to provide specific information on our opex forecast. Our compliance matrix at Attachment 1.02 shows where we have provided the information in our Proposal.

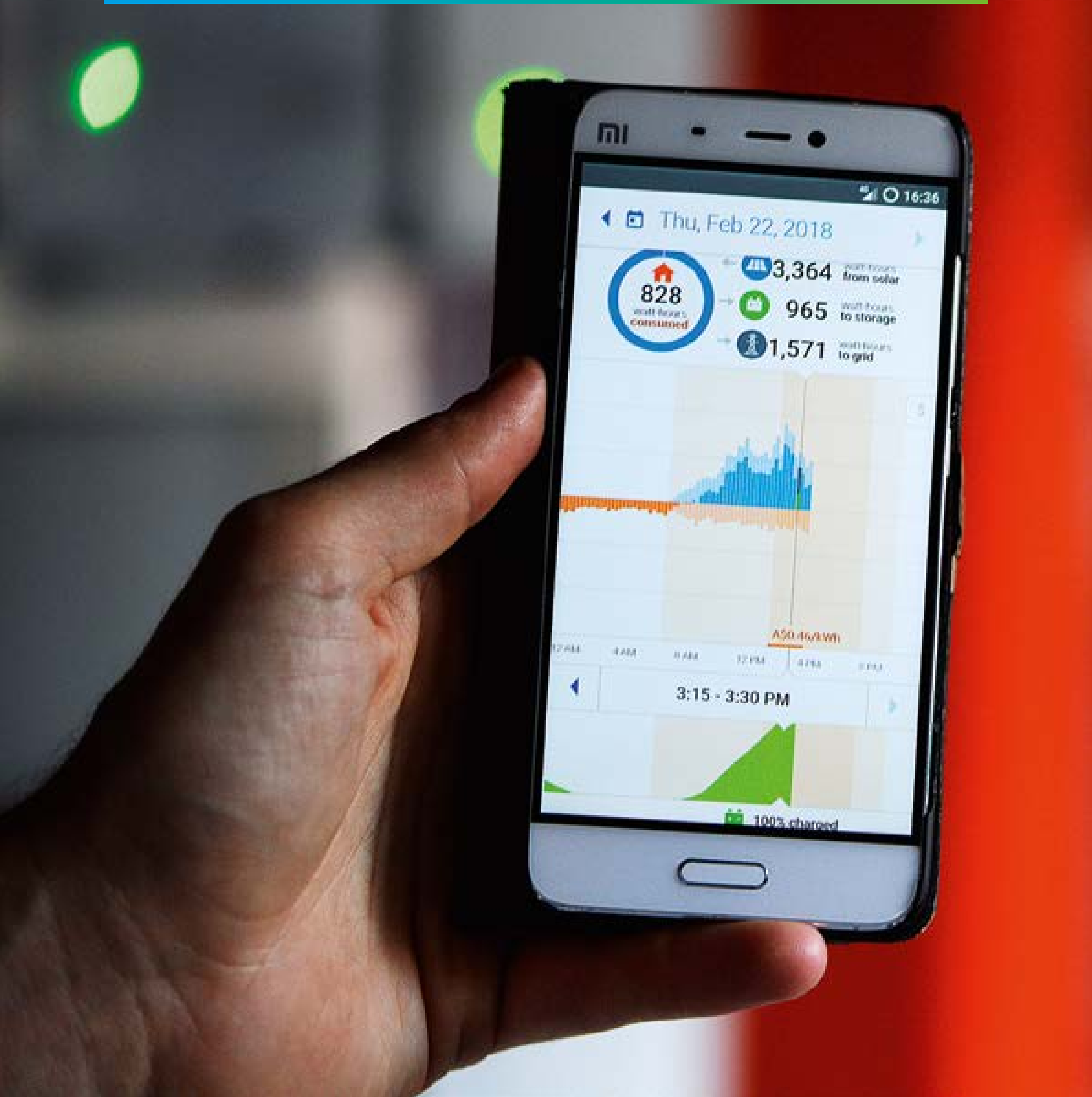
Additionally, the NER requires us to submit information requested by the AER in a RIN. The AER issued a RIN in January 2018, which consisted of a series of data questions in an Excel worksheet, together with written questions on our opex proposal. Our response to the RIN accompanies our Proposal.

6.7 Material to support our opex proposal

Attachment 6.01 provides further information to support our opex forecast for 2019–24. We have provided information in a way that follows the AER's assessment process and our approach has been to target the most relevant information. This follows feedback from the AER and stakeholders that we should simplify and compact the number of documents we submit in regulatory proposals. We are open to providing any other information requested by the AER and stakeholders.

07

Rate of Return



07

Rate of Return

What did we achieve in 2014–19?

In the 2014–19 period, we proposed a rate of return of 8.85% WACC, incorporating a long-term estimate of the required return on equity and a trailing average return on debt.

We also proposed a value for imputation credits (i.e. gamma) of 0.25.

The AER applied its 2013 Rate of Return Guideline. This provided a materially lower allowed rate of return, approximately 6.74%, declining over the 2014–19 period with annual updates to the allowed return on debt.

What outcomes will we deliver in 2019–24?

In the 2019–24 regulatory period, we propose an overall allowed rate of return (nominal, vanilla WACC) of 6.33% for the first year. Within this, the cost of debt will be annually updated for changes in prevailing debt yields.

Our Proposal applies the AER's 2013 Rate of Return Guideline for all elements of the allowed rate of return and a gamma value consistent with recent AER decisions.

Although financial market observations suggest a higher return on equity than calculated using the 2013 Rate of Return Guideline, we are committed to minimising further debate on this issue and to delivering a positive outcome for our customers.

How are we responding to our customers' feedback?

Affordable

Given the large contribution of return on capital to total revenue requirements, adopting a lower rate of return means prices will remain affordable.

Reliable

Our approach on rate of return will allow us to finance the investments necessary to maintain levels of network reliability Ausgrid has achieved.

Sustainable

Our approach on rate of return will allow us to finance the investments necessary to support the transition to a lower carbon economy.

We propose an overall allowed rate of return (nominal vanilla WACC) of 6.33% for the first year of the 2019–24 regulatory period. We propose this allowed rate of return be updated in each year of the regulatory period in line with changes in the transition to trailing average return on debt allowance.

7.1 Our approach

Our proposed rate of return allowance for the 2019–24 regulatory period has been guided by two principal considerations:

1. The requirement in the Rules that the allowed rate of return is to be determined such that it achieves the allowed rate of return objective (ARORO) set out in the Rules.[1] The ARORO is that:

   ...the rate of return for a Distribution Network Service Provider is to be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the Distribution Network Service Provider in respect of the provision of standard control services[2].

2. The feedback received through extensive consultation with consumers and stakeholders. Right now, consumers are facing unusually high cost of living pressures in several areas, including large increases in retail energy prices, as explained in section 2.3.1. Ausgrid is committed to supporting electricity consumers through this challenging period. As such, when formulating our allowed rate of return proposal, we have accepted the AER's 2013 Rate of Return Guideline. This is despite compelling evidence that would, in the prevailing market conditions, justify a higher allowed rate of return more commensurate with the efficient financing costs of a benchmark entity with a similar degree of risk to Ausgrid.

7.1.1 Rate of Return Guidelines

In October 2016, the AEMC amended the Rules to extend the timeframe for the first review of the Rate of Return Guideline from three to five years. A specific transitional arrangement was also included to offer additional regulatory certainty for Ausgrid and several other DNSPs.[3] Under the transitional arrangements: the 2013 Rate of Return Guideline will apply to Ausgrid for its 2019–24 regulatory determination process; provisions apply only in respect of the first review of the Rate of Return Guideline; and provisions do not prevent Ausgrid or the AER from being able to depart from the 2013 Rate of Return Guideline.[4]

In October 2017, The COAG Energy Council's Senior Committee of Officials issued a bulletin outlining the process – including amendments to national energy laws – to introduce binding Rate of Return Guidelines. The bulletin states that the proposed legislative amendments will specify that the new guideline will be binding on all determinations delivered by the regulators following the passage of the legislation (excepting remittals from appeal processes) regardless of when the determination process commenced.[5] At the time of preparing this Proposal, the proposed binding guidelines have not been developed and therefore we have applied the 2013 Rate of Return Guideline.

Specifically, in estimating the allowed rate of return in this Proposal, we have followed the 2013 Rate of Return Guideline in:[6]

- all aspects of the return on equity, and
- all aspects of the return on debt.

1 NER 6.5.2(b).

2 NER 6.5.2(c).

3 AEMC, National Electricity Amendment (Rate of Return Guidelines Review) Rule 2016, National Gas Amendment (Rate of Return Guidelines Review) Rule 2016, Rule Determination, 13 October 2016.

4 AEMC, National Electricity Amendment (Rate of Return Guidelines Review) Rule 2016, National Gas Amendment (Rate of Return Guidelines Review) Rule 2016, Rule Determination, 13 October 2016, p.9.

5 The bulletin is available from the COAG Energy Council web page at: http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/SCO%20Bulletin%20Binding%20Rate%20of%20Return%20Final.pdf

6 In the remainder of this Proposal we refer to the '2013 Rate of Return Guideline' as the 'Rate of Return Guideline'.

With regard to the value of imputation credits, we have adopted the value used by the AER in recent determinations.

The 2013 Rate of Return Guideline does not cover issues related to estimating debt and equity raising costs. The AER's preference has been to consider these matters in the context of individual determinations:

> ***...the final guideline does not cover our position on transactions costs or forecast inflation. These issues will need to be considered in upcoming determinations.*** [7]

However, in this Proposal, we have adopted the AER's long-standing approach to estimating debt and equity raising costs (applying the latest data available). Our approach is consistent with the approach accepted by the AER in its 2015 Determination for Ausgrid.

7.2 Overall rate of return

We propose an overall allowed rate of return (nominal, vanilla) of 6.33% for the first year of the 2019–24 regulatory period. We propose this allowed rate of return be updated in each year of the regulatory control period in line with changes in the transition to trailing average return on debt allowance.

We computed our proposed allowed rate of return as follows:

1. We estimated the allowed rate of return using the vanilla WACC, per the Rules. The WACC is a weighted average of the estimated return on equity and the return on debt.
2. We estimated the return on equity using the Sharpe-Lintner Capital Asset Pricing Model (SL-CAPM). Each of the three parameters within this model (the risk-free rate, the market risk premium and the equity beta) are estimated in accordance with the Rate of Return Guideline.
3. We estimated the return on debt as a 10-year trailing average of the historical yields on 10-year BBB rated corporate bond yields, with transition from the AER's starting point estimate from 2013/14 of 6.51%. The trailing average allowance is computed using data published by the Reserve Bank of Australia (RBA) and Bloomberg, in line with the Rate of Return Guideline.
4. We adopted the Rate of Return Guideline estimate of gearing (the proportion of debt within the capital structure of the benchmark efficient entity). The table below sets out the basis of our estimate.

7 AER, Rate of Return Guideline Explanatory Statement, December 2013, p.21.

Table 35.

Ausgrid's rate of return proposal and basis for estimation 2019-24

PARAMETER	RATE OF RETURN GUIDELINE APPROACH	AUSGRID APPROACH	ESTIMATE
Risk-free rate	Estimated using:[8] • yields on 10-year Commonwealth Government Securities (CGS), and • a 20 consecutive business day averaging period as close as practicably possible to the commencement of the regulatory control period.	Adopt Rate of Return Guideline approach. Current estimate is a placeholder based on average rates over the 20 business days to 16 January 2018.	2.69%
Equity beta	Two stage approach:[9] • estimate an equity beta range using a set of Australian energy utility firms the AER considers reasonably comparable to the benchmark efficient entity, and • select a point within the estimated range using empirical estimates of overseas energy networks and the theoretical principles underpinning the Black CAPM. Resulting point estimate of 0.7.	Adopt point estimate specified in Rate of Return Guideline.	0.70
Market risk premium (MRP)	Estimate a range for the MRP and then select a point estimate within that range.[10] This approach will be applied at each reset to meet the requirement to determine the return on equity having regard to prevailing conditions in the market for equity funds.[11] Point estimate derived by giving: • greatest consideration to historical averages of excess returns, • significant consideration to Dividend Growth Model (DGM) estimates, • some consideration to survey estimates, and • limited consideration to conditioning variables and other regulators' estimates of the MRP.	Adopt Rate of Return Guideline approach. Taking account of consumer feedback, propose an estimate close to the lower end of the estimated MRP range. Resulting estimate consistent with the estimate adopted by the AER in every determination since publication of the 2013 Rate of Return Guideline.	6.50%
Return on equity	Estimate rounded to closest 10 basis points.		7.20%
Return on debt	10-year AER debt transition from 6.51% (28 February 2014–30 June 2014) starting point on-the-day rate to full 10-year trailing average allowance over 10 years. Average of estimates from the RBA and Bloomberg data sources. Return on debt allowance to be updated annually.	Adopt Rate of Return Guideline approach including the AER's debt transition.	5.75%
Gearing	60%	Adopt point estimate specified in Rate of Return Guideline.	60%
Nominal vanilla WACC			**6.33%**

8 AER, Rate of Return Guideline, December 2013, p.15.
9 AER, Rate of Return Guideline, December 2013, p.15.
10 AER, Rate of Return Guideline, December 2013, p.16.
11 AER, Rate of Return Guideline Explanatory Statement, December 2013, pp.92–93.

Additionally, in this Proposal we:

- adopt the gamma (the value of imputation tax credits) estimate of 0.4 used by the AER in recent determinations,
- adopt a placeholder estimate of inflation of 2.5% to be updated in our revised Proposal based on the latest available data, and in accordance with the AER's final position on the regulatory treatment of inflation (published in December 2017), and
- adopt the AER's standard approach to estimating debt and equity raising costs.

Table 36.

Ausgrid's proposed estimates of gamma, expected inflation and debt and equity raising costs 2019–24

PARAMETER/COST	ESTIMATE
Gamma	0.40
Expected inflation*	2.50%
Debt raising costs	8.4 bppa
Equity raising costs	$0

* Placeholder estimate to be updated in line with latest projections at the time of the Final Determination.

7.3 Return on equity

7.3.1 Relevant models for estimation of the return on equity

We adopted the SL-CAPM to estimate the overall return on equity. This is consistent with the approach set out in the Rate of Return Guideline.[12]

The SL-CAPM has the form:

Return on equity = Risk-free rate + Equity beta × MRP

Our approach is to estimate each of these three SL-CAPM parameters according to the methodologies set out in the Rate of Return Guideline, and to input those estimates into the SL-CAPM formula above to derive an estimate of the overall return on equity.

7.3.2 Risk-free rate

The Rate of Return Guideline approach to estimating the risk-free rate is to calculate a 20 consecutive business day average (as close as practicably possible to the commencement of the regulatory control period) of the yield on CGS with a 10-year term.[13]

We have adopted this approach in this revenue proposal. Applying this methodology over the 20-business day averaging period ending 16 Jan 2018 results in a risk-free rate estimate of 2.69%. We note that this is a placeholder that will be updated based on the averaging period set out in confidential Attachment 7.02.

7.3.3 Equity beta

Rate of Return Guideline approach

The Rate of Return Guideline specifies an estimate of equity beta of 0.7. This estimate was derived using a two-stage approach, with the AER:[14]

1. Estimating an equity beta range using a small sample of listed Australian energy utility firms that the AER considered reasonably comparable to the benchmark efficient entity. This process resulted in an estimated range for the equity beta of 0.4 to 0.7.
2. Using the theoretical principles underpinning the Black CAPM to choose a point estimate from within its estimated range and empirical estimates of overseas energy networks. This process led the AER to select a point estimate of 0.7, at the top of its empirically estimated equity beta range.

In recent decisions, the AER has had regard to 'investor certainty' (the uncertainty inherent in estimating unobservable parameters, such as the equity beta for a benchmark efficient entity) when justifying a point estimate at the top of its estimated equity beta range.[15]

When applying the second step of the beta estimation process in the Rate of Return Guideline, the AER stated:

> *Under our approach, we adopt a point estimate for equity beta from the top of the empirical range. This is consistent with the point estimate proposed in our equity beta issues paper. We consider a point estimate from the top of the range to be consistent with alternative evidence international equity beta estimates and the theory behind the Black CAPM for the following reasons:*
>
> – *Theoretically, under the Black CAPM, firms with an equity beta below 1.0 should have higher returns on equity than what the standard Sharpe-Lintner CAPM predicts. This is because, as a result of different starting assumptions, the Black CAPM predicts the slope of estimated returns will be flatter than for the standard Sharp-Lintner CAPM. This information informs our proposal to select a point estimate at the top end of the 0.4–0.7 range of empirical estimates.*
>
> – *We consider empirical estimates from a number of international energy networks across the US, UK and Europe, support a point estimate closer to the upper end of our range.*[16]

During the development of the Rate of Return Guideline, two consumer groups – Major Energy Users (MEU) and the PIAC – submitted that the AER should not select a point estimate from the top of its equity beta range, and that a point estimate around the midpoint of the range would be more appropriate. In response to these submissions, the AER stated:

> *We disagree with these submissions. We consider other relevant information suggests it is reasonable for us to select a point estimate from the upper end of the range of empirical equity beta estimates. This information includes the theoretical principles underpinning the Black CAPM and empirical evidence from international comparators.*[17]

12 AER, Rate of Return Guideline, December 2013, Chapter 5.
13 AER, Rate of Return Guideline, December 2013, p.15.
14 AER, Rate of Return Guideline, December 2013, p.15.
15 AER, Final Decision, AusNet Services transmission determination 2017–2022, Attachment 3 – Rate of Return, April 2017, p.56.
16 AER, Rate of Return Guideline Explanatory Statement, December 2013, p.88.
17 AER, Rate of Return Guideline Explanatory Statement, December 2013, p.88.

In that response, the AER addressed a well-recognised finding in the empirical finance literature that the SL-CAPM has a tendency to under-estimate beta for companies with a beta below the market beta of 1.0. This phenomenon is referred to as the 'low-beta bias' problem.

In Attachment 7.01 of our Proposal, Frontier Economics explains that the AER's use of Black CAPM evidence to select a point estimate from the top of its equity beta range was challenged through a merits review by PIAC. In its merits review decision, the Australian Competition Tribunal (Tribunal) stated:

> ***Upon reviewing the whole of the material before the AER, the Tribunal however is not satisfied that that material does not support a conclusion that the SL CAPM provided a low equity beta bias.*** [18]

As Frontier Economics notes, the Tribunal concluded:

> ***It is, as the AER noted, correct that the three parameters for the SL CAPM – equity beta, risk free rate, and MRP – are recorded as giving a low beta bias for businesses with a beta (that is, the risk of the asset relative to the average asset) of less than 1.0, and that the Network Applicants are all within that group. There was also evidence that the low beta bias is exacerbated when it is combined with conditions of low government bond rates and a high MRP. Those conditions were applicable at the time of the AER Final Decisions.*** [19]

That is, the Tribunal accepted the existence of low-beta bias – that the SL-CAPM systematically understates the returns of low-beta stocks.

Ausgrid continues to support the use of evidence from the Black CAPM to justify adoption of a point estimate towards the top end of the AER's empirically estimated equity beta range. Ausgrid also continues to endorse the examination of empirical estimates of the betas of overseas energy networks to inform the AER's point estimate of the equity beta.

Recent evidence on equity beta

The empirical evidence on equity betas that the AER relied on in the Rate of Return Guideline, and in all subsequent decisions, is now several years out of date. For example:

- In its most recent decisions, the AER relied primarily on a 2014 expert report from Professor Olan Henry to inform its equity beta estimates. [20] That report used data on a set of Australian energy network businesses only up to 28 June 2013. [21]
- In the Rate of Return Guideline, the AER also considered estimates from two equity beta studies by the Economic Regulation Authority (ERA) of Western Australia, the latest of which (at the time the Rate of Return Guideline was being developed) relied on data on Australian energy network businesses up to April 2013. [22]
- In the Rate of Return Guideline, the AER also considered estimates from a 2013 SFG Consulting study, which used data up to 19 February 2013. [23]
- The AER also considered evidence on the equity beta derived using comparators from overseas. This evidence included various studies, [24] none of which used data beyond 2013. [25]

In Attachment 7.01 of our Proposal, Frontier Economics has provided up-to-date evidence on the equity beta. [26] Frontier Economics:

- explains that in its June 2016 decision for DBP [27] the ERA updated its beta estimates for domestic comparators used in the 2014 Henry report and concluded that its best statistical estimate of the equity beta (i.e., without any uplift in relation to international evidence, low-beta bias or investor certainty) is 0.7,
- updates the estimates of equity beta using the same domestic comparator firms used by the AER (in the Rate of Return Guideline) and the ERA (in its decision for DBP), and using the same estimation methods finds that current estimates of the equity beta are higher than the AER's 'best statistical estimate' at the time of the Rate of Return Guideline, and

18 Applications by Public Interest Advocacy Centre Ltd and Ausgrid [2016] ACompT 1, Paragraph 779.

19 Applications by Public Interest Advocacy Centre Ltd and Ausgrid [2016] ACompT 1, Paragraph 731.

20 Henry, O., Estimating β: An update, April 2014. As this study had not been completed at the time of the writing of the Rate of Return Guideline, the AER indicated that it would consider the results of that study in future decisions. The estimated equity beta range in the Rate of Return Guideline was consistent with the evidence presented in the 2014 Henry report.

21 AER, Final Decision, AusNet Services transmission determination 2017–2022, Attachment 3 – Rate of Return, April 2017, p.56.

22 AER, Rate of Return Guideline Explanatory Statement – Appendices, December 2013, p.55.

23 AER, Rate of Return Guideline Explanatory Statement – Appendices, December 2013, p.57.

24 These studies were by CEG, Professor Aswath Damodaran (NYU), NERA Economic Consulting for the Queensland Competition Authority, and the New Zealand Commerce Commission.

25 AER, Rate of Return Guideline Explanatory Statement – Appendices, December 2013, section C.3.2.

26 Frontier, Estimation of certain aspects of the allowed rate of return, April 2018.

27 ERA, Final Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline 2016–2020, Attachment 4, 30 June 2016, paragraphs 473–474.

- Notes that in its February 2016 PIAC-Ausgrid decision, the Tribunal considered the definition of the benchmark efficient entity (BEE) and concluded that the BEE should be considered to be a hypothetical unregulated competitor.[28] Consequently, Frontier Economics examined the beta estimates of a set of ASX-listed transport-related infrastructure firms that are comparable to an energy distribution business,[29] but which operate in workably competitive markets. The equity beta estimates for these firms are materially higher than 0.7.

Based on this evidence, Frontier Economics concludes:

> ***… application of the AER's Guideline approach (i.e., begin with a best empirical estimate and apply an uplift to account for the additional considerations set out above) to the most recently available data would support an equity beta of at least 0.7. If the starting point equity beta estimate is higher and the same type of uplift is applied for the same reasons, the final beta allowance must be at least 0.7.***[30]

Emerging risks for electricity network firms

Since the 2013 Rate of Return Guideline, investors in energy network firms have been facing increased risks stemming from a number of new developments. These risks have put upward pressure on the required returns for equity investors in energy network firms and therefore justify adopting an equity beta at the higher end of the range.

- Increased risks from changes to the utilisation of the network, for example greater grid exports, where those customers able to afford new technologies are not paying a cost reflective price for the network service they receive due to existing pricing structures across the energy network industry.
- Increased availability of "off-grid" solutions that reduce the customer base from which energy network firms can recover their fixed costs. This places increased burden on customers that remain on the grid and increases the risks to cost recovery for energy network firms.
- Reduced regulatory appeal rights due to the removal of limited merits review from the regulatory framework. This has increased risks to investors because energy network firms do not have the opportunity to review the merits of economic decisions made by the regulator, which may have involved errors of fact or errors in the exercise of discretion.
- Increased political risks to the revenues that energy network firms are allowed to earn. Due to the nature of electricity prices at present, there is a heightened level of risk of political intervention that reduces prices/revenues in the short term but this also increases the risks faced by energy network firms and therefore the returns required by equity investors to invest in these firms.

Some of these risks may be reflected in the increased equity beta estimates for the remaining comparator firms in the AER's equity beta sample, which is outlined in Attachment 7.01 of this Proposal. However, all of these risks may not be fully reflected in the latest equity beta estimates.

Ausgrid's equity beta proposal

The evidence presented by Frontier Economics suggests that the most recent empirical evidence on beta, based on Australian data, would support an equity beta estimate of at least 0.7. Accounting for the theoretical principles underpinning the Black CAPM, estimates based on overseas data, the need for investor certainty and the emerging risks to energy network firms outlined above would support a beta estimate higher than 0.7.

However, we have taken on board feedback from stakeholders that consumers of electricity in NSW are facing significant cost of living pressures. Ausgrid is committed to supporting consumers through this challenging period. Therefore, while we consider that an equity beta estimate greater than 0.7 is justified, for the purpose of the 2019–24 regulatory control period, we propose an equity beta estimate of 0.7, consistent with the estimate specified in the Rate of Return Guideline.

7.3.4 Market risk premium

Rate of Return Guideline approach

The Rate of Return Guideline specifies a process for estimating the market risk premium (MRP), rather than a point estimate. Under the Rate of Return Guideline, the AER proposes to estimate a range for the MRP, and then select a point estimate from within that range:

> ***The AER proposes to estimate the range for the MRP with regard to theoretical and empirical evidence – including historical excess returns, dividend growth model estimates, survey evidence and conditioning variables. The AER will also have regard to recent decisions among Australian regulators. Each of these sources of evidence has strengths and limitations.***
>
> ***The AER proposes to estimate the point estimate for the MRP based on the AER's regulatory judgement, taking into account estimates from each of those sources of evidence and considering their strengths and limitations.***[31]

28 Applications by Public Interest Advisory Centre Ltd and Ausgrid [2016] ACompT 1, paragraph 914.

29 The relevant characteristics of these firms that make them comparable to regulated energy networks are that: they own very long-lived, tangible, infrastructure assets; they are capital intensive businesses; and that they provide access service to customers that provides them with a relatively stable series of cash flows.

30 Frontier, Estimation of certain aspects of the allowed rate of return, April 2018.

31 AER, Rate of Return Guideline, December 2013, p.16.

When the AER published its Draft Rate of Return Guideline, which described the MRP estimation process above, several stakeholders asked for more guidance on how the AER would apply its proposed MRP estimation process. In response, the AER published a worked example in its Final Rate of Return Guideline Explanatory Statement, which demonstrated how it would, in practice, apply its MRP estimation methodology to the market data available in December 2013 in order to derive a MRP estimate.[32]

Specifically, the AER explained that it gives:[33]

- greatest consideration to historical averages of excess market returns. As at December 2013, this source of evidence indicated an estimated range for the MRP of 5.0% to 6.5%,
- significant consideration to DGM estimates. As at December 2013, the AER's preferred DGM indicated an estimated range for the MRP of 6.1% to 7.5%,
- some consideration to survey estimates which, based on the survey data available in December 2013, generally supported a MRP estimate of about 6.0%, and
- limited consideration to conditioning variables, which gave mixed results as at December 2013; and limited consideration to other regulators' estimates, which generally supported an estimate of 6.0%.

The AER went on to conclude that applying its Rate of Return Guideline MRP approach to market data available in December 2013 would support an estimate of 6.5%, noting:

> ***This point estimate lies between the historical average range and the range of estimates produced by the DGM. This reflects our consideration of the strengths and limitations of each source of evidence...***[34]

Latest Evidence

In Attachment 7.01 to our Proposal, Frontier Economics shows:

- the most recent data on historical average excess returns on the market suggests a MRP range of 6.0% to 6.5%,
- the most recent DGM evidence suggests an estimated range of approximately 7.15% to 8.2%,
- this produces a combined range of 6.0% to 8.2%, with a midpoint of 7.1% (i.e., close to the lower bound of the most recent DGM estimates),
- the latest MRP survey by Fernandez suggests that the median MRP for Australia has increased to 7.6%,[35]
- several other regulators have recently estimated the MRP to be above 7.0%, and
- independent expert estimates are currently above 7.0%.

As Frontier Economics concludes, the preponderance of this latest evidence, and application of the MRP approach described in the Rate of Return Guideline, would support a MRP estimate greater than 7.0%.

Ausgrid's MRP proposal

For the purposes of the 2019–24 regulatory period, Ausgrid proposes a MRP estimate of 6.5%. This proposed estimate reflects our consideration of consumer feedback on the need to keep electricity network prices low in the face of high cost of living pressures on electricity consumers in NSW.

We note that our proposed MRP estimate is:

- significantly lower than the MRP estimate that we consider is justified using the MRP approach set out in the Rate of Return Guideline,
- at least 50 bps lower than the lower bound of the current DGM MRP evidence, and
- consistent with the MRP estimate adopted by the AER in every decision since 2013, including during periods in which the MRP evidence would justify a lower estimate than would the evidence available in the present market conditions.

32 AER, Rate of Return Guideline Explanatory Statement, December 2013, p.89.

33 AER, Rate of Return Guideline Explanatory Statement, December 2013, p.97.

34 AER, Rate of Return Guideline Explanatory Statement, December 2013, p.97.

35 Fernandez, P., V. Pershin and I.F. Acin, Discount rate (risk-free rate and market risk premium) used for 41 countries in 2017: A survey, April 17.

7.3.5 Overall estimate of the return on equity

As the Table shows, we propose a return on equity allowance of 7.2% for the 2019–24 regulatory control period.

Table 37.

Summary of Ausgrid's return on equity proposal 2019–24

PARAMETER/COST	ESTIMATE
Risk-free rate*	2.69%
Equity beta	0.70
Market risk premium	6.50%
Return on equity**	7.20%

* Placeholder to be updated based on averaging period outlined in Attachment 7.02.
** Rounded to the closest 10 basis points, consistent with the Rate of Return Guideline.

7.3.6 Equity raising costs

Raising equity finance incurs costs that should be recognised in regulated revenue allowances over the 2019–24 regulatory period. In its final decision for Ausgrid for the 2014–19 regulatory control period, the AER noted:

> *Equity raising costs are transaction costs incurred when service providers raise new equity from outside the business. Our equity raising cost benchmark allows for the costs of dividend reinvestment plans and seasoned equity offerings. Equity raising costs are an unavoidable aspect of raising equity that would be incurred by a prudent service provider acting efficiently. Accordingly, we provide an allowance to recover an efficient amount of equity raising costs. This is where a service provider's capex forecast is large enough to require an external equity injection to maintain the benchmark gearing of 60%.* [36]

The Rate of Return Guideline does not set out an approach for estimating benchmark equity raising costs. However, over several years, the AER has developed and refined a methodology for estimating equity raising costs. [37]

The AER's standard practice is to recognise equity raising costs as capex within the PTRM and amortise these costs over the life of the assets they are used to fund. The AER applied this approach in relation to Ausgrid for the 2014–19 regulatory period. For this Proposal, Ausgrid has adopted the AER's standard approach to estimating equity raising costs.

Ausgrid has applied the AER's standard cash flow analysis sheet within the PTRM to estimate the benchmark efficient equity raising costs over the 2019–24 regulatory period. The components of these costs are outlined below.

Table 38.

Benchmark efficient equity raising costs components 2019–24

COMPONENT	COST OVER 2019–14
Retained earnings	0.0%
Dividend reinvestment plan cost	1.0%
Seasoned equity offering/Subsequent equity raising costs	3.0%

Source: AER, Powerlink transmission determination 2012–13 to 2016–17, April 2012, p.108.

In estimating the benchmark efficient equity raising costs, we assumed a dividend reinvestment plan take-up of 30% and a dividend payout ratio of 70%. This is consistent with both our assumption of the imputation credit payout ratio and the AER's assumption in past decisions. [38]

Based on the AER's calculation method, our estimated benchmark cash flows mean that we do not require any external equity raising to finance our proposed capex. Therefore we have not incorporated any equity raising costs in this Proposal. However, following the AER's draft determination, this calculation would need to be performed again as the benchmark cash flows would change if the inputs were changed/updated.

36 AER, Final Decision, Ausgrid distribution determination 2015–16 to 2018–19, Attachment 3 – Rate of Return, April 2015, p.555.

37 This methodology is set out comprehensively, for instance, in: AER, Final decision, Powerlink Transmission determination 2012–13 to 2016–17, April 2012, pp.15–152.

38 AER, Powerlink transmission determination 2012–13 to 2016–17, April 2012, p.108.

7.4 Return on debt

7.4.1 The Rate of Return Guideline approach

The Rate of Return Guideline explains that the return on debt allowance must reflect the efficient financing practices of the benchmark efficient entity.[39] This is because the ARORO requires that:

> *...the rate of return for a Distribution Network Service Provider is to be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the Distribution Network Service Provider in respect of the provision of standard control services.*[40]

The Rate of Return Guideline recognises that network service providers, such as Ausgrid, face:[41]

- **Refinancing risk** – the possibility that the network service provider may be unable to finance its debt efficiently at a given point in time, and
- **Interest rate risk** – the potential for mismatches between the regulatory return on debt allowance and the actual cost of debt.

The Rate of Return Guideline also acknowledges that the benchmark efficient entity would seek to manage refinancing and interest rate risk; and most network service providers hold a diversified portfolio of debt with staggered maturity dates. Under such an approach, a network service provider would only refinance a portion of its debt portfolio at any point in time, rather than its entire debt portfolio at once. The Rate of Return Guideline states:

> *Holding a portfolio of debt with different terms to maturity allows a service provider to manage its refinancing risk.*[42]

The Rate of Return Guideline goes on to explain that a fixed-rate staggered refinancing approach, where the benchmark efficient entity refinances only a portion of its debt portfolio at any point in time, is an efficient debt management strategy for minimising refinancing risk:

> *...the trailing average portfolio approach allows a service provider – and therefore also the benchmark efficient entity – to manage interest rate risk arising from a potential mismatch between the regulatory return on debt allowance and the expected return on debt of a service provider without exposing itself to substantial refinancing risk.*
>
> *Thus, we consider that holding a (fixed rate) debt portfolio with staggered maturity dates to align its return on debt with the regulatory return on debt allowance is likely to be an efficient debt financing practice of the benchmark efficient entity under the trailing average portfolio approach.*[43]

In a recent merits review decision, the Tribunal held that the benchmark efficient entity (BEE) is to be interpreted as a hypothetical efficient unregulated business in a competitive market for the supply of SCS:

> *The BEE, in the view of the Tribunal, is likely to refer to the hypothetical efficient competitor in a competitive market for those services. Such a BEE is not a regulated competitor, because the regulation is imposed as a proxy for the hypothetical unregulated competitor. Otherwise, the starting point would be a regulated competitor in a hypothetically regulated market. That would not be consistent with the policy underlying the purpose of the NEL and the NGL in relation to the fixing of terms on which monopoly providers may operate. Indeed, the concept of a regulated efficient entity as the base comparator would divert the AER from the role of fixing the terms for supply of services on a proxy basis compared to those likely to obtain in a competitive market, and focus its attention on some different and unidentified regulated market.*[44]

A subsequent judicial review decision by the Full Federal Court found no legal error in the Tribunal's decision on this matter.[45]

The Tribunal's decision is consistent with the AEMC's 2012 Rule Change determination, which stated:

> *In its draft rule determination, the Commission considered that the long-term interests of consumers would be best served by ensuring that the methodology used to estimate the return on debt reflects, to the extent possible, the efficient financing and risk management practices that might be expected in the absence of regulation.*[46]

The Rate of Return Guideline recognises the trailing average portfolio approach is consistent with the actual debt management practices of non-regulated businesses and is therefore:

> *...more likely to reflect efficient financing practice.*[47]

39 AER, Rate of Return Guideline Explanatory Statement, December 2013, pp.102–103.

40 NER 6.5.2(c).

41 AER, Rate of Return Guideline Explanatory Statement, December 2013, p.104.

42 AER, Rate of Return Guideline Explanatory Statement, December 2013, p.105.

43 AER, Rate of Return Guideline Explanatory Statement, December 2013, pp.108–109.

44 Applications by Public Interest Advocacy Centre Ltd and Ausgrid [2016] ACompT 1, Paragraph 914.

45 Australian Energy Regulator v Australian Competition Tribunal (No 2) [2017] FCAFC 79.

46 AEMC, Rule Determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012, 29 November 2012, p.76.

47 AER, Rate of Return Guideline Explanatory Statement, December 2013, p.110.

In Attachment 7.01, Frontier Economics presents recent empirical evidence showing that a range of non-regulated infrastructure businesses with large debt portfolios subject to refinancing risk tend to adopt a staggered debt issuance strategy – consistent with the trailing average portfolio approach.[48]

The AER went on, in the Rate of Return Guideline, to adopt a trailing average portfolio approach to estimating the return on debt of the benchmark efficient entity. In doing so, the AER noted the trailing average approach had material advantages, including better matching the allowed return on debt to the actual cost of debt of the benchmark efficient entity and reduced price volatility for consumers:

> *We propose to apply a trailing average portfolio approach to estimate the return on debt. This approach means that the allowed return on debt more closely aligns with the efficient debt financing practices of regulated businesses and means that prices are likely to be less volatile over time. The trailing average would be calculated over a 10 year period. The annual updating of the trailing average should also reduce the potential for a mismatch between the allowed return on debt and the return on debt for a benchmark efficient entity. This should reduce cash flow volatility over the longer term.*[49]

In the Rate of Return Guideline, the AER also decided to apply a 10-year transition from the previous 'on-the-day' approach to the full trailing average return on debt allowance.

7.4.2 Ausgrid's proposed approach

To determine the return on debt allowance for the 2019–24 regulatory period, Ausgrid proposes to continue the move to a trailing average return on debt allowance using yields on 10-year BBB rated Australian corporate bonds. The trailing average approach reflects the benchmark efficient costs of debt for a firm that issues Australian corporate debt on a staggered portfolio basis.

To manage revenue levels and price pressures on our customers, we are proposing to adopt the AER's transition approach for the return on debt over the 2019–24 regulatory period, commencing from the AER's starting point estimate from 2013/14 of 6.51%. This provides a lower return on debt allowance over the 2019–24 regulatory period than a full 10 year trailing average approach.

Whether to apply a transition approach or immediately adopt the trailing average return on debt approach has been a contentious issue for the 2014–19 regulatory period, but Ausgrid does not seek to continue that debate into the 2019–24 regulatory period. For this reason, going forward Ausgrid is proposing to adopt the AER's transition approach to a full trailing average return on debt by the end of the 2019–24 regulatory period.

We propose a trailing average return on debt with the AER's preferred debt transition of 5.75% for 2019–20. This return on debt proposal is based on:

- applying the 10-year trailing average approach with the AER's preferred transition approach,
- giving an equal weighting to Australian corporate bond yield data published by the RBA and Bloomberg. (In any periods where one of these curves is unavailable, the other source receives 100% weight),
- extrapolating the RBA curve to a target tenor of 10 years, since the effective tenor of the corporate bonds within the BBB RBA curve is typically lower than 10 years, and
- extrapolating the seven-year or five-year Bloomberg curve to a target tenor of 10 years in any periods in which the 10-year Bloomberg curve is not available.[50]

In Attachment 7.01, Frontier Economics explains in detail how our proposed return on debt allowance has been calculated.[51] Confidential Attachment 7.02 sets out the averaging periods we used to calculate our return on debt proposal.

Our approach to the return on debt allowance does not differ from the AER's 2013 Rate of Return Guideline. We have adopted the AER's preferred transition from the on-the-day allowance to the 10 year trailing average.

7.4.3 Automatic update of the return on debt

Consistent with the Rate of Return Guideline approach, we propose the trailing average return on debt allowance should be updated annually, for each year of the 2019–24 regulatory period.[52]

In Attachment 7.01, Frontier Economics sets out the proposed process for updating automatically the return on debt allowance for each year of the 2019–24 regulatory period.[53]

48 Frontier, Estimation of certain aspects of the allowed rate of return, April 2018.

49 AER, Rate of Return Guideline Explanatory Statement, December 2013, p.12.

50 The 10-year Bloomberg curve is available from April 2014, the seven-year Bloomberg curve from April 2010, and the five-year Bloomberg curve from October 2009.

51 Frontier, Estimation of certain aspects of the allowed rate of return, April 2018.

52 We note that annual updating of the return on debt allowance is permissible under NER 6.5.2(i)(2), which provides that the return on debt may be estimated using a methodology which results in the return on debt (and consequently the allowed rate of return) being, or potentially being, different for different regulatory years in the regulatory control period.

53 Frontier, Estimation of certain aspects of the allowed rate of return, April 2018.

We have assumed that the last available annual update (for 2018–19) for the allowed return on debt under the AER's approach continues to prevail over the forecast period. This is a placeholder assumption, which will be updated over 2019–24 regulatory period.

7.4.4 Debt raising costs

We adopted the AER's standard approach to estimating benchmark debt raising costs. The AER's approach involves:

- calculating the benchmark bond size. In several recent decisions [54] the AER adopted a benchmark bond size of $250 million, based on the findings of a study by PwC. [55]
- calculating the number of bond issues required to rollover the benchmark debt share (60%) of the opening value of the RAB. Ausgrid's opening RAB for the 2019–24 regulatory period is approximately $15.7 billion. This implies a debt share of RAB of $9.4 billion at a benchmark gearing level of 60%. Under the AER's approach, a benchmark entity of Ausgrid's size would need conduct approximately 38 $250 million bond issuances to rollover its debt portfolio completely.
- identifying the upfront debt issuance costs associated with a benchmark bond issuance. Our Proposal uses the upfront costs adopted by the AER in several recent decisions – see the table below.
- amortising these upfront debt issuance costs incurred using the nominal vanilla WACC applicable to the benchmark efficient entity. We used our proposed allowed rate of return of 6.33%.
- recognising that Bond Master Program and credit rating costs can be spread over multiple bond issues, which lowers the benchmark allowance – as expressed in basis points per annum (bppa) – as the number of bond issues increases.
- summing up the amortised upfront costs for the number of bond issuances relevant to the network service provider in question to arrive at an overall estimate of debt raising costs expressed in bppa.

Our proposed estimate of debt raising costs is 8.38 bppa, as set out in the table below. This rate is multiplied by the debt component of a service provider's projected RAB to determine the debt raising cost allowance.

Table 39.

Ausgrid's proposed debt issuance costs 2019–24

	UPFRONT COST	1 BOND ISSUED	38 BONDS ISSUED
Amount raised		$250 million	$9,500 million
Arrangement fee		7.22	7.22
Bond Master Program	$56,250	0.31	0.01
Issuer's legal counsel	$15,265	0.09	0.09
Company credit rating	$77,500	0.43	0.01
Annual surveillance fee	$35,500	0.14	0.00
Up-front issuance fee	5.2 bp	0.72	0.72
Registration up-front	$20,850	0.12	0.00
Registration annual	$7,825	0.31	0.31
Agents out-of-pockets	$3,000	0.02	0.02
Total (bppa)		**9.35**	**8.38**

54 For example: AER, Final Decision, AusNet Services transmission determination 2017–2022, Attachment 3 – Rate of Return, April 2017, p.403.

55 PwC, Debt financing costs, June 2013.

7.5 The value of imputation tax credits

The Rules require a building block revenue proposal to contain the DNSP's proposed value of imputation credits,[56] which the Rules refer to as 'gamma'. Gamma is used as an input when estimating the cost of corporate income tax.[57]

In recent determinations, the AER has adopted a gamma estimate of 0.4. In our view, the most appropriate estimate of gamma is 0.25. However, for the purposes of this initial Proposal, we have adopted the Rate of Return Guideline's analysis of gamma and the value of 0.4 adopted by the AER in its most recent determinations, on the basis of our engagement with consumers.

7.5.1 Two possible interpretations of the meaning gamma

In recent years, the appropriate interpretation of the meaning of the phrase 'value of imputation credits' has been a matter of contention. The AER has interpreted gamma to mean the rate of *redemption* or *utilisation* of imputation tax credits. By contrast, Ausgrid and other network service providers have interpreted gamma to mean the *market value* that equity investors place on imputation tax credits. These two interpretations of the meaning of gamma have given rise to two alternative approaches for estimating and, in turn, two distinct estimates of gamma:

- **The market value approach** – gamma should be estimated from the observed prices of traded securities in the same way as other WACC parameters. This approach produces an estimate of the extent to which investors value credits relative to dividends and capital gains – essentially, the dividends and capital gains investors would give up to receive a dollar of credits. Ausgrid considers that, in principle, the market value approach is the most appropriate method for estimating gamma.
- **The redemption or utilisation approach** – gamma should be estimated as the proportion of credits available for investors to redeem. This approach – as used in the Rate of Return Guideline – considers the extent to which investors value the credits they redeem less than the dividends or capital gains they receive to be irrelevant.

7.5.2 Gamma must be interpreted and estimated consistent with its role within the regulatory framework

In 2015, the Tribunal that heard the merits review appeals of the NSW distribution businesses, including Ausgrid, found the AER had erred by adopting a redemption or utilisation approach to estimating gamma. The Tribunal concluded that estimating gamma on the basis of the full face amount of credits available for redemption (ignoring all other reasons why credits might be less valuable than dividends or capital gains) was inconsistent with the regulatory framework:

> *...the AER has adopted a conceptual approach to gamma that redefines it as the value of imputation credits that are available for redemption. This is inconsistent with the concept of gamma in the Officer Framework for the WACC.*[58]

The Tribunal went on to note that all other WACC parameters are estimated as market values using the prices of traded securities:

> *Moreover, the AER's reasoning ignores the fact that other parameters in the WACC calculations are market values.*[59]

The Federal Court has held that the Tribunal had erred in reaching its conclusion:

> *...we accept the AER's submission the Tribunal's approach to gamma was underpinned by a misunderstanding on its part about how return to investors was conceptualised in a WACC framework.*[60]

The Court went on to say:

> *In our opinion the Tribunal assumed that other parameters in the WACC calculations were market values that already incorporated investors' tax positions and transaction costs but that misconstrued the 'post-tax' framework.*[61]

The Court concluded that the approach used to interpret and estimate gamma must be consistent with the role of gamma in the regulatory framework.[62] We agree with that conclusion.

A proper understanding of the role of gamma within the regulatory framework, and how it relates to other WACC parameters that determine the allowed rate of return, all suggest that gamma should be interpreted as a market value concept.

56 NER S6.1.3(9B).

57 NER 6.5.3.

58 Applications by Public Interest Advocacy Centre Ltd and Ausgrid [2016] ACompT 1, Paragraph 1100.

59 Applications by Public Interest Advocacy Centre Ltd and Ausgrid [2016] ACompT 1, Paragraph 1073.

60 Australian Energy Regulator v Australian Competition Tribunal (No2) [2017] FCAFC 79, Paragraph 755.

61 Australian Energy Regulator v Australian Competition Tribunal (No2) [2017] FCAFC 79, Paragraph 755.

62 Australian Energy Regulator v Australian Competition Tribunal (No2) [2017] FCAFC 79.

As Frontier Economics sets out in detail in Attachment 7.01 of this Proposal, all other WACC parameters estimated by the AER when determining the allowed rate of return *are* market value estimates that *do* reflect the effects of personal taxes, personal costs and every other consideration investors make when determining how much they would be prepared to pay for stocks or bonds. This is because they are all derived from the observed prices of traded securities. It then follows that the estimates of the required return on equity and debt should include the compensation that investors require in relation to personal taxes and personal costs.

The regulatory framework operates in two steps. The AER:

1. estimates the total required return on equity. This is an estimate of the dividends and capital gains that investors would require in a benchmark efficient firm if there were no imputation credits. This estimate reflects personal taxes and personal costs that relate to dividends and capital gains.
2. deducts the value of imputation credits' and sets the allowed revenues so the firm can pay the difference to investors in the form of dividends and capital gains.

That is, gamma plays the role of determining the amount by which the allowed dividends and capital gains will be reduced to reflect the value of the imputation credits that investors will receive. As Frontier Economics explains in Attachment 7.01 of this Proposal, in the context of the AER's regulatory framework, gamma:

> ***...is an exchange rate – the rate at which investors would exchange dividends and capital gains for imputation credits. Thus gamma must reflect the value of credits relative to dividends and capital gains.*** [63]

This provides the proper indication of the dividends or capital gains investors would be willing to give up to obtain an imputation credit. Only if gamma is interpreted and estimated in this way will investors be appropriately compensated.

As Frontier Economics concludes in Attachment 7.01 of this Proposal, the main implication is that gamma should be estimated using dividend drop-off analysis. That method provides a direct estimate of the extent to which investors value imputation credits relative to the extent to which they value dividends and capital gains. [64]

As Frontier Economics explains, the most robust dividend drop-off estimate currently available is 0.25, which is materially lower than the 0.4 determined by the AER in its recent decisions.

63 Frontier, Estimation of certain aspects of the allowed rate of return, April 2018.

64 Frontier, Estimation of certain aspects of the allowed rate of return, April 2018.

7.5.3 Ausgrid's proposed estimate of gamma

We consider that the correct interpretation of gamma, within the AER's regulatory framework, is the measure of the market value of imputation credits, and that the best available estimate of gamma is 0.25. However, in this Proposal we have adopted an estimate of gamma of 0.4, in line with the estimate specified in the Rate of Return Guideline.

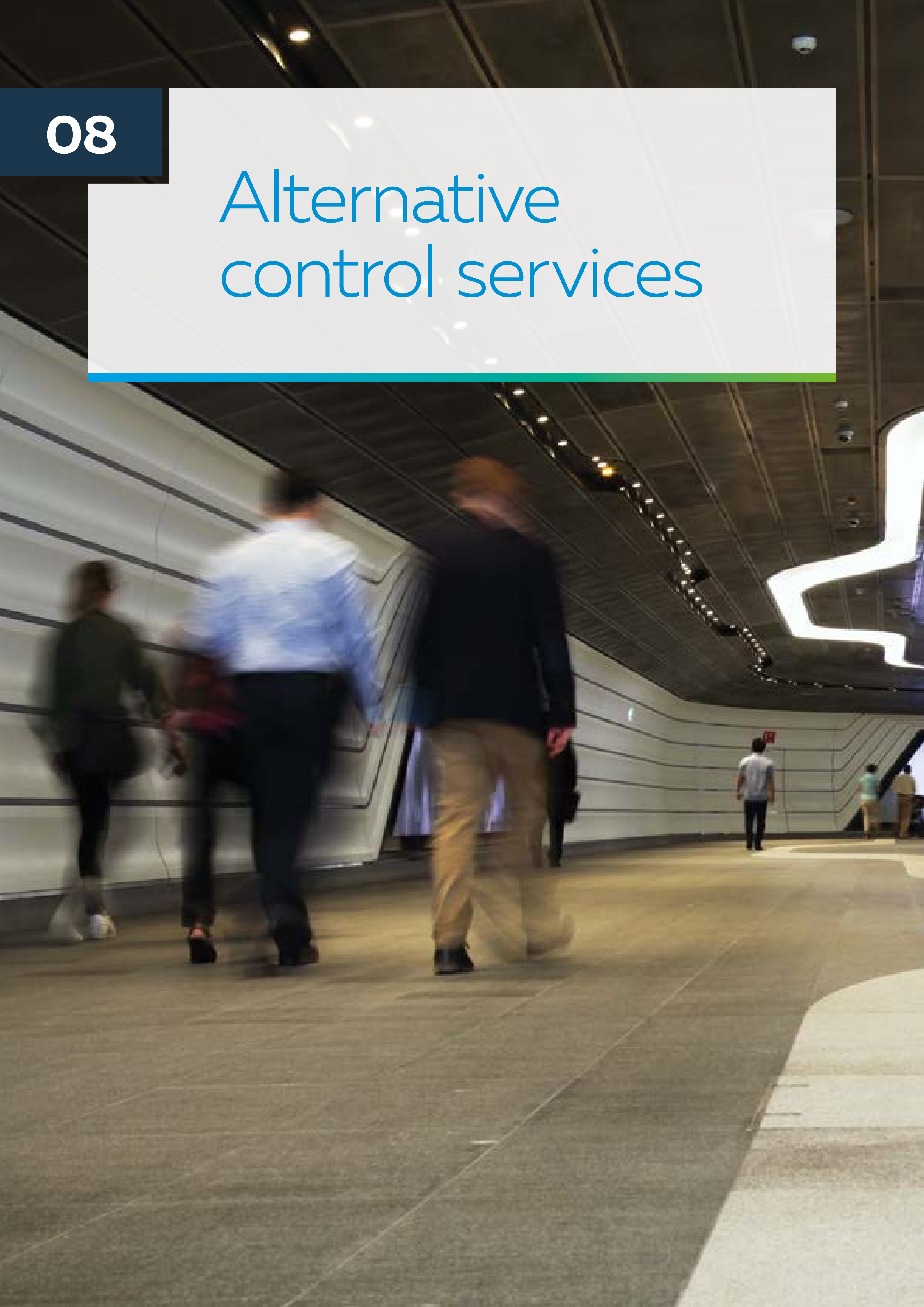
As already noted, our stakeholder consultation indicates that consumers of electricity are keenly focused on keeping electricity network prices low over 2019–24 period and would prefer the application of the AER's approach for estimating the value of imputation credits. We have therefore adopted a gamma estimate 0.40 that will help keep electricity network prices low over 2019–24, but still allow us to maintain safe, reliable electricity supply.

7.6 Expected inflation

For the purpose of this Proposal, we have adopted a placeholder estimate of inflation of 2.50%, which is the mid-point of the RBA's target range for inflation. This estimate will be updated to reflect the latest available information, in accordance with the approach set out in the AER's December 2017 final position on the regulatory treatment of inflation.

08

Alternative control services



08

Alternative control services

What did we achieve in 2014–19?

Public lighting – we invited our customers to choose how we should structure our prices for new LED luminaires — and then implemented their preferred choice

Metering – we proposed, then put into place, a pricing structure that allows customers to smoothly transition to a more advanced metering service offered by retailers in the contestable market

Ancillary network services – we continued to offer a range of one-off ancillary network services that our customers value, and which reflect our actual cost of delivery.

What outcomes will we deliver in 2019–24?

Public lighting – we will transform our service by completing a mass rollout of 125,000 energy efficient LED luminaries – equal to half of all streetlights on public roads in our service area.

Metering – our Proposal aligns with affordability by delivering a $4.18 (or 14%) decrease in annual metering charges for a customer on a basic accumulation meter.

Ancillary network services – the prices customers pay will reflect our efficient costs due to our adoption of the AER's benchmark labour rates.

How are we responding to our customers' feedback?

Affordable

We sought feedback from customers on the rate at which we should recover the capital cost of our legacy metering assets, and then implemented their preferred approach.

Reliable

The technology choices we make – particularly in providing public lighting services – are prudent and will maintain existing levels of reliability.

Sustainable

The mass rollout of energy efficient LED luminaires will lower our carbon footprint and lead to a more sustainable, environmentally responsible service.

Our ACS include public lighting, some metering and ancillary (non-routine) services. As with the energy sector more broadly, these services – particularly public lighting and metering – are undergoing a major transformation. We have taken these changes into account and developed a proposal that is strongly focused on our customers' interests.

8.1 Public lighting

Our proposed approach to pricing public lighting pricing is consistent with the previous two AER Determinations. Our public lighting customers will continue to pay a fixed charge for assets installed before July 2009 and an annual capital charge for assets installed after July 2009.

8.1.1 About our public lighting services

Ausgrid's network area has more than 250,000 public lights, which are typically installed on major and minor roadways. Public lighting services encompass providing, constructing and maintaining public lighting and emerging public lighting technology.[1] Ausgrid provides public lighting services to more than 90 customers, including councils, community groups and government associations.

Our Proposal is to provide lighting services to the standards specified in the NSW Public Lighting Code, which is currently under review. Ausgrid has based its public lighting charges on the published version and may require a review if any significant changes are made.

Our pricing approach is consistent with the AER's cost models in recent determinations. Under this approach, each lamp, luminaire, support structure, bracket and connection are treated individually from a cost build up perspective, resulting in the two types of capital charges mentioned above. The maintenance charge per lighting structure is based on the lamp type and the cost of maintaining each of the five components.

Public lighting is undergoing a major transformation. In developing our Proposal, we listened to local councils' views on technological developments and their eagerness to take up innovations in advanced public lighting solutions.

Consistent with their views, we have started replacing older, less energy efficient luminaires with LEDs. Ausgrid has adopted LED luminaires for all of its new and replacement installations. The LED rollout is set to expand in the 2019–24 regulatory period and will cover nearly 125,000 street lights by the end of the next regulatory period. Of these, about 60,000 will be replaced in 2017/18 and 2018/19.

Our mass rollout of LED lights has broad benefits. Their greater energy efficiency will deliver a more sustainable public lighting service with a lower carbon footprint. Customers who take up LEDs will also benefit from cost savings, in the form of lower energy bills and, due to an increase in reliability compared to older technologies, reduced public lighting maintenance charges. Councils will see a reduction of total yearly charges of $3.4 million.

We undertook significant consultation and negotiation with our public lighting customers to determine a pricing structure that best suited their needs, while adequately recovering the capital and maintenance costs.

We will also begin implementing public lighting smart controls. This technology can increase maintenance efficiency and assist councils in developing smart cities. We will engage further with the AER about smart control pricing when we begin to roll out this technology.

We took our public lighting proposal to stakeholders for comment in February 2018. Strong support was received for a mass rollout of LEDs. Stakeholders in fact questioned whether our plan to install 125,000 streetlights with LEDs by the end of 2023–24 could be more ambitious. Trials into, and a timely implementation of, public lighting smart controls was also supported.

Ausgrid shares stakeholders' views regarding the benefits of a mass rollout of LEDs and the implementation of smart controls. We will review our LED rollout to determine whether it can be scaled up and are aiming for a quick implementation of smart controls once we conclude ongoing trials of this technology.

1 AER, Stage 1 Framework and Approach paper, Ausgrid, Endeavour Energy and Essential Energy, Transitional regulatory control period 1 July 2014 to 30 June 2015 & Subsequent regulatory control period 1 July 2015 to 30 June 2019.

8.1.2 Objectives of public lighting

Although Ausgrid has made some fundamental changes to the way we provide public lighting services, our underlying objectives remain similar to our approach in the 2014–19 period:

- **Minimise total lifetime cost** – ensuring that Ausgrid operates prudently and efficiently is fundamental to providing the required service at the lowest cost. This includes:
  - improving labour productivity,
  - reducing overheads through network reforms,
  - standardising our lighting population, and
  - offering energy efficient lighting technology.

  Ausgrid will also monitor emerging technology that could be used to improve cost efficiency or provide new or enhanced services for our customers.

- **Maintain network performance in accordance with the public lighting code** – the NSW Public Lighting Code describes minimum performance standards and practices for providing public lighting services. This document references the Australian Standard (AS1158) for public lighting. Ausgrid will seek to meet the Code requirements throughout the 2019–24 regulatory period.

- **Decrease complexity and provide more transparency to the customer** – currently, we apply three categories of public lighting charges: capital, maintenance and residual. The public lighting charges are:
  - fixed capital charge for assets installed prior to 2009 and annuity capital charge for assets installed post 2009
  - maintenance charge that is applied to all assets, and
  - residual charges for assets replaced before their regulatory end of life.

  Ausgrid is not proposing changes to the pre-July 2009 model. However, we are proposing changes to the other charges following extensive discussions with our customers on alternative pricing options for LED street lights.

- **Charge cost-reflective prices** – cost reflectivity means customers have a sound basis for decisions about technology and whether to seek an alternative third party to provide public lighting services. It also means that Ausgrid can recover the costs of providing public lighting services equitably across our customer base.

8.1.3 Our costs and revenues

Our capital and maintenance charges are calculated using a cost build up approach that details the tasks performed to install and maintain the public lighting network.

Ausgrid is proposing several capital replacement programs throughout the 2019–24 regulatory period to replace older style luminaires. Further information about our proposed capex and opex is provided in Attachment 8.07 (Ausgrid's public lighting services).

Public Lighting assets installed pre July 2009 are included in the roll-forward of a public lighting asset base, which has been carried forward from the AER's 2009–14 Determination. Attachment 8.08 (Public Lighting – pre 2009 'Fixed Charge' model) includes the calculations underlying this asset base value.

Our prices for assets installed post July 2009 include capital costs based on the annuity model developed at the AER's 2010 Determination, which has been updated for the current inputs. As a result, there is no forecast asset value for assets installed post July 2009. Similarly, our opex forecasts are based on the AER's 2010 Determination opex model updated for the most recent inputs.

See Attachments 8.09 and 8.10 for further details.

8.2 Metering services

We are responsible for type 5 and 6 metering services, which are regulated by the AER. In line with our commitment to affordability, the price we charge for this service is set to decline in the 2019–24 regulatory period, by at least $4.10 annually (or 14%) for residential customers.

In addition to targeting affordability, our metering proposal has been developed in the context of the Power of Choice metering reforms, which are facilitating a market-led rollout of advanced meters managed by retailers. These reforms, which took effect on 1 December 2017, allow residential and small business customers to leave our type 5 and 6 metering service in favour of a retail offering inclusive of an advanced meter.

8.2.1 Forecast opex and capex

We forecast $105.4 ($ million, real FY19) in metering opex but do not propose any capex.

Under the Power of Choice metering reforms, Ausgrid will remain the initial metering coordinator for our existing fleet of type 5 and 6 meters. We have therefore put forward an opex forecast based on the ongoing costs associated with operating this infrastructure.

However, we are no longer responsible for installing new meters or replacing them when they fail. As a result, Ausgrid will not incur – and is not proposing to recover – any metering capex for the 2019–24 regulatory period.

8.2.2 Recovery of legacy metering assets

Prior to the Power of Choice reforms, Ausgrid was required to ensure that all customers had a working meter. To meet this regulatory obligation, we funded the capital cost of all our residential and small business customers' meters at the time of installation. We then recovered that initial outlay of capital via metering charges over the life of the meter.

With the introduction of the market-led rollout of advanced meters, this long-term capital cost recovery process could potentially be disrupted by customers switching to an advanced metering service before the capital costs of their Ausgrid owned legacy meter has been recovered. To address this issue, the AER introduced a charging structure in the 2014–19 regulatory period, whereby customers who leave our metering service continue paying for the capital cost of their Ausgrid meter. This charging arrangement was considered preferable to a lump sum exit fee.

Our Proposal adopts the AER's charging structure. We agree that it is the 'most appropriate way to recover metering capital costs incurred in providing regulated metering services that risk becoming stranded if a customer switches (to a retail offering inclusive of an advanced meter)'.[2]

In the course of consulting with stakeholders, we asked them about the rate at which we should recover the capital costs associated with our legacy metering assets. We provided an option for an accelerated rate of depreciation, yet stakeholders told us that a standard rate of capital cost recovery should be applied. This has therefore been included in our Proposal.

8.3 Ancillary network services

The AER defines 'Ancillary Network Services (ANS)' as non-routine services provided to individual customers on request, such as supplying design-related information for connections to our network, special meter reads and site establishment.

8.3.1 Forecasting approach

Our forecast prices for delivering ANS are based on efficient cost inputs that reflect the circumstances and regulatory environment of our business. As explained below, we used different methods, depending on whether, or not, the AER approved the proposed price for a service in our last determination.

8.3.2 Prices approved at last determination

When developing our ANS proposal, we took the position that any fixed or quoted fees approved by the AER in it's 2015 Determination, or adjusted by less than 1%, should be indexed by CPI and real price changes in labour only.

In our 2014–19 distribution determination, our ANS proposal included 92 fixed and quoted fees. Of these, 26 were considered efficient and approved by the AER and four had their prices adjusted by less than 1%.

2 AER, Final decision on Ausgrid's 2014–19 regulatory determination, April 2015, p.16–46.

8.3.3 Prices not approved at last determination

We applied a 'bottom up' approach to develop our proposed prices for the remaining ANS fees. This involved identifying the type of employee who carries out the service and applying their average hourly rate to our estimated completion time. Thus, labour is the key input into our ANS proposal.

For the forthcoming regulatory period, we propose applying the benchmark efficient labour rates the AER last approved for Ausgrid, updated for CPI and real price changes in the cost of labour. All other components – including the percentage adjustments for on-cost and overheads – have remained the same. Our proposed labour rates are set out in the table below.

Table 40.

Ausgrid's proposed labour rates ($, real FY19)

	RAW LABOUR RATE	ON-COSTS	OVERHEADS	TOTAL
Administrative (R1)	43.72	22.84	33.28	99.84
Technical specialist (R2)	66.14	34.55	59.41	160.10
Engineer/Senior Engineering officer (R3)	77.36	40.40	81.25	199.01
Field worker (R4)	52.69	27.52	69.79	150.00
Senior engineer (R5)	91.93	48.02	96.56	236.51
Engineering manager (R6)	108.40	56.62	113.86	278.88

09

Incentive schemes and pass through

09

Incentive schemes and pass through

What did we achieve in 2014–19?

The AER's CESS provided incentives to deliver capex savings, while the STPIS provided a countervailing incentive to improve reliability. The AER did not apply the Efficiency Benefit Sharing Scheme (EBSS) in the 2014–19 period. However, we had a strong incentive to reduce our operating costs in line with our expenditure allowances.

We responded to the incentives during the 2014–19 period by substantially reducing our capex and opex. We achieved savings in our recurrent opex of $100 million per year. We reduced our capex by 57% from its peak levels in 2012. We also delivered service improvements by more than 50% compared to 2009 levels. We conducted several trials in demand management using our DMIA.

What outcomes will we deliver in 2019–24?

We are proposing that four incentive schemes will apply as follows:

- The EBSS and CESS will provide Ausgrid with incentives to reduce our opex and capex over the 2019–24 regulatory period. Any savings we achieve in response to these incentives will be shared with customers from 2024 onwards, and we will be penalised for any efficiency losses under these schemes.
- The STPIS will provide us with incentives to reduce the frequency and duration of outages and improve customer service by increasing the proportion of calls we answer within 30 seconds.
- The DMIS and DMIA will provide us with incentives to identify potentially more efficient – as well as sustainable – alternatives to building new infrastructure (such as poles and wires), including through partnering with our customers and trialling low carbon technologies to support demand management.

We propose applying the AER's preferred definition of pass through events, subject to an amendment to capture cyber security threats. These arrangements provide an efficient and equitable method for managing unpredictable, high-cost events beyond our control. Our Proposal will ensure we can respond to, and quickly address, any impact on our network from events, such as natural disasters, by allowing us to recover our efficient costs.

How are we responding to our customers' feedback?

Affordable

Expenditure incentive schemes (EBSS and CESS) will encourage further cost savings that will lead to reduced network prices. By applying these schemes, we will have strong ongoing incentives to reduce our costs and share these cost savings with our customers.

Reliable

The STPIS will incentivise us to provide our customers with a reliable grid and to meet customer service expectations. The application of pass throughs, if required following a high-cost but low probability event, will also help us maintain reliability.

Sustainable

The DMIS and DMIA will incentivise us to focus on more sustainable and efficient alternatives to new infrastructure.

Our Proposal includes incentive schemes that cover expenditure, service performance and demand management. These incentive schemes improve affordability for customers by sharing the cost savings we achieve, while at the same time encouraging us to meet or exceed specified reliability and customer service targets.

Our Proposal also includes four pass through events to ensure we can respond to certain circumstances, such as natural disasters. The pass through mechanism allows for our revenue to be adjusted (following AER approval) if our costs change materially as a result of a pre-specified event.

Incentive schemes are crucial elements of our Proposal. These schemes help us achieve our goal of delivering value for money, for all customers, without compromising on safety, reliability or customer service. The schemes give us consistent incentives to identify potentially more efficient alternatives to building new infrastructure and seek other cost reductions, which benefit customers.

Consumers will benefit from each of the incentive schemes that will apply during the 2019–24 regulatory period. The first two schemes (the EBSS and CESS) give us incentives to improve efficiency in our operating and capex, respectively, giving consumers about 70% of any cost reductions we can achieve. The service standard scheme (STPIS) gives us an incentive to improve our reliability and customer service. Lastly, the demand management incentive encourages us to implement lower-cost, non-network solutions consistent with our customers' expectations.

The following section explains how we propose each of the incentive schemes will apply[1] and highlights any areas where our approach differs from that of the AER.[2] See Attachment 9.01 for further technical details of how the schemes should be applied.

9.1 Efficiency Benefit Sharing Scheme

By applying the EBSS our customers will benefit from 70% of any opex cost savings, improving affordability.

The EBSS provides an incentive to improve affordability by continuously reducing our operating costs and giving our customers a fair share of any savings we achieve.

The EBSS works by rewarding us for delivering our services at a lower operating cost than our forecast allowance. We retain any cost savings in a given year for a period of five years. For example, if we reduce our recurrent opex, adjustments are made so that our revenue allowances for opex do not drop for five years. These adjustments flow into revenues for the next regulatory period. Under this approach, efficiency gains in operating costs are shared approximately 70:30 between our customers and us.[3] The scheme is symmetrical, as we are also penalised equally for any efficiency losses.

1 The Rules require that our Proposal contain a description, including relevant explanatory material, of how we propose any incentive scheme that has been specified in the Framework and Approach paper should apply. NER clause s6.1.3.

2 The AER sets out its approach in its Framework and Approach for Ausgrid, Endeavour Energy and Essential Energy: Regulatory control period commencing 1 July 2019, July 2017. The AER is required to publish its approach under NER clause 6.8.1(b)(2).

3 AER, Explanatory statement: *EBSS for Electricity network service providers*, November 2013, p.36–37.

In its F&A paper, the AER indicated it will decide if and how it will apply the EBSS as part of its determination on our revenue proposal.[4] The AER did not apply the EBSS to Ausgrid for the 2014–19 period.

As explained in Chapter 6, we have delivered substantial opex savings during the current regulatory period. These savings, together with our good benchmarking performance, should give the AER confidence that our proposed 2017–18 base year opex is an efficient 'base' for applying its 'base-step-trend' forecasting methodology. As such, the AER should also apply the EBSS in the 2019–24 regulatory period, as it is an integral component of the AER's framework for driving efficient opex outcomes over time.

Ausgrid therefore proposes that the most recent version of the EBSS[5] should apply in the 2019–24 regulatory control period, subject to several cost exclusions set out below.

9.1.1 Cost exclusions

In deciding how the EBSS should apply, Ausgrid has the option of proposing that certain cost categories be excluded from the AER's calculations of efficiency gains or losses for the EBSS reward or penalty. Under the scheme, certain categories of opex may be excluded if doing so better achieves the scheme's objectives. This approach leads to fairer sharing of the efficiency improvements between Ausgrid and our customers. It also prevents windfall gains or losses.

The current version of the EBSS already specifies several adjustments, which Ausgrid agrees should be made.[6] In addition, Ausgrid proposes excluding:

- **Debt raising costs** – Ausgrid calculates its debt raising costs by applying a benchmark debt raising unit rate to the debt portion of our RAB. This is consistent with the AER's approach. We propose that, because the cost is set based on a benchmark debt raising allowance[7] rather than our revealed costs, it should be excluded from the EBSS calculation.
- **Costs associated with the DMIA** – The DMIA is part of the demand management incentive scheme. Under the DMIA arrangements, any underspend must be returned to customers in full. In this case, we propose that customers retain the full amount of any underspend, so these costs should not be subject to the EBSS.

9.2 Capital Expenditure Sharing Scheme

Like the EBSS, the CESS will allow our customers to benefit from improved efficiencies through lower regulated prices in future periods. The CESS shares efficiency gains 70:30 between our customers and us.

The AER intends to continue to apply the CESS in the next regulatory period.[8] In calculating any capital underspend or overspend, the AER takes into account the financing benefit or cost to the distributor of any underspend or overspend amounts. The AER can also make further adjustments to account for deferred capex and ex-post exclusions of capex from the RAB.

Our stakeholders did not express a strong view on how to apply the CESS.

Ausgrid proposes that the mechanism for calculating the penalty or reward under the scheme is calculated in accordance with the AER's current CESS guidelines.[9]

4 AER, Framework and Approach, July 2017, p.66.

5 AER, Efficiency Benefit Sharing Scheme for Electricity Network Service Providers, November 2013.

6 AER, Efficiency Benefit Sharing Scheme for Electricity Network Service Providers, November 2013, clause 1.4.

7 This is consistent with the AER's approach and is applied to all DNSPs.

8 AER, Framework and Approach, July 2017, p.69.

9 AER, Capital Expenditure Incentive Guideline for Electricity Network Service Providers, November 2013.

9.3 Service Target Performance Incentive Scheme

The STPIS will help us maintain and improve our service performance and ultimately deliver better outcomes, including reliability, for customers.

The STPIS works by providing rewards or penalties, depending on whether we meet specified reliability and customer service targets (through an 's-factor' adjustment to our revenue). The rewards allow us to fund reliability improvements. The penalties hold us to account if we do not maintain our current level of performance.

> The STPIS helps to promote reliability. Following stakeholder feedback, we will develop a new customer service measure that better reflects the outcomes that customers value.

Consistent with the AER's proposed approach[10], we propose that the maximum we can be rewarded or penalised is 5% of our revenue. The STPIS scheme may also include a guaranteed service level (GSL) component composed of direct payments to customers experiencing service below a predetermined level. However, GSL already apply to Ausgrid through a jurisdictional scheme, so we do not propose they apply as part of the STPIS.

We are also developing a new approach to measuring customer service performance, as discussed below. See Attachment 9.01 for our complete proposal.

9.3.1 Reliability

Reliability performance is the main component of STPIS. We propose that the maximum rewards and penalties can be up to 4.5% of revenue.

This incentive arrangement is based on how much consumers value reliability. It signals when we should make reliability improvements and ensures we only invest where customer value exceeds the costs. The penalties also work the other way to make sure we do not sacrifice reliability that customers value to achieve cost savings.

Consistent with the AER's proposed approach, we propose a scheme that:

- measures reliability by the length and duration of outages, using the SAIDI and SAIFI,
- calculates performance for different parts of the network separately (for instance rural and urban areas) to provide a more accurate measure of performance,
- removes the impact of extreme weather, which is beyond our control,
- uses the AEMO's 2014 estimate of the value customers place on reliability. We chose this estimate rather than one developed by our consultants, based on feedback from our CCC, and
- uses the average of our actual performance over the last five years to establish the targets.

9.3.2 Customer service

We propose the penalties and rewards for customer service are capped at 0.5% of our revenue.

Currently, our customer service performance is based on the proportion of calls we answer within 30 seconds.

However, stakeholders have told us that the telephone response times are not a meaningful indicator of customer service. We agree, and so we have been working with stakeholders to develop a better measure of customer service (see the box below).

We propose to begin collecting data on this new measure from July 2018 when we will have the right systems in place to report on this metric. We will seek to have it included in the scheme and our revenue determination for the 2024–29 regulatory control period.

10 AER, Framework and Approach, July 2017, p.60.

Designing a new customer performance measure

Our CCC has suggested that more appropriate customer service metrics could be developed, beyond telephone response times. In response, Ausgrid has designed a new customer service metric with stakeholders. Over the course of several meetings, we agreed on a complaints-based metric with five indicators, using a UK approach as our model.

As part of this process, we discussed and agreed with our stakeholders how to define 'complaint' and 'repeat complaint'; and how to obtain the views of elderly customers who may be dissatisfied but hesitant to make a complaint. One of the UK indicators is based on the number of Ombudsman decisions that go against the distributor as a percentage of total complaints. We have adapted this measure for our context.

Following further discussion, we agreed the proposed indicators:

- Percentage of total complaints outstanding after five days
- Percentage of total complaints outstanding after 28 days
- Percentage of total complaints that are repeat complaints
- Percentage of Ombudsman complaints referred back to Ausgrid as a Level 1 investigation
- Customer satisfaction with the quality of complaint handling (independent provider to survey).

This customer service measure will incentivise us to deal with complaints quickly and avoid repeat complaints. Some of the details are still to be finalised, including the weightings for the parameters and targets. Ausgrid and the CCC agreed it would be beneficial to set these measures once we have commenced collecting data to inform these components of the metric.

9.4 Demand Management Incentive Scheme and Innovation Allowance

The DMIS and DMIA will help us to identify potentially more efficient alternatives to building new infrastructure and provide funding to test new demand management options.

Our Proposal incorporates a demand management scheme with two components:[11]

- **The Demand Management Incentive Scheme** – provides DNSPs with an incentive to undertake efficient expenditure on relevant non-network options relating to demand management, and
- **The Demand Management Innovation Allowance** – provides distributors with funding for research and development in demand management projects with the potential to reduce long-term network costs.

Together, the DMIS and DMIA aim to reduce network costs over time, lowering prices in future regulatory periods. The AER intends to apply both the DMIS and the DMIA to Ausgrid in the next regulatory period.[12]

We propose that version 1 of the DMIS[13] and the DMIA apply in the 2019–24 regulatory period, including the full allowance: $200,000 plus 0.075% of our annual approved revenue for our distribution services. Any underspend of the allowance will be returned to customers in full.

We consider that applying the DMIS and DMIA in the next regulatory period will meet the National Electricity Objectives (NEO) set out in the NEL, as well as the individual objectives of the DMIS and DMIA as set out in the Rules.

9.4.1 How the DMIS works

The DMIS will give us incentives to invest in demand management solutions where these are the least cost option. Ausgrid already conducts an economic assessment of demand management options. Our 2017 assessment reviewed $540 million in network investment against non-network alternatives, comparing their respective costs and benefits. Where the net present value of benefits from the non-network solution is equal to or greater than the network option, we choose the non-network solution.

For projects where the network option has an expected capital cost of more than $5 million, we follow the Regulatory Investment Test for Distributors to further assess demand management solutions, including seeking submissions from non-network solution providers. For smaller projects, in compliance with the AER's minimum project evaluation requirements, we consult with market providers if we consider non-network alternatives to be viable.

This approach ensures that only efficient options proceed under the DMIS. It means that Ausgrid also assesses the net benefit from the project, including the DMIS, to ensure that applying the DMIS will deliver net cost savings to retail customers. This is consistent with the NEO and the DMIS's objective.

11 AER, Demand management incentive scheme and innovation allowance mechanism, 14 December.

12 AER, Framework and Approach, July 2017, p.73 and 76.

13 AER, Demand management incentive scheme, December 2017.

9.4.2 How the DMIA works

The DMIA will give us additional funding to trial innovative demand management projects with the potential to reduce long-term network costs. The DMIA will only be used where we are not able to obtain funding for R&D through other means. We will also share our findings publicly, ensuring that both industry and customers can understand and benefit from project learnings, contributing to the NEO.

The table below summarises recent demand management projects financed through the innovation allowance.

Table 41.

Summary of Ausgrid's recent demand management projects

PROJECT NAME	PROJECT DESCRIPTION
CoolSaver air conditioner demand response project	We explored how managing residential air conditioning power consumption during peak demand can offer a cost-effective alternative to network investments. Positive customer feedback has shown that this will be a highly promising approach when lower cost customer adoption techniques, such as home management systems, are more widely available.
Newington Grid Battery	We found it is possible to use a grid-connected battery storage system to reduce the load on a network asset on peak demand days. We also explored power quality effects and potential customer benefits of using solar and battery systems to reduce electricity bills.
Hot water trials	We conducted three hot water load control trials to explore ways to reduce the impact of peak demand from residential hot water systems. While trial results found no technical barriers, the costs to acquire new customers make this approach a high-cost solution. In contrast, alternative load control time schedules proved very cost effective.
CBD embedded generator connection	This project addressed technical limitations in connecting embedded generators on the triplex network in Sydney's CBD, which can offer lower cost non-network solutions on this part of Ausgrid's network.
Solar Power and Battery System Survey	We gained detailed knowledge about customers' awareness, attitudes to, purchase intentions and usage behaviour in relation to solar power systems and storage batteries.
DMIA stakeholder engagement	We engaged with demand management stakeholders through a web-based forum to guide our demand management innovation research program. The project uncovered several innovative options.

For final and interim reports for completed and in progress DMIA projects, see Ausgrid's Future innovation projects (Attachment 3.01).

We have also identified future innovation projects to help improve the range and cost effectiveness of non-network options to network needs. We are currently considering the following projects, which may be fully or partially implemented during the 2019–24 regulatory period.

Table 42.

Summary of Ausgrid's proposed demand management innovation projects

PROJECT NAME	PROJECT DESCRIPTION
Demand management for Replacement Needs	This project aims to refine techniques for using non-network options to defer the retirement of aged assets (54% of Ausgrid's capital investment expenditure). Options considered include: an incentives trial to encourage permanent demand reductions, such as solar power and energy efficiency; and feasibility studies into using traditional demand response solutions for network outages.
Customer battery storage demand response	Building on lessons learned from the Customers at the Centre project and Solar Power and Battery survey, this project will establish a battery storage network support offer similar to the CoolSaver program. It will explore the willingness of customers to participate and assess the costs and benefits from the solution.
Future trends research	This customer research project will use social science techniques to explore future customer lifestyle trends and their implications on electricity demand and demand management options.
Residential peak time rebate	Focus groups and deliberative forums in the Customers at the Centre project showed strong interest in a peak-time rebate. This project might include testing behavioural demand response options, gamification techniques, smartphone applications with real-time feedback from smart meter load profiles and/or network asset monitoring.
Emerging technology research	Continuing from detailed surveys with both residential and business customers, this program of work will conduct further research, surveys and analysis of customer attitudes and intentions to better understand customer preferences with respect to key emerging technologies.
CoolSaver IoT	The proposed CoolSaver IoT (Internet of Things) trial will leverage the increasing automation and connectivity of appliances to test lower cost solutions for demand response from air conditions and other appliances.
Behavioural demand response	This proposed trial would involve Ausgrid partnering with electricity retailers and behavioural science practitioners to test a range of solutions targeted at influencing customer energy choices and reducing demand.
Electric vehicle dynamic charging	As the electric vehicle industry develops, Ausgrid plans to identify and trial innovative dynamic charging options to help customers manage their peak demand and their bills.

9.5 Small-scale incentive scheme

The AER has not published any small-scale pilot schemes, nor proposed them in its F&A paper. On this basis we do not propose that a small-scale incentive scheme should apply to Ausgrid for the 2019–24 regulatory period.

9.6 Pass through events

We propose including four pass through events for the 2019–24 regulatory period and amending the definition of 'terrorism event' to explicitly capture cyber threats.

The pass through event mechanism provides additional (or reduced) funding, subject to AER approval, to cover any significant increases (or decreases) in costs as a result of any pre-defined event. We propose including four additional pass through events to ensure we can respond and address the consequences from unlikely but high-cost events, such as natural disasters.

Cost pass through events are an important part of the incentive framework, allowing for price adjustments before the next price reset in response to large, unexpected and uncontrollable changes in cost. Without pass through events, we would need to reduce costs elsewhere, such as maintenance, which could increase risks and/or costs in the long term. Similarly, cost pass through events allow us to return funding we no longer require. To avoid constant changes, we can only ask to adjust funding if the change in cost exceeds a materiality threshold of 1% of annual revenue.

The NER already specifies four cost pass through events relating to changes in regulations, service standards or taxes, and the insolvency of a retailer. After reviewing our risk management processes and systems, we propose including four additional events:[14]

- **A natural disaster event** – this covers any major fire, flood, earthquake or other natural disaster beyond the reasonable control of Ausgrid
- **A terrorism event** – an act done for, or in connection with, political, religious, ideological, ethnic or similar purposes or reasons
- **An insurer's credit risk event** – where an insurer becomes insolvent, leading to materially higher costs for Ausgrid
- **An insurance cap event** – where we have an insurance policy in place but incur costs over and above what is covered by the relevant insurance policy limit.

The AER has previously approved these four events. We propose minor adjustments to the definitions to reflect the AER's more recent decisions.

We discuss the need for changes to the definition of terrorism event below. The drafting provisions for the pass through events are provided in Attachment 9.02.

See Attachment 9.02 for further details on how Ausgrid manages its risks and why we consider the additional pass through events necessary.

9.6.1 Amendments to the terrorism event

As the number and sophistication of cyber-attacks increases worldwide, we need increasing focus to ensure our electricity networks are secure against such attacks. We therefore propose minor drafting amendments to the definition of a 'terrorism event' to explicitly include cyber-related terrorism, such as espionage, sabotage and coercion.

The Attorney General's Department has assessed the risk of computer intrusion and the spread of malicious code by organised crime to the Australian economy as high.[15] To manage national security risks that cyber-related attacks pose to critical infrastructure, Australia has established a Critical Infrastructure Centre and draft legislation changes under the Security of Critical Infrastructure Bill 2017. In addition, the *Independent Review into the Future Security of the National Electricity Market* (Finkel review) recommended implementing a stronger risk management framework.

14 Consistent with NER 6.12.1(14).

15 https://www.ag.gov.au/RightsAndProtections/CyberSecurity/Pages/default.aspx

Stronger cyber security arrangements

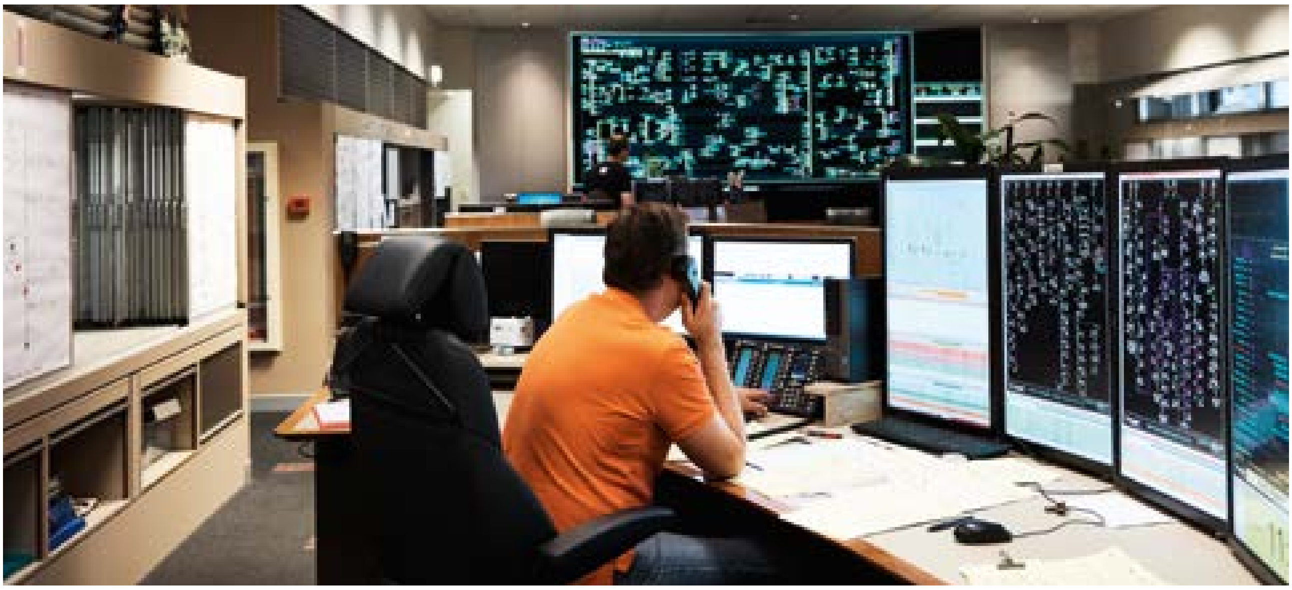
The Finkel review raised concerns about the potential vulnerability of the power system to several emerging threats, including cyber-attacks. The report recommended a stronger risk management framework be implemented. Specifically, the report recommended: [16]

> *An annual report into the cyber security preparedness of the National Electricity Market should be developed by the Energy Security Board, in consultation with the Australian Cyber Security Centre and the Secretary of the Commonwealth Department of the Environment and Energy.*
>
> *The annual report should include:*
>
> - *an assessment of the cyber maturity of all energy market participants to understand where there are vulnerabilities,*
> - *a stocktake of current regulatory procedures to ensure they are sufficient to deal with any potential cyber incidents in the National Electricity Market,*
> - *an assessment of the Australian Energy Market Operator's cyber security capabilities and third-party testing, and*
> - *an update from all energy market participants on how they undertake routine testing and assessment of cyber security awareness and detection, including requirements for employee training before accessing key systems.*

Ausgrid has strong mechanisms and processes to manage risks associated with cyber-attacks. We will also respond to any new requirements stemming from the Finkel recommendations.

The AER previously indicated that the current definition of 'terrorism event' is broad enough to include a cyber-attack if the attack has the characteristics of an act of terrorism. [17] However, Ausgrid considers that amending the definition suggested in Attachment 9.02 will provide greater clarity and certainty on how this low probability, but potentially high-cost, event will be managed under the regulatory framework.

We also consider there to be a need for the definition of a terrorism event to incorporate cyber-security threats given the increased sophistication and frequency of these attacks. Adopting our proposed approach is also consistent with the Australian Government's national security priorities regarding cyber security and recommendations under the Finkel review.



16 Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future, Commonwealth of Australia June 2017, p.22.

17 AER, CitiPower distribution determination final decision 2016–20, May 2016, Attachment 15 – Pass through events, p.19–20.

10

Pricing structures and policies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Pricing structures and policies

What did we achieve in 2014–19?

As a result of feedback from our customers and stakeholders, coupled with our own research and analysis, we made the following improvements to pricing over the 2014 to 2019 period, with the intent of improving pricing signals and efficient network utilisation:

- replacing the declining block price structure with a flat structure,
- removing the peak price from four months of the year for time of use (TOU) customers,
- reducing the times at which the peak price applies in the winter months, and
- assigning more customers to more cost reflective price structures.

What outcomes will we deliver in 2019–24?

We will deliver a 5.7% reduction in Ausgrid's component of network bills in 2019/20. However, customers will experience smaller reductions in the overall network bill which, in addition to recovering Ausgrid's network bill, must also recover the costs of TransGrid's transmission use of system (TUOS) service charge as well as the New South Wales Climate Change Fund (CCF).

While Ausgrid has control over its segment of the customer network bill, the other components of the network bill are not forecast to have similar cost reductions. Further, customers' actual reduction in network bills will vary depending on their own actual consumption levels and characteristics.

Our key proposed pricing reforms for the 2019–24 period build on our reforms to date to deliver more affordable and fair network prices as well as contribute to our overall objectives of assisting the transition to a lower carbon economy at least cost. We propose to achieve these outcomes by:

- focusing on the cost of connection, not on how much energy travels in one direction or the other,
- reflecting the largely fixed daily costs of providing network services, similar to how customers pay for internet access,
- introducing a pricing strategy that rewards efficient investment by customers in new technologies including, Distributed Energy Resources (DER), such as solar PV, battery storage and Home Energy Management Systems and EV where it can reduce future network costs for the community,

- removing inequities between adopters and non-adopters of new technologies,
- implementing targeted measures, including a safeguard price structure, to avoid unacceptable customer bill impacts for low energy users and vulnerable customers, and
- implementing new, more cost reflective pricing for our customers.

Recognising that there is no single approach to pricing that can effectively address all of the above points given, for example, the non-homogenous nature of customer consumption, different approaches will likely be required. In order to assess approaches to pricing, we are launching a comprehensive pricing working group and research program to be framed in collaboration with our stakeholders. This program will lay the foundation for our transition to more cost reflective network pricing, including during the 2019–24 period. Ausgrid commits to commencing work on the pricing program with stakeholders as soon as the Proposal has been submitted to the AER on 30 April 2018.

As a direct response to feedback we received during the extended consultation period, the Proposal now includes a potential new demand pricing structure (that is intended to be refined and implemented during the 2019–24 period). Our research program, and further stakeholder consultation, will assess whether the implementation of this pricing structure is warranted to support the transformation of our network into a dynamic energy trading platform based on DER solutions.

How does our pricing strategy fit with our overall strategy?

Affordable

We will continue to put downward pressure on network costs and prices through improving price signals and by empowering customers to use our network in a way that meets customers' network reliability expectations and helps avoid expensive future network upgrades.

Reliable

We will encourage customers to use our network efficiently, focusing on eliciting more responsive demand-side participation so that we can deliver the reliability outcomes that our customers want at a lower cost.

Sustainable

We will provide incentives for customers to make efficient investments in DER solutions, encourage the efficient use of our network and facilitate its transformation to a platform that facilitates energy trading. Our pricing strategy is aimed at supporting the lowest cost transition to a lower carbon economy.

The proposed changes to our network prices will lay the foundations for a future network and energy supply chain that delivers value for all our customers. It will deliver stable network bill outcomes and improved affordability for our customers without compromising reliability. It will also empower our customers to better manage their energy use by providing greater rewards for using our network outside peak times, contributing to lower network costs and prices over the longer term. We understand that not everyone is able to respond to price signals or afford to invest in DER, so we propose a pricing structure to ensure that all our customers can share in the long-term benefits of sectoral transformation.

10.1 Background

We explain in Chapter 3 that the electricity industry is undergoing a period of unprecedented change. This transformation is being driven by our customers as they embrace new technologies, take control of their energy use and support action on climate change through, for example, the increased take up of DER. In recent years, an increasing number of our customers have also become energy producers as well as energy users, necessitating a shift away from historical network pricing practices which were explicitly linked to how much energy travelled in the 'traditional' direction.

Put simply, the way customers use our network is substantially changing and to ensure our network prices promote affordable, reliable and sustainable outcomes for our customers, we must also change our approach to pricing. It is inherently important that our prices are 'fair' to all our customers. For example, individual users of the network should not be penalised because of their ability, or inability, to invest in DER. Our previous approach to pricing reflected the provision of a one-way transport service which did not provide customers with the information they needed to make decisions that best served their needs, such as understanding the actual cost of using our network at different times of the day.

In this context, better signalling to customers the cost of using our network at peak times (such as hot summer afternoons when air conditioning load is at its highest) will encourage the more efficient use of our network. Efficient price signals will also enable customers to decide whether an investment in DER could potentially meet their electricity needs at a lower overall cost.

On the other hand, the cost of providing network services is very low outside of peak times and so customers should be encouraged to use our network at those times. For example, the use of air conditioners on summer nights when there is excess capacity imposes minimal additional costs on our network. The present rapid roll-out of smart meters also means that we can introduce fairer network pricing structures that reward customers who cost-effectively manage their contribution to peak demand – particularly where such actions help us avoid future network upgrades.

To facilitate the transformation of our network, it is important that our prices reflect the connection service we provide. Focusing our pricing approach based on connection to the grid, as opposed to electricity consumption, reflects the fact that the majority of our costs are stable in nature and are based on investments completed to meet the peak demand reliability needs of our customers. Further, this approach reflects the fact that the network provides access to the market for customers to buy or sell energy and that our network does not sell energy.

Our new pricing approach also focuses on the cost of providing network capacity services, not on how much energy flows one-way out of the grid. Our pricing will reflect these largely stable costs – which is similar to how customers pay for internet access – as well as the additional infrastructure costs associated with using the network when it is congested.

Fundamentally, this new approach will also ensure that customers leading the investment in innovative energy solutions make an equitable contribution to the costs of connected to a network that meets their individual network utilisation needs including, potentially, serving as a platform through which they will buy and sell energy. Rebalancing our pricing approach away from being consumption charges towards daily and TOU charges also provides greater bill stability; lower total network and system costs and accounts for the way that customers now use the network to both import and export energy.

It is important to note that our proposed changes to pricing are specifically aimed at being 'technology neutral', which will ensure that we are not distorting customer decision making or attempting to pick technology winners.

We also recognise that not everyone can afford to invest in DER and that some customers will be more affected by pricing reforms than others. Therefore, our transition to more cost reflective pricing must also be guided by the need to avoid unacceptable customer bill impacts. Where necessary, specific measures will be adopted to address the bill impacts arising from pricing reform.

In summary, the overarching principle guiding our pricing reforms is to place downward pressure on customer prices, and make sure networks costs are shared fairly between our customers. We must achieve this by simultaneously responding to direct customer feedback for greater choice, control and certainty with regards to their network costs. To meet these objectives we must attempt to strike a delicate balance between long-term customer benefits and impacts in terms of fairness and affordability and short-term customer preferences or familiarity with historic pricing approaches.

It is in this context that we developed our proposed pricing reforms for the 2019–24 period.

10.1.1 Our general approach to pricing reform

Our aim is to strive towards prices that promote the efficient use of our network by our customers as they continue to invest in DER and engage in energy efficiency activities. Consistent with the requirements of the Rules, this will make our network services more affordable, reliable and sustainable.

See Attachment 10.01 for our Tariff Structure Statement (TSS), which explains our approach to pricing in detail.

Table 43.

How pricing promotes affordable, reliable and sustainable network services

	HOW CAN PRICING PROMOTE THESE OUTCOMES?
Affordable	• Empower customers to cost effectively manage their contribution to peak demand • Encourage customers to use our network when the cost of doing so is very low • Promote fairer outcomes between customers with different characteristics (e.g. DER and non-DER) • Ensure all customers make a fair contribution to the cost of the connection service they use.
Reliable	• Reduce inefficient spikes in demand and network congestion at peak times • Encourage more responsive demand-side participation to deliver the reliability outcomes that our customers want at a lower cost.
Sustainable	• Empower customers to invest efficiently in DER that can provide the services they want at a lower cost • Encourage further use of the network at times of the day when renewable generation is more prevalent • Encourage customers to invest in DER that reduce their contribution to peak demand, rather than reducing the volume of energy used during non-peak periods • Promoting the lowest cost transition to a lower carbon economy.

Source: Ausgrid 2018.

We acknowledge there is currently no single way to use pricing to achieve these outcomes, particularly given the importance of managing any transitional impacts on customer bills. Furthermore, there is considerable uncertainty and divergence in opinions regarding the impact of alternative pricing structures on our customers' future network use and investment decisions. This results in some differences of views as to the consequent effects on network diversity, maximum demand and our future network costs.

Against this backdrop of uncertainty, our approach for the next regulatory period is:

- to make significant progress in areas where the appropriate next steps in pricing reform are clear, and
- to launch a pricing working group and research program – framed by stakeholder feedback – addressing other potential pricing reforms and to make sure we are well-placed to fast-track their implementation, where appropriate. This work will commence once the Proposal has been submitted to the AER.

The feedback we received through our engagement with customers and stakeholders also played a significant role in shaping our proposed reforms. This feedback enabled us to strike an appropriate balance between the speed of our transition to more cost reflective prices and the avoidance of unacceptable customer bill impacts. In particular, it enabled us:

- to identify the need for specific transitional measures to avoid unacceptable customer bill impacts on low energy users and vulnerable customers, and
- to implement price structures that have the potential to better meet customer preferences.

10.2 Proposed changes to our network prices

In this section we summarise our proposed reforms for the next regulatory period and explain how customer feedback shaped those reforms.

Consistent with our general approach of expediting our transition to cost reflective pricing where the appropriate next steps are clear and, where the way forward is less certain, fast-tracking the research required to speed-up our transition to cost reflective pricing, we propose:

- to include a residential demand price structure that will initially have no customers assigned to it, but that can be implemented during the regulatory period subject to the findings of a comprehensive research program to be developed collaboratively with stakeholders,
  - the research plan and indicative price structure reflect present uncertainty as to whether demand pricing will deliver more affordable, reliable and sustainable outcomes for our customers,
- to improve our approach to recovering the cost of the existing network by rebalancing prices away from non-peak variable charges and towards fixed daily charge charges, and
  - our proposed price rebalancing reflects the clear need for a more efficient and equitable approach to recovering these costs against a backdrop of changing technology and customer preferences.

10.2.1 Demand pricing

Our engagement with customers and stakeholders made clear that there is at present uncertainty and mixed views between customers, customer advocates, Ausgrid and pricing experts on whether demand price structures will deliver more affordable, reliable and sustainable outcomes for our customers.

Further, there is also uncertainty and mixed views on whether demand price structures should be used to signal future network costs or to recover the cost of the existing network, or both. Similarly, there are myriad ways to structure a demand charge depending on its objective, each with differing effects on customers' decisions, network use and network costs.

It is also relevant to note that in contrast to other networks, such as Endeavour Energy's network, Ausgrid has a significant number of customers on TOU pricing (approximately 330,000 residential customers), which is expected to approximately double over the next five years. This means that inappropriately implementing or designing demand pricing could have material adverse implications on network costs and our customers.

In this context, we acknowledge the potential merits of demand price structures but consider that, in light of the present uncertainty and contradicting views, the implementation of demand pricing is not in the best interests of our customers at this point in time. That said, due to those potential merits and feedback from customer advocates, Ausgrid is proposing to launch a comprehensive research plan to be developed collaboratively with stakeholders. A key focus of this collaborative work program will be whether demand pricing will deliver more affordable, reliable and sustainable outcomes for our customers, as compared with other price structures.

However, if our research program indicates that it is the best means of transitioning to cost reflective prices, then we must implement it during the next regulatory period. Therefore, we propose to include in our TSS a residential demand price structure that will initially have no customers assigned to it. We propose that the assignment of residential customers to a demand price structure be contingent on our research program identifying that it is appropriate to commence assigning residential customers to our demand price structure. We expect that theoretical, empirical and customer research, pricing trials and further customer engagement will be required to adequately investigate the appropriateness of demand pricing, as compared with other price structures.

We also propose to include a clearly identifiable trigger for the assignment of residential customers to a demand price structure that it is contingent on written communication from the AER and the Consumer Challenge Panel confirming acceptance of the design and eligibility criteria for the demand price structure, as proposed by Ausgrid following the outcome of the research program. In essence, this will reflect agreement between Ausgrid, customers and the AER on the appropriateness of demand pricing.

We are targeting a decision on whether to action the assignment of residential customers to the demand price structure no later than 2020/21.

Why we are not introducing voluntary opt-in demand pricing on 1 July 2019

During our engagement with customers and stakeholders, some participants expressed the view that customers should be allowed to opt-in to the new demand pricing. Therefore, it is instructive at this point to address why we are not proposing to introduce voluntary, opt-in demand pricing for residential customers at the outset of the 2019–24 period.

The potential benefits of demand pricing result from encouraging customers to change the way they use our network in a manner that enables the avoidance of future network costs, which benefits all customers. Proponents of demand pricing contend that it would be more effective at encouraging our customers to reduce their peak demand, which is the principal driver of our costs.

Customers will generally voluntarily opt-in to a different price if they expect to be financially better off on that new price. Therefore, it is unlikely customers with particularly peaky demand would voluntarily opt-in to demand pricing. Unless they change their behaviour, these customers would likely be relatively worse off under demand pricing. For this reason, we expect that opt-in demand pricing would be ineffective at avoiding future network costs.

On the other hand, the customers most likely to opt-in to demand pricing are those with existing load profiles that would enable them to receive a network bill reduction from demand pricing. By opting into demand pricing, these customers would receive a network bill reduction without any change in behaviour and so a corresponding reduction in future network costs.

In this context, even if it was assumed that demand pricing is appropriate, we expect the benefits of pre-emptively introducing opt-in demand pricing to be limited.

That said, we acknowledge that some of our customers would opt-in to demand pricing regardless of any positive or negative financial incentive to do so, as they view it as 'the right thing to do'. However, in light of the expected limited avoided future network costs, we are not proposing to introduce voluntary opt-in demand pricing at the outset of the next regulatory period.

Instead, we propose to fast-track the research required to make significant strides towards more cost reflective price structures once we are confident that transition path will deliver more affordable, reliable and sustainable outcomes for our customers.

10.2.2 Price rebalancing

In essence, cost reflective prices encourage customers to make decisions about their use of our network, investments in DER and energy efficiency initiatives that best meet their needs at the lowest possible cost. Importantly, cost reflective prices mean that efficient decisions by individual customers benefit not only them, but all customers.

Encouraging efficient use of the network

Cost reflective pricing encourages customers to use our network efficiently by signalling to them the future costs arising from further use of our network, which enables them to decide:

- whether using our network best meets their needs at the lowest possible cost, or
- whether investments in DER and energy efficiency initiatives can better meet their needs at a lower cost (whilst also factoring in overall system cost impacts), which can ultimately benefit all network customers.

Importantly, the level of future costs that could be avoided varies considerably across the day. We estimate that avoidable costs:

- are equal to approximately $56/kW during the peak period, but
- are close to zero outside of the peak period, as there is excess capacity on our network at those times.

This means that, at a very high level, the cost of operating our network will be relatively similar regardless of whether customers use our network more or less outside of the peak period, for instance, in summer before 2pm or after 8pm on working weekdays and in winter, before 5pm or after 9pm on working weekdays. This means that we can enhance our customers' welfare by allowing them to use our network more outside of the peak period, for little or no additional network costs.

By way of example, the additional network costs imposed by customers running their air conditioners on hot summer nights (when there is excess capacity on our network) is very low. If this is something customers value, we do not want to unnecessarily discourage them from using our network with an above-cost price signal.

Relevantly, our current non-peak variable prices – the shoulder and off-peak price – significantly overstate the very low avoidable costs at the times they apply. Therefore, reducing shoulder and non-peak energy prices will better reflect the additional costs of providing network services at those times, which will encourage the efficient use of our network.

Encouraging efficient investments in new technologies

Cost reflective price signals also play an important role in assisting our customers to make efficient investments in DER and undertake efficiency enhancing activities. This is particularly important in the context of rapidly changing technology.

Network prices signal to customers the network bill savings they could realise from an investment in DER. A customer will invest in DER if the cost of that investment is less than the expected network bill savings through time, i.e. that investment would have a positive net payoff. It follows that, if our pricing is cost reflective, customers will invest in DER when the cost of that investment is less than the avoided energy costs, including network costs, resulting from that investment (their bill saving). This is an efficient investment in DER because it better meets that customer's needs at a lower cost. This benefits the customer investing in DER and all other customers, whom benefit from lower network costs.

However, if our prices are above cost reflective levels then we signal to customers that the future network costs that could be avoided by an investment in DER are much higher than they really are. This means that a customer investing in DER may realise a network bill reduction that exceeds the resulting reduction in our future network costs. This may potentially result in an inefficient investment in DER.

The marked adverse implications of inefficient investment in DER are particularly relevant in the context of relatively higher shoulder charges and investments in solar PV that, absent battery technology, predominantly reduce network use in non-peak periods.

We have explained that reductions in the use of our network outside of the peak period generally results in very low, if any, avoided future network costs. However, our shoulder price in particular is significantly above the cost reflective level at present. Since the vast majority of solar PV generation occurs outside of the peak period, this means that, without price rebalancing, future investors in solar PV will receive a network bill reduction that exceeds the resulting avoided future network costs.

On the other hand, lowering non-peak energy charges will encourage efficient investments in DER, since those investments will be targeted at reducing the use of network during peak, rather than non-peak periods. By way of example, reducing shoulder charges creates an incentive to install west-facing solar PV installations that better assist in reducing the use of the network later in the day, for instance, during peak periods.

By reducing non-peak prices and, in so doing, encouraging customers to use the network more outside of peak times, we can also assist in transitioning to a decarbonised economy. This is possible since renewable generation is more prevalent at those times of the day.

In summary, reducing non-peak variable charges will assist in transitioning to a lower carbon economy, encourage efficient investments in DER and avoid potential inequities between adopters and non-adopters of new technologies, we have designed our pricing to be technology agnostic.

Increases in fixed daily charges that leave network bills unchanged

To deliver to customers the efficiency, equity and decarbonisation benefits of reducing non-peak variable charges, we need to increase the price of another charging parameter so that the network bills paid by customers reflect the total efficient cost of providing services to those customers, consistent with the requirements of the Rules.

In essence, we provide an anytime connection service to customers and the nature of this connection service will become increasingly relevant as our network transitions to a platform that enables bi-directional energy flows. Importantly, fixed daily charges reflect the nature of the anytime connection service we provide to customers and so assist in facilitating peer-to-peer trading.

Should our collaborative research program identify that capacity charges (e.g. a fixed daily charge that varies with the maximum capacity that a customer intends to draw from the network during a given period) are the best means by which to recover residual costs, our proposed price rebalancing will also provide a natural progression to these charges. For example, we will be well placed to offer lower fixed daily charges to those customers willing to accept a lower maximum capacity draw from the network. This approach may prove to be appropriate both for signalling the costs of the network to customers and minimising distortions to electricity use in the future.

Consistent with the requirements of the Rules and economic literature, fixed daily charges also recover our historical costs in a manner that least distorts customer's decisions.

Therefore, we propose to offset the reduction in non-peak variable charges by increasing fixed daily charges in a way that leaves a typical customer's network bill unchanged.

We explain in the remainder of this chapter and in our TSS that we propose to implement specific measures to avoid unacceptable network bill impacts on low energy users and vulnerable customers, who might otherwise be disproportionately affected by our proposed price rebalancing.

10.2.3 Summary of our proposed reforms

We summarise our major pricing reforms for the 2019–24 period in the table below.

Table 44.

Summary of major pricing reforms proposals for the 2019–24 period

PROPOSED REFORM	DESCRIPTION	BENEFITS FOR OUR CUSTOMERS
A demand price structure	Introduce a residential demand price structure with no customers initially assigned to it, which can be adopted in the next regulatory period, if supported by further research	• Enables a fast-tracked transition to demand pricing, pending the outcome of our research program • Allows us to expedite our transition to cost reflective pricing
Price Rebalancing	Reduce non-peak variable charges, off-set by a network bill-neutral increase in fixed daily charges	• Represents a first step in a potential future transition to residential capacity charges • Compatible with a range of future price structures, e.g., demand pricing and existing price structures • Promotes efficient investment in DER, e.g. west-facing solar PV installations • Encourages use of the network when our costs are very low and renewable generation is more prevalent • Avoids inequities between adopters and non-adopters of DER • Reflects the nature of the connection service we provide • Results in more stable network bills
Safeguard measures	Introduce transitional and safeguard pricing to reduce network bill impacts for low energy users and vulnerable customers	• Mitigates any unacceptable bill impacts from price rebalancing • Enables a longer transition period for these customers
An Inclining Block price structure	Replace the flat price structure with an inclining block price structure for customers with a basic meter	• Mitigates bill impacts for low energy users • Encourages high energy users to reduce consumption • Provides incentives for large energy users to switch to a more cost reflective price structure
New price structure for large residential and small business customers	Assign to a new more cost-reflective TOU capacity network price structure, all residential and small business customers consuming 15–40 MWh per annum and that have an interval meter	• More cost reflective prices for larger energy users • Provides stronger incentives to reduce maximum demand • Avoids potential bill shock if customers use >40MWh per annum and are moved to another price structure
Consistent seasonal charging windows	Shorten the winter peak period for business customers to 5–9pm	• Provides more cost reflective peak price signals • Reduces the times at which the winter peak price applies for business customers • Enables better management of peak demand • Aligns the residential and business winter peak periods
Opt-out price structure to become TOU	The opt-out transitional price structure for residential and small business TOU customers will move to a TOU structure, from a flat structure	• More cost reflective prices for opt-out customers • Assists in transitioning these customers to a more cost reflective pricing • Weakens the incentive to opt-out of the default TOU price structure

In addition to our proposed pricing reforms and as previously noted, we will launch a comprehensive working group and pricing research program, to be developed collaboratively with stakeholders. This program of work is an important component of our Proposal, since it will inform potential pricing decisions over the next and subsequent regulatory periods. We propose to fund this research program by means of an opex step change, as discussed in section 6.4.3.

For example, the appropriate design (and the respective merits/shortcomings) of a residential demand price structure is a matter on which there exists significant uncertainty and divergence of opinions. Since the number of residential customers with an advanced meter is expected to more than double to approximately 840,000 over the next five years, the system cost consequences of inappropriately designing and implementing a demand price structure could be significant.

On a related note, the significant up-front cost associated with building our network means that, regardless of the price structure used to signal to customers future avoidable network costs (e.g. demand pricing or TOU pricing), we will always have residual costs. Therefore, the benefit to customers of our proposed price rebalancing is not contingent on introducing demand pricing. Further, our proposed price rebalancing (recovering residual costs from charges that are less variable) also represents a first step in a potential transition to capacity charges (which are also less variable), consistent with the stakeholder document, 'Pricing Directions: A Stakeholder Perspective'.[1]

The feedback we received from our customers and stakeholders was instrumental in shaping our proposed pricing reforms. As already discussed, our demand price structure supported by a research program in the next period is a direct response to the further consultation undertaken during the extension approved by the AER.

In light of feedback received, we tempered the extent of our rebalancing to avoid unacceptable customer bill impacts and implemented specific measures (transitional and safeguard pricing) to protect low energy users and vulnerable customers. We will also continue to engage with stakeholders, to address any outstanding issues with this approach, through our pricing working group.

We note that the 'Pricing Directions: A Stakeholder Perspective' document favoured the use of demand or capacity charges to recover our residual costs, rather than fixed daily charges. In this context, it is important to recognise that higher fixed daily charges are not necessarily an end-point in our transition to cost reflective pricing. Rather, it reflects a step towards the potential future recovery of residual costs from capacity charges, consistent with the stakeholder directions.

We include further detail on the feedback we received and assess our proposed reforms against the 'Pricing Directions: A Stakeholder Perspective'[2] document in our TSS.

1 For more information see Attachment 10.14.

2 For more information see Attachment 10.14.

We summarise the compatibility of our key proposed reforms and the 'Pricing Directions: A Stakeholder Perspective' document in the table below.

Table 45.

Compatibility with 'Pricing Directions: A Stakeholder Perspective' [3]

KEY REFORMS FOR RESIDENTIAL CUSTOMERS	HOW THE REFORM REFLECTS THE 'PRICING DIRECTIONS: A STAKEHOLDER PERSPECTIVE'
A demand price structure for potential future implementation	• Adaptable to changing circumstances – it can be implemented if needed • Provides scope for a potential mid-period introduction of demand prices during the next regulatory period • Facilitates potential transition to demand pricing, which is the stakeholders' expected end-point
Price Rebalancing	• Adaptable to changing circumstances – it promotes efficient investment in new technologies • Simplifies pricing structure – reducing non-peak variable energy charges • Network specific – improvements in the recovery of historical costs reflect limited growth • Increase in fixed daily charge facilitates peer to peer trading since it reflects connection service provided by Ausgrid • Extent of rebalancing guided by extensive modelling of customer bill impacts • Promotes economic efficiency by recovering residual costs "through charges that have as little impact on behaviour as possible [3]
Safeguard measures	• Directly addresses customer bill impacts
An Inclining Block Structure	• Integrated with broader incentives and encourages large users to switch to TOU pricing • Assists in avoiding unacceptable customer bill impacts for low energy users
New TOU demand for large residential and small business customers	• Adaptable to changing circumstances – more cost reflective prices for larger energy users. • Assists in a transition to residential demand pricing, an approach consistent with stakeholders' expected end-point

3 Attachment 10.14. Pricing Directions: A Stakeholder Perspective, February 2018, p.3 footnote 2.

10.3 How we will manage transitional customer bill impacts

We present in this section the network bill impacts resulting from our indicative prices for residential customers. A detailed description of our indicative network prices and expected network bill outcomes for all customers is included in our TSS.

It is important to note that the proposed prices do not include any adjustments arising from the remitted 2014–19 decisions on opex and the allowed return on debt. This is the subject of ongoing consultation with the AER and customer groups, and depending on the outcome of this process there may be positive or negative revenue increments applied to our proposed revenues for the 2019–24 regulatory period. Any adjustment amount will reflect the difference between actual revenues recovered over the 2014–19 period and the remade determination revenues for 2014–19. Prices for the 2019–24 period will reflect these adjustments, once agreed with the AER.

10.3.1 Residential time of use pricing

For residential customers on time of use pricing that use more than 2MWh per annum, shoulder prices will decrease by 0.6% per annum on average over the 2019–24 period, accompanied by a 6.4% per annum increase in the fixed daily charge that will leave a typical residential customer's network bill unchanged.

At present, a typical residential customer's network bill comprises approximately 29% fixed daily charges and 39% non-peak variable charges (shoulder and off-peak charges). Assuming no behavioural response over the next five years, in 2024 our proposed price rebalancing will mean that a typical residential customer's network bill will comprise approximately 37% fixed daily charges and 35% non-peak variable charges.

We present indicative prices in the table below.

Table 46.

Indicative residential time of use NUOS[4] pricing ($, nominal)

CHARGING PARAMETER		2019/20	2020/21	2021/22	2022/23	2023/24
Fixed Daily Charge	($ p.a.)	173.36	186.87	198.47	211.38	225.12
Peak Charge	(c/kWh)	24.07	24.14	23.93	23.87	23.67
Shoulder Charge	(c/kWh)	6.46	6.48	6.39	6.35	6.24
Off-peak Charge	(c/kWh)	2.55	2.56	2.53	2.52	2.50

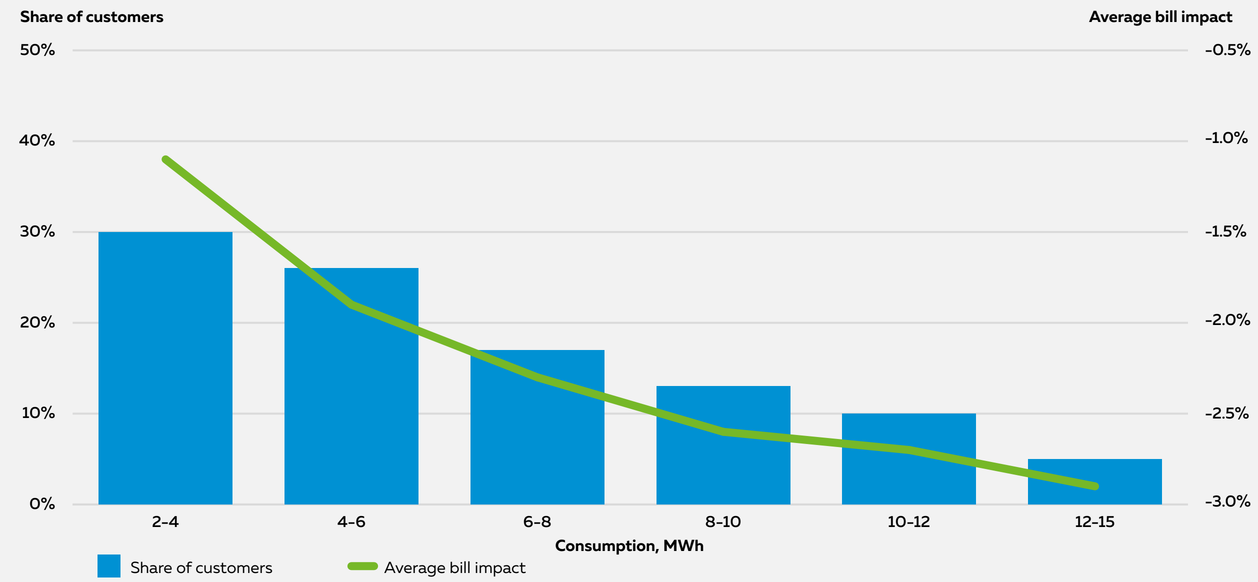
Note: Excludes GST, prices have been rounded.

These prices will deliver a network bill reduction in 2019/20 for the vast majority of residential customers on time of use pricing. Further, network bills will be stable for the remainder of the regulatory period. We illustrate the network bill savings in 2019/20 in Figure 59.

4 Network use of system prices recover, Ausgrid's distribution and transmission costs as well as TransGrid's transmission costs and the cost of the Climate Change Fund.

Figure 59.

Residential TOU NUOS bill impact (%) 2019/20



Further, our indicative prices will deliver in 2019/20[5]

Network bill for customers with a consumption of 2.5 MWh

0.9% pa

e.g. a couple living in a small apartment with a gas hot water system and minimal heating and cooling load

Network bill for customers with a consumption of 4.0 MWh

1.6% pa

e.g. a couple with a single child living in an medium sized apartment with a gas hot water system, small air conditioner and a moderate amount of heating and cooling load

Network bill for customers with a consumption of 6.0 MWh

2.1% pa

e.g. a couple with two children living in a medium sized detached home with gas hot water system with a medium size air conditioner and a moderate amount of heating and cooling load

Network bill for customers with a consumption of 10.0 MWh

2.6% pa

e.g. a couple with three children in a large size detached home with gas hot water system, a large ducted air conditioning system with a high heating and cooling load and a pool

5 In real terms. The indicative customers are assumed to have a load profile which is in line with the average residential customer load profile in Ausgrid region. The reduction level may differ according to the load profile.

To provide an incentive for customers to voluntarily opt-in to time of use pricing from the block structure, we designed our prices so that a typical residential customer would be approximately $63 p.a. better off on time of use pricing. Our proposed reforms for residential time of use pricing will deliver more affordable, reliable and sustainable pricing, consistent with customers' feedback:

- by encouraging efficient use of our network
- by promoting efficient investments in DER
- by delivering equitable outcomes between adopters and non-adopters of new technologies
- by avoiding unacceptable customer bill impacts.

10.3.2 Residential inclining block pricing

We propose to replace the existing flat block structure or non-time of use pricing with an inclining block structure in 2019/20.

We propose to implement price rebalancing for these customers by increasing the fixed daily charge by approximately 11% per annum, off-set by a reduction in the price of block one. The relatively higher per annum increase in fixed daily charge assists in bringing the fixed charges for time of use and non-time of use pricing into line. It also assists in providing an incentive for these customers to voluntarily opt-in to time of use pricing.

We present indicative prices for our residential inclining block price structure below.

Table 47.

Indicative residential inclining block NUOS pricing ($, nominal)

CHARGING PARAMETER [6]		2019/20	2020/21	2021/22	2022/23	2023/24
Fixed Daily Charge	($ p.a.)	149.68	168.85	185.23	203.75	224.13
First Block Charge	(c/kWh)	9.56	9.36	9.06	8.79	8.48
Second Block Charge	(c/kWh)	9.99	10.45	10.75	11.13	11.42
Third Block Charge	(c/kWh)	10.03	10.49	10.80	11.19	11.48

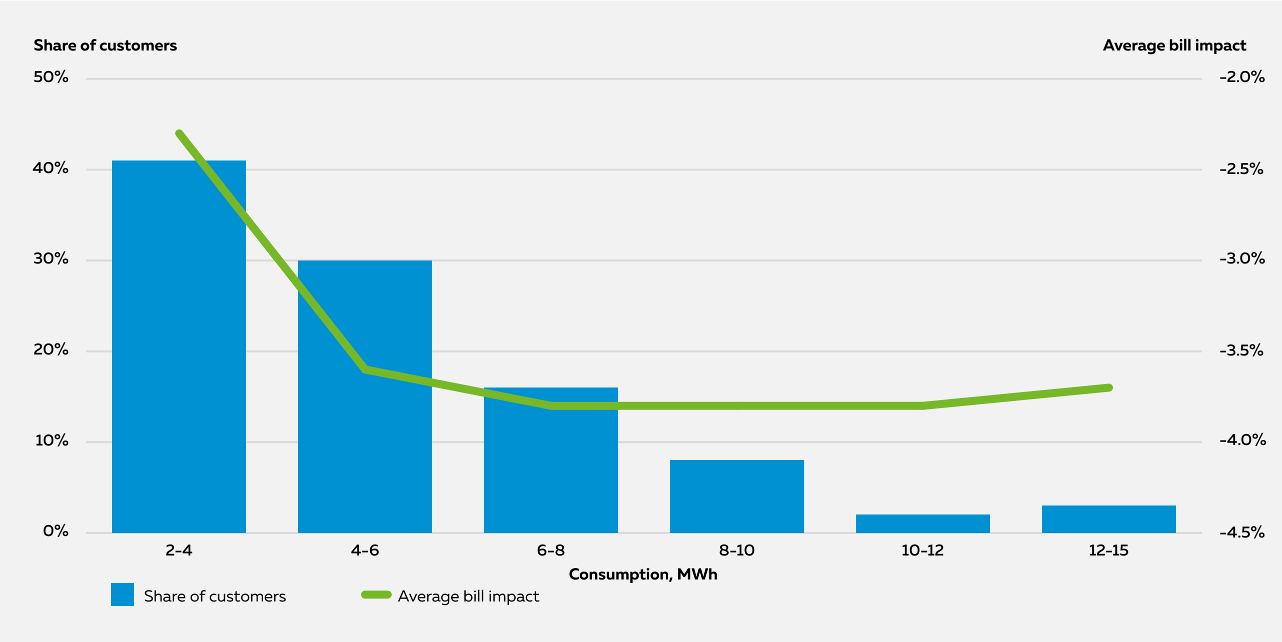
Note: Excludes GST, prices have been rounded.

These prices will deliver a network bill reduction to all customers on our inclining block pricing in 2019/20. Further, network bills will be stable for the remainder of the regulatory period 2020/21–2023/24. We illustrate the network bill savings in 2019/20 in the following figure.

6 The block one price applies to the first 1,000 kWh of consumption per 91 days, the block two price applies to consumption greater than 1,000 kWh and less than 2,000 kWh per 91 days; and the block three price applies to all consumption above block 2.

Figure 60.

Residential inclining block NUOS bill impact (%) in 2019/20



Further, our indicative prices will deliver in 2019/20[7]

Network bill for customers with a consumption of 2.5 MWh

2.0% pa

e.g. a couple living in a small apartment with a gas hot water system and minimal heating and cooling load

Network bill for customers with a consumption of 4.0 MWh

3.6% pa

e.g. a couple with a single child living in an medium sized apartment with a gas hot water system, small air conditioner and a moderate amount of heating and cooling load

Network bill for customers with a consumption of 6.0 MWh

3.8% pa

e.g. a couple with two children living in a medium sized detached home with gas hot water system with a medium size air conditioner and a moderate amount of heating and cooling load

Network bill for customers with a consumption of 10.0 MWh

3.8% pa

e.g. a couple with three children in a large size detached home with gas hot water system, a large ducted air conditioning system with a high heating and cooling load and a pool

7 In real terms.

Our proposed inclining block structure and price rebalancing for residential non-time of use pricing will deliver more affordable, reliable and sustainable pricing, consistent with customer feedback:

- by encouraging large energy users to switch to time of use pricing (as an average large customer would receive a lower network bill if they were on TOU prices),
- by encouraging large energy users that do not switch to time of use pricing to reduce their consumption, and
- by avoiding unacceptable customer bill impacts for low energy users (through the introduction of a transitional non-TOU price).

10.3.3 Transitional pricing for residential and small business low energy users

Our extensive modelling of the customer bill impacts arising from our proposed price rebalancing identified that, absent specific measures, residential and small business customers using less than 2MWh per annum would be adversely affected. This is because these customers would benefit less from the reduction in non-peak variable charges.

So that we can still deliver to customers the significant decarbonisation, efficiency and equity benefits from price rebalancing, we propose to provide network bill discounts to customers using less than 2MWh per annum, so as to avoid unacceptable bill impacts. These measures are a direct response to listening to customer concerns about bill impacts.

These discounts will apply for a period not exceeding 10 years and will be progressively reduced over that period so as to transition these customers to more cost reflective pricing. Under the framework established by the Rules, the most straightforward approach to providing these discounts/rebates is by assigning the relevant customers to new, relatively cheaper network prices and then working with retailers to assist them in calculating the discount/rebate implicit in the new price that should be provided to the relevant customers. This will enable retailers to leave the relevant customers assigned to the same retail price, but to still pass on the network bill discount/rebate provided by Ausgrid.

We understand from retailers that the transaction costs of establishing, marketing and implementing additional retail prices would be prohibitive and so some retailers, such as EnergyAustralia, indicated strong support for the use of rebates to avoid unacceptable customer bill impacts from price rebalancing. It is for this reason that our proposed approach enables retailers to leave customers assigned to the same retail price, but to still pass on the network bill discount/rebate provided by Ausgrid.

We present indicative prices for our inclining block transitional price structure for small businesses and residential customers below.

Table 48.

Indicative residential and small business transitional NUOS pricing ($, nominal)

CHARGING PARAMETER[8]		2019/20	2020/21	2021/22	2022/23	2023/24
Fixed Daily Charge	($ p.a.)	136.38	140.85	144.68	149.02	153.49
First Block Charge	(c/kWh)	10.09	10.46	10.69	10.99	11.20
Second Block Charge	(c/kWh)	9.99	10.45	10.75	11.13	11.42
Third Block Charge	(c/kWh)	10.03	10.49	10.80	11.19	11.48

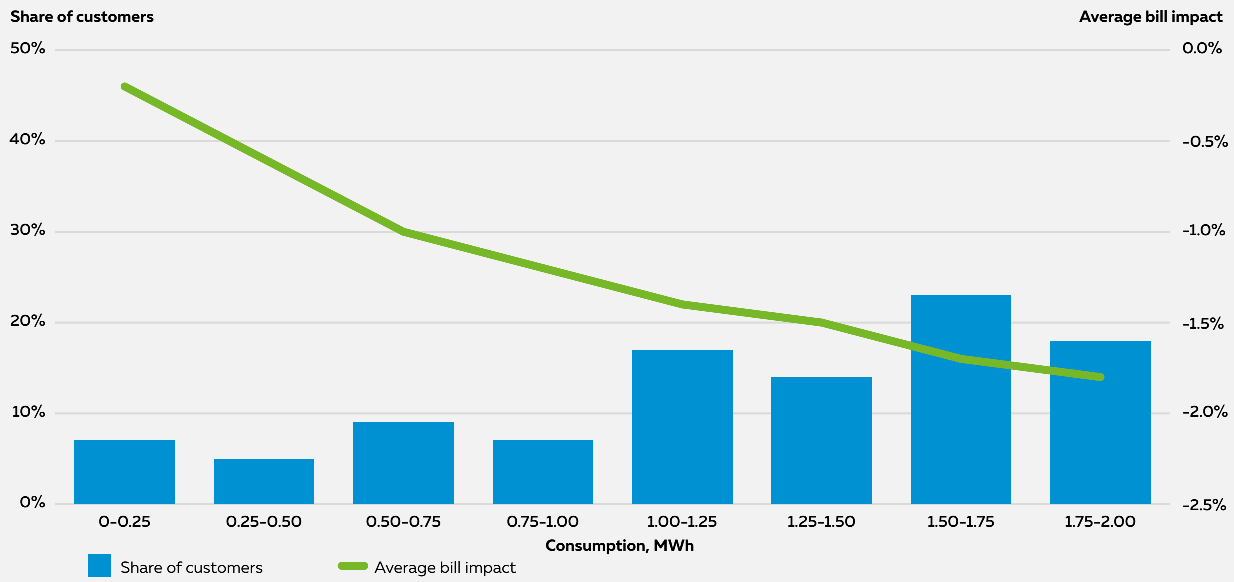
Note: excludes GST, prices have been rounded.

Almost all of these customers will receive a network bill reduction in 2019/20 and network bills will be relatively stable thereafter. We present customer bill impacts for these customers below.

8 The block one price applies to the first 500 kWh of consumption per 91 days, the block two price applies to consumption greater than 500 kWh and less than 2,000 kWh per 91 days; and the block three price applies to all consumption above block 2.

Figure 61.

Residential and small business transitional NUOS bill impact (%) in 2019/20



10.3.4 Transitional safeguard pricing for vulnerable customers using <2MWh

We also propose to include transitional safeguard pricing to further avoid any potential unacceptable customer bill impacts on vulnerable residential customers.

We propose that this price structure is available to residential customers that hold either a Pensioner concession card issued by the Department of Human Services (DHS) or Department of Veteran Affairs (DVA); a DHS Health Care Card; or a DVA Gold Card.

We acknowledge these eligibility criteria could be improved to better target customers most affected by our proposed price rebalancing. Therefore, we propose that the eligibility criteria for this discount/rebate is determined at our discretion and in consultation with the CCC and stakeholders as part of the collaborative research program. We would also work with retailers and the pricing working group to investigate ways to automate the assignment of eligible customers. We propose that any changes are addressed in the annual pricing proposal process and so approved by the AER before implementation.

We present indicative prices for our transitional safeguard pricing in the following table.

Table 49.

Indicative residential transitional safeguard NUOS pricing ($, nominal)

CHARGING PARAMETER[9]		2019/20	2020/21	2021/22	2022/23	2023/24
Fixed Daily Charge	($ pa)	136.38	140.17	143.28	146.86	150.53
First Block Charge	(c/kWh)	10.09	10.36	10.49	10.67	10.77
Second Block Charge	(c/kWh)	9.99	10.45	10.75	11.13	11.42
Third Block Charge	(c/kWh)	10.03	10.49	10.80	11.19	11.48

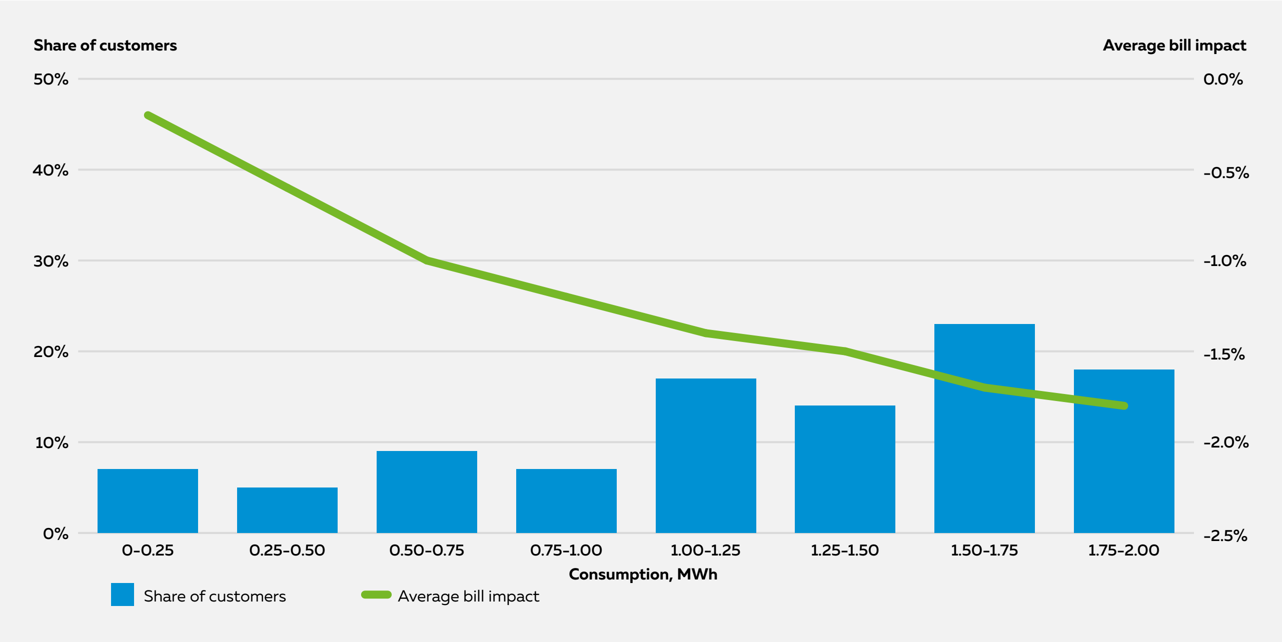
Note: Excludes GST, prices have been rounded.

We illustrate below that the vast majority of customers eligible for transitional safeguard pricing will receive a network bill reduction in 2019/20. Network bills will be relatively stable thereafter. Note that the bill impact for these customers in 2019/20 is identical to those on the transitional low energy pricing, although they differ over the rest of the regulatory period differ.

9 The block one price applies to the first 500 kWh of consumption per 91 days, the block two price applies to consumption greater than 500 kWh and less than 2,000 kWh per 91 days; and the block three price applies to all consumption above block 2.

Figure 62.

Residential transitional safeguard NUOS bill impact (%) in 2019/20



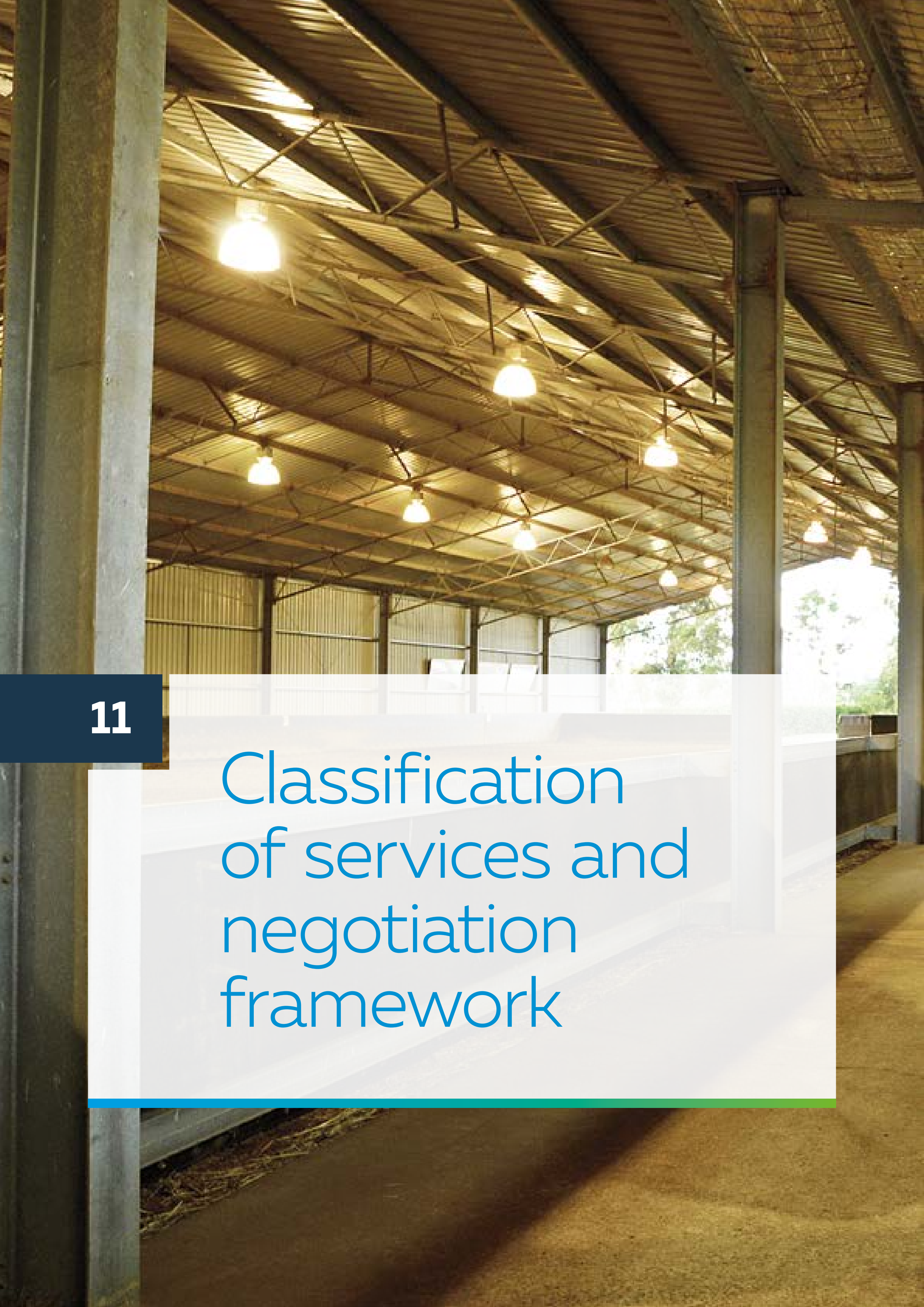
10.4 How we assign customers to network price structures

We do not propose to make any changes to our existing 'tariff classes' or our procedure for assigning or reassigning customers to a 'tariff class', as previously approved by the AER. However, we do propose changes to our approach to assigning customers in a 'tariff class' to network price structures (network tariffs), which will ensure more customers are assigned to cost reflective pricing.

A full description of our proposed approach to assigning and reassigning customers to network price structure is included in our TSS. In summary, we propose that from 1 July 2019:

- existing and new residential and small business customers using less than 2MWh per annum will be reassigned to the proposed LV Transitional <2MWh per annum price structure in FY20,
- existing and new residential customers that satisfy the eligibility criteria for our transitional safeguard price structure would, if possible, be automatically reassigned to this price structure[10],
- all new residential and small business customers consuming between 2MWh per annum and 15MWh per annum will be assigned to the applicable cost reflective seasonal TOU pricing,
- all new residential and small business customers consuming between 15MWh per annum and 40MWh per annum will be assigned to the applicable cost reflective seasonal TOU capacity pricing, and
- existing residential and small business customers that upgrade their basic accumulation meter will be reassigned to the applicable cost reflective seasonal TOU price structure from 1 July 2019. These customers can opt-out of the cost reflective TOU pricing to the applicable transitional TOU price structure.

10 We are committed to working with retailers and the Pricing Working Group to implement a process that automates the assignment of eligible customers to the transitional price structure.



11

Classification of services and negotiation framework

11

Classification of services and negotiation framework

Our service classification proposal is customer focused. It broadly applies the AER's regulatory treatment of our services in its final F&A paper, but offers additional protections for vulnerable customers who experience an outage that is not a network outage.

We agree with the AER that none of the services provided by Ausgrid should be classified as negotiated services. However, as there is scope for some of our transmission services to be negotiated, we have proposed a negotiation framework and criteria.

The health and safety of vulnerable customers will be subject to additional protections under our proposed service classification.

Our Proposal will achieve this by allowing Ausgrid to rectify simple customer faults (e.g., fuse) that extend beyond our network, where the health and safety of a customer would be placed at risk if they were required to source rectification works from contestable markets.

11.1 Ausgrid's classification proposal

As explained in Chapter 1, the AER classifies our services into standard control, alternative control, negotiated and unclassified services. Different service classifications may attract different forms of regulatory control; unclassified services are not subject to regulatory control. Service classification is important as it determines the extent and form of regulation that applies to our services.

The AER has already set out its proposed approach on service classification as part of the final F&A process. However, neither the AER nor Ausgrid are bound by the proposed service classification. Ausgrid is permitted to propose a different approach, provided we include the reasons for the difference.[1]

We have considered the regulatory treatment of our services in the AER's final F&A paper and are of the view that changes should be made to offer additional protection for vulnerable customers who experience an outage not directly related to our distribution network. Our Proposal also includes minor wording changes to three services, from the descriptions given in the final F&A paper. Our proposed service classification is summarised at Attachment 11.01.

11.1.1 AER's approach to classifying services

In classifying services, the AER may group distribution services together and apply a single classification. Consistent with the current regulatory period, the AER has adopted this approach.

In its F&A paper, the AER proposed to group Ausgrid's distribution services as:

- common distribution services (formerly 'network services'),
- ancillary services,
- metering services,
- connection services,
- public lighting services, and
- unregulated distribution services.

These service groups are the same as the classification applied in the current period. However, some of the components making up these service groups have changed.

1 NER clause 6.8.2(c)(1)(ii).

The table below summarises the components to the service groups listed above that the AER has proposed to change in the 2019–24 regulatory period. These changes involve classifying services that were previously 'unclassified' or 'unregulated'.

Table 50.

Components of service groups that will change classification under final F&A paper

COMPONENT	2014–19 CLASSIFICATION	PROPOSED 2019–24 CLASSIFICATION
Emergency recoverable works	Unregulated distribution service	Standard control services
Shared asset facilitation	Unclassified	Standard control services
Rectification of simple fault for a life support customer	Unclassified	Standard control services
Rectification works to maintain network safety	Unclassified	Alternative control services
Training to third parties for network related access	Unclassified	Alternative control services
Security lights	Unregulated distribution service	Alternative control services
Meter recovery and disposal	Unclassified	Alternative control services
Distribution asset rental	Unclassified	Unregulated distribution service
Contestable metering support roles	Unclassified	Unregulated distribution service
Non-standard connection services	Unclassified	Unregulated distribution service
Provision of training to third parties for non-network related access	Unclassified	Unregulated distribution service

These relatively minor changes reflect the expansion of contestability in metering services which, from 1 December 2017, introduced additional services that we must now provide. The changes also reflect the AER's new ring fencing guidelines that limit the services Ausgrid is able to offer our customers if a service is not classified.

11.1.2 Ausgrid's proposed approach to classifying services

The Rules require that our Proposal shows how the distribution services we provide should, in our opinion, be classified for the next regulatory period.[2]

In relation to this requirement, Ausgrid's classification proposal largely adopts the AER's classification of services position in its final F&A paper. This is with the exception of an amendment that expands the protections offered to vulnerable customers and minor editorials to three service groups.

Expanded protection for vulnerable customers

Our Proposal offers additional protections to vulnerable customers who have lost supply of electricity and require urgent rectification works due to a health or safety risk.

Under the AER's classification of our services in its final F&A paper, Ausgrid is limited to providing rectification works that address a fault on our distribution network infrastructure. Any other rectification works, not directly related to our network, must be sourced by customers from contestable markets. This is unless the work relates to a life support customer.

2 NER clause 6.8.2(c)(1)(i).

We strongly support the AER putting in place protections for LSC who urgently require restoration services when they experience an outage. We propose that these protections should be extended to other vulnerable customers who do not rely on life support equipment, yet whose health and safety may be placed at risk if they are required to source restoration services from contestable markets.

To give effect to this, we propose that the 'standard control services' definition in the AER's final F&A paper is amended. Presently, this definition allows Ausgrid to rectify a 'simple customer fault (e.g., fuse) relating to a life support customer'. We propose that it should be expanded to the following:

> *the rectification of simple customer fault (e.g.,fuse) relating to a life support customer **or a customer whose health and safety may be placed at risk if they are required to source restoration services from contestable markets.***

We have proposed this amendment in recognition that the presence of life support equipment is not necessarily a key determinant of the health or safety risk faced by a customer who loses supply. Circumstances may arise where Ausgrid investigates a fault at a remote location or outside of business hours and finds that the loss of supply to an elderly or sick customer is unrelated to our distribution network. If these vulnerable customers face a significant delay in sourcing restoration services from contestable markets, then the risk to their health or safety could potentially be significant, irrespective of whether they have life support equipment or not.

Our Proposal would also have minimal impact on contestable markets. The rectification works performed by Ausgrid would be strictly limited to the 'simple customer faults' such as the replacement of a fuse. Any work that is beyond necessary to restore supply (e.g., the repairing of a hot water service) would remain contestable.

Ausgrid provides an essential service to 1.7 million customers – the well-being of whom is of paramount importance to us. Our proposed service classification will help facilitate our commitment to the health and safety of our customers and will have minimal impact on service providers in contestable markets.

Minor wording changes to other services

We propose minor wording changes to three services in the AER's final F&A paper.

The services and our proposed editorials are listed in the table below. These wording changes, although minor, have been proposed so that the AER's service classification determination more accurately reflects the scope of work involved in providing these services to customers. The editorials we are seeking to have approved by the AER are shown below in bold.

Table 51.

Proposed changes to the AER's service classification in its final F&A paper

SERVICE	AER'S DESCRIPTION	AUSGRID'S PROPOSED CHANGES
Provision of materials to ASPs	Provision of materials/equipment **for** ASPs for connection assets that will become part of the shared distribution network.	Minor edits are proposed. This is to replace the word 'to' with 'for' in the description of this service. We have put forward these edits in recognition that non-ASPs also purchase materials. This typically happens when a customer receiving a connection service purchases materials or equipment on the behalf of the ASP that has been engaged to augment or extend our existing network.
Inspection services	Inspection of and reinspection by a distributor, for safety purposes, of: • private electrical wiring work undertaken by an electrical contractor and contestable works undertaken by ASPs • the investigation, review and implementation of remedial actions that may lead to corrective and disciplinary action of an ASP due to unsafe practices or substandard workmanship • inspection of privately owned low voltage or high voltage network infrastructure (i.e. privately owned distribution infrastructure before the meter) • **investigate, review and implementation of remedial actions associated with a Local Government Authorities' vegetation works**.	Minor edits are proposed. These edits add an additional dot-point to this service description relating to the inspection of vegetation management performed by local councils and other authorised parties. This dot-point has been added to reflect the availability of local councils and other authorised bodies to manage vegetation surrounding our distribution assets and, to facilitate this, our role in reviewing the quality of the work that they perform, and in some cases taking remedial action.
Authorisation of ASPs and local councils	Activities include: • authorisation of individual employees and sub-contractors of ASPs and additional authorisations at request of ASP and other administrative services performed by the distributor relating to work performed by an ASP • **authorisation of local councils to conduct vegetation works**.	Minor edits are proposed. This is to clarify that Ausgrid authorises local government authorities to perform vegetation management work.

See Attachment 11.01 for our full classification proposal, including our proposed amendments to service descriptions.

11.2 Negotiation framework and criteria

This section sets out Ausgrid's proposed negotiation framework and criteria that would apply to any of Ausgrid's services classified as negotiated distribution services. Negotiated distribution services are those requiring a less prescriptive regulatory approach because all relevant parties have sufficient market power to negotiate the provision of those services. Prices are negotiated between Ausgrid and our customers according to a prescribed framework, with the AER providing arbitration if required.

Historically, Ausgrid has not had any of its services classified as negotiated services. In its F&A paper, the AER proposes that, once more, none of Ausgrid's services will be classified as negotiated services for the 2019–24 regulatory period. While Ausgrid agrees with this approach, we note there is scope for some transmission services to be negotiated. We therefore set out our proposed negotiating framework below.

11.2.1 Classification of services as negotiated distribution services

Ausgrid agrees with the AER that none of our services are suited to being classified as negotiated distribution services. While we do not anticipate any negotiated distribution services to arise over the 2019–24 regulatory period, we note there is scope for some services provided by means of Ausgrid's transmission network (i.e. dual function assets) to be negotiated distribution services. If Ausgrid is required to provide these transmission services, we will apply our AER approved negotiating framework.

Under Chapter 10 of the Rules, negotiated transmission services – and therefore potentially negotiated distribution services – could include:

- **Connection services** – provided to serve transmission network users at a single connection point (excluding connection services between network service providers), and
- **Use of system services** – agreed at the time of a connection where the network service provider has augmented or extended the network.

Consequently, a new connection to Ausgrid's transmission network would be a negotiated transmission service, which must be treated as a negotiated distribution service.

11.2.2 Negotiating framework

If Ausgrid is required to provide negotiated distribution services, we will apply our negotiating framework – see Attachment 11.02. The negotiating framework has been prepared to comply with the requirements of Part D of Chapter 6 of the NER.

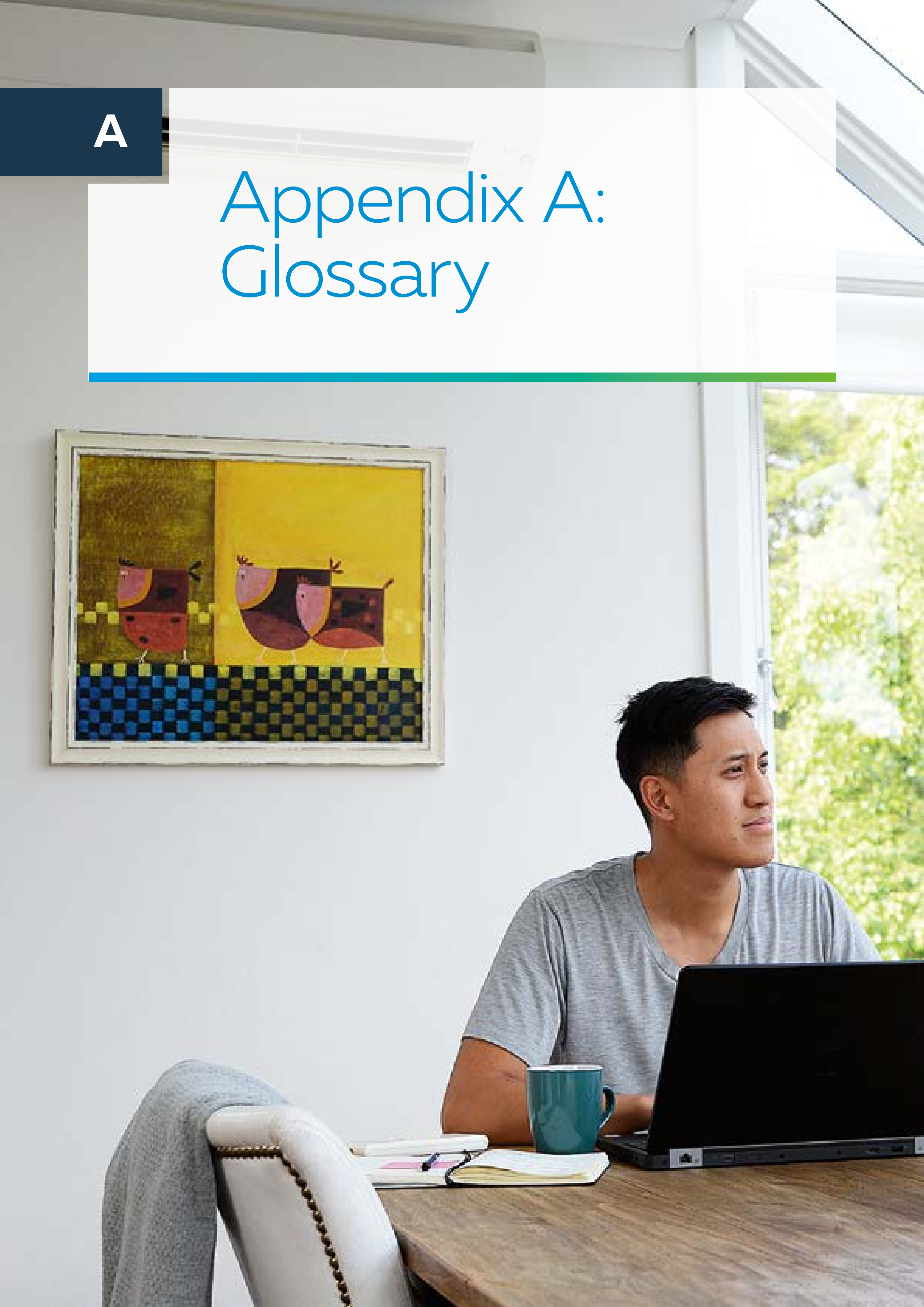
11.2.3 Proposed approach to negotiated distribution service criteria

In addition to considering the negotiating framework, clause 6.12.1(16) of the Rules requires the AER to make a decision on Ausgrid's negotiated distribution service criteria as part of its distribution determination. These criteria are to be applied by Ausgrid in negotiating terms and conditions of access and by the AER in resolving any access disputes.

NER clause 6.7.4 requires that the negotiated distribution service criteria must give effect to and must be consistent with the principles set out in clause 6.7.1. Ausgrid would support the AER in maintaining the current negotiated distribution service criteria.

A

Appendix A: Glossary



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Appendix A: Glossary

ABBREVIATION	MEANING
($, nominal)	These are nominal dollars of the day
($ million, nominal)	These are nominal dollars of the day, in millions
($, real FY19)	This denotes dollar terms as at 30 June 2019
($ million, real FY19)	This denotes dollar terms as at 30 June 2019, in millions
2014-19 regulatory period	The period that comprises both the transitional regulatory control period 1 July 2014 to 30 June 2015 and the subsequent regulatory control period 1 July 2015 to 30 June 2019.
2019–24 regulatory period	The regulatory control period commencing 1 July 2019 and ending 30 June 2024
Current regulatory period	Regulatory control period of 1 July 2014 to 30 June 2019
Next five years	The five year period between 1 July 2019 to 30 June 2024
Next regulatory period	Regulatory control period of 1 July 2019 to 30 June 2024
Proposal	Ausgrid's proposal for the next regulatory period submitted under clause 6.8 of the Rules
ADMS	Advanced Distribution Management System
ARORO	Allowed Rate of Return Objective
ACS	Alternative Control Services
ANS	Ancillary Network Services
ARR	Annual Revenue Requirement
AMS	Asset Management System
ABS	Australian Bureau of Statistics
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
Black CAPM	Black Capital Asset Pricing Model
Capex	Capital expenditure

ABBREVIATION	MEANING
CESS	Capital Expenditure Sharing Scheme
CCR	Career, Capability and Remuneration framework
CCF	Climate Change Fund
CGS	Commonwealth Government Securities
CPI	Consumer Price Index
CAM	Cost Allocation Methodology
CALD	Culturally and Linguistically Diverse
CCC	Customer Consultative Committee
DMIS	Demand Management Incentive Scheme
DMIA	Demand Management Innovation Allowance
DHS	Department of Human Services
DVA	Department of Veteran Affairs
DNSP	Distribution Network Service Provider
DSO	Distribution System Operator
DUOS	Distribution Use of System
DGM	Dividend growth model
EBSS	Efficiency Benefit Sharing Scheme
EV	Electric vehicles
ERW	Emergency recoverable works
ENA	Energy Networks Australia
F&A	Framework and Approach
FTE	Full-time equivalent
GWh	Gigawatt hours
GSL	Guaranteed service level

ABBREVIATION	MEANING
HV	High voltage
IPART	Independent Pricing and Regulatory Tribunal of NSW
ICT	Information & Communications Technology
IT	Information Technology
LSC	Life Support Customers
MRP	Market risk premium
MWh	megawatt hours
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER or **Rules**	National Electricity Rules
NUOS	Network Use of System
Opex	Operating expenditure
PTRM	Post Tax Revenue Model
POE	Probability of Exceedance
PIAC	Public Interest Advocacy Centre
RAB	Regulatory Asset Base
RIN	Regulatory Information Notice
Repex	Replacement expenditure
RBA	Reserve Bank of Australia
RWG	Reset Working Group
RFM	Roll Forward Model
SL-CAPM	Sharpe-Lintner Capital Asset Pricing Model
SCS	Standard Control Services
TSS	Tariff Structure Statement
TOU	Time of Use
TUOS	Transmission Use of System
WACC	Weighted average cost of capital


Ausgrid