Endeavour Energy
Regulatory Proposal 2024-2029

January 2023

Endeavour Energy

POWER together

Endeavour Energy acknowledges the Traditional Custodians of the lands on which we work — the people of the Dharawal, Dharug, Gundungarra, Wiradjuri and Yuin nations — and recognises their continuing connection to Country, cultures and community. We pay our respect to elders past, present and emerging.

Featured artwork: 'Powering A Brighter Future Together' by Rhonda Sampson

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Table of contents

Endeavour Energy

CEO Foreword

Australia's energy sector is amid an unprecedented transformation, with a shift from fossil fuels to renewables and from large scale generation to distributed generation, increasingly from customers' rooftop solar panels, home batteries and electric vehicles. This transition is offering opportunities for customers to participate more actively, saving money and powering their lives in new and innovative ways.

This transition is also taking place during a time of increasing economic uncertainty and cost of living and cost of doing business pressures, as more extreme climate events impact our communities, and at a time that Western Sydney and our regions transform into hubs of industry, innovation and 'liveable' urban development.

Every five years, we work with customers and stakeholders to prepare investment plans to build, operate and maintain a vast electricity network. That plan is reviewed by the Australian Energy Regulator (AER), which considers feedback and then decides the final revenue we can recover from customers to fund our operations. These costs make up about 30% of the average residential or small business electricity bill, so it's vitally important that every dollar we spend aligns with our customers' priorities.

Our revenue proposal is vital to the affordability, security, and long-term interests of our customers. The revenue that is finally determined will be used to build and maintain an electricity network that powers economic growth, creates jobs, keeps communities safe, resilient, sustainable, and productive; and will enable customers' energy choices and lifestyles beyond the five-year period.

We have undertaken our most extensive customer engagement and research process to inform this Proposal. This engagement, co-designed with our key customer stakeholder representatives, has consistently confirmed that customers have increasing and evolving expectations of their energy supply and its security and sustainability. They want to be confident about the energy system's performance during this period of transformation. Customers have also urged us to support them through the recent volatility in electricity markets and broader cost-of-living and cost-of-doing-business pressures by delivering an affordable energy transition. In keeping with our responsibility to our

customers, we have faithfully heeded these priorities in this Proposal.

Our network is powering the lives of our communities with over 2.7 million people increasingly depending on our service every day. This will grow to 3 million people by 2029. Even with this growth we plan to deliver significant efficiency gains with a Proposal that includes a 15% real reduction in operating costs and an 8% real reduction in gross capital cost compared to the 2019-24 regulatory period allowance. Despite these improvements in our costs and ongoing declines in our expenditure per customer, our distribution bills will increase over the next regulatory period by an estimated $48 per annum for the average residential customer and $86 per annum for the average small-medium business customer. These increases are largely driven by inflationary pressures and the increased cost of debt and equity.

Investing in your future

We are investing in your future. While the next 5-year regulatory period starts in 2024 and finishes in 2029, Endeavour Energy is planning for the critical investments required in the long term that can support our regions, facilitate the energy transition and deliver our purpose of powering communities for a brighter and affordable future. We are doing this while responding to the economic volatility and cost of living pressures our customers are currently facing.

Our plans are focused on:

Deploying growth enabling energy infrastructure in Greater Western Sydney and our regions

Endeavour Energy is actively supporting and enabling the growth of our regions including three of the six Cities Regions of the Greater Cities Commission; the Central River City, Illawarra-Shoalhaven City and Western Parkland City. The unprecedented growth of Greater Western Sydney will be delivered through the efficient, timely and innovative deployment of critical electricity infrastructure and strategic partnerships. Western Sydney is undergoing rapid growth and transformation as a hub of industry, innovation, and 'liveable' urban development, attracting local and global companies as hundreds of thousands of people are drawn to the enormous potential of the Western Parkland City and the Western Sydney International (Nancy-Bird Walton) Airport that serves it.

Supporting the NetZero economy and rapidly changing customer technology choices

Endeavour Energy is actively supporting the pursuit of a NetZero economy, which will transform the way our customers generate and consume energy. As customers take up technologies such as solar, batteries and electric vehicles, the network will need to evolve through investment and strategic partnerships that allows for two-way energy flows and active market participation from customers and third parties. Sophisticated digital platforms will be deployed to interact with a more dynamic, integrated network that facilitates the low carbon energy system.

Adapting to a changing climate and extreme weather events

Endeavour Energy has developed plans to support partnerships that will improve community resilience and deploy the critical infrastructure that can ensure services continue to operate in the face of a changing and more extreme climate. Climate modelling suggests that extreme weather events will continue to increase in both frequency and intensity over the coming decades despite global efforts to reduce carbon emissions. Our critical investments will reduce the impact of climate change-related weather events and increasing urban heat on our customers' electricity supply.

Actively driving efficiency and insights in the electricity-digital age

The digitisation of the electricity grid enables insights, efficiencies, and new markets to emerge that support customers' choice in new technologies and how they interact with energy. The introduction of new digital technologies and enhanced data capabilities transform the roles, required skills and location of our future workforce. At the same time, we must invest to reduce the impact of increasing cyberattacks as they become more sophisticated, targeted and risk disrupting energy supply.

Maintaining the high-quality level of service our customers seek

We must maintain and upgrade our existing electricity infrastructure which is core to maintaining the high-level of service, reliability, safety and emergency response our customers expect of us.

Our priority has been to develop this Proposal to deliver the outcomes that customers want and value in the most affordable manner. In collaboration with our customers and stakeholders along the way, we have strived to improve the efficiency and robustness of our engagement process, for Endeavour Energy, our customers, stakeholders and the AER.

I encourage you to find out more about what's planned and what this means for your future electricity bills on the pages that follow.

We invite you to continue to have your say on how you want us to meet your electricity needs, now and in the future.

Guy Chalkley

Chief Executive Officer

Endeavour Energy

A snapshot of our plan

Standard Control Services ($M, Real 2023-24)	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Operating expenditure (including debt raising costs)	287.8	294.7	298.2	305.0	312.0	1,497.6
Net capital expenditure	430.6	400.5	359.6	347.9	312.2	1,850.9
Regulatory Asset Base (end period)	8,200.4	8,158.8	8,096.5	8,052.9	7,979.1	N/A
Revenue Requirements						
Return on capital (WACC %)	469.3 (5.84%)	470.1 (5.90%)	474.1 (5.98%)	476.9 (6.06%)	481.9 (6.16%)	2,372.3 (5.99%)
Regulatory depreciation	267.7	218.7	199.4	170.7	165.9	1,022.4
Revenue adjustments	57.1	22.6	36.9	31.4	3.6	151.6
Corporate tax allowance (Gamma 0.595)	25.2	18.1	16.8	14.9	14.5	89.5
Annual revenue requirement (unsmoothed)	1,107.1	1,024.2	1,025.3	998.9	977.9	5,133.4
Revenue x-factors (%)	-14.12%	0.00%	0.00%	0.00%	0.00%	N/A
Annual revenue requirement (smoothed)	1,028.4	1,028.4	1,028.4	1,028.4	1,028.4	5,141.9
Energy consumption (GWh)	16,750.8	16,849.9	17,186.7	17,448.2	17,679.0	N/A
Customer numbers	1,135,889	1,159,087	1,182,139	1,206,023	1,230,499	N/A
Maximum Demand (MW)	4,594.9	4,646.0	4,771.7	4,888.9	5,014.2	N/A

Key Decisions	
Service Classification	We propose service classifications and definitions as per the AER's 2024-29 Framework and Approach paper. This includes the AER's decision to continue to regulate our Dual Function Assets as distribution assets for pricing purposes.
Control Mechanisms	We accept the AER's decision to apply a revenue cap to standard control services and price cap to alternative control services. We propose the formulae to give effect to these control mechanisms as per the AER's 2024-29 Framework and Approach paper.
Incentive Schemes	We accept the AER's decision in the 2024-29 Framework and Approach paper to apply the following incentive schemes to us: • the Efficiency Benefit Sharing Scheme (EBSS); • the Capital Efficiency Sharing Scheme (CESS); • the Demand Management Incentive Scheme (DMIS) including the Demand Management Innovation Allowance (DMIA); and • the Service Target Performance Incentive Scheme (STPIS) In accordance with the STPIS Guideline, we have proposed an alternative approach to calculate Major Event Day thresholds. This is consistent with the methodology we applied during the previous and current period. We also propose to apply a tailored Customer Service Incentive Scheme (CSIS) in place of the customer service component of the STPIS.
Pass-throughs	We propose to apply the same four nominated pass-through events as approved by the AER for the 2019-24 period. We have updated the definitions to align with those contained in recent AER decisions and events.
Contingent Projects	We have no eligible contingent projects for the 2024-29 period.
Tariffs	Our tariff structure statement (TSS), Attachment 0.14, outlines our proposed tariff structures for the 2024-29 period. To summarise, we will: • simplify our tariff strategy by replacing our Seasonal TOU Demand tariff as the default tariff offering with our Seasonal TOU Energy tariff. • introduce an export and reward tariff. We propose to offer our 'prosumer' tariff on an optional basis. Any customer can opt-in to the tariff from 1 July 2024, however from 1 July 2025, we will place all new and upgrading customers on the tariff as the default. • encourage ongoing efficient use for new technologies with a prosumer reward and tariff structure for customers who adopt new technologies including, batteries, and vehicle to grid, as an opt-in basis. • implement new tariff structures to efficiently and fairly enable grid and community batteries, embedded networks and scheduled load structures. • advance cost-reflective tariff reform by assigning all customers with smart metering to a cost-reflective tariff.

	• manage the customer impacts of this transition over a two-year transition period. • work with retailers to help educate customers on tariff choices and with the industry as a whole to facilitate uniformity of tariff design in response to retailers' feedback.
Alternative Control Services	
Public Lighting	We propose to simplify our public lighting pricing approach and we have modified our pricing approach to include a differential price for LED lighting in response to customer feedback. We have made these changes while reducing our LED public lighting revenue requirements noting we currently expect to fully transition to LED technology over the remainder of the 2019-24 period.
Type 5 & 6 Metering	We propose to adopt the AER's standardised models for pricing our metering services. Our proposed metering revenue over the 2024-29 period is $87.3 million (real; 2023-24) with primary residential charges increasing by $18 (real, 2023-24) over the period and small business charges by $27 (real, 2023-24). The increase is driven by the impacts of the transition to metering contestability reducing the scale efficiencies of meter reading.
Ancillary Network Services	We propose to adopt the AER's standardised model for pricing ANS. We have developed our proposed prices for new and existing services using the latest benchmark labour rates consistent with the AER's approach. Our proposed ANS pricing X-factor is equal to the real labour cost escalation forecast applied to derive our standard control services opex forecast.

Alignment with Better Resets Handbook expectations

Through engagement, we believe our plans support the long-term interests of customers, reflect the diverse and detailed feedback we have received from customers and stakeholders and align with the AER's expectations of what constitutes a quality proposal as outlined in the AER's Better Resets Handbook – Toward Consumer Centric Regulatory Proposals.

Through this process, we have been continuously engaging with the AER and submitting information as part of the Early Signal Pathway under the Better Resets Handbook. At several stages the AER has provided feedback on our Proposal, where improvements could be made and where additional information has been required. We have responded to this feedback throughout this determination process and in developing this Proposal. Below we set out how we consider we have satisfied the requirements of the Handbook.

Component	AER Expectation (in brief)	Endeavour Energy's Position (in brief)
Overall assessment	Options for fast-tracked regulatory proposals (or key elements) through greater and earlier collaboration and transparency by networks and commitment of AER resourcing.	We have conducted detailed pre-lodgement engagement including the development of business narrative, preliminary proposal, stakeholder deep dives, customer deliberative forums (in English and other languages) and a quantitative survey of customers. A total of 1,813 customers and stakeholders have directly participated in our engagement program. We have actively engaged and welcomed the AER involvement and feedback throughout this process.
Customer engagement	Consumers partner with Endeavour Energy in forming proposals, rather than just providing feedback. There is a breadth and depth to the engagement that is outcomes focusses, accessible, transparent and multi-faceted with a clearly evidenced impact on the proposal.	A 'live document' Engagement Plan and topics have been co-designed using best practice international engagement principles and led by the Board and executive engagement. Peak customer committee membership expanded, and a Regulatory Reference Group (RRG) formed to co-design formation of the proposal and its engagement. An extensive engagement program has been conducted with both customers and informed stakeholders in keeping with a live Engagement Plan that was updated six times during the program. We have openly and sincerely tested key aspects of our Proposal and adjusted our Proposal accordingly. An independent assessment of our engagement was undertaken to ensure its independence and impact which was confirmed.
Capital expenditure	Endeavour Energy should demonstrate that forecast total capex is not materially above current period actual spend. Recurrent categories of expenditure to align with top-	Headline figures within current period actuals with a reprioritisation of investment within categories. A new customer value framework and asset management practices have been implemented, and detailed cost-benefit analysis sit behind all plans.

Component	AER Expectation (in brief)	Endeavour Energy's Position (in brief)
	down models and historic trends (e.g., repex). Material, increasing or new categories spend to be supported by cost-benefit analysis and all spend by good asset and risk management practices.	Forecasts for existing categories in line with top-down models (where available). Forecasts for new categories of expenditure are relatively modest and accord with AER guidance and key input methodologies. Overall capex has been constrained with further productivity commitments given in capitalised overheads and foregone cost escalation (reductions totalling in excess of $100 million).
Operating expenditure	Efficiency scope at 0.75 (OEF), productivity of at least 0.5% p.a. Operating Environment Factors (OEFs) and base year adjustment need to be discussed with AER prior to submission. Step changes should be limited to legislative changes and capex/opex trade-offs.	Endeavour Energy is positioned beyond the Efficient Frontier and will apply base-step-trend method. We have consulted with customer advocates on step changes and accounting changes. A constrained approach has been taken in accordance with stakeholder feedback to accept a degree of risk and further productivity commitment.
Regulatory depreciation	Utilises AER post-tax revenue model, roll forward model and depreciation tracking. Proposal for accelerated depreciation, and any changes to asset classes or asset lives, should be discussed with customers.	Endeavour Energy has utilised AER models including adoption of a year-by-year tracking method. There is no proposal for accelerated depreciation. Changes have only been proposed to introduce capitalised lease asset classes following a change in accounting standards.
Tariff Structures	Progress transition to cost-reflective tariffs (import and export) and demonstrate incorporation of tariff strategy within overall business plan. Proposal linked to stakeholder engagement, broadly supported and adverse customer impacts managed.	Tariff proposal informed by extensive engagement and tariff trials. However, our Proposal may not enjoy broad support as there are divergent views between customers, retailers and stakeholders on the appropriate transition path to cost-reflective tariffs (consumption and generation). Our analysis suggests that it is in the long-term interests of customers to strengthen our tariff assignment policy and propose a transition period to manage adverse customer impacts which we have proposed.

1. Summary

1.1 Purpose of this document

Over the next five years we will maintain stability in our portion of the electricity bill whilst delivering a safe, resilient, reliable electricity service, supporting the economic growth of our regions and facilitating customer choice and control as energy decarbonises.

Every five years, we are required to submit a plan for what needs to be spent to operate and maintain a vast electricity network. In accordance with the National Electricity Rules, the AER reviews this Proposal to determine our revenue requirements and other matters relating to the provision of regulated electricity distribution services. This review includes a public consultation process following its release that builds on the extensive engagement that has shaped this Proposal.

This Proposal covers the period from 1 July 2024 to 30 June 2029. It details our proposed operating and investment plans developed and presented in accordance with the AER's *Better Resets Handbook* and includes:

- Expenditure forecasts;
- Rates of return;
- Pricing methodology; and
- Tariff Structure Statement.

This Proposal and the engagement that supports it have been co-designed with our Regulatory Reference Group (RRG), which includes an independent panel of experts representing a diverse set of stakeholder views. It has been heavily influenced by broad and deep engagement with our customers and stakeholders over the last few years. This Proposal demonstrates the sincere and significant uplift in our commitment to best practice customer engagement. It therefore sets out our understanding of their expectations for the services we deliver and the network charges they pay. Accordingly, this Proposal also includes an overview document to summarise and make it easier to understand the different elements that contribute to the network charges customers pay for electricity distribution.

This Proposal is submitted so that the AER can ultimately determine the final revenue we can earn from the services that we intend to provide and how that flows through to the electricity bills of over a million customers. Once we receive the AER's feedback, we will continue to engage with customers and stakeholders to address any concerns before submitting a revised proposal (if required) in December 2023 for determination.

Structure of this Regulatory Proposal

Introductory sections – introduces our Regulatory Proposal and includes a foreword from our CEO highlighting our performance-to-date, plans for the future and how we will continue to work with our customers and stakeholders in delivering services that meet their expectations in the most efficient way.

Chapter 1 (this chapter) sets out the purpose and structure of this Proposal.

Chapters 2 - 5 explains the context that has informed our Proposal for the next five years. This includes: a report on our performance for the current period; the opportunities and challenges we face in providing network services to our customers; an account of how we have engaged with our customers to gather their views; and how these views have been incorporated into this proposal.

Chapters 6 – 13 focus on the detail of our Proposal. We set out: the savings and investments we plan to make; our regulated asset base; proposed rate of return; income tax allowance; and various incentive schemes. These details inform the overall revenue required to provide distribution services and describe the implications for customer bills.

Chapter 14 focuses on alternative control services. These services are only required by a small group of customers or have the potential to be provided on a competitive basis in the future, such as public street lighting, and are subject to service-specific prices set by the AER to enable full cost recovery by those using these services.

Attachment 0.14 is our Tariff Structure Statement (TSS) which further expands on the billing implications by detailing our proposal to simplify our tariff strategy by replacing our Seasonal Time of Use (STOU) Demand tariff as the default tariff offering with our STOU Energy tariff. It also includes our proposal to introduce an Export and Reward tariff for all new and upgrading customers from 1 July 2025 with an ability to opt-out and a series of prosumer tariffs to encourage the long-term efficient use of new technologies like home batteries and electric vehicles, including through their potential aggregation.

To complement this document, we have developed a Plain-Language Overview of our Regulatory Proposal. This provides a summary of the key aspects of our proposed revenue requirements for 2024-29. It complies with all the requirements set out in 6.8.2(c1) of the National Electricity Rules.

2. About Endeavour Energy

2.1 Overview

We power our customers lives and businesses and support the economic and liveable urban development of our regions including Greater Western Sydney. Our enduring focus is providing affordable, safe, resilient, sustainable and reliable electricity to the 2.7 million people across our network, reaching 3 million people by 2029.

Endeavour Energy plans, builds, operates and maintains the poles and wires and other distribution assets to provide an affordable, safe and reliable power supply to and from households and businesses across Sydney's Greater West, the Blue Mountains, the Southern Highlands, the Illawarra and the South Coast.

The timely and efficient provision of these services is fundamental to supporting employment growth, economic development and housing affordability across one of the fastest growing metropolitan and regional economies in Australia.

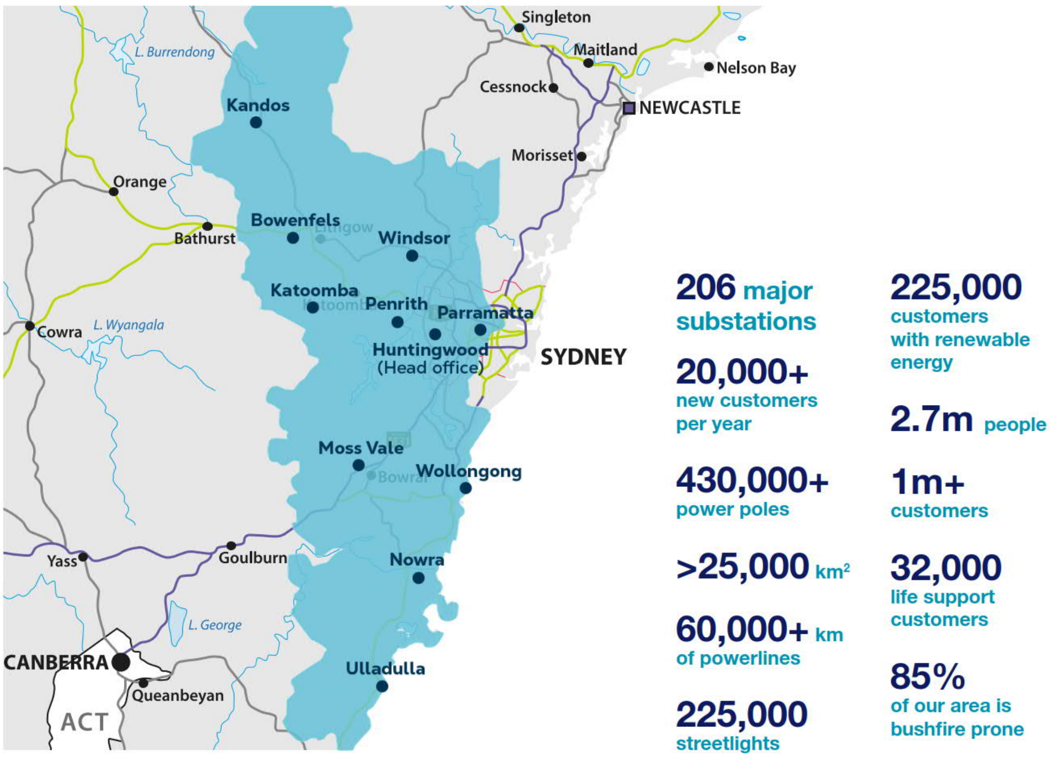
Over the current regulatory period (2019-24) we have improved our performance against our three key performance indicators of affordability, safety and reliability. Over the last ten years, Endeavour Energy's average network charges decreased by $116 in nominal terms (for an average residential customer). Our performance has therefore allowed our customers continue to benefit from some of the lowest distribution network charges in the National Electricity Market (NEM).

2.1.1 Who we are

Endeavour Energy manages a $7.7 billion ($FY24) regulated electricity distribution network for 1,080,000 customers in households and businesses across an area spanning Sydney's Greater West, the Blue Mountains, the Southern Highlands, the Illawarra and the South Coast of NSW.

Our network services communities with some of the highest cultural and language diversity in Australia across the lands of the traditional custodians – the people of the Dharawal, Dharug, Gundungarra, Wiradjuri and Yuin nations. We recognise first peoples' continuing connection to Country, cultures, and community. We pay our respect to elders past and present.

Figure 2-1 Endeavour Energy overview



Endeavour Energy is 50.4% owned by an Australian-led consortium of long-term investors in the private sector operating the network under a 99-year lease. The private sector consortium comprises of funds and clients managed by Australia's Macquarie Infrastructure and Real Assets, AMP Capital on behalf of REST Industry Super, Canada's British Columbia Investment Management Corporation and Qatar Investment Authority.

The remaining 49.6% is held by the State of NSW via a corporation constituted under the *Electricity Retained Interest Corporations Act 2015*.

This change in ownership in 2017 means we continue to leverage the vast infrastructure management experience of the consortium to transform our business into a world class utility, delivering further improvements in safety, operating efficiency and customer service outcomes.

Our customers are central to our plans. We're committed to making a serious and sincere effort to deliver the best value for customers by reducing our costs, without compromising safety or services.

2.1.2 What we do

We own and operate a network used to transport electricity from the high voltage NSW transmission network (managed by TransGrid) directly to the homes and business of our customers in a form they can use. Increasing numbers of solar panels and batteries mean the network is also used to store and transport energy from these 'customer energy sources' back into the system.

We perform this role according to extensive obligations, standards, conditions and requirements, particularly in relation to customer and community safety, and the security and reliability of supply. We recover costs from customers through network tariffs. Our costs make up almost a third of an average residential customer's electricity bill.

Figure 2-2 Electricity industry structure

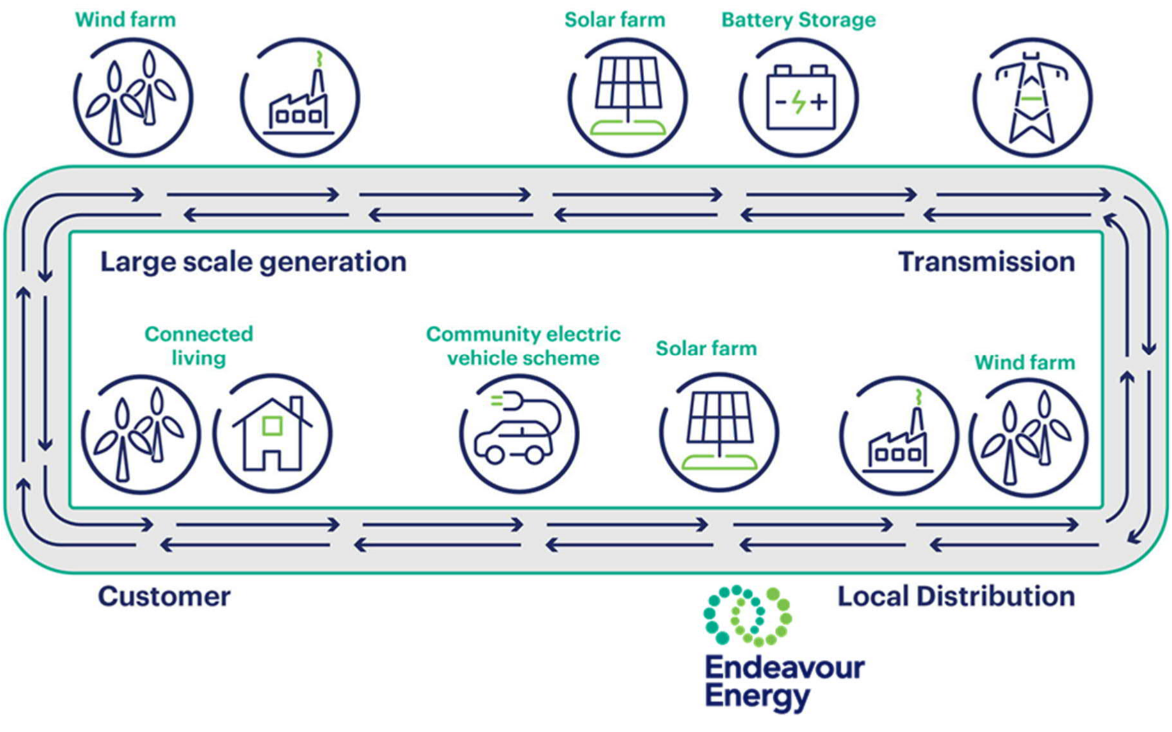


Table 2-1 Electricity bill breakdown (source: AER default market offer prices 2022-23 and Endeavour Energy analysis)

Each part of the bill	Wholesale (generation)	Transmission (Transgrid)	Distribution (Endeavour)	Retail	Green schemes	Total
Residential without electric hot water (4,900 kWh pa)	36%	4%	30%	22%	7%	= $1,836
Residential with electric hot water (7,400 kWh pa)	41%	4%	27%	19%	8%	= $2,383
Small business without electric hot water (10,000 kWh pa)	36%	4%	26%	24%	10%	= $3,782

There are significant costs in building and maintaining a distribution network of our size and complexity. Our core activities include:

- Safely maintaining distribution lines and substations to keep the lights on
- Building new substations, poles and wires, including in new suburbs
- Responding to emergencies like storms which bring down power lines and poles
- Tree trimming to maintain safety clearances, manage bushfire risk and prevent blackouts caused by falling trees
- Facilitating the connection of new customers to the network
- Researching, trialling, and installing new technology, like batteries, to use as alternatives to poles and wires
- Installing and maintaining streetlights
- Various ‘user pay’ services like meter testing, off-peak conversion and design certification.

Our Network includes:

- **206** major substations
- **33,000** distribution substations
- **60,000+ km** of powerlines
- **430,000+** power poles
- **225,000+** streetlights

We manage these assets across an area of which 85% is bushfire prone.

2.1.3 Our customers

We serve a diverse population with over 1 million customers across 24,980 square kilometres. Most of our customers are households and small to medium businesses located in urban and developing rural areas. We also serve large urban areas, medical precincts and manufacturing and industrial customers who have specific needs for a safe and reliable supply, and we provide high voltage support directly to very large businesses.

Our network includes significant development areas such as the Western Parkland City and the Western Sydney International (Nancy-Bird Walton) Airport and its surrounding aerotropolis. It's also home to Sydney's North West, South West and Greater Macarthur Priority Growth sectors, planned as new release areas to house communities similar in size to Wollongong and Canberra. By 2036, half of Sydney's population will be expected to reside within Sydney's west. 725,000 new dwellings are expected in the region into the future under the Greater Sydney Region Plan.

In addition to population growth, our customers have the third highest energy density and demand density in the NEM. This means that our customers consume a relatively high amount of energy, particularly during peak times (4pm to 8pm). This is largely due to a combination of higher summer temperatures (often up to 10 degrees higher than the Sydney CBD) and energy-intensive economic activity.

As the electricity industry undergoes rapid transformation, many customers are changing the way they interact with the network, and we are seeing more small-scale renewable forms of generation connecting to the network. By June 2022, approximately 225,000 customers had connected their own small scale renewable generation (mostly solar panels) to the network, representing a cumulative capacity of around 1GW. Our network will continue to play a critical role in enabling a range of customer benefits from the increasing uptake of customer energy resources (CER), also commonly referred to as distributed energy resources (DER). In Chapter 4, we provide more detail on the way our customers consume and produce energy is evolving.

We manage our operations over three distinct geographic regions:

Northern region

North-west Sydney and the Blue Mountains – Wiradjuri and Dharug nations

Most of our customers (and our network infrastructure and assets) are located in Greater Western Sydney which includes the major cities of Parramatta (Central-River City), Blacktown and Penrith, along with the Hawkesbury and the Hills regions located in the Northern region. Combined with other major centres in the Central region, they form the third largest economy in Australia.

Previously, the suburban development was driven by the largest coordinated land release in the history of NSW. This included the development of the North-West and South-West Sydney regions as they continue to become increasingly liveable urban communities supported by increased transportation infrastructure including the Sydney Metro North-West.

With over half of Sydney's population expected to reside within Sydney's west within the next 15 years, our investment plans for the next regulatory period support required growth in these areas.

We also supply customers throughout the Blue Mountains and beyond. This is a World Heritage Area featuring dense vegetation with challenging topography. Managing bushfire risk and reliability is a key focus for this part of our network.

Central region

South-west Sydney and the Southern Highlands – Gundungurra, Dharug and Dharawal nations

The central area of our network incorporates the major urban centres of Liverpool, Fairfield and Campbelltown. In common with the Northern region, strong greenfield growth has been experienced in areas that were previously low-density rural communities. Large transport infrastructure investments underpin population and economic growth in the area.

More recently, the growth has accelerated to support the development of the Bradfield City Centre at the heart of the Western Sydney Aerotropolis, the area surrounding the Western Sydney International (Nancy-Bird Walton) Airport. The 114-hectare development will supercharge the creation of jobs and economic opportunities across Western Sydney. With the airport set to open in late 2026, we are working closely with planning authorities and developers to support this and other planned development in the surrounding area.

South-west of the Sydney metropolitan region, the rural townships of Picton, Bowral, Mittagong and Moss Vale form the major regional communities of the Southern Highlands.

Southern region

Illawarra and the South Coast – Dharawal and Yuin nations

Most of our resources in the Southern region are focused in Wollongong and the wider Shellharbour district. After Sydney and Newcastle, Wollongong is NSW’s third largest city and is home to approximately 300,000 people. Significant growth is planned for the region, led by the West Lake Illawarra area which will ultimately accommodate an estimated 38,000 new dwellings. This region includes Port Kembla Harbour and an industrial complex that is the largest single concentration of heavy industry in Australia.

The most southern areas of our network are predominantly small coastal communities, popular with holiday tourists and retirees, and often subject to severe weather events. Our growth story extends to this area too, with an estimated 5,000 new homes possibly in the greenfield Moss Vale Road Urban Release Area in the Shoalhaven region.

3. Our Performance

3.1 Overview

Endeavour Energy's network charges are the lowest in NSW and one of the lowest in the National Electricity Market due to our long-term efficiency programs and commitment to incentive-based regulation. We have achieved this without compromising safety or reliability.

Our primary goal is fundamental and enduring; to ensure our customers have reliable access to an electricity network that is affordable, safe and sustainable, and enables access to power in a way that suits them and their energy needs. We work together to adapt quickly to the needs of our customers, and continually strive to find better ways to power our communities.

Our performance over this regulatory period (2019-24) demonstrates our commitment to becoming one of Australia's best performing electricity network businesses, while preparing for the future grid. Between 2019 and 2024 we will have achieved:

Table 3-1 Endeavour Energy 2019-24 key outcomes

Effectively and efficiently meeting customer needs		Meeting future expectations
Real average distribution network bills for customers ▼15%	Operating costs ▼21% of operating cost allowance	Total capital expenditure spent — 100% of capital expenditure allowance
System capital investment ▼16% of system capital allowance	New customers connected ▲94,910	Transformation projects ▲150% of non-system capital allowance

We achieved these efficiency improvements through the concerted effort of our people and a commitment to providing our customers value for their money.

Our improvements have accelerated since the 2017 long term lease of Endeavour Energy by the NSW Government.

3.2 Value for money

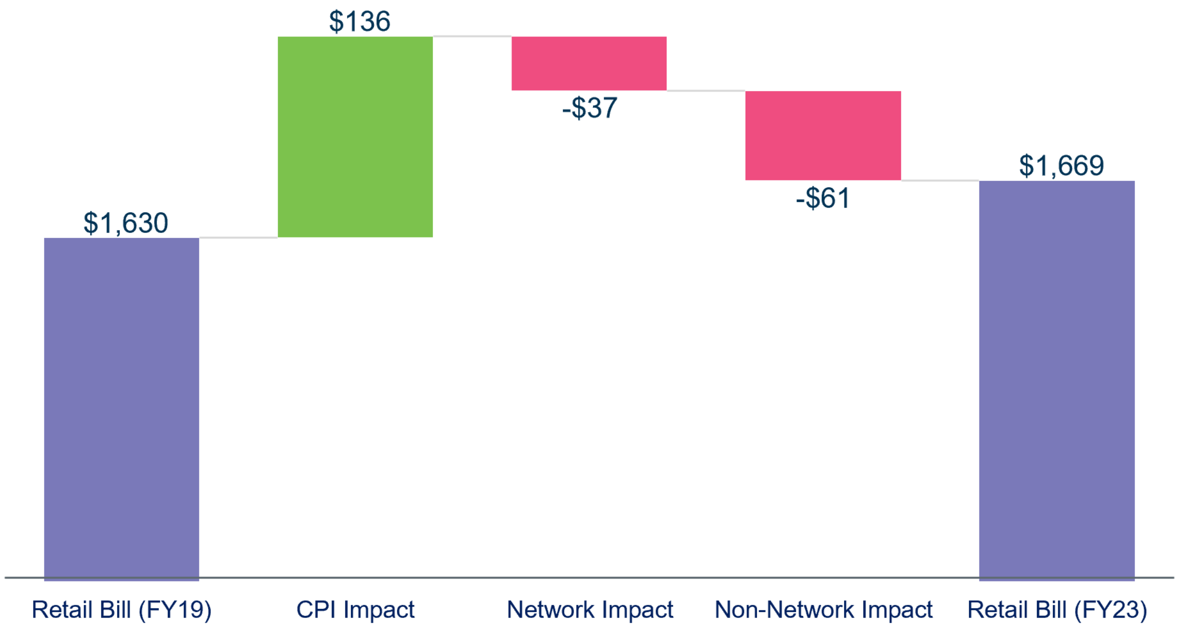
Our engagement with customers consistently tells us that affordability is a key priority for many of our customers. Electricity is valued because it provides security and lifestyle benefits to residential customers and communities, and because it connects new homes and underpins prosperous businesses and regions. There's a clear expectation our plans should reflect measures that continue downward pressure on our part of electricity bills. This commitment is becoming increasingly important as other parts of the supply chain, such as Government schemes to support large-scale renewable generation, forecast significant cost increases over the coming years.

We're committed to improving the efficiency and productivity of our business to drive cost savings and keep downward pressure on our part of customers' electricity bills.

Since the peak of our investment in 2011-12, following several efficiency and transformation initiatives, we have reduced annual total annual expenditure by 41% from $1,251 million (real, 2023-24) to $741 million (real, 2023-24) in 2022-23. We have focused on making our workforce more competitive and agile, improving the commercial aspects of our asset management decisions, transforming our ICT & digital systems and making our business operations more efficient. We have achieved these reductions despite the added cost pressures that have arisen from the need to extend the network to meet significant growth in new connections, the need to maintain an ageing asset base in existing areas of our network and managing increasingly frequent and severe weather events.

This has meant that Endeavour Energy's residential customers are paying $37 less in real terms on average for network services in 2022-23 than they were in 2018-19 as a result of our revenue requirements over the 2019-24 period. Accordingly, our customers to continue to benefit from some of the lowest network charges in the NEM.

Figure 3-1 Change in average residential bills over the last 5 years

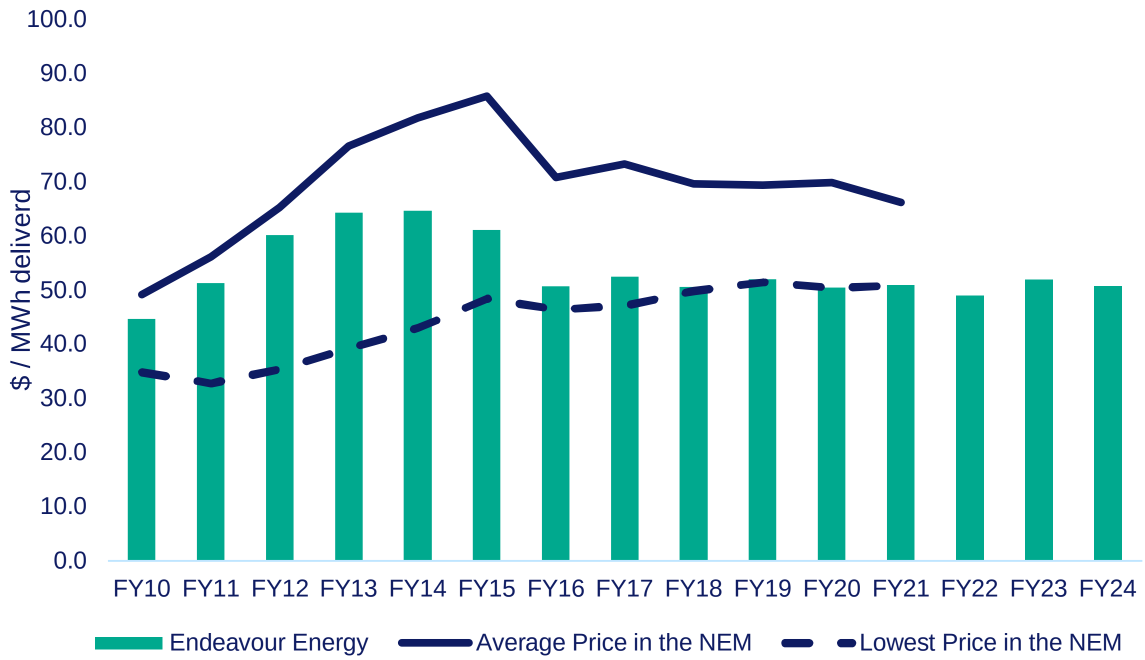


CPI impact is Consumer Price Impact, or household inflation, which is outside of Endeavour Energy's control.

As a result of the reduction in our network charges, our share of an average residential customer's electricity bill has fallen to 29% in 2022-23, a decrease of 1% from 2018-19. Our network charges now rank as the lowest in the NEM based on the most recently published AER data[1].

[1] AER Network Performance Report 2022

Figure 3-2 Average network costs per unit of energy ($/MWh) compared to NEM



3.2.1 Tariffs

A tariff is the way customers are charged for their energy. Endeavour Energy charges network tariffs to retailers who then pass them on to their customers. These tariffs enable distributors to recover revenue to build, operate and maintain the network that is used to convey electricity. The AER regulates these tariffs annually so that consumers pay no more than necessary for safe and reliable electricity services.

The overarching purpose of our tariff strategy is to make energy more affordable by providing customers with the information they require to make informed and efficient decisions about their use of the network and their investment in new technologies such as solar, batteries and electric vehicles.

Enabling customers to make appropriate decisions about network use and investments in alternative technologies like solar PV, batteries and electric vehicles will assist Endeavour Energy to make future network investments that customers are willing to pay for and, ultimately, to provide the network services customers want to use at the lowest possible cost.

The pace of this reform is impacted by:

- what customers want;
- what impacts they will face; and
- the roll out of smart meters, which make it possible to record when energy is used at different times of the day.

One of the central parts of Endeavour Energy's tariff strategy for the 2019-24 regulatory control period was a shift towards cost reflective tariffs. This included introducing seasonal time of use components and reducing the on-peak period to a small and specific charging window. These tariffs are further along the cost-reflective spectrum than our network peers and provide a real opportunity for our customers to respond to save money by responding to the price signal.

In implementation, an opt-out provision for cost reflective tariffs was included to help manage bill impacts. The opt-out provision was applied in conjunction with an agreement with the AER to ensure that:[2]

[2] Endeavour Energy, *Tariff Structure Statement | 1 July 2019 – 30 June 2024*, January 2019, p 29.

- no less than 90% of small LV customers can expect bill reductions when transitioning from the flat tariff to any of the cost reflective tariffs; and
- no less than 50% of small LV customers can expect bill reductions when transitioning from the transitional demand to the standard demand tariff.

Despite this, the period started with a large proportion of retailers opting out of the cost reflective tariffs on behalf of Endeavour Energy customers, noting this option is already limited by the number of customers who have a smart meter. This has meant that despite having some of the most targeted and leading cost-reflective tariffs in the NEM, the number of customers on these tariffs is amongst the lowest. We have actively engaged with retailers over the past 2 years to actively support customers transition onto customer reflective tariffs, which are more equitable and provide opportunities for customers to make more informed decisions about their energy use, potentially reducing their costs.

Supporting the transition, we have seen an acceleration in the smart metering penetration across Endeavour Energy's network. As at June 2022, 31% of our residential customers and 25% of SME customers have smart metering compared to 14% and 11% respectively in June 2019.

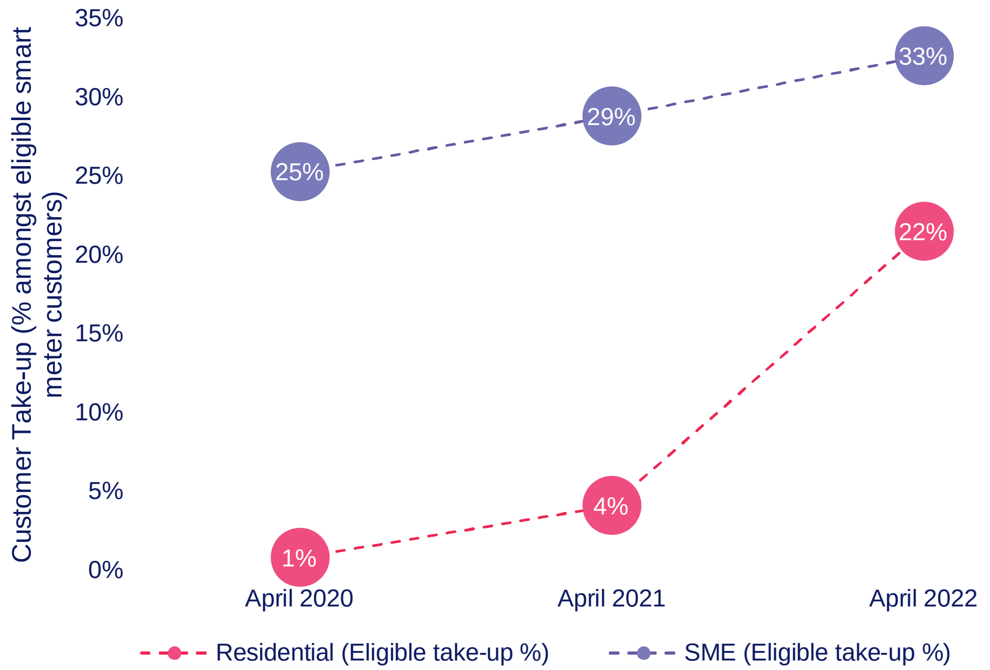
We have also seen an increase in the take-up of cost-reflective tariffs by retailers more recently. This is reflected in the significant transition of residential customers to cost reflective tariffs by several large retailers.

Despite these significant improvements in cost reflective tariff take-up, 34% of eligible SME customers and 22% of eligible residential customers are on cost reflective tariffs as shown in the table and figure below.

Table 3-2 Smart meter penetration amongst Endeavour Energy customers

Customer Type	Technology	Jun-19	Jun-22
Residential	Customers with a smart meter	14%	31%
	Smart metered customers on a cost reflective tariff	0%	22%
	% of total residential customers on cost-reflective tariffs	0%	7%
SME	Customers with a smart meter	11%	25%
	Smart metered customers on a cost reflective tariff	29%	34%
	% of total small-medium business customers on cost-reflective tariffs	3%	9%

Figure 3-3 Cost reflective tariff take-up across Endeavour Energy's network (Residential and SME)



To put this into perspective, with 31% of residential customers with a smart meter, and less than 22% of them on a cost reflective tariff, only 7% of all residential customers are on a cost reflective tariff across Endeavour Energy's network.

As a result, we are proposing a new customer assignment policy for the 2024-29 period to ensure that our customers are placed on cost reflective tariffs. This is consistent with the direction of policymakers, our tariff strategy and its engagement and proposed as reasonable, given retailers and customers have had and will have more time to adjust to options to best suit different customers.

3.2.2 Efficient connection of new customers

In addition to the prices existing customers pay, we must also be mindful of connecting new customers to our network in a timely and efficient manner to support jobs, economic development and housing affordability in Sydney's West and the Illawarra.

In NSW, the NSW Electricity Supply Act 1995 establishes a framework for electricity customers to contract directly with Accredited Service Providers (ASPs) to do the work that is necessary to connect them to a distribution network. NSW is unique in its approach as no other Australian jurisdiction allows a customer to engage a service provider of their choice to complete work that the DNSP will own and maintain[3].

Under the framework, contestable work is defined as customer connection and the extension or increase in capacity of the distribution system. ASPs are accredited under the ASP Scheme to complete this work. Customers engage ASPs to undertake their work directly and the relevant DNSP takes on ownership and responsibility for maintenance of work completed on the distribution network.

Our role is to facilitate and administer aspects of the ASP scheme (e.g., approving and inspecting designs) and providing upstream network extensions and augmentations that provide a benefit to the shared network. The total cost of a connection in NSW therefore includes the ASP works (which is then gifted to Endeavour Energy as a capital contribution) and the connections capex we incur.

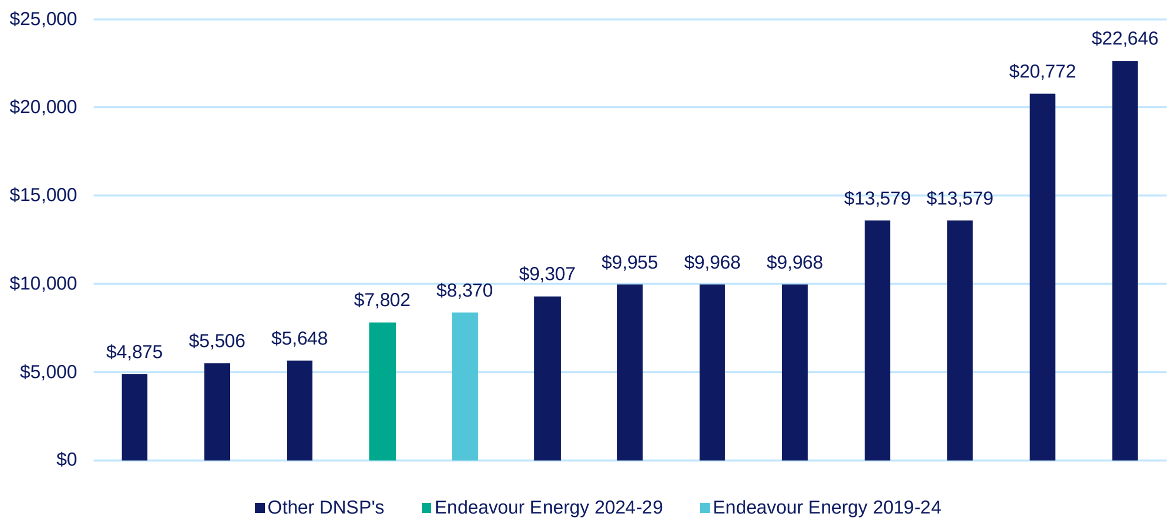
Over the 2019-24 period we have made several improvements to our connection processes to provide a timelier and more positive customer experience. Recent improvements include:

[3] In Victoria, there is a limited approach to contestability where a DNSP enters into a contract directly with a service provider, on behalf of a customer.

- Introduction of a Connections Portal to replace paper-based application processes with a web based online solution. This new portal also introduces a dashboard to provide our customers real time transparency of application status, key milestones, and fee information.
- Launched a new fast track application process to improve connection timeframes and cut unnecessary red tape, based on direct customer feedback. During an initial pilot, Endeavour Energy cut on average 10 weeks from application to design certification, saving our customers valuable time and improving measured customer satisfaction.

We have also sought to maintain the efficiency of our contribution to the connection costs. Our total cost per connection remains one of the lowest in Australia over the last several years and we forecast our average connection cost per customer will continue to improve over the 2024-29 period.

Figure 3-4 Average DNSP connection cost per customer[4] ($; Real FY24)



3.2.3 ICT and Digital Transformation

Historically, our ICT investment was below the AER allowance and industry benchmarks. Following our partial privatisation in 2017 a decision was made to prioritise ICT business transformation for the following reasons:

- To deliver services to customers at the optimal balance between cost and quality (i.e., allocative and productive efficiency).
- As a critical enabling investment to deliver streamlined, integrated, and efficient systems to better manage the transitioning energy marketplace and changing customer demand (i.e., dynamic efficiency).
- Due to the lack of suitability of existing systems and the need to future-proof the resilience of ICT and network systems (i.e., technical compliance).

As a result, our ICT and digital transformation focussed on three key initiatives:

1. **ICT Transformation Program** to build a core SAP platform to replace 26 legacy systems. This business transformation provides Endeavour Energy with a sustainable base level platform to consolidate systems of record for operational and customer facing purposes while having a stable system capable of handling market rule changes.

[4] Source: RIN data, FY17-FY21 average performance for non-Endeavour Energy DNSPs.

2. **ADMS Implementation** this enabled Endeavour Energy to replace a manual pin board control room operation and an ageing Outage Management System with a real-time, electronic management system reflecting the increasing convergence of network and non-network infrastructure. The electronic ADMS proved to be the critical change that enabled Endeavour Energy to mitigate operational risks while operating in the fast-changing COVID environment.
3. **Security Improvement Plan (SIP)** which allowed Endeavour Energy to continue to operate and meet the Distributor's Critical Infrastructure Licence Conditions 9 and 10.

Overall, our forecast ICT capital expenditure for the current regulatory period is forecast to be 16% of the total capital spend versus the 5% anticipated in the allowance ($225 million higher than expected). Noting that the incentive-based regulatory framework provides two options for funding efficiency enabling investments:

1. **Productivity adjustment:** whereby the cost of the program is included within the approved expenditure allowance and the associated operating and capital saving benefits are also accounted for (typically via a productivity adjustment)
2. **Self-funded:** whereby the proposed expenditure is not explicitly included within the approved expenditure allowance. However, as a "bucket" of expenditure a business is free to re-allocate expenditure as it sees fit in order to derive benefits.

As our transformation program was not fully scoped or finalised in advance of our 2019-24 Determination, we adopted the latter approach for this program. This meant that over the course of the previous (the final year of the 2014-19 period) and current period, we re-prioritised investment towards our ICT and digital transformation. Our intention has been to achieve re-prioritisation of investment through efficiencies in other categories of expenditure and/or through within-period deferrals that would subsequently be accommodated by the associated transformation efficiency benefits.

Consistent with the AER's ICT Assessment Guideline we have conducted a post-implementation review (PIR) of this program to validate the benefits and to determine whether improvements could be made to our procurement, governance, project management, cost and benefit quantification and tracking processes for future non-recurrent ICT projects. This review has found:

- The transformation project was required due to the state of Endeavour Energy's ICT systems and applications at the time when the investment decision was made and strongly aligned with Endeavour Energy's strategy.
- Endeavour Energy took a prudent approach to the identification and management of key challenges and implemented a strong governance structure to refocus the transformation project on its core outcomes, functionality and embed the lessons learned.
- Endeavour Energy has invested in modules similar to what its peers have invested in its costs on average, are below those of its peers for similar investments.
- Endeavour Energy has taken a robust approach to identify the scope of benefits that can reasonably be attributed to the enhanced functionality associated with the deployment of SAP. The quantified benefits expected to be realised for the ICT transformation exceed the anticipated costs with a **Net Present Value (NPV) of $108.2 million** and a **Benefits to Cost Ratio (BCR) of 1.52**
- Endeavour Energy has identified areas of improvement over the lifecycle of release delivery and the PIR process has also provided an opportunity to identify lessons learned and opportunities for improvement.

This transformation program has been the key driver of the substantive productivity improvements we have made over the 2019-24 period. This can be observed by our improving benchmarking performance and our operating costs being 21% below the efficient allowance set by the AER for the period.

The period of renewal has provided a good foundation for future investment, optimisation and service delivery to adapt to the changing external landscape. This means our forecast, discussed further in Chapter 10, is returning to long-run levels of ICT non-system capex that is below historic trends and is reflective of our improvements.

3.2.4 Productivity

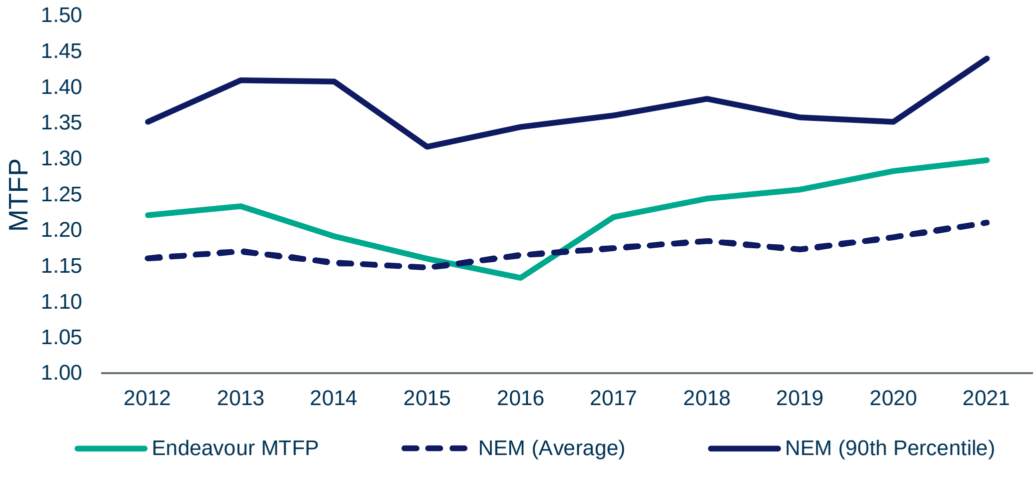
Endeavour Energy has performed strongly under the revealed cost framework, improving our opex Australian benchmark ranking from 10th in 2016 to 4th in 2022. The considerable reductions we have made in opex over the last several years have escalated since our partial privatisation in July 2017 and are driven by sustainable efficiencies we have achieved and continue to expect to achieve. In particular, during the 2019-24 period we:

- Embarked on a significant and necessary transformation of our ICT enterprise systems and processes. This is the primary source of our more recent efficiency gains and driver of a forecast reduction in our number of full-time equivalent (FTE) employees of 183 since 2018.
- Re-structured our key operations to better utilise (and thereby reduce) our workforce while improving service quality.
- Conducted a thorough and strategic review of all procurement processes and agreements to materially reduce our contract costs.
- Initiated an innovation fund and continuous improvement project team to continually assess and review internal processes to identify better ways of working and productivity improvements.
- Increased the scale of our unregulated activities which reduces the corporate overheads allocated to our standard control service activities.

Benchmarking techniques are increasingly being used by the AER as a tool to assess the efficiency of networks over time and against NEM peers. Despite some debate about benchmarking measures and models, Endeavour Energy supports benchmarking as it can identify potential opportunities for efficiency improvements that can improve affordability for our customers.

At the time of our 2019-24 Proposal, we noted that whilst we benchmarked as the most efficient network in NSW, our ambition was to be amongst the most efficient networks in the NEM. We have made significant progress against achieving this objective and now consider ourselves to be one of Australia's most efficient networks as shown below from the AER 2022 annual benchmarking:

Figure 3-5 Productivity (outputs / inputs) under multilateral total factor productivity (MTFP)[5]

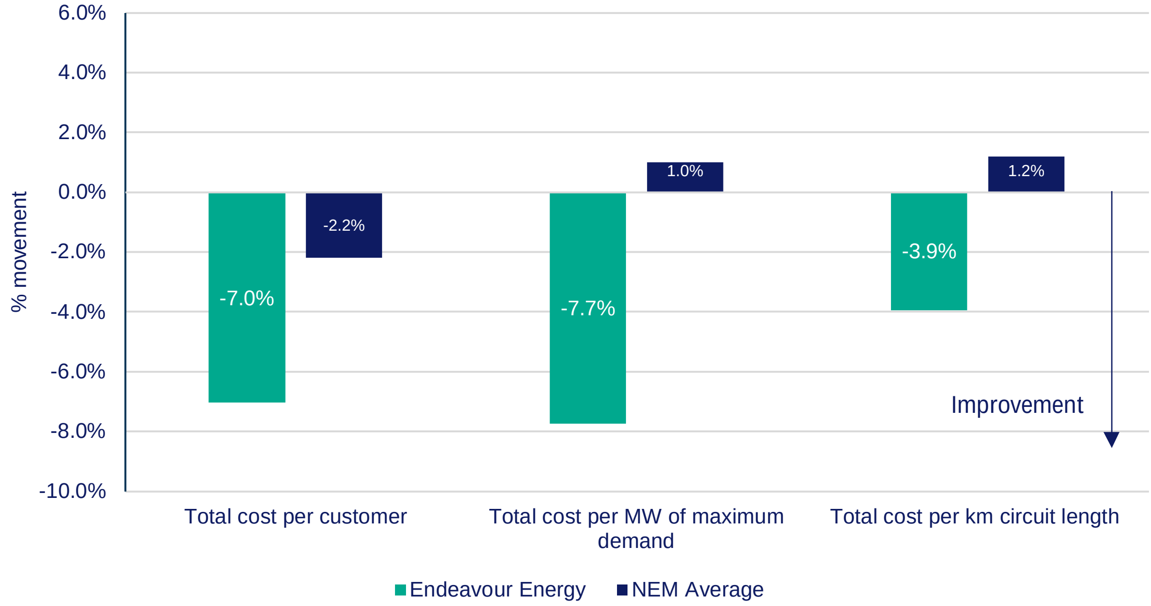


The AER also uses a variety of partial performance indicators (PPI) to provide a simple visual representation of input costs relative to a specific output. We have made significant reductions in our

[5] Pooled MTFP Output, Input & TFP Indexes from the AER 2022 Annual Benchmarking Report

totex per customer, unit of maximum demand and km of line compared to the flat or increasing trend in performance across the NEM in recent years.

Figure 3-6 Endeavour Energy percentage change in total cost PPIs compared to NEM average (2012-2021)[6]



3.2.5 Responding to incentives

The NEM uses an incentive-based regulatory framework to ensure that networks like Endeavour Energy continually improve their efficiency without compromising the safety or reliability of their services. The incentive schemes are:

- the Efficiency Benefit Sharing Scheme (EBSS): is designed to provide networks with a continuous incentive to pursue opex efficiency improvements;
- the Capital Efficiency Sharing Scheme (CESS): is designed to provide networks with an incentive to spend less than the approved capex allowance during a regulatory period;
- the Service Target Performance Incentive Scheme (STPIS): is designed to ensure networks target a level of reliability and customer service that is valued by customers; and
- the Demand Management Incentive Scheme (DMIS), including the Demand Management Innovation Allowance (DMIA): are designed to ensure networks trial, investigate and utilise innovative non-network solutions to address network constraints.

We have responded efficiently to these incentive schemes over 2019-24 and our customers will receive the majority of the benefits associated with our performance. We have reduced our forecast opex and RAB while maintaining reliability and investigating non-network solutions (like our Albion Park Off-Peak Plus trial).

We plan to respond efficiently to incentives over the 2024-29 and share the benefits of doing so with our customers in accordance with the incentive based regulatory framework.

[6] The comparison reflects average total cost (opex plus asset cost) across the 2012-16 and the 2017-21 analysis periods as reported in the AER's 2017 and 2022 Annual DNSP Benchmarking Report respectively.

3.3 Innovation

A key part of achieving future efficiency gains is innovating in how we manage and operate the network. As discussed above, our ICT and digital transformation has been a critical enabler of productivity improvements over the current period. Innovation is also a key to responding to emerging challenges and opportunities our customers face from the de-carbonisation and decentralisation of the energy industry to managing the impacts of climate change. Some initiatives and customer programs are listed in the table below.

Table 3-3 Endeavour Energy innovation examples

Initiatives/Programme	Programme Description
Off Peak Plus	In May 2021 we launched our Off Peak Plus program installing smart meters at 2,500 homes across Albion Park in the Illawarra in partnership with ten energy retailers and two metering companies. This avoided replacing and upsizing ageing off-peak control systems at a nearby zone substation. The smart meters represented a lower cost option that would provide additional benefits through energy and power quality data. This supports lower bills for customers along with improved reliability and export hosting. The smart meters enable the dynamic control of hot water systems to switch on during the day when surplus power is being generated from household solar systems.
Digital twin	In 2021, we became the first electricity network in Australia to deploy an engineering grade digital twin to combat the impacts of climate change and extreme weather events and enable two-way power flows. Using LiDAR data, the twin provides a full 3D virtual model of the network and processes large amounts of data quickly to enable better, faster and more accurate engineering decisions. This includes better assessing the bushfire risk associated with 12,000km of power lines and 160,000 poles. In March 2022 we were able to simulate the impact of major flooding in the Hawkesbury and Nepean River catchments to help restore power to affected customers in a safe and timely manner. This saved 300 hours of inspection time compared to having to wait for flood water to recede and visual inspections to occur.
Bawley Point/ Kioloa Microgrid	Bawley Point and Kioloa customers, living at the edge of the traditional grid and recently bushfire affected, needed more resilient, reliable and sustainable energy supply. This demand came off the back of a challenging few years for the regional community, which had faced regular power outages due to bushfires, storms and population spikes during holiday periods, placing strain on their regular electricity supply. In a first for Endeavour Energy, we collaborated with local residents, businesses and Shoalhaven City Council to design a community microgrid to generate a renewable and reliable electricity supply which will reduce the frequency of outages and improve the community's resilience. As part of our commitment to keep customer voices central to our plans for the future, we established a Community Reference Group to serve as a sounding board for community issues and ideas. We also collaborated with customers to have their say by attending regular community workshops or via our online engagement portal. Significantly, the community is also seeking to contribute to sustainable goals around reducing their carbon footprint and being part of a program to build the greater good. This innovation will change the way we design the grid of the future for remote communities.

Initiatives/Programme	Programme Description
Grid transformation and future network initiatives	Covers a range of initiatives including: • Conservation voltage optimisation – enabling a solar hosting profile in various zones to reduce solar energy challenges • Project Ikea – implementing quicker turn-around modular and digital substations to service growth more efficiently • Grid automation – implementing automated switches to increase outage optimisation • Grid support battery – Trialling battery projects with partners to increase resilience and reliability • Community battery network support – partnering with third parties to investigate options to install smart grid batteries in neighbourhoods to support the network, and providing shared access to customers for storage of rooftop solar generation • Standalone power systems – Engaging with partners to promote distributed energy and resilience in remote areas of the network
Electric Vehicle partnership	In supporting the uptake of EVs across our network in 2022 we entered a partnership with JOLT to build a network of free and fast electric vehicle charging stations across Western Sydney. More than 100 EV charging stations will be installed on existing Endeavour Energy streetside substations by 2025 with the number expanding to more than 1,000 chargers over the next decade throughout the partnership. Providing free charging in more urban locations will allow more people into the EV market, breaking down the key barriers to EV adoption and helping our customers to realise the benefits of a greener future.
Demand management testing	We have developed a New Technology Master Plan (NTMP) tool in collaboration with ENEA to develop a more proactive approach to the efficient use of non-network solutions to alleviate network constraints and respond to network needs. This tool integrates existing network data and enables the efficient exploration of the net-benefits (from a customer's perspective) of various non-network solutions at a pre-feasibility stage, considering the various uncertainties and sensitivities. The NTMP tool furnishes Endeavour Energy with the knowledge and business capabilities that will allow for the effective identification of new technology options (as potential non-network options).

Our 2024-29 proposal builds off these innovations and includes a proposal for an Innovation Fund in recognition of the unprecedented technological growth and change occurring in the industry and the desire from our customers to see Endeavour Energy support this transition. See Chapter 9 for further details.

3.4 Safety and Sustainability

There is nothing more important to us than the safety of our workers and the community, but we also have to balance this with affordability. This does not mean we cut corners. We foster a proactive and consistent approach to hazard identification, risk assessment and the effective management of risk through the implementation of preventative controls and actions. While customers have told us that supporting the energy transition, improving network resilience and affordability are their primary concern, they see safety and reliability as a given that we must deliver against.

3.4.1 Electrical safety

Every day our people perform work that has the potential to be hazardous. The inadvertent and uncontrolled discharge of electricity from our network remains the highest consequence hazard for our network and presents a risk to which our employees and the public are constantly exposed. To mitigate electrical risks, workplace instructions and processes have been developed to preserve safety above all other considerations, and without exception.

Electrical safety awareness is embedded through a set of mandatory safety rules called the Rules We Live By. Developed with direct input from frontline workers across our business, this sets out the core rules our workers must follow and use to prevent serious injury or fatality when they perform work involving a network fatal risk. As a key component of our Network Fatal Risk Program, the Rules We Live By aims to minimise high consequence, low frequency life-changing events that have the potential to result in loss of life or permanent disabilities.

Safety is also a key consideration in our asset management decisions. We undertake inspections and monitor our assets carefully to identify signs of impending failure which may result in danger to property or people. Bushfire risk is managed through targeted asset replacements and relocations; a program of pre-summer bushfire inspections and an extensive vegetation management program.

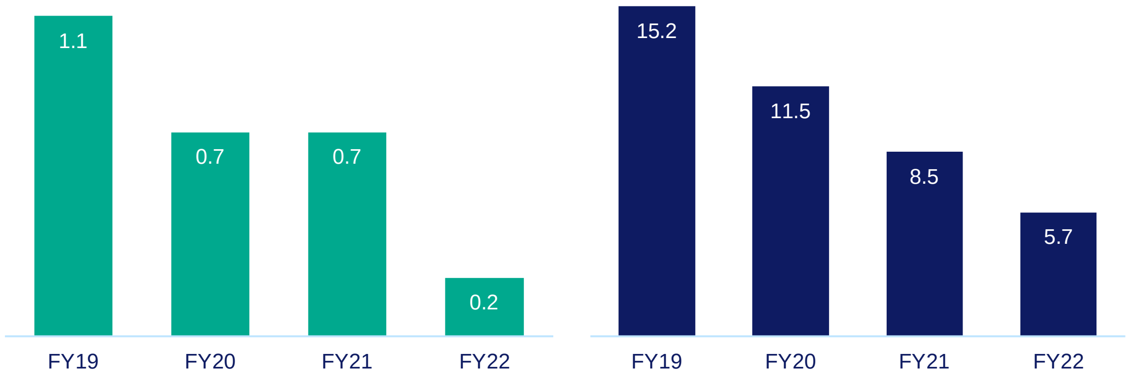
We also run electrical safety awareness programs to educate the community and our customers of the dangers associated with electricity. We design programs to create greater awareness of electrical safety based on an analysis of safety incidents involving our network and relevant data sources. Resources are made available to our customers, mainly through our website and highlight the dangers posed by electricity in many everyday situations and scenarios. We provide suggestions for preventative action and instructions on what to do during an incident.

3.4.2 Workplace safety

Whilst negotiating a period of significant organisational change, we have maintained our focus on improving safety performance in the workplace and maintained a continuing trend of improvements against the standard industry key performance indicators.

- Lost time injury (LTI): a work injury that results in the inability of the employee to work for at least one full day or shift.
- Total recordable injuries (TRI): an incident which resulted in a fatality, lost time injury, medical treatment injury and/or restricted work cases.
- Frequency rate (FR): the number of occurrences of injury or disease for each one million hours worked.

Figure 3-7 Endeavour Energy lost time injury frequency rate (LTIFR) and total recordable injuries frequency rate (TRIFR) FY19-FY22



Endeavour Energy's safety journey is one of growth and continuous improvement, underpinned by the following key strategic initiatives focus areas:

- Leadership & Culture
- Fatality & Injury Prevention
- Health & Wellbeing
- Systems, Analytics & Processes
- Sustainability

Whilst the measures above are widely recognised, we are also focusing on a number of leading indicators including safety chats, near miss reports, hazard reports and fatal risk control checks. In addition, health and safety legislative requirements are actively monitored and included into updated policies, procedures and processes where required along with regular independent audits.

Endeavour Energy's excellent health and safety performance reflects the priority assigned to this area by the Board, management and workers as well as the ongoing development of Endeavour Energy's culture and health and safety management system. This improvement was recently recognised with Endeavour Energy winning the 2022 Australian Institute of Health & Safety Excellence Award for outstanding Safety Leadership & Culture.

3.4.3 Sustainability

Endeavour Energy has been committed to sustainability, driving value beyond compliance for environmental and social impacts. We have prioritised emission reduction projects for many years, supported broader clean energy transition technology upgrades, social impact and community focussed programs as well as founding signatory of the Energy Charter. We welcome both the opportunity and challenge to lead the shift from a traditional electricity network to a smarter, cleaner and more efficient energy system.

Over the 2019-24 period we launched our new Sustainability Strategy which focuses on material issues of climate, resilience, nature, circularity, well-being and inclusion. For each of the areas of focus where we can have the most impact, we have set clear priorities and short, medium and long-term targets. Our focus is in in three areas:

- **Renewable Revolution** – creating a modern, clean energy grid that keeps everyone reliably connected.
- **Regenerative Economy** - Working towards a circular economy that recovers resources and protects the planet.
- **Resilient Communities** – Ensuring health, wellbeing and inclusion for our people and communities.

We have committed to:

- 40% emissions reduction by 2030 (excluding line losses and against FY21 baseline); 100% new fleet by 2030 where it is economic to do so, and all fleet by 2040 be zero emissions; aim to connect 590,000 solar systems and batteries by 2030. Also strive to be climate positive by 2040 which means net zero for our own footprint and supporting the community to reduce their emissions
- Nature positive by 2050, planting more vegetation than we remove
- 90% waste diverted from landfill by 2025 and waste neutral by 2030, also engaging suppliers to improve material circularity across our supply chain
- 97% employee participation in our bespoke wellbeing program by 2025 and continue and measure investment of social impact programs
- Being an employer of choice for a diverse workforce; focussing on women in leadership, gender balance in apprenticeship intake and deliver our Reconciliation Actions Plans

In addition to the societal and environmental benefits our sustainability strategy promotes, we consider our efforts will promote financial and operational benefits for our customers as well, such as:

- Improved financial and nonfinancial performance.
- Increase in operational efficiency and risk mitigation.
- Improved supply chain reliability and security.
- Increased access to capital through ESG Investing and Sustainability-linked credit.

On the latter, in 2021, via our financing entity, we signed a landmark five-year sustainability-linked loan (SLL) facility, becoming the first known DNSP in Australia to access sustainability linked financing. The funds raised under the sustainability-linked loan can be used for general corporate purposes, however, the pricing of the loan is tied to achieving a set of agreed sustainability performance targets focused on four areas including greenhouse gas emissions reduction, landfill waste diversion, net habitat gain and mental health and wellbeing. The mechanism causes a direct link to financial loss or gain from our commitment to meeting sustainability targets[7].

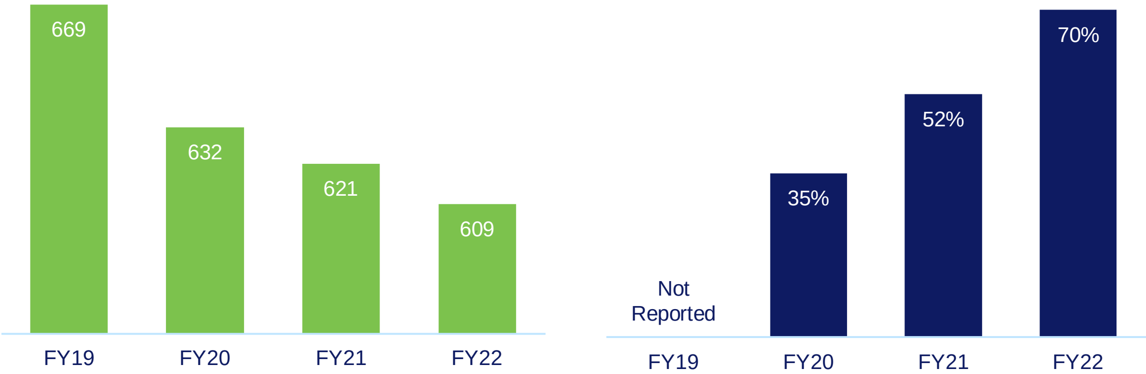
We will continue to integrate sustainability into our strategy, activities, decision making processes and aim to become an industry leader in driving sustainability outcomes. To assess this, we align to multiple international frameworks and benchmarks that promote sustainability, including:

- United Nationals Sustainable Development Goals
- National Greenhouse and Energy Reporting (NGER)
- GRESB global environmental, social and governance (ESG) benchmarking
- The Energy Charter

As a result, we have been making significant progress against some of our key focus areas over the last few years.

[7] Noting that the AER sets a benchmark Rate of Return for setting our revenue. This means our investors bear the risk/reward of any under/over performance against this benchmark in accordance with the incentive regulatory framework.

Figure 3-8 Greenhouse Gas Emissions (GHG) (kt CO2-e) and Landfill diversion rate FY19-FY22

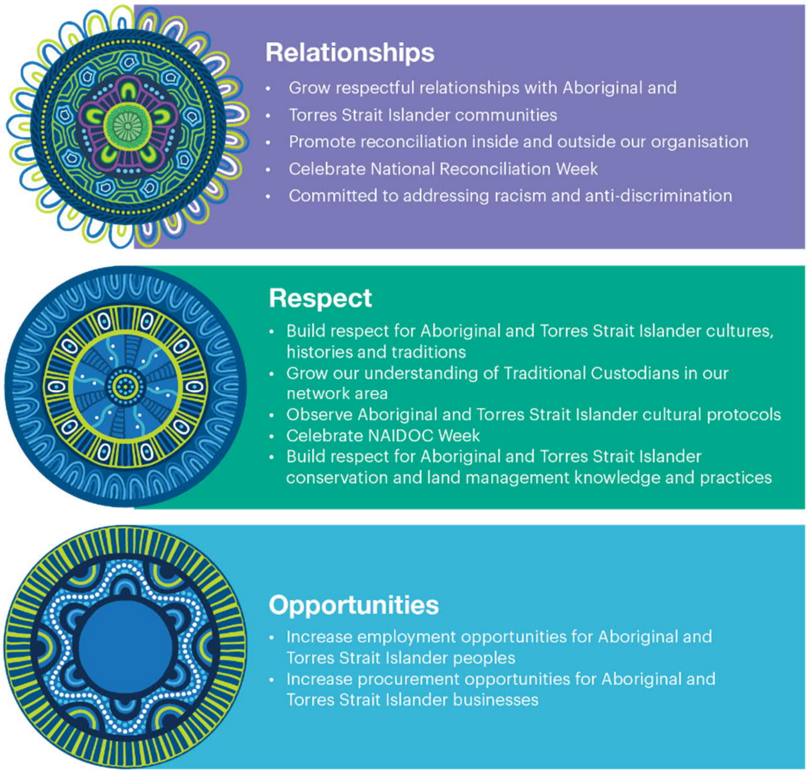


Also, in the last two years we have achieved a five-star rating GRESB assessment with a score of 97% in 2022 and 95% in 2021 with Endeavour Energy ranked amongst the top 5% of global respondents. This represented a significant improvement from previous scores that we aim to maintain and further improve upon, continuously aligning to industry best practice frameworks.

3.4.4 Reconciliation

In 2021 we launched our first Reconciliation Action Plan (RAP), which outlines our commitment to reconciliation and supports building relationships, respect and opportunities for Aboriginal and Torres Strait Islander peoples and communities. It inspires our efforts to strengthen our community relationships and promote respect for Aboriginal and Torres Strait Islander peoples, cultures and traditions.

Figure 3-9 Endeavour Energy RAP



As an essential services provider operating in high-growth regions of New South Wales, we are well-positioned to deliver impactful and sustainable actions towards reconciliation.

The majority of our people live and work in the communities we serve, which provides us with a unique opportunity to create and strengthen meaningful relationships.

Endeavour Energy has embarked on a foundational Reflect RAP which includes practical actions to help drive our contribution to reconciliation within our organisation and in the communities in which we operate. Committing to a Reflect RAP allowed us to spend time developing relationships with Aboriginal and Torres Strait Islander stakeholders, exploring our sphere of influence and shaping our vision for reconciliation. This process has provided solid foundations to ensure our future RAPs are meaningful, mutually beneficial and sustainable. Endeavour Energy plans to launch its second RAP (an Innovate RAP) in the second quarter of 2023.

3.5 Reliability, Resilience and Customer Service

Most of Endeavour Energy's customers agree that they enjoy high levels of reliability and have told us they do not want to pay more for reliability improvements, nor do they want to pay less if it meant a poorer standard of reliability. We invest to ensure our network delivers the level of reliability our customers expect that meets minimum licence conditions in the most efficient way.

3.5.1 Reliability

Service reliability is often impacted by a combination of internal and external events. Our inability to directly control many of these factors means that some level of unplanned interruption is likely to be experienced somewhere on our vast network each year.

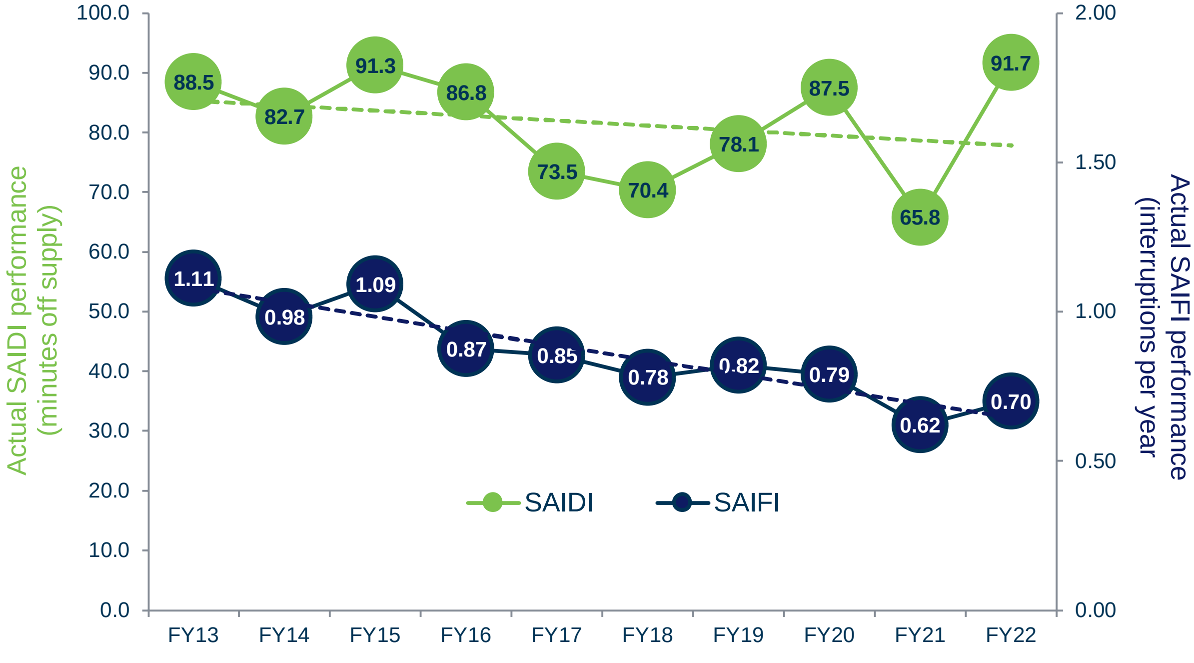
During the current regulatory period, our customers expected that reliability would be maintained at existing levels, and this has largely been achieved by providing a stable and reliable service within licence conditions that is reflective of the expectations of our customers.

Maintaining reliability has required investment to manage both the risk of failure from assets whose age and condition suggest they are at the end of their useful life, and the demands of a rapidly growing population.

This has been done in the most efficient way possible to deliver improvements in affordability while maintaining the network's reliability and resilience towards achieving the optimal service/price mix. The AER recognises that we should seek to maintain or improve reliability, but any improvements should be efficient. To support efficient reliability management, the AER has implemented the STPIS.

The STPIS ensures cost efficiencies encouraged by the EBSS and CESS are not made at the expense of supply reliability and customer service quality. The STPIS also provides capped incentive payments that are used to pay for reliability improvements. This cap ensures that we only invest in improvements that deliver actual improvements of value to customers without over investing.

Figure 3-10 Endeavour Energy normalised reliability performance FY13-FY22



3.5.2 Resilience

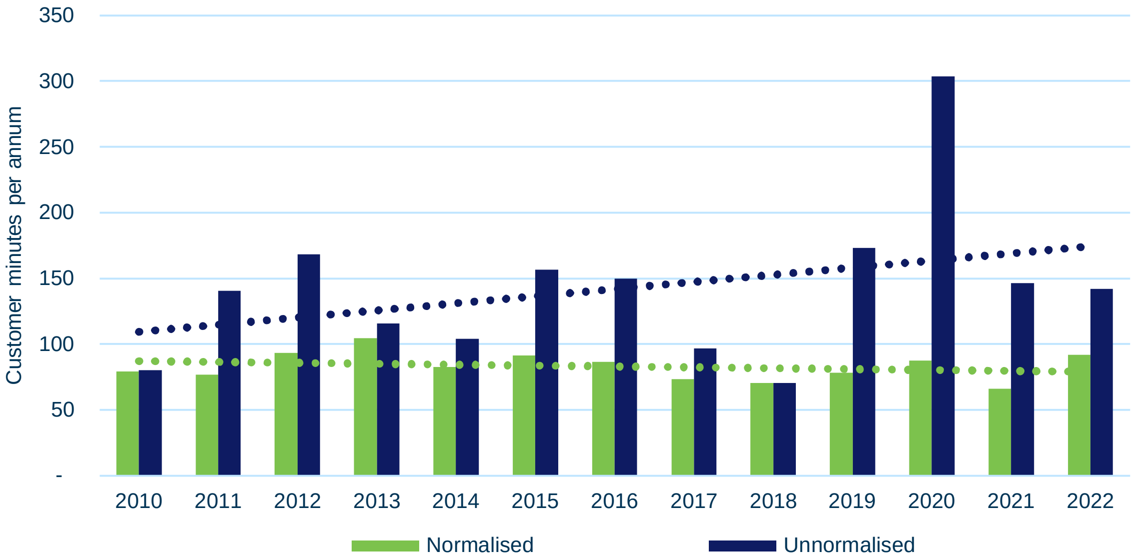
The resilience of an energy system or network is a characteristic of good energy system planning practices, asset management and an increasingly important topic in the NEM and globally. We define resilience as the ability to anticipate, withstand, quickly recover, and learn from major disruptive events. This means improving reliability will not necessarily improve resilience. Nevertheless, these are not discrete concepts but are instead related, interdependent, and overlapping.

Table 3-4 Overview of Endeavour Energy's approach to resilience and reliability

	Resilience	Reliability
Definition	The ability to anticipate, withstand, quickly recover and learn from disruptive events	To reduce the frequency and duration of planned and unplanned network outages
Focus of Initiative	Network and Community performance factoring in major events	Performance not factoring in major events (out of the control of the DNSP)
Type of Approach	Combination of Proactive and Responsive	Predominately Post-event analysis
How it is measured	Electrical Network Resilience – Un-normalised SAIDI Community Resilience – no defined measure	Normalised SAIDI/SAIFI

This relationship can best be observed in comparing normalised SAIDI/SAIFI[8] to un-normalised performance. The latter is inclusive of the impacts of major disruptive events (like storms, floods and bushfires) and whilst it reflects factors outside of our control it also reflects the felt experience of our customers:

Figure 3-11 Endeavour Energy average unplanned customer minutes without supply FY10-FY22

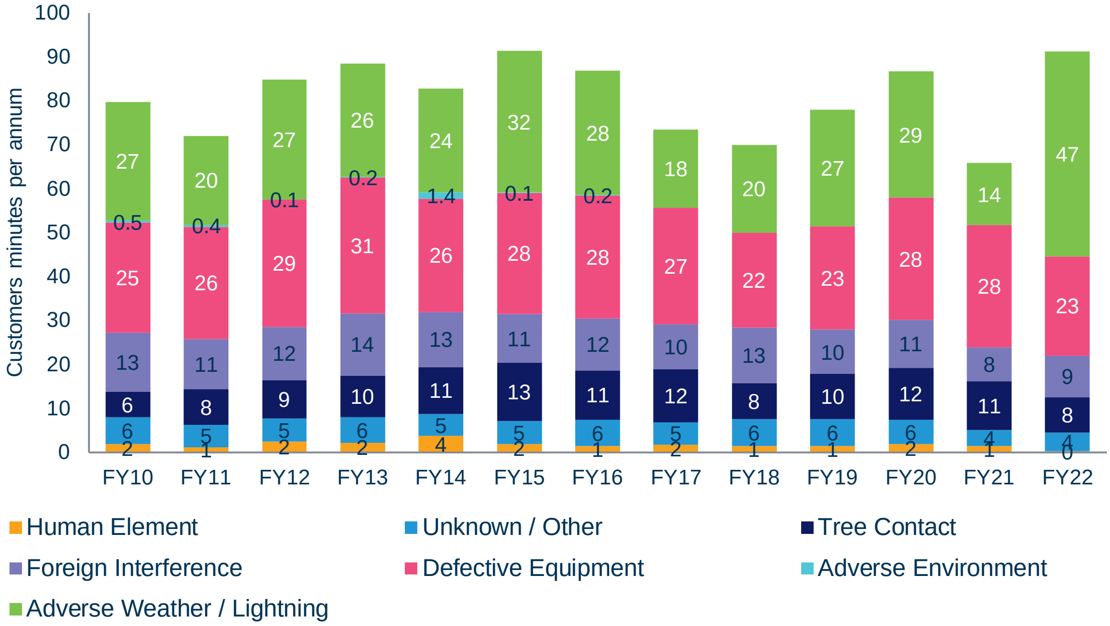


The growing gap between these measures has been driven by the increasingly severe and frequent major weather events, although it is important to note that weather events still impact our 'normalised results'. The normalised results remove the impacts of major disruptive events meaning that weather events that fall below the threshold of extreme are included in our incentivised reliability performance.

The impacts of worsening weather help explain our most recent (FY22) reliability performance, our worst result in over a decade at over 92 minutes per customer on average compared to 66 minutes in FY21. This is despite an improving trend in the factors within our control, such as managing defective equipment, due to an unprecedented increase in adverse weather driven outages.

[8] System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI)

Figure 3-12 Endeavour Energy average unplanned customer minutes without supply FY10-FY22 by cause.



3.5.3 Customer service

The customer service component of the STPIS relates to answering emergency telephone calls within 30 seconds. This measure has been in place since the original STPIS and reflects the importance of receiving timely and accurate information from networks, particularly about unplanned interruptions. Over the 2019-24 period we expect to materially out-perform the 81.4% target with average performance to date at 85.9%

However, we maintain our view expressed in the 2019-24 Proposal that this measure of customer service is, while important, antiquated and narrow. We note several networks have proposed to replace and/or complement this measure with other measures of customer service as part of a bespoke Customer Service Incentive Scheme (CSIS). We intend to propose a CSIS for the 2024-29 period to reflect our broader and sincere commitment to improving the customer experience in a range of areas. See Chapter 9 for further detail.

During the 2019-24 period, we have significantly improved and expanded our business-as-usual (BAU) engagement program which features ongoing listening to customer and stakeholder segments and deep analysis of insights and trends which drive innovation and improved processes.

This has involved several customer focused initiatives aimed at improving our service quality which our Board monitor on a monthly basis:

- Organisational strategy, purpose and key performance metrics: we have revised our organisational strategy, purpose and vision to place customers at the heart of our decision making and priorities. This includes incorporating measures of Customer Satisfaction (CSat) as a key organisation wide performance metric.
- Customer Journey mapping: in 2020-2021 we conducted a detailed review of our connections, complaints, claims, outage and disconnection processes from a customer perspective to identify common pain points and opportunities for improvement.
- Voice of Customer (VoC) program: in 2021, we commenced real time digital customer surveying via SMS to replace previous phone surveys to enable broader customer coverage and more timely insights. By way of example, in January and February 2022 we received 3 times the amount of feedback responses as our prior method related to incidents within the last 7 days as opposed to a 2 month + lag. The surveys, designed in consultation with a Peak Customer and Stakeholder Committee (PCSC) interface to an online analytical platform which provides easily extracted customer feedback and details insights.

- Customer advocacy system (CAS): in 2021 we commenced implementation of a CAS to replace multiple legacy systems for complaint management allowing us to better understand our customers, make smarter, quicker decisions, and centrally manage all complaints for transparency, consistency and seamless case management.
- Reputation surveys: to better understand customer and stakeholder expectations and their perceptions of Endeavour Energy in support of continuous improvement and customer centricity we have implemented reputational surveying. We now commission surveys to measure our reputation among key stakeholders annually and customers monthly. This provides actionable insights to inform BAU communications and engagement strategy.
- New connections process: we have greatly enhanced customer experience when connecting to the network by digitising processes and creating self-service capability.
- New disconnections process: we have successfully trialled a ‘knock-before-disconnect’ program to encourage customers in financial stress to contact their retailer and avoid over 47% of disconnections. In FY22, 2,151 customers avoided disconnection due to this innovation.
- New Customer Experience Team: we re-structured our customer experience team to increase our contact centre and experience expertise and introduce a social programs team. Our social programs lead will oversee customer support programs and develop further initiatives for customer facing vulnerable circumstances.
- New website: in 2021 we launched our new website designed to provide an enhanced user experience and better information presentation, including a map view of outages within the network.
- Incident response and notification: we have sought to continually improve our management and communication of outages. This includes implementing a customer liaison function during the 2021 and 2022 Flood Responses and implementing a Customer Assistance Package to help customers and communities get back on their feet[9]. We have also implemented a customer notification system to automate messaging regarded planned and unplanned outages events.

As noted above, we remain committed to being a customer-centric organisation that prioritises the interests and needs of our customers. Our CSIS proposal, Attachment 9.02, reflects our ambition to strengthen and broaden our commitment to continuous improvement in customer service.

[9] This program included undertaking free inspections of meter boards to determine if safe to reconnect, waiving all application, site establishment and electrical contractor fees for customers reconnecting and pausing disconnections and follow up on private powerline defects.

4. Our Operating Environment

4.1 Overview

Never before has the community been so focused on the affordability, resilience, reliability, sustainability and security of their electricity service, as the energy industry in Australia undergoes a dramatic transformation. We're committed to efficient investment and giving customers more choice and control.

The challenges to providing a safe, reliable and affordable service are evolving as the NEM is impacted by decarbonisation, decentralised generation and changing energy consumption patterns. We must evolve to keep pace with these trends in order to meet the expectations of our customers into the future.

There are seven key trends shaping our current and future operational landscape. These are:

- **Customer centrality:** A focus on customers' needs and experiences from high energy users to pensioners to empowered prosumers means customers play a more central role in the operation of the network as networks evolve to be platforms of energy services. Underpinned by new technologies, customer expectations and service needs will evolve. Customers will expect to help shape the direction of the business through deep engagement on regulatory proposals and beyond.
- **Trust, reputation and purpose**: The reliable delivery of an affordable crucial service underpins trust and is core to our purpose. Customers also increasingly expect organisations to align with personal and community values for environmental and social governance (ESG). Purposeful decision making, with an emphasis on ESG outcomes, will be essential to retain social licence, attract investment, and to establish and maintain a high-performance culture.
- **Western Sydney regional growth:** The NSW Government is driving the substantial and rapid growth of Western Sydney, at a rate nearly 40% higher than the rest of Metropolitan Sydney. By 2036, half of Sydney's population will reside within the city's west, supporting a new international airport, new industry and manufacturing, and a new science park. This plan is akin to building a new city, from scratch.
- **Economic volatility and cost of living pressures:** International and domestic developments have contributed to rapidly rising inflationary pressures, including in energy prices, with rising concerns about a possible slowdown in the Australian economy. Cost of living pressures are increasingly centre of mind now for all customers small and large. Transitioning the grid to ensure long term value for money services as customers make energy choices in the most efficient way requires balancing in the short and long-term.
- **Climate change and extreme weather events:** Climate modelling suggests that extreme weather events will continue to increase in both frequency and intensity over the coming decades. Climate change-related events damage, destroy and/or compromise the performance of infrastructure, and increase risks to the reliable supply of electricity.
- **A changing grid in a low carbon economy:** The pursuit of a net zero economy will transform the way we generate and consume energy. As customers take up technologies such as solar, batteries and electric vehicles, the network will need to evolve to allow for two-way flows and active participation from customers and third parties. Over time, more sophisticated digital platforms will seek to interact with a more dynamic, integrated network that orchestrates the low carbon energy system.
- **Efficient and effective service in the digital age**: Introduction of digital technologies and enhanced data capabilities create significant operational efficiencies, while transforming the risk,

roles, required skills and location of the future workforce. At the same time, cyber-attacks will become more frequent and sophisticated, targeted at the disruption of energy supply.

With these external factors and based on our deep engagement with customers discussed further in chapter 5, we co-designed our priority investment themes in the long term interests of our customers, as shown in the figure below. There have also been several significant developments globally, nationally and within the industry that have shaped our engagement program and this Proposal. We provide more detail on these key trends and events and the implications for Endeavour Energy.

Figure 4-1 Customer priority investment themes

4.2 Customer Centricity

A deep and broad understanding of all customers' expectations and views is increasingly central to investment and operational improvement. Customers will help shape the direction of business through deep engagement on our regulatory proposal and investment decisions. To ensure we continue to meet the needs of all customers we will focus on:

- **Informing investments and approaches:** For networks and network regulators, understanding the evolving expectations and preferences of customers will allow networks and regulators to find the best options and approaches for investment planning. This will include increased transparency and more open conversations with customers and focus on equity and the need to ensure no customer is left behind.
- **Setting customer priorities and service levels:** Increasingly customers expect personalised and timely services, seamless transactions and accurate information. With an understanding of needs and expectations, the business can focus on higher-value services, and reduce effort and spend on services that are less of a priority.
- **Creating operational efficiency:** The use of data to improve operational decision-making and deliver improved service will become the hallmark of the efficient network business.

Our understanding of these benefits is driving Endeavour Energy to provide genuine, early and regular consideration of the unique and evolving needs of our customers.

Implications for Endeavour Energy and this Proposal:

Where and how Endeavour Energy invest in the Future Network will be shaped by customer support for our role.

A deep and broad understanding of all customers' expectations and views is increasingly central to investment and operational improvement.

The community will inform our approach to improving the resilience of the network, and how investments in this are prioritised with investment in other areas.

4.3 Trust, reputation and purpose

As an active and high-profile member of the community it is essential for us to retain our social licence, attract investment, and to establish and maintain a high-performance culture. In doing so, our priorities are:

- **Increasing focus on ESG**: Corporate social responsibility (CSR) and the analysis of ESG performance is already becoming a fundamental driver of investment (both by shareholders and/or customers into companies and services, and companies into actions). Involvement in social and sustainability endeavours, and a consistent demonstration that these principles are front-of-mind in decision-making, will form a key component of how a social licence will operate, and the ability to attract and retain talented staff. Our customers will expect this.
- **Ensuring we attract and retain our talented people**: Empowerment and flexibility have already become the ‘battleground’ for talent. People want meaningful work, they demand a say in the direction of the organisation, they are constantly checking the alignment of their values with their employers and are increasingly seeking more flexible ways of working.

Looking forward, the way that Endeavour Energy approaches its investment priorities, decision-making and how it engages around this, will need to be fundamentally values driven. Importantly, it demands an ‘outside-in’ and transparent approach to being involved in, listening to and acting on engagement with our community, customer and employees

Implications for Endeavour Energy and this Proposal:

Active contribution to ESG goals and the community in which we operate is an important part of meeting our customers evolving expectations

As part of our ESG commitment, we will need to ensure we facilitate growth in the most sustainable way possible

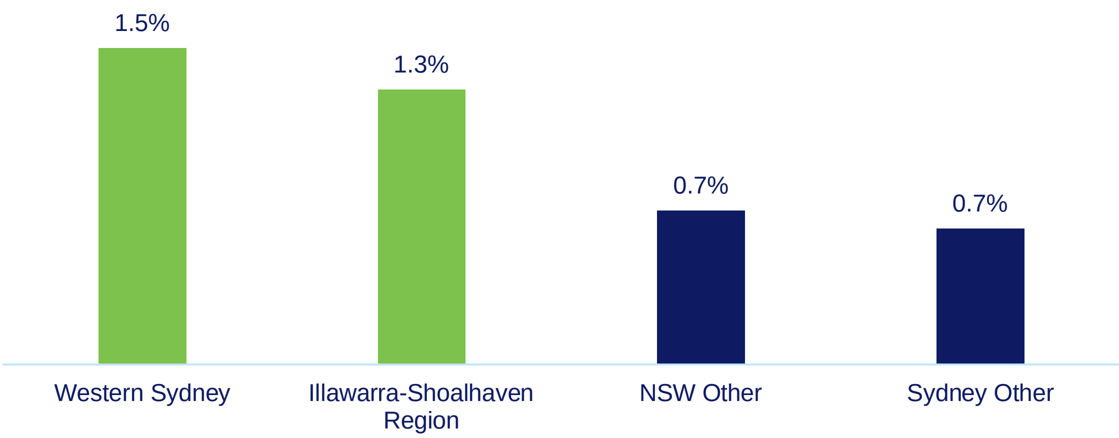
4.4 Western Sydney regional growth

NSW population and industrial growth has focused on the urban expansion of Sydney's Greater West. This strategic expansion will drive the substantial and rapid growth of the region, at a rate nearly 40% higher than the rest of Metropolitan Sydney. By 2036, half of Sydney's population will reside within the city's west, centred around new 'satellite cities'. Projections suggest the need for an additional 725,000 dwellings into the future, in a region that is also planned to cater for a new international airport, new industry, rejuvenation of manufacturing, and a science park. We will be part of building a new city, from scratch.

Endeavour Energy is responsible for the expansion of the distribution network to facilitate this growth and industry, and to support the NSW Government's planning and development of liveable, productive and sustainable communities that thrive. This focus has been a driver of our investment for several years and it will continue to be in the foreseeable future. To continue to accommodate this growth, new networks must be planned and delivered in a way that both facilitates this vision and futureproofs the network. For residents, small and large business and emerging needs such as datacentres and hydrogen hubs. This requires a focus on:

- **Planning for the future:** This predicted expansion of the asset base is occurring at the same time as the changing nature of the grid. Endeavour Energy will need to work with developers and Governments to ensure greenfield developments are future-proofed, efficient and remain cost-effective.
- **Ensuring network infrastructure is not a barrier to growth:** The roll-out of new infrastructure across Western Sydney will require significant investment, and the expansion cannot occur without this supporting infrastructure in place. Endeavour Energy will need to work with the Government to ensure the infrastructure expansion meets the growth of the of the community.

Figure 4-2 Population Growth in key franchise areas (2022-2041)



In supporting the sustainable growth of the Western Sydney community, we must also continue to deliver value for our existing customers. It is important that the costs and benefits of expanding the network are shared equitably through our connection charges and ongoing tariffs.

Implications for Endeavour Energy and this Proposal:

- Expansion should be future proofed, taking up opportunity for new approaches and the network has the capacity to provide access to emerging technologies
- Investment is needed to sustainably and equitably support the growth of the Western Sydney and the Illawarra-Shoalhaven Region while continuing to deliver for our existing customers

4.5 Economic volatility and cost of living pressures

International and domestic developments have contributed to rapidly rising inflationary pressures, central bank decisions to then respond with interest rate rises and increased concern about a possible slowdown in the Australian economy are impacting our operating environment. Events in Ukraine and local factors in the National Electricity Market (NEM) have contributed to supply chain challenges, wages pressure and significant rises in energy prices for Endeavour Energy customers. Cost of living pressures are increasingly centre-of-mind now for all customers small and large.

Achieving an efficient balance between cost and service quality requires risk to be managed by the party best equipped to do so. For Endeavour Energy, that means improving our service quality, especially in targeted areas most valued by customers, within a constrained budget through innovation ('finding a better way') and productivity improvements ('doing more with less'). Achieving this balance is also central to developing a proposal that represents value for money for customers and promotes their long-term interests.

Energy affordability has been the dominant theme of the last decade following increases in distribution charges and the introduction of jurisdictional green schemes during the 2009-14 period. These increases coincided with the Global Financial Crisis and were followed by increases in the retail and generation component of bills for several years.

Our customers acutely felt the impacts of these increases and it became a clear priority to resolve. We have worked hard to reduce our contribution to energy bills over the last decade through improving our productivity. This has led to Endeavour Energy's distribution charges ranking amongst the lowest in the NEM.

We have been preparing our Proposal over the last two years and during this time we have observed the emergence of several challenges and threats to the downward trend in energy prices over the last several years.

These trends impact the cost of doing business, energy costs themselves and financing costs which are a substantive portion of our costs as an operator of a large infrastructure asset base.

4.5.1 International factors

The global COVID-19 pandemic has continued to impact NSW, Australia and internationally and society has continued to adjust to this unfortunate reality in how they live and work. While many industries and businesses have been negatively impacted by the pandemic, as an essential service provider, Endeavour Energy has seen an increase in the dependence on its service.

Notwithstanding changes in public health orders relating to lockdowns and isolation rules, people continue to work from home, such that the reliance on reliable and quality electricity supply remains high. In addition, Federal and State Governments have implemented a number of economic stimulus measures to support ongoing activity in the building and infrastructure sector.

Endeavour Energy, and its staff, continue to meet the challenge of operating and maintaining the network throughout the pandemic. As a result of COVID-19, the cost of doing business has increased. For Endeavour Energy, this involves managing staff unavailability, providing a safe work environment, prioritising critical work, and adjusting to global and domestic supply chain shortages for materials.

The ongoing war in Ukraine has further contributed to increasing prices, delays and shortages in key materials affecting both our customers and our own activities. This conflict has driven and exacerbated a downturn in economic activity. Together, these impacts have increased the complexity of operating the network to service growth and maintain a safe and reliable service in an affordable way.

In the early part of the current regulatory period these challenges, along with the need to manage frequent natural disaster events, led to an underspend of our capital allowance. However, as we and our customers become more accustomed to these issues we have adapted and improved our capacity to deliver our services. As a result, in FY22 Endeavour Energy was able to deliver a significant increase in budgeted spend to address early period deferrals and continue to service the ongoing accelerating growth across our network.

4.5.2 NEM 'Energy Crisis'

The need for these national and state reforms was highlighted in recent months by the 'energy crisis' that occurred between 10 June 2022 and 24 June 2022. On 15 June 2022, AEMO announced the suspension of the wholesale electricity spot market which lasted until 24 June 2022. This followed an extreme surge in wholesale prices due to:

- high coal and gas prices driven by the war in Ukraine;
- almost a quarter of NEM-wide coal power stations being unavailable due to scheduled maintenance and the unexpected exit of 3,000 MW due to unplanned outages; and
- high demand due to the coldest winter start in over a century.

To ensure there would be enough supply to meet demand, AEMO directed 5GW of generation through direct interventions on 14 June 2022 before then suspending the wholesale market and setting a price cap at $300 per MWh the next day.

In addition to the factors above, the energy crisis has highlighted the need for clear and consistent energy policy in Australia to facilitate an efficient transition to renewable energy sources. AEMO has released a report on the incident with several recommendations[10].

At the same time of the risk of widespread outages in NSW, increasing electricity prices in NSW from 1 July 2022 were also national news[11]. Driven by network and wholesale market factors the AER announced increases in its Default Market Offer (DMO) across the NEM. For NSW customers, prices were forecast to increase by 9% to 18% (between $210 and $369 annually).

Our peak period of engagement occurred during this unprecedented crisis, including holding a Customer Forum on 15 June 2022, the very night the market was suspended. At this time, our customers were acutely aware of increasing electricity prices and the risk of widespread outages. As noted by the Independent Members Panel of our RRG, this awareness is now translating into actual experience of these changes over time as energy price increases appear on customer bills. We discuss our engagement approach and findings in relation to this issue in more detail in the following chapter.

4.5.3 Global economic downturn

Due to a confluence of factors, some discussed above, there has been a significant and rapid downturn in the global economy. This can be observed in the inflation projections in the RBA's quarterly Statement of Monetary Policy[12]:

- In November 2021, the inflation outlook was 2.25% by the end of 2022 and 2.5% by the end of 2023.
- In February 2022, the inflation outlook was a forecast peak around 3.25% during 2022 before returning to 2.75%.
- In May 2022, headline inflation was forecast to peak around 6% by the second half of 2022 before returning to the 2-3% target range in 2024.
- In August 2022, inflation was the highest it had been since the early 1990s and expected to reach 7.75% by the end of 2022 before returning to the target range in 2024.
- In November 2022, inflation remains the highest it has been in three decades and is expected to reach around 8% by the end of 2022 with higher electricity and gas prices expected to slow the return of inflation to the target range to 2025.

This trend has been driven by strong demand, supported by monetary and fiscal stimulus as part of pandemic economic recovery measures, coming up against rising energy, food, and commodity prices as a result of the war in Ukraine and ongoing pandemic driven supply shortages.

[10] AEMO media release
[11] 7News, ABC, 9News
[12] RBA Statement of Monetary Policy

Wage growth has not kept pace with the higher cost of living and rising interest rates. The RRG's report to our Preliminary Proposal (refer Attachment 5.13) provides a useful and detailed overview of several indicators of the changing pressures our customers face and the energy market more specifically[13].

We are mindful that our customers are increasingly vulnerable to electricity prices and require a service from Endeavour Energy that genuinely provides value for money.

4.5.4 Draft 2022 RORI

The largest driver of our revenue requirement is the cost of previous investments. This includes depreciation of our existing assets and a financial return on these investments. The rate of return, set as a Weighted Average Cost of Capital (WACC), is determined by the AER's binding Rate of Return Instrument (RORI) which will be finalised in February 2023. Small changes in the WACC can have a material impact on our revenue requirement. The RORI is therefore closely scrutinised and deeply consulted on by the AER and stakeholders to ensure it sets a return that best promotes the achievement of the NEO.

On 16 June 2022, the AER released its Draft 2022 RORI. The draft maintains most aspects of the AER's 2018 RORI with the notable exception of the term of the risk-free rate used in calculating the return on equity. This has been reduced from 10 years to match the term of the regulatory period (typically 5 years) which in turn requires an update to the Market Risk Premium (MRP).

Collectively, these changes result in marginal changes from the 2018 RORI. However, our concern is that the reduction in equity term is poorly justified, out-of-step with similar national and international regulators and exposes customers and investors to substantial volatility in the long-term.

Of greater consequence from a customer perspective is the change in economic conditions discussed above. Regardless of what term of equity is used, rising interest rates are significantly increasing the cost of debt and the return required by equity investors.

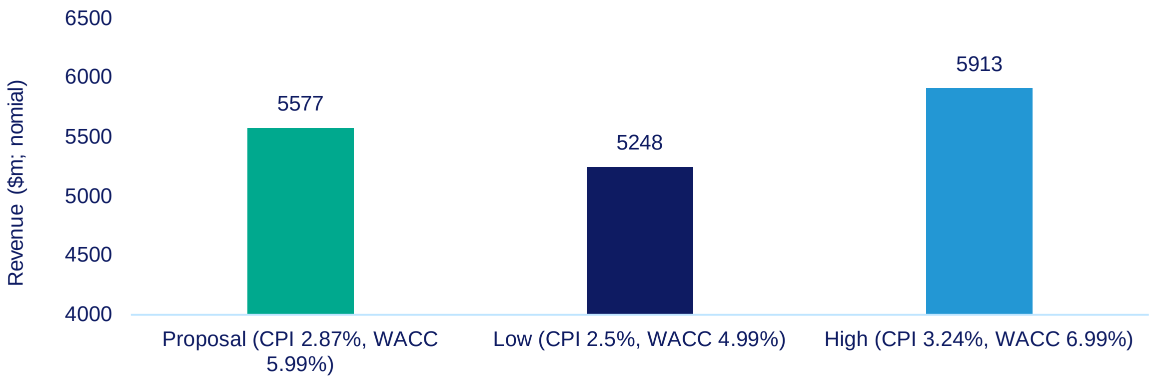
For instance, the yield on 5-year Commonwealth Government Securities (CGS) was 1.40% at the start of 2022 – around the time we started preparing our Preliminary Proposal. As of mid-October 2022, the 5-year CGS yields had increased to over 3.64%.

These market conditions result in a higher WACC which in turn increases our revenue requirement. This is important context for assessing the feedback we received from stakeholders and customers. Similar to the NSW Infrastructure Roadmap and wholesale market costs, any desire for increased expenditure to improve service levels must be weighed against the upward pressure on electricity prices from the WACC and other sources.

4.5.5 Implications for this Proposal

While these factors remain outside of our control, our forecast revenue is sensitive to movements within them. For illustrative purposes, we present our revenue requirements below based on varying market conditions:

Figure 4-3 Endeavour Energy forecast revenue sensitivity to exogenous market conditions



[13] Attachment 5.13 Endeavour Energy Regulatory Reference Group Independent Members' Panel, Advice to Endeavour Energy following the release of the Preliminary Positions Paper, 14 August 2022, pp. 44-49

At the time of our Preliminary Proposal the prevailing market conditions was more reflective of the lower scenario. If this remained the case our proposal would have delivered significant price reductions to customers (in the order of $30-$40 for residential and small business customers over 2024-29).

However, the significant deterioration in market conditions since our Preliminary Proposal has placed upward pressure on our forecast revenue requirement. Collectively, these factors highlight the challenges we face in managing our costs and the financial pressures our customers are becoming increasingly aware of and vulnerable to.

Over the course of our engagement activities customers became increasingly wary of increasing cost of living pressures, with stakeholders expressing particular concern about increases in energy costs that are outside Endeavour Energy's control, including the Rate of Return, Wholesale market volatility and the NSW Renewable Energy Zone (REZ) costs.

These considerations have been front of mind and central to our commitment to developing a Proposal that constrains our expenditure forecasts and promotes prudency and efficiency. We note that the AER's final decision is made in April 2024 and further changes from this January 2023 Proposal will occur.

Implications for Endeavour Energy and this Proposal:

- Increasingly we must balance long-term service outcomes and long-term investment decisions with the shorter-term volatility in economic conditions. This includes a focus on key affordability metrics as a constraint on our overall plans and service outcomes.
- Fairness and equity in pricing or tariffs for new as well as existing services is key, as well as appropriate transition rates to support the orderly empowerment of customers energy choices.

4.6 Climate change and extreme weather events

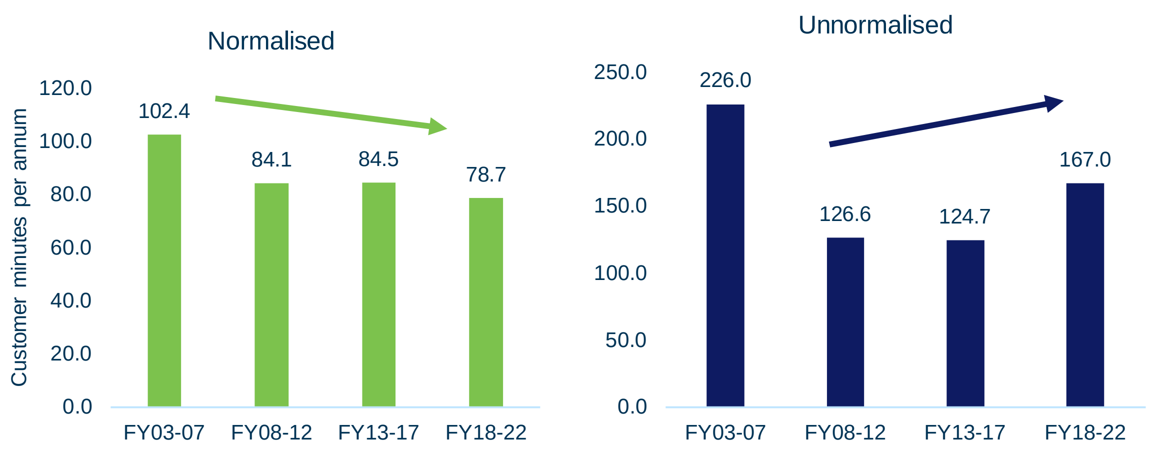
Climate modelling suggests that, regardless of the global action taken to reduce carbon emissions in the coming years, extreme weather events will continue to increase in both frequency and intensity over the coming decades. The risk of bushfires increases as heatwaves become hotter and last longer, and our storms (including East Coast Lows) are expected to increase in frequency and intensity, resulting in more common storm damage and flash flooding.

Climate change events pose a risk to the reliability of the network. Endeavour Energy is experiencing increased impacts from:

- **Bushfires:** The 2019/20 bushfire season was the most devastating in NSW history, impacting 44% of Endeavour Energy's network supply area and causing significant damage to parts of the network at a cost of more than $26.7 million and interrupting services to more than 55,500 across the network.
- **Heat Waves:** By 2030, NSW is expected to experience 10 more days in heatwave each year, with the yearly maximum intensity of heatwaves seeing an increase of ~5˚C. As heatwaves become more common and more severe, the network will be threatened by asset deterioration and reduced system reliability, decreased system capacity and an increased load. With some of the warmest areas in NSW, our ability to reliably deliver electricity through these periods will be increasingly important for customers and reduces risk to life.
- **Storms and Floods:** Like bushfires and heatwaves, severe storms and their associated floods are on the rise and are expected to become a common threat to the network, particularly for non-submersible assets.

While Endeavour Energy has invested in solutions to address our impactable outage times, customers will not experience the benefits due to the impact of major event-related outages.

Figure 4-4 Normalised reliability performance compared to un-normalised performance



A summary of the more notable events we have managed over the 2019-24 period to date is provided below.

The 2019-20 Bushfire Season

The 2019-2020 bushfire season was the worst bushfire season in NSW history. A confluence of factors including a prolonged period of hot weather without significant rainfall (with 98% of NSW being drought affected at the time) provided the catalyst for an unprecedented level of bushfire activity across the State. The NSW Rural Fire Service (RFS) reported that 11,264 bush and grass fires burnt 5.5 million hectares or 6.2% of the State, destroyed 2,448 homes and claimed 25 lives over this period. The area burnt in NSW was three times larger than in any other bushfire season.

The catastrophic nature of the bushfires and the threat encountered by several towns and communities across the State led to the NSW Government declaring a State of Emergency on three separate occasions. Each declaration was in force for a week, and it was the first time a State of

Emergency had been made in NSW since October 2013. On announcing the third State of Emergency on 2 January 2020, NSW Premier Gladys Berejiklian stated[14]:

> *Declaring this State of Emergency is vital to the safety of communities in NSW as we face the most devastating bushfire season in living memory.*

The bushfires ultimately burnt through approximately 11,000 km² or 44% of our network area. The fires either damaged or destroyed 840 homes and businesses connected to the network and interrupted supply to over 55,000 customers. Approximately 20,000 customers were without power at the peak of the bushfires during the New Year period, mostly in communities in the Shoalhaven and NSW South Coast.

The worst affected areas saw some customers without power for more than 10 days as Endeavour Energy crews worked through challenging conditions to rebuild large sections of the network in the Blue Mountains, the Southern Highlands and the Shoalhaven/South Coast districts. These regions of the network were predominantly impacted by the Gospers Mountain, Green Wattle Creek and Currowan bushfires respectively from mid-November to early-February. Managing the multiple bushfire threats required a sustained, whole-of-organisation response and collaboration with several authorities led by the RFS. At all times during the response, our priority was to maintain the safety of our workforce and the communities we serve.

The Floods of 2021-2022

There have been three State of Emergency Declarations in NSW for Floods which destroyed 600 homes and 300 businesses across our network area. 2022 was the wettest year on record for Sydney.

To adapt to the changing climate, targeted solutions are required to ensure a safe, affordable and reliable network service is provided. Ultimately, a more resilient network will be required to maintain reliability as extreme weather events become more common and severe.

Improving resilience beyond the purpose of maintaining reliability is something we wish to test further with customers and stakeholders. The regulatory framework provides both proactive (like capital expenditure programs) and reactive (like pass throughs) options for managing resilience risk. It will be important to strike the right balance between these options to ensure customers pay no more than what is necessary for the level of resilience they desire.

Implications for Endeavour Energy and this Proposal:

- To adapt to the changing climate, targeted solutions are required to ensure a safe, affordable and reliable network.
- As extreme weather events become more common and more severe, the network will need to be more resilient.
- Growth can be facilitated in new ways, with new designs, to enhance the resilience of the network

[14] Media release from the NSW Government, Premier declares third State of Emergency, 2 January 2020

4.7 The evolving grid within a low carbon economy

Governments, businesses and communities are setting increasingly ambitious emissions reduction targets to limit the impacts of climate change.

This requires fundamental changes to the way we produce and consume energy and changes the nature of the energy system. Our electricity networks will underpin this evolution, and we must keep pace with the change.

In the coming years, our network needs to cater for the growing customer uptake of clean and distributed energy resources such as solar PV, battery storage, and electric vehicles. As our customers take up these technologies they will participate more actively in the market and unlock more value from their investments. Sophisticated digital platforms will increasingly underpin and automate more responsive users, coordinated by energy 'aggregators' such as virtual power plants. These changes form part of the solution to limit the impacts of climate change, and the augmentation of our network must reliably and affordably deliver the capability to balance dynamic, responsive, bi-directional flows.

These new technologies, and the changes to the way our communities will choose to use and share electricity, will change the role of the network. Open, real-time data sharing will become critical to the successful operation of a network, allowing and incentivising customers and third parties to use their technologies to help balance the system. The network will become a platform of energy trade, and underpin the modern, low carbon way of living. We will shift from being operating as a distributor by enhancing our capabilities as the Distribution System Operator.

4.7.1 Energy policy

These changes are being driven by changing societal priorities and expectations and as a result Government policy.

In May 2022, the Australian Labor Party achieved majority government following the federal election. This change in government marks a significant shift in energy policy which will impact the pace of decarbonisation and transition to distributed and large-scale renewable generation.

The suite of announced reforms include:

- **Emission Reduction Targets:** in support of the bipartisation net zero by 2050 target, Labor has introduced the Climate Change Bill (2022) and Climate Change (Consequential Amendments) Bill (2022) to codify this commitment and also set a target reduction of 43% by 2030 and net zero in the Australian Public Service by 2030.
- **Safeguard Mechanism:** The mechanism, established in 2007, sought to regulate the emissions of over 200 large greenhouse gas emitting facilities. Labor has indicated that it will ask the Department of Industry, Science, Energy & Resources (DISER) and the Clean Energy Regulator (CER) to determine revised baselines which reduce gradually over time.
- **Rewiring the Nation Corporation (RNC):** Labor has proposed establishing a new RNC to centrally coordinate the investment of $20 billion for the upgrade of the electricity grid, particularly the transmission networks, to support and accelerate the transition to renewable generation.
- **National Reconstruction Fund (NRF):** Relatedly, Labor announced up to $3 billion from the NRF to support renewables manufacturing, low-emissions technology and co-investment of up to $100 million for 85 solar banks and 400 community batteries across Australia.
- **Electric Vehicles and Transport:** Labor has indicated that it will develop a National Electric Vehicle Strategy. The strategy will encourage the transition to EVs including electrifying 75% of the Commonwealth's fleet by 2025.

On 12 August 2022, the Energy Ministers Council (which consists of State and Federal Energy Ministers) met and endorsed fast-tracking the expansion of the National Electricity Objective (NEO) to include an emissions objective to support Australia's emissions reduction goals. This reform is significant and means that the AER and networks must consider the environment when determining and incentivising efficient levels of service quality and costs.

At a State level, the NSW government is targeting a 50% reduction in emissions, including 12GW of new low emissions generation and 2GW of storage by 2030. The most prominent policy to drive this decarbonisation being the Electricity Infrastructure Roadmap which seeks to co-ordinate $32 billion of investment in renewable energy zones (REZs) across NSW to replace coal-fired power stations over the next decade.

The Central-West Orana REZ was the first REZ to be declared in Australia with EnergyCo currently carrying out a competitive tender for a Network Operator. The cost of this and all subsequent REZs will be recovered from NSW electricity customers via our network tariffs as a jurisdictional scheme.

The NSW Government expects the Roadmap to deliver benefits relative to a late and/or un-coordinated transition away from coal-fired generation. The cost remains uncertain, but it is likely to materially increase electricity bills in NSW. We have been mindful of highlighting this uncertainty in our engagement activities and have consulted extensively with the NSW Government on reforms to implement the Roadmap. Our position remains that the Roadmap costs and benefits should be transparently communicated to NSW electricity customers.

In addition to the Infrastructure Roadmap, the NSW Government has also been consulting on the following additional reforms:

- **NSW EV Strategy:** In June 2022 the NSW Government announced initiatives to promote the uptake of EVs in NSW by 52% by 2030-31. Key actions include rebates for new purchases, phasing out stamp duty on EV purchases, offering fleet incentives and investing in EV fast-charging infrastructure.
- **NSW DER Strategy:** the NSW Office of Energy and Climate Change (OECC) continues to consult on reforms to support a net zero carbon emissions future in NSW where DER is efficient, affordable and available to all NSW customers and that supports a stable, secure and reliable energy system.
- **Promoting Innovation for NSW energy customers:** The OECC is also consulting on a broad suite of reforms to support the transition of the NSW energy industry. This includes considering options to accelerate the smart meter rollout, uptake of DER, EVs and community batteries and customers' access to information

These reforms are ongoing but are likely to impact our plans for the 2024-29 regulatory period. Similar to the national reforms, there is a clear and strong policy direction in NSW in support of accelerating the de-carbonisation of the energy industry and empowering customer choice.

As emerging technologies become more prevalent, we must find ways to equitably deliver customer choice. We must also innovate in using these technologies to service new growth and to maintain the affordability and reliability of our network. Below we provide more detail on these new technologies and how each of them impacts our network.

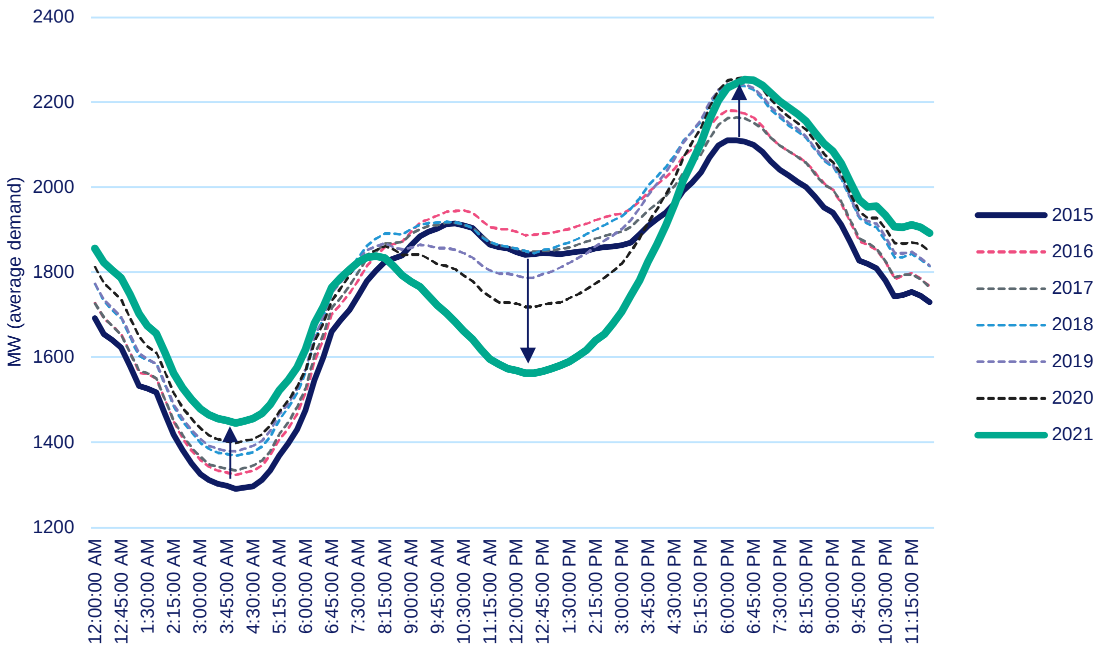
4.7.2 Solar Photovoltaic (Solar PV) systems

The uptake of solar PV systems by households and businesses on Endeavour Energy's network is forecast to increase rapidly in the coming years. Currently, more than 20% of Endeavour Energy's customers have installed solar PV systems to supplement their energy requirements. By 2030, this figure is projected to reach 55%.

The changing profile and volatility of supply and demand as a result of the high penetration of solar PV creates network wide and localised issues which will need to be addressed. At the network scale, this includes the 'duck curve' whereby solar input reduces the demand for electricity during the day at the same time as growth in electricity use increases night-time peak demand.

This also increases the ramp-up required to meet evening demand (Figure 4-5). Local volatility, including voltage surges, can damage equipment, cause 'trips' or 'faults', and result in the temporary shutdown of solar inverters to restore voltages to safe limits.

Figure 4-5 Endeavour Energy average network demand curve 2015-2021



Network augmentation and new operational rules can successfully address these issues. However, any solution must minimise limitations on household market participation (e.g., localised curtailment), and address equity concerns that will become more prevalent as localised saturation levels are reached. Equity is needed both around new 'entrants' being able to access benefits and ensuring the cost of the system is equitably shared between those who receive benefit and minimised for those who don't.

Lessons can be drawn from distribution networks already managing a high penetration of solar in other states, such as the setting of appropriate solar export limits to reduce grid congestion and upgrading voltage management systems across substations. This allows Endeavour Energy to better develop proactive and equitable measures to address the operational and reliability issues that have emerged elsewhere.

4.7.3 Energy storage

As more variable renewable energy sources feed into the grid, such as solar PV, energy storage will play an increasing and crucial role to balance supply and demand. As costs of storage technology decline (e.g., batteries) and market and/or tariff-based incentives grow, the installation of storage is expected to increase rapidly across our network.

Storage will be delivered at the household, local and grid-scale, and will be a vital contributor to the management of seasonal, daily and micro variations in supply and demand. These services can only be delivered via the active participation of customers and third parties, which requires a dynamic and digital capability and necessitates the more central role of the grid.

Household: As the costs of battery storage decline, more customers are choosing to install privately-owned, behind the meter storage systems. In its simplest use, battery storage allows customers to store the solar energy otherwise fed into the grid during the day and consume that energy at night when its needed (load shifting). This has the benefit of 'flattening the 'duck curve' created by solar.

Grid-scale: There are several energy storage solutions that are becoming increasingly viable at the system level, from traditional Battery Energy Storage Systems (BESS') to the Seasonal Hydrogen Storage Systems. These technologies enable distributors to more accurately manage the demand and supply of energy across the network.

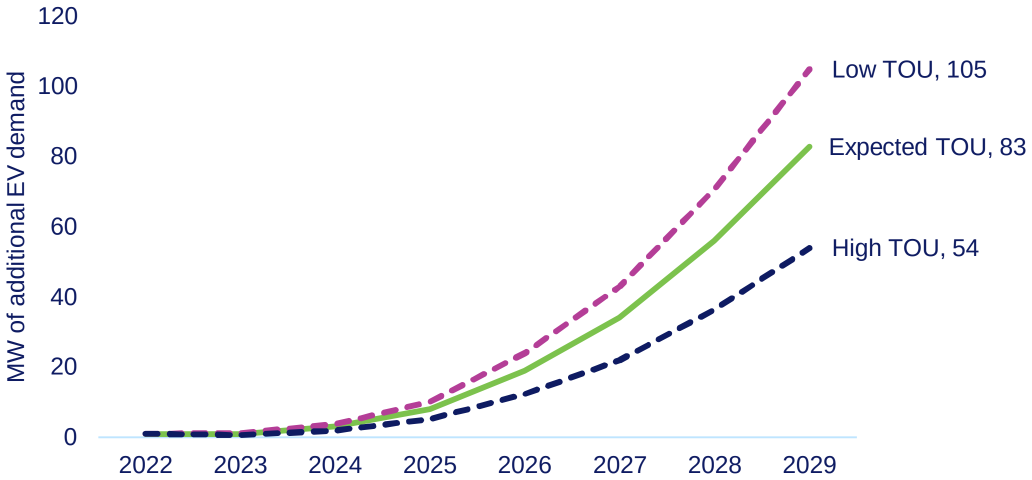
Aggregation and Virtual Power Plants (VPPs): Sophisticated digital platforms and energy 'aggregators' (such as VPPs) unlock value for households by accessing wholesale markets. This transforms households into market participants, responding to price signals and delivering market services. However, this can create local network capacity issues, as households become orchestrated in their supply and demand from networks.

Shoalhaven pumped-hydro: Large-scale energy storages and 'base-load' generation from pumped-hydro such as Shoalhaven will play an important role in addressing peak and seasonal demand changes, allowing more reliable integration of variable renewable energy.

4.7.4 Electric Vehicles (EVs)

While the projected uptake of EVs in Australia is still wildly uncertain, market indicators are pointing towards increasing penetration at the back end of the decade. While price, model and charging infrastructure barriers are currently in place, experience from Europe indicates that once these constraints are addressed, the market can shift rapidly. By 2029, 200,000 EVs are expected in households on the Endeavour Energy network, up from 2,000 currently.

Figure 4-6 AEMO forecast EV take-up scenarios (with and without effective time-of-use tariffs)



EVs are an emerging consumption on the network, and a changing profile of demand. The contribution of 200,000 EVs to peak load increase from 1MW now to 83MW by 2029. This will result in requests for new connection points and will likely require some network augmentation.

However, EVs will also represent the opportunity for mobile (battery) storage. The rise in EVs will rapidly enhance the flexibility of consumption and will form a crucial component of the dynamic architecture of the future network. They will become a very useful tool to balance loads, but will require sophisticated, transparent, digital capabilities operating with a proliferation of third parties to optimise this value.

With the Australian and NSW Governments announcing their intentions to invest in EV infrastructure, and global manufacturers declaring the cessation of production for most Internal Combustion Vehicles by 2030-35, Endeavour Energy needs to ready its network, operational and digital planning for the fairly rapid, yet unpredictable, rise in EVs once the settings are right.

4.7.5 Demand response devices and flexible load

When managing the capacity of the grid, the focus has historically fallen on the energy generators to ensure the supply to the grid matches demand. But with changes in consumer behaviour affecting when, where and how people access the grid, there's a growing opportunity to manage capacity by tackling the demand for energy.

A shift to a more dynamic and transparent tariff regime will further incentivise these behaviours. In a system with abundant, but variable, renewable energy, households and businesses will benefit from the ability to reduce demand or transition to more flexible operations. This is part of the solution to balancing the low carbon, variable energy system.

Demand response is the voluntary reduction or shift in the customer's use of electricity. This is typically achieved by financially incentivising consumers to switch their use of power to off-peak periods to ease the demand on the network.

Flexible load refers to the coordination of electricity consumption used for existing loads. For households this includes water heaters, air-conditioning systems and pool pumps. For business and industry, this includes flexible production which can lower individual production costs and balance loads on the network.

The role of the network is to facilitate the ability of customers to participate in such a way. In this light, the value of the network shifts more in favour of its capacity to allow participation, rather than the electricity demanded. This change requires re-consideration of tariff structures to reflect the alternative value of the network (such as capacity charges).

4.7.6 Renewable generation

Decarbonising Australia's economy will be challenging, involve a variety of alternative fuels developed through multiple different pathways, and approaches will vary within and across industries and use cases based on needs and opportunities. Hydrogen, which is very similar to natural gas and can be produced from renewable electricity, represents one such option.

The NSW Government through its Electricity Infrastructure Roadmap and Hydrogen Strategy is aggressively pursuing the activation of new renewable energy zones to drive decarbonisation of its electricity generation and establishment of a hydrogen industry, for both domestic and export markets. This will drive significantly more variable renewables into the generation mix and may add considerable load to the distribution network.

The scale of electricity generation associated with large-scale hydrogen production dwarfs that of Australia's current demand. NSW is targeting 12GW of renewables to deliver 110,000 tonnes per annum of hydrogen by 2030. It is focusing on production in two key hubs, Illawarra and the Hunter Valley (with Wagga Wagga considered a strategic location mainly for transport).

The wave of renewables will create system challenges, but also new opportunities. Hydrogen may act as a flexible way to lift minimum demand and store excess energy. It may also play a role in decarbonising gas networks, with localised production, storage and potentially generation, supporting grid stability.

However, with the commercial pathway to hydrogen production still some way off, we will need to prepare for scenarios where we see large scale electrification, a hydrogen economy emerges, or something in between.

4.7.7 Microgrids and SAPS

Microgrids and Stand-Alone Power Systems (SAPS) are essentially a group of localised energy sources and loads that are capable of functioning autonomously in times of need. Thus, they require less or no connection to the traditional electricity network, mitigating the need for new, or significant augmentation or replacement of existing, connections to communities. The transformation of the grid will lead to a more 'compartmentalised' network, with many localised networks functioning like microgrids, and interacting in a broader system.

The increasing value that can be derived from microgrids and SAPS is twofold. Firstly, with the decreasing cost of distributed generation and storage technologies, as well as the increasing costs of providing traditional network connection, SAPS are becoming more commercially feasible. Secondly, and in addition to the potential commercial value, SAPS can avoid the need for long, stringy connections. In the face of increasing extreme weather events, this will reduce the risks to the safety and reliability of the network.

In addition to these two benefits, microgrids can offer communities a chance to help co-design their energy system, specifically creating elements for their unique values and needs.

For Endeavour Energy, microgrids in particular present new opportunities to deliver growth and replace assets more affordably, with lower risks. With a huge range of different areas for our network to cover, and that creates many different challenges for both existing locations and newly developing areas, designing and maintaining a network that is safe and reliable, but also makes best use of all locally generated renewable energy is what we are striving to achieve with microgrids.

However, any use of SAPS and microgrids will need to align with the guidance from the AEMC and AER regarding appropriate distributor-led use.

Implications for Endeavour Energy and this Proposal:

- As emerging technologies become more prevalent, our customers trust us to enable their future energy choices
- We must find ways to equitably deliver customer choice, innovating to maintain the affordability and reliability of our network and ensuring no one is left behind
- New technologies enable us to support growth in new and varied ways.

4.8 Effective and efficent service in the digital age

The continual evolution of digital capability is needed to facilitate customer choice in new technology, to enhance cyber security to maintain a reliable network and to efficiently and effectively service growth and operate our network.

While this requires investment it also enables us to do much more with less; affordably, safely and reliably integrating more dynamic services through our existing infrastructure.

Leveraging the use of digital sensors, automation, artificial intelligence and quantum computing will transform our capability to manage the network's operation. Evolving digital capabilities will underpin our role as the energy system orchestrator, and facilitate seamless, dynamic, real-time interactions between the network and the third-party platforms driving VPPs, charging stations, and active behind the meter participants.

At the same time, we will be seeking to facilitate open data sharing with third parties, we will need to protect against an increasing frequency and sophistication of cyber-attacks. Endeavour Energy, like all networks, will need to enhance our cyber defences to protect the integrity of the network and our customers' data.

While the network's management becomes more automated, our workforce will also evolve. Virtual reality, robotics, driverless vehicles and other innovations implemented alongside our human workforce will allow us to service our customers' needs more safely and efficiently. For example, drones (or UAV's) have enabled distributors to quickly locate and diagnose network disruptions, without risking the safety of employees.

Implications for Endeavour Energy and this Proposal:

- The continual evolution of digital capability is needed to facilitate customer choice
- We must demonstrate how digitisation helps us to delivers new services with less investment
- Technology allows growth to be delivered most efficiently and effectively
- Enhanced cyber capability will underpin reliable networks in the future.

5. Customer-Focused Decision Making

5.1 Overview

We have undertaken our most comprehensive and ambitious engagement program to ensure that our plans reflect the service priorities our customers have told us are in their long-term interests. We've kept downward pressure on network charges, simplified tariffs for retailers, and priced streetlighting and smart cities technologies to support councils.

Everyday Endeavour Energy engages with people and organisations who have an interest in what we do and who are, in some way, connected to our purpose. The quality of those relationships determines how well we will deliver on our vision to power communities for a brighter future.

As the Australian energy industry changes, we recognise that we need to continually improve our engagement so that our day-to-day operations and plans benefit from fresh insights and ideas.

Endeavour Energy is committed to embedding quality stakeholder engagement across our business to inform our actions and underpin our decisions, always placing our customers at the heart of what we do.

Importantly, this demands an 'outside-in' approach to listening and acting on engagement.

Our stakeholders have told us they are interested to engage with us on many issues, including Western Sydney growth, regulatory proposals, climate change, bushfire prevention, community resilience, future grid, pricing and tariff reform, how we help vulnerable customers and how we can work in increasing partnership to deliver on common objectives for our customers.

We welcome this interest and related opportunities to listen and incorporate stakeholder views so that we can design outcomes that are good for the business, good for customers and good for our communities.

We are aiming high. We are committed to listening, identifying better practice, learning from experience, utilising international standards and building a culture of effective engagement that is recognised across the industry. Our goal is to embed effective business-as-usual engagement to strengthen our customer-centric culture, reflecting the changing needs of customers and our evolving ecosystem.

5.2 Our engagement approach

Ahead of this regulatory review period, the Endeavour Energy Board and Executive Leadership Team committed to ensuring that customer engagement is an organisational priority and is always led from the top.

To achieve this, the Board and Executive approved a new Stakeholder Engagement Framework and an organisation-wide uplift in engagement that ensured engagement would be a focus and priority of the Executive and the Board. This included appointing a Chief Customer and Strategy Officer and engaging SEC Newgate Australia for their expert support and experience in engagement, research and independent facilitation.

To ensure that this commitment would be embedded in our day-to-day operations, we reflected on the experience and learnings of previous regulatory determinations and sought to better understand what best practice looks like across Australia and internationally.

This process of reflection and critical evaluation led us to commit to engagement that is:

- Led from the top, with significant commitment from and involvement of the Executive and Board Directors.
- Integrated with a broader uplift in customer focus and engagement across Endeavour Energy's business.
- Co-designed with customer advocates, including the engagement design and the development of proposal itself.
- Comprehensive, including expanded representation of and engagement with informed stakeholders via Endeavour Energy's Peak Customer and Stakeholder Committee (PCSC) and three supporting sub committees - the Regulatory Reference Group (RRG), the Future Grid Reference Group (FGRG) and the Retailer Reference Group (ReRG). We also removed barriers to participation with some RRG and FGRG members being remunerated for their time to ensure the right capabilities and experience across the members.
- Inclusive, featuring more engagement with a Culturally and Linguistically Diverse (CALD) group and Aboriginal and Torres Strait Islander (ATSI) consumers, including, for the first time, in-language engagement and expanded social programs.
- Proactive, particularly in relation to our engagement with the AER and via the Early Signal Pathway under its Better Resets Handbook.
- Upfront, providing an early indication of Endeavour Energy's key positions through the publication of Preliminary Proposal that will inform future engagement.
- Collaborative, working closely with other distribution networks and agencies on issues of common interest to our stakeholders (e.g., resilience) but also taking a coordinated approach to respect the time of stakeholders participating in multiple regulatory processes.

5.2.1 Co-designing our engagement process

To deliver on this plan we developed our Engagement Plan through a co-design process with our Board, Executive and customer and stakeholder representatives.

To that end, in late 2020 we invited members of our PCSC and other experience stakeholders to participate in a newly created RRG, acting as a sub-committee of the PCSC.

The RRG comprises independent stakeholders and representatives of Endeavour Energy. The RRG was established on a principle of co-design; in which independent members of the RRG and representatives of Endeavour Energy have worked collaboratively on the development and implementation of an engagement plan and the development of the Endeavour Energy 2024-29 Regulatory Proposal.

Co-design is a process whereby different stakeholders come together to develop the solution to a challenge. It is a process of collaborative creation, rather than the traditional 'consult and obtain feedback' approach. The independent members of the RRG (or Independent Members Panel), acting in an advisory capacity, have been performing the following roles in accordance with an agreed Terms of Reference throughout the development of the Regulatory Proposal:

- representing the long-term interests of Endeavour Energy customers;
- co-designing of the engagement program;
- participating as key stakeholders in the Regulatory Proposal engagement; and
- challenging Endeavour Energy throughout the development of its' 2024-29 Regulatory Proposal both on its proposal and the engagement program.

Endeavour Energy has been scrupulous to ensure that this commitment to the principle and practice of co-design should not infringe on the autonomy of the Independent Members Panel, who represent peak stakeholder organisations and consumers at large; and who are expected to report separately to the AER on the Endeavour Energy Proposal, and Endeavour Energy's engagement program.

We formally commenced the regulatory engagement process with a co-design workshop with the RRG in May 2021. The outcomes agreed at this workshop guided the development of our engagement plan and goal for the 2024-29 regulatory reset. The latter being as follows[15]:

> *To undertake engagement that delivers our vision of powering communities for a brighter future by developing a revenue proposal that balances*
>
> - *the priorities, preferences, diversity and current and future needs of our customers*
> - *with sustainable returns to shareholders, and*
> - *can be considered prudent and efficient by the Australian Energy Regulator.*
>
> *This means providing fair access to the modern grid and ensuring customers pay no more than is necessary for a safe, reliable and secure electricity supply and quality service.*

Our detailed engagement plan was also guided by:

- Endeavour Energy's Corporate Strategy
- Endeavour Energy's Stakeholder Engagement Framework
- The Energy Charter
- IAP2 Core Values for Public Participation

Eight key principles guided our engagement activities to help build consistent, open and trusted relationships:

- **Purposeful**: We begin every engagement with a clear understanding of what we want to achieve and link this to our strategy
- **Inclusive**: We identify relevant stakeholders and make it easy for them to engage
- **Timely**: We involve stakeholders from the start and agree on when and how to engage
- **Transparent**: We are open and honest in our engagement and set clear expectations
- **Responsive**: We consider and respond to concerns and provide prompt feedback
- **Best practice**: We will aim high
- **Collaborative**: We will work with interested parties for mutual benefit

[15] Attachment 5.04 Endeavour Energy, Endeavour Energy Engagement Plan, April 2022, p. 8

- **Measurable**: We will assess progress on a continued basis and drive improvements

We note that the Engagement Plan (refer Attachment 5.04), is a ‘living’ document and as a result has been collaboratively amended six times over 15 months.

5.2.2 Engagement scope

Our engagement scope has been set looking outward from the regulatory framework as required by the Australian Energy Regulator.

The RRG, together with representatives of Endeavour Energy’s Board and our Executive Leadership Team co-designed a map of issues for engagement, identifying their impact on the proposal and the ability of customers to influence the outcomes for each aspect of our revenue proposal on the IAP2 Spectrum of Participation.

The outcome of this process is depicted in the matrix below. If a topic sits towards the left of the matrix, there is less ability for feedback to influence an outcome (for example, that item might be governed by a regulatory instrument like the RoR).

However, if a topic sits towards the right of the matrix, there is a greater capacity for feedback to shape outcomes.

This engagement map (next page) formed a foundational reference for the entire engagement program, and as agreed with the Independent Members Panel includes some inform and consult elements, with many involve and collaborate opportunities – particularly for our most informed and engaged stakeholders.

Figure 5-1 Engagement map of 2024-29 determination matters against IAP2 spectrum

Increasing impact on the decision

	Inform	Consult	Involve	Collaborate	Empower
Public participation goal	To provide the public with balanced and objective information to assist them in understanding the problem, alternatives, opportunities and/or solutions.	To obtain public feedback on analysis, alternatives and/or decisions.	To work directly with the public throughout the process to ensure that public concerns and aspirations are consistently understood and considered.	To partner with the public in each aspect of the decision, including the development of alternatives and the identification of the preferred solution.	To place final decision-making in the hands of the public.
Promise to the public	We will keep you informed.	We will keep you informed, listen to and acknowledge concerns and aspirations and provide feedback on how public input influenced the decision.	We will work with you to ensure that your concerns and aspirations are directly reflected in the alternatives developed and provide feedback on how public input influenced the decision.	We will look to you for advice and innovation in formulating solutions and incorporate your advice and recommendations into the decisions to the maximum extent possible.	We will implement what you decide.

Level of IAP2 Public Participation Spectrum	
Empower	To place final decision-making in the hands of customers and stakeholders.
Collaborate	To work together with our customers and stakeholders to formulate alternatives and incorporate their advice into final decisions to the maximum possible extent.
Involve	To work directly with customers and stakeholders to ensure their concerns and aspirations are directly reflected in the alternatives developed.
Consult	To obtain feedback on alternatives and draft proposals.
Inform	To provide balanced information to keep customers and stakeholders informed.

5.2.3 Alignment with the AER's Better Resets Handbook

The AER released its Better Resets Handbook in December 2021. It encourages electricity distribution and transmission networks to engage meaningfully with customers and stakeholders and ensure consumer preferences drive the development of regulatory proposals. The Handbook sets out the AER's expectations on consumer engagement. They cover:

- The nature of engagement;
- The breadth and depth of engagement; and
- The clearly evidenced impact of this engagement.

Endeavour Energy has utilised a wide variety of engagement methods and channels to ensure the overall regulatory engagement program achieves both deep and broad engagement with a diverse cross-section of customers and stakeholders.

Some of these engagement opportunities are business-as-usual (for example, State of the Network and the ongoing Voice of Customer or Reptrak programs), but some were developed to meet specific needs of the regulatory program (for example, the RRG and the Customer Panel).

Endeavour Energy also considered ways to target specific stakeholders and customers who might be more difficult to involve in broader engagement forums. This might be because they have very specific areas of interest (e.g., large energy users or local councils) or because they are time poor, unable to share frank feedback in public settings (e.g., due to privacy or competition reasons) or just need a bespoke approach to ensure their voices are properly heard and then considered in decision making (e.g., non-English-speaking customers).

This targeted engagement typically took the form of small group meetings or workshops with smaller customer groups or stakeholder segments.

This multi-faceted engagement approach took into account feedback received following Endeavour Energy's last Regulatory Proposal and was refreshed in the Discover, Explore and Prioritise phases of this program, where stakeholders were asked for their engagement preferences.

This mixed method approach ensured a comprehensive understanding of a wide range of customer and stakeholder views and preferences.

Figure 5-2 Summary of breadth and depth of Endeavour Energy 's engagement methods

Deep engagement methods	Broad engagement methods	Targeted engagement methods
• Customer panel (Attachment 5.09) • RRG engagement, including a series of additional small workshops ('mini–Deep Dives) with subject matter experts on key topics chosen by the RRG • Peak Customer and Stakeholder Committee (PCSC) engagement • Stakeholder Deep Dives (Attachment 5.10) • Future grid workshops	• Residential and SME customer quantitative survey (Attachment 5.11) • RepTrak surveys with end customers and stakeholders • Exploratory focus groups with end residential and SME customers (Attachment 5.02 and 5.03) • State of the Network forum with a broad range of stakeholders • Joint stakeholder workshops with other DNSP's including on Resilience (Attachment 5.06) • A 'Have Your Say' section on the Endeavour Energy website • LinkedIn and Facebook posts	• Culturally and linguistically diverse (CALD) in-language engagement (Attachment 5.16) • High-energy users workshop (Attachment 5.05) • 'Dinners with Endeavour' in-language engagement • Local council workshops (Attachment 5.07 and 5.08) • Meetings with commercial and industrial energy users • Meetings with retailers, market aggregators, large storage providers and other new market entrants

5.2.4 Engagement program

The engagement program initially comprised four key phases, each with distinct deliverables. In response to recommendations of the RRG Independent Members Panel, a fifth phase, the 'Confirm Phase' has been added to our engagement plan to cover the period post the submission of our Regulatory Proposal to the AER, and the 'Refine Phase' has been augmented to sense check potentially changing customer preferences. The program is summarised as follows:

Figure 5-3 Endeavour Energy 2024-29 Engagement program summary

Preparation	Phase 1 Discover	Phase 2 Explore	Phase 3 Prioritise	Phase 4 Refine	Phase 5 Confirm
Oct 2020 – Mar 2021	Apr 2021 – Sept 2021	Oct 2021 – Apr 2022	May 2022 – Oct 2022	Nov 2022 – Jan 2023	Feb 2023 – Jul 2023
A period of forward-planning to prepare Endeavour Energy for the launch of the regulatory cycle	A research period to better understand customer and stakeholder needs and preferences to help shape our engagement approach	A period of deeper exploration of key issues to help inform the development of our Preliminary Proposal	Broad and deep engagement on our Preliminary Proposal, identifying aspects of greatest importance to customers	Developing and refining our Final Proposal using insights from the previous phase	Confirming our customers' priorities in the context of a changing economic environment
• Benchmarking previous engagement with best practice • Engagement partner appointed • PCSC membership enhanced	• Establishment of RRG, FGRG and ReRG and determine the Terms of Reference • Board/Executive/ customer co-design workshop • RRG engagement planning • Joint DNSP engagement (emerging services) • Future Grid workshop • Co-designed exploratory research straw man • Board check-in • PCSC • Exploratory research (residential) • Exploratory research – SME (Dinners with Endeavour) • Exploratory research (CALD) • Ongoing engagement with AER	• RRG and AER Investment Value Framework • BAU State of the Network Forum (Illawarra and South Coast) • BAU State of the Network Forum (Greater Western Sydney) • High-energy users' workshop • Future Grid workshops • RRG • PCSC x 2 • Joint DNSP engagement (tariffs) • Ongoing RRG mini Deep Dives • Board check-in • Commence engagement of AER's CCP • Ongoing engagement with AER • One-on-one briefings with stakeholders • RepTrak benchmarking study	• Local Council Workshop (Illawarra and South Coast) • Local Council Workshop – Western Sydney) • Customer Panel Wave 1 • Customer Panel Wave 2 • Deep Dive 1 • Deep Dive 2 • One-on-one briefings with stakeholders • Quantitative survey • RRG webinars x 3 • PCSC x 3 • Ongoing RRG mini Deep Dives • In-language direct engagement with CALD communities • Customer Panel Wave 3 • Ongoing engagement with AER	• Stakeholder check-ins • Individual retailer engagements • Local council workshop (street lighting tariffs check-in) • RRG bi monthly meetings • RepTrak benchmarking study	• Customer Panel check-in • Stakeholder check-in • RRG bimonthly meetings • AER public hearing
	• Engagement Plan • Exploratory Customer Research Report	• Preliminary Proposal • Business Narrative	• Draft Proposal • Engagement Summary Report	• Final Proposal • Final Proposal Customer Overview	

Our Engagement Summary Report (refer to Attachment 5.01) provides comprehensive overview of the design and execution of our Engagement Plan, which was designed to be iterative and is characterised by constant and incremental changes to our positions based on numerous 'pillars of evidence'. A 'by the numbers' summary of our program is provided below as an overview:

Figure 5-4 'By the numbers' summary of Endeavour Energy's 2024-29 engagement program over 2021 to 2022

Overall engagement reach

129 unique engagement events or opportunities

1,813 individuals directly engaged (including customers and stakeholders)

124 organisations engaged

646 hours of face-to-face engagement, with Board and Executive participation

2,400 total hours of face-to-face engagement by Endeavour Energy overall

Regulatory Reference Group

13 RRG members

31 formal RRG meetings

24 informal RRG meetings

14 Independent Members Panel meetings

26 mini deep-dives and individual engagements on subjects determined by RRG members

AER Consumer Challenge Panel

8 informal CCP check-ins

Peak Customer and Stakeholder Committee

15 members

7 PCSC meetings

Business as usual engagement (feeding into the regulatory engagement process)

Number of **RepTrak** surveys and participants

13 surveys comprising **1,700** customers & **246** stakeholders

75,134 Voice of Customer surveys issued to customers (Dec 21 to Aug 22)

4,940 Voice of Customer survey responses received (Dec 21 to Aug 22)

Online and digital engagement

16 regulatory reset stories posted to LinkedIn with a reach of

40,075

6 regulatory reset stories posted to Facebook with a reach of

41,743

Your Say engagement
(private RRG page)
97 newsfeed articles,
179 documents and
565 downloads

Newsletters
5 sent
913 opens
68% average open rate

Your Say engagement (public engagement portal)
1,871 'aware visitors'
1,362 'informed visitors'
(engaged with material on the site)
3,150 downloads
1,066 downloads of the Preliminary Proposal
369 downloads of Draft Proposal
202 downloads of Engagement Summary Report

Customer Panel

89 Customer Panel members

1,513 hours of Customer Panel engagement

10,633 unique responses from Customer Panel members

CALD and First Nations people engagement

20 different language groups represented

230 CALD participants

52 First Nations people participants

Core engagement documents and co-designed revisions

6 versions of the Engagement Plan

5 versions of the Business Narrative

8 versions of the RRG Terms of Reference

A highlight of our process was the Prioritise Phase of engagement, which involved the most extensive and broad reaching component of our program. It followed the release of our Preliminary Proposal in April 2022, and sought to reveal what customers valued most, acknowledging constraints on investment were necessary to balance our customers' vision for their future service with affordability that delivers value. We provide a brief summary of some of the key aspects of our Prioritise Phase of engagement below.

Customer Panel

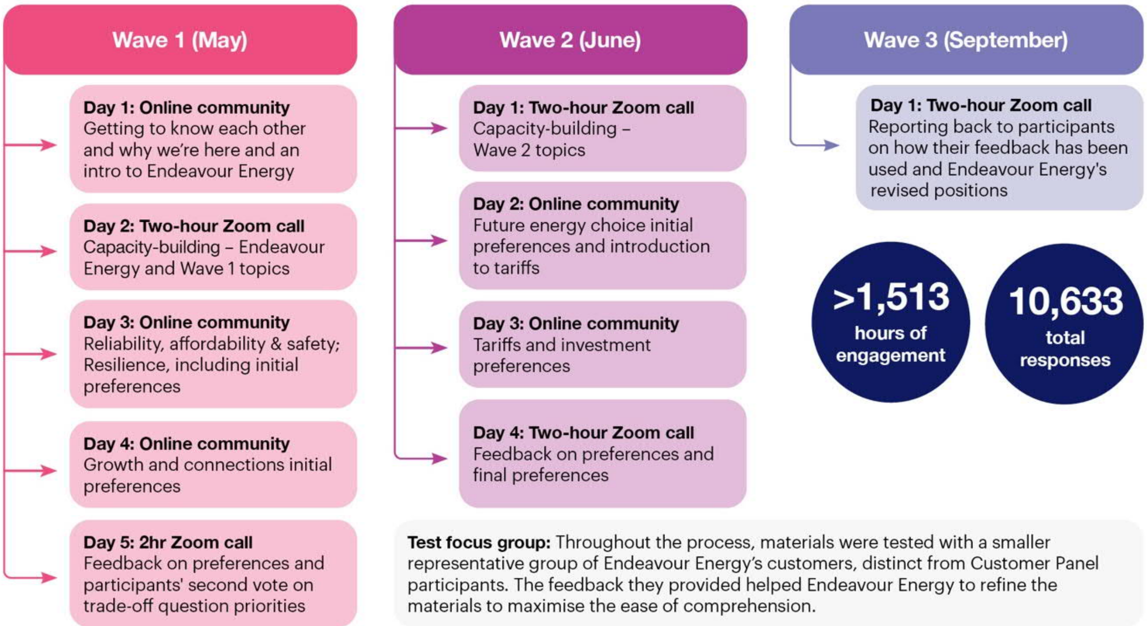
The Customer Panel was a key element of our engagement approach. Its purpose was to deeply engage with a broad and representative cross-section of residential and small business customers through an extended deliberative process to inform Endeavour Energy's Draft Proposal.

The Panel comprised 89 participants who were provided extensive background information and undertook many different capacity-building activities in an online community to deliberate on the following key questions that were co-designed with the RRG Independent Members Panel:

1. How should Endeavour Energy best meet customer expectations for a safe, reliable and affordable electricity supply?
2. Should Endeavour Energy take a more proactive or responsive approach to maintaining network services in the face of increasing major weather events (storm, bushfire, flood, urban heat, etc)?
3. How should Endeavour Energy time the delivery of the electricity infrastructure required for the economic development of Greater Western Sydney and other areas?
4. Should new customers be required to pay "upfront" for the infrastructure required to service new development, or should the costs for this infrastructure be recovered over time from all customers through existing charges?
5. How do we modernise the network to meet emerging and future customer service expectations as technology and markets evolve?
6. Should tariffs reflect the different demands customers place on the network?
7. Should solar exports tariffs be introduced by Endeavour Energy to reflect the different demands customers place on the network?
8. Does Endeavour Energy's proposal reflect customers' priorities, preferred outcomes and long-term interests by providing a reliable, affordable and safe distribution network?

These questions were tested multiple times both with and without indicative bill and service outcomes, both individually and in combination over multiple waves. This process is depicted below:

Figure 5-5 Summary of Customer Panel process and engagement



Deep Dives

In order to explore any divergence between the views of customers and stakeholders, the Customer Panel's preferences from Waves 1 and 2 were shared with a broad group of stakeholders in a series of full day Deep Dives in July and August 2022.

The Deep Dives involved more than 100 well-informed customer advocates who represented a diverse set of views across 13 different customer segments, from Accredited Service Providers (ASPs) to developers, sustainability and technology businesses to advocates of vulnerable customers. Ahead of each session, participants were urged to read the Preliminary Proposal to understand Endeavour Energy's current positions. Participants were also sent a range of questions to consider, ensuring they arrived ready to provide meaningful contributions.

Stakeholders attending the Deep Dives were asked for their preferences on the same questions put to our Customer Panel – and asked to explore the alignment or misalignment of their views with our customers.

This process allowed for sophisticated and informed discussion, which included robust challenge of Endeavour Energy's positions and deep examination of how the competing preferences of customers should be balanced. It put our customers' views at the centre of our 'Prioritise Phase' of engagement.

These stakeholder views were subsequently shared with the Customer Panel to provide them with oversight of different perspectives for their final deliberations in Wave 3.

Quantitative survey

The Customer Panel involved an extended deliberative process with customers and significant capacity-building. While this allowed for more detailed discussion, it can mean the Panel participants are no longer considered representative of Endeavour Energy's general customer base by the end of the process.

In addition, the Customer Panel was conducted at specific points in time. Notably, the second wave of our Customer Panel deliberative forums occurred during the announcement of large increases in electricity prices from July 2022, several flood disasters and the suspension of the wholesale electricity market. The effects of the Ukraine War and international economic downturn were also beginning to take shape during this period.

Therefore, in addition to testing the Customer Panel's preferences with expert stakeholders in the Deep Dives, we also conducted further broad research through a quantitative survey. The purpose of the quantitative study was to test key findings from the Customer Panel with the broader customer base and to provide another, later point-in-time snapshot of customer preferences to understand the effect of ongoing changes in the broader environment, particular cost of living pressures.

The 20-minute quantitative survey was conducted in August 2022 among a diverse sample of 1,000+ residential customers and 200-250 business customers from across Endeavour Energy's supply area. The survey achieved a total sample size of 1,266, which included 1,001 residential customers and 265 small business customers across the network.

The study focussed on the following key areas:

- Knowledge and awareness of Endeavour Energy
- Ratings and performance of Endeavour Energy's current services; and
- Ratings and performance of Endeavour Energy's proposed future services.

5.3 Our engagement findings and response

It is important to note that the engagement program for this Proposal was conducted at a time of significant international and national upheaval and change in the energy sector, in the economy more broadly, and in the community.

For example, in June 2022 our online Customer Panel deliberative forum was at risk of disruption due to potential load shedding as a result of generator shortfalls. On that same day the AEMO suspended the National Electricity Market – both of which raised concern for some customers about their power remaining on.

Around that time, the AER approved increases to the Default Market Offer (DMO) due to increased wholesale costs, and the war in the Ukraine began to impact energy markets here and abroad. In addition, during this engagement period AEMO released its ISP as the NSW Government continued to develop its Electricity Infrastructure Roadmap – both of which are expected to impact prices for consumers.

Additionally, our customers were facing record high petrol prices and many homeowners faced their first ever interest rate rises, with five consecutive interest rate rises now recorded for 2022. All these factors combined to see cost of living concerns increase for many.

This context was on top of the first-hand experiences of many customers of the impacts of extreme weather events. Endeavour Energy customers living in the Nepean and Hawkesbury catchment areas endured four catastrophic floods in just 15 months between 2021 and 2022. In addition, 55,000 Endeavour Energy customers experienced electricity disruptions during the 2019-20 summer bushfires which burned across 45% of our supply area, leaving some customers deeply traumatised.

We note these external factors to help place the insights and preferences we received from customers in their proper context, but also to highlight the fact that all research and engagement reflects a ‘point in time’, capturing the views and concerns of customers in the moment. These views cannot be considered as ‘set in stone’, but rather they offer powerful guidance.

Indeed, the approach Endeavour Energy has taken of weaving in the results of business-as-usual and ongoing engagement reflects this understanding. We acknowledge that feedback must be regularly sought and considered to ensure evolving trends are identified and addressed quickly.

In Attachment 5.01 to this Proposal, we provide a detailed overview of the methodology and findings associated with each engagement activity undertaken with respect to each priority area. Below, we summarise the feedback we received at a cursory level and outline our response.

5.3.1 What we heard and how we have responded

As aforementioned, our engagement program has been iterative with small and incremental changes to our positioning throughout the engagement process. Each engagement activity has provided a ‘pillar of evidence’ for Endeavour Energy to consider and action accordingly.

We recognise that each pillar of evidence (and indeed all engagement designs) has its own limitations, and therefore no one piece of feedback was intended to compel us to make changes to our Preliminary or Draft Proposals, however more weight was given to the deeper engagements with our Customer Panel and stakeholders attending the Deep Dives. Nevertheless, we have carefully reviewed and considered multiple sources of feedback over time to determine whether clear and consistent directions or customer mandates existed that we should address in order to deliver what a genuinely customer-centric proposal.

The Independent Members Panel of the RRG has been particularly valuable in providing expertise and insights to not only iteratively shape our engagement activities but also how we interpret and consider the results.

What is clear from our engagement program is the emergence of two key challenges to manage:

1. Actively supporting the empowerment of customers through an equitable transition to renewable and decentralised energy whilst managing the increasing risks of climate change to network and community resilience; and

2. Providing value for money services, in the context of increasing energy prices and cost of living pressures, that meets customers' service expectations through a constrained expenditure allowance that promotes efficiency and innovation.

Our engagement findings, broadly speaking, suggest that our Preliminary Proposal struck an appropriate balance between these competing priorities. However despite the increasing environmental and economic challenges over the course of the Prioritise Phase of our engagement program, the direction from customers became clearer and we saw consistent preferences from customers and stakeholders to invest more than was proposed by our Preliminary Proposal in improving network resilience and in enabling customers' future energy choices.

These were the consistent preferences across our pillars of evidence – particularly the Customer Panel outcomes and the Stakeholder Deep Dives, where these questions were considered deeply. This is detailed further in Attachments 5.09 and 5.10, respectively.

Customers and stakeholders were in almost perfect alignment in the degree of their preference for Endeavour Energy to take a more proactive response to network resilience.

With regards to enabling future energy choices – both customers and stakeholders expressed strong preferences over time for Endeavour Energy to prepare for either a 'rapid', or an 'accelerated' energy transition, as opposed to the 'gradual' transition planning that formed the basis of our Preliminary Proposal.

In both of these key areas of influence (resilience and future energy choices), there was a consistent sentiment from customers and stakeholders that investment in the next regulatory period would set customers up for longer term benefits both in the provision of service and in the management of their future energy costs.

There were no other key areas of influence where strong alignment existed between customers and stakeholders that Endeavour Energy should do more than what was proposed in our Preliminary Proposal.

Nevertheless, we recognise that these preferences were expressed within an environment of genuine concern about the rising cost of energy and the broader cost of living. Further, the conditions of the economy continue change, with customers likely to face greater financial pressures into next year.

Our interpretation of the customer priorities in our Draft Proposal was to propose additional, modest and highly targeted investments in the key areas of influence that customers and stakeholders have strongly and consistently supported. In doing so, we have sought to respond adequately to customer preferences to deliver the services they most value while balancing this imperative (to deliver a customer-centric proposal that genuinely responds to the outcomes of customer engagement) with a focus on value for money investment and affordability.

Specifically, the adjustments made in our Draft Proposal in response to our Prioritise Phase engagement were as follows:

- We continued to constrain our capex forecast to below identified NPV positive projects to manage RAB growth and commit to productivity improvements in order to deliver our service outcome commitments. We did not revise this position despite a decline in FY22 reliability performance and customer preferences to improve long-term service outcomes through a short-term uplift in expenditure.
- We further increased our capex efficiency commitment by adopting a capitalised overheads forecast below both our internal forecast and $70 million (real, 2023-24) below the AER's standardised capex model derivation. We will also did not include any real cost escalation (for labour and materials) for our capex program which would have totalled more than $32 million (real, 2023-24).
- We made targeted and modest increases to our resilience-related expenditure and proposed an Innovation Fund for resilience, technology and Customer Energy Resource (CER) related trials.
- We used the AER's CECV methodology to develop our CER related expenditure program. This is despite our preference to average the AER's expert estimate and take a more proactive approach

to DER enablement in accordance with customer feedback. We also took a conservative position on other components of VaDER, including not valuing environmental benefits, as part of our broader commitment to constraining capex.

- We constrained our operating expenditure (opex) step change proposal to an amount significantly below the range estimated internally and from expert advice.
- We adopted a tariff assignment policy for our tariff structures and export tariffs based on the feedback provided by customers, retailers and stakeholders. We also proposed to introduce export charges and rewards.
- We revised our Business Narrative to recognise cost of living pressures as a new external factor and updated our objective to provide a value for money service to customers that addresses their long-term interests.
- We updated our engagement plan to add a 5th phase in order to "confirm" our findings to date in an evolving environment.

The release of our Draft Proposal in October 2022 included as Attachment 5.14, provided an opportunity for stakeholders and customers to review our engagement process and findings and consider whether we had correctly interpreted and responded to this feedback. We note this is a significant task and therefore our engagement on these questions remains ongoing as part of Phase 5 engagement. Noting that to date, and at the time of preparing this Proposal we have received positive feedback on our Draft Proposal and our response to the Phase 3 engagement findings.

5.3.2 Refine Phase (Phase 4)

We have received positive feedback on our Draft Proposal, which responds to the outcomes of the Prioritise Phase from the Customer Panel and the Independent Members Panel of the RRG. We continued to engage with key parties to refine our proposal prior to submission of this Proposal to the AER. This included:

- **Sense check survey & individual submissions:** Following the publication of the Draft Proposal in October 2022, we sought further feedback from customers and stakeholders regarding the Draft Proposal to refine our plans for lodgement with the AER. In addition to seeking individual submissions, a 'sense check' survey was issued in November 2022 to more than 350 customers and stakeholders and published on our Your Say Engagement Platform and social media channels to capture a broad range of feedback regarding our responses to the key themes of our engagement.

  The November survey was also designed to capture any recent shifts in preferences, especially with regards to affordability, in the changing economic environment. This survey was developed in consultation with the Regulatory Reference Group and complements feedback from stakeholders gathered during the development of the Draft Proposal. We received responses from Council of the Aging NSW, Energy Australia as well as a Council and customer. Across the individual topic areas in the Draft Proposal covered by the survey, 57% of responses rated Endeavour Energy's approach as 'somewhat acceptable', 18% 'very acceptable', 21% 'neither acceptable nor unacceptable' and 4% 'somewhat unacceptable'.

  Endeavour Energy also received three individual submissions. These included a combined submission from Business NSW and Business Western Sydney that commended Endeavour Energy's engagement for its engagement and endorsed the Draft Proposal; a submission from the Caravan, Camping & Touring Industry & Manufactured Housing Industry Association of NSW that encouraged further discussion about fair and equitable approaches to embedded network tariffs and their potential impacts on holiday parks and residential land lease communities; and a submission from a residential customer seeking information about microgrids and offering advice regarding the accessibility of our regulatory documentation. Refer to Attachment 5.18 for more detail.

- **Ongoing engagement with Retailers and Market Small Generator Aggregators (SGA):** In addition to the ongoing engagement with retailers through our Retailer Reference Group, Endeavour Energy held roadshows with six retailers (large and small) in the Refine Phase of engagement. Retailers supported the direction of the tariff strategy, which is centred on an accelerated uptake of cost reflective tariffs and increased simplicity. Retailers had differing views on the value of demand-based tariffs and on what constitutes increased simplicity for customers and increased simplicity for retailers. Retailers can continue to respond to options regarding the implementation of cost reflective tariffs for Endeavour Energy customers including the adoption of a transitional tariff and offering demand tariffs as an alternative to time of use tariffs.

  Given the increasing importance of the emerging energy markets, Endeavour Energy also actively sought feedback from emerging market participants on innovation, non-network market providers, and how tariffs can support a fair and efficient energy transition. This included workshops with several Market Small Generator Aggregators (SGA) with energy storage, aggregation or hybrid facilities. SGA's supported the direction of Endeavour Energy's proposal in regard to new and flexible market considerations, tariff reform, and how to best facilitate the increasing uptake of Customer Energy Resources. They highlighted the need for continual engagement and support to ensure customers long term interests from all parties in the energy supply chain.

- **Tariff engagement and pioneering Persona work:** Given the support for tariff reform from the Customer Panel weakened over the 5 months of engagement, Endeavour Energy sought to develop a greater understanding of the non-technological barriers to the uptake of cost-reflective tariffs by customers, and the narratives, messages and collateral that might lead to increased customer comfort with a move to mandated cost-reflective tariffs. Research was commissioned and completed in January 2023 to target our ongoing engagement in order to support our approach to introducing mandated cost-reflective tariffs that meet the needs of customers. This included pioneering persona work, transitional arrangements, simple educational messaging and key information, engagement and resources to best support customers adapt and respond to pricing signals. Refer to Attachment 5.19.

- **Ongoing local council engagement:** Endeavour Energy routinely engages with local councils and Regional Organisations of Councils. Following our Prioritise Phase local council workshops and a webinar regarding public lighting tariffs, three of the 22 councils we engaged responded to our offer of one-on-one engagements in the Refine Phase on the implications of the new public lighting tariffs for their communities. The public lighting tariffs have been well received by councils and the Independent Members Panel of the RRG.

- **Independent review of our engagement:** We also commissioned an independent review of our customer engagement program supporting the development of this Proposal. This review included twenty-five interviews with key stakeholders and identified differences of opinion were at the margins, with all stakeholders agreeing that the co-design engagement had been successful and that Endeavour Energy had met the AER expectations as defined in the AER's Better Resets Handbook. Further, this review identified that the customer engagement was genuine, authentic, sincere, active, and positive.

  There were innovative features of the engagement, in particular the "Dinner with Endeavour Energy" events that were very successful in engaging customers of culturally and linguistically diverse backgrounds. The review concluded that the involvement of Board members, the CEO, executives and senior staff in the engagement sessions had a significant positive impact, with customers reporting that they felt listened to and respected. Finally, the report reflected that while there was no single major change in the proposal, instead it was a longitudinal series of waves of changes, with a pattern of inform, listen, adapt, re-present, listen, adapt. For further details refer to Attachment 5.17.

5.3.3 How we have responded

Based on the feedback we received, through all phases of our engagement, we have in most respects, maintained our position from the Draft Proposal released in October 2022 with only minor amendments made to capture most recent actual expenditure results and forecasts. Our key engagement findings and response are summarised below:

Table 5-1 Electricity Summary of Endeavour Energy 2024-29 engagement findings and response

Key Findings	What we heard	How we have responded
Affordability and value for money	• Customers and stakeholders wanted a safe and reliable supply of electricity at an affordable price. • They wanted Endeavour Energy to find ways to limit spending due to growing concerns about affordability from higher interest rates and cost increases from other parts of the energy supply chain. • Despite this focus on affordability, customers told us they would support a small cost increase to improve network resilience due to extreme weather events, and to enable greater innovation.	• We have continued to adopt a restrained approach to investment in the delivery of priority customer services, tightly managing the costs we can control to keep our contribution to customer bills as low as possible despite rising external pressures driving up our costs including interest rates. • These decisions would mean the annual average price increase over 2024-2029 for a typical residential customer is limited to $48 (9.8% average increase on 2024 prices); and the average annual increase for small-medium businesses is limited to $86 (9.8% average increase on 2024 prices). These price increases are almost entirely driven by external factors, reflecting our commitment to ongoing customer affordability in the investment decisions we make on their behalf.
Reliability	• Most customers and stakeholders told us they would prefer the same level of reliability at a similar cost to today. Many customers also supported long term reliability improvements for customers with poor reliability.	• We are proposing investments to maintain reliability levels in keeping with customer preferences. We also propose $16m on targeted investments to support customers in the worst served areas of our network in accordance with our license conditions. • We will manage the increasing challenge of maintaining reliability by pursuing operational and technology efficiencies rather than additional investments that would drive up costs for customers.
Resilience	• Both customers and stakeholders wanted Endeavour Energy to take a more proactive approach to maintaining electricity supply during major weather events and other extremes such as cybersecurity threats and pandemics, and to work more closely with Government, other utilities and communities to improve community resilience.	• We are proposing additional capital expenditure of $28m to improve network and community resilience. • This will be invested in targeted initiatives that deliver value to impacted communities, including the replacement of 212km of bare conductor in bushfire prone areas; raising powerlines in flood-prone areas of the Hawkesbury Nepean catchments; and providing back-up power to critical infrastructure at community hubs in times of emergency.

Key Findings	What we heard	How we have responded
Sustainable growth	• In servicing new developments, most customers wanted electricity infrastructure to be built at the same time as other utilities at a steady cost. • There were mixed views about the fairest way to fund new connections, with a majority of customers and stakeholders opting for the existing 'causer pays' approach in which new customers cover the cost of their connection.	• We continue to propose a 'just in advance' approach to the timing of investment to support new growth, in line with customer preferences. • In line with customer and stakeholder feedback, we are also proposing to maintain the 'causer pays' approach to fund new growth. • Despite an increase in connection growth and forecast costs, we plan to offset the additional connection cost compared to the current period through greater internal efficiencies.
Supporting customer choice and innovation	• Customers and stakeholders wanted us to support an accelerated transition to a low carbon economy and minimise limitations to customer exports of energy, like rooftop solar. • As well as a cleaner environment, they want to save through smarter, more efficient technologies and greater choice and control of their energy use.	• We propose to increase our focus on innovation by establishing a $25m Innovation Fund, which will have oversight from a new customer reference group. The Innovation Fund will be invested in technology trials to open up opportunities for customers to participate in new energy markets to maximise the value of the energy they generate and the distribution of customer generated resources on the grid. • The Innovation Fund will be used in partnership with stakeholders to build community resilience and to innovate the delivery of our service, making it more resilient, sustainable and affordable.
Tariffs	• In-principle, customers are supportive of cost-reflective tariffs. Cost-reflective tariffs (which include off-peak and peak rates for electricity consumption) are considered fairer, because customers are charged for how and when they use the network. • The majority of customers preferred an opt-in approach to both cost-reflective and solar export tariffs as they prioritised choice and were concerned about the ability of customers to change their behaviour in response to different tariffs. • Most customers felt that a transition period and education would be important. • Other stakeholders were more supportive of mandating cost-reflective, solar export and other future new tariffs quicker.	• We are working with retailers to transition customers with smart meters to cost reflective tariffs, and we will support this change by conducting the transition over a two year period to help customers understand their energy usage and adjust their behaviour to take advantage of cost reflective tariffs; by offering transitional tariffs to help customers make that adjustment; and by working with retailers to understand what educational support customers need to make a smooth transition to cost reflective tariffs. • We will work with retailers to introduce a solar export and reward tariff on an opt-in basis from 1 July 2024. However, from 1 July 2025, we will place all new and upgrading solar customers on the tariff as the default, which they can chose to opt out of.

Key Findings	What we heard	How we have responded
Keeping customers at the centre of our decision making	• Customers wanted to be kept informed of planned and unplanned outages to minimise disruptions. They also wanted improved access to data to manage their electricity usage and bills more actively. • Other stakeholders focused on embedding our improved engagement approach into business-as-usual activities.	• We are improving our communication and management of planned outages and carefully measuring and responding to customer satisfaction in general customer interactions, as well as in interactions relating to planned and unplanned outages. We are also increasing access to information for customers through our website and via social media channels. • Our increased commitment to customer and stakeholder engagement is being adopted as part of our business-as-usual approach.
Smart cities and communities (streetlighting / councils)	• Local councils want to partner with us on managing severe weather, particularly extreme heat; improving community resilience; and accelerating the transition to renewable energy. • Councils are also seeking to rapidly transition to more energy efficient public lighting.	• We will continue to collaborate with the Western Sydney Regional Organisation of Councils and will expand this approach with all 22 councils across our supply area, focusing on resilience, sustainability and renewable technologies. • We are making new technology for public lighting more affordable, while also delivering significant energy savings to local councils. • We have updated our Public Lighting Modelling approach to simplify it so that new technologies can be transparently priced and more quickly introduced over the course of a regulatory period.

5.4 Assessment of our engagement and key learnings

5.4.1 Our assessment

Endeavour Energy's evaluation approach sought to genuinely and consistently measure whether our engagement reflected the intent of five key references:

- our engagement goal;
- the AER's Better Resets Handbook;
- professional advice from SEC Newgate Australia;
- Endeavour Energy's Stakeholder Engagement Framework; and
- IAP2 Core Values.

To achieve this, our engagement has been evaluated across three streams that combine opinion-based survey metrics and data that details the scope of the engagement plan. The three streams were:

1. Evaluation surveys for each engagement event.
2. More detailed quarterly evaluation surveys of the overall engagement approach, completed by the RRG.
3. Collection of data in relation to the scale of engagement.

The feedback has been consistently positive, with 95% of attendees rating the quality of our engagement event(s) as 'good' or 'excellent'. Attachment 5.01 to this proposal provides the more detailed evaluation findings. Evaluation ratings by our RRG were also consistently positive and are presented further below.

Our broader reflections are that while our Preliminary Proposal was driven by a desire to manage bill impacts and maintain existing service levels, we were surprised by and welcomed the strong sense of community that emerged in our customer research. In combination with deeply held views on de-carbonisation, climate change, and customer views that actions taken today would better serve their long-term interests, this drove a consistent desire for action on enabling customer choice, technological innovation and improving resilience.

We consider this community-mindedness and forward-thinking approach from customers to be an interesting development compared to the direction networks have previously received from customer engagement over the last decade. If this feedback is common across other networks and persists, the energy industry more broadly may need to reflect on whether the regulatory framework is keeping pace with the expectations and needs of customers.

While a high-quality engagement program was co-designed (and implemented) there is always room for improvement. We were surprised by the rapid and significant change in our operating environment throughout the Prioritise Phase. We tried to adapt to these changes as they arose, for instance we amended a Wave 2 Customer Panel agenda on the night of the AEMO market suspension to instead spend considerable time explaining this event to customers.

A faster and more obvious response to our changing environment is one area in which we think could have done better. This is the focus of the additional phase of engagement we have co-designed and are implementing following the release of our Draft Proposal in October 2022 (refer Attachment 5.14).

Another area for reflection is how we manage engagement fatigue among stakeholders, particularly those working across more than one Regulatory Reset at the same time. This requires continuous improvement in deciding which topics we take to which stakeholders and to what level of depth. As we deal with a diverse set of highly technical issues it is critical that we disseminate these issues in the right level of detail to the right audience.

We will continue to reflect on our engagement approach and consult on opportunities for improvement. Overall, we believe our engagement program has been high quality and reflects the honest and hard-working relationship between our staff and RRG. In Attachment 5.01 to this proposal, we provide a summary of how we consider our engagement approach satisfies the requirements of the AER's Better Resets Handbook as well as an assessment by our RRG in Attachment 5.13.

5.4.2 RRG assessment

A primary role of the RRG has been co-designing our engagement approach in an advisory capacity based on their extensive experience and knowledge of the energy industry. In its August report covering our Preliminary Proposal and the majority of our phase 3 engagement, the RRG made a number of observations and recommendations with respect to our engagement approach. The RRG note several aspects of our engagement program have been of a high quality[16]:

Consequently, we believe that Endeavour has done a high quality and comprehensive job so far on engagement in the 'Discover' and 'Prioritise' phases of the programme. The engagement and co-design plans initially devised in May 2021 have been followed with a high degree of consistency and capability. Our benchmarks for this assessment are clarity of the issues being consulted on, fairness and objectivity in the questioning, and breadth of engagement considering Endeavour's wide demographic makeup.

We recognise the extensive, carefully planned and executed, and inclusive way Endeavour has engaged with a wide range of consumer groups - including households, businesses, local councils, developers and their representatives. We have observed the significant resources Endeavour has put into the engagement and believe there has been a genuine commitment to 'listening'. There is evidence of strong consumer and wider stakeholder relationships indicated by the enthusiasm of the Customer Panel throughout the engagement process, as demonstrated by very few members discontinuing their involvement, the willingness to provide supportive messages, and the number and diversity of participants in the wider deliberative forums.

With the assistance of SEC Newgate, Endeavour has undertaken an engagement programme that, in our view, has been extensive and multifaceted.

From an Independent RRG perspective, we acknowledge that Endeavour has given us ample opportunity to work with them in the design and execution of the engagement, asked for and considered our advice and challenges, and sought to respectfully engage with consumers with a high degree of detail.

The RRG also identified several recommendations for how Endeavour Energy can improve its engagement and respond to emerging challenges for the energy industry:

- Presenting a clear distillation of the engagement data – 'what we heard': The RRG consider this is of critical importance and could have been better articulated in the Preliminary Proposal.
- Clearly linking 'what was heard' to 'how we respond': The RRG expected the Draft Proposal to clearly link engagement to how it was interpreted and reflected. They note the importance of this exercise highlighting the challenging economic environment and highlighting how the immediate influences were considered in interpreting the results.
- Adapt engagement to the evolving nature of 'lived experience': The RRG consider our engagement was initially slow to pivot to the economic challenges that emerged during our

[16] Refer to Attachment 5.13

engagement. The RRG considered that further engagement would be useful in ensuring we can be confident that the Proposal continues to meet the expectations of customers as their views may evolve.

- Reframing the concept of affordability through the lens of value for money: the RRG note the factors beyond our control that will increase electricity prices. Endeavour Energy should be transparent about these impacts and ensure customer preferences are confirmed in the full knowledge and experience of these challenges.
- Delivering on a challenging target for the Draft Proposal: Endeavour Energy has set a commendable but challenging target to maintain in the changing context. The RRG recommended we update our business narrative and conduct regular engagement to continually evaluate the impact of external factors on customer's energy needs.

We sought to continue our collaboratively engagement approach and respond to the RRG's feedback in developing our Draft Proposal. Following the release of the Draft Proposal, the RRG provided an additional report in November 2022 reaffirming the quality of our engagement process and adherence to the Better Resets Handbook requirements and acknowledging we had addressed their recommendations[17]:

In August 2022, we provided comprehensive and detailed feedback to Endeavour Energy's Preliminary Proposal published in April 2022 and subsequent engagement. That feedback was supportive of Endeavour Energy's consumer and stakeholder engagement programme through the Discover and Explore phases. One key recommendation of that feedback was to encourage Endeavour Energy to distil the extensive data drawn from the many instances and forms of engagement into a concise and well-reasoned summary of 'what was heard.' This led to the development of the Engagement Summary Report, published at the same time as the Draft Proposal, which is a comprehensive overview of the extensive engagement activities and the way Endeavour Energy has interpreted the findings into the Draft Proposal.

Endeavour Energy has addressed each of the issues we raised in our August report. This includes an increased focus on affordability and options that provide customers with value for money, and the need to adapt engagement to reflect a fast-changing social environment and increasing energy costs.

Since the work on the Preliminary Proposal, we have worked with Endeavour Energy in updating the overarching business narrative of the reset to reflect the emerging economic volatility and increasing pressures in the cost of living stemming from rising energy prices. In addition, we have examined several technical capex business cases in detail to consider Endeavour Energy's approach to energy supply risk and the application of non-network solutions to consumer needs. We have also worked with Endeavour Energy to encourage the transparency of the productivity improvements flowing from the significant ICT investment in this period, and how that productivity is delivering downward price pressure for consumers.

In the transition from the Prioritise to the Refine phase of the reset process, we have invested significant time into considering the form and purpose of the proposed Customer Panel deliberative forum waves and local targeted workshops with retailers, local councils and energy retailers.

[17] Refer to Attachment 5.15

Overall, we consider Endeavour Energy has met the guidelines of the AER's Handbook in the development and execution of its engagement process. This observation results from our extensive involvement in the development of the Draft Proposal to date, but more importantly reflects our first-hand observation of Endeavour Energy's commitment to an accessible, wide-ranging, clear and transparent engagement process and their willingness to share information early on and to listen and respond to feedback.

As part of the ongoing 'Refine' and then 'Confirm' phases of our engagement program the RRG noted the increasing pressure for Endeavour Energy to continue to find cost reductions to help restrain overall electricity bill increases. The RRG was also interested in further engagement on understanding our Innovation Fund, the impacts of SOCI on cyber security spend, customer needs regarding network resilience and our draft TSS.

Evaluation outcomes: how our Regulatory Reference Group rated our performance

We worked with the RRG to co-design a quarterly survey to measure our performance against key elements of the AER's Better Resets Handbook as well as our revenue determination goal and stakeholder engagement framework principles, and IAP2 core values.

This survey was fielded five times through the development of the Regulatory Proposal to give us timely feedback on how we were progressing and allow adjustments to our engagement approach as necessary. Results for the final fifth wave are shown below.

All attributes were measured on a scale of excellent, good, fair, poor or very poor and open-ended responses on reasons for scores were encouraged. The reports were shared with the RRG and feedback was discussed.

We set a stretch target of 100% combined 'good' or 'excellent' ratings, reflecting our commitment to deliver best practice engagement. The tables below show that we met these targets on all but one metric where one independent RRG member scored us 'fair'. This related to feedback on the framing of some of the questions we used for engagement.

Table 5-2 AER Better Resets Handbook Criteria

Key Performance Indicator	Outcome at time of submission (% 'good' or 'excellent')
Nature of engagement overall: Delivering a customer-focussed engagement program	**100**
Sincerity of engagement: **D**emonstrating sincerity in engaging with consumers to understand and reflect their preferences in the Regulatory Proposal, extending down from the Board and Executive	**100**
Accountability: Commitments arising from consumer engagement are reported to allow for evaluation and ensure accountability	**100**
Sincerity of engagement: Being genuinely open to feedback and willing to explore new ideas and change	**100**
Consumers as partners: The business collaborates with consumers, making them partners in forming proposals rather than simply being asked for feedback.	**100**
Multiple channels of engagement: Providing multiple channels of engagement to gain a comprehensive understanding of consumer preferences	**100**

Key Performance Indicator	Outcome at time of submission (% ‘good’ or ‘excellent’)
Consumers’ influence on the proposal: Considering the IAP2 Spectrum of Public Participation in development of the engagement plan, working with consumers to agree the issues they can influence	**100**
Clearly evidenced impact overall: A proposal that clearly explains how customer feedback has influenced it	**100**
Proposals linked to consumer preferences: Delivering a proposal that clearly links consumer research and engagement, the outcomes desired by consumers and how the proposal gives effect to those outcomes	**100**
Proposals linked to consumer preferences: Delivering a proposal that explains how diverse or divergent consumer views were considered	**100**
Equipping consumers: Providing consumer advocates with impartial support to engage with energy sector issues	**100**
Accountability: Regularly evaluating the effectiveness of engagement, taking feedback on board and refining the approach as appropriate	**100**
Accessible, clear and transparent engagement: Delivery of transparent engagement plans that include objectives, issues/topics and level of participation and influence that consumers can expect; with consultation time frames appropriate to the complexity of the issue and different engagement methods used when appropriate	**100**
Consumers as partners: Ensuring consumer engagement is a continuous business-as-usual process and not only undertaken solely in preparing for regulatory proposals	**100**
Equipping consumers: Equipping consumers with accurate and unbiased information necessary to participate in a meaningful way	**100**
Breadth and depth overall: Appropriate breadth and depth of engagement with consumers	**100**
Consultation on desired outcomes and then inputs: Consulting consumers on the long-term outcomes they want from the proposal and how they would like Endeavour Energy to engage with them to develop a proposal that will deliver those outcomes	**83**

Table 5-3 Additional attributes from Endeavour Energy’s Revenue 2024-2029 Determination Engagement Goal

Key Performance Indicator	Outcome at time of submission (% ‘good’ or ‘excellent’)
Engaging with a broad, diverse group of customers and stakeholders	**100**
Engaging on topics that reflect customer priorities	**100**
Delivering a Proposal that provides fair access to the modern grid	**100**

Table 5-4 Additional attributes from Endeavour Energy's Stakeholder Engagement Principles

Key Performance Indicator	Outcome at time of submission (% 'good' or 'excellent')
Transparent: Provides appropriate feedback loops for engagement with RRG members	**100**
Responsive: Doing what we say we will do	**100**
Best practice: Appropriate level of involvement of Executive, CEO and Board in engagement	**100**
Purposeful: Clearly explaining the purpose of each engagement activity and how feedback will inform Endeavour Energy's Proposal	**100**
Timely: Provide peak stakeholders (including RRG members) with timely information on engagement schedules and timely responses to questions and feedback	**100**
Responsive: Reflecting stakeholder needs and preferences in the design of our stakeholder engagement methods	**100**
Best practice: Striving to take a best practice approach to stakeholder and community engagement, including using the IAP2 framework	**100**
Collaborative: Sharing the results of engagement activities and associated evaluation with our stakeholders	**100**
Transparent: Provides appropriate feedback loops for engagement with end-customers	**100**
Collaborative: Working collaboratively with peak groups from the start to develop an appropriate approach to consumer engagement that considers topics, audience segments and scope for customer influence	**100**

Table 5-5 Additional attribute from IAP2 Core Values

Key Performance Indicator	Outcome at time of submission (% 'good' or 'excellent')
Ensuring that anyone who wishes to contribute to the discussion, can do so	**100**

Table 5-6 Additional attributes from Endeavour Energy's translation of engagement into the development of the Proposal

Key Performance Indicator	Outcome at time of submission (% 'good' or 'excellent')
Explaining how customer feedback has clearly influenced the Proposal	**100**
Working collaboratively with customers and stakeholders to develop the Proposal	**100**
Explaining the reasons why customer feedback has not influenced the Proposal where relevant	**100**
Delivering a Proposal that reflects customer preferences and priorities	**100**

Key Performance Indicator	Outcome at time of submission (% ‘good’ or ‘excellent’)
Delivering a Proposal that provides fair access to the modern grid	**100**

5.4.3 Embedding BAU engagement

Endeavour Energy is committed to embedding high quality engagement as a feature of the way we do business. We have monthly reporting by the Chief Customer & Strategy Officer to the Board on customer service initiatives and we have committed to a regular, proactive engagement program with different customer segments, not just throughout the regulatory review process, consistent with feedback provided to Endeavour Energy in its last regulatory process.

To achieve this, Endeavour Energy has made significant investments in engagement in recent years to upskill and support staff, to increase dedicated resources (for example, customer account managers have been assigned to deepen engagement with key customer segments, including local government; data centres and high energy users; retailers and sensitive/vulnerable customers) and to establish new channels to regularly ‘check-in’ with customers and stakeholders to understand their views and preferences and then ensure these are considered in decision making.

We have also pursued better engagement across all sectors of the energy industry as one of the original signatories to The Energy Charter, committing to work collaboratively to achieve better customer outcomes. Endeavour Energy has actively contributed to Energy Charter #BetterTogether Teams which this year resulted in 2,000 fewer customers being disconnected; helped to rebuild trust across CALD communities by engaging in-language and in-community; and partnered with other signatories to build a community of practice that promotes deeper understanding and improved responses to customer and community engagement.

To this end, many aspects of the regulatory engagement process are actually business-as-usual activities that were established ahead of the regulatory cycle. Now enhanced, we expect they will remain in place for the years to come.

Results from these activities are reported to the Board and Executive Leadership Team on a regular basis to enable strategic leadership that is informed by customer preferences. These include forums like the PCSC (meeting quarterly), the State of the Network forums (due to take place bi-annually), the monthly Voice of Customer which helps to identify actionable customer pain points and Endeavour Energy’s monthly customer and annual stakeholder reputation surveys.

Endeavour Energy will also continue as an Energy Charter signatory, publicly accounting for its journey towards a customer centric culture as the industry transitions to a clean energy future while collaborating across the energy industry on some of its most complex customer issues.

Our retailer engagement strategy includes ongoing coordination with retailers to ensure customer can access fair and innovative tariff structures, as well as educational support, in order to ensure all customers have access to the energy market.

Looking ahead, plans are in place to review the learnings from this regulatory engagement period and to embed the structures, processes and channels required to ensure high quality engagement sits at the core of what we do. This is dependent on future decisions on strategy, resourcing, accountabilities, and capability needed to sustain Endeavour Energy’s position as a leading, customer-centric energy business.

As part of this review process, we will also revise the role, capabilities and membership of our PCSC and Sub Committees to ensure customer voices are central to our plans for the energy transition, and also consider the scope, purpose, operation and costs of an ongoing Customer Panel.

6. Service Regulation & Control Formulae

6.1 Overview

We are aligned with the AER position on service classification and will apply a number of the AER's modelling outcomes to support our Proposal

Through service classification, the AER examines which services relate to the shared distribution network are specific to an individual customer or can be provided by others in a contestable market. Categorising services in this way allows the AER to determine how the cost for providing these services should be recovered from customers. The classification of a service also determines the extent to which the AER's Ring-Fencing Guideline applies.

For the 2024-29 period we propose to:

- adopt the service definitions and classifications as per the Framework and Approach (F&A) paper;
- accept a revenue cap for standard control services and a price cap for alternative control services;
- accept the AER's proposed formulae to give effect to the control mechanisms;
- accept the AER's decision to continue to regulate our dual function assets (DFAs) as distribution assets for pricing purposes;
- submit a compliant negotiating framework document;
- apply forecast depreciation when rolling forward the RAB at the commencement of the 2029-34 period (as discussed in Chapter 8); and
- apply all incentive schemes for the 2024-29 period (as discussed in Chapter 9) including a Customer Service Incentive Scheme (CSIS) as a small-scale incentive scheme in accordance with clause 6.6.4 of the NER.

We also propose to apply the same four nominated pass-through events as approved for the 2019-24 period with some proposed definitional changes to clarify their scope and application.

6.2 Framework and approach

The AER published the final F&A paper for the NSW DNSPs on 29 July 2022. It established the AER's approach in regard to:

- classification of distribution services;
- control mechanisms;
- pricing of dual function assets;
- incentive schemes;
- Expenditure Forecasting Assessment Guideline; and
- depreciation to apply to the RAB.

This chapter discusses service classification and the control mechanisms adopted by the AER to regulate our services. The remaining issues are discussed elsewhere in this regulatory proposal.

6.2.1 Service Classification

The AER determines the most appropriate level of regulation for each of the services we expect to provide to customers. To do this, regard is given to a number of factors listed in the Rules. This helps to determine how the cost of providing particular services will be recovered from customers.

Although the current service classification has been appropriate and effective, we believe several recent developments meant that some changes to the classification were required for the new regulatory period. For instance:

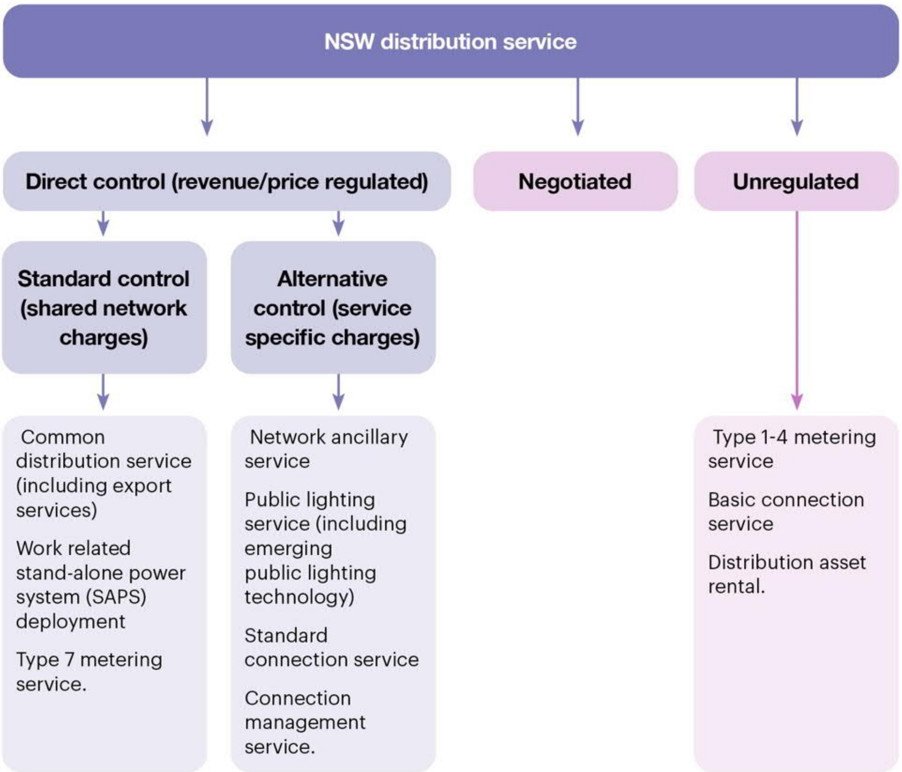
- the access, pricing and incentives arrangements for AEMC's DER rule change which clarified the role of networks in providing export hosting services;
- the emergence of "community batteries" and EVs;
- the introduction of a national framework for the regulation of Stand-Alone Power Systems (SAPS); and
- ongoing reforms relating to distribution system operator (DSO) and system strength services.

The AER considered these issues during the F&A process and modified the 2019-24 service listing accordingly.

2024-29 Service Classification

In consideration of the changes described above, the AER has replaced the 2019-24 service classification. The AER's service classification of NSW distribution services for the regulatory period 2024-29 is outlined below.

Figure 6-1 AER service classification summary for the FY25-FY29 period



The listing is largely consistent with the existing classifications with limited changes made to accommodate the matters listed above and to bring it into alignment with the AER's Distribution Service Classification Guideline.

We note that some drivers of change, such as system strength service reforms, were at a nascent stage at the time of the AER's F&A process whilst others, such as the AEMC's ongoing metering competition review, have largely progressed since the F&A was completed.

In the final F&A the AER noted that a departure from its final decision may be warranted where circumstances materially change during the determination process. This was particularly with respect to work by the Energy Security Board (ESB), the AEMC's metering review and the AER's own incentives review.

We agree that changes are likely to be required to the AER's service classification prior to the AER's final determination. However, at the time of preparing this Proposal we are not in a position to propose any amendments. In preparation for our Revised Proposal, we intend to engage with the AER and stakeholders on the following:

- **'Powering Australia' Community Battery rollout:** The 2022-23 Federal Budget includes $224 million over 4 years to rollout 400 community batteries across Australia. Distribution networks will be a key deliver partner in facilitating this initiative. A ring-fencing class waiver is being consulted on to enable the participation of networks in an efficient manner with controls around cost allocation and/or revenue sharing. However, there may also be merit in updating the service classification guideline as opposed to a ring-fencing waiver.

- **AEMC Metering review:** the AEMC released its draft recommendations report in November 2022[18] which sets out a series of options to accelerate the transition to smart metering and improve access to power quality data (PQD). Based on the draft recommendations it does not appear the role of networks will extend beyond developing a legacy meter retirement plan. However, we would expect this activity to be a standard control service.

  We note our support of accelerating the rollout of smart metering with a target date of 2030. However, this could create material pricing impacts for our ACS Type 5 and 6 Metering service as diseconomies of scale become more pronounced and the remaining metering asset base is

[18] https://www.aemc.gov.au/market-reviews-advice/review-regulatory-framework-metering-services

recovered over a progressively smaller customer base. It may therefore be worth considering whether a service classification change could be made for the recovery of the remaining asset base to better facilitate the transition to full competition.

A more fulsome assessment will need to be made following the final report as to whether any changes are required to the service classification.

- **AER RERT Class Waiver:** In November 2022 the AER commenced consultation on granting a class waiver to allow DNSPs to provide RERT services via voltage management to AEMO for the 2022-23 Summer period. This issue has previously been considered as part of the AER's Distribution Service Classification Guideline, however it may be worth revisiting in our service classification for the 2024-29 period which we consider to be preferable to a waiver-based approach.
- **AEMC Operational Security Mechanism (OSM):** In September 2022, the AEMC released its OSM draft determination. The OSM will be used to value, procure and schedule security services which may include distribution networks. The final determination may therefore warrant the inclusion of security services within the role of a distribution network in the service classification listing.
- **AER Connection Guideline review:** In October 2022 the AER published draft changes to the Connection Charge Guideline to specify the limited circumstances under which a network may impose a zero static export limit. Following the final changes, a new service may be required (or confirmation of its coverage within the existing listing) related to a customer funded alleviation of a static zero export constraint where the cost of augmentation is not economic.
- **The Energy Security Board's (ESB) Post 2025 Market Reforms:** This suite of reforms calls for DNSPs to assume new responsibilities and operate as a Distribution System Operator (DSO). This is expected to involve enabling the dynamic management of the distribution system and coordination of the uptake in CER in a safe and efficient manner, while maximising customer outcomes[19]. Based on the ESB's three-year horizon of CER implementation plan[20], the clear pathway to defining and developing DSO roles and responsibilities is expected to be engaged on in 2023.

We also confirm that we have not sought an exemption to include any restricted assets[21] within our proposal for standard control services capex, pass-throughs or contingent projects.

Dual Function Assets

As part of the 2024-29 F&A, the AER confirmed its decision from previous determinations that distribution pricing would continue to apply to our dual function assets. This was due to our dual function assets being an immaterial proportion of our overall regulated asset base. Further, these assets are dedicated to our distribution network meaning that separately pricing them as transmission assets would not have any material impact on our distribution prices.

Negotiating Framework

We agree with the AER that none of the services we provide are suited to being classified as negotiated distribution services. Nevertheless, it is our intention to provide a compliant negotiating framework outlining the procedures we would otherwise follow in negotiating the terms and conditions of any prospective services with other parties for completeness.[22] Our negotiating framework, Attachment 0.12 to this proposal, remains largely consistent with the negotiating framework we submitted for the 2019-24 period.

6.2.2 Control Mechanism and Formulae

Control mechanisms provide the basis of how the AER is to regulate standard control and alternative control services. That is, they determine how the prices charged and revenues raised from customers for regulated distribution services are to be controlled. The control mechanisms available to the AER are listed in clause 6.2.5(b) of the NER.

[19] ESB Post 2025 market design final advice to energy ministers Part B (released 26 August 2021).
[20] ESB 2021 DER Implementation Plan – Appendix A.
[21] A restricted asset refers to an item of equipment that is electronically connected to a retail customer's connection point on the same side at the metering point, excluding a network device.
[22] NER 6.7.5 (a)(b)(c)

Typically, the AER applies either a cap on the price we can charge for a particular service or a cap on the total revenue we may collect from our charges. In its F&A paper, the AER has elected to maintain the existing forms of control for standard control services and alternative control services for the 2024-29 regulatory period. We support the AER decision and propose no change at this time.

Formulae to give effect to the form of control

In addition to specifying the basis of the control mechanism for direct control services, the AER is also required to set out its proposed approach to the formulae that give effect to the controls adopted[23]. In the 2024-29 F&A paper, the AER has largely adopted the same formulae for both standard and alternative control services with minor amendment.

We note that the AER is able to amend its formulae that give effect to the control mechanisms only if the AER considers that unforeseen circumstances justify departing from the formulae. We do not propose any changes to the formulae, and therefore we have adopted the AER's decision.

Relatedly, in November 2022 the AER published its final position paper on the Annual Pricing Process Review – Side constraint mechanism. We accept and will adopt the AER's decision on how the side constraint mechanism will be applied per this paper.

[23] NER 6.8.1(b)(2)(ii) and 6.12.3

6.3 Maintaining our focus on risk management

Occasionally events of either uncertain timing or cost occur that cannot appropriately be included within our forecast plans.

Pass-through events provide a mechanism by which a DNSP can recover costs incurred in response to the occurrence of events of a particular nature as prescribed in the Rules or nominated and approved as part of a determination. For the 2024-29 period we propose the same four nominated pass-through events that applied for the 2019-24 period. Our approach to contingent projects is contained in Chapter 9 of this proposal.

6.3.1 Pass-through events

The pass-through mechanism in the NER recognises that a DNSP can be exposed to risks beyond its control, which may have a material impact on its costs. A cost pass-through allows a business to seek the AER's approval to recover (or pass through) the costs of a defined, unpredictable, high-cost event.

A building block proposal may include an indication as to the events that should be defined as pass-through events, in addition to the events defined under NER clause 6.6.1(a)(1).

As part of our BAU risk management, we regularly undertake a thorough risk assessment of our operations using the bow-tie risk analysis methodology.[24] We have cross-checked the results of this analysis against our historical risk register. From that analysis we have identified a number of risks which we consider should be managed via a nominated cost pass-through event rather than an allowance in our regulatory proposal. If a pass-through event occurs a proposal will be submitted to the AER who will then make a determination on the amount to be added (if any) to our revenue allowance for the 2024-29 period.

Based on this assessment, we propose the following events be approved as part of our regulatory determination, which are to apply as nominated pass-through events during the 2024-29 regulatory control period:

- insurance coverage event;
- natural disaster event;
- terrorism event; and
- insurer's credit risk event.

We have amended the names and definitions of these events to bring them into alignment with recent AER decisions and/or to improve their clarity.

In proposing these events, we have had regard to the qualifying criteria detailed in the Rules and consider that each event meets the necessary requirements to be approved as a nominated cost pass through event. We also note that these nominated events were proposed in our 2019-24 proposal and subsequently approved by the AER (with amendments).

We consider these events continue to pose a risk to our network and our ability to manage these risks outside of the pass-through mechanism has not changed. We have assessed our practices and circumstances and consider these nominated pass-through events remain valid. Our detailed assessment of how they meet the pass-through event considerations is provided in Attachment 0.11 of our proposal.

Insurance coverage event

We have amended the name of the insurance cap event to insurance coverage event and the associated definition to align with the AER's final guidance note on insurance coverage pass through events and recent decisions.

We also note the AER's expectations as set out in the final guidance note for the proposed information a network should provide in support of any proposal for this pass-through event.

[24] The bow-tie methodology considers plausible worst case hazardous events and identifies both the preventative controls to reduce the likelihood of the risk occurring and mitigation controls to reduce the consequence of the event.

Natural disaster event

We have amended the definition of a 'natural disaster' event to clarify that an 'event' can relate to an isolated and/or series of related natural disasters consistent with the AER's application of the existing definition[25]. We note that this amended definition does not expand the coverage of this event but to instead provides clarity given extreme weather events can occur over several days (and weeks) and/or locations with fluctuating impacts.

For instance, the 2019-20 Bushfire season involved multiple mega fires burning across large areas of NSW and triggered pass-through applications from multiple NSPs including Endeavour Energy, Essential Energy and TransGrid. Unlike previous seasons, bushfires commenced burning from July 2019 until most were extinguished by heavy rains in February 2020.

The multiple, dispersed and concurrent nature of the fires required affected NSPs to undertake a holistic network response to manage the damage to their network and impact to customers. Despite different temporal and spatial aspects of this response, each individual bushfire shared a common underlying cause – lightning strikes in highly vegetated areas impacted by sustained hot, dry weather and drought.

Similarly, the 2019-20 storm season was punctuated by high intensity weather events including torrential rainfall, damaging winds and lightning. Major storms were experienced from November 2019 through to February 2020 and impacted areas across Greater Sydney and the Hunter regions. High temperatures and prolonged drought were factors that contributed to the unusually severe storm season.

Given the events over recent years and expectations that networks will be more frequently and materially impacted by climate change, we believe there is scope to refine the definition to make it clear that a natural disaster can occur on different days and be spread across disparate geographical locations. Where the underlying cause is the same, we believe it is reasonable that a series of interrelated events should be considered collectively as a single pass-through event.

The AER has applied the existing definition in a manner consistent with this understanding of the dynamic nature of natural disasters. Whilst this definition change may therefore not be necessary, we consider it good practice for the definition to be updated to clarify and reflect its effect in practice. We also note that the AER's assessment would continue to have close regard to what constitutes a related event.

Unlike other definitions, we have not updated this event to reflect the AER's most recent decision. Historically, the definition has noted that in assessing a natural disaster event pass through application, the AER will have regard to, amongst other things, whether a relevant government authority has made a declaration that a natural disaster has occurred.

This factor has not been included in recent decisions, although a similar one has been maintained for the 'Terrorism' event. We consider it should remain a relevant, if not determinative, factor in the AER's assessment of a natural disaster event. We accept that there may be circumstances where a declaration by a government authority is not made but the definition and assessment criteria are satisfied. However, where a declaration has been made this would be compelling evidence in support of a proposal. It would be difficult to fathom a circumstance wherein a natural disaster is declared by a government but not recognised by the AER as one in assessing a pass-through proposal (setting aside the assessment of the efficiency and prudency of the costs incurred).

We therefore consider this factor should be maintained and note it does not bind the AER but simply ensures regard is given to what we consider to be a highly relevant factor.

Terrorism event

We note networks have previously proposed additional events for other malicious acts such as cyber-attacks and war. The AER has previously confirmed cyber-terrorism would be captured by the terrorism event and considered a war event may be too broadly defined to satisfy the pass-through considerations besides where a physical invasion of Australia occurs.

[25] Whilst the existing definition allows for multiple, related weather events to be considered collectively a 'natural disaster' event for pass-through purposes we consider it good practice for the definition to be updated to remove any potential for ambiguity.

On the latter point, we do not consider establishing the nexus between an act of war and increased costs to be any more or less difficult than doing so for a terrorism event. The only difference between an act of war versus an act of terrorism is likely to be the belligerents involved and their motivations.

In our view, the ‘terrorism’ event remains a valid and enduring threat, but it is also risks becoming antiquated and narrow in its language and focus. By its current definition, the event refers to acts done for, or in connection with, political, religious, ideological or similar motivations. This could be applied in a limited away to exclude other acts of aggression or malice, such as, cyber-attacks done for ransom or for the sake of causing disruption alone rather than to stoke fear in the community to achieve an ideological end.

There may be merit in changing the ‘Terrorism’ event name itself to ‘Acts of aggression’ and/or adjusting the definition to focus on intentional and malicious acts of aggression rather than a subset of them (terrorist attacks). Alternatively, the AER could re-confirm and/or clarify how the event as currently defined remains suitable in an evolving geopolitical environment. We consider acts of war, terrorism and/or cyber-attacks to be so similar in the outcomes they impose on customers that they should be captured collectively by this nominated pass-through event.

7. Demand, Energy & Customer Forecasts

7.1 Overview

Customer growth, peak demand, energy consumption and customer technology uptake are all forecast to grow. This means focusing on the necessary investment to ensure safe, sustainable, resilient and reliable electricity for our rapidly developing communities.

We currently have over 1.08 million customers connected to our network and expect a further 119,000 new customers to connect before the end of the 2024-29 period. These customers have energy, demand and generation export requirements that we are expected to meet.

Our customers are also changing how they use our network and investing significantly in CER to supplement their energy requirements. Currently, 23% of our customer base own solar PV systems with a capacity of 1GW and a further 200MW of commercial and industrial sized solar generation. This is expected to grow substantially in coming years along with uptake of batteries and EVs.

We are currently experiencing significant growth in customers, energy consumption and demand due to both the population, and industrial and commercial growth in our network area. We have forecast this growth to continue during and beyond the 2024-29 period:

- **System peak demand[26]:** the peak demand for 2021-22 was 3,716 MW. We expect this growth to continue over the 2024-29 period to a new record system peak demand of 5,014 MW[27] by 2028-29 on account of new connections and increased industrial activity;
- **CER (DER) penetration:** consistent with AEMO's ISP Step Change scenario we expect the number of solar PV customers to grow to 40% by the end of the period along with 16% of customers owning an EV and 9% owning a battery.
- **Customer numbers:** we expect to connect an average of almost 24,000 new customers each year over the 2024-29 period particularly driven by the unprecedented commercial, industrial and residential growth in Greater Western Sydney and forecast economic recovery; and
- **Energy consumption:** over the period from 2024-25 to 2028-29 we expect annual average growth in electricity consumption of 1%, largely a result of increased connections and increased commercial activity.

Our role is critical in supporting growth in demand, CER hosting, customer numbers and consumption. The primary driver of our augex and connections capex over the 2024-29 period is extending our network into greenfield development areas where there is no, or very little electricity services available. Whilst our CER capex is to support the ability of customers to connect and export CER across our low voltage network.

Our objective is to connect new development areas, CER and customers to the network in an efficient and timely manner. This will support affordable housing, employment opportunities, de-carbonisation and economic growth in our network area.

To achieve this objective and ensure we can meet the expected demand for our services, our expenditure forecasts must reflect a realistic expectation of the demand forecast and cost inputs required. We have robust forecasting methods that are tested and verified by independent experts and against the expectations of the NSW Government, AEMO and developers.

Table 7-1 Our system demand, energy and customer number forecasts

	2024-25	2025-26	2026-27	2027-28	2028-29
Maximum demand (MW) 50% PoE	4,595	4,646	4,772	4,889	5,014
Energy delivered (GWh)	16,751	16,850	17,187	17,448	17,679
Customer numbers (000's)	1,136	1,159	1,182	1,206	1,230

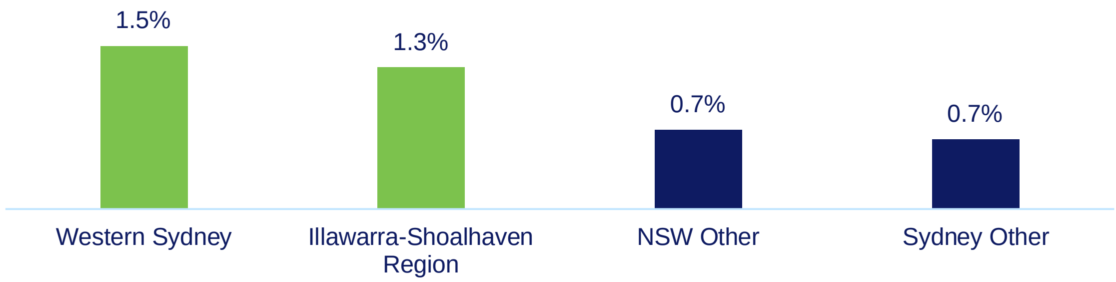
[26] The highest amount of energy being collectively consumed across our network net of embedded generation.
[27] Figure is based on a 50 percent probability of exceedance (POE) which is what is used for network planning purposes.

7.2 Our network

Our economic regions and customer base are growing

Greater Western Sydney is the focal point of future population and industrial growth in NSW. This strategic expansion, supported by the NSW Government, is expected to grow at a rate double the rest of metropolitan Sydney, as indicated below.

Figure 7-1 Population Growth in key franchise areas (2022-2041)



The Greater Sydney Commission has defined a vision of Sydney as a metropolis of 6 cities:

- The Eastern Harbour City (centred on the existing Sydney CBD)
- Greater Parramatta
- Western Parkland City (having the largest greenfield component)
- Metro Wollongong
- Gosford
- Newcastle

By 2036 half of Sydney's population will reside in Sydney's west, which lies entirely within Endeavour Energy's network. Whilst there have always been large areas of greenfield residential development there has been noticeable shift in the current period towards developing increased employment and services within Western Sydney which in turn has led to a shift to industrial/commercial development. A series of major transport, health and education projects are planned for these regions in 2024-29. The recent commencement of construction of a second international airport at Badgerys Creek within Western Sydney will drive further demand growth in the mid-term.

Figure 7-2 Greater Western Sydney 'by the numbers

Our network area encompasses a number of the Priority Growth Areas and Precincts designated by the NSW Government Department of Planning and Environment, including:

- **Western Sydney Aerotropolis:** a significant land rezoning in close proximity to the new Western Sydney International (Nancy-Bird Walton) Airport that will create more than 100,000 new jobs.
- **Greater Parramatta Area:** Redevelopment and $10b infrastructure investment plans to create 113,000 additional jobs and 72,000 new homes over the next 20 years.
- **Western Sydney Employment Area:** a region close to major road transport to providing businesses with land for industry and employment including transport, logistics, warehousing and manufacturing.
- **Westmead:** targeted to become Australia's premier district for jobs in health, education and innovation while promoting diverse housing (students, key workers) and connect via new Light Rail facilities.
- **Greater Macarthur Area:** Further land release to provide 30 000 new local jobs and 33 000 new homes around the Campbelltown region.
- **Southwest Sydney Area:** Continued staged land release and major road and rail infrastructure investment to improve economic development.
- **Northwest Sydney Area:** Significant rezoning changes of semi-rural regions and new planning controls to facilitate 33,000 new homes built by 2026 and improved transport infrastructure.
- **Sydney Metro Corridor:** Major urban renewal centred on the Northwest Metro - Australia's largest transport infrastructure project under construction.

This increase has driven above NEM average growth in our network for the last several years. Since the time of our last Proposal in 2019 there has been a significant increase in employment lands as summarised below.

Figure 7-3 NSW Government Land zoning changes 2020

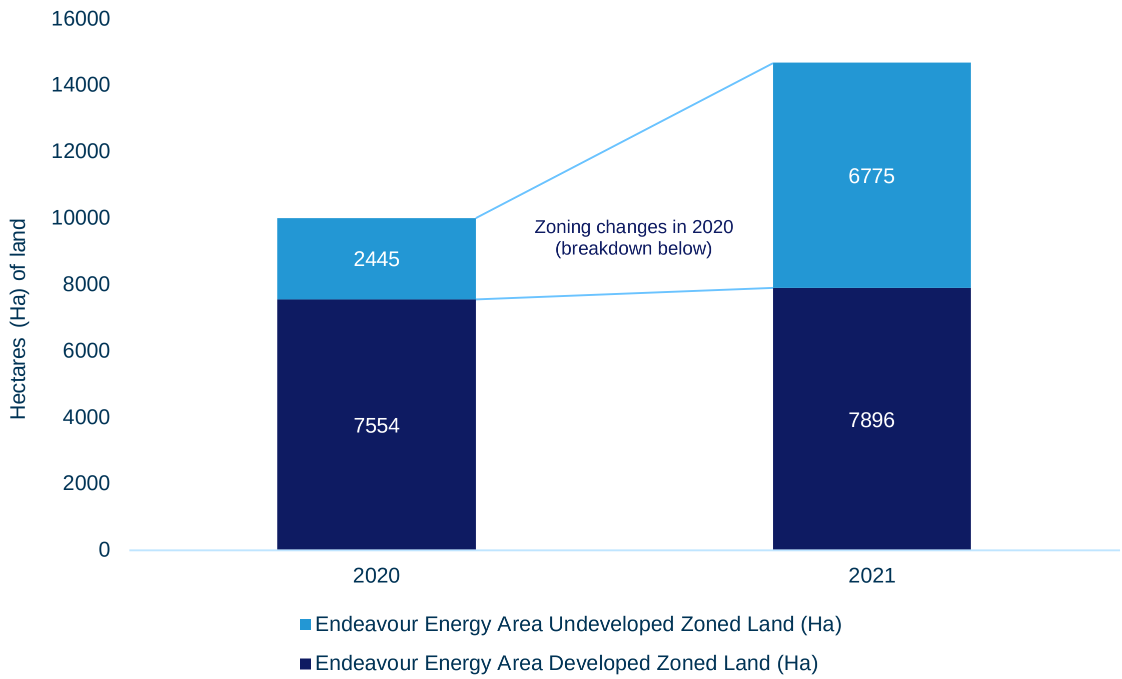
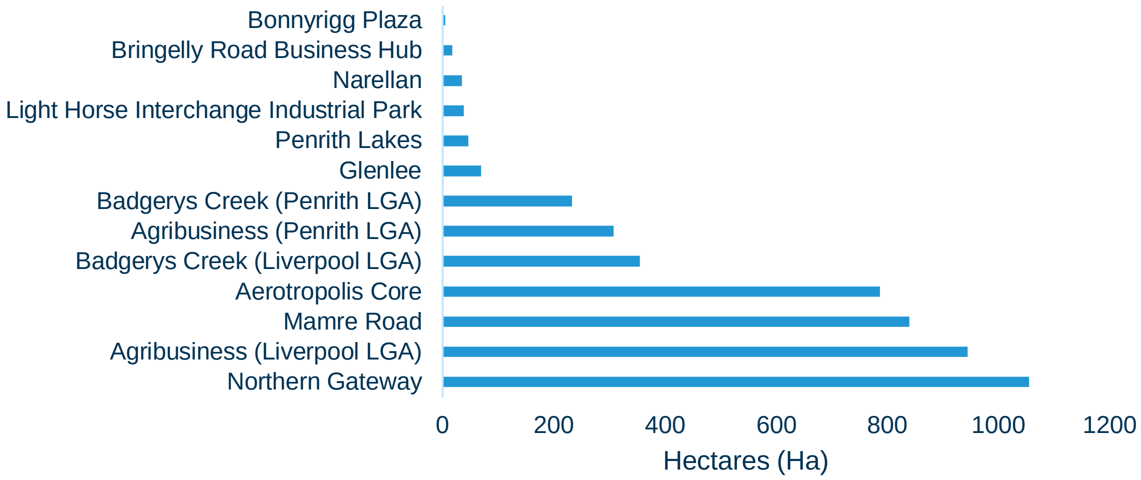


Figure 7-4 Breakdown of NSW Government Land zoning changes in 2020



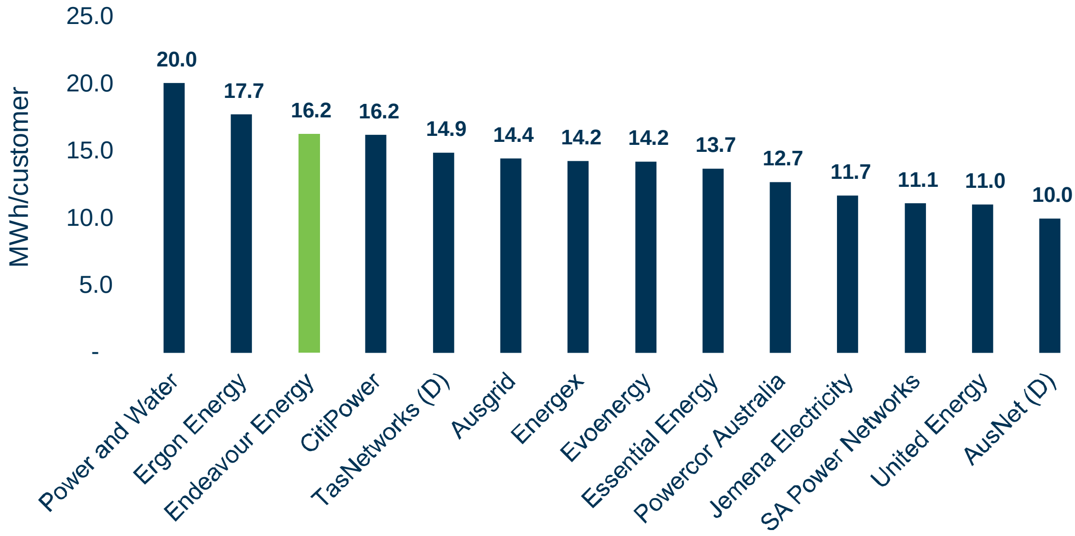
We work closely with developers, planning authorities and local councils to develop an understanding of the scope, scale and timing of developments to establish an accurate estimate of the number of new residential and commercial customer connections to our network.

As demand and usage profiles will vary across consumer types, understanding who our customers are and how their energy needs impact on the network helps us to derive accurate forecasts of demand and necessary investment on an as needed basis. This approach is facilitated by our Growth Servicing Strategy which identifies the status of plans to service all known brownfield and greenfield developments within the network area (refer to Attachment 10.14).

Our customers require a high amount of energy at peak times

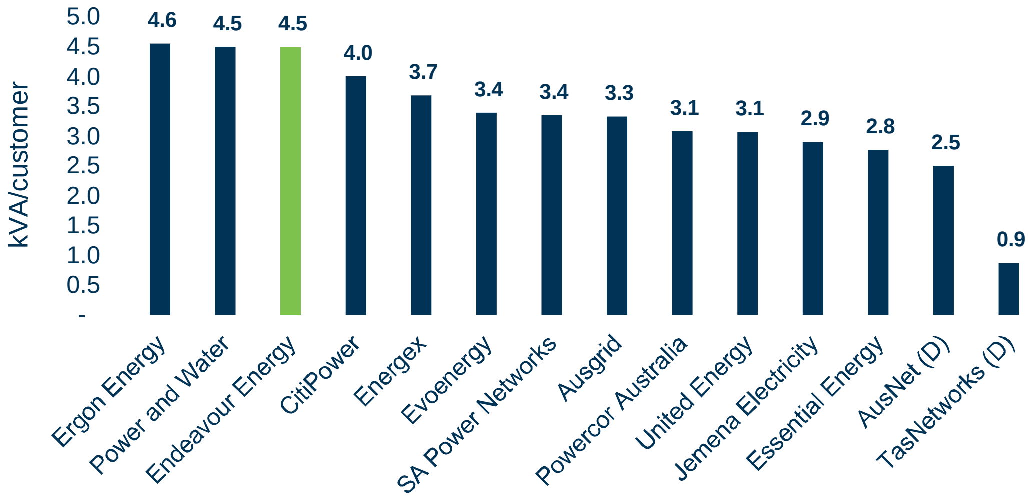
Our customers are reliant on their access to a dependable electricity supply. On average our customers have the third highest level of energy consumption and third highest peak demand at an individual level in Australia[28].

Figure 7-5 Energy density (average FY17-21)



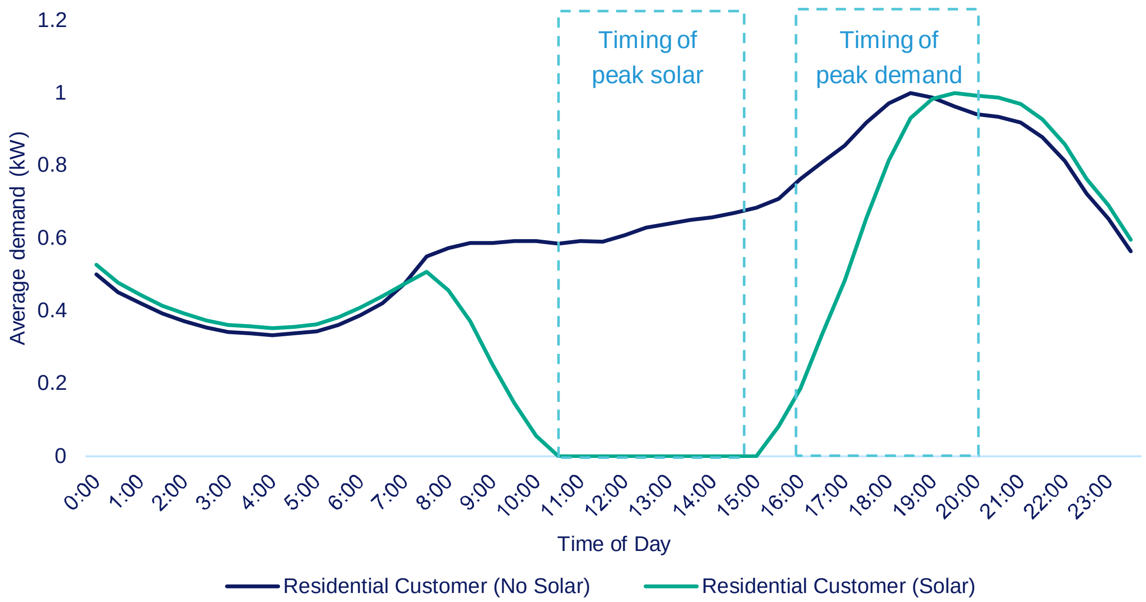
[28] Source: AER Benchmarking RIN Data

Figure 7-6 Demand density (average FY17-FY21)



The average consumption pattern of our customers is displayed below with peak demand likely to occur between 4pm to 8pm for residential customers.

Figure 7-7 Endeavour Energy - average residential customer consumption profile



Our customers require more energy at peak times due to the extreme temperatures that occur in our network area. Summer temperatures in Western Sydney can regularly exceed 40° Celsius with greater frequency than elsewhere in the Sydney metropolitan area in the absence of cooling coastal sea breezes. Conversely, during winter Western Sydney typically experiences lower average minimum temperatures than the Sydney CBD with snowfall in the upper Blue Mountains not uncommon during July and August.

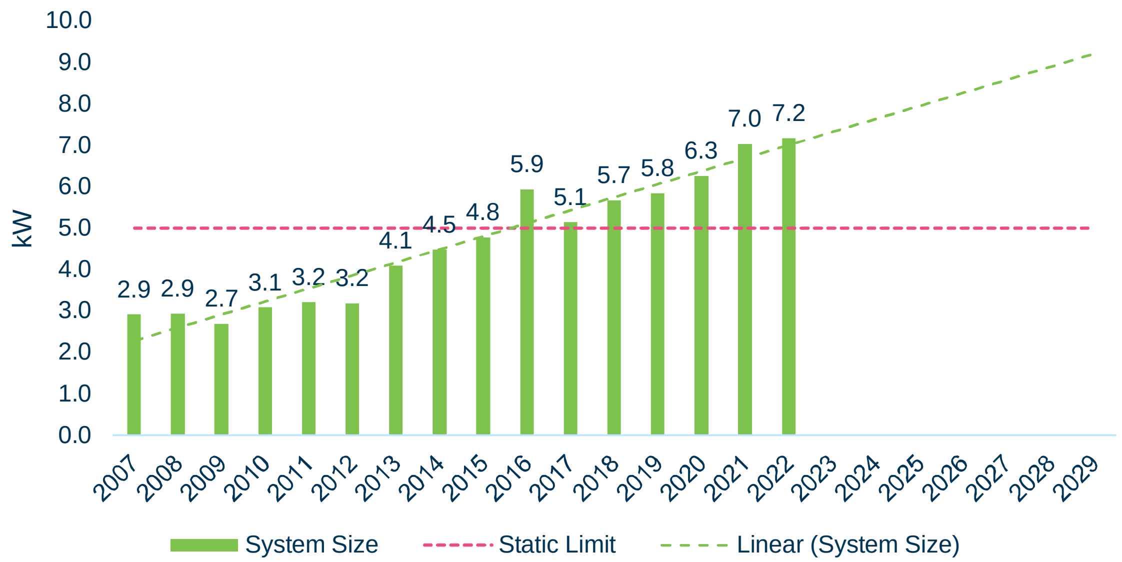
As a result, air conditioners are widely relied upon by our residential and business customers to provide relief during these temperature extremes. Air conditioning penetration rates in Western Sydney are approximately 80% with a high proportion of installs in newly constructed dwellings continuing to drive this trend. Despite recent improvements in energy efficiency and design, ducted and split system air conditioners remain relatively high energy consuming appliances and typically contribute a significant portion of our average customer's energy bills. There is also a timing mismatch between embedded generation and peak load times. This means that energy consumption is forecast to grow at a slower rate than demand over the 2024-29 period.

Our customers are adopting renewable technologies

Customers are increasingly turning to CER investments to take control of their energy use and electricity bills. These types of technology, and the network services that accompany their integration, is shifting the role of the network from a one-way flow supply to a platform of energy sharing. As Endeavour Energy enhances its capabilities as a platform for energy trading its role will shift from traditional distributor to Distribution System Operator.

There are approximately over 225,000 customers with small scale renewable generation connected to our network, representing a total capacity in excess of 1 GW. In addition to the increasing number of customers with solar PV, the average size of residential PV systems is also increasing. Between 2007 to 2022 the average residential solar system size steadily increased from 2.9kW to 7.2kW as a result of declining solar PV system costs and solar feed in tariffs.

Figure 7-8 Average residential PV system size 2007-2022



While customers with rooftop solar generation are still reliant on our network for supply during peak periods, the changing profile and volatility of supply and demand as a result of the high penetration of solar PV is evident. This can create network wide and localised issues which will need to be addressed. At the network scale, this includes the “duck curve” whereby solar input reduces the demand for electricity during the day at the same time as growth in electricity use increases night-time peaks.

This also increases the ramp-up required to meet evening demand. Local volatility, including voltage surges, can damage equipment, cause ‘trips’ or ‘faults’, and result in the temporary shutdown of solar inverters to restore voltages to safe limits.

We anticipate that battery storage will provide customers with solar PV systems the ability to control their energy usage and utilise their local generation during peak times.

Over the current period we have implemented both residential and grid-scale battery trials as well as our Solar Soak “Off-Peal Plus” trial to better understand the potential impact and benefits of CER and flexible demand. Consistent with AEMO’s Step Change scenario, we consider the take-up of this technology will increase materially as it becomes more affordable and familiar to customers over the next several years.

As a result, we intend to adapt our suite of cost-reflective tariffs and introduce export rewards and charges along with specific tariffs for grid-scale batteries, see our TSS (Attachment 0.14) for more details. We also have developed a CER Investment Strategy that sets out our process for identifying and alleviating export hosting constraints (Attachment 10.40). We discuss our export hosting forecasting approach in more detail in the remainder of this Chapter.

7.3 Network demand

As the energy industry undergoes transformational change the demand consumption patterns on our network also continue to change. Conventional measures such as maximum (peak) demand remain key to our understanding across much of our network, however, these are being increasingly challenged by the presence of significant levels of customer energy resources, increasing self-consumption patterns and two-way energy flows.

The maximum (peak) demand forecast is representative of the upper most level of combined network consumption at a given point in time and broadly representative of the combined demand of our network onto the NEM. This is, however, a net figure of customer demand and embedded generation after both self-consumption and local re-consumption. The energy both serviced and facilitated by our network (grid presence for operation of grid-tied inverter sources) is considerably higher.

As a summer constrained network, the highest levels of demand on our network are reached when hot weather drives simultaneous use of air-conditioning and other cooling loads (fans, evaporative coolers, pool pumps etc.). It is during these periods that the maximum demand most closely approaches the capacity of our network assets to provide a safe and reliable supply of electricity to our customers.

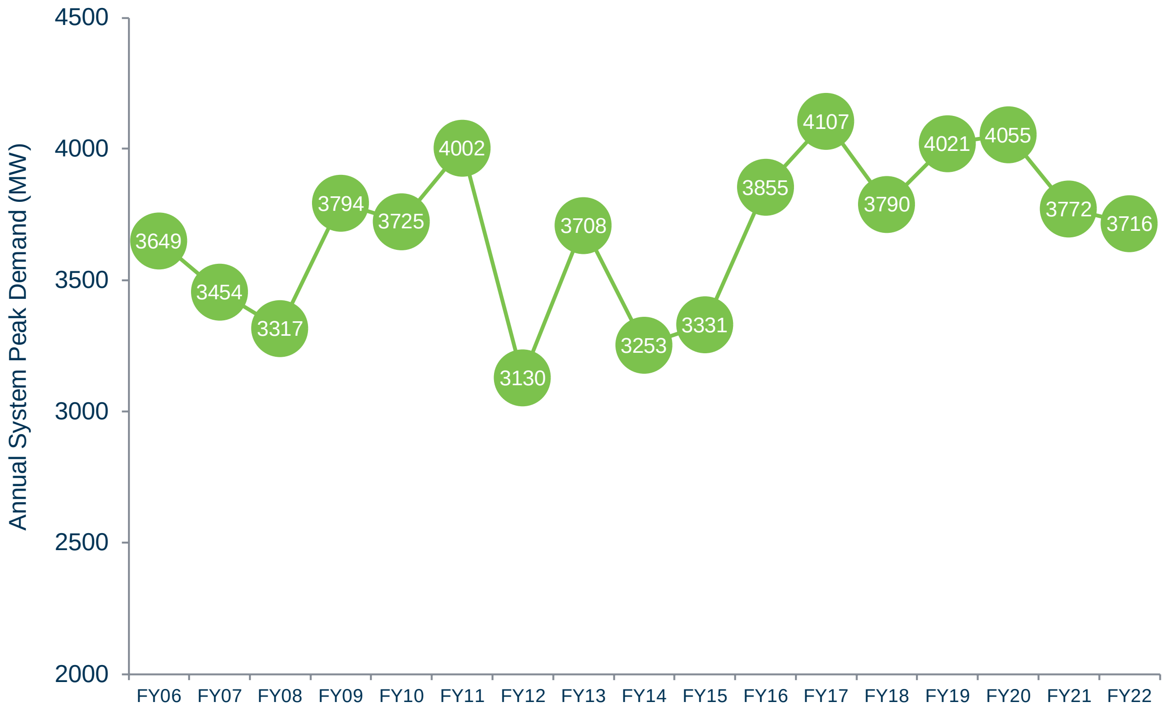
Research clearly indicates the risks associated with extreme heat days and heatwaves[29] and we take our responsibility to maintain supply at times when customers need power the most.

To ensure our customers do not suffer from interruptions during peak periods when supply is most valued, we need to accurately forecast maximum demand in advance so we can effectively review demand management and other non-network solutions to subdue network demand at these peak times or alternatively invest in extending the capacity of the network.

7.3.1 Our total system demand forecast

The customer growth on our network has been driving increasing demand in recent years. On 30 January 2017, demand on our network reached a record 4,107 MW[30]. This was 105MW above the previous record set in 2011. We expect this record to be broken over the remainder of the current period and again over the 2024-29 period.

Figure 7-9 Summer peak demand (FY06-FY22)



[29] Climate Council of Australia - The Silent Killer: Climate Change and the Health Impacts of Extreme Heat – 2016.
[30] Coincident Raw System Annual Maximum Demand at the transmission connection point.

Our forecast system maximum demand is forecast to continue to grow from 4,021 MW in 2018-19 to 5,014 MW[31] in 2028-29, an average annual growth rate of 2.9%[32] over the 2024-29 period.

Table 7-2 Forecasts of maximum system demand (excluding data centres) for the FY25-FY29 regulatory period

Demand exceedance	2024-25	2025-26	2026-27	2027-28	2028-29
Maximum demand (MW) 10% PoE	4,877	4,927	5,053	5,169	5,294
% change	5.3%	1.0%	2.5%	2.3%	2.4%
Maximum demand (MW) 50% PoE	4,595	4,646	4,772	4,889	5,014
% change	5.7%	1.1%	2.7%	2.5%	2.6%

For investment planning purposes, forecasts of overall network maximum demand growth do not provide sufficient information. Network augmentation decisions are generally driven by spatial demand forecasts to ensure that customers in specific locations, particularly in the high growth pockets of our network, are not exposed to supply interruption or connection delay.

Our spatial maximum demand and load area forecasts are provided for each of the existing and new zone substations on our network in the Reset RIN. There are a number of zone substations forecast to experience significant demand growth over the 2024-29 period and beyond:

- 21 zone substations are expected to experience demand growth rates of greater than 5%;
- 22 zone substations are expected to experience demand growth rates of between 1.5% and 5%; and
- 66 zone substations are expected to experience demand growth rates of between 0% and 1.5%.

Spot loads and commercial / industrial growth

Across the vast greenfield precincts where there are no existing substation assets, the conventional processes do not apply as the starting point is zero demand. The process of incorporating spot loads (in particular, the new connection of commercial and industrial customers) determines the rate of growth in the forecast period. This process is the same for both an existing substation where the starting points are determined by temperature correction and for greenfield precincts where the starting point is zero.

Step changes in residential or industrial/commercial development are captured by either connection applications received (short term) or an allowance for longer term development (lot release, and ground floor area projections) as connection applications are typically only received with a 1 to 3-year time horizon. For industrial/commercial applications, the load applied for by customers and developers is reduced by probability factors as appropriate in the range from 0.6 to 0.8.

There are many connection enquiries at the feasibility stage for which we have applied a zero probability in the forecast, but some of these are necessarily included with an appropriate probability factor in the demand forecast to ensure a sensible integrated planning approach with government, utility, and developer stakeholders.

The emergence of data centres is a new and unique source of substantial energy growth across our network area. We are forecasting a significant and unprecedent level of growth from data centres and other industrial customers that represent a new type of commercial and industrial customer. Currently, we have sixteen existing data centres, some of which are planning expansions; and a total of seventeen further data centres that plan to come online in the period 2023-2032. Together this represents total connected load of 2100MVA in 2029. After applying diversity and load probability

[31] Weather corrected 50% PoE.
[32] Note for opex forecasting purposes we have used a lower underlying growth rate (exclusive of spot loads) to constrain our opex forecast to an efficient level in line with stakeholder expectations.

factors, our projections indicate that network peak demand will increase by over 1200 MVA in 2029. This is additional to the demand forecasts in Table 7-2 above.

Each major customer connection will be assessed on a case-by-case basis consistent with our connection policy to determine the funding of the required connection assets and network extensions and/or augmentations. It is likely that a significant portion of these works will be dedicated to the connecting customer and therefore funded by them in accordance with the application of our existing policy.

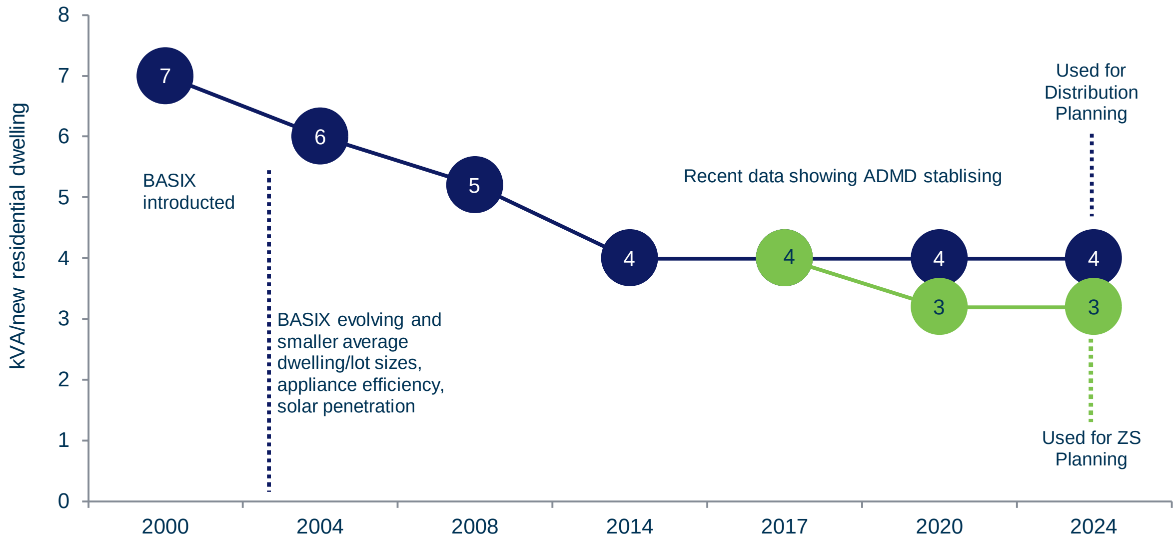
However, there is a risk that our connection and augmentation capex forecasts will be insufficient if this growth is realised in areas and/or a manner that provides a shared network benefit. This forms part of our overall commitment to balance risk in constraining our expenditure forecasts to a level that supports a prudent and efficient revenue proposal.

After Diversity Maximum Demand (ADMD)

As noted previously, demand growth in greenfield areas is the primary driver of our augex and connections capex forecast. In particular, NSW Government led development of Employment lands is promoting significant land use for commercial and industrial purposes. While a significant proportion of augex is related to commercial and industrial spot load forecasting, the use of ADMD values is applicable for planning within the residential setting.

These values provide us with an estimate of the level of demand newly constructed dwellings are likely to require from the network to ensure optimal network design and asset utilisation. As such, ADMD values are an important input into our spatial demand forecasts for our growth regions. We have routinely reviewed and updated our estimates of ADMD to reflect changes in consumer trends and mandated building energy ratings for new constructions.

Figure 7-10 ADMD values used for planning purposes



Some of the factors that have impacted demand include:

- **The Building Sustainability Index (BASIX):** Energy sustainability requirements on new developments including minimum appliance efficiency and thermal insulation standards. These appear to be contributing to reduced demand in new areas relative to established areas.
- **Solar/Battery Storage Systems:** Our data suggests that whilst current PV cell output does not coincide with peak system demand, battery discharge during peak times can reduce premise contribution to overall demand. Also, panel orientation has changed to capture more sun during the peak periods.
- **Technological advances:** Minimum Energy Performance Standards (MEPS) have driven improvements in appliance efficiency (white goods, lighting, air-conditioning and home entertainment) and contributed to the general downward trend of household peak demand.

- **Lot sizes:** There is a strong correlation between energy usage and dwelling size. As lot sizes continue to be restricted, a dwelling's footprint and energy requirements tend to also be constrained.

Looking forward we expect to review ADMD on a more frequent basis. Increases in electrification (including transportation) and a reduced reliance upon the gas network are likely to result in localised adjustments to demand density. Data and insight platforms will inform our adjustments in future proposals.

7.3.2 Our system demand forecast methodology

Each year we develop summer and winter demand forecasts for the ensuing 10 years to coincide with our forward network investment planning period. As summer maximum demand consistently and comfortably exceeds winter demand levels, we most often use our summer forecasts to inform our investment planning decisions in each region within our network area. Consistent with industry practice, we present Temperature Corrected Maximum Demand (TCMD) forecasts reflecting a 10% and 50% PoE.

Our maximum system demand forecasts also inform our augmentation capex forecast for the 2024-29 period, albeit to a significantly lesser extent then growth demand forecasts. Our maximum demand forecast has also been used in deriving our forecast opex requirements as one of the standard output factors used by the AER in calculating the rate of change component that is part of the base-step-trend approach.

Maximum demand forecasting process

Our maximum system demand forecasting process involves a bottom-up approach beginning with a forecast of peak demand at the zone substation level, then moves upwards to the sub-transmission substation level and bulk supply points. Total network level demand forecasts are determined by aggregating forecast values progressively.

Historical demands are normalised for various weather and calendar effects from which a starting point is established. From this starting point, local planning knowledge of known events such as future spot loads, lot releases and load transfers from one substation to another are accounted for in the 10-year forecast horizon. A collaborative planning approach with industry stakeholders such as the NSW Department of Planning and Environment and the Greater Sydney Commission enables us to derive accurate forecasts of expected customer connection requirements and network area growth. Regular interaction also allows us to plan for the optimal delivery and timing of augmentation works.

We then consider the growth from existing customers as well as new customer connections. Organic growth for each zone substation was taken from a report prepared for us from the National Institute of Economic and Industry Research (NIEIR), Attachment 7.02 and 7.03. This report informed the post model adjustments we applied to the 10-year forecast to account for other drivers that influence demand such as energy efficiency improvements, generation from solar PV systems and government energy policies. The forecast at each zone substation is finally aggregated to produce an overall system peak demand forecast for our network area. Our demand forecasting process is set out in further detail in Attachment 7.01.

Impacts of Consumer Energy Resources (CER)

As mentioned above, we apply post modelling adjustments (PMA), to capture future changes in maximum demand which may not be adequately considered by our forecasting model. These adjustments include impacts from different state and national energy policies and programs, such as Minimum Energy Performance Standards (MEPS), NSW Energy Savings Scheme (ESS), change of building codes (e.g., BASIX) and the impacts of DER. PMAs are applied to each year of the forecast for each zone substation based on the residential, commercial, industrial mix and its peak demand for the season as each policy and program targets different customer sectors.

An increasingly important factor in developing PMAs is the need to consider the impacts of CER. The role of the traditional grid is evolving to enable customer-driven take up of new services, such as renewable generation, battery storage, electric vehicles and home automation.

Our forecast accounts for the expected impacts of CER. We note that in the short-term (the 2024-29 period) CER technologies may reduce energy consumption per customer however, but only marginally offset our forecast growth in maximum demand. This is due to the current timing mismatch between rooftop solar generation and our peak demand period and the relatively slowly up-take up of electric vehicles and batteries (to date that is) until they become more cost-effective and accessible to customers. Our CER related PMAs as well as the Energy Savings Scheme are summarised below, and reflect AEMO data which provides a higher and therefore more conservative assumption.

Table 7-3 Endeavour Energy Demand Forecast - Post Model Adjustments

Category	FY29 System Wide Demand Impact (MW and % of System Demand)	Number of Customers in FY22
Energy Savings Scheme	-121.0 (2.1%)	
Solar PV	-311.0 (5.3%)	271,805
Battery Storage	-91.9 (1.6%)	11,970
Electric Vehicles	+141.1 (2.5%)	2,431
Total[33]	**-382.8 (6.7%)**	

Forecasting verification

The validity of our forecasting processes has previously been externally reviewed and is continually assessed internally for accuracy and improvement opportunities. On the latter, we compare recent historical loads to forecast predictions using a Mean Absolute Percentage Error (MAPE) assessment. The MAPE is calculated at an aggregate level by comparing the 50% Probability of Exceedance (PoE) summer demand forecast and the actual 50% PoE weather normalised peak demand.

This has shown ongoing improvement in forecast accuracy over time, most recently averaging 2.1% over 2020 and 2021 period. The forecast performance has been improved after the introduction of a new weather normalisation method based on a simulation approach.

We also compare our forecast to other available forecasts to understand the drivers of any difference. In particular, AEMO published a transmission connection point forecast in December 2020 in accordance with its national transmission planner (NTP) functions. This forecast included connection point maximum demand forecasts at the transmission level across NSW. In addition to being less current than our rolling forecasts, its comparability is further reduced by the need to apportion the forecast to our network.

Our 50% PoE peak demand forecast growth shows an annual growth rate of 2.9% over the 2024-29 period (excluding data centres) which compares to AEMO's largely flat forecast peak demand annual growth for the same period. We have sought to understand the drivers of this difference noting that our augex capex is primarily driven by spatial growth from new connections, meaning a discrepancy at the system level demand has no material impact on our augex forecast.

Historically, AEMO utilised a trend method to forecast demand growth. In doing so, they subtracted spot loads[34] that were above 5% of the connection point maximum demand from historical trends. This subtraction can vary from 0.2 MW to over 170 MW depending on the size of the connection point. This subtraction is made to avoid double counting as AEMO assumed that historical spot load growth is indicative of future spot load growth. Once the trend is developed the known future spot loads are not re-added to the forecast.

This differs from our approach which develops a forecast using weather normalised actuals as the starting point of the forecast. We then adjust these actuals using PMAs (as described above) and for known future spot loads and lot releases. The AEMO forecast remains comparable to this point prior to the addition of spot loads.

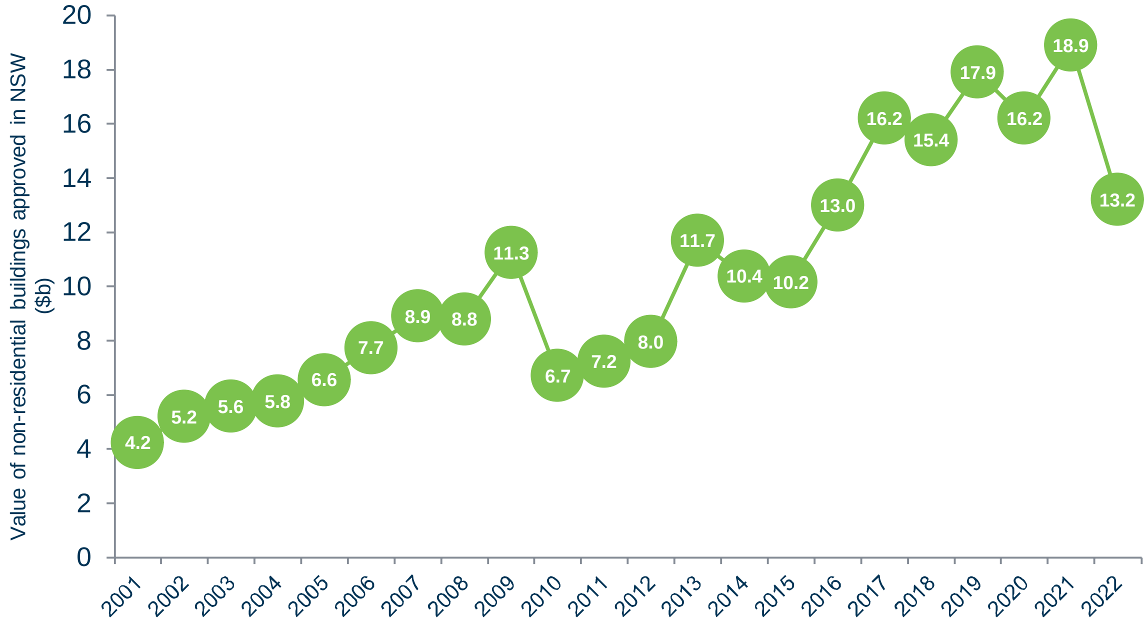
We determine likely spot load increases using load applications from developers/customers and the latest lot release figures provided from the Department of Planning and Environment NSW. We assign a probability to the likelihood that these spot loads will eventuate, for large customers this involves a planning review where we assess the certainty of demand and typically meet with the applicant to

[33] In future regulatory periods as customers are transitioned to more cost-reflective tariffs we expect tariff design will become a PMA factor.
[34] A spot load refers to a defined project which is expected to draw a defined amount of load, on a specified date (i.e. from the time of connection) at a particular point in the network, e.g. Western Sydney Airport.

discuss demand management options. This typically results in reductions in demand compared to the original application. We then diversify the spot load demand when adding it to the forecast (i.e., we do not assume that the entire spot load will occur at peak times).

We consider this approach produces a more accurate forecast that better accounts for the spatial growth we must cater for in future periods. The assumption that historical spot load growth is indicative of future spot loads and lot releases is not supported by the upward trend in non-residential building approvals in our network area over several years.

Figure 7-11 Non-residential building approvals in NSW 2001-2022



7.3.3 Managing peak demand

As discussed earlier in this proposal, local peak demand is a key driver of future network investment. We need to ensure sufficient capacity exists on our network to meet peak demand otherwise customers will experience blackouts at the most critical times of the year. We are taking a number of steps to manage and, where possible, reduce peak demand to reduce our future investment requirements and in turn electricity prices:

- **Demand management:** we routinely test our investment options using our NTMP tool and formally via the Regulatory Investment Test for Distribution (RIT-D) process in accordance with the NER. We also have a number of demand management initiatives including battery storage trials, demand response, distributed generation and programs like SolarSaver and CoolSaver to reduce demand and/or defer investment. See section 9.5 and Attachment 10.06 for further detail;

- **Utilising network capacity:** we efficiently stage our network development in the early phases of growth regions by making use of existing network capacity. We will continue to make use of excess capacity when doing so is technically feasible and represents the most cost-efficient outcome as revealed through our cost-benefit analysis. However, we note that these staging options will become less feasible as the development of the priority growth areas and ensuing customer connections increases, or where new development is occurring distant from existing assets that have capacity headroom; and

- **Cost-reflective tariffs:** we are seeking to improve the cost-reflectivity of our tariffs by adapting them for export generation and new battery technology. Our proposed tariff structure will provide customers greater incentive and control to manage their energy usage during peak periods (including export peak periods) in order to reduce future investment needs and prices. See our TSS, Attachment 0.14, for further details.

7.4 CER & Hosting Capacity Forecast

As noted previously, the transition towards decentralised, renewable generation means that it is becoming increasingly important for Endeavour Energy to forecast CER uptake, understand the hosting capacity of our network and through recent rule changes, and value and plan for investments that alleviate any curtailment.

7.4.1 Forecasting CER

The AEMO 2022 ISP has coverage of four primary scenarios to span plausible energy transformation futures, namely, Slow Change, Progressive Change, Step Change and Hydrogen Superpower.

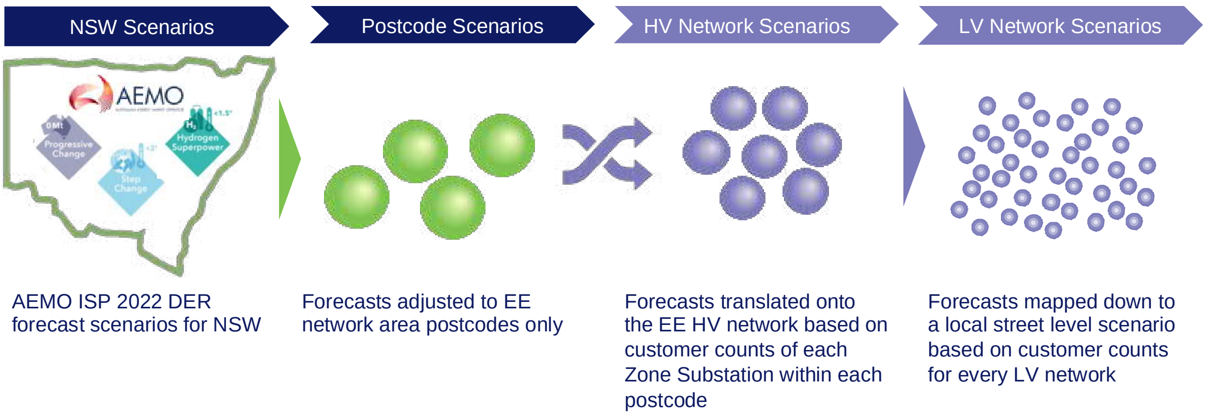
Endeavour Energy requested input on AEMO's ISP scenarios from its Customer and Stakeholder Future Grid Reference Group. The reference group supported a focus on the Step Change scenario which is described as a "rapid consumer-led transformation of the energy sector and co-ordinated economy-wide action". However, we will also consider book end scenarios to this central case, namely a high and low case as follows:

- **High Case:** Hydrogen Superpower
- **Central Case:** Step Change
- **Low Case:** Progressive Change

Currently the AER's work on Customer Export Curtailment Value (CECV) only considers the Step Change scenario in its modelling and this further supports our use of this scenario as the central case.

To forecast the expected CER uptake on the Endeavour Energy network, we engaged the National Institute of Economic and Industry Research (NIEIR) to translate AEMOs ISP 2022 CER forecast scenarios for NSW to Endeavour Energy's network out to 2040.

Figure 7-12 Translation of AEMO ISP Scenarios to Endeavour Energy's Network

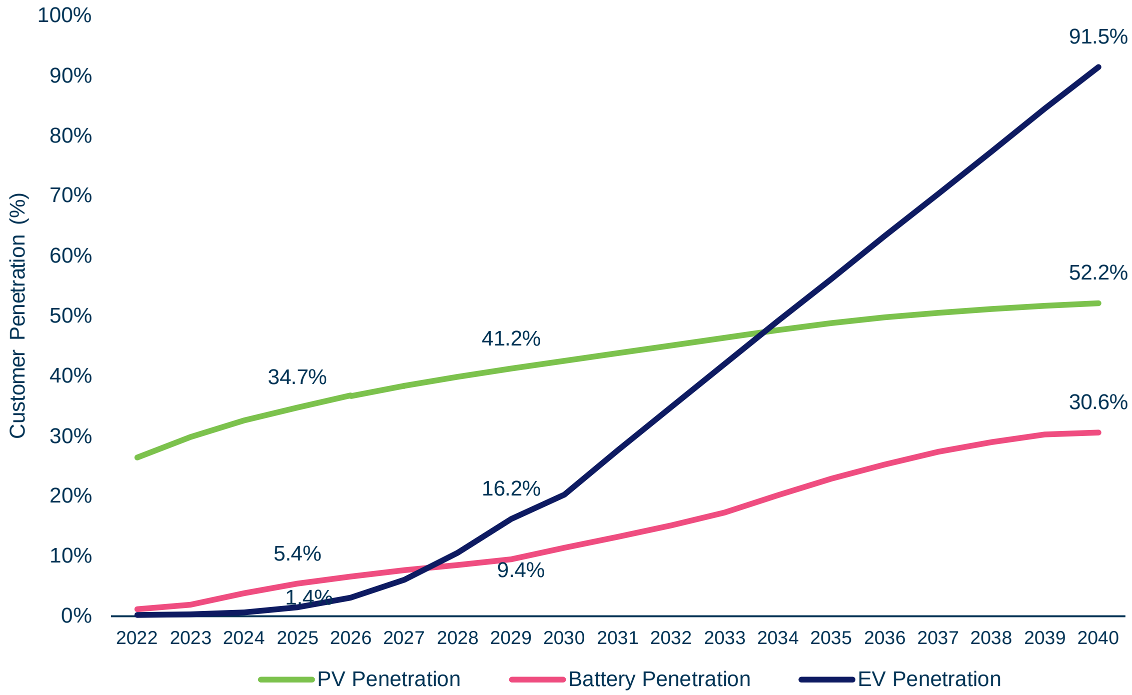


At a high level this has been done as follows:

- **Solar PV:** NIEIR pro ratas AEMO's NSW solar PV forecasts based on Endeavour Energy's current share of NSW solar PV. The current percentage share of NSW solar PV is held constant into the future.
- **Batteries:** NIEIR pro ratas AEMO's NSW battery forecasts based on Endeavour Energy's current share of NSW solar PV. The current percentage share of NSW solar PV is held constant into the future to translate the battery forecast.
- **Electric Vehicles:** NIEIR's initial starting point is based on existing EV vehicle registrations mapped to Endeavour Energy postcodes then translated to a share of the NSW total EV registrations. NIEIR then considered NSW postcode demographics data to determine what share of the forecast NSW EV growth is attributed to Endeavour Energy postcodes. This was then mapped to our substations.

Using the customer CER forecast as a percentage of total customer connection points forecasted on the network, we have derived the expected penetration levels for each type of CER as shown below in Figure 7-13. PV penetration is expected to double by 2040 and EV growth becoming most significant during 2030-2040.

Figure 7-13 Endeavour Energy forecast CER penetration (2022-2040)



Refer to Attachment 10.40 for further details on our approach to forecasting CER penetration and hosting capacity.

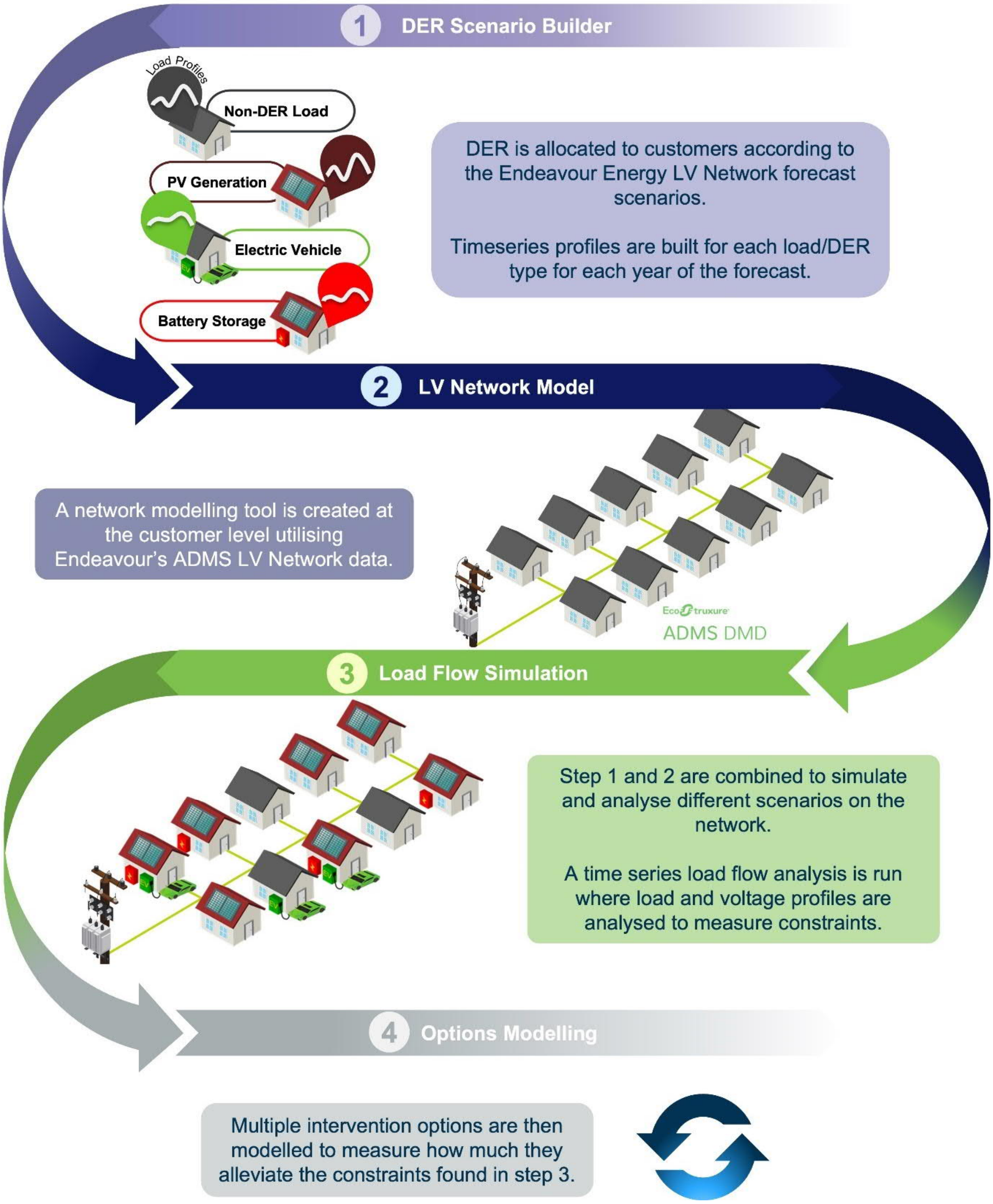
7.4.2 Modelling Hosting Capacity

Our CER forecast is an input amongst others into a simulation tool that allows us to simulate and assess CER hosting capacity, or inversely quantify the impacts of unconstrained CER uptake on the network.

Endeavour Energy has developed a LV simulation tool in partnership with researchers at the University of Wollongong's Australian Power Quality and Reliability Centre. The tool takes advantage of the open-source electrical power flow engine OpenDSS to run time-series power flow simulations.

The hosting capacity analysis utilises the CER Forecast mentioned in the previous section and focuses on modelling residential customers. The 4 key stages; CER/DER Scenario Builder; LV Network Model; Load Flow Simulation; and Options Modelling are summarised below.

Figure 7-14 Endeavour Energy's hosting capacity modelling process



A description of each of the 4 stages and the key features is provided below in the following sections.

A complete detailed explanation of this tool and the associated basis of preparation of the various data inputs is provided in Hosting Capacity Modelling Basis of Preparation (Attachment 10.40).

CER / DER Scenario Builder

As discussed above, Endeavour Energy is modelling a selection of AEMO's ISP scenarios, a central case (Step Change) along with two bookend cases (Progressive Change and Hydrogen Superpower). With each scenario, there are varying amounts of CER forecasted on the Endeavour Energy network.

In this way, the CER Scenario Builder allocates PV systems, batteries and EVs to customers on the network so that the model aligns with the selected AEMO ISP Scenario. Within each year of the model, new CER is allocated accordingly.

PV Allocation

PV inverters are modelled explicitly in the system, so it is important to select the placement of these systems appropriately.

Existing PV customer locations are modelled accurately in the developed LV feeder model according to existing CER register data. If the forecasted additional PV systems are assigned to the customers located at the far end of the feeder or closer to the distribution transformer this would result in extreme network conditions. It is required to assign the new PV systems forecasted each year to non-solar customers in a way that represents average network conditions. Therefore, we developed a LV feeder modelling algorithm to distribute the new PV systems evenly among the non-solar customers along each LV feeder.

Batteries and Electric Vehicles

Unlike PV inverters, battery storage systems and electric vehicles are not modelled explicitly in the software. For these CER types, the forecasted load profiles for each are combined with the baseline load profiles obtained from smart meters to create a new net profile that is given to all customers. The magnitude of the CER load that is added to the baseline is proportionate to the uptake forecast for each specific LV feeder.

Once these scenarios have been developed, a network model is required to host the load flow of these inputs.

LV Network Model

The simulation tool builds a network model in the OpenDSS power flow software. The topology and line characteristics of the network has been modelled using exports of Endeavour Energy's ADMS and GIS LV network model data. Operational characteristics and transformer characteristics were obtained from the enterprise asset management systems and imported into the model.

Notably, within the network model, the AS4777 inverter power quality response modes such as volt-watt and volt-var are explicitly modelled in PV systems placed in the simulation.

Due to the size and complexity of the modelling, only downstream network from the distribution transformer is explicitly modelled in the load flow analysis. The exact HV network was not included in the load flow, rather approximation of network characteristics was used to account for upstream impacts.

Overall, our modelling is expected to be conservative (under-estimate curtailment).

Load Flow Simulation Model

Once the network model has been built to reflect the current network state, the parameters can then be modified to simulate future CER uptake on the network.

The CER scenarios and inputs discussed above are then used to modify the network model for each scenario, each year, out to the year 2040.

The load flow simulation produces 30-minute time series results at the customer and distribution transformer level. It should be noted that modelling at 30-minute time intervals is likely to underestimate curtailment compared to 5-minute intervals however due to the computational strain of 5-minute load flows this modelling was completed using 30-minute data only.

The model seeks to understand the constraints on the network resulting from increasing residential CER uptake, namely:

- **CER Inverter Curtailment:** as per AS4777 trip settings and response modes
- **Distribution Transformer Capacity:** Transformer loading kW, maximum and minimum demand voltages
- **High-Voltage Feeder Capacity:** High voltage feeder loading kVA

The above constraints are measured for all input scenarios to understand the impacts on the network and to set a quantified baseline to explore interventions to alleviate these constraints.

Options Modelling

In response to the measured constraints, we have explored various intervention actions according to our CER Integration Plan (refer to DER Strategy). These interventions are modelled sequentially, to quantify the curtailment alleviation profile of each intervention, starting at lowest cost and operational interventions. These intervention alleviation profiles are then valued under the VaDER framework, including Customer Export Curtailment Value (CECV)

Attachment 10.40 explains these interventions in greater detail and our rationale behind each.

For these interventions to be accurately modelled, we built additional functionality into the simulation tool to:

1. modify load profiles to simulate tariff reforms, and
2. modify the scripts that build the OpenDSS model, changing parameters of equipment configurations, voltage setpoints, tap settings and customer connection point phase balance.

This additional functionality has created a robust simulation tool that can measure the improvements in curtailment as each intervention is added to the scenarios.

7.5 Customer & energy consumption forecast

As noted previously, energy consumption is expected to grow at a slower rate than peak demand. This is due to increased take up of small-scale PV systems and various energy efficiency schemes and standards, e.g., NSW Energy Saving Scheme which provides financial incentives to install energy efficient equipment and appliances in residential and commercial buildings. In the sections below we provide more detail on our customer number and energy consumption forecasting methodologies.

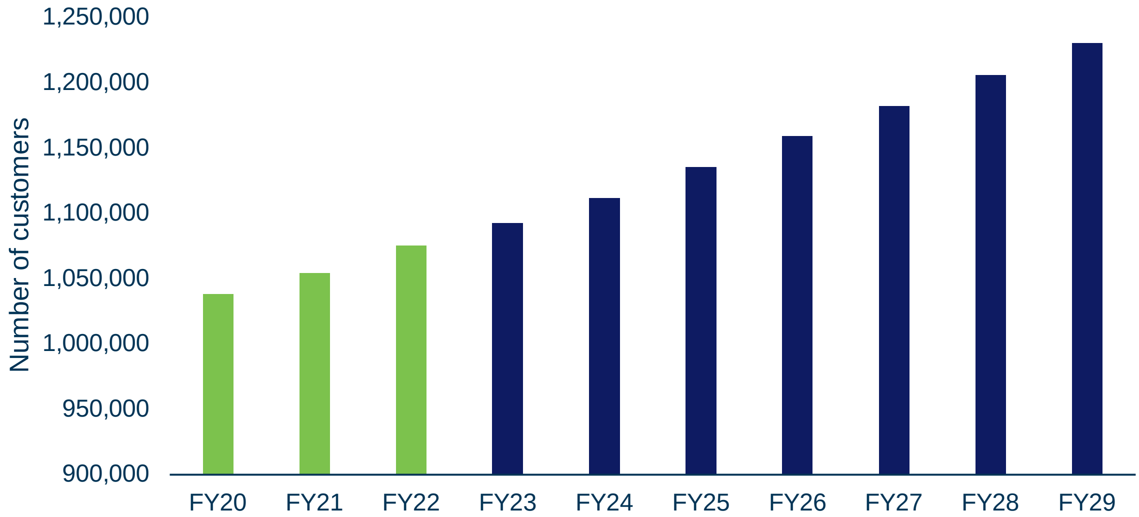
7.5.1 Our customer numbers forecast

Customer numbers for our network are forecast to grow at an average annual growth rate of 2.1% over the 2024-29 regulatory control period as illustrated in Table 7-4 below:

Table 7-4 Customer numbers FY25-FY29

Customer numbers	2024-25	2025-26	2026-27	2027-28	2028-29	Average
Total customers ('000s)	1,136	1,159	1,182	1,206	1,230	**1,183**
Growth rate (%)	2.2%	2.0%	2.0%	2.0%	2.0%	**2.1%**

Figure 7-15 Customer number forecast (000's)



We use our customer number forecasts to inform our connection capex forecast, greenfield augex forecast and the output component of the rate of change trend factor that applies to our opex forecast. Our customer number forecasts are produced using the following methodology and assumptions:

7.5.2 Our customer forecast methodology

Domestic customers

- Short-term customer numbers for the months remaining in the current financial year (FY23) and next financial year (FY24) are forecast using historical trends.
- Long-term forecasts for FY25 to FY29 are produced using a projection of household number growth for the Endeavour Energy network area. Household growth rate projections are sourced from a third-party macroeconomic forecaster, NIEIR. NIEIR provide a range of macroeconomic forecasts of which we have taken the base/medium case, see Attachment 7.04 for further detail.

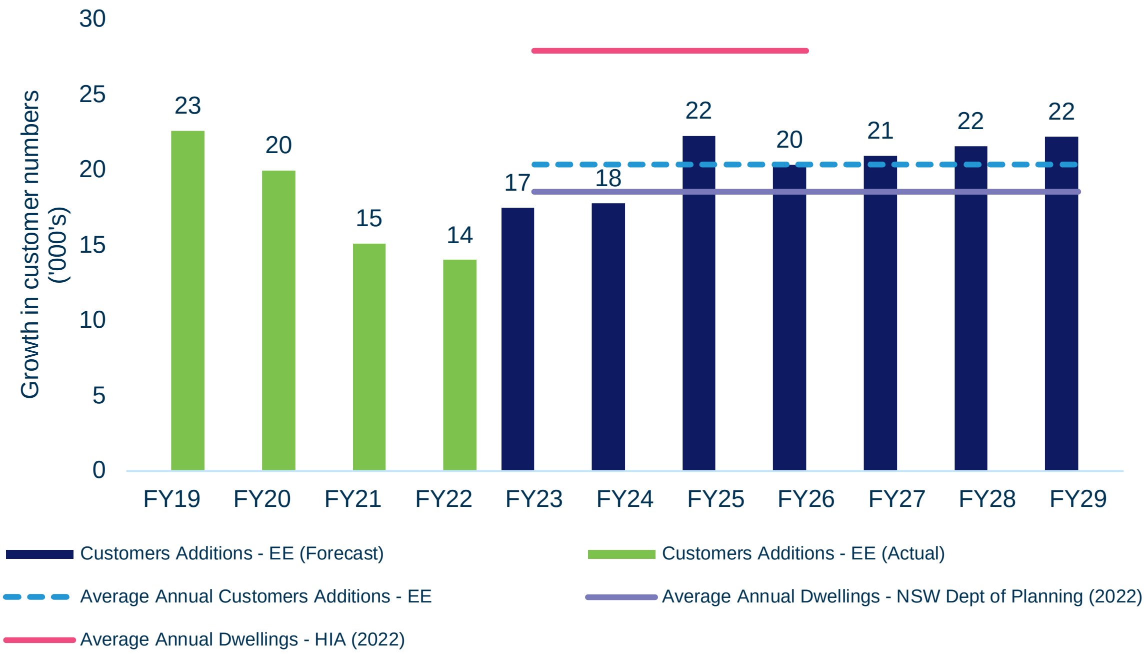
Commercial and industrial customers

- Short-term commercial and industrial customer numbers take account of recent monthly movements.

- Long-term forecasts increase in line with the forecast GSP growth rate as sourced from NIEIR. The exception to this is large, site-specific industrial customers and non-metered commercial customers, which are assumed to remain unchanged.

We also assess the reasonableness of our model outcomes against comparable, independent forecasts of growth activity in our network, e.g., Department of Planning and Environment and Housing Industry Association.

Figure 7-16 Customer number forecast compared to third party forecasts (residential)



Our forecasting approach has also been independently reviewed previously and was found to be consistent with good industry practice. We continue to use this methodology to prepare our forecasts.

7.5.3 Our energy consumption forecast

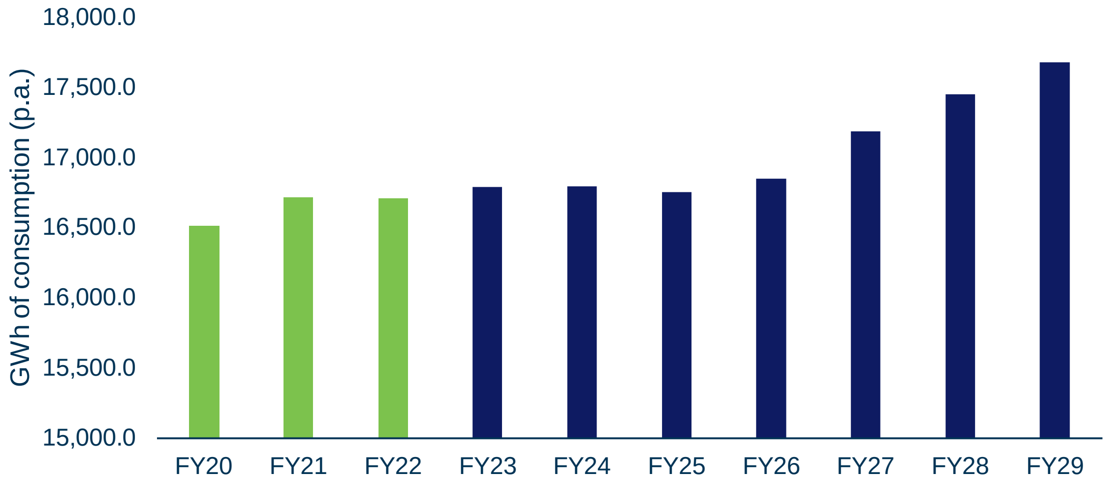
Energy consumption is the volume of electricity sold to our customers as measured in GWh over a set period. As we are subject to a revenue cap, energy consumption affects the price of electricity but not the revenue we collect. This means that if customers consume more energy than expected we will return the additional revenue we have collected in the subsequent year (and vice versa). To limit the reconciliation required each year we have robust methods in place to forecast energy consumption as accurately as possible.

We forecast consumption on our network to increase from 16,751GWh in 2024-25 to 17,679GWh in 2028-29, representing an annual growth rate of 1.0% over the 2024-29 regulatory period.

Table 7-5 Energy consumption forecast

Energy Consumption	2024-25	2025-26	2026-27	2027-28	2028-29	Average
Total energy (GWh)	16,751	16,850	17,187	17,448	17,679	**17,183**
Annual growth rate (%)	-0.3%	0.6%	2.0%	1.5%	1.3%	**1.0%**

Figure 7-17 Energy consumption forecast (GWh)



We note the consumption remaining steady over the remainder of the current period and first few years of the next period and then a material uplift over the latter part of the 2024-29 period. This reflects a shift taking place from a slower economic activity and a price rise in the first few years to a higher economic growth, fall in electricity price and a rise in electric vehicles in the latter part.

Our energy forecasting methodology, which consists of a short-term and long-term forecasting process, is described in more detail below.

7.5.4 Our energy consumption forecasting methodology

Short-term forecasts

Short-term forecasts cover the next two years. Forecasts are made monthly by applying monthly growth rates on the weather-normalised consumption values of recent months. The monthly growth rates are estimated from trend analysis of the past five years of total system import (TSI) values for that month, after weather-normalisation of these values.

Long-term forecasts

Long-term forecasts cover the period beyond the next two years. The long-term energy forecasting methodology consists of a combination trend analysis and econometric method:

- domestic energy forecasts are produced by applying an econometric approach. In this approach, an econometric model is estimated by fitting historical domestic consumption per customer values against disposable income per capita, retail domestic price, PV capacity per customer and temperature variables in a log-linear regression model. Standard statistical tests are performed to examine precision of the estimates and robustness of the model. The forecast produced is then adjusted for post model adjustments for the impacts that would result from ESS (Energy Saving Scheme), Electric Vehicles, etc;
- commercial and industrial consumer energy forecasts are based on an econometric approach. In this approach, growth rates for energy consumption are estimated by multiplying forecasts of growth rates of GSP and price and their respective elasticities (i.e., income and price elasticities). The growth rates estimated for energy are then applied to the annual consumption values for the starting year (FY24). The forecasts produced are then adjusted for post-model adjustments recommended by NIEIR, Attachments 7.02 and 7.03. In cases where customer specific information is available adjustments are made accordingly; and
- the forecast for large industrial consumer energy is derived from trend analysis, which involves a review of recent historical trend data and adjustment for business specific information where available.

8. Regulatory Asset Base & Depreciation

8.1 Overview

We are proposing a more accurate year-by-year depreciation method to better reflect the beneficiaries of investments we make on their behalf and align with NEM best practice.

The value of our distribution network assets used to provide standard control services is reflected in the regulatory asset base (RAB). These include system assets directly used to safely transport electricity to and from our customers such as poles, power lines, transformers and switchgear as well as non-system assets such as ICT, land, plant and equipment.

Our RAB has increased over the 2019-24 period due to capital investment to accommodate strong customer growth in developing regions within our network and to transform our ICT systems. Our opening RAB as at 1 July 2024 is forecast to be $8,031 million.

Through our robust governance framework, we have sought to limit this growth by ensuring only capital investment required to meet the capex objectives is undertaken and included in the RAB. Our proposed capex for the 2024-29 period has been actively constrained at a category and overall level to recognise our commitment to achieving productivity gains and providing a value for money service.

To further limit RAB growth in future periods, we have proposed a year-by-year asset tracking approach to depreciate the investments made during the current, and future, regulatory period.

This new approach separately depreciates assets by period over standard lives which better reflects their economic usage, and it is consistent with standard accounting practice. Relative to our current averaging approach, this approach will reduce RAB growth in future periods addressing intergenerational issues.

Table 8-1 Proposed opening RAB values for standard control services for the 2024-29 period

$m; Real FY24	2024-25	2025-26	2026-27	2027-28	2028-29
Opening RAB	8,031.3	7,971.2	7,930.9	7,870.3	7,827.8

8.2 Regulatory asset base values

8.2.1 Opening 2019-24 RAB value

The value of our RAB as at 1 July 2024 is $8,031 million. This value has been calculated based on clause 6.5.1 and schedule 6.2 of the Rules and derived using the AER's roll forward model (RFM) provided at Attachment 0.05.

Capital investment over the current regulatory period has increased the value of the RAB. We have used a combination of actual and forecast capex values as detailed in Chapter 10 of this Proposal to derive the opening RAB value. These capex values reconcile with those provided in annual regulatory accounts and we will update the RAB for actual 2022-23 capex in our Revised Proposal.

We have made adjustments to the opening RAB value in accordance with Clause 6.5.1(a). These adjustments have been made in accordance with the Rules and a described below.

2014-19 movements in provisions

We have accounted for movements in provisions attributable to capex in accordance with recent AER decisions.

Immediate expensing of capex

In 2018, the AER finalised its regulatory tax approach review which resulted in changes to the regulatory models (namely the PTRM and RFM). The review resulted in a number of changes to better align the regulatory benchmark approach with the tax paid by networks. This included adopting a diminishing value approach for new assets for calculating tax depreciation and addressing depreciation mismatches arising from immediate expensing.

The latter occurs as for tax purposes certain types of capex (such as refurbishment capex) can be immediately expensed. In accordance with the model changes implemented by the AER we have adjusted our RAB for immediately expensed capex over the 2019-24 period as reported in the RIN.

We also note our forecast RAB has been adjusted for a forecast of immediately expensed capex that is informed by our actuals to date.

Lease accounting changes

Leasing is an important activity for entities including electricity distribution businesses as it provides a means of gaining access to assets whilst reducing exposure to the risks of asset ownership.

The previous accounting standard for leases, *AASB 117 Leases*, was replaced by *AASB 16 Leases* which included a new requirement for a lessee to recognise assets and liabilities for the rights and obligations created by leases. This approach is considered to provide a more faithful representation of a lessee's assets and liabilities and greater transparency of a lessee's financial leverage and capital employed.

Specifically, *AASB 16 Leases* requires lease liabilities and the corresponding right of use asset to be capitalised and recognised in the balance sheet. In the income statement, lease payments are replaced by a depreciation expense on the asset and an interest expense on the lease liability. The new standard applied to annual reporting periods beginning on or after 1 January 2019.

For financial accounting purposes, Endeavour Energy adopted the changes from this date with operating lease contracts recognised in the balance sheet as an asset and liability to be amortised over the life of the lease contract.

For our regulatory accounts we were not in a position to adopt this change in the standard at the time of our 2019-24 proposal. We have therefore been unable to report leases in our regulatory accounts on a consistent basis with our statutory accounts[35]. Moving forward, we intend to apply a consistent approach per the principles of regulatory accounting and therefore have the value of capitalised leases reflected in our RAB. The leased asset will then be depreciated at a rate equivalent to the term of the contract (or remaining term of the contract in the case of existing leases).

[35] For FY20 and FY21 the lease amounts were treated as an 'Adjustment' between the Statutory and Regulatory accounts.

Importantly, our intent to adopt the new accounting standard has been discussed with our Regulatory Reference Group (RRG) and accepted on the provision adopting the changes does not deliver any unintended windfall gains at the expense of customers.

We have therefore engaged with the AER, along with other networks, to confirm the appropriate treatment of mid-period accounting changes for the 2019-24 period. From a regulatory perspective, it has been demonstrated that a revenue neutral approach is to align the accounting treatment of the expenditure within a period to the treatment underpinning the approved expenditure. Accordingly, we will continue to treat lease costs as opex for the remainder of the 2019–24 regulatory control period and commence reporting them as capitalised expenditure from 1 July 2024. Specifically:

- for EBSS purposes leases are reported within opex for the 2019-24 period consistent with the treatment of leases used to set the 2019-24 opex allowance;
- for opex forecasting purposes leases are removed from opex and instead included as part of the capex forecast; and
- for leases entered into during the 2019-24 period a final year adjustment will be made to establish an opening asset base for the 2024-29 period.

For the latter, we have calculated the present value of leases entered into over the 2019-24 period and assigned remaining asset lives to reflect the average remaining term of the relevant contract. Over the 2019-24 period we entered into leases on an annual basis for Motor Vehicles and our Sydney CBD Office. We also entered into a lease for our new Parramatta head office during FY23. The RFM adjustments are outlined in the table below and Attachment 8.01.

Table 8-2 Proposed end of period RFM asset adjustments

RFM Asset Category	RAB ($m; nominal)	TAB ($m; nominal)	Remaining average asset life - RAB (years)	Remaining average asset life - TAB (years)
Short Term Leases	16.65	11.35	3.6	3.6
Long Term Leases	28.11	22.74	9.0	9.0

We provide further details on our approach to opex in Chapter 11, our forecast capex in Chapter 10, and our overall approach to lease capitalisation in Attachment 8.01 to this proposal.

Efficiency review of past capex

We note prior to making a decision on the opening RAB value for the 2024-29 period, the AER may review the efficiency of past capex under certain circumstances and exclude amounts in accordance with S6.2.2A of the Rules. This component of the capex incentive scheme is designed to ensure that only capex that is efficient and prudent should be added to the RAB.

An adjustment may be made if one of the following criteria is satisfied:

- **overspending requirement:** where the sum of capex during the review period exceeds the AER allowance;
- **margin requirement:** where capex that will result in an increase to the RAB includes an amount that represents a margin paid by the DNSP that does not reflect arm's length terms; and
- **capitalisation requirement:** where capex that will result in an increase to the RAB includes an amount that, under the DNSP's applicable capitalisation policy submitted to the AER as part of a regulatory proposal, should have been treated as opex.

For the 2017-18 to 2021-22 years, we have assessed whether a reduction to the RAB is required in accordance with S6.2.2A of the Rules. We can confirm that our capex over the review period is efficient and no adjustment is required. The reported capex was prepared in accordance with the capitalisation policy submitted at the time of our 2019-24 Proposal and there have been no related party transactions.

We note that our capex over this period has exceeded the allowance on account of the phasing of our ICT Transformation. However, overall our actual capex was below the AER allowance for the 2014-19 period and is forecast to be below or at the allowance for the 2019-24 period. Further, as per Attachment 10.45, our ICT Transformation has been independently reviewed and its efficiency (i.e. benefits in excess of costs) validated.

8.2.2 RAB during the 2024-29 regulatory period

We have used the AER's RFM to roll forward our opening 1 July 2019 RAB value into each year of the 2019-24 regulatory period. Table 8.3 below provides a summary of the inputs used to derive these values. To comply with the Rules, only forecast capex attributable to the provision of standard control services and in accordance with our Cost Allocation Methodology has been included in the RAB. The RFM is provided as Attachment 0.05.

Table 8-3 Roll forward of the RAB over FY25-FY29

$m; Real 2023-24	2024-25	2025-26	2026-27	2027-28	2028-29
Opening RAB	8,031.3	7,971.3	7,931.0	7,870.5	7,828.1
Add: Forecast net capex[36]	436.8	406.4	365.0	353.3	317.2
Less: regulatory depreciation	-267.7	-218.7	-199.4	-170.7	-165.9
Closing RAB	8,200.4	8,158.8	8,096.5	8,052.9	7,979.1

As evident in the table above, our RAB is decreasing over the 2024-29 period. Further, on a per customer basis the RAB is declining from $7,442 per customer in FY24 to $6,550 per customer in FY29. As our 2019-24 expenditure is forecast to be at the AER allowance, this reduction is instead driven by:

- Our 2019-24 capex is below historic highs and reducing further in the 2024-29 period. Specifically, our 2024-29 capex averages $376 million per annum compared to $412 million per annum over the 2019-24 period and $548 million per annum over the 10 years prior to this period (2009-2019).
- Our 2019-24 capex was re-prioritised with a significant uplift in ICT capex as part of our ICT and digital transformation. This asset class is relatively shorter lived then system categories of expenditure resulting in a material uplift in our 2024-29 depreciation allowance.

It should be noted that the figures above are presented in real terms for the sake of comparison and because the rate of inflation is a factor outside of our control. However, our RAB is adjusted for expected inflation.

The consequence of this is that a long-lived asset will accrue value (via indexation) over its first several years which increases the RAB value. Based on our analysis it can take up to three regulatory control periods (15 years) for a long-lived asset to simply be depreciated back to its original cost. In addition to the significant investments required in the network, this is a key driver for the increases we observe in our RAB in nominal terms. This is exacerbated by the prevailing economic conditions which result in a higher inflation forecast.

As noted above, the treatment of inflation in the PTRM and the forecast itself is a factor outside of our control. However, we have taken steps to limit RAB growth as far as reasonably practicable by improving our capital efficiency and constraining our capex forecast. We discuss this further in Chapter 10.

[36] This relates to Endeavour Energy funded capex and does not include capital contributions or gifted assets received from third parties.

8.3 Depreciation (Return of capital)

Return of capital (or regulatory depreciation) enables capital investors to recover the cost of their investment incrementally over the standard life of an asset. It is calculated as the depreciation on the value of the opening RAB value offset by the indexation on that asset base. Regulatory depreciation is based on the age profile of the assets within the RAB and the method of calculation.

We have calculated the depreciation on the RAB using the straight-line depreciation method as employed by the AER's PTRM. Regulatory depreciation for each year of the 2024-29 regulatory control period is shown in Table 8-4 below.

Table 8-4 Forecast regulatory depreciation

$m; Real 2023-24	2024-25	2025-26	2026-27	2027-28	2028-29
Straight-line depreciation	-498.6	-447.9	-427.4	-396.9	-390.9
RAB Indexation	230.9	229.1	228.0	226.2	225.0
Regulatory Depreciation	-267.7	-218.7	-199.4	-170.7	-165.9

Remaining Asset Life

The remaining standard lives of existing network assets is a key determinant of regulatory depreciation. Clause 6.5.5(b)(1) of the Rules requires depreciation schedules to conform to a number of requirements, one of which is that:

'the schedule must depreciate using a profile that reflects the nature of the assets or category of assets over the economic life of that asset or category of assets'.

In previous regulatory proposals, we adopted a Weighted Average Remaining Life (WARL) method for calculating remaining asset lives. However, this approach resulted in a depreciation profile that did not accurately reflect the useful lives of individual assets in practice. This is because it over-weights new assets in the calculation and therefore over-estimates the remaining life of assets on our network. This results in investment cost recovery to be spread over a longer period of time than the actual economic life of assets and results in under-compensation for depreciation expenses.

To correct this, we adopted a period-by-period approach in the 2019-24 period. We are proposing a further refinement to this approach for the 2024-29 period by adopting the AER's preferred year-by-year tracking method. As we moved from a WARL approach to a period-by-period approach during the current period this further change has a minimal impact on revenues

Under this approach:

- assets in existence at 1 July 2014 are depreciated by asset class using straight-line depreciation with the previously determined remaining lives;
- capex in the 2014-19 and 2019-24 periods are grouped by asset classes and separately depreciated over their standard lives; and
- capex in 2024-29 (and subsequent periods) will be grouped by year and asset classes and separately depreciated over their standard lives.

We consider that this approach, by keeping track of depreciation on a year-by-year basis for each asset class, is preferred over the period-by-period method as it presents a more accurate method of estimating depreciation.

This method produces depreciation schedules that better reflect the nature of the assets and their economic life and ensures that total depreciation (in real terms) equals the initial value of the assets. This addresses intergenerational equity issues created by less accurate methods which defer the recovery of assets to future periods beyond the economic life of the asset. Overall, this is a more transparent approach that is easier for stakeholders to understand and consistent with accounting practice.

We note that this approach is used by almost all other networks in the NEM. We consider our proposed approach is consistent with the legislative requirements in the Rules and in our experience the PTRM and RFM can be updated without undue effort.

Standard Asset Lives

In previous regulatory proposals, we independently reviewed the accuracy of our standard asset lives. A previous review found that we recover our RAB over a much longer period than other DNSPs as our standard asset lives for several classes were considerably longer than comparable peers.

Our circumstances and approach have not changed since this review and is likely to remain the case. Whilst shortening our asset lives would resolve this inconsistency and limit future RAB growth, it could materially increase our revenue (and therefore prices) in the short term. In light of concerns around increasing energy prices more broadly, we remain of the view that this change would be inconsistent with concerns raised by customers and stakeholders with energy affordability.

Attachment 0.04 shows the standard and remaining life values (as at 1 July 2024) used to determine regulatory depreciation. These are unchanged from the standard asset lives used for the current period.

Tax asset lives

Attachment 0.04 shows the standard and remaining life values (as at 1 July 2024) used to determine tax depreciation. These are unchanged from the standard asset lives used for the current period.

New asset classes

As discussed earlier in this Chapter, the accounting treatment of leases has changed following the introduction of *AASB 16 Leases*. We intend to align the regulatory accounting treatment with the statutory accounting treatment for the 2024-29 period (and beyond). This accounting change means that leases are now capitalised rather than expensed.

To facilitate this we propose the addition of two new asset classes being:

- Short term leases with a 5-year standard life – this covers leases pertaining to our Motor Vehicle fleet and our Sydney CBD office.
- Long term leases with a 10-year standard life – this covers our Parramatta head office lease.

Refer to Attachment 8.01 for the derivation of the opening values for these asset classes.

Forecast inflation

The AER finalised its review into the regulatory treatment of inflation on 17 December 2020. The AER decided to:

- Shorten the target inflation horizon from ten years to a term that matches the regulatory period (typically 5 years).
- Apply a linear glide-path from the RBA's forecasts of inflation for years 1 and 2 to the mid-point of the inflation target band (2.5%) in year 5.

This conception of regulatory inflation is that its role is to 'take out what you expect to put back in' in which case the term is determined by RAB indexation in the RFM. We support this approach as it ensures that in expectation, the nominal rate of return and real rate of return is achieved over the regulatory period.

Consistent with this method, we have used the forecast headline inflation rate from the RBA's Statement on Monetary Policy released in November 2022 for years 1 and 2. This results in a placeholder inflation estimate of 2.87%.

9. Incentive Schemes

9.1 Overview

Our commitment to incentive-based regulation has helped the business to become more efficient and keep downward pressure on network charges.

We consider incentive based regulation provides the most efficient outcomes for customers. Our performance over the previous and current period demonstrates that our management has responded efficiently to the regulatory incentive schemes.

Between 2019 and 2024 we will achieve (figures real; 2023-24):

- A $88 reduction in our contribution to the average residential[37] customer's electricity bill
- A $133 reduction in our contribution to the average small business electricity bill
- Connecting almost 100,000 new customers to the network
- Real RAB per customer reduced from $7,510 to $7,442
- Real OPEX per customer improved from $335 in FY20 to $323 by FY24
- Improving reliability performance
- Global ESG Benchmark (GRESB) 5 Star Rating achieved in 2021 and 2022
- Improving safety performance
- Increasing network utilisation

We achieved these efficiency improvements through the concerted effort of our people and a commitment to providing our customers value for their money. Our current period performance has been driven by:

- achieving sustainable capital delivery productivity improvements and materials and contract cost reductions.
- improved asset planning, risk prioritisation and investment governance practices which are detailed further below.
- an increased use of innovative and non-network solutions to defer and/or reduce traditional network investments. This includes ongoing investigations to partner with third party suppliers to provide Battery Energy Storage (BESS) solutions providing network support services to defer network augmentation.
- prioritising investment in transforming our ICT systems and Buildings and Property to improve our organisational efficiency and create a culture of excellence and innovation.
- catering for unprecedented growth across our network area, highlighted by the establishment of the Western Sydney International Airport and the emergence of data centres.
- supporting the ongoing transition of customers to decentralised and decarbonised renewable generation.
- managing the impacts of several natural disasters, such as the 2020 Bushfires and 2020 and 2022 Floods, and the Covid-19 pandemic on our development levels and BAU activities. This, in addition to our early period focus on ICT transformation, has resulted in a deferral of some system capex within, and potentially between, periods.

[37] Consumption 4,900 kWh p.a.

These results are a positive outcome for customers. By reducing our costs efficiently over the 2019-24 period we have reduced our opex requirements and maintained downward pressure on our RAB for the 2024-29 period which goes to ensuring our contribution to electricity bills represents value for money.

We have made these improvements without compromising safety, the quality of our customer service and reliability levels. Instead, we have been able to maintain and/or improve the quality of our services as promised in our 2019-24 Proposal.

The AER has proposed that all available incentive schemes apply to Endeavour Energy for the 2024-29 period. We have asked our customers for their views. The general consensus was that incentive schemes should continue to operate and particular attention should be paid to innovative schemes in light of the industry transformations.

There was also support to replace the current customer service component of the STPIS (calls answered within 30 seconds) to a stand-alone CSIS with a suite of measures that better reflect the services customers value.

We therefore:

- support the AER's decision to apply all available incentive schemes;
- propose an Innovation Fund of $25 million to investigate and trial emerging technologies and network solutions beyond the scope of the DMIA; and
- a CSIS containing measures of outage management and customer satisfaction across a number of areas.

In addition to incentive schemes, we can also confirm for the 2024-29 period we expect to earn a material amount of unregulated revenue from the shared use of our distribution assets. As a result, we have made the following adjustments to our revenue forecast in accordance with the Shared Asset Guideline.

Table 9-1 Proposed shared asset revenue adjustments for the 2024-29 period

$m; Real 2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Revenue Adjustment	-1.1	-1.1	-1.1	-1.1	-1.1	-5.4

9.2 Efficiency Benefit Sharing Scheme (EBSS)

The EBSS is designed to provide DNSPs a continuous incentive to pursue efficiency improvements in opex and spend less than the approved amount. The EBSS applies to us for the 2019-24 period and we have demonstrably responded to the incentive scheme, driving efficiency. We will reduce our opex from $319.6 million (real, 2023-14) in 2017-18 (our previous base year) to $260.5 million (real, 2023-24) in 2022-23 (our proposed base year). This will result in an EBSS carryover benefit that is included in our 2024-29 Proposal.

Taking this into account, customers will receive the majority of the benefit (over 70%) as this lower opex amount will be used to set our allowance in the 2024-29 period (and beyond) thereby reducing network prices.

9.2.1 EBSS carryover amounts accrued during 2014-19

Our 2017-18 base year was deemed efficient by the AER and therefore it was used for setting our opex allowance for the 2019-24 period. On this basis, the EBSS has applied to us for the current period.

In applying the EBSS, the AER specified a number of cost categories, or types of costs, that would be excluded from reported opex for EBSS purposes. This is to ensure that the allowed and actual opex have been prepared on the same basis so that genuine efficiency improvements (or declines) are captured rather than reporting differences. The AER nominated several excludable costs for EBSS purposes[38].

We have assessed our reported opex to exclude any categories or types of opex nominated by the AER. We have calculated the carryover payments in accordance to the Rules and the AER's EBSS Guideline to ensure that the reported opex has been prepared on a consistent basis with the opex allowance. On this basis, we have:

- Adjusted our opex allowance for the approved 2019-20 Bushfire season pass-through event;
- Adjusted actual opex to reverse movements in provisions;
- Adjusted actual opex to remove actual DMIA expenditure; and
- Adjusted actual opex for mid-period accounting treatment changes to lease capitalisation.

The latter adjustments were not specified at the time of the AER's 2019-24 determination as they were unknown at the time. However, the reversal of these changes is consistent with the objective of the EBSS and the AER's established practice of ensuring actual opex is reported on a consistent basis with the allowance for EBSS purposes to reward (or penalise) genuine efficient changes rather than accounting changes.

As discussed in Chapter 8, the introduction of AASB16 Leases results in the capitalisation of lease costs that were previously expensed. For the first two years of the 2019-24 period we treated our lease costs as an adjustment between the statutory and regulatory accounts given the uncertainty as to their regulatory treatment. From 2021-22 we have reported our lease costs as opex following discussions with the AER and other networks on the appropriate treatment of this mid-period accounting change.

As a result, we have adjusted our reported opex for the first two years of the 2019-24 period for EBSS purposes to ensure our actual opex is consistent with the treatment of leases in the opex allowance.

Based on these exclusions our forecast EBSS carryover benefit for the 2014-19 period is contained in Table 9-2 below.

Table 9-2 Forecast EBSS FY20-FY24 carryover benefit

$m; Real FY24	2024-25	2025-26	2026-27	2027-28	2028-29	Total
EBSS carryover payments	53.3	18.9	33.2	27.8	-	**133.1**

[38] AER, Draft Decision Endeavour Energy distribution determination 2019-24 – Attachment 8 – Efficiency benefit sharing scheme, November 2018, p. 11

Refer to the EBSS worksheet in the Reset RIN, Attachment RIN0.03, for further details.

We describe our current period performance in section 11.4 of this proposal. To summarise, our forecast EBSS carryover benefit is largely the result of our ICT & Digital transformation program. The benefits of this program are reflected in the significant forecast opex reduction for the 2022-23 base year.

We note that customers will receive a greater benefit from these reductions in accordance with the EBSS. The lower opex amount in 2022-23 has been used to forecast our 2024-29 opex resulting in an opex forecast that is significantly lower than it would have been if we had made no reductions to our opex over the 2019-24 period.

9.2.2 Application of the scheme in 2024-29

In the final F&A paper, the AER indicated its intention to apply the EBSS in the 2024-29 regulatory period if[39]:

> *"We intend to apply the EBSS to the NSW distributors in the 2024−29 regulatory control period if we are satisfied the scheme will fairly share efficiency gains and losses between the distributors and consumers. This will occur only if the operational expenditure (opex) forecast for the following period is based on the distributors' revealed costs.".*

We understand the EBSS is intrinsically linked to the revealed cost opex forecast approach. We have used the base-step-trend method to develop our proposed opex and have provided evidence that our 2022-23 base year represents an efficient level of opex. The base-step-trend approach is the AER's preferred method for setting opex allowances.

As explained further in Chapter 11, our base year opex is forecast to be $59.2 million (real, 2023-24) less than the amount we spent in 2017-18. We have achieved this reduction through our ICT & Digital transformation program and the commercial discipline and experience of our management following the lease of 50.4% of Endeavour Energy in 2017 to an Australian-led consortium of long-term investors in the private sector operating the network under a 99-year lease.

It is noteworthy that our forecast base year opex results in a forecasting starting point for the 2024-29 period that is 25% below the opex allowance for the 2022-23 year, as determined by the AER in their 2019-24 decision. This reduction in opex has and will result in a significant improvement in our benchmarking performance using the AER's Opex MPFP. During the 2019-24 period our opex performance has ranked amongst the efficient frontier within Australia.

This provides strong evidence that we have been responding efficiently to the EBSS over the course of the 2019-24 period which has resulted in an efficient base year opex and reduced opex forecast for the 2024-29 period. On this basis, we consider the EBSS should continue to apply to Endeavour Energy in the next regulatory period to ensure operating cost improvements continue to be sought and provide customers the opportunity to further benefit from reduced network prices.

Proposed excludable categories of opex

In accordance with the EBSS guideline, we propose to exclude costs from the EBSS that are not forecast using a single year revealed cost approach for the 2019-24 period. Consistent with the AER's 2014-19 determination and more recent decisions, we propose to exclude the following categories of operating expenditure for the purposes of calculating EBSS payments:

- debt raising costs;
- non-network alternatives costs (DMIA) and Innovation Fund costs;
- movements in provisions; and
- any changes in capitalisation policies and/or accounting standards that occur over the 2024-29 period (if any).

[39] AER, *Final framework and approach for Ausgrid, Endeavour Energy and Essential Energy – Regulatory control period commencing 1 July 2024*, July 2022, p. 47

We consider excluding these costs will ensure allowed and reported opex for the 2024-29 period are prepared on a similar basis and consistent with the scope of the EBSS (i.e. costs forecast on a revealed cost basis).

9.3 Capital Expenditure Sharing Scheme (CESS)

The CESS is designed to provide a strong continuous incentive to undertake efficient capex by rewarding DNSPs that outperform their capex allowance and penalise spending above the allowance. The CESS also provides a mechanism for sharing these gains and losses between DNSPs and customers that mirrors the 70:30 ratio offered through the EBSS. This provides a strong incentive to not over invest in the network.

9.3.1 CESS benefit accrued during 2019-24

For the 2019-24 period our forecast net capex[40] spend of $1,922.6 million (real, 2018-19) is 5.1% below the allowed amount. As discussed in section 10.4 of this Proposal, we expect to spend at the AER capex allowance over the 2019-24 period. This follows an early period re-prioritisation of our allowance towards our ICT & Digital transformation.

This was accommodated, in part, by lower system capex earlier in the period due to COVID-19 and responding to several natural disasters that limited much of our activity to essential operations and maintenance work only. We expect to increase our system capital spend over the remainder of the period, particularly augex as development activity recovers following a series of COVID-19 and economic stimulus related Government initiatives.

The underspend in net capex is therefore driven by our higher than forecast disposals over the 2019-24 period. Notably, we are moving our head office location from Huntingwood to Parramatta and therefore disposing of the Huntingwood location.

Our CESS model has been prepared in accordance with the Rules and the AER's CESS Guideline. Specifically:

- We have included an adjustment to our 2015-19 CESS outcome which was based on an estimate of final year (2018-19) capex at the time, with the actual capex performance now available.
- We have used a forecast for actual capex in the final two years of the current regulatory period.
- We have adjusted our capex for short-term deferrals from the 2019-24 period to the 2024-29 period.
- Also, consistent with the EBSS, we have adjusted our reported capex for movements in provisions attributable to capex.

We can also confirm that Software as a Service (SaaS) costs have been treated as capex consistent with the capex allowance for the 2019-24 period. Similar to lease accounting, there has also been a change in the treatment of SaaS costs following clarification from the International Financial Reporting Interpretations Committee (IFRIC) in April 2021.

The IFRIC confirmed that configuration and customisation costs for cloud-based software in a SaaS arrangement should be expensed rather than capitalised. This is because, unlike a traditional software application licence that is purchased and controlled, the customer only has rights to access cloud-based software.

This does not affect the vast majority of the ICT transformation costs we have incurred over the 2019-24 period. Instead, it will impact Endeavour Energy on an ongoing basis as we customise and renew software application licences.

Table 9-3 Forecast CESS FY20-FY24 carryover benefit

$m; Real FY24	2024-25	2025-26	2026-27	2027-28	2028-29	Total
CESS carryover payments	2.8	2.8	2.8	2.8	2.8	**13.8**

[40] For CESS purposes, capex net of disposals and capital contributions is used (i.e. RAB additions). In other parts of this proposal we discuss our capital spend exclusive of the impacts of disposals.

Deferred capex adjustments

The CESS may be adjusted where a CESS reward (or part of) has been earned by deferring capital work into the next regulatory period that fails to provide any benefits to customers. The AER will adjust CESS payments where capex has been deferred and[41]:

- the amount of deferred capex is material;
- the amount of the estimated underspend over the current period is material; and
- total approved forecast capex in the next period is materially higher than it is likely to have been if capex had not been deferred.

We have reviewed our delivered capital program over 2019-24 to determine whether any adjustment to our CESS payment is required to account for material project deferrals. Over the 2019-24 period we have responded to changing circumstances efficiently. The circumstances have been challenging, we have had to manage multiple natural disaster events, the impacts of the COVID-19 pandemic and ongoing global economic downturn.

We also embarked on an ambitious ICT & Digital transformation program which required a significant re-allocation of capital during the first half of the 2019-24 period.

This re-allocation was facilitated by the lower-than-expected system capex early in the period which was driven by the challenging circumstances noted above as well as temporary deferrals. Our system capex is forecast to be 9.8% below the current period allowance before increasing by 5.1%. Within this, augex has varied significantly over the period as we manage increasing material and project costs and several unexpected projects. These system capex deferrals are expected to be resolved either within the current period and/or the next period.

We do not consider the conditions for a deferral adjustment outlined above have been satisfied. For instance, net capex is below the 2019-24 allowance on account of higher-than-expected disposals and our overall 2024-29 capex is reducing compared to our actual/forecast capex for the 2019-24 period.

However, we are still proposing a CESS adjustment for the deferral of system capex from the current period to the next. This is because the variations between periods are significant and the results of this period have largely been driven by forces outside of our control (e.g. economic conditions and development activity) rather than management efficiency.

We have compared our augex project listing underpinning the 2019-24 determination (which extended out until FY29 at the time) and compared this to our 2024-29 proposal. We have identified projects that have had a material shift in timing from one period to the next and assessed the drivers of the changes. The latter is to separate efficient drivers, such as a demand management initiative or efficient investment staging, from timing shifts driven by exogenous factors.

Based on this assessment we have identified $54 million (real, 2023-24) of short-term deferrals between the current and next period. This amount currently relates to augex projects, however it could equally relate to repex should augex be higher than forecast over the remainder of this period, necessitating a re-balancing within the overall allowance.

It should also be noted that we have identified ‘unexpected’ capex from other augex projects that were not anticipated at the time of the 2019-24 determination. This unexpected capex is far in excess of the deferral capex and, under the CESS[42] should also be recognised to offset the impact of the deferrals in full.

However, we have not accounted for this unexpected capex in our CESS carryover calculation and instead only captured the between period deferrals. Whilst this application is not in strict accordance with the CESS it is consistent with feedback we have received from our RRG and broader concerns from stakeholders about the operation of the CESS raised as part of the AER’s review of incentive schemes[43].

[41] AER, Capital Expenditure Incentive Guideline, Explanatory Statement, Nov. 2013 p.46.
[42] AER, Capital Expenditure Incentive Guideline, Explanatory Statement, Nov. 2013 p.40-45.
[43] AER Review of incentive schemes for networks – Draft decision – December 2022.

We consider this proposal demonstrates our commitment to transparently accounting for our actual period performance and ensuring that incentive scheme outcomes reflect genuine efficiency improvements.

9.3.2 Application of the scheme in 2019-24

The AER intends to apply the CESS to Endeavour Energy for each year of the 2024-29 regulatory period[44]. We support the AER's decision and consider the CESS will contribute to the capital expenditure incentive objective[45].

We note that following the AER's final F&A for the 2024-29 period it released its draft report on its review of incentive scheme arrangements. This report, subject to confirmation in the AER's final decision, which is expected in April 2023, sets out the AER's intention to modify the application of the CESS as follows:

- a tiered incentive rate where the first 10% of underspend is subject to a 30% incentive rate followed by 20% thereafter. Noting that a 30% incentive rate applies to any overspend; and
- inclusion of a new section setting out expectations for transparent reporting and explanation of capex variances.

These changes are in response to concerns raised by some stakeholders that the CESS was not effective and/or rewarding genuine efficiency gains. We remain of the view that the CESS has not been in operation long enough to be properly assessed. However, the available evidence suggests it has resulted in (or contributed to) lower capex across the NEM.

Notwithstanding these concerns, the AER intends to modify the Capex Incentive Guideline to implement these proposed changes. An outstanding matter of consultation is whether the amended CESS should apply to Endeavour Energy and other DNSPs for the upcoming 2024-29 determinations. Whilst our position is that the CESS should be unmodified, if the AER remains of the view that changes are required, we accept their application to our 2024-29 regulatory control period given these amendments are being made prior to the period commencing.

We also note that the AER has proposed to use forecast depreciation to establish the RAB at the commencement of the 2029-34 regulatory control period for NSW distributors. The AER considers that this approach, in combination with the CESS, will provide sufficient incentive for the distributors to achieve capital expenditure efficiency gains over the 2024-29 period. We support this decision and consider it is consistent with the incentives provided by the CESS.

[44] AER, Final framework and approach for Ausgrid, Endeavour Energy and Essential Energy – Regulatory control period commencing 1 July 2024, July 2022, p. 47.
[45] NER 6.4A(a).

9.4 Service Target Performance Incentive Scheme (STPIS)

The STPIS provides us with a financial incentive to maintain and improve service performance (being reliability and customer service) where customers are willing to pay for these improvements. In doing so it balances the incentives to reduce expenditure with the need to maintain or improve service quality. In other words, the STPIS ensures cost efficiencies encouraged by the EBSS and CESS are not made at the expense of supply reliability and customer service quality.

Below we set out our performance in the 2019-24 period and how we propose to apply the STPIS in the 2024-29 period, including proposed targets.

9.4.1 Our reliability performance

Service reliability is often impacted by a combination of internal and external events. Our inability to directly control many of these factors means that some level of unplanned interruption is likely to be experienced somewhere on our vast network during the course of a year. While it can be difficult to totally control our SAIDI and SAIFI performance we seek to build a resilient network and respond promptly to any unplanned outages that do occur.

STPIS performance

Our annual SAIDI, SAIFI and customer service performance against the set targets for the most recent five years are shown in the tables below.

Table 9-4 Unplanned SAIDI (average annual minutes off supply per customer)

Unplanned SAIDI (minutes)	2017-18	2018-19	2019-20	2020-21	2021-22
Urban Target	60.3	60.3	60.1	60.1	60.1
Urban Actual	48.7	50.3	58.1	48.2	45.3
Variation	**-11.6**	**-10.0**	**-2.0**	**-11.9**	**-14.8**
Short Rural Target	175.86	175.86	172.0	172.0	172.0
Short Rural Actual	126.9	139.2	159.3	109.8	205
Variation	**-48.96**	**-36.66**	**-12.71**	**-62.21**	**32.99**

Table 9-5 Unplanned SAIFI (average annual number of interruptions per customer)

Unplanned SAIFI (number)	2017-18	2018-19	2019-20	2020-21	2021-22
Urban Target	0.800	0.800	0.716	0.716	0.716
Urban Actual	0.587	0.615	0.598	0.501	0.447
Variation	-0.213	-0.185	-0.118	-0.215	-0.269
Short Rural Target	1.765	1.765	1.493	1.493	1.493
Short Rural Actual	1.286	1.29	1.245	0.915	1.312
Variation	-0.479	-0.475	-0.248	-0.578	-0.181

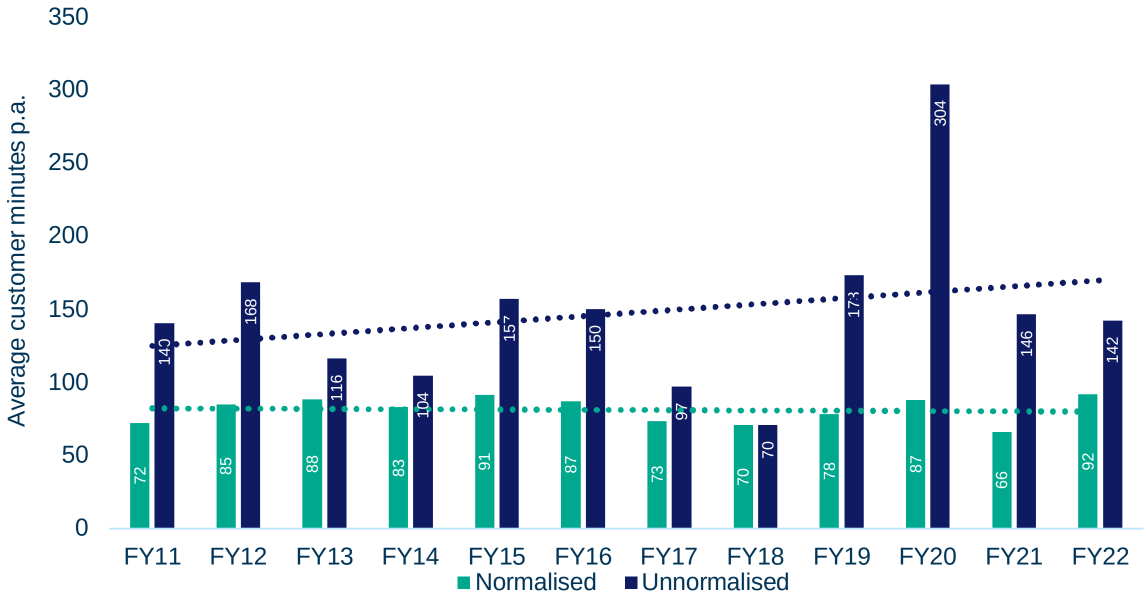
Table 9-6 Telephone answering performance (% of calls answered within 30 seconds)

Telephone answering (%)	2017-18	2018-19	2019-20	2020-21	2021-22
Target	75.0	75.0	81.4	81.4	81.4
Actual	82.9	82.6	88.8	89.5	85.5
Variation	7.90	7.60	7.40	8.10	4.10

At the time of our 2019-24 proposal we committed to maintaining reliability over the period. Our results over the last five regulatory years reveal that we have done so.

However, the adverse movement in FY22 provides a further example of the growing impacts of climate change as weather events become increasingly frequent and severe in addition the BAU task of managing an ageing asset base. Whilst the STPIS excludes Major Event Days (MEDs) the number of events at or below this threshold are also increasing. The growing importance of network resilience was outlined in Chapter 3. At a high level, the difference between resilience and reliability is best depicted in the growing gap between the unadjusted and adjusted SAIDI results.

Figure 9-1 Endeavour Energy unplanned SAIDI results FY11-FY22



In regard to the customer service measure, we have generally outperformed the AER's telephone answering targets.

9.4.2 Application of the scheme in 2019-24

As detailed in the final F&A paper, the AER has proposed to continue applying the STPIS for each NSW DNSP as follows:

- set revenue at risk for each distributor at ±5%;
- segment the network according to the four STPIS feeder categories (CBD (Ausgrid only), urban, short rural and long rural) as per the scheme's definitions;
- apply the system average interruption duration index or SAIDI, system average interruption frequency index or SAIFI and customer service (telephone answering) parameters. The latter only in the absence of CSIS;
- set performance targets based on the distributor's average performance over the past five regulatory years;
- apply the method in the STPIS for excluding specific events from the calculation of annual performance and performance targets;
- apply the method and value of customer reliability (VCR) values as most recently published by the AER; and
- not apply the GSL component in NSW provided we remain subject to a jurisdictional GSL scheme.

We support the AER's decision to apply the STPIS to Endeavour Energy for the 2024-29 period. The STPIS plays an important role in ensuring cost efficiencies pursued under the CESS and EBSS do not come at the expense of service standards.

We propose to attribute the revenue at risk between the reliability of supply and the CSIS. For the CSIS, discussed further below, the maximum revenue increment or decrement will be ±0.50%. The revenue at risk for the reliability of supply component of the STPIS for each year will therefore be subject to the customer service component outcomes within the constraints of the overall revenue at risk requirement of ±5%.

Performance targets

We support the AER's decision to set targets based on our average performance over the past five regulatory years. Based on this approach, performance parameter targets for the current and next regulatory period are displayed in Table 9-7 below. We expect to provide updated targets in our Revised Proposal to include our measured performance over the 2022-23 year.

Table 9-7 Proposed performance parameters for FY19-FY24

Performance parameter	2019-24 STPIS Target	2024-29 STPIS Target
Unplanned SAIDI (minutes)		
Urban	60.1	50.1
Short Rural	172.0	148.0
Unplanned SAIFI (number)		
Urban	0.716	0.550
Short Rural	1.493	1.209
Telephone Answering (%)		
% calls answered within 30 seconds	81.4%	N/A* (85.9% for comparison)

*Telephone answering is not proposed to be continued for the 2024-29 STPIS and is proposed to be replaced with a CSIS, refer to section 9.5 below.

In accordance with the expectations of customers and expenditure objectives, our proposed capex and opex plans are designed to meet these targets and maintain our existing performance.

Excluded events

The STPIS allows the impact of some major exogenous events to be excluded from measuring DNSP reliability performance. Clause 3.3(a) of the STPIS provides a list of specific events leading to a supply interruption that may be excluded when calculating a revenue adjustment under the STPIS.

Events that cause the daily unplanned SAIDI to exceed a pre-defined threshold may also be excluded from the STPIS. A statistical formula is used to identify this threshold value which when exceeded, is determined to be a major event day (MED). The STPIS currently sets this threshold at 2.5 standard deviations from the mean and is commonly referred to as the "2.5 beta method".

We propose to use an alternative approach to calculate MED thresholds using the power transformation (Box-Cox) method. In accordance with Appendix D of the STPIS, we are required to propose an alternative data transformation method which results in a more normally distributed data set. We have proposed this variation in accordance with clause 2.2 of the SPTIS and the requirements outlined in Appendix D.

The Box-Cox method was approved by the AER in our two previous determinations, and it results in a more normally distributed data set compared to the natural logarithm transformation method. This is supported by a number of testing techniques we have undertaken to compare the performance of these two methods. Refer to Attachment 10.07 for these findings in further detail. As the Box-Cox method has applied to the previous and current period, our historical data and resulting 2024-29 STPIS targets would need to be updated should an alternate method be approved by the AER.

Value of customer reliability

The value of customer reliability measure (VCR) is an estimation of the value customers place on improved service reliability. A rise in the VCR indicates an increased willingness from customers to pay for a more reliable supply with a VCR reduction suggesting the opposite. We use the VCR to inform our capital investment decisions and also to calculate the reward and penalties for exceeding or failing to meet our STPIS performance targets.

The AER is responsible for determining the VCR, updating it annually and reviewing its methodology every five years following an AEMC rule change[46]. The AER published its most recent VCR in December 2021. We accept these values for use in both the STPIS and as an input to the economic cost-benefit analysis used to derive and optimise our capital plans.

As our network is divided into urban and short rural segments, the STPIS requires us to weigh each parameter attributable to each segment between unplanned SAIDI and unplanned SAIFI. We propose to attach the weights as set out in Table 1 under clause 3.2.2 of the STPIS.

Guaranteed Service Levels

The AER has stated the GSL component of the STPIS will once again not apply as it is currently provided through an equivalent scheme administered by our jurisdictional regulator IPART. We support this decision.

We note that in September 2022, IPART amended our licence conditions of which a new GSL scheme will apply from July 2024. The new service standard being:

- **Level 1:** 20 hours or 10 outages per calendar year resulting in a $120 compensation payment; and
- **Level 2:** 48 hours or 20 outages per calendar year resulting in a full refund of the typical distribution network service charge for the year.

In addition to setting new service standards the amended conditions include requirements to increase the information provided to customers and timeliness of payments increasing the likelihood of a material increase in the compensation payments.

Banking mechanism

The STPIS allows DNSPs to propose delaying a portion of the revenue adjustments for one year. This may be requested to limit price volatility and is offered regardless of whether the s-factor adjustment is positive or negative.

In response to our customers' desire to limit fluctuations in electricity prices, we will diligently review the impact of our reliability performance and STPIS rewards and penalties on network charges and inform the AER of our intention to bank or defer any payments.

[46] AEMC, Rule Determination – National Electricity Amendment (Establishing values of customer reliability) Rule 2018, 5 July 2018.

9.5 Customer Service Incentive Scheme (CSIS)

As aforementioned, incentives are designed to achieve an optimal mix between the cost and quality of services provided by networks. The input-based schemes focus on opex and capex spending (the EBSS and CESS respectively) while the output-based schemes focus on innovation (to drive future efficiency) and service quality (the DMIS/A and STPIS).

We recognise that the intention of this system of incentive schemes is to ensure that gains made on either side of this ledger are genuine improvements that are sustainable over the longer term and are not made at the expense of the other.

Currently, customer service levels are subject to both standards, such as those covered by National Energy Customer Framework (NECF) and NSW GSLs, and incentives via the telephone answering component of the STPIS. Standards (typically accompanied by a penalty regime) are suitable to provide safeguards for customers, particularly vulnerable customers, where an essential service level can be defined and/or is necessary (e.g., life support). Incentives are suitable for services that are valued by the average customer but for which the desired service level cannot be precisely known or objectively defined (e.g., customer satisfaction levels).

The existing customer service component of the STPIS is percentage of customer calls answered within 30 seconds and currently worth incentive/penalty of ± 0.5% maximum allowable revenue (MAR). For the 2024-29 period we propose this component of the STPIS is replaced with the following measures with an equivalent ±0.5% total revenue at risk.

Table 9-8 Proposed CSIS parameters for FY25-FY29

Performance parameter	Revenue at risk	2024-29 CSIS Target
Customer Satisfaction (CSat)		
Unplanned outage	±0.083%	5.99
Planned outage	±0.083%	4.69
General enquiry	±0.083%	7.57
Planned outage management		
% of planned outages starting within 30 minutes of communicated start time	±0.125%	25.83%
% of planned outages finishing within 1 hour of the planned duration	±0.125%	22.40%
Total	**±0.5%**	**-**

Below we set out our rationale for applying a CSIS and the process we followed in developing our proposal.

9.5.1 Developing a CSIS

We engaged with stakeholders on our intention to apply a CSIS for the 2024-29 period in place of the telephone answering measure in the STPIS. This intention was driven by several factors:

- Telephone answering was identified as an antiquated measure of customer service during our 2019-24 determination process. As it was too late in the process to modify the STPIS to address this concern we committed to re-engaging on this issue in advance of our next determination.
- The Customer Challenge Panel (CCP) has maintained its position that telephone answering remains a valid but incomplete measure of customer service.
- We expect to achieve maximum positive performance (94%) against the telephone answering target during the 2019-24 period. Given the ratcheting nature of STPIS target setting the measure is reaching the point of saturation whereby further improvements in performance are not justifiable.

- All Victorian networks have now consulted on a CSIS resulting in varied measures of customer service applying. We not that, following feedback from its customers, only Jemena decided against applying a CSIS.
- The AER has published a CSIS setting out assessment principles and design parameters reflected in the approach taken by the Victorian DNSP's.

Above all else, we have committed to improving our organisational focus and commitment to continuously improving our customer service levels.

As outlined in Chapter 3, we have made a number of improvements in support of our ambition to become increasingly customer-centric. This has been highlighted by our updated organisational strategy, establishing CSat key performance metrics, customer journey mapping, our VoC program, new CAS, and ongoing participation in the Energy Charter.

We therefore consider it imperative to implement an incentive scheme that reflects our commitment to improving customer service with measures that genuinely reflect customer preferences.

As a starting point, we sought to identify customer priorities and preferences in order to develop alternate measures. Our BAU uplift in customer service provided us with a wealth of data and insights as to the expectations of our customers and key 'pain points' in our existing processes and practices. We complemented this insight with more specific customer research on customer priorities.

The findings of this research are detailed in Attachment 5.09 and 5.11 to our proposal. Below is a ranking of our core services provided in order of how frequently they were included in a customer's top five priorities:

1. Providing a reliable supply of electricity to all customers by building, maintaining, and managing the substations, poles, and wires, underground cables, and other equipment.
2. Responding to emergencies like storms which bring down power lines and poles to reduce the safety risk and restore power as quickly and safely as possible.
3. Managing the network efficiently to deliver electricity services in the most affordable way.
4. Researching, trialling, and installing new technologies such as batteries to improve efficiency of infrastructure investment where possible, helping contribute to long-term affordability of electricity bills.
5. Managing safety-related issues to reduce risks to the community by monitoring infrastructure, trimming trees to maintain safety clearances, managing bushfire risk, and preventing blackouts caused by falling trees.
6. Planning for the future by building the infrastructure to accommodate growing suburbs and industries.
7. Keeping customers informed (via SMS for all customers plus mailbox drops for life-support customers) of planned and unplanned outages to minimise disruption.
8. Helping vulnerable customers to keep the power on when things go wrong or when they need medical equipment to preserve life (life support customers).
9. Providing customers with tools to help manage electricity usage and costs via telephone, text, and website
10. Installing and maintaining streetlights to keep communities safe.
11. Reading electricity meters and sending the data to retailers so your electricity bills are accurate
12. Providing prompt connections and disconnections when required, including new services and solar connections.
13. Answering emergency telephone calls within 30 seconds.

The first six priorities are unsurprising and go to our core objectives and purpose as a DNSP. Further, these priorities are addressed by existing incentive schemes that focus on reliability, efficiency, and innovation whilst safety is suitably addressed via licence conditions and various legislative obligations.

Of the remaining priorities, telephone is notably ranked 13th whilst keeping customers informed and supporting vulnerable customers are two of the higher ranked priorities. We note the latter is partly addressed by our NECF obligations and we are taking steps to improve our support of vulnerable customers via our 'knock-before-disconnect' program.

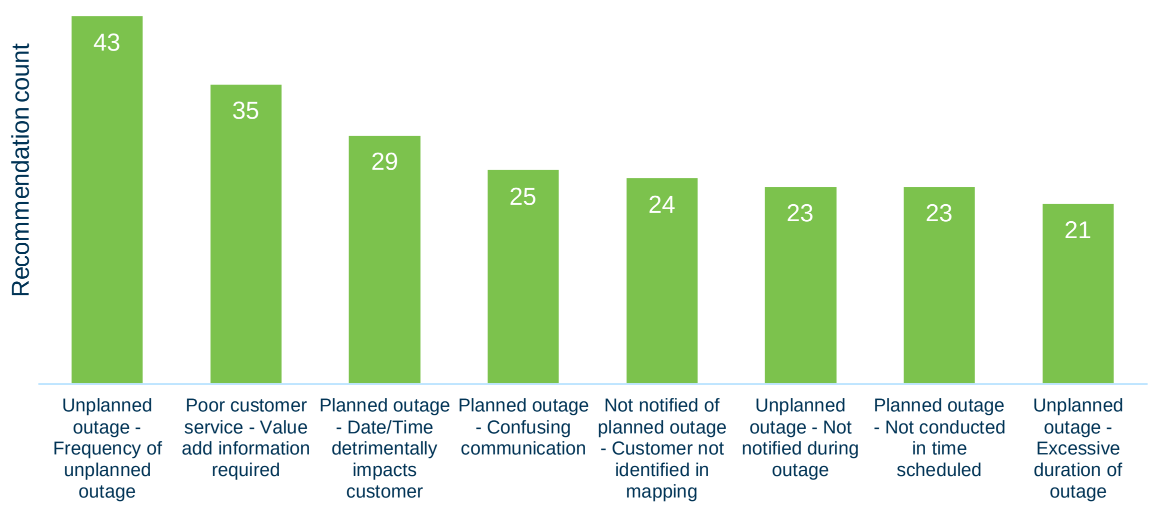
In combination with customers two overall priorities, reliability, and timely supply restoration, we consider improving our management of planned and unplanned outages to be area wherein customers would value improvements in service quality.

This is supported by our BAU customer journey mapping initiative and VoC insights which both highlighted complaints and claims and outage management as critical pain points for customers. Outage management pain points include:

- When outage information from Endeavour Energy was not delivered in the first instance. Customers who aren't expecting an outage experience significant stress when power interrupted, and they have no back up plan
- Disruption to customer regular schedules can be painful especially working from home and the cost and effort of organising alternative supply arrangements
- Customer frustrated when planned outages cancelled or rescheduled, particularly business and industrial customers who can suffer financial loss when planned outages are cancelled
- When outages are cancelled, customers want an explanation and feel let down when not provided or the rationale makes no sense
- For life support customers anxiety can highly fluctuate during periods of prolonged outages especially when estimate time to restore changes

Through our VoC program we have received over 100 recommendations for how our outage management processes could be improved. The provision of timely, accurate and informative messaging before, during and after outages being highly ranked.

Figure 9-2 Endeavour Energy VoC program outage management recommendations



We also engaged with our RRG to co-design our customer research and develop our CSIS at a more detailed level. As the CSIS was identified as an opportunity to collaborate we engaged with the RRG on potential measures and design features. Some key pieces of feedback were developing meaningful measures linked to customer preferences. There was also concern around relying solely on CSat measures but conversely diluting the CSIS and a desire to incentivise objectively measurable services we directly provide customers.

9.5.2 Proposed CSIS measures

Based on the preferences of customers and feedback from the RRG we propose the measures outlined in Table 9-8. Our proposed CSIS includes a mix of CSat and outage management measures which we detail below.

Customer Satisfaction (CSAT)

Customer Satisfaction Score, often referred to as CSat, is a service metric that expresses a customer's level of satisfaction with a brand, its product or services, or a particular interaction during the customer's journey.

The purpose of CSat surveys is to measure customer contentment after each meaningful touchpoint, like completing a transaction or before an important milestone. CSat measures short-term gratification following a recent interaction and speed to survey is key to a successful VoC program.

Unlike Net Promoter Score (NPS), which measures overall customer satisfaction, CSat surveys measure customer satisfaction with specific areas or aspects of a business.

We conduct CSat surveys across three areas on a constant basis through our VoC program, with over 5,000 respondents since December 2021. The areas surveyed and questions include:

- Planned outage:
    - Completed in timeframe communicated
    - Sufficient information provided before outage
    - Adequate time given for customers to prepare
- Unplanned outage:
    - SMS notification received within minutes of outage
    - Power restored in accordance with communications
    - Information was sufficient without the need to seek additional advice
- General enquiry:
    - Information given was clear, accurate and understood
    - Enquiry resolved at 1st contact
    - Able to easily liaise with a Contact Centre agent

Outage management

Planned Outages can occur to facilitate upgrades, repairs, and maintenance to the network; upgrading supply or connecting new customers; replacing metering equipment or service lines; and vegetation management.

Network Switching – Planned Outages

For outages that impact multiple customers and require network switching, planning occurs at least six weeks in advance, with customers notified at least two weeks ahead of the outage. Specifically, request to determine isolation and preparing the switching plan undertaken one week in advance, followed by performing of switching on date of scheduled job.

These outages are in scope for the CSIS service target.

Accredited Service Provider (ASP) Jobs – Planned Outages

Accredited Service Providers are accredited by the NSW Government in accordance with the Electricity Supply Act 1995 and the Electricity Supply (General) Regulation 2001. ASPs must also be authorised by Endeavour Energy before they can undertake construction work on or near our network. Level 1 ASPs are authorised to perform construction activity on the electricity network and as such require planned outages.

Planned outage activity requiring network switching for ASP work is managed as above, and in scope for the CSIS service target.

Individual Customer Outages (Metering)

Where a customer requires metering to be replaced requiring an outage Endeavour Energy arrange the work to be carried out to perform outage of supply for specific request from a customer.

This outage activity is not in scope for the CSIS service target.

Start and End Outage Time Analysis

While planned outages can be inconvenient, the accurate notification of when the outage will start and end, is critical to enable customers to organise and manage alternative arrangements.

We implemented an ADMS and Customer Notification Systems (CNS) in April 2021. This technology implementation facilitated the automatic generation of SMS and postal letter notification for customers impacted by planned outages. Given the data now available, analysis has been conducted to assess the percentage of jobs that commenced and finished as at the time advised to the customer.

We analysed planned outage jobs conducted from April 2021 to 30 June 2022, inclusive of ASP activity, which has been extracted from our distribution management system (ADMS). The results of that analysis confirmed:

- 25.83% of planned outages commenced at the time communicated to customers; and
- 22.40% of planned outages were for the duration time communicated to customers

Based on customer feedback and insight regarding the importance of being kept informed of planned outages, this new data reveals there is opportunity to improve and to do so would be of significant value to our customers.

9.5.3 Proposed CSIS Design

We propose to evenly allocate half (0.25%) of the CSIS revenue at risk to the three CSat measures and the remaining 0.25% evenly across the two outage management measures.

The targets have been set based on planned outage jobs conducted from April 2021 to 30 June 2022 for the outage management measures and January 2022 to September 2022 for the CSat measures. We intend to update these targets at the time of the Revised Proposal.

We consider our proposed CSIS is consistent with the key principles and criteria outlined in the AER's CSIS Guideline. Specifically:

- **Performance parameters:** the measures relate to customer experiences associated with our standard control services that customers value, want to see improved and are within our control. They are also not captured by any other existing incentive scheme.
- **Measurement methodology:** the CSat surveys are conducted independently and outage management data from internal systems which can be audited as part of our annual RIN audit (or in parallel to it). The measures can be objectively and reliably measured and accurately capture the performance parameter.
- **Assessment approach:** baseline performance has been measured to establish targets and each measure allows for a clear assessment to be made of improvements and/or deterioration in performance to determine a reward or penalty.
- **Financial component:** in the absence of a willingness to pay study we have set the revenue at risk and incentive rate to cap our incentive payment (penalty) at our aspirational level of performance by FY29 relative to our baseline level performance. These aspirational targets were consulted on with our RRG to test their reasonableness. We consider our approach ensures the penalties and rewards are commensurate with customer benefits and do not provide an incentive to over-invest.

Refer to Attachments 9.02 - 9.04 for further detail on our CSIS design and how it satisfies the requirements of the AER's CSIS guideline. We note that if the AER were not to approve our proposed CSIS we would revert to the existing customer service measure within the STPIS.

9.6 Demand Management Incentive Scheme (DMIS)

Effective demand management can defer, limit, or eliminate the need to invest in traditional network assets which can lead to long-term savings for customers.

Demand management solutions have typically been sought to dampen or shift customer demand during peak periods. As network planning generally seeks to provide sufficient capacity during these peak periods, demand side responses (e.g., peak shaving, load shifting and broad-based load reductions) can be effective in lowering peak demand and removing the need to invest in assets to accommodate these demand levels.

The AER has indicated that demand management can offer alternatives to network investment outside of peak demand driven constraints. To reflect this view, they broadly define demand management as the act of modifying the drivers of network demand to remove a network constraint.[47]

We agree that the search for efficient non-network alternatives should not be limited to addressing peak demand issues and believe demand management may have the potential to provide an alternative to network asset replacements and power quality issues such as voltage regulation and frequency control.

We also note that existing planning requirements, the Regulatory Investment Test (RIT-D) and Distribution Annual Planning Report (DAPR) also ensure that we pursue and evaluate demand management for a wider range of network constraints.

9.6.1 Demand Management Incentive Scheme (DMIS)

The objective of the Demand Management Incentive Scheme (DMIS) is to provide distributors with an incentive to undertake efficient expenditure on relevant non-network options relating to demand management.[48]

The DMIS provides a 50% cost uplift for undertaking efficient and eligible demand management projects. The scheme allows the value of this multiplier to vary but prohibits changes to committed projects. We believe the certainty of receiving a pre-defined and fixed return will further incentivise investigation of non-network solutions.

We note that our Regulatory Proposal does not need to outline an exhaustive list of eligible DMIS projects we intend to undertake for the 2024-29 period. Instead, we will identify eligible DMIS projects over the course of the period as we investigate non-network solutions through the RIT-D process or BAU planning activities. A demand management compliance report will be prepared on an annual basis to allow the AER to validate the outcomes achieved and the pass through of incentive payments to be included in the annual pricing proposal process.

The DMIS is an important mechanism that incentivises increased adoption of efficient non-network solutions that benefit customers through a transparent process. We support its ongoing application to Endeavour Energy for the 2024-29 period.

9.6.2 Demand Management Innovation Allowance (DMIA)

Our performance during the 2019-24 period

Pilots and trials provide an efficient way to test the potential usage and value of emerging technologies for customers. Over the previous and current regulatory periods, the allowance provided through the DMIA was used to fund a number of trials and pilot projects. Some of these include:

- power factor correction trial;
- pool pump trial;
- demand management education project;
- ripple control development project;
- residential battery storage trial; and

[47] AER, Demand Management Investment Scheme (DNSP), December 2017, p.18
[48] NER, Clause 6.6.3(b)

- grid scale battery storage.

We note that our DMIA expenditure will primarily occur in the latter years of the 2019-24 period. This is primarily due to the COVID-19 pandemic inhibiting our ability to engage with customers to participate in trials and the prioritisation of essential work.

Our actual and forecast DMIA expenditure for the 2019-24 period is set out in Table 9-9 below.

Table 9-9 Actual and forecast DMIA expenditure to allowance

$m; Real FY24	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Allowance	0.81	0.85	0.86	0.85	0.80	**4.2**
Actual/Forecast	0.25	0.03	0.08	1.92	1.92	**4.2**

In accordance with the DMIA, any unspent DMIA amounts for the 2019-24 period will be returned to customers via a single adjustment in the second year of the 2024-29 period (2020-21) once the full results for the 2014-19 period are known.

Application of the DMIA in 2024-29

The DMIA, which was revised in 2017, provides funding for research and development for innovative demand management projects that have the potential to reduce network costs in the long term.

It provides an annual allowance calculated as $200,000 + 0.075% of the MAR for each respective DNSP (as opposed to a specified amount as per the previous DMIA). This allowance is provided ex ante and is recovered from consumers throughout the regulatory control period.

Based on this method our proposed DMIA for 2024-29 is outlined in Table 9-10 below. We note that we will bear any overspend to these amounts and any underspend will be returned to customers in the following period.

Table 9-10 Proposed annual allowance caps

$m; Real FY24	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Allowance	1.06	1.00	1.00	0.98	0.96	**5.0**

In developing pilots and trials, we will engage with customers, stakeholders, and industry participants to identify research opportunities which may benefit customers. We are interested in any opportunities to engage in industry wide trials and research projects that allow for collaboration and a transparent sharing of knowledge.

9.7 Innovation Fund

We are also proposing $25 million (Real FY24) to fund innovative projects in addition to and beyond the scope of the DMIA. Innovation, from testing new technologies to research and development, is a critical enabler of future efficiencies. We must find new and better ways of providing network services to keep pace with the rapidly changing energy environment and remain efficient in the long-term.

Whilst always essential, innovation is becoming increasingly important as the energy industry transitions to a de-centralised, de-carbonised, digitalised, and democratised system with two-way energy flows and the emergence of significant new technologies like batteries and EVs. This is a significant shift for networks who must adapt to facilitate this transition and making use of these advancements as a Distribution System Operator (DSO).

The DMIA, whilst valuable, is limited in scope and scale as it equates to 0.1% of our total expenditure for the 2024-29 period and focuses on demand management, which is underscored by a one-way view of the customers' role in the energy system.

Given the increasing pace and importance of technological change and innovation we consider there is a need for increased innovation expenditure via a formalised allowance. By nature, the benefits of innovation are uncertain, however they are likely to be positive and in the long-term interests of customers. Further, customers have indicated an expectation that Endeavour Energy take an active role in the energy transition and willingness to pay for increased innovation spending.

This approach has been pioneered by other networks such as Ausgrid and Ausnet Services, and we have modelled our program from their engagement approach and governance arrangements with strong support from the RRG Independent Members Panel.

9.7.1 Developing an Innovation Fund

As discussed in Chapter 5, we co-designed our engagement approach to the 2024-29 proposal with our RRG, a collection of informed stakeholders and customer advocates. Similar to the CSIS, innovation funding was identified as a topic for collaboration under the IAP2 spectrum.

We therefore sought to consult with the RRG on whether an Innovation Fund was required in addition to the DMIA and, if so, the appropriate quantum, focus and governance arrangements. To help inform this collaboration, we engaged with customers and a broader set of stakeholders to understand their preferences and expectations of Endeavour Energy. These engagement activities and findings are summarised below (see Attachment 9.05 for further detail):

- **Exploratory Phase Focus Groups:** customers felt Endeavour Energy should be responsive to the energy transition and act to ensure they keep pace with it.
- **In-language CALD engagement:** In the English-language quantitative study, those with CALD backgrounds were more likely than other residential customers to be interested in researching, trialling, and installing new technologies such as batteries to improve efficiency of infrastructure investment where possible, helping contribute to long-term affordability of electricity bills. They also gave higher priority to Endeavour Energy providing future support for solar panels, electric vehicles, and electricity trading than other segments.
- **Customer Panel:** The majority (73%) of participants, including 84% of SMEs and three-in-four residential customers, want Endeavour Energy to modernise the network in preparation for either a rapid (very fast) or accelerated (fast) energy transition to accommodate future customer expectations as technology and markets evolve. A fifth of customers who opted for a rapid transition supported a $9 p.a. increase in bills to do so whilst the majority (52%) preferred an accelerated transition with limited trials for a smaller cost increase of $3 p.a.
- **Local Council Workshops:** Councils were very keen to understand more about how they could partner with Endeavour Energy to meet their sustainability goals – new or evolving technology options like community batteries, VPPs and EVs were all seen to be an important part of this.
- **Stakeholder Deep Dives:** Stakeholders were more likely than Customer Panel participants to prefer Endeavour Energy's plan for a rapid energy transition, the fastest and most ambitious of the four options presented (64% in favour of rapid and 32% for accelerated).

- **BAU engagement:** Reptrak community surveys showed 60% of customers believe it is very important for Endeavour Energy to focus on designing renewable energy solutions and planning the transition to a low carbon environment.

Overall, it was clear that customers and stakeholders are keen to be involved in the transition to a low carbon economy and want Endeavour Energy to take steps to prepare for an accelerated transition. Customers see this as a win-win outcome; a cleaner environment while unlocking personal savings through improved energy choice and control. There was an expectation that Endeavour Energy increase its focus on technological innovation.

Our RRG was supportive of including additional funding for innovation and the amount proposed. They were keen to understand how the funding would be used and the governance arrangements that would apply to promote transparency and ensure customers would benefit from the innovation. Our proposed focus areas and funding and governance arrangements are discussed further below.

9.7.2 Innovation focus areas & benefits

Endeavour Energy considers the innovation investment model a critical catalyst to better enable the energy transition on our network.

This is because it will allow some investments that would be considered risky or might not immediately pass the cost benefit test on their own but are considered by Endeavour Energy and its Customer Panel to hold significant potential.

The future of energy that Endeavour Energy is working towards is a smarter, flexible, and modernised grid that will allow Endeavour Energy to adapt to the evolving customer needs, while operating and maintaining a safe and reliable network.

The investment in exploring new technologies based on the following four innovation themes address the challenges and opportunities to provide customers with more choice and control on how they use and receive energy.

- **Orchestration & DSO:** facilitating consumer participation in the energy market rather than building more infrastructure and go beyond “poles and wire”.
- **Electric Vehicles Services:** enabling grid stability and flexibility as EV uptake rises.
- **Sustainability Solutions:** developing sustainable services from renewable-based supply and improve energy efficiency.
- **Climate Resilience:** adopting climate resilience measures contributing to improve electricity access and network services with a particular focus on enhancing community resilience.

In order to best answer our customer needs, Endeavour Energy will work on the four innovation themes with an ecosystem of partners when relevant. The innovation investment fund will allow us to:

- Accelerate our participation in emerging technology in an agile manner.
- Incubate fast-growing use cases (that may currently be further away from our core operations), issues and opportunities beyond demand-management such as the benefit that electrical vehicles may have in soaking up excess solar and providing network support under emergencies.
- Maintain the radar for emerging and unforeseen technology and business model innovations.
- Consolidate and unlock value stacks in the electricity supply chain, to benefit customers and to improve supply efficiency.
- Bring forward successful trials for productionisation earlier that could become material drivers of consumer benefits.
- Improve the equity of access to emerging energy solutions for all customers.

9.7.3 Funding & Governance arrangements

We propose a $25 million (Real FY24) Innovation Fund for the 2024-29 period split between capex ($20 million) and opex ($5 million). Whilst customer feedback supported a higher level of funding than

Endeavour Energy indicated in our Preliminary Proposal, we are mindful that this feedback should not be considered in isolation.

Instead, we have weighed this consistent customer priority against concerns raised about energy affordability and an external environment of increasing cost-of-living pressures. At the same time, customers clearly view innovation as a critical enabler of achieving future energy savings. We consider our Proposal achieves an appropriate balance between increasing innovation whilst limiting the short-term pricing impacts of doing so.

We also consider customers should not bear the full risk of this funding as they would for traditional investment. Instead, similar to the DMIA, we propose:

- innovation expenditure be excluded from the CESS and EBSS so to not reward Endeavour Energy for underspending the Fund.
- a 'use it or lose it' mechanism whereby any underspend is returned to customers via a true-up in the following regulatory period. Noting this would apply to the total innovation fund over the 2024-29 period, rather than operating on an annual basis, to allow smoothing of expenditure from year to year.
- the innovation expenditure will only be available for the 2024-29 period, meaning the opex element would not become a permanent part of our base year opex.

Our proposed five principles and governance arrangements are set out below.

Continuity of engagement

While deeply consultative, the regulatory proposal process is only a snapshot of best predictions and customer sentiment on what will come to play over 5 years of the next regulatory period. Continual engagement beyond the regulatory determination process will be necessary to keep in step with evolving customer expectations and industry reforms.

We will achieve this by:

- Establishment of an Innovation Reference Group (IRG). For ongoing operation of the process Endeavour Energy would seek that the Peak Customer and Stakeholder Committee (PCSC) will create a sub-committee and be joined by Endeavour Energy experts and leaders, customer advocacy and industry representatives in order to continue the engagement and commitment to place the customers at the heart of what they do.
- The IRG will meet at least twice per year and help to shape the direction of the innovation program and be asked to contribute to, review and provide feedback on forward plans and updates. In the initial years, we expect more regular meetings (quarterly) would be most appropriate but subject to further discussion.
- When needed, customers will be able to communicate through the company website and dedicated customer forums.

Transparency of plans, findings (and failures)

In periods of sectoral transformation and disruption, the best pathways on innovation may not be evident, but it is important that in any undertaking, objectives, actions, and learnings are captured and communicated.

The innovation plans and lessons we seek are relevant to all regulated network businesses and broader energy industry stakeholders, so it is important for initiatives and results to be shared publicly.

We will achieve this by:

- Prior to IRG meetings, producing reporting of forward plans for the activities in the program, reporting progress, outcomes and lessons learned.
- Supplying the IRG with information that will allow it to perform its role, which may include business cases, decision documents, reports, and other material.

Enhanced Customer Value Proposition

Our engagement program has highlighted that customers and stakeholders wish to see Endeavour Energy take steps to accelerate the energy transition through increased innovation. The expectation is that doing so will improve the choice and control customers have over their energy usage to reduce their consumption and network costs over the longer term.

Under a traditional cost benefit approach, proven technologies are favoured at the expense of more uncertain but transformative investments.

We expect there to be considerable benefits to facilitating the energy transition, not all of which are considered under the current regulatory framework. For instance, the environmental benefits of enabling renewable generation and the net value created by reducing other costs to customers such as fuel for transportation, heating, and cooking.

That is not to say the Innovation Fund will be allocated to speculative or high-risk projects. Instead, we will have a number of measures in place to ensure innovation expenditure provides value for money. Specifically:

- Any underspending will be returned to customers, and this will be excluded from the Capital Expenditure Sharing Scheme.
- By the nature of innovation, investment proposals should be inclined to favour options that are speculative, and potentially lower NPV then traditional investments offset by long term customer benefits.
- Endeavour Energy will seek to maximise leverage on the funding contribution, by pursuing external funding from other grant and research programs (e.g., ARENA, local, state, and federal government programs, RACE for 2030).
- Investment opportunities should seek to progress the evolution of the regulatory framework and government policy and will seek IRG feedback on ways to influence these organisations.

Clear and Adaptable Objectives

It is important that the process provides sufficient oversight and transparency whilst not becoming administratively burdensome. For innovation to be effective we must be agile and quick to scale successes and identify failures.

We must also ensure the objectives of our innovation expenditure are clear and in alignment with customer expectations. Clarity of purpose will help assess and prioritise projects that have the best potential to generate network learnings and long-term value for customers.

To achieve this, we will adhere to the following:

- All programs in the innovation program will have application under nominated investment themes but need to be clear and unambiguous on their objectives.
- These themes could change on agreement with the IRG and in line with these principles, foreseeably to adapt to emerging customer needs or industry trends.
- Collaboration with other networks to build on their key learnings.

Responsible and Accountable

As noted above, we have a responsibility to our customers to advance their long-term interests. This innovation expenditure in particular should help us to provide a more resilient network and communities, meet the evolving energy needs of customers and facilitate the decarbonisation of the economy.

Whilst the program will be planned with the IRG, Endeavour Energy is ultimately answerable to customers on the results of this expenditure.

We will deliver on this commitment by:

- Any underspending will be returned to customers, and this will be excluded from the Capital Expenditure Sharing Scheme.

- We will also continue to work with third parties and/or seek to obtain funding from Government agencies, such as ARENA, to trial and scale innovative solutions.
- In addition to the above, we also note that this funding does not overlap with the DMIA or other incentive schemes.

9.8 Shared asset guideline

The AER may reduce our annual revenue requirement to reflect the costs we recover from using network assets to provide services that are not regulated. This means customers of standard control services do not unfairly pay for the entire cost of the shared asset. In making this decision, the AER must have regard to the shared asset principles and the shared asset guideline.

One of the shared asset principles is that a shared asset cost reduction should be applied where the use of the assets other than for standard control services is material. The AER's shared asset guideline sets out its approach to making a reduction to a DNSP's annual revenue requirement to reflect the use of shared assets, including the definition and calculation of 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.[49] If this material threshold is not met, no shared asset cost reduction applies.[50]

We have applied the AER's shared asset guidelines and calculated the materiality of our use of shared assets to earn unregulated revenue. The calculation of materiality for each year of the 2024-29 period is provided in the table below.

Table 9-11 Shared Asset Revenue materiality test

$m; Real FY24	2024-25	2025-26	2026-27	2027-28	2028-29
Forecast smoothed revenue	1,029.5	1,029.5	1,029.5	1,029.5	1,029.5
Forecast shared asset revenue	10.5	10.6	10.7	10.8	10.9
Materiality (%)	1.02%	1.03%	1.04%	1.05%	1.06%

Based on these calculations, we expect to earn a material amount of shared asset revenue in the 2024-29 period. This is driven by increased asset rental opportunities through the rollout of 5G and EV charging infrastructure along with organic growth in existing shared asset revenue streams. Consequently, a shared asset cost reduction has been applied to the proposed annual revenue requirement for any regulatory year of the 2024-29 period as detailed in the table below.

Table 9-12 Proposed shared asset revenue adjustment

$m; Real FY24	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Revenue adjustment	-1.1	-1.1	-1.1	-1.1	-1.1	**-5.4**

[49] AER, Better Regulation, Shared Asset Guideline, November 2013, p8.
[50] AER, Better Regulation, Shared Asset Guideline, November 2013, p6.

10. Capital Expenditure

10.1 Overview

Our focus is containing investment to ensure safe and reliable electricity for our rapidly growing region. This means replacing ageing assets, building new infrastructure needed for almost 119,000 new customers and supporting the transition to a decentralised, decarbonised energy industry.

Our proposed capex for the 2024-29 period is $1.88 billion (real, 2023-24) which is lower than our allowance and forecast actuals for the 2019-24 period and is driven by:

- our replacement program to replace assets that have reached their end of useful life or are no longer suitable in order to manage safety and reliability risks. Our proposed replacement capex has been constrained in accordance with the AER's top-down 'Repex model' forecast and optimised (along with our entire capex program) on an economic cost-benefit basis.
- the energy transition and accelerating customer investment in CER and EVs. Our proposed CER expenditure is needed to support our customers' ability to export energy to the grid without adversely impacting the quality, safety, or reliability of our supply to all customers.
- managing the increasing frequency and severity of weather events as we realise the impacts of climate change. Our proposed resilience expenditure includes proactive and targeted investments to reduce the risk our customers are exposed to. We will also investigate options to partner with Government, Local Councils, and other utilities to improve community resilience and implement innovative solutions such as batteries and microgrids.
- a reduction in connections capex whilst we expect to connect over 24,000 new customers to our network each year. The 2019-24 connections capex partly reflected our transition away from a change in our capital contribution policy back to our 'causer pays' approach, whereby connecting customers and developers will fund the majority (approximately 87%) of required new network assets.
- an increase in network augmentations to cater for the growth in customers and demand in several greenfield locations across our network. We continue to see significant growth across our network, including in areas that are currently not serviced with electricity, that cannot alone be addressed through tariff settings, non-network and temporary supply options and existing capacity over the 2024-29 period.
- the completion of our ICT & Digital transformation program during the 2019-24 period and return to sustainable levels of ICT investment during the 2024-29 period.

We have used a combination of bottom-up, condition-based assessments and top-down model challenges to prepare our forecast. Our capex forecast is prioritised on a quantified assessment of costs and benefits. We have engaged with customers and stakeholders extensively in preparing our capex forecast to understand their preferences and consult on key trade-offs. We have also engaged with the AER on the expectations set out in the Better Resets Handbook.

In accordance with the feedback we have received, we have constrained our capex forecast and made targeted adjustments to our innovation and resilience plans.

Table 10-1 Forecast standard control services capital expenditure

$m; Real FY24	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Capital Expenditure	436.9	406.8	365.9	354.2	318.5	**1,882.2**

Endeavour Energy

We have challenged our overall forecast capex using the AER's models

We prepared detailed investment plans based on asset condition information prioritised on a probabilistic, risk adjusted basis to ensure our forecast is adequate to meet our obligations and maintain service quality. We tested the resulting forecast with customers and against the AER's calibrated repex and augex models and made further adjustments.

The investment projection models, and our detailed needs-based investment plans rely on several key inputs and assumptions such as customer growth, expected demand and consumption, utilisation rates and asset age and condition-based information. We provide these forecasts in this Proposal and the 2024-29 Reset RIN along with our forecasting methodology and expert, independent verification of several of these inputs.

We will continue to service the significant growth in our network area and replace assets at a sustainable rate

A focus of our capex forecast is continuing to service the significant growth in our network area. The NSW Government is driving the substantial and rapid growth of Western Sydney, at a rate nearly 40% higher than the rest of Metropolitan Sydney. By 2036, half of Sydney's population will reside within the city's west, supporting a new international airport, new industry and manufacturing, and a new science park.

In addition to servicing growth, we will continue to replace assets that have reached their end of useful life or are no longer suitable in order to manage safety and reliability risks.

We will meet the challenges of climate change and support customers' energy choices as the industry transitions to decentralised and decarbonised energy sources

As a network, we must also adapt to our changing environment and the priorities and needs of customers. Our capex proposal supports the grid modernisation required to facilitate increased customer choice and participation in new and emerging energy services without adversely impacting network safety, security, and reliability.

In addition to facilitating CER, we will make targeted and prudent investments to increase the resilience of the most vulnerable parts of our network to the effects of climate change.

We have developed a forecast capex that reflects the feedback we have received from our customers and stakeholders

Our overall objective is to serve the long-term interests of customers' as per the NEO. We have engaged extensively with customers in preparing our Regulatory Proposal including exploratory research on customer preferences, our Customer Panel, and Deep Dives with stakeholder groups.

The clear message from our customer engagement program is that customers expect our capex allowance to maintain existing service levels (at a minimum). However, customers are also keen to see Endeavour Energy facilitate the energy transition so that they can better manage their own electricity bills and to take a more proactive approach to improving network resilience.

This feedback also came with a challenge of providing a value for money service in the face of increasing cost of living pressures and energy costs. Feedback varied on how best to do this with some suggesting Endeavour Energy increase investment in a targeted but limited fashion to deliver long-term benefits and some urging us to improve our service quality through efficiency gains.

10.2 Customer insights

In accordance with the NEO, our objective is to manage and invest in the network in a way that best serves the long-term interests of customers. In preparing our Proposal it is therefore critical to engage with customers and develop our plans and priorities with them to ensure our proposal advances their long-term interests.

As described in Chapter 5 and Attachment 5.01 of this Proposal, we have consulted extensively with our customers in preparing our plans for 2024-29. In this section, we highlight the insights of customers with respect to our capital plans and how we have sought to respond to these insights.

- **We will continue to deliver a safe and reliable network service:** we have developed our forecast capex with the objective of meeting our obligations and maintaining the safety, reliability, and resilience of our network;
- **We will manage our network prudently and efficiently to provide a value for money service:** in meeting our investment drivers we have sought to do so efficiently and prudently. We have constrained our forecast capex through our optimisation process and built-in productivity savings through reducing our overheads by $70 million (real, 2023-24) and not applying over $32 million real, 2023-24) of real cost escalation.
- **We will provide a more resilient network to manage the growing risks of climate change:** we have made targeted and small adjustments to our preliminary positions to account for growing customer concern and interest in taking a more proactive approach to managing network resilience.
- **We will enable customer choice and innovation:** our demand and capex forecasts account for the growing impacts of CER and emergent technologies. As part of our business-as-usual planning processes we routinely test our investment plans for efficient non-network alternative solutions. We will continue to transparently and efficiently trial innovative solutions through increased innovation funding.
- **We will service the growth on our network in a timely and efficient manner:** our demand and capex forecasts account for the ongoing and accelerating customer growth across our network. In doing so we maintain our existing approach to funding new connections and manage uncertainty through our robust forecasting process, staging investments and investigating non-network alternatives.

10.2.1 Customer feedback and our capex response

We will continue to deliver a safe and reliable network service

We sought customer feedback on whether we should maintain, reduce, or improve the level of safety and reliability for our network over the 2024-29 period.

Safety was viewed as a non-negotiable priority and core expectation for customers.

Network reliability was identified as the number one service outcome across all feedback from diverse customers and stakeholders. Customers and stakeholders also broadly told us that they are comfortable with the current levels of reliability we provide. In principle, most would prefer the same level of reliability that they experience now at a similar cost (80% of Customer Panel participants).

I would prefer to receive an equivalent quality of delivery in the future, because that would mean my costs are still controlled, thus ensuring a decent degree of reliability as well as affordability

My supply and reliability is very good in my area. I'd probably consider the small increase in cost, but feel it is Endeavour's responsibility to keep reliability at a certain standard.

When asked their specific preferences for network reliability as a standalone consideration, the majority (66%) of the Customer Panel preferred higher investment that could deliver long-term improvements to reliability (at an indicative annual cost of $10). However, when the Customer Panel was asked to prioritise its preferences across different service outcomes all together, taking potential combined costs into account, increased reliability was a lower service outcome priority than resilience and enabling future energy choices.

Stakeholders also preferred Endeavour Energy maintain reliability or seek to improve it through operating efficiencies rather than increased investment.

The company can always do things better or smarter at no cost to customers.

Although improved reliability across the grid was a lower investment priority for our Customer Panel, there was strong in principle support (80%) for Endeavour Energy to take action that improved reliability for those living and operating businesses at the edge of the grid (typically worst-served).

I am tired of so many power outages, I live in a rural area and it happens more than 77min a year. I would estimate that our outages would be more that 24hours worth in a year. Upgrading the system we have now would help eliminate these problems and would also reduce the risk of bushfires, that we also suffer with.

Our proposed capex is designed to maintain the existing safety and reliability of the network. We consider this appropriately balances the feedback we have received from customers and stakeholders. A relatively small portion of our capex forecast, less than 1%, will be used to improve the reliability performance of our worst performing feeders (refer to Attachment 10.07) in accordance with our ministerially imposed licence conditions (refer Attachment 10.09). Any other improvements in supply reliability are not included in this Proposal and will be justified on a business-case basis in accordance with the STPIS.

We will manage our network efficiently and prudently to provide a value for money service

Customers want a safe and reliable of supply of electricity at an affordable price. Affordability became an increasingly important issue over the course of our engagement program as cost-of-living pressures increased with further increases in energy prices expected. Our quantitative study indicated that cost of electricity is one of the most concerning issues for residential customers and the majority are more concerned than they were 12 months ago.

Stakeholders in particular were mindful of the cumulative impact of energy costs outside of our control, including inflationary pressures, wholesale market volatility and costs associated with the NSW Renewable Energy Zones (REZs).

However, despite these concerns customers still saw value in small investment increases in targeted areas that they believed would deliver long-term value and enable them to save money in the longer term. A significant number of customers preferred

I am happy to pay a little extra for the electricity network per year to keep it in good order (this will result in lower electricity prices over time).

However, stakeholders urged Endeavour Energy to meet customers' expectations through efficiency gains. High energy users and Councils also shared this view and expect us to provide our services at the lowest possible cost.

We are under incredible budget and cost pressures, so it's important to keep costs down.

Overall, it was clear that customers and stakeholders are satisfied with our current service levels but are keen to see improvements where this can provide value in the longer term and empower customers.

In response to this feedback, we have:

- developed a capex proposal based on four investment drivers that reflect customer priorities
- constrained our investment below bottom-up and NPV positive levels to balance affordability over the short and long term
- adopted the AER's CECV methodology and Value of DER (VaDER) framework for assessing the costs and benefits of export hosting capacity investments
- constrained our capitalised overheads forecast below our internal forecast and $70 million (real, 2023-24) below the AER's substitute estimate and not applied over $32 million (real. 2023-24) of escalation to our capex program for real increases in labour or materials.

We will maintain the resilience of electricity supply in the face of growing risks of climate change

While customers and stakeholders were generally satisfied with the reliability of our network they were keenly aware of the growing risk that climate change induced weather events, such as extreme heat, bushfires, and floods, pose to their electricity supply and to community wellbeing.

Both customers and stakeholders favoured Endeavour Energy taking a more proactive approach to maintaining network services in the face of major weather events (recognising that some resilience initiatives will always be responsive in nature), and working more closely with Government, other utilities, and Communities to improve community resilience overall.

Endeavour Energy was seen as having done a good job in the way we have responded to and restored power after major weather events to date. The majority (75%) of our Customer Panel felt Endeavour Energy should take a mix of proactive and responsive approaches to maintaining network resilience in the future, with priority given to providing back-up power to critical infrastructure and taking targeted actions like the use of concrete poles and covered conductors to reduce bushfire risk in the most risk-prone areas.

An in between option would be the best as obviously any increase in costs of already expensive but absolutely essential utility services like electricity is not preferable. Therefore, a fine balance between a proactive and a reactive approach would be the optimum solution at this stage.

The majority (81%) of Deep Dive stakeholders shared this view but also urged Endeavour Energy to consider the extent to which recent experiences impacted customer views (refer Attachment 5.10).

Both stakeholders and customers recognised the shared responsibility of resilience between all three tiers of government, network utilities and individual customers.

In response to this feedback our capex proposal includes:

- an increase of $28 million for both a covered conductor replacement program targeting high bushfire risk areas and the raising of select feeders in flood-prone areas of our network per updated climate change impacts modelling from Deloitte
- the establishment of an Innovation Fund of $25 million to research and trial, inter alia, opportunities to improve community resilience.

Collectively these investments are targeted and modest (2.6% of our total capex proposal) and complement existing measures such as continual improvement in our BAU processes for managing emergency response events and unplanned outages, obtaining insurance, and making use of the pass-through framework as required.

We will enable customer choice and innovation

Customers and stakeholders are keen to be involved in the transition to a low carbon economy and want Endeavour Energy to take steps to prepare for an accelerated transition, with customers considering further significant take-up of Solar Panels, Electric Vehicles (EVs) and Batteries. The majority (85%) of our Customer Panel were supportive of Endeavour Energy planning for either a rapid or accelerated transition.

This support reflected customers view of the energy transition delivering a win-win outcome: a cleaner environment while also achieving personal savings through smarter, more efficient technologies and greater choice and control of their energy usage.

There was therefore an expectation that Endeavour Energy increase its focus on technological innovation and implement smarter ways of serving customers and communities.

Stakeholders also supported planning for a rapid (64%) or accelerated (32%) energy transition and were mindful of meeting customer expectations to generate and share their energy with minimal limitations on the uptake of CER to support a low carbon future and customer energy savings. However, stakeholders were also concerned about the impact the transition to large scale renewable generation across NSW would have on electricity bills and the need to support the transition to CER in a fair and equitable manner for all customers

Based on this feedback we have:

- developed our CER proposal based on AEMO's 'Step Change' scenario DER penetration forecasts, using the AER's CECV methodology and aligned to the AER's DER expenditure guideline.
- taken a multi-step approach in our CER investment strategy that considers tariff reform, demand flexibility and operational optimisation before network investment is undertaken.
- establish an Innovation Fund to research and deploy new technologies across our network to accelerate the energy transition and benefits it can unlock.

We consider our proposal balances the clear direction from customers to support the energy transition with feedback from stakeholders to do so efficiently and prudently.

We will service the growth on our network in a timely and efficient manner

A key driver of our capex program for the 2024-29 period is servicing the growth areas in our network. These are described in more detail in section 10.5.2 of this Chapter. Customers acknowledge that growth is inevitable and must be serviced in a timely manner. The majority of our Customer Panel (71%) and Deep Dive stakeholders (81%) consider this means building infrastructure at the same time as other utilities at a steady cost. Whilst SMEs were more likely to support early electricity infrastructure to further boost economic growth.

> *I feel that building infrastructure in advance is definitely the way to go. This would ensure that all the future needs are covered. It also covers the needs for the large number of customers who will move into the area in the future. It would also ensure the best economic outcome for growth in the area.*

There were mixed views from customers on how this growth should be funded by existing and newly connecting customers. 'Beneficiary pays' was generally seen as a fairer approach that removes cross-subsidies between new and existing customers resulting in all customers benefitting from the growth in the network. However, there was concern that developers would not be obliged to pass on savings to newly connecting customers that would result in greater equity among customers.

A clear majority (74%) of stakeholders and of the Customer Panel (52%) preferred Endeavour Energy maintain the existing 'causer pays' approach, considering this would encourage the most efficient use of the network and be the best outcome for customers.

Based on this feedback we have maintained our existing 'causer pays' capital contributions policy, updated our staging timeframes and reduced our augex forecast by $30 million. We will continue to work closely with stakeholders, including customer interest groups, State and Local Government and developers, to ensure our investment is both efficient and timely. Our Growth Strategy and Servicing Plan, Attachment 10.14 and 10.15 - 10.19, provide further detail on our intended approach while Chapter 7 provides more detail on the robustness of our demand and customer number forecasts.

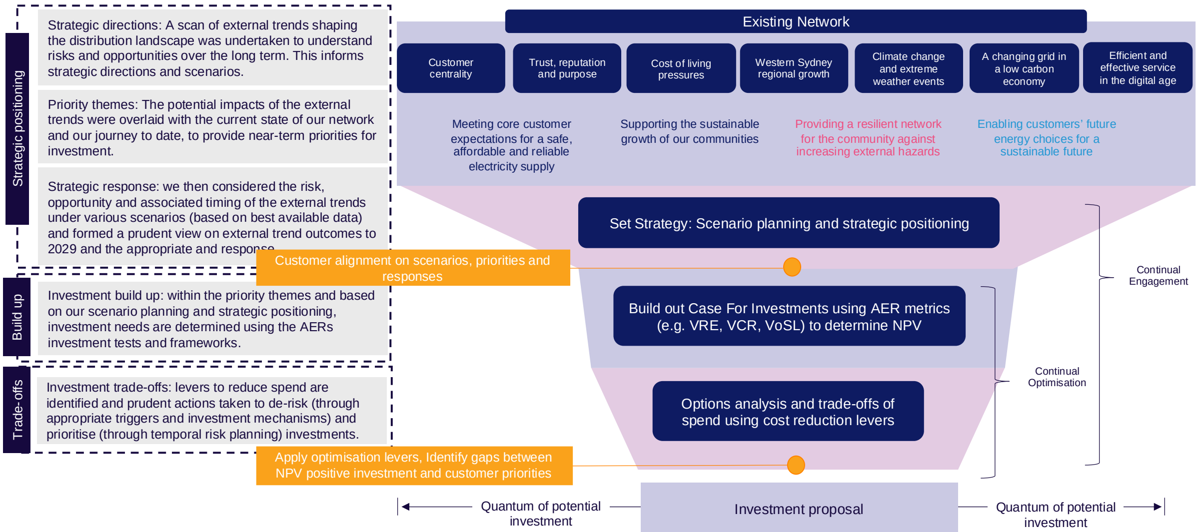
10.3 Capital governance, forecasting methodology and key inputs

Our capital plans are developed to achieve identified outcomes and objectives that align to the capex objectives, our network strategies and customer insights.

10.3.1 Approach to forecasting capital expenditure

Our forecasting approach involves both top-down and bottom-up elements and is designed to determine an appropriate balance between our investment priorities and the expectations of customers on service quality and affordability outcomes. This process of detailed build up, refinement and prioritisation are depicted and summarised in the below figure.

Figure 10-1 Proposal development process



During our 2019-24 regulatory determination, the AER and EMCa identified several areas for improvement in our capital governance, risk prioritisation and planning approach. Since then, there have also been several significant regulatory reforms that have occurred, and some remain ongoing. These learnings and trends have been critical in informing our updated capital planning and value optimisation framework.

We have made significant improvements and changes to our forecasting methodology since the 2019-24 Proposal to respond to this feedback, adopting a best practice approach to asset management and to reflect the latest policy and regulatory developments. Specifically, we have invested in developing our customer Value Framework and an Investment Decision Support Tool (IDST). These changes have helped improve the efficiency of our decision-making and maximise the overall value of investments. We have also rationalised and updated our asset management system framework to reflect these changes. These improvements have been enabled through our ICT & Digital Transformation which has increased the availability of data, our data processing and analysis capability, and process standardisation and automation.

We provide an overview of our approach below. Our Expenditure Forecasting Methodology Statement (Attachment 0.07), Investment Management Framework (Attachment 10.01), Investment Portfolio Decision Making (IDM) (Attachment 10.04), Asset Management System (AMS) (Attachment 10.02) and Value Framework (Attachment 10.05) provide a more detailed explanation of our investment need forecasting methodology, investment planning and governance framework, and overarching strategic direction and principles for asset management which guide us in developing the right balance between costs, risks and benefits.

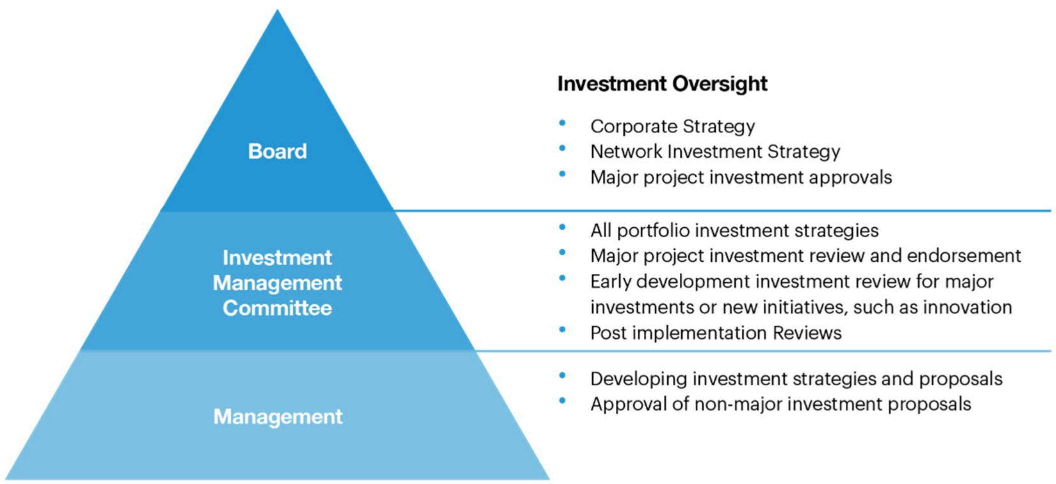
Investment Management & Governance Framework

Our Investment Management Framework (Attachment 10.01) has been revised to ensure best-in-class customer investment outcomes and business governance and to adopt our digital transformation platforms. This includes risk-based approaches to economic benefits quantification and alternative options, risk, and uncertainty management. The Investment Management Framework is consulted on and revised annually and was socialised with the RRG and the AER in late 2021.

Figure 10-2 Endeavour Energy Investment Management framework

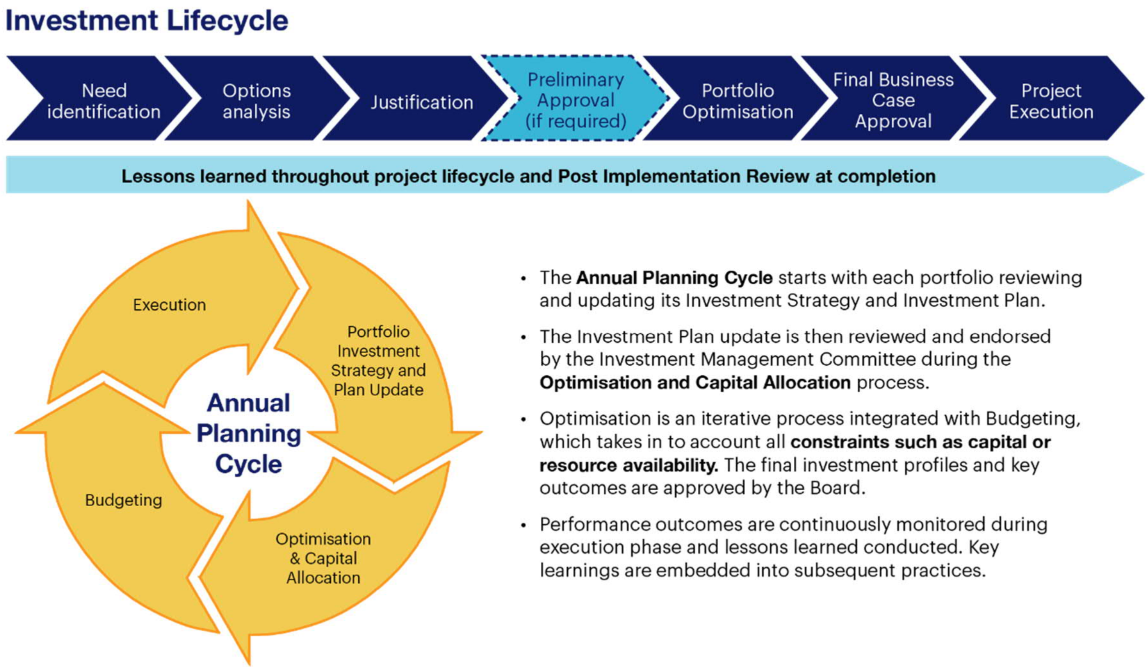
Investment oversight is multilayered and based on strategic importance and investment levels. The Board oversees the Corporate and Network Business Strategy as well as large, single project investment approvals. The Investment Management Committee, chaired by the CFO, oversees all asset investment strategies, major project endorsement and post implementation reviews and learnings.

Figure 10-3 Endeavour Energy Investment Governance



An annual planning and investment cycle oversees key capital allocation from a management level for optimisation.

Figure 10-4 Endeavour Energy Investment lifecycle management



Investment Strategy

Broadly, we have developed our system capex forecast in response to the seven key drivers shaping our future operational landscape as defined in Chapter 3. To guide our investment activities, we adapted these insights and implications into four priority themes that balance affordability for customers with their long-term interests. The four themes are explained below:

- **Meeting core customer expectations for a safe, affordable, and reliable electricity supply:** We invest in the replacement and renewal of assets across our network to ensure they continue to meet our customers' expectations for a network that is safe for our workers and the community, provides a reliable electricity supply to our customers and is affordable.
- **Supporting the sustainable growth of our communities;** As the ongoing transformation of Western Sydney and our regions continues to drive growth across the Endeavour Energy network, we need to align our investments with other lead infrastructure provisions by facilitating grid technologies that will be adaptable to the evolving needs of businesses and communities.
- **Providing a resilient network for the community adapting to changing climate and external hazards:** Endeavour Energy defines resilience as the ability to anticipate, withstand, quickly recover, and learn from major disruptive events. As the effects of climate change become real, our infrastructure needs to meet our high levels of service in an increasingly challenging environment. Our organisation needs to be prepared, enabling our trained personnel to respond to incidents and provide support services to those in need.
- **Enabling customers' future energy choices;** As customers seek to connect more distributed energy resources and increasingly use sophisticated digital platforms, the network and its management must evolve. Our objective is to enable customers' future energy choices for a sustainable future, moving use towards the future integrated and low carbon energy system.

Our capital expenditure forecast will balance long term affordability with reprioritised investment to meet customer expectations and long-term interests. To guide our capital decision making we have developed a Network Business Strategy that translates our organisational strategic commitments and targets into network objectives.

Our network objectives are also informed by external drivers including customer insights and other stakeholder requirements including changes in the regulatory landscape.

This strategy informs the Asset Investment Strategies and provides a basis for decision making and planning. Many of these decisions are based on a view of the relative risk appetite that the organisation is willing to accept for the asset within the context of the overall business plan. It also outlines the high-level asset lifecycle strategies that inform the level of analysis within the Asset Investment Strategies. Refer to Attachment 10.22 of our proposal for further detail.

Investment Decision Making

Our Network Business Strategy is implemented through our Investment Decision-Making (IDM) process which aligns with our Investment Management Framework (IMF) and is a key driver of our Asset Management Framework (AMF). Individual plans in the key network investment areas are developed and supported by detailed analysis that explicitly take into account:

- externally imposed obligations and requirements including service standards, design standards, safety and environmental obligations, and specific asset performance targets;
- information about the network system including loading, condition of assets, performance variability, current capacity, age, and the criticality of key assets;
- forecasts of demand growth and connections by location; and
- inputs obtained from stakeholder engagements.

These plans are integrated and optimised in the IDST, which serves as the single source of truth to evaluate their NPVs using a consistent approach (Value Framework) to maximise value to our customers and communities. The principles which guide this process are:

- **Value based decision-making:** An investment's NPV is used to determine its independent merit (i.e., NPV positive investments are considered commercially feasible) and its standing among other investments competing for resources in a constrained optimisation process
- **Maximising value:** During optimisation the IDST will select the combination of investments and determine the best timing for expenditure that will lead to the highest overall NPV for the portfolio being achieved over the specified period, e.g., 2024-29, reflecting the priorities of our customer informed network business strategy.
- **Line of Sight:** Alignment of investment decisions with organisational objectives – using value measures that reflect customer and stakeholder interests to quantify benefits and calculates NPVs for investments
- **Investment Trade-offs:** Enable investments from different streams to be compared so that we can use our limited resources efficiently

We aim to balance affordability for customers with investments that address the long-term interests of customers. Whilst we always strive to achieve these principles in full, we are continuously refining and improving our approach based on customer engagement and stakeholder feedback.

Value Framework

To optimise the mix of investments, we apply a consistent approach to quantify risk and benefits and determine the timing for investments based on the need and the best overall value provided by the portfolio. This is the basis of the value framework and is underpinned by:

- Using a rational economic approach to allow the comparison of dissimilar investments
- Using a consistent and repeatable approach to assess all the benefits, risks, and cost of the investment
- Ensuring that both financial and non-financial benefits are included, where their contributions are aligned to a common scale, and

- Measuring its alignment to the organisation's corporate strategy & risk appetite.

To support this revised framework (since the previous regulatory determination) we have made several enhancements to our value framework so that we quantify economic benefits on behalf of our customers (being either risk reduction or opportunity to lower cost). This has involved implementing the IDST in addition to the amended Investment Governance and Risk Management framework outlined above.

Each value measure is defined and calculated in accordance with AER guidance, where available, or otherwise per best industry practice. This focus on quantified economic benefit by several value measures allows us to consider risk in a more sophisticated manner and to align our investment plans with our organisational strategy more directly and clearly. It also more readily supports informed trade-off discussions with management, stakeholders, and customers by allowing for the justified investment portfolio to be prioritised to maximise different value drivers and for the impacts on overall value to be compared.

10.3.2 Key inputs and assumptions

As noted above, we have made significant improvements and changes to our investment forecasting methodology since the 2019-24 Proposal to respond to AER feedback, adopting a best practice approach to asset management and to reflect the latest policy and regulatory developments.

Several key external regulatory developments since our last determination that have been incorporated in our approach include:

- Publication by the AER of a Practice Application note on Asset Replacement Replanning detailing expectations with respect to replacement decision making.
- New Value of Customer Reliability (VCR) values have been set by the AER (previously administered by AEMO).
- Increased industry focus (and ongoing reforms) on Future Grid/DER enablement related expenditure and ongoing AER work on DER valuation and expenditure assessment including the recently published DER guidance note.
- A series of extreme weather events / natural disasters resulting in several pass-throughs and an increased stakeholder interest in network resilience. The AER has recently published a guidance note outlining its expectations for how networks should consider and justify network resilience related investments.
- The AER has standardised several regulatory models including developing a capex model.
- AEMO continues to refine the Integrated System Plan (ISP) providing context for the future state of the energy market and in particular customer energy choices.
- IPART has updated our licence conditions adopting a new approach to specifying individual feeder performance standards and to implement a new GSL scheme.
- Publication of the 'Better Resets' Handbook which outlines the AER's expectations for best practice customer engagement and building block proposals capable of accessing an early signalling pathway.

Additional key inputs and considerations that underpin our forecast capital expenditure at the time of preparing this Proposal include:

- refer to Chapter 7 for our demand and customer forecasting methodologies
- refer to Attachment 0.09 for our proposed Connection Policy for the 2024-29 period
- refer to our NSW Distribution Licence Conditions (Attachment 10.09); and
- refer to the Reset RIN, Attachment RIN0.01, for forecast utilisation, asset life, reliability performance and other expected network performance information.

The Rules also require us to identify the key assumptions that underlie the capital expenditure forecast. The section below summarises the key assumptions that underlie our forecast of required capex for the 2024-29 period, with further information on the reasonableness of each assumption provided. These are provided in Attachment 0.08 and outlined below.

- **Structure & ownership:** Our capex forecasts are based on our current company structure and ownership arrangements.
- **Compliance requirements:** Our capex forecast is based on achieving compliance with our legislative and regulatory obligations including the requirements set out in our NSW Ministerially imposed licence conditions which apply at the time of submitting our Regulatory Proposal.
- **Service classification:** We will apply the service classification in the AER's Framework and Approach (F&A) paper and the current ring-fencing arrangements will not change materially.
- **Stakeholder and customer engagement:** We have engaged with stakeholders and customers in developing our opex forecast in accordance with the AER's Better Resets Handbook. The preferences and expectations of participants revealed through our co-designed stakeholder engagement program accurately reflect those of our customers generally. Our capex forecasts have particular regard to the affordability of our services and appropriately respond to these concerns.
- **Service reliability:** Our capex forecast reflects requirements to maintain the current average level of service reliability performance (which is distinct from resilience) across the network.
- **Asset management:** Capex programs have been developed using a strategic risk-based value framework which optimises investment expenditure and timing to maximise value to our customers and communities. The scope of works selected for each capex category are appropriate to meet the capital expenditure objectives outlined in the NER.
- **Growth capex:** Our spatial demand forecasts provides an appropriate basis for our augmentation capex forecast and are adjusted to account for weather, energy efficiency improvements and the expected impacts of customer energy resources (CER). Forecast growth for residential and commercial connections has been prepared by the National Institute of Economic and Industry Research (NIEIR) and provides an appropriate basis for determining our connection capex forecast.
- **Replacement capex:** Our approach to asset replacement conforms to the guidance on efficient and prudent asset retirement and de-rating decisions as detailed in the AER's Asset replacement industry practice application note. We have applied the AER's current approach of setting the Repex model threshold equal to the higher of the 'cost scenario' and the 'lives scenario'.
- **VCR and VaDER:** Our cost benefit analysis applies the AER's latest Value of Customer Reliability (VCR) estimates. For export-related capex, we have applied the Value of Distributed Energy Resources (VaDER) methodology as guided by the AER's DER integration expenditure guidance note.
- **Unit costs:** The unit rates and project costs applied in developing our capex forecast are representative of the efficient costs that will be incurred in the next regulatory period.
- **Price escalation:** Our capex forecast does not include any real price increases for materials consistent with the AER's accepted approach.
- **Inflation:** Our inflation forecasts have been derived by applying the AER's preferred approach as outlined in its *Regulatory treatment of inflation* final position paper.

- **Cost allocation:** Our capex forecast is consistent with our capitalisation policy and our existing Cost Allocation Methodology (CAM) which provides the basis for attributing and allocating forecast capex to standard control services and other services.
- **Connections Policy:** The AER will approve, and we will apply our Connections Policy.
- **Managing uncertainty:** The AER will approve our nominated pass-through events, and we will not have any contingent projects.

Our licence conditions in particular have a material impact on our asset management framework and capex requirements. As the compliance regulator, IPART conducts frequent audits to demonstrate ongoing compliance with our obligations. These include:

- **Distribution reliability and performance conditions:** set overall reliability, individual feeder performance and customer service standards that we must comply with. This drives our proposed reliability compliance capex as detailed in section 10.5.3.
- **Critical infrastructure licence conditions:** set out requirements regarding our management and operational presence in Australia and data security requirements. Our technology capex addresses, amongst other things, our data security obligations.
- **Management systems;** our asset management system must be consistent with International Standard (ISO) 55001 and our environmental management system must be consistent with ISO 14001. Our safety management systems must also comply with Australian Standard (AS) 5577 in accordance with the NSW Electricity Supply (Safety and Network Management) Regulation 2014.

In regard to real cost escalation, we have received real cost escalators based on the most recently available market data and economic analysis. However, in keeping with our commitment to continually improve our productivity and provide a value for money service we have not applied any real labour escalators to our forecast capital expenditure

10.3.3 Program Delivery

We note there are significant cost increases forecast in materials and labour over the remainder of the current period and into the following period. However, we have been managing these challenges over the current period and have adapted accordingly.

For labour, we have an existing workforce trained with specialist skills that have the capability and capacity to deliver the planned works for the forecast regulatory period evidenced by a prolonged history of delivering similar and significantly larger capital programs.

In addition to internal labour, we have a strong Contracting Strategy with agreements in place with key contractors. This is a long-standing and well-tested approach. Bundling is currently completed at an operational level with the plan to mature to a Master Schedule to improve efficiencies.

We have also adopted a live workforce resourcing approach that is reviewed monthly and facilitated by our Portfolio Management Office (PMO) for consistency across the program.

For materials, we have multiple procurement practices and processes to mitigate supply chain risks such as formalised commercial agreements, scans of market supply and demand planning to identify potential constraints on supply.

Our workforce and procurement planning has also been improved by the increased accuracy of our revised planning processes, e.g., rolling forecasts, improved information, and systems to anticipate arising needs. These improved processes have enhanced our ability to anticipate required inputs (labour and materials) well in advance of the project delivery dates and to increase lead times to account for delays, where necessary.

10.4 Our performance in the 2019-24 period

During the 2019-24 regulatory period, we expect to deliver net capital investment totalling $1,922.6 million (real, 2023-24), which is almost equal to our allowance of $2,026.5 million (real, 2023-24). Over the 2019-24 regulatory period, our capital program has focused on our ICT & Digital transformation, supporting growth areas across our network, and ensuring our customers continue to receive a reliable electricity supply from a safe and secure network.

Table 10-2 Actual and forecast net capital expenditure compared to the FY20-FY24 regulatory allowance

$m; Real FY24	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Allowance	427.8	388.4	392.4	413.8	404.1	**2,026.5**
Actual/Forecast	383.8	385.5	354.0	439.5	359.9	**1,922.6**

In the sections below we detail the outcomes and challenges we faced during the current regulatory period and explain why we expect to spend our capital expenditure allowance[51].

10.4.1 2019-24 outcomes

Our expected capital expenditure for 2019-24 has allowed us to meet our core objectives and deliver on our commitment of maintaining a reliable supply from a safe and secure network at an efficient and affordable cost to customers. Over the course of the 2019-24 period, we will:

- install or replace several thousand assets, including:
  - 10 power transformers
  - 2,300 km of network power lines and cables;
  - 31,500 poles;
  - 3,900 distribution substations; and
  - 185,000 service lines;
- service NSW's largest growth areas and connect approximately 95,000 customers to our network, a record high;
- service a near record peak system demand of 4,056 MW;
- meet our reliability objectives, specifically:
  - improve network reliability (SAIDI and SAIFI results over period); and
  - performing over 400 investigations into non-compliant feeders, resulting in reliability improvement initiatives being actioned on over 100 individual feeders, in accordance with our obligations;
- deliver key investments and innovations in support of enabling customers' energy choices:
  - commencement of both residential and network grid-scale battery trials;
  - SCADA master station upgrade to support better visibility and control of the network;
  - automation of pole top devices;
  - proof of concept and rollout in selected areas of fully automated network switching to restore customers after a fault;
  - neutral integrity monitoring device trial and rollout to improve customer safety and targeting of low voltage cable replacement programs; and

[51] In accordance with S6.1.1(6) of the NER our capex for each year of the previous, current and forecast regulatory periods is provided in Attachment 10.11. We can confirm these capex amounts has been treated in accordance with our approved CAM, reflect arm's length terms and do not include amounts that should have been treated as opex under our previously submitted capitalisation policies.

- technology transformation and cyber security improvements.

We achieved these outcomes while improving our safety performance all within the AER's overall capex allowance. This performance was in part due to our ICT & Digital transformation program which improved our asset monitoring and performance data, processing and analysis capability and process standardisation and automation to enable a more optimised investment program along with delivery and procurement efficiencies.

10.4.2 Key events

ICT & Digital transformation program

Historically, as a wholly government-owned utility, Endeavour Energy did not invest in non-recurrent ICT capex and ICT expenditure levels benchmarked below NEM peers. Instead, legacy ICT systems were maintained, with multiple customers facing systems operating at 20 years old and finance systems over 5 years old. In the lead up to the partial privatisation in 2017 there was a further reluctance to invest as the business continued to avoid non-recurrent ICT investment.

During the partial privatisation process it became clear that our ICT risk profile had grown materially and that a transformation was required. As a result, our new management embarked on a company-wide transformation agenda, recognising its historical underinvestment in technology, as well as the need to position the company to respond to industry uncertainties caused by changing market dynamics and customer preferences.

The program was developed with the intention of enabling us to deliver critical services to customers through the long term at lowest cost. The program was initiated due to the lack of suitability of existing systems and a known need to future-proof the resilience of ICT and network systems.

The systems implemented under the program included:

- Optimus Program to build a core SAP platform to replace legacy systems. This business transformation provides Endeavour Energy with a sustainable base level platform to consolidate systems of record for operational and customer facing purposes while having a stable system capable of handling market rule changes.
- Advanced Distribution Management System (ADMS) Implementation. This enabled Endeavour Energy to replace a manual pin-board control room operation and an ageing Outage Management System with a real-time, electronic management system reflecting the increasing convergence of network and non-network infrastructure. The electronic ADMS proved to be the critical change that enabled us to mitigate operational risks while operating in the fast-changing COVID environment.
- Security Improvement Plan (SIP) which allowed us to continue to operate and meet the Distributor's Critical Infrastructure Licence Conditions 9 and 10 and enhance cyber security capability to protect customers, assets, and data

This transformation has resulted in a number of benefits that outweigh the costs of the program and include:

- Productivity gains including improved scheduling and management of the field force, insourcing of previously outsourced activity and increased workforce flexibility
- Enhanced organisational capabilities and efficiencies allowing headcount reductions from automation and improved systems
- Improved safety outcomes including risk avoidance from consolidation of safety and environmental risk data and reduced staff injury rate via EHS Incident Management module
- Improved customer outcomes including reduced frequency of planned outages with planned SAIFI reducing from 0.1888 in FY17 to 0.1733 in FY20 and improved customer and retailer experience
- Reduced risk through avoided major cyber security breaches

- Avoided capex costs through better asset visibility, risk management and asset management and provided an integrated platform that will increase flexibility to respond to changes in customer demand and energy usage.

For capex in particular, enhanced digital capabilities are an integral component to deliver energy services efficiently and securely in the future. Investments in ICT have enabled us to both respond to changing customer demands and enable more cost-effective future network enhancements.

Over the remainder of the period, we aim to complete building our capability which involves building the underpinning skills, processes and technologies that reduce business friction, establish common data practices, and create reusable components that support scaling of use cases. We aim to achieve this by:

- Building consistent and self-service access to readily available, high-quality business and external data to support the priority use cases and for routine operational analytics and reporting
- Improving trust in our data by establishing tool driven data governance to effectively manage the quality, integrity and coverage of data required to deliver use cases
- Equipping all layers of the business with advanced analytical tools and capability to improve efficiency and effectiveness of decisions (capabilities include simulation, optimisation, AI/ML, and geospatial analytics)
- Creating a data-driven organisation that effectively and consistently uses data in decision making processes across all levels of the organisation.

Consistent with the AER's ICT capex Assessment Guideline we have obtained an independent Post-Implementation Review (PIR) from Deloitte (Attachment 10.45). This PIR confirms that quantified benefits exceed costs with a benefits-cost ratio of 1.52 and that a prudent approach was followed, and similar level of costs incurred compared to similar transformations. The learnings and improvement opportunities identified in the PIR have been incorporated into our forward planning and ICT governance approach.

We also note this program was not included in our capex allowance for the 2019-24 period. This is consistent with what the AER considers to be the 'self-funding approach', where[52]:

> *Proposed expenditure is not included in the forecast. However forecast is a bucket, so the business if free to spend if it considers it will reduce overall costs where it can benefit from the incentive schemes.*

To contain our overall capex within the AER's allowance this meant reductions were made to other categories of capex. The early period challenges of COVID-19 and several natural disasters also contributed to an underspend of system capex early in the period. For repex it is anticipated that this will be corrected over the remainder of 2019-24 and for augex we have adjusted our CESS outcomes for short-term deferrals into the 2024-29 period as described in Chapter 9.

As a result of this transformation program, we expect ICT capex to return to a more sustainable level of investment over the 2024-29 period.

International factors

Since early 2020, the global COVID-19 pandemic has adversely impacted NSW, Australia and the international community. Over the 2019-24 period society has continued to adjust to this unfortunate reality in how they live and work. While many industries and businesses have been negatively impacted by the pandemic, as an essential service provider, Endeavour Energy has seen an increase in the dependence on its service.

Notwithstanding changes in public health orders relating to lockdowns and isolation rules, people continue to work from home and the reliance on a dependable and quality electricity supply remains

[52] AER non-network ICT capex assessment approach – November 2019, p. 12

high. In addition, Federal and State Governments have implemented a number of economic stimulus measures to support ongoing activity in the building and infrastructure sector.

Endeavour Energy and its staff continue to meet the challenge of operating and maintaining the network throughout the pandemic. Early in the 2019-24 period these challenges contributed to underspends as essential worker restrictions were in place that resulted in critical maintenance work only being permitted at times. Over the remainder of the period these challenges have continued in the form of managing staff unavailability, providing a safe work environment, prioritising critical work, and adjusting to global and domestic supply chain shortages for materials.

The ongoing war in Ukraine has further contributed to increasing prices, delays and shortages in key materials affecting both our customers and our own activities. This conflict has driven and exacerbated a downturn in economic activity. Together, these impacts have increased the complexity of operating the network to service growth and maintain a safe and reliable service in an affordable way.

As noted above, these challenges, along with the need to manage frequent natural disaster events, led to an underspend of our capital allowance early in the period, particularly within system capex. However, as we and our customers become more accustomed to these issues we have adapted and improved our capacity to deliver our services. As a result, in FY22 Endeavour Energy was able to deliver a significant increase in budgeted spend in system capex to address early period deferrals and continue to service the ongoing accelerating growth across our network. We now expect to spend at the allowance for the 2019-24 period in total.

Managing the effects of climate change

The increasing frequency and severity of climate change induced weather events is becoming increasingly difficult for Endeavour Energy to manage and of concern to our customers.

The 2019-2020 bushfire season was the worst bushfire season in NSW history. A confluence of factors including a prolonged period of hot weather without significant rainfall (with 98% of NSW being drought affected at the time) provided the catalyst for an unprecedented level of bushfire activity across the state. The NSW Rural Fire Service (RFS) reported that 11,264 bush and grass fires burnt 5.5 million hectares or 6.2% of the State, destroyed 2,448 homes and claimed 25 lives over this period. The area burnt in NSW was three times larger than in any other bushfire season.

The catastrophic nature of the bushfires and the threat encountered by several towns and communities across the State led to the NSW Government declaring a State of Emergency on three separate occasions. Each declaration was in force for a week, and it was the first time a State of Emergency had been made in NSW since October 2013. On announcing the third State of Emergency on 2 January 2020, NSW Premier Gladys Berejiklian stated[53]:

Declaring this State of Emergency is vital to the safety of communities in NSW as we face the most devastating bushfire season in living memory.

The bushfires ultimately burnt through approximately 11,000 km² or 44% of our network area. The fires either damaged or destroyed 840 homes and businesses connected to the network and interrupted supply to over 55,000 customers. Approximately 20,000 customers were without power at the peak of the bushfires during the New Year period, mostly in communities in the Shoalhaven and NSW South Coast.

The worst affected areas saw some customers without power for more than 10 days as Endeavour Energy crews worked through challenging conditions to rebuild large sections of the network in the Blue Mountains, the Southern Highlands, and the Shoalhaven/South Coast districts. These regions of the network were predominantly impacted by the Gospers Mountain, Green Wattle Creek and Currowan bushfires respectively from mid-November to early-February. Managing the multiple bushfire threats required a sustained, whole-of-organisation response and collaboration with several authorities led by the RFS.

[53] Media release from the NSW Government, Premier declares third State of Emergency, 2 January 2020

At all times during the response, our priority was to maintain the safety of our workforce and the communities we serve.

Since the 2019-20 bushfires there have been three State of Emergency Declarations in NSW for Floods which destroyed 600 homes and 300 businesses across our network area. 2022 was the wettest year on record for Sydney.

As a result, our FY22 reliability performance is the worst it has been in over a decade at over 91 minutes per customer on average (normalised) compared to 66 minutes in FY21. This is despite an improving trend in the factors within our control, such as managing defective equipment, due to an unprecedented increase in adverse weather driven outages (refer to Figure 3.12).

This also continues the trend of a widening gap between normalised and 'raw' reliability performance. For reporting and incentive scheme purposes the results are 'normalised' to remove the impact of outlier events. While these are extraordinary and uncontrollable events, they are becoming more common, and the 'raw' results more closely reflect the felt experience of our customers (refer to Figure 3.11)

The federal Labor Government has also committed to conduct a climate change and security risk assessment of Commonwealth assets and the economy more generally; while the AER has published a guidance note setting out expectations for engaging on and justifying resilience related expenditure.

These developments underscore the ongoing and growing importance of managing climate change induced risk and meeting customer expectations for network and community resilience. Whilst managing these events contributed to early period system capex underspends as critical emergency response works were prioritised.

Customer and demand growth

At the time of preparing our plans for 2019-24 significant planned expansion of our network was required to support the NSW Government's priority growth areas that were projected to accommodate 900,000 new residents over a 20-year period as part of the largest coordinated release of greenfield land for residential, commercial, and industrial development in the state's history.

Over the course of the 2019-24 period, the NSW Government announced additional growth areas within our network area which included:

- **Western Sydney Employment area:** plans to commence construction of the proposed Western Sydney International Airport, Sydney Science Park, and Western Sydney Employment Lands.
- **Greater Macarthur Priority Growth Area:** the NSW Government identified approximately 7,700 hectares of land that can be developed to ultimately establish over 60,000 new homes and 700 hectares of commercial/industrial lands.
- **West Lake Illawarra Growth Area:** approximately 5,000 hectares of land in the Wollongong and Shellharbour Local Government Areas that will accommodate an estimated 26,000 homes and over 300 hectares of commercial/industrial lands.
- **Inclusion of Metro Wollongong and the Illawarra-Shoalhaven City in The Six-cities Vision** which will see the development of vision and strategies to accelerate our regions to become a globally competitive network of cities.
- **Orchard Hills:** at the doorstep of the Western Sydney Aerotropolis, this future growth area will provide a mix of housing types and thriving public spaces including shops, services, and entertainment.
- **Greater Penrith to Eastern Creek Corridor:** a strategy developed by (the then) Greater Sydney Commission seeks to promote land reuse, densification, and infill along the strategic corridor between Penrith and Eastern Creek and north of the Aerotropolis and Orchard Hills.
- **NSW Government EnergyCo are in the early stages of planning for a Renewable Energy Zone in the Illawarra.** Significant investment in generation is expected to be coupled with growth

in the Hydrogen production and reuse industries, transforming the way our network is used to support energy.

See section 10.5.3 and Attachments 10.15 - 10.19 to this proposal for further details on our growth areas.

This customer growth, in combination with more frequent and extreme temperatures experienced in Western Sydney, is forecast to drive new record network peak demand in excess of our previous record of 4,107MW that was recorded on 30 January 2017 during the 2019-24 period. See section 7.3.2 and Attachment 7.01 for further details regarding our demand forecast process.

Ongoing energy transition

The emergence of new technologies and regulatory reforms has meant our customers have more choices about how they access and consume their electricity. Our objective is to enable customers to take advantage of these technological changes through efficient price signals, improved planning frameworks and targeted network investments.

At the time of developing our plans for the 2019-24 Proposal we aligned with the ENA/CSIRO's Electricity Network Transformation Roadmap which was released in April 2017. This Roadmap outlined a detailed and comprehensive plan for how the energy market in Australia can be transformed over the coming decades to incorporate technological advancements to the benefit of customers.

Since then, the ESB, in collaboration with the market bodies, has released and commenced work on a series of reforms to integrate DER as part of its Post-2025 Electricity Market Design Project. The aims of these DER integration reforms are to:

- enable DER owners to sell DER services into wholesale energy, ESS, and network services markets
- ensure DER does not cause any technical system or network operation challenges
- have integrated transmission and distribution planning

Relatedly, AEMO has commenced publishing an Integrated System Plan (ISP) every two years that sets out an optimal development path which considers multiple scenarios to identify the likely investments required to meet the future needs of the NEM. This includes in transmission projects, non-network options and distribution assets, generation, storage projects and demand-side developments.

The ISP is a critical roadmap that supports Australia's complex and rapid energy transformation. It forms a key component of our forecasts and plans as well as guiding a series of market reforms and the timing and placement of major generation and transmission investments.

The 2022 ISP, released in June, highlights the ongoing and accelerating shifts in technologies, government policies, participant behaviours and business models. AEMO is now forecasting enough potential variable renewable energy (VRE) resources in the NEM to supply 100% of grid demand by 2025 and 40% more VRE deployed across Australia by FY24 than was forecast in the 2020 ISP.

The AEMC has released several rule changes related to the ESB reforms most notably the DER Access, pricing and incentive arrangements for DER rule change. The AER have also progressed a number of decisions and reforms during the 2019-24 period such as:

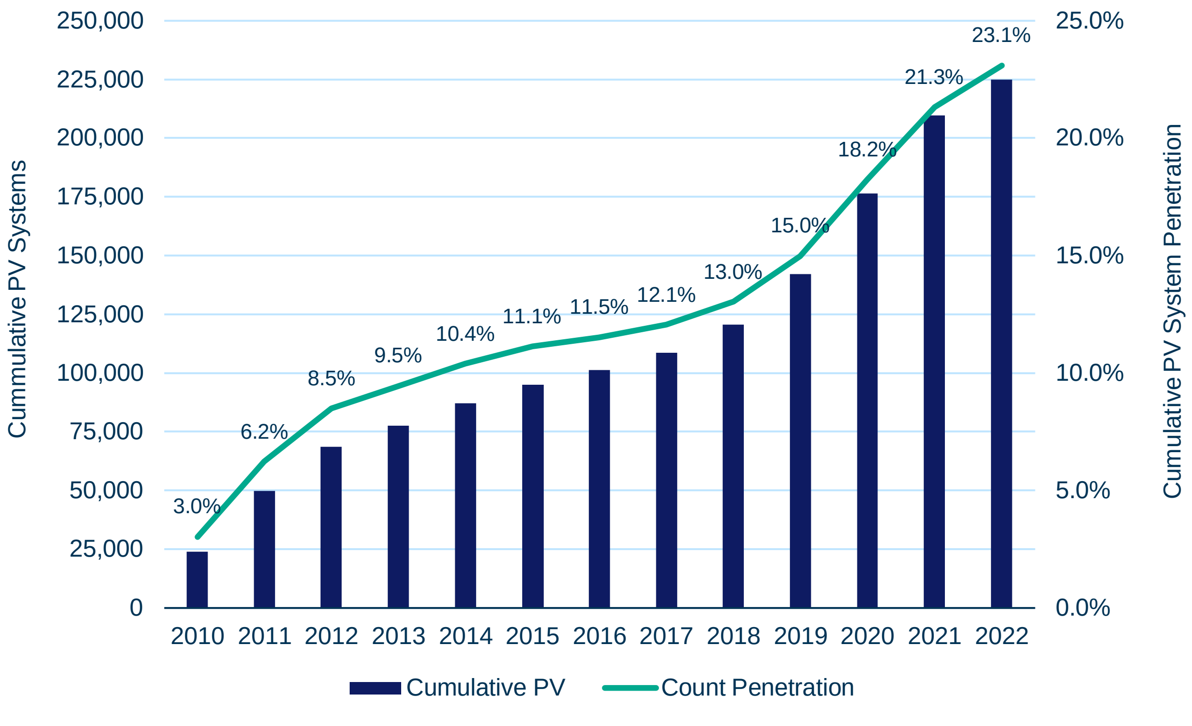
- **Ring-fencing review and Final Framework & Approach (F&A):** The AER revising our ring-fencing arrangements and service classification to address the role of distribution networks in providing export services, standalone power systems (SAPS) and community batteries. The AER is awaiting further work from the ESB reforms before determining the treatment of the potentially enhanced role of distribution networks in system support services.
- **DER Expenditure guidance note:** the AER has provided guidance as to how networks should develop a Value of DER (VaDER) and use this in assessing and proposing expenditure targeted at DER/CER hosting service levels.

- **CECV methodology:** the AER has published its final CECV methodology. The CECV is an input for our CER expenditure proposal that mostly relates to the wholesale market benefits associated with CER exports.
- **Export hosting incentives review:** the AER is consulting on whether new incentive arrangements are required to encourage networks to provide efficient levels of export hosting capacity.
- **Connections export limits review:** the AER is reviewing the Connections Charging Guideline to clarify the circumstances under which a network can apply a static export limit to CER customers. The AER has recently commenced work on reviewing flexible export limits in support of networks implementing dynamic operating envelopes.

These reforms set expectations, provide guidance, and directly impact how we develop and justify our CER investment plans.

During this time, we have also observed continue growth in the number of customers with CER. At present, 23% of Endeavour Energy's customers have solar PV systems with a cumulative capacity of 1GW. This corresponds to 27% of Endeavour Energy's summer 2021/22 recorded peak network demand of 3.7GW. It should be noted that in addition to this, there is a further 200MW of commercial and industrial sized solar generation within the Endeavour Energy network.

Figure 10-5 Endeavour Energy Residential Customer's solar PV take-up



Continued declining PV system costs as well as robust solar feed-in tariffs (FITs) have meant that customers are investing in larger systems over time. Between 2007 to 2022 the average residential solar system size steadily increased from 2.9kW to 7.2 kW. If the trend in system size take-up was to continue then the average system size would rise to 9kW by 2029, significantly well above current static export limits as shown previously in Figure 7-8.

CER integration investments in the current regulatory cycle have been incremental but foundational for our future in the energy transition. The focus has been on:

- Enabling Systems: The no regrets foundational steps that will be required to deliver future initiatives such as establishing our CER register database and infrastructure as well as RTU upgrades to enable dynamic voltage management setpoints at zone substations.

- Pilots: Smaller scale trials to test new technology to inform best scaling approach. This has included distribution transformer monitoring, our LV visibility and analytics platforms, trial of LV STATCOMS and network support batteries and dynamic hot water control system (our Off Peak Plus pilot).
- BAU/Rollouts: Business as usual ready projects to rollout across the network such as our distribution transformer tap change program.

Reliability Performance

Reliability of supply is a key driver of customer satisfaction and an important aspect of our network performance. In our 2019-24 Proposal, we committed to maintaining our overall reliability performance and addressing our worst performing feeders in accordance with our obligations under Schedule 3 of the NSW Design & Reliability Performance Licence Conditions.

To date, we have delivered on these commitments over the 2019-24 period. However, factors outside of our control are driving more volatility in our overall network level SAIDI and SAIFI performance as depicted in Figure 4-3.

It should be noted that these measures exclude extreme weather events like the 2019-20 bushfires and major storms.

Also, over the 2019-24 period over 400 non-compliant feeders will be addressed through a capital project in accordance with Schedule 3 of our Licence Conditions to maintain individual feeder performance within the minimum standards.

10.5 Forecast capital expenditure program

The investment proposed over the next period will allow us to prudently and efficiently meet customer demand and ensure that our network continues to meet the statutory obligations in relation to reliability and security.

The table below summarises the capital expenditure forecasts required for our network for the 2024-29 regulatory period. These forecasts align with the objectives of our network business strategy, reflect the feedback and direction we have received from customers and stakeholders and have been prepared in accordance with our key assumptions, outlined in section 10.3.2. Forecast capital expenditures have been allocated to standard control services in accordance with the approved CAM.

Table 10-3 Forecast capital expenditure over the FY25-FY29 regulatory period

$m; Real FY24	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Connections	26.0	24.5	23.0	22.5	23.1	**119.0**
Augmentation	103.5	118.8	78.9	63.8	47.5	**412.6**
Replacement	133.1	104.2	113.4	115.1	108.7	**574.5**
Resilience	5.6	5.6	5.6	5.6	5.6	**28.0**
DER	9.0	9.0	9.0	9.0	9.0	**45.0**
Capitalised Overheads	92.5	91.8	90.5	89.5	88.1	**452.4**
Non-System Assets	63.1	48.9	41.5	44.7	32.5	**230.7**
Innovation Fund	4.0	4.0	4.0	4.0	4.0	**20.0**
Total Capex	**436.8**	**406.8**	**365.9**	**354.2**	**318.5**	**1,882.2**
Disposals	*6.3*	*6.3*	*6.3*	*6.3*	*6.3*	*31.3*
Total Net Capex	**430.6**	**400.5**	**359.6**	**347.9**	**312.2**	**1,850.9**

10.5.1 Connections and contributions

Overview

As discussed earlier in this Proposal, we are currently experiencing significant customer growth in our network area and this will continue over the 2024-29 period. When customers seek approval to connect to our network, augmentation or extension work may be required to accommodate their connection. This falls into one of two categories:

- **Capital contributions[54]:** for dedicated network assets, a customer is required to fund these at their own cost and then ‘gift’ them to Endeavour Energy to maintain and operate; or
- **Connections capex:** large residential developments and new commercial and industrial sites can require augmentation and extension of the shared network which services our broader customer base. Modifications to the shared network are funded by Endeavour Energy and therefore our customers.

Relatedly, we also incur augex to support the connection of new customers. Augex involves expansion of the upstream network at higher voltages (e.g., the construction of new zone substations) whilst connections expenditure relates to the expansion and augmentation of the distribution network

[54] There is a contestability framework in NSW that allows customers to choose their own accredited service provider (ASP) and negotiate prices for connection services. This means capital contributions are made up of the value of assets constructed by third parties. These contributions are valued by Endeavour Energy and subtracted from total gross capex which decreases the revenue that is recovered from all customers.

(e.g., new distribution substations and lines and cables connecting to the customer). Our forecasts for both connections capex and capital contributions are provided in the tables below.

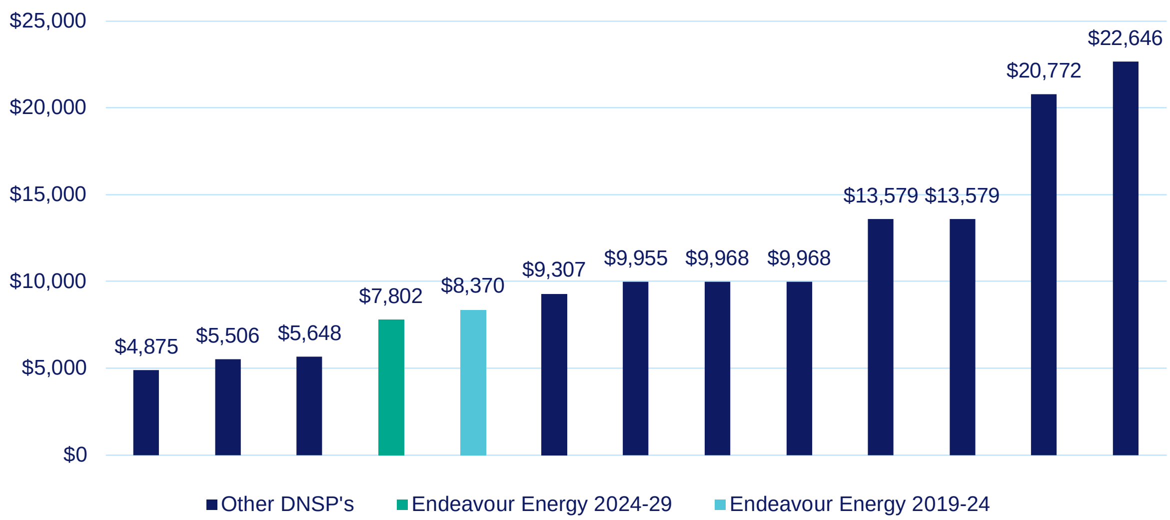
Table 10-4 Proposed connections costs for FY25-FY29

$m; Real FY24	2019-24 Allowance	2019-24 Actual/Forecast	2024-29 Forecast
Connections Capex	131.3	122.0	119.0
Capital Contributions	809.4	657.3	809.2
Connection Cost	961.8	794.4	928.2
Customers connected (number)	105,158	94,910	118,874
Connection Cost per New Customer ($s)	**9,147**	**8,370**	**7,802**

As evident above, our connection capex in 2024-29 is forecast to be $119.0 million (real, 2023-24) compared to $122.0 million (real, 2023-24) during the 2019-24 period. This improvement is driven by our decision to constrain our forecast from $133.8 million to $119.0 million in response to customer and stakeholder feedback. It also reflects our higher customer growth forecast for the 2024-29 period which is largely offset by the 2024-29 Proposal being fully reflective of our 'causer pays' funding approach whereas the 2019-24 period involved a transition away from the temporary application of a 'beneficiary pays' approach in the early years of the period.

The reduction in our connections capex despite the increase forecast customer connections from 94,910 to 118,974 further improves our connection cost per customer. Noting that our unit rates are improving they are likely to remain amongst the most efficient in the NEM as shown in Figure 10-6. This provides prima facie evidence of the efficiency and prudency of our forecast connections capex.

Figure 10-6 Connection cost (connection capex plus capital contributions) per new customer[55] ($; Real FY24)



As detailed in Chapter 7, our connection volumes are based on expected customer and dwelling growth and development activity over the period. Our customer number forecast reflects a robust estimation method informed by independent expert NIEIR and consultation with the Urban Development Institute of Australia (UDIA), councils and the State Government to ensure it is reasonable.

Table 10.5 also highlights that the majority (around 87%) of the combined connection costs are funded by the connecting customer and delivered competitively in NSW.

[55] Source: RIN data, FY17-FY21 average performance for non-Endeavour Energy DNSPs.

Forecasting approach

Endeavour Energy manages its connections capex expenditure through administering four programs:

- Urban Residential
- Industrial Commercial
- Non-Urban
- Asset Relocations

Expenditure incurred in the four connections categories has historically been reactive and difficult to forecast for future years. The implementation of and later removal of increased Endeavour Energy funding for shared connection assets has added to the complexity of forecasting based on historical spend.

To address this, a connections capex model has been created to produce a connections capex forecast. The main inputs to the model are customer numbers growth and a 'per connecting customer' unit rate derived from historical connections capex and capital contributions. As noted above, we temporarily changed our contributions policy between 2017-19 (with a lagged transition of up to 18 months to revert our policy). We have therefore excluded these years from the historical period from which our unit rate is derived.

The model also incorporates a 'dial' setting which can vary the components of Endeavour Energy's connections reimbursement regime to test and develop alternate funding arrangements. For our 2024-29 Proposal, this 'dial' is set to recent historical levels consistent with our 'causer pays' funding approach.

Customer feedback

We note that our Connections model produces a higher forecast of connections capex for the 2024-29 period of $133.8 million (real; 2023-24). However, consistent with other aspects of our capex proposal we have constrained this amount to $119.0 million (real; 2023-24) as part of our commitment to improving productivity and providing a value for money service in response to customer and stakeholder feedback.

More specifically, as part of our engagement we tested who should pay for growth related capex – the new customer (i.e., causer) or shared with the existing customer base (i.e., based on long term beneficiary). Noting a change in policy has the potential to significantly increase both connections capex and augex.

Our current approach is closer to 'causer pays' while the NER reflects a 'beneficiary pays' approach based on an economic test. This difference in NSW is driven by application of the NSW Electricity Supply Act and the contestability framework.

We therefore considered it prudent to make this difference clear to customers and test whether this was acceptable to them. Noting this was an issue explored in detail during our 2019-24 determination.

The feedback was mixed on 'causer pays' vs. 'beneficiary pays':

- Our Customer Panel provided a mixed response to this question, with some favouring the 'beneficiary pays' approach while a small majority (52%) favoured retaining the 'causer pays' approach. The mixed feedback reflects that this is a complex issue and largely based on individual perceptions of what is fair.
- Stakeholders were more uniformly in favour of maintaining the existing 'causer pays' approach as they considered it was fairer, more efficient and avoided the risk of the savings of the 'beneficiary pays' approach not being passed through the connecting customers.

On the basis of this feedback, we propose to maintain our existing 'causer pays' policy.

10.5.2 Augex

Overview

We are proposing $413 million (real, 2023-24) of augex for the 2024-29 period. This is equal to our current period forecast.

Our forecast augex is primarily driven by supporting the sustainable growth of our communities. It involves expanding the network to new areas to cater for customer growth and increasing the capacity of the existing network to cater for demand growth from existing customers.

The development of our regions, in particular the Western Sydney Parkland City, including Bradfield and the International Airport are key aspects driving forecast augmentation expenditure growth. Western Sydney is one of the fastest growing regions in Australia. Whilst there have always been large areas of greenfield residential development there has been noticeable shift in the current period towards developing increased employment and services within Western Sydney which in turn has led to a shift to industrial/commercial development – with a considerable uplift in the speed of redevelopment in these precincts.

The Greater Sydney Commission has defined a vision of Sydney as a metropolis of 6 cities:

- The Eastern Harbour City (centred on the existing Sydney CBD)
- Greater Parramatta
- Western Parkland City (having the largest greenfield component)
- Metro Wollongong
- Gosford
- Newcastle

We have been and will continue to be an active and integral part of greenfield planning processes being part of formal collaboration/coordination groups that include key government planning authorities, other utilities, and infrastructure agencies. Key to this is a coordination to ensure that all types of essential infrastructure are available at the same time in a precinct by using common planning assumptions and minimise disruption to the community (avoid digging up the same road multiple times).

A 2020 Department of Planning Infrastructure and Environment (DPIE) employment lands reported noted that in 2019 $2 billion worth of development activity in Metropolitan Sydney with $1.4 billion within Endeavour Energy locations. Activity in Western Sydney has further increased since that time with ABS data showing non-residential building approvals in Blacktown LGA at $825 million in FY21. The Aerotropolis council areas, Liverpool Council and Penrith Council, registering increases to $2.1 billion and $0.7 billion respectively in non-residential building approvals in FY21.

Endeavour Energy has historically had large volumes of greenfield residential land release in Western Sydney and the Illawarra region. The demand in these areas is affected by market forces as well consumer energy trends including BASIX, rooftop PV, batteries and electric vehicles, an emerging transition away from natural gas.

Our forecast augex for the 2024-29 period is outlined in the table below.

Table 10-5 Proposed augex for FY25-FY29

$m; Real FY24	2019-24 Allowance[56]	2019-24 Actual/Forecast	2024-29 Forecast
Brownfield	53.7	51.5	58.5
Greenfield	376.9	361.4	354.2
Total	**430.6**	**412.9**	**412.6**

A similar level of augex is required to accommodate the customer and associated demand growth on our network over the 2024-29 period. Specifically;

- **Substantial increase in the number and size of employment focussed developments** within Endeavour Energy's franchise area, both industrial and commercial in nature, in response to government planning initiatives
- **Customer growth:** our customer numbers are expected to grow by approximately 24,000 per annum compared to 19,000 per annum over the 2019-24 period; and
- **Spatial demand growth:** approximately one third of our 164 zone substations are expected to experience growth rates of greater than 1.5% per annum and almost half expected to experience growth rates of between 0% and 1.5%, per annum.

As aforementioned, we have experienced significant growth over the last decade and expect this to continue. However, much of the impact of this anticipated growth will occur in the later parts of this period when compared to our 2019-24 Proposal, deferring the need for investment. At the same time, investments not catered for in our current period allowance, such as the 132kV supply for the Aerotropolis have been brought forward.

This means it is likely that augex will increase over the remainder of this period and into the next period due to the timing of customer driven development. Given some of these deferrals are driven by forces outside of our control we propose to adjust our capex for the current period by $54 million for CESS purposes to ensure customers only pay for this investment once.

Forecasting approach

Augex is a largely non-recurrent category of capex that is driven by broader economic growth and development within our network area. Augex is therefore developed on a bottom-up basis that involves a probabilistic assessment of spatial new connection activity, as well as demand and customer growth assumptions to determine how much additional network capacity is required and when.

Broadly, the figure below shows our approach to developing our forecast.

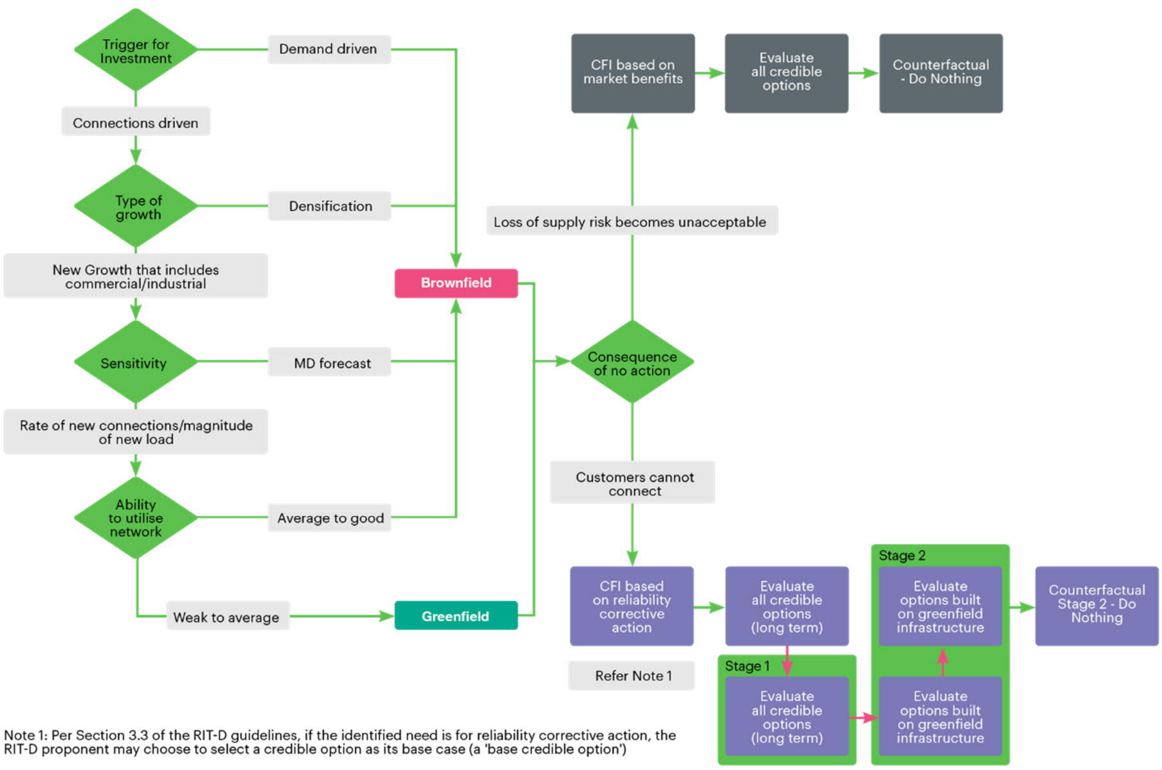
[56] An allowance was not provided at the augex category level. For comparison we have split the total allowance in the same proportion as the actual/forecast augex.

Figure 10-7 Endeavour Energy approach to forecasting augex

	1 Apply Lessons Learned	2 Qualify Need	3 Determine Timing	4 Analyse Options & Determine Solutions
Greenfield Stage	• Lessons from projects reviewed to inform the scope and timing	• Trigger: Connections and growth forecasts • Identified Need: Reliability Corrective Action • Sensitivity: Timing of the connections headworks	• Just in Advance approach that uses application from developers and synergies with other utility works to service the new load.	• Credible Base Option: Network only solution for headwork infrastructure
Brownfield Stage		• Trigger: Connections and growth forecasts or Maximum Demand (MD) forecasts • Identified Need: Reliability Corrective Action or Market Benefit • Sensitivity: Maximum Demand (MD) Forecast of existing and known new connection	• Just in Time approach that uses connections application database and probabilistic analysis to service the increase in demand.	• Credible Base Option (For reliability corrective action): Network or Non-Network solution • Credible Base Option (For market benefit): BAU – No proactive Intervention • A range of solutions are considered for the treatment of identified emerging capacity constraints

To provide a fit-for-purpose response to the growth challenge as well as be consistent with the NER and AER guidelines, Endeavour Energy has established a decision framework. The figure below outlines the decision framework from the Growth Servicing Strategy, which is used to inform the development of Case for Investments (CFIs) to address the uncertainties and identified need.

Figure 10-8 Endeavour Energy augex decision making framework



This approach enables us to select the most efficient and prudent response to address the consequence of no action based on the type of Augex investment required (greenfield or brownfield).

As per the figure above, the type of augmentation expenditure results in differing approaches to reflect the needs of customers.

To facilitate growth there are three types of Augex investment supplemented by customer-initiated works:

1. **Connection driven Augex** creating new upstream assets to enable customer/development connection. This makes up approximately 60% of our combined augex and connections capex forecast.
2. **Demand driven Augex** designed to maintain secure and reliable supply as load increases over time. This makes up approximately 15% of our combined augex and connections capex forecast.
3. **Customer Initiated Works**, supplementing developer provided/gifted new assets to enable customer connection at the time of connection. This makes up approximately 25% of our combined augex and connections capex forecast.

In the table below we set out how this framework applies in practice between greenfield and brownfield investment more specifically.

Table 10-6 Attributes of decision-making framework for different types of augex

What is the Trigger for investment?	
Connection driven • There is substantial growth in new connections as new residential precincts are developed. This includes the development of new commercial centres, development of "employment lands" and the provision of supporting social infrastructure all of which adds to growth impacts and demand on network infrastructure • Development in areas that have not been built on before. This often includes rural/non-urban areas that are located on the edge of towns or cities	**Redevelopment and Demand driven** • Growth in connections in older areas is due to redevelopment, increased housing density and land re-use due to re-zoning (urbanisation of older industrial and commercial lands) • Demand growth in existing established areas is being driven by general economic activity and changes in customer end-use patterns and appliance uptake. This is termed 'organic growth'. The post modelling adjustment (PMA) process modifies the rate of organic growth as adjustments for the uptake of PVs and other energy efficient appliances may reveal no organic growth
What is the type of growth?	
New Growth (Step Change in new load) There is a substantial growth in the area primarily due to release of new land and / or high industrial loads such as data centres being established that increases the demand manifolds	**Densification** Urbanisation in existing areas or growth forecast in new areas in future years.
What is the ability to Utilise adjacent network to service the growth?	
Average to Weak (Light Orange to Dark Orange on DAPR)	Average to Strong (Light Orange to sky blue on DAPR)
What is the Identified Need?	
Reliability Corrective Action NER 5.10.2 defines reliability corrective action as a network business' investment in its network to meet 'the service standards linked to the technical requirements of schedule 5.1 or in applicable regulatory instruments and which may consist of network options or non-network options.	**Sum of Consumer of Producer Surplus** The sum of consumer and producer surplus maximises the NPV of the market benefit, where the market benefit is the total net benefits of the project to all consumers and producers in the market. NER 5.17.1 specifies classes of market benefits
Which input is the need most sensitive to?	
Magnitude of load requirement and/or rate of new connections	Maximum Demand (MD) Forecast of existing and known new connections

The framework helps with:

- Identifying learning opportunities
- Managing uncertainty by evaluating the trigger, type of growth and sensitivity to growth.
- Optimising the utilisation of the existing network by always looking at ability of adjacent network to service the initial phases of growth until intervention is required.

- The proactive usage of non-network solutions and integrated planning by looking for alternative market-based solutions to respond to customer increase demand.

Lessons learnt

We have progressively refined our approach to augex during this extended period of growth. We acknowledge however that we underspent our augex allowance in the early part of the current period. The factors driving this were outlined in Table 10-7 and we have adjusted our CESS outcomes accordingly as described in Chapter 9.

Nonetheless we have reviewed the drivers of the underspend early in the period at a granular level and implemented changes to improve the accuracy of our forecasting approach. A summary is provided in the table below

Table 10-7 Proposed Assessment of augex variability

Reason	Detail	Action
Delays from developers	Endeavour Energy deferred investment in several projects due to delays from the developers	Developer applications are analysed with a continual scan of the region that includes engagement with DPIE and other utilities to gain higher level of confidence.
Staging the provision of capacity	The delays from developers and the revision in the rate of growth (being slower than originally estimated) has resulted in deferment of investments.	Staging options (e.g., mobile substations or more extensions of 11kV) that include use of mobile substations is considered as part of the BAU options evaluation.
Non-Network Options	The outcomes of RIT-D process and other commercial arrangements substituted capital expenditure with operating expenditure (e.g., battery as a service).	Non-Network optioneering is now standard BAU with further investment in NTMP. All CFIs consider non-network options and selects the most commercial and technically credible option
Quantitative Risk Analysis	Endeavour Energy applies probabilistic risk assessment on servicing maximum demand.	Risk enabled approach by performing more sophisticated quantitative risk analysis
Capital efficiency – reduced unit rates	Through innovation funding several improvements have been made in design, delivery and standards resulting in lowering of unit rates.	Unit rates are progressively updated.

Managing uncertainty

Whilst we have made improvements to our forecasting approach, augex remains different to other capex categories in that the need for investment is heavily influenced by what action external stakeholders such as government, developers, other infrastructure providers take, as well as demographic and economic trends. There are number of key aspects to uncertainty in future demand and connections growth such as the rate of development, customer energy trends and CER uptake, the planning approval process, government investment in infrastructure and broader economic conditions.

Our Augex investment forecast is put together by collating individual projects through a bottom-up process, although with projections out to 2029 there is some expectation of timing adjustments across projects both within and beyond the period. We engaged an independent consultant to provide a top-down challenge of investment using the AER Augex model.

At a portfolio level, we need to manage the uncertainty around whether certain capex projects will be required. It is possible that a small number of projects may be affected by uncertainty in the development proceeding or may be deferred by non-network options. It is also possible that there will be unforeseen investment needs due to step changes caused by customer connections during the next regulatory period.

Demand and connection forecasting

Our approach to demand forecasts and growth forecasts is outlined in Chapter 7. As a point of emphasis, a probabilistic approach is taken to assessing spot loads in greenfield precincts:

- For residential development, the number of forecast dwellings is multiplied by the ADMD. Furthermore, a probability factor of 0.8 is applied to reduce resultant expected demand growth on the substation.
- For industrial/commercial applications, the load applied for by customers and developers is reduced by probability factors as appropriate in the range from 0.6 to 0.8.

There are many connection enquiries at the feasibility stage where we have applied a zero probability for in the forecast, but some of these are necessarily included with an appropriate probability factor in the demand forecast to ensure a sensible integrated planning approach with government, utility, and developer stakeholders.

Utilisation of existing assets

In addition to our forecasting methodology and validation process, another means of managing this uncertainty is through the timing and staging of investment. This can involve the utilisation of existing capacity in a location (or nearby) to service growth where it is technically feasible and the optimum economic solution. The stages are broadly as follows:

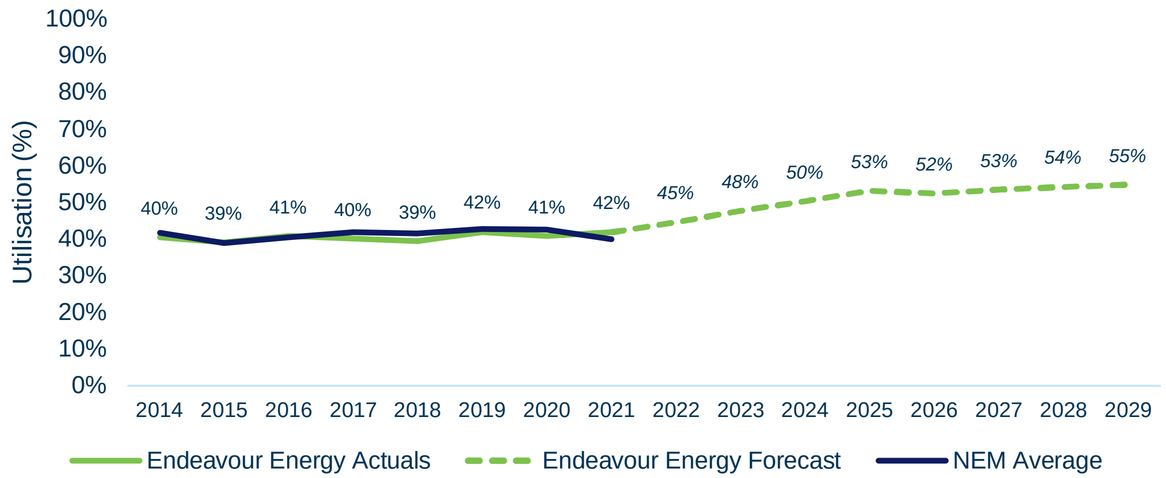
- **Stage 1:** Utilise existing capacity in the 11kV network (connection costs only);
- **Stage 2:** Augment/Extend 11kV feeders (typically $1-7 million in augex);
- **Stage 3:** Temporary/Mobile supply or single interim transformer (typically $5-20 million in augex); and
- **Stage 4:** Full zone substation establishment (typically $20-40 million in augex).

This approach means we provide supply on an as needed basis to growth areas.

In stages 1 and 2 for 11kV/22kV capacity we are generally providing supply at ‘N’ security meaning the load on the feeder is the trigger for further investment. We will move beyond stage 3 when the risk and cost of failure, noting a single asset failure will cause an interruption at ‘N’, outweighs the cost of investment. To value expected unserved energy, we apply the AER determined VCR estimates.

A key indicator of utilisation for Augex is the utilisation of zone substation level transformer capacity which measures the actual peak demand of all zone substations against our installed capacity. Our utilisation has been increasing in recent years and generally at the NEM average. We are forecasting a material increase over the coming years and 2024-29 period.

Figure 10-9 Endeavour Energy network utilisation (2014-29)



As evident in the figures above, the faster pace of developments and location of developments to existing network with capacity headroom limits the ability to utilise existing capacity or temporary supply options for the 2024-29 period. This means that for the 2024-29 period several projects are moving into the latter stage solutions which involve more expensive network investments, such as HV feeder augmentations, underground circuit lines and increasing capacity through the establishment of new zone substations.

This has resulted in an increase in land costs and associated civil works to construct and house new assets in new locations rather than being able to upgrade and rely on existing network assets. This means that the increase in greenfield augex is driven by volume (i.e., the number of zone substation establishments required) rather than unit prices.

However, it should be noted that only measuring utilisation using peak demand does not reflect the overall usefulness of the network as at lower levels, particularly as the network is increasingly being required to cope with reverse power flow due to rooftop solar generation. We assess and manage demand growth at a more granular and localised level when developing our augex plans.

Non-network solutions and integrated planning

To service the growth challenge, Endeavour Energy evaluates network, non-network and hybrid options. New technologies will continue to play an increasing role across all these options and Endeavour Energy will evaluate credible options to efficiently service the growth challenge. New Technology and its applications continue to move in all dimensions in respect to changes in price, capabilities, ownership models, partnerships, investment value stacks, as well as the maturation of industries that were previously considered high risk.

To address this issue, Endeavour Energy is moving to a more consistent and proactive approach for the consideration and adoption of new technology and customer-based solutions on our network. This includes:

- **Implementation of cost-reflective tariffs:** Over the 2019-24 period we continued our transition to cost-reflective tariffs noting the take-up is subject to the rollout of advanced metering and retailers have the ability to opt-out of cost-reflective tariffs. We plan to strengthen our assignment policies in the 2024-29 period and update our tariffs to provide a signal to customers who export energy into the grid and to cater for new technologies such as batteries. Whilst our augex forecast is primarily greenfield driven (i.e., new customer growth) our brownfield augex reflects the impacts of tariffs through the PMAs applied to our demand forecasts as described in Chapter 7. Specifically, these PMAs include an estimation of the behavioural impacts cost-reflective tariffs have on customers.
- **Utilising the New Technology Master Plan (NTMP):** We have developed a proactive approach to the efficient use of non-network solutions to alleviate network constraints and respond to network needs, in the interest of the business and our customers. This tool integrates existing network data and enables the efficient exploration of the net-benefits of various non-network solutions at a pre-feasibility stage, considering the various uncertainties and sensitivities. The NTMP tool furnishes us with the knowledge and business capabilities that will allow for the effective identification of new technology options (as potential non-network options).
- **CAPEX/OPEX balance:** The impact of new technology and non-network options may have an impact on the totex, where some network capex in Augex maybe deferred or substituted by non-network options that are opex in nature. We will proactively evaluate the options and the CER / Augex capital expenditure will continue to be evaluated using a holistic approach.

Customer feedback

As part of our engagement, we tested when we should cater for forecast growth. Our Customer Panel (and informed stakeholders participating in Deep Dives) were aligned with our preliminary position to support growth in a timely manner, essentially at the time of other infrastructure providers rather than being leading or lagging.

However, compared to other priorities, such as resilience and the transition toward decentralised and renewable energy, supporting growth was of lower importance to the Customer Panel, particularly when cost became a consideration.

Consistent with our commitment to providing a value for money service we have constrained our Augex proposal to $413 million for the period despite our bottom-up forecast totalling over $550M.

In setting a constrained Augex proposal we are committing to managing the uncertainty associated with forecasting growth. This reduces our revenue requirement and increase the risk we must manage in meeting our obligations to connect and service customer growth. As a result, it may be worth considering (at the time of the 2029-34 determination) how Augex is treated for CESS purposes if the bottom-up forecast, which we consider to be efficient, is realised.

Key projects and details

We provide more detail on our augex proposal in the following attachments:

- Growth Servicing Strategy (Attachment 10.14) which:
  - **Defines the growth challenge** for Endeavour Energy including clarifying the charactertistics of greenfield and brownfield development
  - **Outlines Endeavour Energy's approach** to investment in augmentation capital that addresses the growth challenge. The approach will inform development of prudent and efficient case for investments to service the growth challenge.
  - **Provides a line of sight** between Endeavour Energy's corporate strategy and strategic asset management plan and DPIE's growth objectives and customers needs.
- Area Plans (Attachment 10.15 - 10.19) the next layer of detail are a series of detailed plans developed for areas that are expected to require significant investment in the future. The purpose of these area plans is to outline an overarching view of the network infrastructure that will be required to service the identified growth area. The Area Plans aim to assess the state of the network, identify the critical external influences to determine the likely future network requirements, and identify the high-level needs and opportunities to be refined and options (external to the Area Plan process) through the investment governance process
- Augex CFIs (Attachments 10.20) the final layer of detail are augex CFIs which applies our decision-making framework to an individual project within a growth area. Each CFI sets out an overview of the proposed investment, including the underlying need, our recommended solution, a discussion of the key drivers, and the options considered to address the identified need.

The identification of growth focus areas covered by area plans is based on the following triggers:

- Priority Growth Areas are identified by the NSW Government that require a level of analysis, rendering these growth focus areas in need of network development area plans;
- annual planning reviews of the capacity of the network and its ability to meet forecast demand for electricity and the growth in new customer connections; and
- our ongoing interactions with councils, urban planning bodies and developers, which serve to identify future development needs and development areas.

The growth areas identified for which we have long-term development area plans are as follows:

- Aerotropolis Area Plan;
- Greater Macarthur Priority Growth Area;
- Greater Parramatta Area;
- North West Priority Growth Area;
- South West Priority Growth Area;
- West Lake Illawarra Growth Area.

In addition to these strategic growth areas, existing large urban centres within our supply area such as Parramatta, Liverpool and Penrith are experiencing significant brownfield re-development and increases in density, which in themselves attract special planning consideration.

In accordance with the Rules[57] some of our forecast capex relates to projects which have already satisfied the requirements of the RIT-D. These are:

- The new Aerotropolis Foundation Supply 132kV Feeder (NPR-000025) ($1.7million in 2024-29; with the majority of the capex being in the existing 2019-24 period) with final project assessment report issued January 2022; and
- Sydney Science Park Zone Substation (NPR-000021) ($30.9 million in 2024-29) with final project assessment report issued in October 2022; and
- Westmead Health Precinct Augmentation (NPR-000026) ($12.8 million in 2024-29) with final project assessment report issued in October 2022; and
- Carlingford Transmission Substation Reliability and Safety Risk Mitigation (NTS-000131) ($4.3 million in 2024-29) with final project assessment report issued in November 2021.

A draft project assessment report for North Bradfield Zone Substation (NPR-000078) ($38.4 million in 2024-29) has also been recently published. A draft project assessment report for Badgerys Creek Zone Substation (NPR-000080) ($41.7 million in 2024-29) is set to be released in the near future.

Below, we provide an overview of some of the key projects and deliverables associated with our forecast augex focusing on the most material area plans.

[57] NER Clause 6.5.7(b)(4)

Western Sydney Aerotropolis

The Western Sydney Aerotropolis is an 11,200-hectare area surrounding the Western Sydney International (Nancy-Bird Walton) Airport located within the Western Parkland City. The Aerotropolis will become a hub of industry and innovation, attracting local and global companies drawn to the enormous potential of Western Parkland City and the airport that serves it.

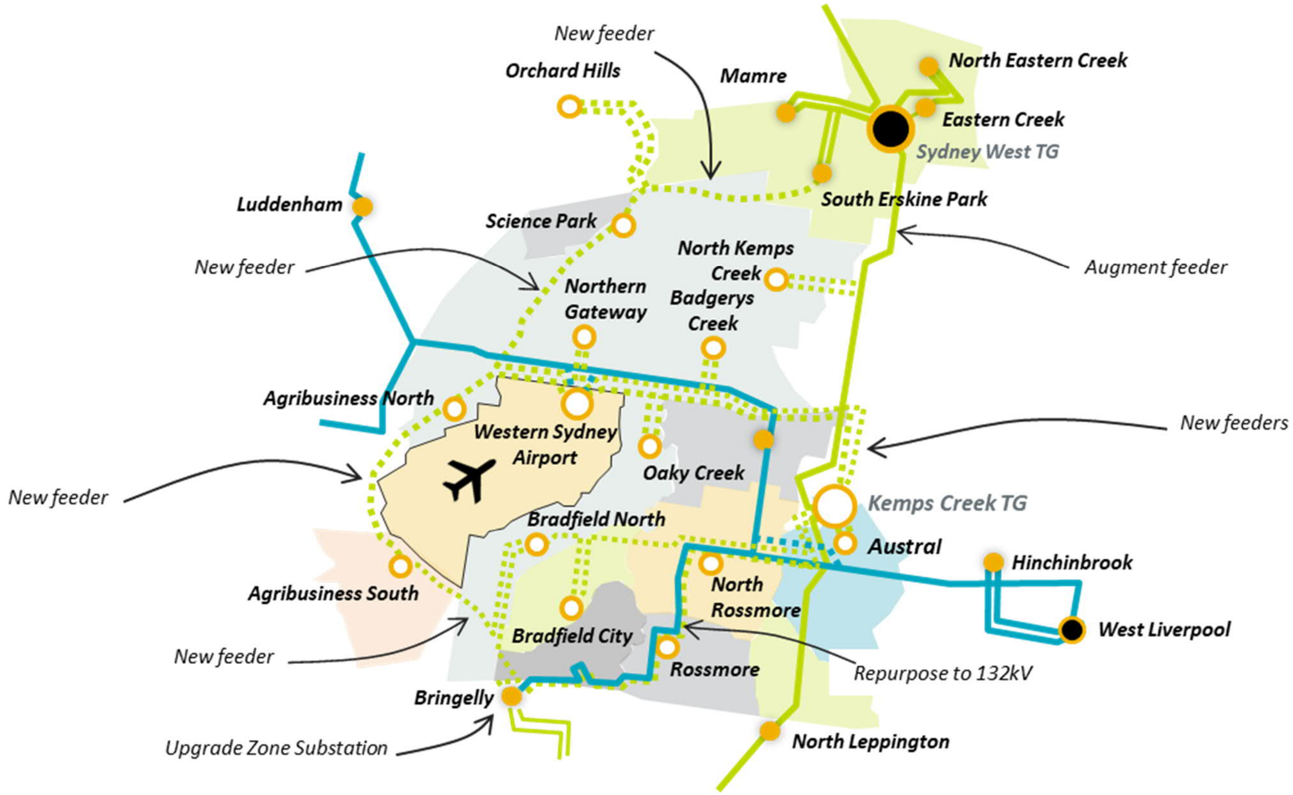
The NSW Government has also recently announced over $1 billion in funding to start building Bradfield City Centre at the core. This is the next step in delivering Australia's newest, most advanced, green and connected city. Our enabling works and partnerships support the growth of the Aerotropolis.

During a five-year period starting from 1 July 2024, we plan to invest approximately $199 million on major growth projects to ensure continuing connection capacity is available in the Western Sydney Aerotropolis.

The ultimate development of the Western Sydney Aerotropolis Priority Growth Area will take place over a 30-year period and will require ongoing investment to provide a forecast electricity capacity of around 1,000MVA.

See Attachment 10.15 for the full area plan.

Figure 10-10 Western Sydney Aerotropolis Growth Area



Existing Transmission Line
Proposed Transmission Line
Existing Zone Substation / Switching Station
Future Zone Substation / Switching Station
Existing Transmission Substation
Existing Bulk Supply Point
Future Bulk Supply Point

North West Priority Growth Area

The North West Priority Growth Area is approximately 10,000 hectares of mostly rural land that is progressively being urbanised with greenfield development. It is within the boundaries of three local government areas of The Hills, Blacktown, and Hawkesbury, which will ultimately have 90,000 homes and over 500 hectares of employment lands.

The NSW Government aims to facilitate delivery of 33,000 homes by 2026 by investing into road, rail, and water infrastructure to release land in this area for development, for example the Sydney Metro North West rail line completed in 2019. The State Government is also actively pursuing increased housing supply to tackle housing affordability via policy changes and provision of infrastructure. In addition, there has been strong growth in employment lands such as Sydney Business Park at Marsden Park where larger businesses have moved in. Investing in electricity capacity to connect greenfield development is necessary to supply these investments and developments

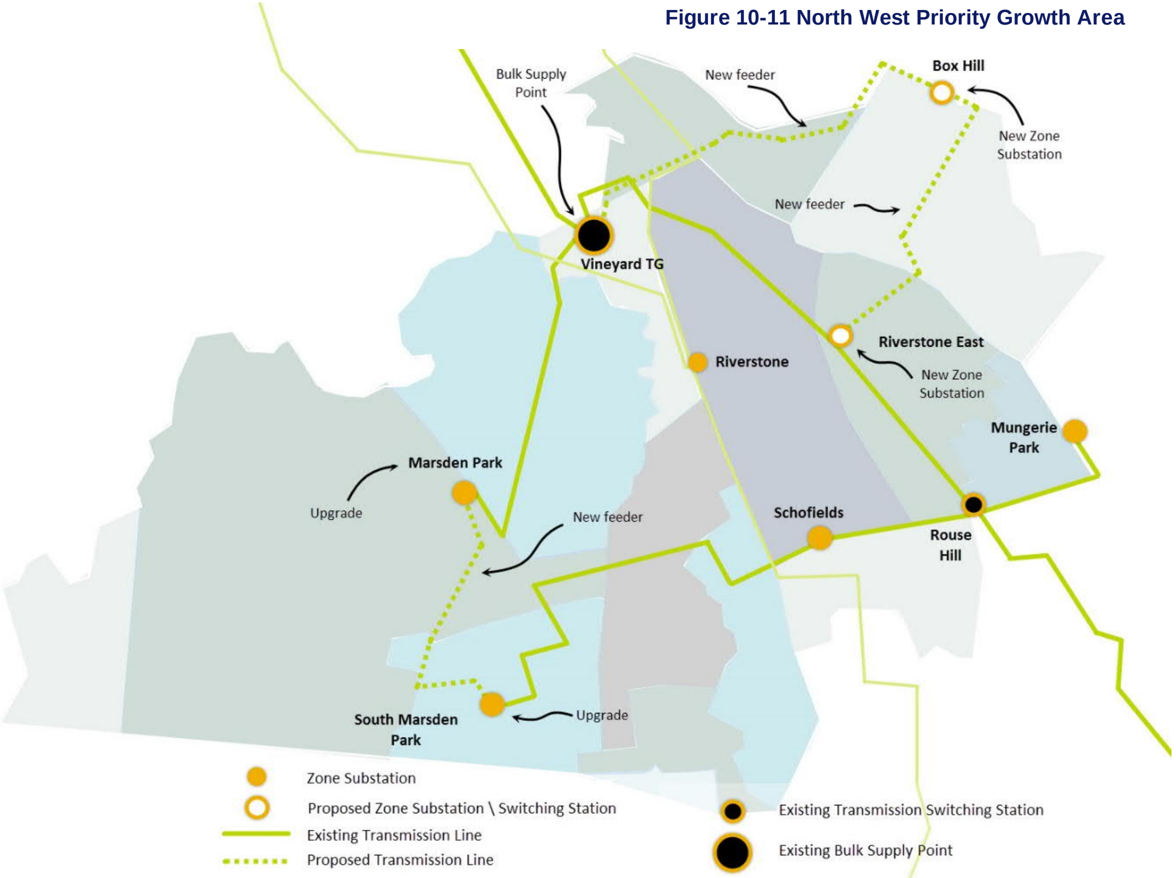
Western Sydney has a hotter climate than coastal areas, often 10 degrees warmer than the coast, with temperatures above 40°C occurring during most summer periods. Demand is summer peaking driven by air conditioning demand. Although penetration of solar PV continues to grow, the peak generation of output of solar at midday does not align with the evening peak when air conditioners and other household appliances are used.

Endeavour Energy has previously invested prudently to support growth in the North West Area, however capacity constraints for greenfield development remain in specific locations. This is because new precincts are released over time, creating new development frontiers; higher densities are being encouraged; and the fact that previous investment has been efficiently staged.

During a five-year period starting from 1 July 2024 Endeavour Energy plans to invest approximately $28 million on growth projects to ensure continuing connection capacity is available in the North West Priority Area.

See Attachment 10.18 for the full area plan.

Figure 10-11 North West Priority Growth Area



Greater Parramatta Area

The Greater Parramatta area has a number of major developments occurring in different precincts. These developments are occurring at the moment and will continue for over 10 years.

The Westmead Hospital precinct is undergoing a $1 billion expansion and is one of the largest health complexes in the Southern Hemisphere. It includes Westmead Hospital, Westmead Children's Hospital and supporting departments, research facilities and accommodation.

Parramatta CBD is undergoing major developments including the $2.8 billion transformation of Parramatta Square. This area also includes other major developments including new commercial buildings, residential buildings, schools and is also the new home for the Powerhouse Museum. Overall, the CBD will provide 7,500 homes and 27,000 jobs.

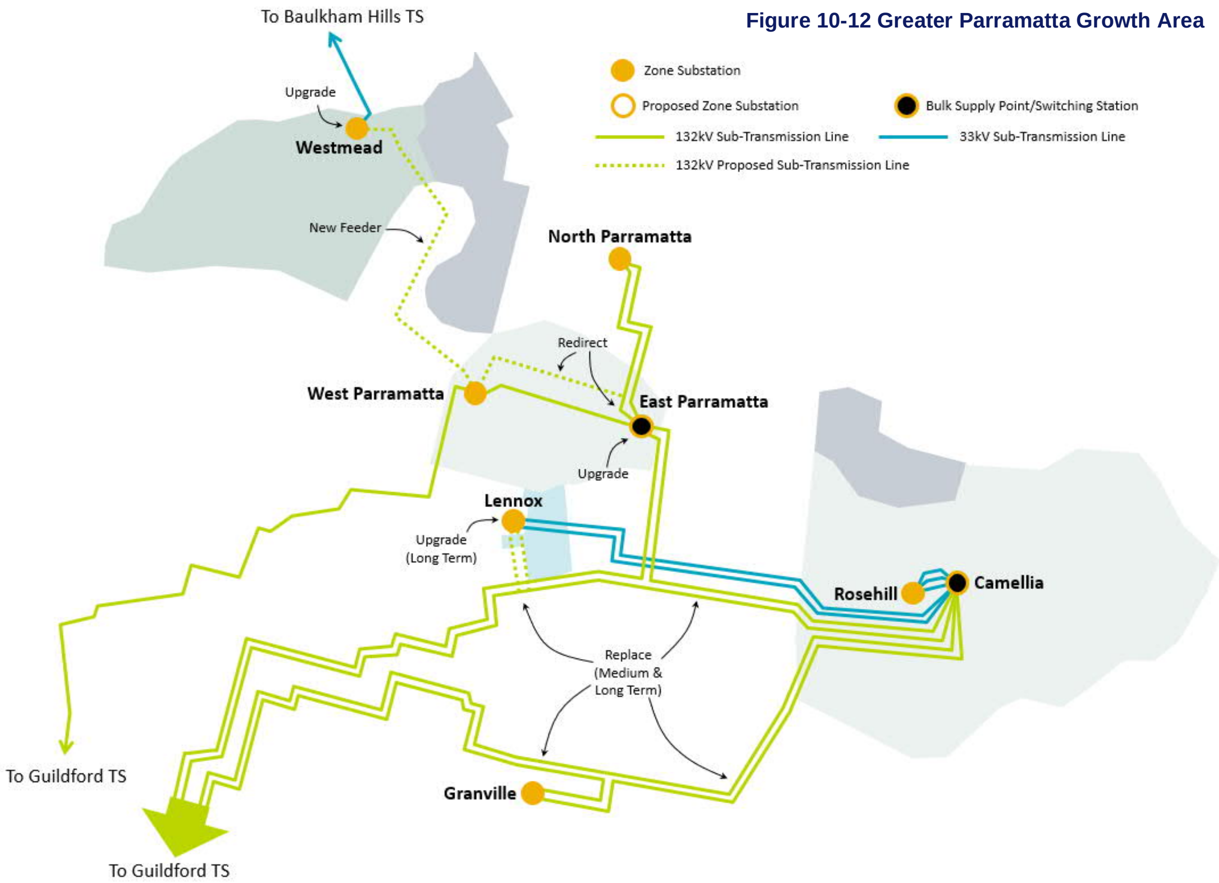
The Parramatta North precinct is planned to be revitalised by restoring and protecting existing heritage buildings and infrastructure. The area will become a vibrant place to live with new shops, restaurants, cafes, and parks to support 3,000 new homes.

The Camellia-Rosehill area has a plan to breathe new life into its industrial past. The vision includes a new town centre with an 18-hour entertainment precinct and 10,000 new homes. This will create up to 14,500 jobs and will also feature a new urban services precinct as well as retain some industrial zoning that will ensure this precinct continues to be an industrial powerhouse for Sydney.

During a five-year period starting from 1 July 2024 Endeavour Energy plans to invest approximately $40 million on growth projects to ensure continuing connection capacity is available in the Greater Parramatta Area.

See Attachment 10.17 for the full area plan.

Figure 10-12 Greater Parramatta Growth Area



South West Priority Growth Area

The South West Priority Growth Area is approximately 10,000 hectares of mostly rural land that is progressively being urbanised with greenfield development similar to the North West Priority Growth Area.

The area is located within the boundaries of the Liverpool, Camden, and Campbelltown local government areas. It will ultimately have 132,000 homes and over 450 hectares of employment lands including the new Leppington and Edmondson Park Town Centres.

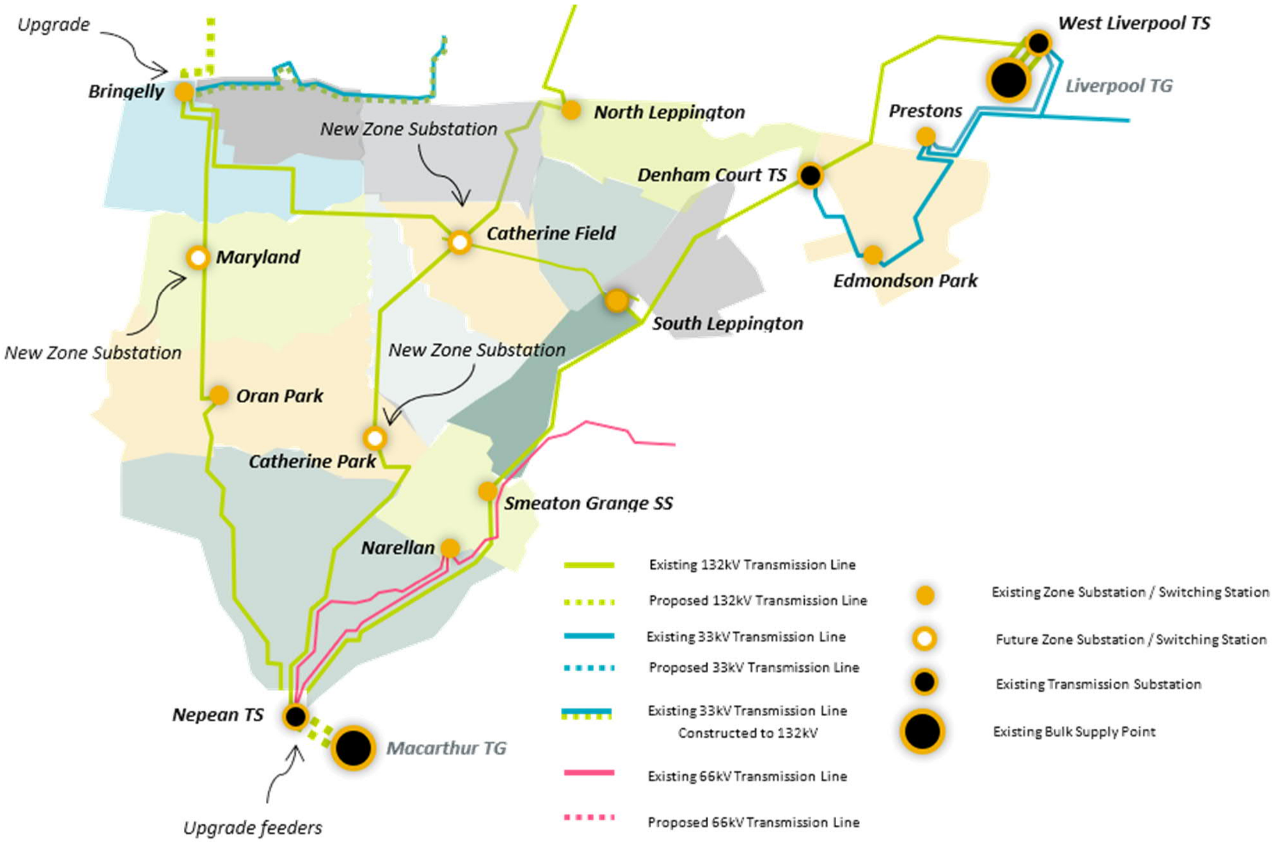
The NSW Government has delivered the South West Rail Link from Glenfield to Leppington via Edmondson Park to stimulate residential and commercial development in this priority growth area. Investment in road, rail, sewer, water, gas, telecommunication, and electricity infrastructure is occurring to meet demand as each precinct is released.

Endeavour Energy has previously invested prudently to support growth in the South West Growth Area however capacity constraints for greenfield development remain in specific locations. This is because new precincts are released over time creating new development frontiers; higher densities around transport corridors and town centres; and the fact previous investment has been staged.

The ultimate development of the South West Priority Growth Area will take place over a 30-year period and will require ongoing investment to provide a forecast electricity capacity of 600MVA.

During a five-year period starting from 1 July 2024 we plan to invest approximately $22 million on major growth projects to ensure continuing connection capacity is available in the South West Priority Growth Area.

Figure 10-13 South West Priority Growth Area



Greater Macarthur Priority Growth Area

The Greater Macarthur Study area is approximately 17,600 hectares of mostly rural lands across Campbelltown and Wollondilly local government areas. Of this area, the NSW Government has identified approximately 7700 hectares of land that can be developed in the short term and will be priority growth precincts.

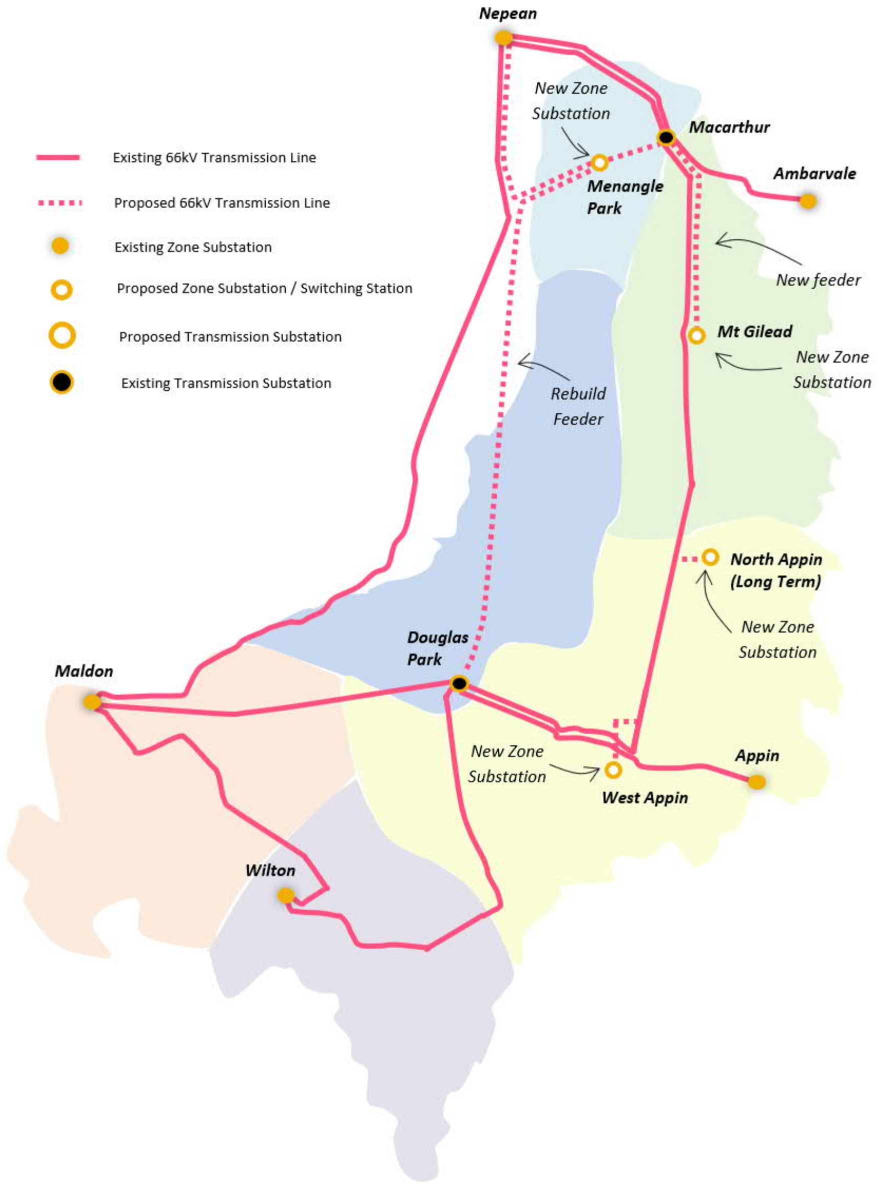
Developments at Menangle Park, Mount Gilead, Wilton New Town, and the West Appin precincts are expected to yield over 60,000 dwellings and 700 hectares of employment lands. There has also been more recent interest in developing areas south of Mt Gilead and will result in additional residential dwelling yields. Collectively this will ultimately impose network demand in excess of 300MVA.

Development in the precincts listed is predominantly driven by large single developers and landowner consortiums and consequently could develop at a faster pace than fragmented precincts.

During a five-year period starting from 1 July 2024 Endeavour Energy plans to invest approximately $42 million on growth projects to ensure continuing connection capacity is available in the Greater Macarthur Priority Area. Further investment will be required as this new development frontier gathers pace.

See Attachment 10.16 for the full area plan.

Figure 10-14 Greater Macarthur Priority Growth Area



West Lake Illawarra Growth Area

The West Lake Illawarra growth area is approximately 5,500 hectares of mostly rural land across Wollongong and Shellharbour local government areas. It will ultimately accommodate an estimated 28,000 residential dwellings and comprise 3.1km2 of employment lands. Based on the total number of dwellings and employment lands, the ultimate imposed network demand is estimated at 130MVA.

There are four main Greenfield development precincts in the area. These are Calderwood, West Dapto, Tallawarra and Avondale. These precincts are located within the boundaries of the Illawarra escarpment to the west, the existing suburbs of Horsley, Dapto and Tallawarra to the east, the existing Kembla Grange employment lands to the north and Albion Park to the South.

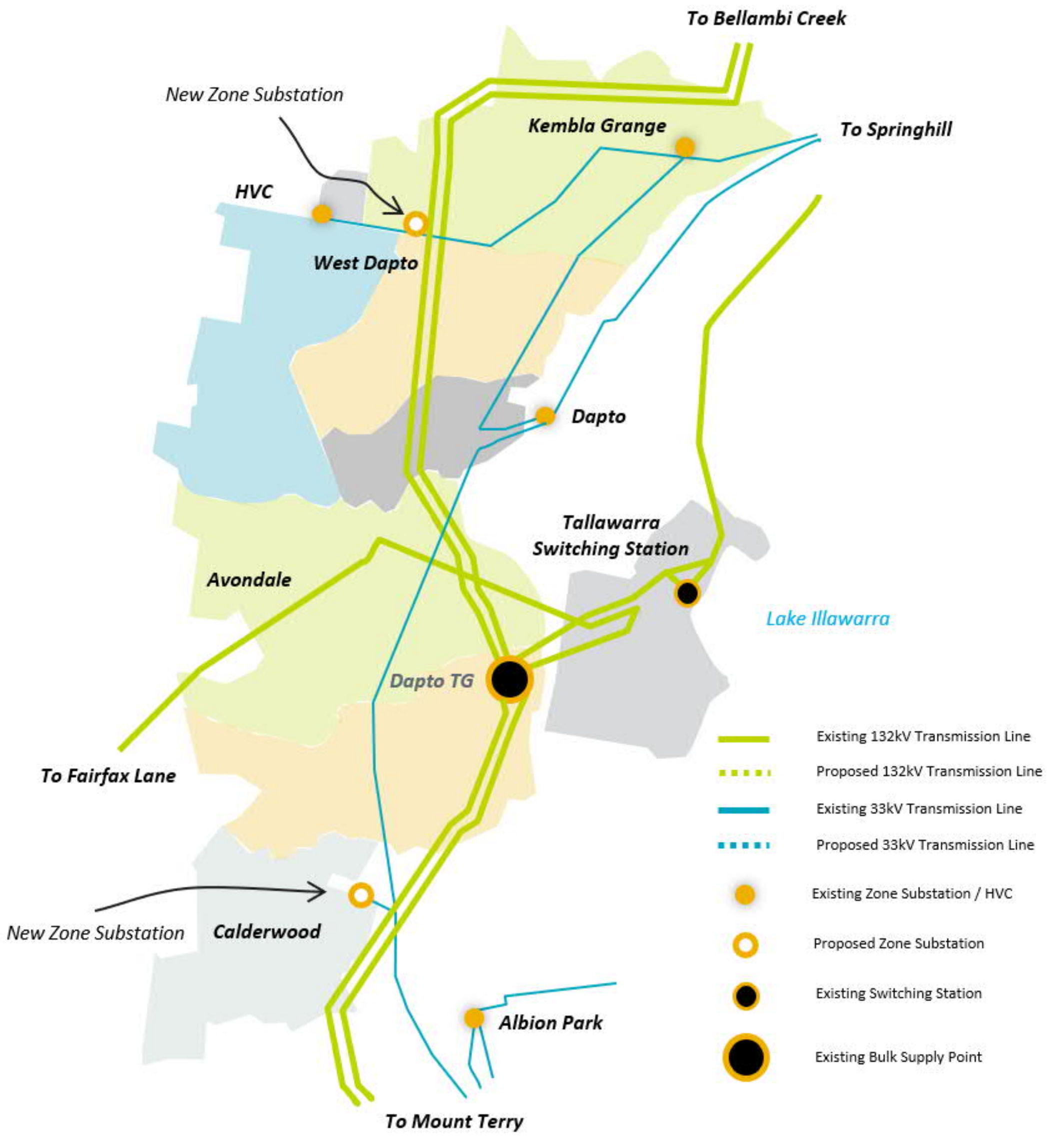
Current developer activity within the Calderwood precinct is driven by a single large developer whereas the larger West Dapto precinct comprises fragmented land ownership with small developments. Initial development activity has commenced in the Avondale precinct, but there is presently no activity in the Tallawarra precinct.

The NSW Government through the Wollongong office co-ordinates the Illawarra Shoalhaven Development Program. It aims to manage continued land and housing supply in the Illawarra and Shoalhaven through implementation of regional strategies.

During a five-year period starting from 1 July 2024 Endeavour Energy plans to invest approximately $15 million on growth projects to ensure continuing connection capacity is available in the West Lake Illawarra Growth Area. Further investment will be required as development matures.

See Attachment 10.19 for the full area plan.

Figure 10-15 West Lake Illawarra Growth Area



10.5.3 Asset replacement

Overview

We invest in the renewal and replacement of assets when the condition of the asset indicates that the continued safe and reliable operation of the existing asset is no longer conditionally, functionally, or economically viable. There are a number of regulatory obligations that drive our investment including public safety, workplace safety and environmental legislation. Our objective is to optimise customer benefit, while aligning risk with our customers' expectations.

Our forecast repex requirements for the 2024-29 period are outlined in the table below.

Table 10-8 Proposed repex for FY25-FY29

$m; Real FY24	2024-29 Repex model	2024-29 Forecast
Modelled repex		
- Poles & Crossarms	$149	$155
- Overhead conductors	$113	$106
- Switchgear	$80	$116
- Distribution Transformers	$16	$13
- Services	$27	$10
- Underground cables	$37	$23
Total modelled repex	**$422**	**$423**
Unmodelled repex	N/A	$152
Total repex	**-**	**$575**

We consider many drivers in developing our proposed repex investment such as:

- deterioration in asset condition, associated with ageing assets, and the associated reliability and safety risk;
- asset failure risk, which may cause supply interruptions, increased risk of collateral asset damage, safety risk to public and field personnel, and environmental damage from asset failure;
- whether assets can be retired;
- technical obsolescence, which increases the cost and risk of retaining assets in service;
- asset damage caused by third parties; and
- cost differences between planned and reactive intervention.

Our approach to forecasting repex is set out below, see Attachment 10.22 and 10.05 for further detail.

Forecasting Approach

Shortly after the last determination process, Endeavour Energy embarked on a significant transformation of asset replacement decision making, which is focused on a data-driven, quantified benefits approach. Our processes and tools have been developed to align with the guidance and expectations of our customers and the AER. Investment in ICT, digital platforms, system overhauls and capability uplifts have allowed Endeavour Energy to develop robust cost-benefit analysis at an asset level that we believe aligns with best industry standards of practice.

Top-down repex modelling provides a network wide overview of the forecasted asset replacement volumes and expenditure, however it is less accurate at the asset class level (e.g., power transformers, poles, circuit breakers etc) and furthermore it is unable to determine the particular assets that need to be considered for intervention. Current top-down modelling also does not allow asset condition and/or risk to be considered and therefore cannot and should not be used independently to determine an optimal repex forecast.

Instead, top-down modelling is suitable for providing a reasonably accurate indication of estimated total future expenditure to maintain current levels of risk / benefit. Our approach therefore makes use of both top down and bottom-up tools.

Top-down modelling results

We have modelled repex using calibrations relied upon by the AER in previous determinations, these are as follows:

1. Historical unit costs and calibrated expected replacement lives (Historical)
2. Comparative unit costs and calibrated expected replacement lives (Cost)
3. Historical unit costs and comparative expected replacement lives (Lives)
4. Comparative unit costs and comparative expected replacement lives (Combined)

where:

- comparative unit costs are the minimum of a distributor's historical unit costs, its forecast unit costs and the median unit costs across the NEM.
- comparative replacement lives are the maximum of a distributor's calibrated expected replacement life and the median expected replacement life across the NEM.

The AER's prevailing approach has been to set the repex model threshold equal to the higher of the 'cost scenario' and the 'lives scenario' to account for the relationship between unit cost and the expected replacement life.

Based on this, we have applied the cost scenario as our repex model threshold which is $422 million (real; 2023-24). As per Table 10-8 above, the modelled component of our repex forecast aligns with this threshold.

We engaged Dr Nuttall to review, validate and interpret our repex modelling findings and to test additional scenarios (such as alternate calibration periods) and datasets. Key findings included:

- **the threshold was sensitive to the calibration period adopted:** Our preference is to use the most recent five-year period to calibrate the repex model. However, our 2017-18 year represents an unusually high year (to correct pre-privatisation capital underspending) of repex. As this year will not ultimately form part of our calibration period at the time of the AER's draft decision and our Revised Proposal we decided to exclude it and adopt a three-year calibration period for this Proposal. Subject to the findings of the AER's draft determination we will assess whether reverting to a five-year calibration period is necessary for our Revised Proposal.
- **correcting data-gaps increases modelled repex:** Our ambition was to reduce the level of 'unmodelled repex' by addressing RIN data gaps. For instance, by introducing data for power transformers which has not previously been reported in the RIN separately. Whilst we did not include these data anomalies and corrections in our cost scenario above it has provided a useful check on components of our unmodelled repex.

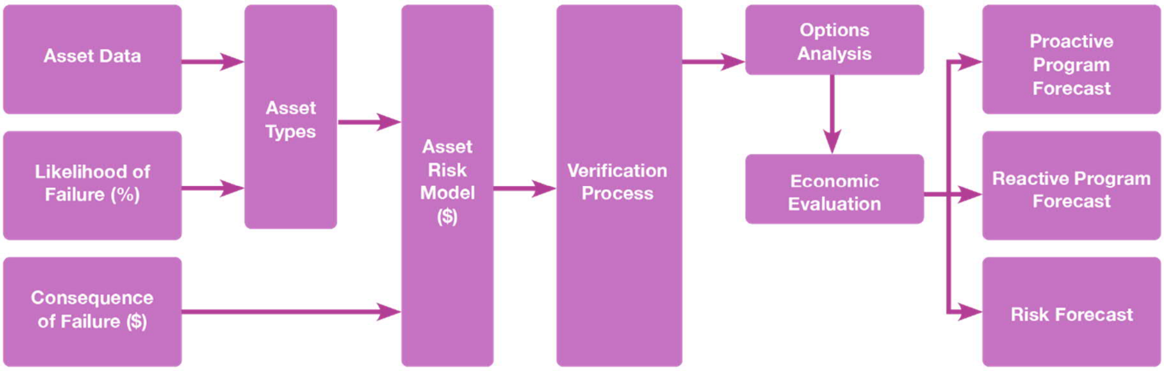
See Attachment 10.23 for further details on our repex model approach and outcomes. We have also discussed our repex modelling approach and results with the AER as part of the Better Resets Handbook and note our approach aligns with AER expectations.

Bottom-up modelling approach

Ultimately an asset will reach end of life (economic or technical) and the aim of Endeavour Energy's replacement strategy is to understand the *Cost of Consequence* (CoC) and *Probability of Failure* (PoF) at the most granular level possible, prior to the event occurring. Our risk model framework, Attachment 10.22 to this Proposal, provides more detail about how we determine CoC and PoF and explains how risk is used to make investment decisions.

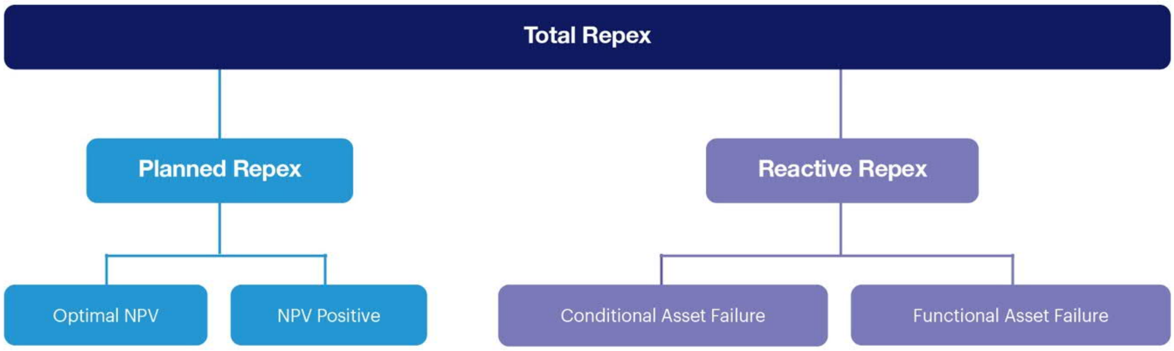
This approach effectively allows Endeavour Energy to determine which assets are more suitable for a proactive intervention program and which are best suited to a reactive asset management strategy. This process is depicted in the figure below.

Figure 10-16 Bottom-up repex forecasting process



The balance between proactive and reactive asset intervention is also a balance best discussed in terms of timing of expenditure, risk and/or customer benefit. Since ultimately an asset will reach end of life, the repex process is looking to achieve the best balance of these three factors at the most granular level possible. The answer must be driven by asset risk, cost of intervention and benefit to the customer. Based on this, repex can broadly be divided into four categories as illustrated in the figure below.

Figure 10-17 Repex decision making hierarchy



The objective of the repex strategy (refer sample Attachments 10.24 and 10.25) is to determine which of these strategies should be applied to each individual asset and which one provides the greatest benefit to our customers.

Our approach starts by dividing the asset base up into groups (asset types) defined by assets with similar *Probabilities of Failures* and *Costs to Intervention*. Each asset is assigned an individual *Cost of Consequence* based on that asset's location, criticality, and redundancy within the network.

The *Cost of Consequence* is calculated per Endeavour Energy's value framework and focuses on key customer risks / benefits including:

- Reliability
- Public Safety
- Financial
- Employee Safety
- Environmental *(incl Bushfire Risk)*

The outcomes of these consequence models are calibrated against current measurable metrics (e.g., number of asset failures) to ensure that the models are generating realistic outputs in line with the current network performance.

A cost-benefit analysis is completed on each asset against one or multiple intervention options to determine the NPV and BCR for replacement of the asset today and every year in the future.

The point at which a particular asset reaches NPV maximum does not alone provide the greatest benefit for customers. For example, a project that has reached its maximum NPV may have a much lower BCR compared with projects that are marginally NPV positive. Additionally, allowing a project to go beyond the optimal point (e.g., deferring the project) may allow a project with higher benefits to be completed.

The true network wide view of optimised customer benefit can only be determined by allowing all NPV positive projects to be considered and optimised based on greatest benefit to customers and real-world limitations (including project lead times, critical milestones, timing of third-party projects).

Assets that fail to have a NPV positive result are therefore not candidates for consideration as a Proactive intervention and are dealt with via a reactive modelling process. The forecast level of repex required for the reactive component of a program is calculated using the same PoF data that is used for the Proactive intervention modelling and is simply summated for each year into the future.

The process provides a repeatable and transparent methodology for determining the Proactive and Reactive repex forecasts into and beyond the following regulatory period as well as a clear link between Proactive and Reactive repex (e.g., an increase in Proactive work results in a decrease in the Reactive forecast).

The introduction of new network options as well as resilience and CER enablement has some overlap with repex. This overlap is considered at both the individual asset level justification for planned repex or at the network-wide level for reactive repex.

The final optimised repex proposal will also be constrained / adjusted through the top down repex model, management challenge and customer engagement.

Customer feedback

Our forecast is unchanged from our Preliminary and Draft Proposals. Noting that we have updated the repex model for FY22 actuals and adjusted our approach to modelled vs unmodelled repex categories following feedback from the AER as part of the Better Resets Handbook engagement.

The feedback we have received from customers suggests they expect Endeavour Energy to provide a safe, reliable, and affordable service as a baseline minimum. Further, our customers and stakeholders are broadly satisfied with the current level of reliability we provide, noting that this is on average, and that there are some customers in less reliable areas of the network who would like to see improving levels of reliability.

This feedback was obtained in the context of cost-of-living pressures and the ongoing realisation of climate change risks on network performance. On meeting these challenges, the feedback diverged slightly between stakeholders and customers:

- Our Customer Panel were supportive of Endeavour Energy increasing expenditure in the short-term to deliver long-term reductions in price and to manage the risk of deteriorating reliability performance.
- Our stakeholders were more concerned with managing cost of living pressures and considered service quality challenges (noting our network is relatively younger than others in the NEM) are better met through innovation and productivity improvements in our asset management practices than increased expenditure.

On balance, we consider targeted and modest uplifts in resilience and innovation spend are warranted. But for repex, we agree with stakeholders that an increase would not maximise the value of our investments within the efficient and prudent allowance set by the AER's repex model.

As such, our initial position constrained repex below the bottom up NPV positive forecast on the expectation that we can achieve the same outcomes at a lower cost whilst better targeting assets with a higher level of risk. Specifically, we will seek to:

- achieve productivity gains through ongoing improvements to workforce planning and delivery efficiencies;
- continue to realise the benefits of our ICT & Digital transformation program. This program has allowed us to refine our risk identification and management processes through improved targeted asset condition information, analytics capability, and process automation; and
- mitigate risk through non-network options following the expansion of the RIT-D to repex and the expected increase in embedded generation and storage devices in coming years.

Based on this, we consider our repex forecast represents an efficient estimate of our replacement needs and cost over the 2024-29 period. Our repex forecast is consistent with the repex model outcomes and below pure bottom-up modelling forecasts.

Key projects and details

We provide more detail on our approach to repex in the following attachments:

- **Investment Decision Making** (Attachment 10.04): Whilst this relates to an entire capex proposal it is particularly useful for understanding how our repex plans and their associated estimates are developed, prioritised and forecasted along with the fundamental principles underpinning this process.
- **Risk Model Framework** (Attachment 10.22): This provides an overview of how we define and measure common asset management concepts such as asset health, PoF, LoC and CoC and how this informs our investment evaluation, sensitivity analysis, options assessment, and investment selection.
- **Asset Class Strategies** (Attachments 10.24 – 10.25): for each major asset category (e.g., Overhead Conductors) we use all current knowledge of the asset, legislative requirements, customer expectations and trade-off analysis to establish a series of KPIs to monitor the ongoing performance of the asset. This provides line of sight from the Network Business Strategy to the system performance targets and objectives.
- **Asset Class Plans** (Attachments 10.26 – 10.31): These plans define a strategic plan for the asset class based on its risk and cost and asset class KPIs. These plans assess three primary asset management strategies; Risk based replacement, condition-based replacement and functional asset failures (i.e., reactive) and play a key role in ensuring:
  - A continuous feedback loop is established between the performance of the individual assets and the performance of the more macro level Asset Class
  - Monitoring of the performance of the asset class against KPI to identify changes in the performance or risk (positive or negative) as early as possible
  - Communicating the historic, current, and proposed balance of risk and cost (as shown via the number of asset replacements caused by functional failures, condition-based replacements, and risk-based replacements).
- **Repex CFIs** (Attachments 10.32): For each individual asset group within a class, for example overhead Air Break Switches (ABSs) (within overhead switches), we develop CFIs which identify the risks and investment needs, set out PoF and CoC, assess options and scenario test in order to assess and recommend proactive and reactive repex strategies.

Key 'modelled' repex investments include:

- **High voltage distribution switchgear replacement** $38 million planned program across five years to address an increasing customer reliability, collateral damage, and public safety risk across parts of the network. This asset class is experiencing a continued increase in assets functionally failing whilst still in service and is forecast to continue to do so over the coming regulatory period. The replacement of assets that functionally fail have an increased cost of replacement (due to collateral damage to neighbouring assets) whilst additionally incurring both public safety and reliability risk to customers. The increase in planned / risk-based interventions are expected to reduce the reactive failures and expenditure into the future.

- **Pole replacements** $99 million reactive program over five years to reinforce or replace poles that no longer have an acceptable safety factor and are at increased risk of functionally failing whilst in service. This asset class has been tested for planned / risk-based intervention program, however it was deemed to be in the customers interest that a purely reactive program was of greatest value. Proposed expenditure in this asset class plan is in alignment with historical spend and the REPEX model outputs.

- **Pole Top Assemblies** $16 million planned risked based and $41 million reactive program for the management of the Pole Top Assembly (insulators and crossarms) asset class. Low Voltage and Sub-Transmission (33kV and above) pole top assemblies are proposed to be managed in a purely reactive manner (e.g., replaced on conditional and/or functional failure) due to their lower probability of failure (as seen by historical failure rates) and cost of consequence (due to the typical N-1 level of security in the sub transmission network). High Voltage (11 and 22kV) Pole Top assemblies are being targeted in both a reactive and planned / risk-based manner due to their five (5) times higher functional failure rate and higher impact on customer reliability and public safety.

- **Major substation circuit breaker and switchboard replacements** $37 million targeting predominately oil filled circuit breakers within zone substations to manage the reliability, asset damage, obsolescence and safety risk posed by these units. Due to the high potential consequence of failure (predominantly driven by reliability and reactive replacement risk) associated with this asset class a planned / risk-based program delivers an improved customer outcome compared to a reactive program.

Key ‘unmodelled’ repex investments include:

- **Power Transformer replacements** $20 million planned and reactive replacement program for the management of risk associated Power Transformers. The introduction of a risk-based program based an individual units probability of failure (calculated as per international standards using the assets condition data) and a consequence calculation that considers the level of redundancy and condition of parallel transformers has allowed a risk based targeted program to be developed.

- **Oil Cable Replacement** $36 million to replace, prior to end of life, sections of oil filled cables that support the Parramatta CBD. These cables are approaching end of technical life and the replacement is justified from both a REPEX and AUGEX (increased load requirements in the Parramatta area) perspective. Due to the configuration (location and technology type) of the cables a staged asset replacement of these feeders is not possible, current development in the Parramatta area also provides an opportunity for reduced delivery costs whilst other utilities have projects in the area. The removal of these cables will significantly reduce the risk associated with this asset type that has limited spares and/or capability to repair across the country.

- **SCADA RTU replacements** $5.1 million risk-based program proactively targeting the risks associated with ageing population as well as functional failure of substation SCADA systems, namely the Remote Terminal Units (RTU) and associated equipment. The failure of the substation RTU may lead to safety, reliability, financial, or bushfire consequences. As the correct operation of SCADA systems underpins many critical and emergency functions at substations, a reactive replacement strategy for SCADA is considered to pose a greater risk and hence not acceptable. In the risk-based program, consequences of these risks are quantified and coupled with statistical modelling to determine the risk associated with the fleet of in-service substation RTU. This program has been optimised to smooth the annual rate of replacement by minimising the peaks and troughs in each year of delivery over the coming period.

- **Reliability improvements for worst performing feeders:** $16 million to ensure compliance with reliability performance targets set out in jurisdictional licence conditions, which in themselves are to improve service standards for our worst served customers. We note that this spend is solely for maintenance of our reliability performance and compliance with our licence obligations. Any STPIS improvements will be assessed on a case-by-case basis and funded via the STPIS. Given the target for the licence condition is poor performing feeders and given that in the majority of cases these areas supply a very small number of customers, it is unlikely that the outcome of addressing these poor performing areas will have any appreciable impact on SAIDI/SAIFI, and thus no appreciable impact on the STPIS performance calculation.

10.5.4 Resilience

Overview

Resilience has been an emerging theme in the NEM with the increasing frequency and severity of natural disasters. Resilience refers to the ability to anticipate, withstand, quickly recover, and learn from major disruptive events.

A reliable electricity network is not necessarily a resilient one. This means our BAU repex may improve reliability but not resilience. This can be observed through the widening gap between our unnormalised and weather normalised reliability performance.

We have always sought to manage resilience within our repex activities. However, the increasing risk profile means that we have decided to propose a targeted increase to our repex proposal for incremental resilience capex. Our forecast resilience requirements for the 2024-29 period are outlined in the table below.

Table 10-9 Proposed resilience capex for the FY25-29 period

$m; Real FY24	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Resilience	5.6	5.6	5.6	5.6	5.6	**28.0**

We note that building resilience can involve a mix of proactive and responsive actions from all levels of Government, other utility providers, communities, and individuals. From a network perspective, we approach resilience in various ways:

- **Network Hardening** – strengthen our network to better withstand climate impacts through network and non-network solutions responding to the rate of change of climate
- **Network Augmentation** – we are exploring different ways to deliver energy solutions to customer through microgrids and non-traditional planning methods
- **Partnerships** – we have been developing partnerships with councils, DNSPs, and other utilities to explore different approaches to investments
- **Community Resilience** – help and support our customers in the lead up to, during and post a disruption to a major loss of supply event
- **Emergency Response** (immediately prior, during and post event) – our strategy will still incorporate a responsive, pre/post-event component of emergency response

Our approach to forecasting resilience is set out below, see Attachment 10.36 for further detail.

Forecasting Approach

As noted above, resilience and reliability are not discrete concepts but are related, interdependent and overlapping. This means we have always invested in 'resilience' as part of our BAU repex, augex and opex through a mix of proactive (e.g., network hardening) and responsive (e.g., outage response and insurance) measures.

However, our value framework and/or input assumptions may not have been adequately capturing or valuing the risks or impacts of climate change, and in particular how these risks increase with time.

On the latter, we note that the AER has previously considered introducing a value similar to the VCR for Widespread and Long Duration Outages (WALDO). However, this is a complex exercise that the AER was unable to reach a preferred position on.

While we have not developed our own WALDO, we did engage Deloitte to provide a more accurate assessment of the risks of climate change at a localised level.

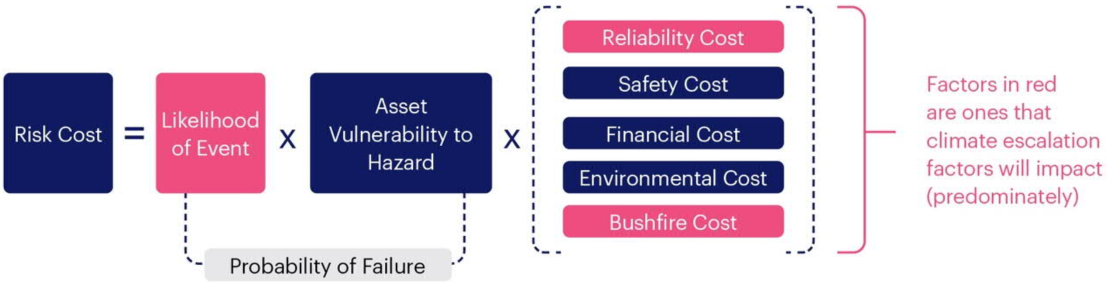
To understand possible future impacts, climate modelling was conducted using multiple climate models under moderate and high emissions scenarios[58]. This was done out to 2090 in order to overcome natural variability over time and to understand the possible hazards our assets will be exposed to over their lifetime. Noting this does not mean that investments will be made now to address all risks over that lifespan.

The results of this exercise can be found in Attachment 10.37 and are summarised below (changes from 2022 to 2090):

- **Bushfire risk:** number of average bushfire weather days to increase between 63% to 155%.
- **Extreme heat risk:** number of extreme heat days increases anywhere in the network between 122% to 629%.
- **Large scale flood risk:** wettest day rainfall to increase anywhere in the network between -9% to 39%
- **Wind impacts:** high wind frequency is set to decrease from 38-44 days per year, to 18-29 days. However, high wind intensity is set to increase by -3.0 to 8.5km/h.

Our forecasting inputs have been adjusted to incorporate these modelling results within our value framework as depicted below.

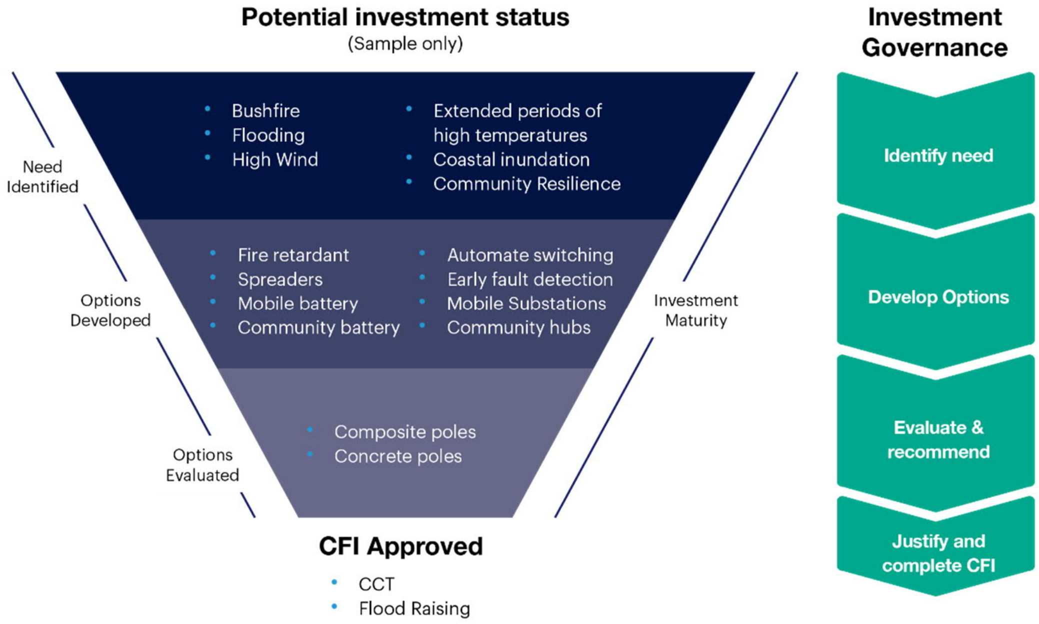
Figure 10-18 Climate change influence on asset risk calculations



From this, we can then develop and value investments to address and manage climate change risks in accordance with the process set out in the above repex section (10.5.3) and depicted below.

[58] A low emissions scenario (aligned to global warming of 1°C was not modelled, as the advice was this scenario is no longer achievable.

Figure 10-19 Approach to developing proposed resilience capex for FY25-29



Customer Feedback

Our customers have acutely felt the impacts of climate change in recent years:

- **the 2019/20 bushfires:** 45% of our network area was burnt with 840 homes and business destroyed or damaged; and
- **the floods of 2021 and 2022:** 600 homes and 300 businesses destroyed or damaged in our franchise area over a number of previously rare flood events.

Generally, customers were satisfied with our response to these disasters

> *Endeavour Energy had the worst fires in NSW history thrown at its supply chain and still managed to keep a town … alive, accessible and powered.*

However, unsurprisingly, customers and stakeholders alike were mindful of the growing risk of climate change and therefore both clearly in favour of Endeavour Energy taking a more proactive approach to resilience, particularly for its most vulnerable and/or worst served customers.

Action on resilience was seen as a top priority by our Customer Panel, both with and without cost constraints. There was a strong desire for us to improve our resilience, noting this may not necessarily avoid or reduce outages.

> *If major weather events are going to continue, the flow on effects from taking reactive measures rather than proactive measures will have a greater effect on the community than an increased power bill.*

> *Proactive approach should be taken. I believe doing this will save lives and property well beyond what is required by Endeavour Energy. If a bushfire is started because of sparks from old wires this has proven to be fatal in the past. Not undertaking this maintenance is life changing.*

Our stakeholders were however mindful of the role recent experience with floods and bushfires may have had on the views of customers. As well as stressing the importance of considering resilience more broadly than network hardening and in the context of increasing cost of living pressures.

As noted above, resilience is the responsibility of multiple parties. Our RRG in particular considered resilience to include both community and network actions and trade-offs between proactive and responsive measures. So, in addition to testing preferences around proactive and responsive measures we also tested with our Customer Panel which party should be responsible for the range of available actions.

Figure 10-20 Customer feedback regarding expectations for provision of community and network resilience by various parties

Actions	Responsibility (%)					
	Endeavour Energy	NSW Gov.	Local Council	Individual Customer	Federal Gov.	Local community group
Automation for storm response	**83**	10	3	2	1	0
Swap bare conductors for bushfire risk	**78**	10	5	2	5	0
Update protection for bushfire risk	**76**	13	5	2	5	0
Concrete poles in bushfire areas	**71**	10	6	0	13	0
Non-network technology for response	**66**	14	12	2	6	0
Lift conductors for flooding	**65**	17	6	1	10	0
Learn from events	**58**	**21**	8	3	7	2
Infrastructure replacement for urban heat	**56**	19	3	2	**20**	0
Back-up supply for critical facilities (phone towers)	**47**	**28**	12	2	10	1
Emergency workforce	**47**	**31**	8	1	9	3
Increase insurance	**35**	**28**	3	16	17	0
Home batteries to support individual customers	19	**20**	**20**	**27**	12	3
Coordinated information	19	**23**	**35**	7	9	7
Emergency response education	13	**29**	**23**	14	14	7
Community hubs for emergencies	8	12	**60**	1	2	16
Sharing generators	3	10	**69**	6	0	12

In response to the feedback from customers and stakeholders we are proposing to:

- Increase capex by $28 million for targeted investments in network hardening to address the most significant climate change risks in the short-term.
- Investigate initiatives to improve community resilience as part of our proposed Innovation Fund (of $25 million) detailed in the next section.
- Constrain our opex step changes by:
  - Managing the likely increasing trend in emergency response opex within the AER's trend factors; and
  - Constraining our insurance step change below the expert range estimate in recognition of improved insurance management practices and, to a lesser extent, our investment in network resilience.

As evident in Figure 10-20 above, we have considered a number of investment options for addressing the risks of climate change. Similar to other categories of capex we have constrained our resilience proposal below the NPV positive bottom-up estimate. In this case, we have identified $55.3 million (real; 2023-24) of justifiable incremental resilience projects. This has been constrained to a proposal of $28 million (real; 2023-24) as part of our commitment to a value for money proposal and pursuing productivity improvements.

Key projects and details

We provide more detail on our approach to incremental resilience capex and proposal in the following attachments:

- **Climate risk methodology** (Attachment 10.34): this methodology sets out the framework in which we assess the current and potential future impact climate events can have on our network and customers. An effective climate risk methodology will enable us to develop and implement investment opportunities in support of customers. Independent climate modelling by Deloitte (Attachment 10.37) supports this consideration.
- **Customer engagement methodology** (Attachment 10.35): this sets out our approach to customer and stakeholder engagement with the aim to ensure their views are reflected in our resilience strategy and plans.
- **Resilience Investments** (Attachments 10.36 and 10.38): this sets out the resilience risks and consequences, investment options assessment and our recommended investments for the 2024-29 period.

A summary of key projects by climate risk is provided below.

Bushfire risk

High Bushfire Danger days represent weather conditions which are conducive to conditions to sustain/support fires if they occur. With the moderate increase in bushfire danger days, bushfires started from external sources are more likely, resulting in more frequent impact to the network.

We have assessed the cost of proactively assessing segment-by-segment bare conductors and replacing them with covered conductor. Targeted conducted strengthening is cost justified in higher risk areas, specifically 212km of our network which constitutes $38.1 million (real; 2023-24) of potential investment.

This would be a step up in addition to our existing covered conductor replacement program from approx. 24km p.a. over the last decade to 46km p.a. over the 2024-29 period.

We have also assessed improving resilience to bushfires through the proactive replacement of timber poles in bushfire prone areas with non-combustible poles (concrete or composite). We currently have 113,000 poles in bushfire risk areas; however, our analysis indicates that proactive replacement is only cost justified for 100 poles which equates to potential investment of $1.3 million (real; 2023-24).

Flood risk

Endeavour Energy has been impacted by multiple large scale flooding events, with 2022 being the wettest year on record. Four significant flood events have occurred in the past 15 months (March 2021; March 2022; April 2022; July 2022).

Electricity supply must be isolated due to rising water impacting overhead conductors, interrupting thousands of customers, including customers whose properties are not flooded. By raising low sections of conductor, supply can be maintained for longer periods or indefinitely for people in flood affected areas. We have identified 18 Feeders (HV and Sub-transmission) which were significantly impacted by flooding which cover several areas across our network.

In addition to raising conductors, we have considered the replacement of individual poles, feeder sections, re-tensioning lines, replacement of conductors over river crossings and installation of automated switches to manage this risk. Across these options, we have identified up to $7.2 million (real; 2023-24) of investment to improve our resilience to flooding risk. Noting the overall constraint applied to our resilience proposal we have commenced work on these options within the 2019-24 period allowance.

Extreme Heat risk

A large number of hot days, especially consecutive hot days, means our network is at risk of not being able to ensure consistent supply to our customers. This is due to overloading of single feeders, but also a reduced ability to transfer load to adjacent feeders (due to them also being simultaneously overloaded in widespread extreme conditions).

This would result in potentially large-scale outages, load shedding or long duration outages at times when customers are vulnerable to the health impacts of prolonged heatwaves.

We have considered gradual adjustments to investment in the 2024-29 period to address the risk of feeders getting overloaded causing tripping. There are a number of solutions such as re-configuring feeders to shift load, implementing load reduction initiatives (such as battery support), and augmenting the network to replace circuit breakers, conductors, transformers, and fuses.

We note the latter option is typically cost prohibitive and we are keen to prioritise non-network alternatives through the use of the Innovation Fund, DMIA and/or DMIS to address this risk over the 2024-29 period.

Wind risk

High wind intensity and frequency will lead to increased outages due to the increased possibility of conductors clashing or vegetation being blown into the mains.

Similar to bushfire risk, bare conductors have a higher probably of being impacted by vegetation and clashing under extreme winds where tension has not been maintained. Recently, we have installed 1500 LV spreaders, which even under impact of an external object, help to separate phases and reduce the probably of a phase-to-phase fault. We are now exploring the roll out of HV spreaders within our network.

We will also re-assess our covered conductor program to determine additional cost-justified locations and consider this initiative as a supplement to the specified investment.

Endeavour Energy has received expert advice to administer caution when it comes to current climate modelling as it applies to wind at a localised level. To ensure prudent and unbiased investments, Endeavour Energy will wait until the modelling has become more mature before it proposes any large-scale interventions to improve resilience to high wind events.

Community resilience and innovation

We understand the vital role we play in supporting and servicing our customers. Part of this is seeing what we can do to best serve our customers, and in terms of resilience this means:

- Provide readily accessed information regarding outages
- Keep customers informed to our plans
- Consult with customers
- Providing a service level they expect

Our community resilience approach encompasses:

- Continue our support and partnership with local councils to help deliver best outcomes during a local emergency.
- Exploring new investments with councils and other utilities to best support the community during an event
- Aiding / partnering with councils to ensure future climate hazards are incorporated in their plans

These actions will involve collaborating on local emergency management plans, reviewing communication protocols and resources, developing education programs, and developing local resilience hubs.

The latter is a new concept that involves partnering with local councils to identify sites where people gather in the event of an emergency. For these sites, we could partner with councils to ensure a consistent electricity supply is available during an emergency. This will likely involve the deployment of local generation and/or batteries.

We have identified up to 200 potential sites with an initial plan focusing on 34 sites (1 per urban LGA, 2 per non-urban LGA). We estimate this initiative could cost between $3.4 million to $13.6 million over the 2024-29 period. As aforementioned, we will explore funding this initiative through our Innovation Fund before scaling it through our capex allowance more broadly in the next or future periods.

10.5.5 CER Enablement

Overview

The transformation of the energy sector is accelerating. Our customers and our network are at the very centre of the change. Whether it be the huge popularity of rooftop solar, the increasing ubiquity of behind the meter and community energy storage, the rise of EVs and the rising ambitions of our community to achieve net-zero - there is a once in a lifetime transformation underway.

It is therefore important that we invest in ensuring customers' have the ability to make energy choices and share in the costs and benefits of doing so in a fair and equitable manner. If we fail to respond to changing customer behaviour the take-up of new technologies could be constrained and/or adversely impact the reliability and stability of the network.

CER management and enablement is therefore a relatively new category of expenditure that is primarily driven by enabling customers' future energy choices. Our forecast CER enablement capex for the 2024-29 period is set out in the table below.

Table 10-10 Proposed CER capex for the FY25-29 period

$m; Real FY24	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Distribution Substation LV Monitoring	2.3	2.3	2.3	2.3	2.3	**11.7**
LV Planning	6.7	6.7	6.7	6.7	6.7	**33.3**
Total	**9.0**	**9.0**	**9.0**	**9.0**	**9.0**	**45.0**

Our proposed program focus on four key areas of focus and investment:

- Enabling systems
- Tariff reform and demand flexibility
- Network capability and operational optimisation
- DSO operations

Collectively our proposal will alleviate over 6,000GWh of export curtailment over the 2024-29 period noting that this still represents a decline in the average export service quality customers currently receive. However, consistent with the AER's DER forecast expenditure guideline we only invest in supporting DER/CER export hosting to the extent it is cost-justified based on a Value of DER (VaDER) that uses the AER's Customer Export Curtailment Value (CECV) methodology.

Forecasting approach

To plan for the Future Grid, we need to understand and accept the uncertainty involved in forecasting and plan to adapt as the future unfolds. Our approach has been to adopt and translate the AEMO ISP scenarios as credible external reference points to plan and compare different outcomes.

Our approach to forecasting the take-up and use of CER across our network is described in Chapter 7 and briefly summarised below.

We have taken our forecast for the "step change" AEMO ISP scenario as a central case but will continue to consider other scenarios and pursue adaptive planning as we monitor and evaluate uptake. This was a favoured approach from both our customer groups and the broader stakeholder groups involved in the AEMO's 2022 ISP.

We then assess CER hosting capacity using this forecast. To do so, we have developed a deterministic LV simulation tool in partnership with researchers at the University of Wollongong's Australian Power Quality and Reliability Centre (APQRC). This simulation tool:

- Builds customer load profiles from an available sample of smart meters, solar profiles based on historical irradiance data, and assumed battery and EV charging profiles from AEMO and CSIRO.

- Builds LV models for each of Endeavour Energy's residential LV circuits based on the ADMS LV network electrical model data.
- Adjusts customer profiles based on our CER forecast and forecast scenario.
- Runs average daily as well as full year time series power flows simulations between now and 2040, calculating inverter curtailment energy as well as baseline and forecast power flows and voltage levels.
- Simulates the benefits of operational interventions such as distribution transformer optimisation and Dynamic Voltage Management as well as identify which LV circuits remain constrained after applying operational optimisation and where a network investment intervention is economically justified.

We are using this tool to quantify and value service outcomes (DER curtailment) using the AER's VaDER methodology, of which a key input is the CECV. Despite several concerns with the CECV methodology, we have adopted the AER's CECV without amendment based on feedback from stakeholders.

Under the VaDER framework we have also included the following benefits:

- **Improved Reliability** – quantified using value of customer reliability (VCR) where the integration of CER creates overloads to network assets.
- **Network Long Run Marginal Cost (LRMC)** – quantified using Endeavours approved LV LRMC rate.

We are also exploring other components including:

- **Environmental Benefits** – based on assumed forecasted cost of carbon emissions noting Energy Ministers have agreed to amend the NEO to include an emissions objective.
- **Avoided Generation Investment** – based on reduced need for wholesale generation demand because of increasing DER.

These additional components will strengthen the overall CER integration business case. We will engage further on these matters in preparing our Revised Proposal CER forecast.

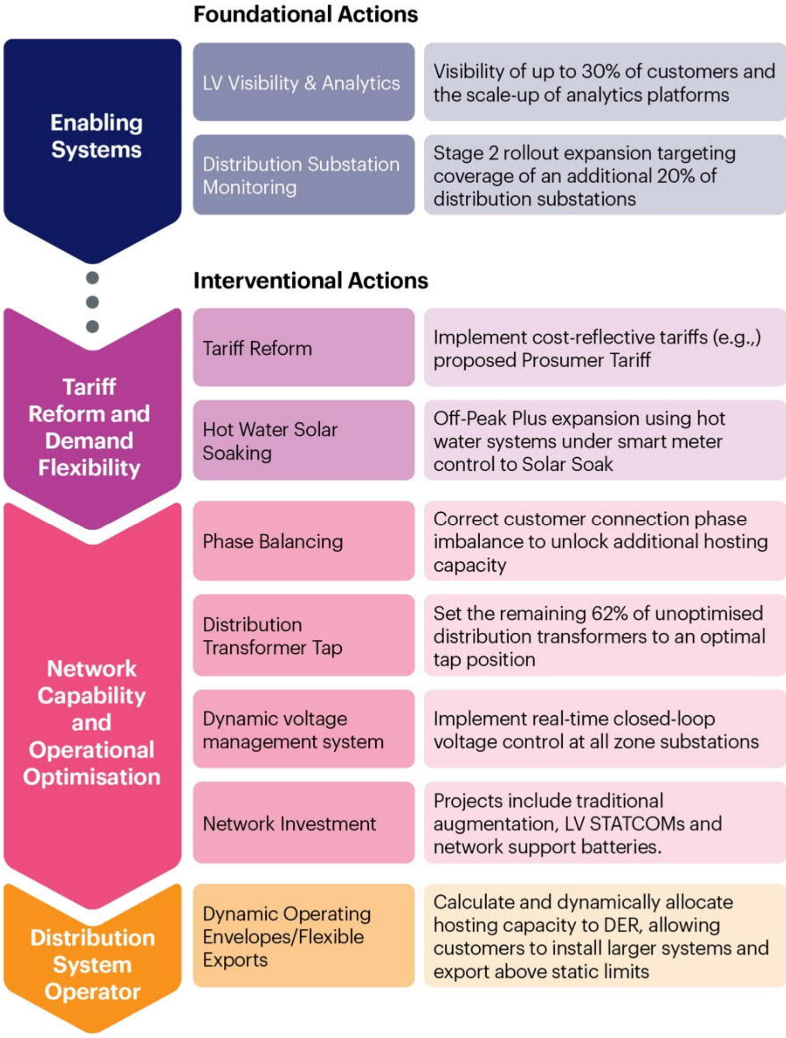
Following the identification and valuation of constrains a base case scenario was developed in the model to serve as a comparison case for all intervention actions listed in the CER Integration plan to be quantified against.

The base case was developed using the following key assumptions:

- Customers install PV and battery systems in accordance with the Step Change ISP forecast (as explained previously) translated to Endeavour Energy's network
- All new PV systems match the current average inverter size
- All new inverters are compliant to AS4777.2020 Power Quality Response Modes (Volt-Watt and Volt VAR).
- No intervention actions are included. i.e., transformers are left on their current tap position and phases remain unbalanced.

Using the base case scenario, the forecasted network curtailment value was then determined for each year of the forecast. We then tested intervention options that build upon each other. The latter means we will only invest in each option after considering the remaining constraints any upstream intervention cannot alleviate.

Figure 10-21 Endeavour Energy CER Integration Planning Approach



Customer feedback

We sought customers' views on what they expected to be able to do with their energy supply in the context of decarbonisation and the decentralisation of the NEM. We also tested their expectations around CER service levels and how the costs of facilitating CER should be shared between customers.

We tested this feedback with stakeholders as well as seeking views on more technical aspects of our CER proposal, particularly with respect to our VaDER assumptions and export tariff settings.

Our Customer Panel were strongly in favour of Endeavour Energy modernising the network in preparation for either a rapid or accelerated energy transition to accommodate future customer expectations as technology and markets evolve.

The majority of our Customer Panel, in principle, considered that anyone who wants to install solar should be able to connect and export to the grid at any time. Similar views were held about EVs accessing the grid.

The results were driven by a desire for customers to be able to manage their electricity bills more actively through increased independence, flexibility, and control. They see the transition as inevitable and consider future personal savings and environmental benefits can be accessed sooner if Endeavour Energy takes a more proactive approach to CER hosting and innovation to support technological change.

Our stakeholders held similar if not more ambitious views, also preferring that Endeavour Energy prepare for a rapid or accelerated energy transition (with a higher proportion of stakeholders aiming for a rapid transition than our Customer Panel).

The Independent Members panel of the RRG:

- expect technical matters will be addressed by the AER but in principle consider the AER's CECV methodology should be used.
- raised broader industry questions as to how environmental impacts should be valued given a clear interest from customers in decarbonisation and the Energy Ministers' priority action to amend the NEO to include an emissions target.
- saw merit in Endeavour Energy developing an Innovation Fund, similar to those employed by other networks, to action the direction from customers.

In response to this feedback, we have proposed CER expenditure of $45 million based on AEMO's 2022 ISP and the AER's final CECV. To support the accelerating uptake of CER across our network we are proposing an Innovation Fund of $25 million (split $20 million and $5 million between capex and opex respectively) to support and integrate technological change as outlined in Chapter 9.

Our CER investments will benefit customers in several ways:

- hosting more CER which will put downward pressure on wholesale prices for all customers and reduce customer carbon footprints.
- making it easier for customers to participate in voluntary demand response programs and/or earn incentives through tariffs.
- improving our visibility of existing and emerging constraints so they can be resolved and so the network can be managed more dynamically to maximise value for customers.
- improving our ability to work with customers, aggregators and VPPs to coordinate and optimise flexible loads.
- improving the ability of non-DER customers to access and benefit from excess solar.
- increased resilience for customers in areas whereby local generation and CER resources can be utilised to reduce the frequency and duration of outages.

Key projects and details

We provide more detail on our CER capex proposal in the following attachments:

- Future Grid Strategy (Attachment 10.39): this strategy:
  - provides a long-term CER penetration forecast developed from credible sources and contextualised to Endeavour Energy's network and customer base.
  - details how tariff reform will be used to accommodate the forecast and reduce network investment.
  - reviews current and past investments into CER integration to track their effectiveness in delivering customer outcomes.
  - develops a portfolio of credible and industry leading options for better integrating CER and equitably managing and sharing network hosting capacity.
  - details our plans to implement Dynamic Operating Envelopes as well as any relevant jurisdictional requirements, directives or priorities as identified by regulators, government, or market operator.
- DER Integration Strategy (Attachment 10.40): this includes our CER forecasts and cost-benefit analysis underpinning our investment plans. It also provides more detail of our approach to forecasting CER constraints through our simulation tool.

Key initiatives across our four focus areas are summarised below.

Enabling systems

LV visibility and analytics (LVVA) is critical to efficiently supporting two-way energy flows from CER and for networks to deliver their DSO functions in line with regulatory reform. It enables improved hosting capacity through operational actions and dynamic LV voltage management, improving the utilisation of existing network assets. LVVA underpins all the intervention actions included in our proposed CER Integration Plan.

We have assessed multiple visibility sources for 2024-29 and consider smart meter power quality data access and distribution transformer monitoring to be the most mature, proven, and consistent sources. We have also assessed the minimum viable level of visibility required to support several CER intervention actions.

Across all these CER targeted use cases for LV Visibility, a common minimum access requirement is 20-25% broad based visibility with increased visibility beyond this targeted to specific areas of the network with high CER utilisation. Without this base visibility, many of these use cases could not be achieved or only achieved through very costly, non-scalable and time-consuming means (such as truck rolls for temporary monitoring).

We will also merge all available visibility sources into a common analytics platform to automate algorithms that optimise operational strategies. To do this we will leverage market leading off-the-shelf analytics platforms rather than develop more costly in-house analytics.

Tariff reform and demand flexibility

As an initial step to increase CER hosting capacity on the network we plan to introduce new tariffs which help manage the constraints we are forecasting. Tariffs offer a widespread non-network opportunity to deliver greater value to customers whilst better managing the energy consumption patterns on the network without significant investments.

A feature of this is our Solar Soak tariff trial which provides a two-way tariff and solar soak period to incentivise export shift to peak windows which are outside of the middle of the day. We have modelled the impact of this tariff on customer behaviour out to 2040 by adjusting baseline customer load profiles.

Similarly, we have trialled utilising flexible demand through our Off Peak Plus pilot project during the current period. This project successfully demonstrates smart meters can be used to deliver flexible and reliable hot water solar soaking through dynamic control. We plan to target further rollouts of this program as an intervention action to improve hosting capacity by shifting hot water heating loads into the solar period. This also avoids investment in new or replacement off-peak ripple control systems at substations.

Network capability and operation optimisation

We can first seek to optimise the operation of network by:

- Using our LV analytics platform to identify opportunities for phase balancing, through operational actions like tap optimisation.
- Implementing more advanced approaches to voltage management, such as implementing dynamic voltage management systems, to adjust target voltage settings at the zone substation level in real time.

Following this, we can improve network capability through traditional network investment. Our 2024-29 CER capex will include investment in distribution transformer tank replacement, LV STATCOMs, LV network amplification and splitting and network support (e.g., batteries).

DSO operations

Our average residential solar system size trend shows a clear linear growth trajectory towards larger systems. This has already exceeded on average our standard 5kW static limit. Our customers intend to continue to install larger solar systems and therefore our static limits will (and already are) becoming a constraint to this.

Given the compliance to static limits is poor there is additional impetus to implement Dynamic Operating Envelopes (DOEs) which would improve compliance and equity of export access (reduce the number of customer’s taking more than their “fair share”).

We are currently developing a detailed DOE implementation plan and trial project with the aim to have a flexible exports offer by FY25. As such we plan to implement a CER Management System (DERMS), customer connection portals and associated installer processes that:

- Enrols a new CER customer to a Dynamic Exports connections offer
- Uses LVVA to calculate DOEs informed by local distribution network level constraints. This includes utilising the DOE mechanism for passing through AEMOs minimum demand curtailment directives (as applicable)
- Communicates these constraints to applicable CER via standardised protocols

Our DOE pilot over the remainder of the 2019-24 period will also inform how we allocate DOEs noting there are two boundary options available:

- Equal/Equitable Dispatch: allow all customers the same incremental kW export opportunity
- Optimal/Maximum Dispatch: allow the maximum total kW export.

10.5.6 Overheads

In support of our network operations and investment activities we incur support costs that are allocated across our operating and capital plans. Our proposed capitalised overheads are set out in the table below.

Table 10-11 Proposed capitalised overheads for the FY25-FY29 period

$m; Real FY24	2019-24 Allowance[59]	2019-24 Actual/Forecast	2024-29 Forecast
Network Overheads	290.5	316.7	296.9
Corporate Overheads	152.1	165.9	155.5
Total	**442.6**	**482.6**	**452.4**

CAM and capitalisation approach

We have ensured that the total forecast capex in our building block proposal only relates to standard control services that are properly allocated in accordance with the CAM approved by the AER on 8 March 2018. The CAM can be found at Attachment 0.06.

Our capitalised overheads comprise of both direct overheads and indirect overheads. Direct overheads represent the costs of functions which exist only to support the capital program, such as our Project Management Office, Program Directors and Project Managers of which 100% of these costs are capitalised. Indirect overheads represent the cost of other functions throughout the business which indirectly support both operating and capital programs, and therefore the portion of indirect overheads related to the capital program must be calculated.

To ensure we comply with AASB 116, in relation to indirect overheads, Company Policy 6.9 Capital Expenditure Overhead Calculation (Attachment 10.13) provides a methodology for the capitalisation of indirect overhead expenditure. This Policy states that an overhead pool is determined based on an analysis of activities undertaken, and the nature of costs incurred, at a granular organisational unit (responsibility centre) level.

A capitalisation rate is then calculated by reference to the proportion of direct capital labour to total direct labour for each organisational unit. The capitalisation rate is then applied to the overhead pool to determine the amount of eligible indirect overhead expenditure to be capitalised.

Efficiency of our overheads

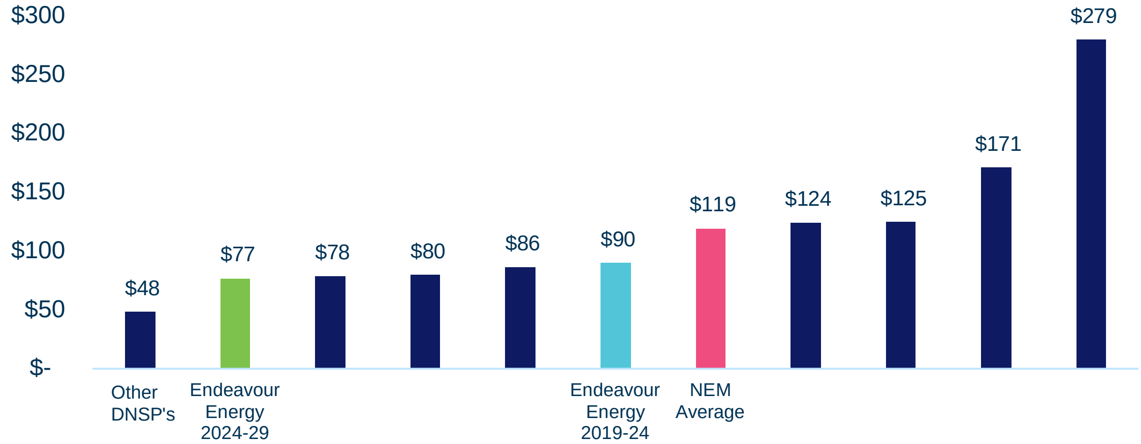
As overheads relate to a number of activities, it is difficult to assess or determine what the efficient level of overheads are for a business. However, we have constrained our capitalised overheads forecast for $452 million (real; 2023-24) below our internal forecast of $489.0 million.

[59] The capitalised overheads allowance was provided at the total level. Category level figures have been developed in line with the 2019-24 actual category splits.

This is also below the substitute estimate derived by the AER's standardised capex model. This model calculates capitalised overheads based on an assumed relationship between direct costs and overheads. For the 2024-29 period the model estimates capitalised overheads of $522.1 million for Endeavour Energy. We have therefore substituted this derivation with our internal, constrained forecast and consider this provides prima facie evidence of the efficiency of our capitalised overheads.

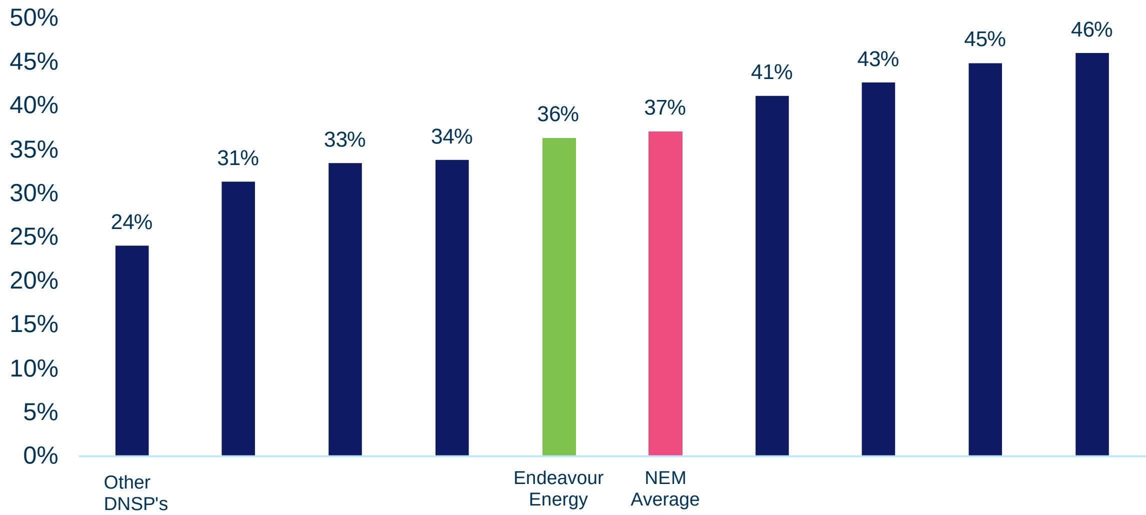
We also conducted benchmarking analysis using recent RIN data to support our overheads efficiency and forecast. Over the 2019-24 period, our capitalised overheads per customer compares favourably against other comparable DNSPs[60]. Through our continued efforts to reduce these costs we expect this metric will improve materially over the 2024-29 period.

Figure 10-22 Capitalised overheads per customer – Average FY16-21 ($; real 23-24)



We also reviewed our capitalisation rate to understand whether our policies were in line with industry benchmarks. As evident in Figure 10-23 below, our capitalisation rate is slightly better than the DNSP average. This suggests our methodology for attributing overhead costs to our RAB is reasonable and our performance compares well against our peers.

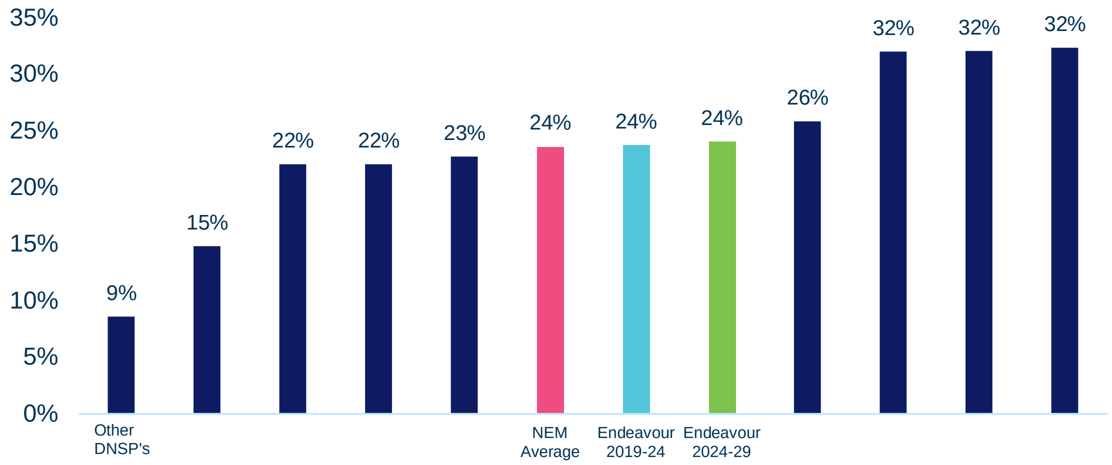
Figure 10-23 DNSP capitalisation rates - Average FY16-FY21[61]



Our forecast capex seeks to maintain this level of capitalisation. Because of this, capitalised overheads will make up a slightly higher proportion of our total capex for the 2024-29 period compared to 2019-24 period and other DNSPs. This is a result of our total overheads remaining largely fixed despite decreases in direct totex.

[60] Source: AER Category Analysis RINs. Analysis of capitalised overheads excludes DNSPs reporting no or negative capitalised corporate overheads over the analysis period FY16-21. These DNSPs are Powercor, CitiPower, United Energy and SA Power Networks.
[61] Source: Category Analysis RIN Data, which was not available or comparable for SA Power Networks, Powercor, CitiPower and United Energy.

Figure 10-24 Capitalisation overheads as a percentage of capex comparison - Average FY16-FY21

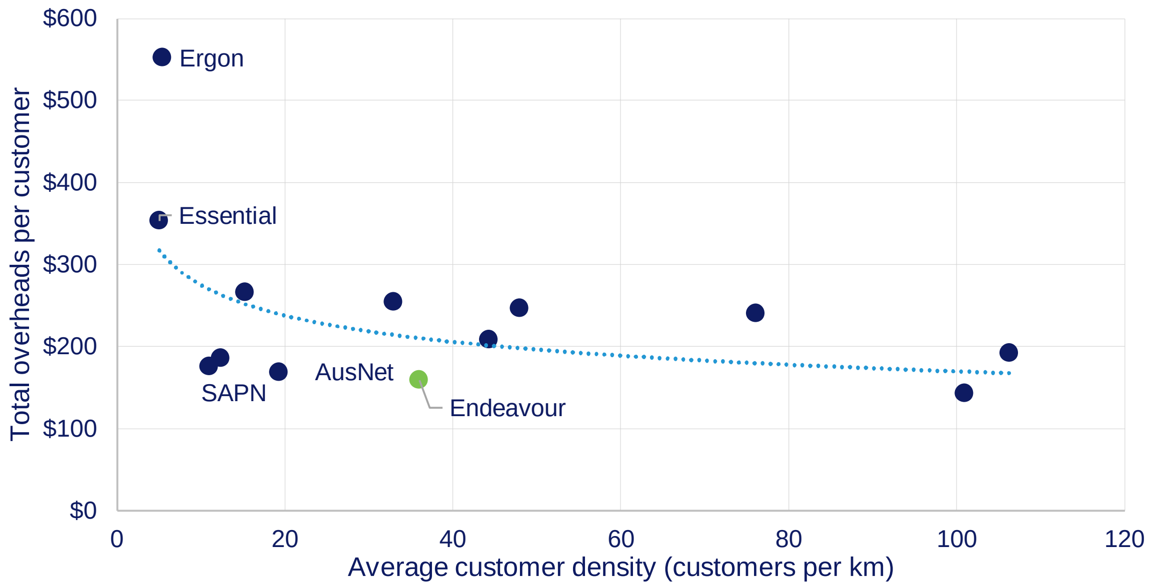


We note there have been several DNSPs who have changed their approach to capitalising overheads over the analysis period. These changes have caused capitalisation practices to differ materially between DNSPs and has reduced the comparability of capitalised overhead data and performance. To assess a DNSPs overhead performance, a more holistic consideration of overhead costs is required.

The AER typically provides this through its partial performance indicators that it publishes as part of the annual distribution network benchmarking report. Specifically, the overheads PPI includes network and corporate overheads allocated to both capex and opex to ensure that differences in DNSPs' capitalisation policies do not affect the analysis. Importantly, the AER examines total overheads with customer numbers because it is likely to influence a DNSPs overhead costs. By doing this, any differences in capitalisation policy between DNSPs, i.e., whether to expense or capitalise overheads, does not impact the comparison.

Figure 10-25 demonstrates that we are amongst best performing networks when expensed and capitalised overheads are considered collectively. We consider this further supports the efficiency of our overheads performance and our forecast of the amount to be capitalised over 2024-29.

Figure 10-25 Total overheads per customer - Average 2017-21 ($; real 2021)[62]



We consider this further supports the efficiency of our overheads and the amount capitalised.

[62] Source: AER, 2022 DNSP Annual Benchmarking Report.

10.5.7 Non-system capital expenditure

The non-system capital expenditure category includes expenditure which supports the operation of the regulated network system (not directly related to the construction or replacement of system assets). This expenditure is required to safely and reliably service our asset base and deliver the outcomes defined in our network strategy.

Our non-system capex includes buildings and property, vehicles, furniture and fittings, plant and equipment (other) and information and communications technology (ICT) and is shown in Table 10-12.

Table 10-12 Proposed non-system capital expenditure for FY25-FY29

$m; Real FY24	2019-24 Allowance	2019-24 Actual/Forecast	2024-29 Forecast
ICT	100.9	325.7	129.0
Motor Vehicles	24.5	46.7	29.1
Capitalised Leases[63]	n/a	n/a	18.1
Buildings and Property	42.2	84.8	33.2
Other Non-System	20.7	15.6	21.3
Total Non-System Capex	**188.2**	**472.9**	**230.7**

ICT

Overview

ICT provides critical business support to meet our obligations as a DNSP in line with our strategic direction. More specifically, ICT provides the technology tools and data to enable the business to efficiently manage our current network safely and reliably, supports the effective planning of the network, fulfils our corporate and regulatory obligations, and with the prudent adoption of technology it enables the delivery of better services to customers at a lower cost over time.

Our ICT strategy aligns with our overall vision, strategic goals and priority themes. Each of the priority themes are reliant on investment in information technology to deliver the information, infrastructure, and capability for the broad range of customers for Endeavour, and the ecosystems of employees, contractors and suppliers required to deliver the services that customers expect.

The capital expenditure investments in our 2024-29 Proposal are therefore according to the following themes:

- Meet changing customer expectations for a safe, affordable and reliable electricity supply by simplifying capabilities and building on current foundations to unlock value.
- Enable and facilitate customers' future energy choices and known preferences through the provision of smart, seamless digital service platforms, secure connectivity to behind the meter devices, and support for real-time flow of data.
- Provide a resilient network by supporting delivery of network services through enhanced platforms and services for increased protection against cyber security threats and to comply with regulatory obligations such as the Security of Critical Infrastructure Act; and to enhance data and analytics to make better informed enterprise decisions and information sharing requirements
- Support the sustainable growth of our communities by enabling and supporting the provision and operation of systems and non-network assets in greenfield areas such as Western Sydney

[63] For the 2019-24 period capitalised leases are treated as an expense consistent with how the allowance was set.

International Airport through better data and insights, enhanced operational capabilities and automation.

Our ICT investment for the 2024-29 period is as follows:

Table 10-13 Proposed ICT capex for the FY25-29 period

$m; Real FY24	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Meet customer expectations	5.3	3.5	1.3	0.4	3.3	**13.8**
Enable customer choice and control	7.1	4.4	2.9	1.8	1.8	**18.0**
Provide a resilient network	22.1	14.4	11.6	15.1	8.9	**72.1**
Support sustainable growth	5.6	5.4	3.2	5.5	5.4	**25.1**

As discussed in sections 10.4 and 3.2.3, we embarked on a major ICT & Digital transformation program. After a prolonged period of under-investment our technology platforms were beyond end-of-life, poor performing, expensive to maintain, without ongoing support in some instances and unable to meet our compliance obligations or facilitate the customer service and productivity improvements available with modern technology.

Following the completion of this program in 2019-24 our 2024-29 ICT capex returns to a more sustainable level of investment (an 60% reduction). However, the pace of change in ICT is fast meaning a significant portion of our forecast ICT will remain non-recurrent. We provide a breakdown of our program below:

Table 10-14 Breakdown of ICT capex for the FY25-29 period

$m; Real FY24	Recurrent	Non-recurrent	Total
Customer expectations	6.4	7.4	**13.8**
Customer Future Choice	14.4	3.6	**18.0**
Resilient Network	30.5	41.6	**72.1**
Sustainable Growth	7.5	17.7	**25.2**
TOTAL	58.7	70.3	**129.0**

This categorisation is central to the AER's assessment approach as recurrent is typically reviewed against historical trends and industry benchmarks while non-recurrent is assessed on a cost-benefit basis at a project level.

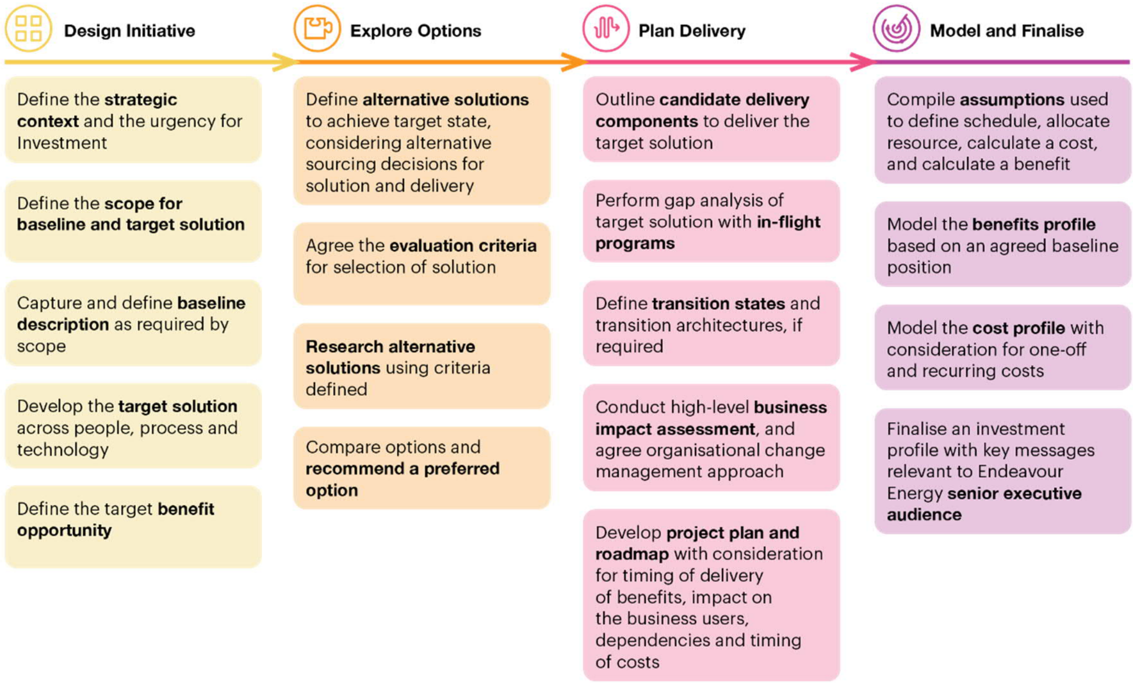
We have conducted quantified cost-benefit analysis for our entire forecast of ICT capex for the 2024-29 period. Also, in accordance with the AER's ICT guideline, our approach to forecasting non-recurrent ICT capex is informed by learnings from our PIR of our most recent non-recurrent ICT program.

Forecasting approach

We apply sound management processes for the planning, delivery and governance of the ICT investment program. Investments in both applications and infrastructure are planned according to industry capital planning practices. Investments are then defined, prioritised and delivered through our IT Program Delivery Lifecycle.

Technology industry opportunities are continually evolving. We therefore commence our forecasting process by assessing future scenarios and organisational goals to determine our investment priorities. Following this, our investment planning process involves four phases as summarised in the figure below.

Figure 10-26 ICT Investment Brief Development Methodology



The ICT investment program will be delivered in accordance with the Program Planning and Delivery Framework and the corporate Investment Management Framework described in section 10.3. Key elements of the framework related to ICT cost/budget management include:

- **Annual planning:** Budgets are allocated to projects as part of an annual planning process, with carry-over commitments considered as part of the evaluation and prioritisation of proposed new investments
- **Portfolio budget governance:** An ICT portfolio governance committee monitors and manages dependencies, assesses the impact of unbudgeted projects/change requests and reprioritises investments to maintain budget control
- **Program/Project Steering Committees:** Steering committees are established to direct the successful delivery of programs and major projects, including tracking budget forecasts, with accountability for timely escalations and justified change requests
- **Project Closure:** Project managers are accountable for cost reconciliation and initiating capitalisation activities

The combination of these activities provides a multi-layered and time-blocked approach to budget management that minimises the risk of unplanned budget exposures.

Customer engagement

As a more technical area of expenditure with clear AER expectations, our engagement on ICT was mostly with the RRG.

Our RRG Independent Members Panel was keen to understand the benefits of our 2019-24 ICT transformation and to ensure that customers received the benefits of this capability uplift. The expectation is that there would be material productivity benefits embedded in both forecast opex and capex.

For the forecast ICT, the RRG expected that we clearly demonstrate compliance with the AER's ICT guidance note and that our non-recurrent ICT was associated with customer focussed KPIs.

On the issue of efficiency, we conducted a PIR of our current period ICT transformation. This PIR and the supporting analysis demonstrate that expected benefits exceed the costs (BCR of 1.52) and are almost entirely achieved by our FY23 base year which is forecast to be 25% below the AER allowance. This has driven our ongoing improvement in our benchmarking performance and our material outperformance of the AER's substitute opex benchmark.

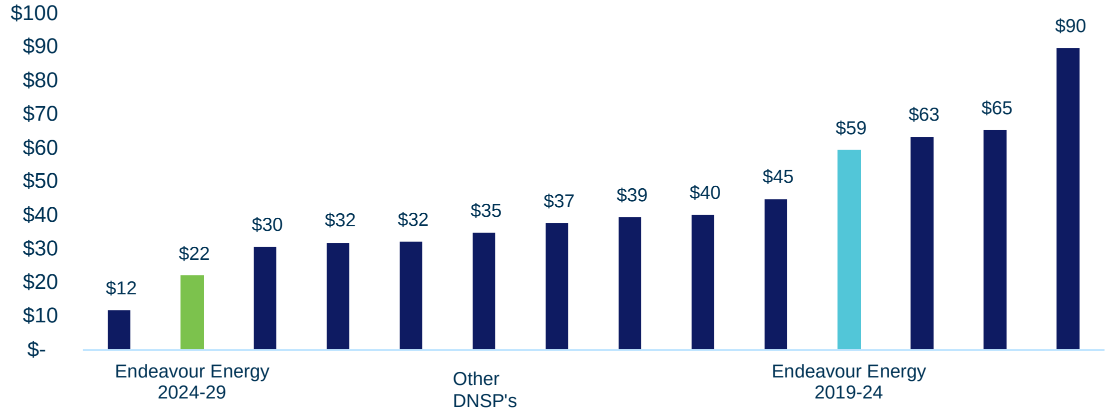
This means that customers will benefit from these ICT related productivities into perpetuity. We therefore remain of the view that the AER's 0.5% productivity benchmark is appropriate. For capex, we have decided to constrain our capitalised overheads and forgo any real escalation of our capex program to ensure a productivity factor is embedded across our expenditure proposal.

In addition, we have materially constrained our capex allowance in several categories as part of our commitment to delivering a value for money service. This will require further productivity improvements to be made to allow us to deliver the outcomes desired by customers at a lower cost.

We have also reviewed our proposed ICT capex and consider it is efficient for the following reasons:

- **Lower than previous periods:** our ICT capex is less than the amount spent in the 2014-19 and 2019-24 periods;
- **Market tested:** we source our ICT applications from the market and implement and operate them using an outsourcing model;
- **Governance:** we have a detailed governance process and evaluation criteria that optimises ICT investment on an NPV and risk basis; and
- **Benchmarking:** we have tested the efficiency of our proposed ICT capex through a number of measures. For instance, our ICT capex forecast is lower than other DNSPs:

Figure 10-27 NEM comparison of average annual ICT capex per customer[64] (Average 2017 – 2021)



We also engaged Deloitte to conduct more detailed benchmarking (up to FY20 performance). The results support the efficiency of our forecast, with our ICT totex as a % of revenue below the industry average for the last several years with the exception of FY18 and FY19. See attachment 10.43 for further details.

Key projects and details

We provide more detail on our ICT capex proposal in the following attachments:

- **ICT Asset Strategy** (Attachment 10.43): this plan summarises our strategic plan for ICT. It sets out our current period performance, approach for planning, delivery and governance of ICT, strategic direction for FY25-29 and investment program.
- **ICT Investment briefs** (Attachments 10.44): for each of the four investment drivers we have prepared detailed CFIs for each program. Each brief sets out the strategic context, investment options and assessment criteria, the recommended option and delivery, governance and resourcing strategy.

[64] Source: RIN data, FY17-FY21 average performance for non-Endeavour Energy DNSPs.

- ICT & Digital Transformation PIR (Attachment 10.45): Deloitte was engaged to conduct an independent PIR of our transformation program. Deloitte undertook the following activities:
  - Considered the Project's delivery against the AER's expectations as outlined in its ICT guidance note including:
    - A comparison of the actual cost to the proposed cost in the business case
    - A comparison of the actual timeframe to complete the project with the forecast timeframe
    - A comparison of the actual achieved benefit to the forecast benefit (as best estimated) in the business case
    - An explanation of any material variations in costs, delivery timeframe, and benefits realised.
  - Consulted key business leads to identify challenges experienced during implementation, including the impacts of those challenges for costs, delivery timeframes and benefits realised, and the actions applied in response
  - Compiled a list of recommendations in the form of lessons learned that could be applied to Release 4 and other comparable projects within Endeavour.

The ICT investment briefs (Attachments 10.44) provide a summary of the individual projects and their alignment to strategic drivers. In accordance with RRG feedback, these briefs provide traceability of benefits, from drivers through to ICT strategic responses, and benefit realisation accountability:

- **High-level benefit summary:** The quantitative and qualitative benefits are summarised in customer-friendly terms
- **Benefit traceability:** The linkage between the drivers for change, the required benefits and the ICT investments provides traceability, which ensures clarity of purpose for all ICT programs of work
- **Benefit quantification:** Where applicable, benefits are quantified across each of the drivers for change in the respective investment briefs
- **Benefits realisation:** The Program Planning and Delivery Framework (see previous slide) includes assignment of benefit realisation accountability, establishment of a benefit tracking and reporting protocol and oversight by the corporate Investment Management Committee (IMC)
- **Post Implementation Reviews:** In accordance with the corporate Investment Management Framework, the IMC will conduct a PIR for major projects to assess if the project delivered the expected scope, was managed within the approved funding envelope and achieved the anticipated benefits

Motor Vehicles

Overview

Our $29.1 million (real, 2023-24) motor vehicle capital expenditure program is an essential enabler in supporting the investment, maintenance and operational activities of our system assets. Endeavour Energy's program of work is the key driver of fleet expenditure, directly influencing both the volume and type of vehicles required to support operational needs.

Table 10-15 Proposed fleet expenditure for FY25-FY29

$m; Real FY24	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Lifter Borers	0.2	0.0	0.4	0.0	1.1	**1.6**
Elevated Work Platforms	1.6	6.3	9.5	4.7	0.5	**22.6**
Heavy Commercial Vehicles	1.3	0.8	1.3	1.0	0.5	**5.0**
Total	3.1	7.1	11.1	5.8	2.1	**29.1**

Further detail on our strategic approach, asset management plan and expenditure forecasts can be found in Attachment 10.42, our Fleet Asset Strategy. This strategy is informed by our Fleet Services Transformation Strategy which outlines key objectives and actions planned to driver efficiencies and innovate over the next several years.

We note that as an organisation, we have an objective to transition to net zero by 2040 and to support this target we will look to transition our fleet to electric vehicles (EVs) where it is economically efficient to do so. For the purposes of the Fleet Asset Strategy, we have assumed that the life-cycle cost of moving to a sustainable fleet is cost neutral and therefore no specific additional funding has been included in the strategy for this purpose.

For the current period (2019-24), Endeavour Energy is forecast to spend $46.7 million ($FY24) on the fleet, which has been driven by a decision to replace rather than refurbish 36 Elevated Work Platforms (EWPs) during this period.

EWPs and Lifter Borers are required to undergo (at a minimum) a major rebuild at ten years in compliance with AS2550 and AS1418. As part of our ongoing review of our fleet replacement approach, NPV analysis was undertaken which indicated that it was more efficient to pursue a full replacement approach for EWPs at 10 years, rather than continue with our previous approach of a 10-year refurbishment in order to extend their life to 15 years. This NPV analysis has been revisited as part of developing this strategy, which again has demonstrated that replacement of EWPs at 10 years is still the best outcome. However, a similar analysis for Lifter Borers, has shown that refurbishment at 10 years to extend the life to 15 years is the better outcome. The fleet program for 2024-29 has been developed on this basis.

Forecasting methodology

The forecast for fleet has been built through a bottom-up build, based on the drivers and assumptions outlined in this Fleet Asset Strategy, including the replacement of assets based on assumed asset lives and maintenance (asset life cycle costs).

Our fleet capex is based on minimising the total life cycle cost of our fleet assets in meeting our operational requirements and regulatory obligations for the next regulatory period. This is achieved by ensuring our employees are equipped with vehicles that are capable of supporting the planned network program of work through an optimum mix of fleet resources.

In addition to the expenditure drivers highlighted above, the key forecasting considerations include:

- Planned fleet replacement schedule and criteria
- Cost of maintaining each vehicle against the alternatives
- Current market costs
- Ongoing availability and access to suitable fleet.

Our forecast investments and expenditure are based on the following assumptions:

- Vehicles will be replaced at end of life or lease, which will impact expenditure requirements and will result in ‘lumpy’ expenditure trends.
- Vehicles will continue to be replaced on a like-for-like basis until the transition to net zero emission vehicles becomes the most efficient and least-cost option.

- Unit costs have been assumed to remain steady.
- Fleet leases as they are entered into will be capitalised from 1 July 2024.
- The network (or system) program of work and employee numbers will remain stable from their current position as of 30 June 2022.

The resultant bottom-up build forecast is then compared to the top-down constraint and if there is insufficient funding then the fleet forecast is then prioritised first to meeting safety requirements, then satisfying Australian Standards, then vehicle condition, age and kilometres.

Key projects and details

A focus on operational requirements and an improved alignment of fleet and its allocation to operational demands, has resulted in a decrease in fleet asset numbers (38%) over the last ten years (FY13 - FY22). This includes a consolidation of vehicle variants (e.g., a consolidation to five light vehicle and ten truck models), a standardisation of their operation, and focus on specific fleet requirements.

In particular, the consolidation of vehicle variants has enabled the establishment of structured supplier arrangements, (including pricing rebates, smart forecasting and delivery programs), 'right sizing' of internal maintenance resources, better fleet sharing opportunities and operational familiarity benefits.

In developing our forecast, we have benchmarked our asset lives and expenditure with other distributors to validate our efficiency and prudency. Our asset lives are largely consistent with peers and with respect to our expenditure:

- Endeavour Energy's annual fleet operational expenditure is 19% of its total non-system operational expenditure. This is in line with the benchmarked median of 20%
- Endeavour Energy's annual fleet capital expenditure is 10% of its total non-system capital expenditure. This is lower than the benchmarked median of 17%
- Endeavour Energy's annual fleet total expenditure is 15% of its total non-system expenditure. This is slightly lower than the benchmarked median of 18%

In addition to this and consistent with other categories of capex, our proposed spend of $29.1 million (real, 2023-24) has been constrained via top-down challenge to manage our contribution to electricity prices. Without this constraint, the application of our replacement/refurbishment criteria to our fleet as a bottom-up assessment would have led to a requirement for $45.4 million (real; 2023-24).

With a priority to apply Australian Standards to both EWPs and Lifter Borers, expenditure on Heavy Commercial Vehicles has had to be reduced to operate within this top-down constraint. To enable more Heavy Commercial Vehicles to be replaced during this period there will be a focus on efficiency improvement and innovation across the overall fleet program. As a result, adjustments to this program will no doubt occur as we progress through 2024-29 to reflect the priorities and constraints of the day.

Given the above, we consider our program represents an efficient and prudent forecast. As aforementioned, refer to Attachment 10.42 for additional details.

Capitalised leases

As outlined in section 8.2 and 9.2, there has been a change in the accounting treatment of leases following the introduction of AASB 16 Leases during the current 2019-24 period. For regulatory accounting purposes, we have not adopted this change during the 2019-24 period so that our reported performance is consistent with the manner in which our allowance was set for incentive scheme purposes.

For the 2024-29 period, we propose to align our regulatory accounting approach with AASB 16 requirements.

We currently have leasing arrangements relating to the use of particular classes of motor vehicles and office premises. Specifically, we lease our passenger and light commercial motor vehicles and have a lease contract for our small Sydney CBD office. The lease contracts for vehicles and the Sydney CBD office cover a right of use period of five and three years respectively.

Additionally, we expect to relocate to our new head office in the Parramatta CBD in 2023 following the sale of our existing corporate site at Huntingwood in Western Sydney. The terms of the occupancy were negotiated in a lease agreement which has a 10-year 3 months term with an option for two five-year extensions after the initial expiry. No decision has yet been made on whether this option will be taken up.

For the 2024-29 period, we propose $18.1 million (real; 2023-24) of capitalised leases consisting entirely of short-term leases. Specifically, $17.7 million of capitalised fleet leases and $0.3 million of capitalised property leases.

Refer to our Fleet proposal, Attachments 10.42 and 8.01, for further detail on the capitalisation of fleet leases proposed for 2024-29. We note that this proposal will be accompanied by a corresponding reduction in operating expenditure for 2024-29. Under the base-step-trend framework to determine opex for 2024-29, the opex for the base year of FY23 will be adjusted downwards by $5.9 million (real $FY24) to reflect the application of AASB 16.

Buildings & Property

Overview

Our $33.2 million buildings and property capital expenditure program is a result of renewal and compliance-based drivers. Non-system buildings and property are essential in supporting the day-to-day system investment, maintenance, and operational activities of our network. Changes in the level and type of system capex and its locality will often drive a proportional change in the amount of non-system expenditure needed to efficiently support the level of planned capital works.

We manage a substantial and varied property portfolio under complex ownership structures and governance requirements. Over 1200 properties with a combined area of 11.7 million square metres, plus a network of over 40,000 easements make up the portfolio of owned, leased, and licensed sites across the franchise area. Our portfolio of non-system properties and buildings comprises of:

- **Field Service Centre (FSCs)** – Endeavour Energy has 15 FSCs, located across our network. Our FSCs provide a strategic operational base from which our staff conduct construction and maintenance activities and respond to supply interruptions. FSCs perform an important role in maintaining the reliability and safety of the distribution network in accordance with our compliance obligations and strategic objectives
- **Offices** – Endeavour Energy's offices provide an important base for staff involved in the planning of network projects and activities, control centre operations as well as other back-office support functions such as finance, technology, human resources, legal, facilities management and billing
- **Specialist Sites** – Endeavour Energy's specialist sites may include logistical facilities, warehouses, pole storage yards, transformer yards, testing facilities and training centres.

In managing our portfolio of buildings and property and other non-system assets, we must ensure that we:

- Optimise the enterprise value of the buildings and property portfolio
- Minimise the holding and operational costs of the assets
- Provide safe, efficient, and fit-for-purpose assets to facilitate the efficient and effective delivery of our strategic direction and operational requirements
- Ensure ongoing compliance with the range of legislative and regulatory compliance obligations
- Continue to focus on Environment, Social and Governance (ESG) in our decision making.

By meeting these challenges, we aim to create long-term value for our customers. Our mission is to balance our core service commitments of safety, affordability and reliability with a transformation from a traditional 'poles and wires' network to a facilitator of customer technologies.

Under our previous government ownership, we historically underinvested in non-system assets, prioritising investment in system assets and focusing on affordability for customers. Despite this, at the time of submitting our 2019-24 Regulatory Proposal, we were not anticipating any significant buildings and property related capital expenditure projects.

However, subsequent to our submission, we received an unsolicited offer for our Huntingwood Head Office site. Following this offer, we engaged an independent third party to review and conduct a financial assessment of the offer including the financial impacts and risks as well as potential relocation options. This offer coincided with material changes to working patterns during and post COVID-19 which led to decreased utilisation of Huntingwood thereby providing an opportunity to move to a smaller, better utilised and more cost-effective office accommodation.

As a result, we identified an opportunity and pressing need to relocate and refurbish our head office and FSCs to ensure these remain compliant, better utilised and attractive to both current and future employees.

A corporate office in Parramatta (Parramatta Square) was chosen due to its location and access to public transport, as well as to key stakeholders and represented the best value. We believe this solution will provide the most optimal outcome for our staff, stakeholders and the community. We also commenced a project to augment the FSCs at Kings Park, Hoxton Park and Glendenning to support a distributed office network. We developed a business case to support this direction which supports its efficiency (a 1.28x BCR) and a net reduction to the RAB (a $100 million disposal of land and buildings).

It is anticipated that our forecast expenditure for 2024-29 will return to historical long-term trends with a proposed capex for buildings and property.

Forecasting methodology and detail

The network program of work and employee numbers are two key drivers for property and other non-system capex and have a material influence on the quantity, type and location of assets. Other drivers for property and other non-system expenditure include:

- Compliance with various regulatory and legislative obligations such as building codes, workplace health and safety requirements, and environmental standards
- Ensuring security of critical infrastructure and day-to-day security to mitigate theft and vandalism
- Planning for necessary building maintenance and repairs to ensure the properties and buildings remain fit-for-purpose and safe
- Ensuring Endeavour Energy continues to meet the day-to-day needs of our customers and stakeholders
- Supporting workforce productivity and efficient use of workspaces.

A significant portion of our planned investment for property and buildings focuses on corrective replacement or refurbishment of aged, damaged, faulty or inefficient property assets. These needs are recurrent and forecast expenditure is based on condition-based assessments to determine if they remain fit-for-purpose and compliant.

Our forecast is driven by our four key investment themes which are then balanced with an overall objective of developing an affordable proposal that is in the long-term interests of customers.

Within this context, our buildings and property forecast are also informed from historical trends and the development of a bottom-up portfolio of projects supported by business cases and investment governance approval processes that respond to our corporate priorities. We then prioritise these projects using an assessment tool, with business cases developed and approved in accordance with our governance and procurement processes.

During 2024-29 the planned capex for non-system buildings and property is grouped into four categories as outlined in below:

- Building Refurbishments and Upgrades
- FSC Yard Works
- Fix on Fail

- Implementation of Agile and Connected Workspaces

Refer to Attachment 10.46, our Buildings & Property and Other Non-System Asset Strategy, for more detail on each of these programs.

Other non-system (furniture, fittings, plant and equipment)

Our $21.3 million furniture, fittings, plant and equipment capital program is made up primarily of capitalised tools and equipment which support the network construction and maintenance programs. It also includes the furniture and fittings component of the buildings and property program.

Our furniture, fittings, plant and equipment expenditure has historically been equivalent to one to two percent of our system capex forecast. The 2024-29 forecast is line with previous periods and will cover the following key areas.

Table 10-16 Breakdown of other non-system capex for FY25-29

Project	Proposed Expenditure ($2024; M)	Benefits	Description
Tools and Equipment	12.2	Ensures staff have fit for purpose tools and equipment to perform work safely and efficiently and ensure our workshop facilities are compliant	Provision and replacement of everyday tools and equipment, including hand tools and workshop equipment
Major Equipment and Furnishing Upgrades	5.0	Ensuring both equipment and furnishing are available and fit for purpose to support FSC operational requirements	Planned upgrade and replacement as required based on age and condition across 20 operational sites of carpet, vinyl flooring, window furnishings, furniture, ice machines, air-conditioners (including a large chiller unit at Technical Training Centre), water pumps, hot water systems, storage racking and other miscellaneous equipment
Security, including Padmount Cylinders	4.1	Compliance driven to ensure physical access and control of system assets remains restricted to authorised personnel	Provision of security locks, CCTV, electronic security systems and upgrade of locking cylinders on padmount substations
Total	**21.3**		

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11. Operating Expenditure

11.1 Overview

Operating costs per customer will improve from an average of $328 in 2019-24 to an average of $252 in 2024-29.

Our base year opex is $59.2 million (real, 2023-24) lower than it was in 2017-18 (our 2019-24 base year), 25% below the AER's allowance and below the AER's substitute opex estimate. This reduction will directly flow through to lower prices for customers. This reduction has also seen an improvement in our benchmarking performance; our opex now ranks amongst the most efficient in Australia with our Opex MPFP ranking having improved from 10th in 2016 to 4th in 2022.

We have worked hard to deliver our services at the lowest cost to customers without compromising safety, service quality or our ability to comply with our obligations. During 2019-24 we embarked on our ICT & Digital Transformation along with several other efficiency initiatives that ensure our workforce and practices are right sized, efficient and prudent.

Customers and stakeholder groups expect us to meet or better the AER's opex benchmark and to use the AER's preferred 'base-step-trend' model to forecast our opex requirements for 2024-29. We have met these expectations.

The 'base-step-trend' approach involves taking the 2022-23 base year opex and trending this amount over the 2024-29 period. We have also applied 'step changes' to our forecast associated with new obligations or requirements noting these estimates have been constrained below our internal and/or independent forecast in order to manage our contribution to electricity prices. We have also applied a trend consistent with the AER's benchmark weightings to account for expected labour cost increases and the growing size of our network.

Importantly, the average cost to each customer declines when compared to previous periods. Our average opex per customer was $369 per annum (real, 2023-24) for the 2014-19 period. Through our ICT & Digital transformation program we improved this to $328 per annum (real, 2023-24) for the 2019-24 period. The $252 per annum (real, 2023-24) we are forecasting in the 2024-29 period compares favourably to the current period and extends this downward trend.

The forecast opex is the efficient cost of meeting the opex objectives and includes expenditure to meet and manage the expected demand for standard control services over the 2024-29 regulatory period; comply with all applicable regulatory obligations; and ensure our distribution system and network services, meet relevant safety, quality, reliability and security of supply standards.

The forecast for 2022-23 is better than the AER's own benchmark amount. We have been able to achieve more efficiencies than those established by the AER in the current period. These are immediately passed through to customers for the 2024-29 period. The change in costs for each year is consistent with the AER's own methodology.

Table 11-1 Forecast standard control opex over the FY25-FY29 regulatory control period (including debt raising costs)

$m; Real FY24	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Opex	287.8	294.7	298.2	305.0	312.0	**1,497.6**

11.2 Customer insights

In accordance with the NEO, our objective is to manage and maintain the network in a way that best serves the long-term interests of customers. In preparing a proposal it is therefore critical to engage with customers and test our plans and priorities with them to ensure our proposal advances their long-term interests.

Customer and stakeholder engagement is vital to meeting customers' long-term energy needs by providing a safe, reliable and affordable electricity supply. In Chapter 5 and Attachment 5.01 we provide a detailed overview of who are our customers, how we engage with our customers and how we respond to their concerns and priorities in our proposal for the 2024-29 period.

Below we summarise how our proposed opex responds to these concerns and advances customers' interests.

11.2.1 Customer feedback and our opex response

We will continue to constrain our contribution to customers' electricity bills

We have made significant reductions to our opex over the 2019-24 period to ensure our base year provides an efficient estimate of our opex requirements for the 2024-29 period. We will reduce our opex from $319.6 million (real, 2023-24) in 2017-18 to $260.5 million (real, 2023-24) in 2022-23. This improvement is reflected in our benchmarking performance which has improved from 10th in 2016 to 4th in 2022.

We have used the 2022-23 year as our base year for forecasting our opex for the 2024-29 period. This means the $59.2 million (real, 2023-24) reduction we have made to our opex since 2017-18 will be passed through to customers in our forecast opex over 2024-29. Additionally, to provide further assurance that our base year is efficient we note it is below the AER's efficient allowance for the 2019-24 period.

In addition to this, we will constrain our estimate of step changes $178 million (real; 2023-24) to $60 million in keeping with our commitment to achieve productivity gains in excess of the AER's 0.5% benchmark and to manage our contribution to electricity prices.

We will provide a safe and reliable supply of electricity

In making these reductions to our opex over the 2019-24 period we have not compromised our safety, service quality or our ability to comply with our obligations. Our reliability performance has been steady over the entire period, and we have continued improving our safety performance.

We consider the base-step-trend method will produce an opex forecast that will be in the best interest of our customers and will allow us to continue to meet our obligations and maintain service levels at an efficient cost.

We will trial and deploy innovative technologies where it is efficient

We note that customers and stakeholders wanted us to support a rapid and/or accelerated transition to a decarbonised and decentralised energy industry so they could realise the benefits of greater choice and control over their energy usage.

Customers and stakeholders were also increasingly mindful of the impacts of climate change and the need for Endeavour Energy to take a mix of proactive and reactive measures to improve network and community resilience.

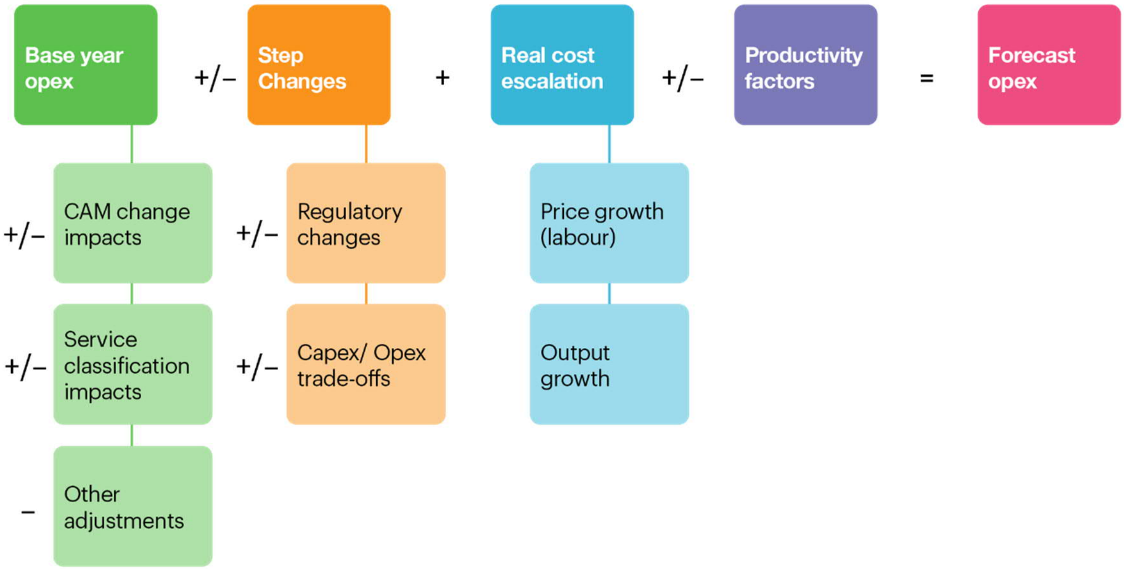
We therefore propose an Innovation Fund of $25 million ($5 million of which as opex) for the 2024-29 period. This will allow us to trial and invest in innovative solutions and technologies to support the energy transition and community resilience measures.

11.3 Opex forecasting method

11.3.1 Our forecasting approach and method

The forecasting method adopted is critical in deriving a forecast opex that reasonably reflects the opex criteria and is sufficient for us to achieve the opex objectives. We have used the base-step-trend methodology for estimating our forecast opex requirements. In applying this approach, we have used the AER's top-down Opex Model which can be described as follows:

Figure 11-1 The base-step-trend forecasting approach



We note that there are a number of key steps involved in the application of a base-step-trend forecasting method to ensure the resulting opex forecast reasonably reflects the operating objectives, criteria and factors.

First, it is necessary to assess the extent to which the base year used for forecasting purposes is both efficient and sufficient to allow a DNSP to meet its obligations and maintain a safe, secure and reliable supply. Secondly, it is necessary to assess, as far as practicable, the extent to which this base year opex amount will allow a DNSP to efficiently and sustainably deliver the outcomes discussed above into the future. This requires an assessment of potential changes in our:

- service classification;
- Cost Allocation Methodology or capitalisation policies;
- regulatory obligations;
- productivity levels;
- costs of inputs; and
- operating environment and network scale.

Our approach to each of the forecasting stages above is discussed in further detail in sections 11.5 to 11.7 of this Chapter.

We also note that our forecast opex has been prepared in accordance with; the CAM that applies to Endeavour Energy (approved 8 March 2018) and the requirements of the Reset RIN, Attachment RIN0.01 to this proposal.

11.3.2 Forecasting assumptions

The Rules require that we provide details of the key assumptions underpinning our forecast opex and a director's certification as to the reasonableness of these key assumptions.

The directors' certification is provided at Attachment 0.08. The summary below provides details of assumptions underlying our forecast opex. These are assumptions relating to facts or circumstances, the truth or correctness of which underpins or is highly material to the forecast of opex. We note that there are other key assumptions that apply solely to forecast capex and have been identified in Chapter 10.

Table 11-2 Our opex forecasting assumptions

Assumptions	Description
Structure & ownership	Our opex forecasts are based on our current company structure and ownership arrangements.
Compliance requirements	Our opex forecast is based on achieving compliance with our legislative and regulatory obligations including the requirements set out in our NSW Ministerially imposed licence conditions which apply at the time of submitting our regulatory proposal.
Service classification	We will apply the service classification in the AER's Framework and Approach (F&A) paper and the current ring-fencing arrangements will not change materially.
Stakeholder and customer engagement	We have engaged with stakeholders and customers in developing our opex forecast in accordance with the AER's Better Resets Handbook. The preferences and expectations of participants revealed through our co-designed stakeholder engagement program accurately reflect those of our customers generally. Our opex forecasts have particular regard to the affordability of our services and appropriately respond to these concerns.
Service reliability	Our opex forecast reflects requirements to maintain the current average level of service reliability performance (which is distinct from resilience) across the network.
Base year	We have applied the AER's revealed cost base-step-trend method to forecast opex that meets the operating expenditure objectives in the NER. 2022-23 has been adopted as the efficient base year with adjustments made to ensure it is representative of recurrent prudent and efficient future opex requirements. We will update our base year opex forecast for actual opex in our revised proposal consistent with the standard approach.
Trend factors	Our forecast changes in output growth are reasonable and reflect the trend in future opex given our adjusted base year. We have applied a productivity adjustment consistent with the AER's *Forecasting productivity growth for electricity distributors* final decision paper.
Price escalation	Our opex forecast does not include any real price increases for materials consistent with the AER's accepted approach. We have applied real cost escalation for labour based on the advice provided by expert independent consultant BIS Oxford Economics.
Inflation	Our inflation forecasts have been derived by applying the AER's preferred approach as outlined in its *Regulatory treatment of inflation* final position paper.
Cost allocation	Our opex forecast is consistent with our capitalisation policy and our existing Cost Allocation Methodology (CAM) which provides the basis for attributing and allocating forecast capex to standard control services and other services.
Managing uncertainty	The AER will approve our nominated pass-through events, and we will not have any contingent projects.

Other opex

Non-routine costs are not a function of the current base year costs; therefore, the base-step-trend ‘revealed cost’ method would not be appropriate. Our debt raising costs are set using benchmark costs. We use the AER’s method for the calculation of debt raising costs. That is, debt raising costs are calculated by applying a benchmark debt raising unit rate to the debt portion of our regulated asset values.

11.4 Our performance in the 2019-24 period

We expect to reduce our opex from $304.8 million (real, 2023-24) in 2017-18 to $248.4 million (real, 2023-24) in 2022-23 (our base year) which is a reduction of $56.4 million (real, 23-24).[65] Our performance compared to the AER's allowance is set out in the table below.

Table 11-3 Actual and forecast expenditure for EBSS purposes the FY20-FY24 period

$m; Real FY24	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Actual/forecast[66]	280.4	305.1	287.0	266.5	273.7	**1,412.7**
AER Allowance	343.9	354.3	341.6	348.9	356.0	**1,744.8**

As evident in the table above, we have managed to reduce our opex over the 2019-24 period. It is worth noting that we have reduced our opex despite facing the following additional cost pressures:

- We had to manage an increase in emergency response due to several natural disasters including the 2019-20 Bushfire season and the 2021 and 2022 Floods.
- We had to manage the impacts of Covid-19, the war in Ukraine and global economic downturn on our labour and material costs.
- We had to absorb a short-term cost increase to fund the ICT & Digital transformation initiatives and redundancy costs;
- We had to supply resources to support the connection of an additional 95,000 customers and maintain, repair, and operate a growing network including an additionally installed:
  - 2,300 km of network power lines and cables;
  - 31,500 poles;
  - 3,900 distribution substations; and
  - 185,000 service lines;

We had to comply with several changes in our regulatory obligations.

The considerable reductions we have made in opex over the last several years have escalated since our partial privatisation in July 2017 and are driven by sustainable efficiencies that we have achieved and continue to expect to achieve. In particular, during the 2019-24 period we:

- Embarked on a significant and necessary transformation of our ICT enterprise systems and processes. This is the primary source of our more recent efficiency gains
- Re-structured our key operations to better utilise (and thereby reduce) our workforce while improving service quality
- Conducted a thorough and strategic review of all procurement processes and agreements to materially reduce our contract costs
- Initiated an innovation fund and continuous improvement project team to continually assess and review internal processes to identify better ways of working and productivity improvements
- Increased the scale of our unregulated activities which reduces the corporate overheads allocated to our standard control service activities.

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[65] In accordance with NER S6.1.2(7), opex for each of the past regulatory years of the previous and current regulatory control period is provided at Attachment 11.02.
[66] For comparison, this actual expenditure excludes amounts relating to DMIA, movements in provisions and debt raising costs

11.5 Efficiency of the base year

A key aspect of determining the efficiency of our forecast opex is assessing the extent to which the base year is efficient. The revealed cost framework that applies to us incentivises the pursuit of achieving operational efficiency. Our own performance over time and compared to our peers is therefore central to assessing the allocative and productive efficiency of our base year. A key indicator of the efficiency of our base year opex is that it is below the benchmark efficient opex allowance set by the AER.

In this section, we provide more detail on why our base year can be considered efficient. We then outline the forecast 'trends' and 'step changes' which address the dynamic efficiency of our forecast, i.e., that our opex remains efficient over time.

11.5.1 Our base year is efficient

Base Year Selection

The base-step-trend 'revealed cost' forecasting approach necessitates an efficient base year level of expenditure be utilised. In deciding whether the AER is satisfied that our proposed opex forecast meets the expenditure objectives at an efficient and prudent cost, the AER relies on the expenditure criteria and the expenditure factors.[67] Broadly, the expenditure criteria and factors combined are directed at assessing the efficiency and prudency of the forecast. In selecting our base year for the 2024-29 period we have considered prudency and efficiency as follows:

- **Efficiency:** no objective, external factors that can be relied upon to demonstrate that the overall level of the opex forecast is perfectly efficient. Instead, partial indicators exist that can be used to assess the efficiency of the overall level of costs. We have therefore considered our past expenditure in response to the EBSS, benchmarking and outsourcing as indicators of efficiency.

- **Prudency:** we have assessed the extent to which our recent actual costs have allowed us to meet our obligations and maintain existing service levels[68]. We have also assessed whether any trend or step factors are required to ensure we can continue to meet our obligations and maintain existing service levels. Our forecasting process, and its prudency, is addressed in further detail in Attachment 0.07.

Based on this assessment, we have selected the 2022-23 year as the base year for forecasting purposes. Our rationale/steps are as follows:

Efficiency measures

Our past performance

The base-step-trend 'revealed cost' methodology works together with the EBSS to provide us with a continuous incentive to become more efficient in a sustainable way.

A critical aspect of assessing forecast opex is therefore determining whether a DNSP has been responding efficiently to the revealed cost framework and EBSS over the current regulatory control period. If a DNSP is responding to incentives its actual opex, the nominated base year, can be relied upon for forecasting purposes.

Our actual performance over the 2019-24 period demonstrates that we have responded to the incentive scheme by reducing our opex over the period while maintaining our increasing base of network assets and customer connections and continuing to meet our broader licence conditions and obligations while maintaining our service quality. Specifically, over the 2019-24 period:

- we will achieve a better opex outcome in 2017-18 than the AER set as the efficient allowance for that year;

- our base reflects the cost reduction initiatives we have implemented as part of our ICT & Digital transformation program and other efficiency measures;

[67] Clauses 6.5.6(e) of the rules
[68] For the purposes of S6.1.2(4) of the NER, we can confirm the objective of our opex forecast is to maintain existing levels of reliability. Forecast maintenance programs are not designed to improve the performance of Endeavour Energy under the STPIS.

- we have responded efficiently to the incentive regime as evidenced by our positive EBSS carryover benefit; and
- the EBSS provides the strongest incentive to Endeavour Energy to “reveal” its most efficient cost.

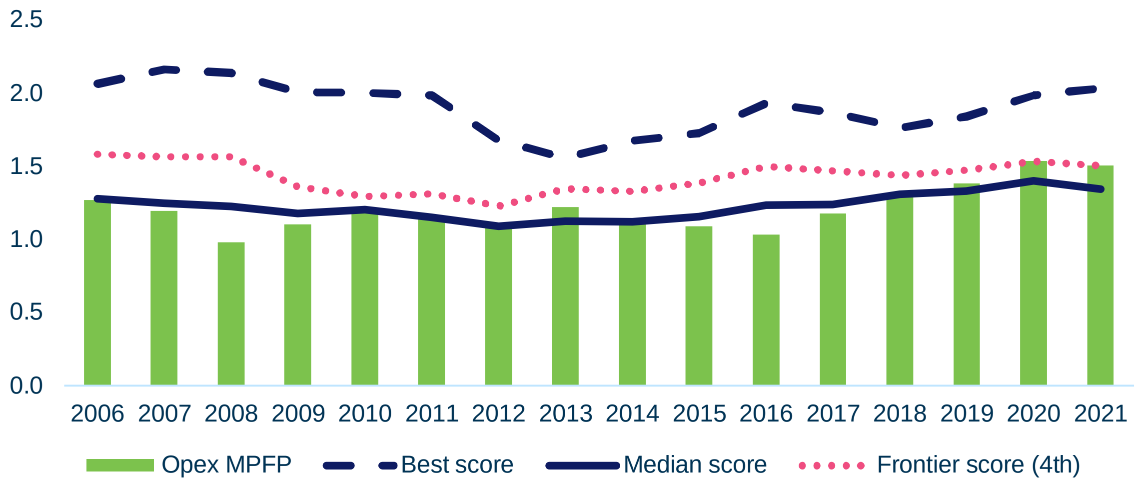
Benchmarking

Generally, we consider benchmarking total opex is preferable to category level forecasts as these can be subject to disparate accounting and reporting practices which impacts comparability. For similar reasons, we also consider benchmarking is of more probative value for assessing the individual performance of a DNSP over time.

We note that the AER releases an Annual Benchmarking Report which measures the benchmark performance of Australian DNSPs. As a result of the opex reductions we have made over the current period our benchmarking performance has improved;

- our Opex MPFP score has improved from 10th in 2016 to 4th in 2022; and
- our opex per customer will improve from an average of $328 during the current period to $251 in the 2024-29 period.

Figure 11-2 Endeavour Energy’s Opex MPFP performance

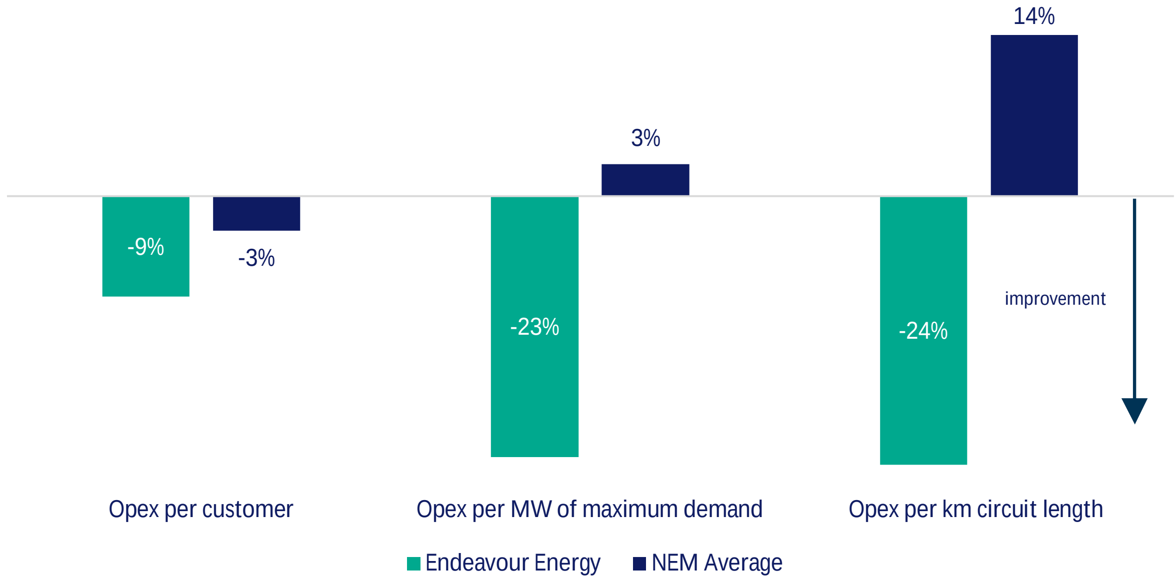


As a result, our 2022-23 opex is forecast to be materially below the AER’s efficient substitute estimate.

Figure 11-3 Assessment of 2022-23 opex against AER substitute estimates

We have also examined a number of key PPIs the AER typically examine to check the reasonableness of econometric benchmarking results and the MTFP and MPFP models. Our performance against these opex PPIs is amongst the most improved in the NEM over the last few years as evident in Figure 11-4 below. Notably, our opex per MW of maximum demand and per km of line have both been reducing while the NEM average has been increasing.

Figure 11-4 Endeavour Energy percentage change in opex PPIs compared to NEM average (2016-21)



We consider these measures indicate our opex efficiency has improved and our 2022-23 base year represents an efficient forecast.

Outsourcing

As noted by NERA Consulting[69]:

> *Where a DNSP's expenditure forecasts are based on cost estimates for activities that have been sourced from an effectively competitive market, this provides a prima facie indicator that the level of that expenditure is efficient…….where the relationship clearly is at arm's length, then the use of cost information derived from an effectively competitive market provides a strong basis for the presumption of efficiency.*

We have consistently sought to market test functions and outsource activities where it is efficient to do so. The nature of the work outsourced has ranged from small scale works, like ongoing routine work through to major initiatives such as vegetation management. We have consistently been effective in managing the development and implementation of workplace reforms, including outsource proposals which have consequently helped reduce our workforce numbers.

As a result, approximately a third of our base year opex will reflect market tested and/or outsourced activities. We have built on this market testing by strategically reviewing all procurement processes and agreements over the 2019-24 period.

Change in ownership

The 2019-24 period has been the first full period under our new ownership arrangement and therefore more likely to be reflective of our operating costs in future years and capacity to respond to the incentive based regulatory framework. The consortium of investors that has leased Endeavour Energy assets has extensive, international experience in efficiently managing and operating energy businesses.

[69] NERA Economic Consulting, *Economic Interpretation of Clauses 6.5.6 and 6.5.7 of the National Electricity Rules – Supplementary Report*, 8 May 2014, p. 29

Prudency measures

Our actual expenditure has been enough to satisfy our obligations and maintain our reliability and service quality. For instance:

- we were compliant with our licence conditions;
- our reliability performance (SAIDI and SAIFI) continues to trend down (i.e., improve) over the long-term despite the increasing impacts of climate change;
- each year we complete 100% of our network area in accordance with our vegetation management clearance standards;
- our safety performance has continued to trend favourably over the period; and
- in the most recent 2022 GRESB assessment a five-star rating was achieved with a score of 97 out of 100

11.5.2 Base year adjustments

Consistent with the AER's application of the EBSS, we adjust our actual opex performance and base year for

- debt raising costs;
- non-network alternatives costs (DMIA) and Innovation Fund costs;
- movements in provisions; and
- any changes in capitalisation policies and/or accounting standards that occur over the 2024-29 period (if any).

On the latter, we note there have been two changes in accounting standards over the 2019-24 period that necessitate an adjustment to our base year. These are AASB 16 Leases which now requires the capitalisation of leases and the clarification of the treatment of Software as a Service costs as opex rather than capex.

For EBSS purposes we have adjusted and/or reported our opex on a consistent basis with the accounting treatment of these costs underlying our 2019-24 allowance. However, for forecasting purposes we have adjusted our base year in order to give effect to the new accounting treatment of these costs.

This means for leases we have reduced our 2022-23 opex by $5.9 million (real; 2023-24) to remove these costs from our opex forecast as they are instead now captured within our 2024-29 capex forecast. For Software as a Service costs, we have increased our 2022-23 opex by $0.9 million (real; 2023-24) to capture these costs within our opex allowance as they no longer form part of our ICT capex forecast.

11.6 Step changes

The AER, in the Expenditure Forecast Assessment Guideline considers that step changes may arise from either a change in regulatory obligations or a substitution between forecast capex and opex or vice versa. We also note that unforeseen changes, that are material, will be managed separately via the pass-through mechanism as discussed in section 6.3 of this proposal.

It has been established over the last several determinations that simply demonstrating that a new cost will be incurred – that is, a cost that was not incurred in the base year – is not a sufficient justification. Instead, a valid step change should:

- Not double count costs included in other elements of the total opex forecast. For instance, the output growth component accounts for increased volume or scale. The productivity factor is also likely to reflect incremental changes in obligations historically (i.e., average changes).
- Be material and either unavoidable (e.g., a new regulatory obligation) or a prudent and efficient capex/opex substitution opportunity (e.g., a demand management solution).
- Be supported by clear economic analysis and a quantified assessment of alternative options.

We are mindful of the impact increases in opex can have on our revenue requirement and therefore our network prices. In addition to the above criteria, we also agreed with our RRG that a 'constrained view' is required to manage these impacts similar to our approach to setting our capex forecast.

We identified and assessed several potential step changes for the 2024-29 period. These are summarised in the table below.

Table 11-4 Proposed step changes and assessment for FY25-29

Proposed Opex Step change	Cost Driver	Constrained step change FY25-FY29 ($m; FY24)	Self-assessment criteria			
			Material	Reliably Quantifiable	Not accounted for elsewhere	Type
Insurance Premium	Unprecedented tightening of global insurance market conditions and cessation of joint renewal arrangements.	$36.6	✓✓✓	✓✓	✓✓✓	Unavoidable
Security of Critical Infrastructure	Ensuring the physical and cyber security of critical assets meet regulated requirements.	$0.0	✓✓✓	✓	✓✓	New obligation
Network Visibility	Acquiring meter data to improve CER visibility in order to support efficient levels of export hosting investment	$14.2	✓✓	✓✓✓	✓✓✓	New obligation and Capex/Opex trade-off

Proposed Opex Step change	Cost Driver	Constrained step change FY25-FY29 ($m; FY24)	Self-assessment criteria			
			Material	Reliably Quantifiable	Not accounted for elsewhere	Type
Solar Soak/Off-peak conversion	Accelerating the roll-out of smart metering to improve hosting capacity and defer network capex	$5.8	✓	✓✓	✓✓✓	Capex/Opex trade-off
Demand Management	Expected demand management solutions to defer Augmentation capex	$3.4	✓	✓✓	✓✓	Capex/Opex trade-off
NSW Guaranteed Service Levels (GSL)	Increased penalty payments to customers associated with new NSW GSL scheme	$0.0	✓	✓	✓	New obligation
Total		**$60.0**				

We discuss each step change in more detail in the section below.

11.6.1 Proposed step changes

Overview

We are committed to the application of prudent asset management strategies to reduce the risk of bushfires caused by network assets and aerial consumer mains to as low as reasonably practicable (ALARP) level. The company is also committed to mitigating the associated risk to network assets and customer supply reliability during times of bushfire whilst achieving practical safety, reliability, quality of supply, efficient investment and environmental outcomes.

We have a risk management policy in place, based on AS/NZS ISO 31000:2018 Risk management–Guidelines, which outlines our appetite for risk and sets out our Risk Management Framework. The risk management policy is supported by various plans and policies including:

- Risk Management Procedure - to communicate the risk management process, assessment methodology and reporting requirements to enable the consistent management of risk across the business. Risk management performance is assessed and reported to the Executive Audit, Risk & Compliance Committee (EARCC), Board Audit & Risk Committee (ARC) and Board on a periodic basis. Feedback is also sought periodically from key stakeholders including the EARCC, ARC and Board.
- Bushfire Risk Management Policy which defines the strategy, framework and principles for ALARP management of network assets and aerial consumer mains that are installed in bushfire prone areas
- Detailed Bush Risk Management Plan which contains the processes and procedures in managing and responding to bushfire risks.
- Vegetation Clearance Management Policy and Bushfire Risk Model to manage vegetation proximate to Network Assets and prioritise defects found within these clearances.

These policies and plans were developed in compliance with relevant acts, regulations and codes.

One of the risk management strategies we have adopted is to use insurance policies to transfer an appropriate amount of risk from the balance sheet to third parties (i.e., Insurers) to manage unforeseen losses, maintain profitability and solvency. Most notably, our Combined General Liability insurance program covers claims made against Endeavour Energy related to bushfire damage and injury and general liability. Refer to attachment 11.03 for further details of our existing program.

Uncontrollable cost increases

Insurance premiums paid by Endeavour Energy over recent years has increased significantly. In particular, the annual GLIS premium has increased from $2.7 million in 2019 to $12.1 million in 2021 to continue the limit of liability of $860 million with no gaps in cover

Global financial and insurance markets have been in the process of remediating underperforming aspects of their portfolios for some time now – a process which has been overlayed with the need to react to increasingly prominent Environmental, Social and Governance factors and the impact of COVID-19.

Recent catastrophic bushfires in Australia and the USA have also had an impact on the availability and pricing of bushfire liability insurance in the global market, which is of critical importance to Endeavour Energy noting that our Combined General Liability Insurance program accounts for some ~72% of total insurance premium spend.

Endeavour Energy is in a period when insurers are either withdrawing from the market or increasing premium pricing to an unsustainable level. Other classes of insurance have also seen significant increases to premiums over recent years such as Industrial Special Risks (“ISR”) that covers property damage and loss of revenue from $1.7 million in 2018 to $3.1 million in 2021.

Our insurance broker, BMS Risk Solutions, has provided an expert estimate of our insurance premium costs over the remainder of the current period and the 2024-29 period. Given the significant year-on-year variation that can occur BMS provided an estimated range of scenarios. In their view, the trend of increasing premiums will continue into future years resulting in a step change ranging from $46 million to $105 million over the 2024-29 period.

Noting these estimates are based on the following assumptions:

- No major changes to Endeavour Energy’s risk profile or the basis for declaration under each policy.
- No changes to the Limit of liability or deductible structure from current year positions.
- No additional significant losses incurred by Endeavour Energy, or in the Australian Bushfire Liability market generally.

We consider it is well established that the cost increases are likely to be material, unavoidable and outside of our control.

Efficiency and options assessment

We have a rigorous internal review process in procuring insurance to ensure we obtain the best possible deal. In renewing insurance, we consider the following factors:

- Insurance cap or liability limit
- Value of deductible
- Whether to have gaps in insurance coverage
- Aggregated or each and every claim limits
- Terms of cover

We undertake periodic bushfire scenario modelling and analysis, to help make an informed decision about limits of insurance, appropriate deductibles, and retentions for the GLIS insurance program. The analysis considers:

- Likelihood and probability of exceeding certain limits

- Likely cost and extent of damage
- Limits purchased by peers of Endeavour Energy
- Deductibles or retentions self-insured by peers of Endeavour Energy

Risk appetite and financial metrics are also considered alongside the bushfire scenario analysis.

Our current deductible and limit is underpinned by analysis conducted in 2016 by our previous brokers Aon. We currently hold a limit of $860 million in insurance cover which includes unlimited cover for “each and every loss” caused by Endeavour Energy and proportional “annual aggregated” limits which provide cover up to the annual prescribed limits.

A report from independent analyst Risk Frontiers indicates that an insurance limit of $860 million is now likely to cover a bushfire event caused by Endeavour Energy once in every 450 years, not 1,461 years as previously assessed by Aon in 2016.

It would cost around $2 billion to maintain a similar insurance program to cover a 1:1,461-year bushfire event at renewal and this is not possible in the current insurance market. Rather than simply maintain our previous position we have therefore taken on a higher degree of risk in recent years given it would not be commercial to maintain our previous position.

Additionally, to manage the growing costs of insurance, we commenced using a “Protected Cell” Captive Insurance Company in 2020. The Protected Cell provides Endeavour Energy with access to the Re-insurance market. The alternative to a Protected Cell Captive Insurance Company would be to create a wholly owned subsidiary Captive Insurance Company of Endeavour Energy.

A Captive Feasibility Study is currently in the process of being undertaken by Endeavour Energy’s insurance broker’s recommended independent captive managers to assess whether it should continue operating a Protected Cell or create a wholly owned subsidiary Captive Insurance Company.

The full suite of options we have considered in managing our insurance premiums and risk position are as follows:

- No policy / rely exclusively on pass throughs
- Reduction in limit of liability and/or declared values
- Increase in policy deductibles
- Removal and/or reduction of Professional Indemnity from placement.
- Captive Insurance Company
- Reduction in breadth of policy terms and conditions
- Aggregation of Bushfire Limits throughout entire placement

We explore these options further in Attachments 11.04 and 11.05 to our proposal.

Based on our commitment to constraining our impact on electricity prices and the potential savings some of the options above may provide, we have adopted a constrained step change forecast of $36.6 million (real; 2023-24) for the 2024-29 period. This is materially below even the low range estimate provided by BMS.

Security of critical infrastructure (SOCI)

Under our existing licence there are conditions which apply to how we protect and manage critical assets. In addition to our licence conditions the Federal Government amended the SOCI Act in March 2022 to strengthen the security and resilience of critical infrastructure.

The SOCI Act places obligations on specified entities in a variety of sectors, including electricity. On 2 April 2022, the Security Legislation Amendment (Critical Infrastructure Protection) Act 2022 (Cth) (SLACIP Act) came into effect. The SLACIP Act amends the SOCI Act to introduce:

- A new obligation for responsible entities to create and maintain a critical infrastructure risk management program (this obligation has not yet been 'switched on' by the Minister for Home Affairs, nor have the rules around the risk management program been finalised)
- A new framework for enhanced cyber security obligations required for operators of 'systems of national significance' (Australia's most important critical infrastructure assets).

The objectives of the SOCI Act and its amendments are to uphold the Australian Government's commitments to protect the essential services that all Australians rely on by uplifting the security and resilience of critical infrastructure. The SOCI Act aims to mitigate threats from natural hazards (including weather events) and human induced threats (including interference, cyber-attacks, espionage, physical attacks, and malicious insiders), all of which have the potential to significantly disrupt critical infrastructure.

Under the SOCI Act, as a responsible entity of a critical infrastructure asset, we are required to develop and operationalise a written Risk Management Plan (RMP). We are in the formative stages of our compliance journey. The obligations in the RMP Rules are currently only draft and Part 2A has not yet been activated. We are nevertheless committed to assessing the impacts and working transparently with stakeholders appreciating:

- Challenges around the timing posed by the SOCI Act;
- Impacts on expenditure in the current regulatory period (2019-24); and
- Impacts on the next regulatory period (2024-29) given that these will be primarily driven by efforts in the current regulatory period.

We have a high-level understanding of the activities required to bridge the gap between current and future state. Based on that, we have formed an initial view on the range of anticipated expenditure that may be required within the current and next regulatory periods.

We know that, even based on reasonable assumptions regarding the level of risk that will be assumed by our organisation, a significant uplift in capability will be required to meet compliance. This uplift in capability will be required on both an initial and ongoing basis.

The majority of expenditure is anticipated in the following areas, given the potential threats in these areas identified through the SOCI legislation and the need to upgrade systems to mitigate and adapt to these potential threats:

- Cyber and information security hazards
- Physical security hazards
- Personnel hazards.

There is considerable uncertainty that remains for the cyber and information security hazards and physical security hazards, given the need to disaggregate our critical assets into critical components and related sites, to determine the level of risk that the business is prepared to accept as well as the need to properly scope the systems and personnel positions required and to test these with the market.

For this reason, there remains a degree of uncertainty of the costs and timing associated with SOCI compliance. On this basis, we do not consider the step change is reasonably quantifiable at this stage of the determination process noting work is ongoing to clarify and confirm the cost of compliance. We will continue to consult on our position in advance of our Revised Proposal.

DER related step changes

We are proposing two step changes related to our CER Integration Strategy, Attachment 10.40, as capex/opex trade-off step changes. These are described below.

Network visibility

As discussed in section 10.5.5, LV network visibility is a foundational and enabling step in our CER Integration Strategy. It enables improved hosting capacity through operational actions and dynamic

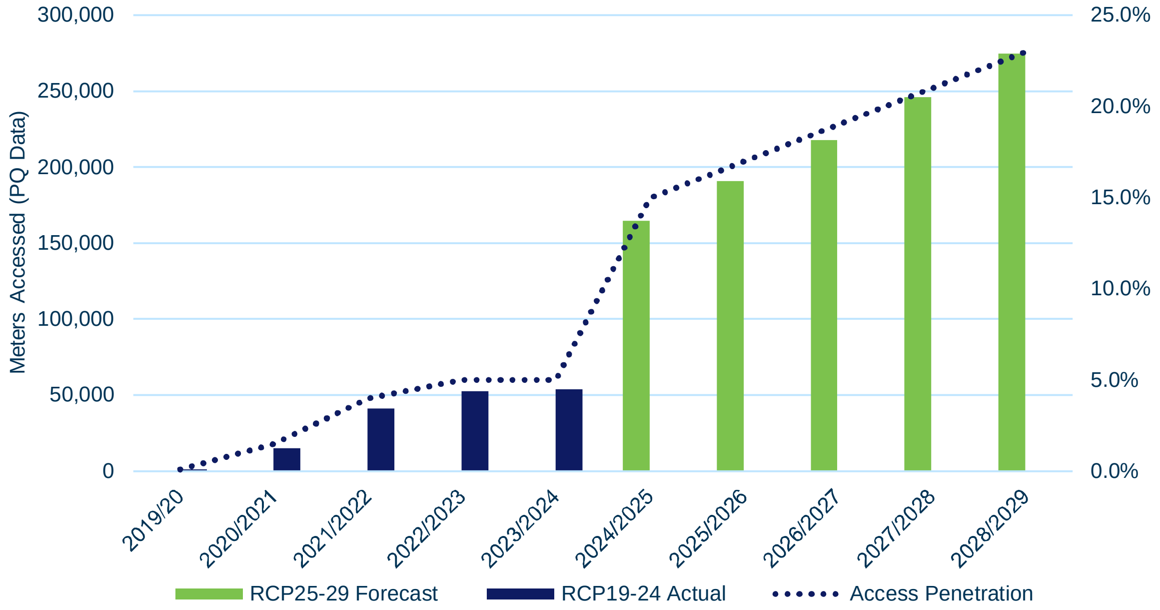
LV voltage management, improving the utilisation of existing network assets. LVVA underpins all the intervention actions included in our proposed CER Integration Plan.

LVVA also contributes to improved customer safety, reliability and operational efficiency as demonstrated by our LV visibility and analytics platforms trials and as shown through other jurisdictional and international experience.

As part of our CER strategy, we have assessed both the sources of LV visibility and the minimum level of visibility required that drives the optimal cost-benefit balance. Based on this assessment, refer to Attachment 10.40 for further details, we have determined that smart meter power quality data access is a mature, proven and consistent source of visibility.

To determine the level of visibility we have considered the need to manage the bill impacts of increasing opex, growing our visibility commensurate to our analytics maturity and establishing a minimum viable visibility level to enable our CER Plan interventions. Based on these factors we have determined broad based visibility of 20 - 25% is required and increased levels in targeted areas of high CER utilisation.

Figure 11-5 Smart meter data access trend and forecast



Based on prevailing market costs of acquiring metering data from the competitive metering market we have estimated the level of visibility opex required from FY23 through FY29. We have also considered the AEMC's draft metering review recommendations released in November 2022. This review is considering a range of options for accelerating the take-up of smart metering and improving network access to PQD.

It remains subject to consultation what terms and conditions will apply to our access to basic and non-basic PQD (noting we would require access to both). We assume there will be a higher availability of PQD following the review (i.e., a higher smart meter penetration) and subject to the price, our business case is likely to support a higher level of minimum visibility. The business case reflects our best understanding of the optimal level of visibility at this time and we will continue to monitor and update our revised proposal as further details emerge.

Based on our current forecast, the rate of change for this project is beyond the trend factor that applies to our base year opex as visibility opex grows from $1 million in FY23 to almost $5 million by FY29. This results in a step change estimate of $18.1 million (real; 2023-24) of which we propose a constrained amount of $14.2 million.

In the absence of this visibility our CER related augmentation could not be optimised and would increase by $33 million as a result. The project has numerous other benefits detailed in Attachment 10.40 across voltage management, DOEs, tap balancing and phase optimisation, reliability and safety.

Solar Soak / Off-Peak conversion

In 2021, we launched our Off Peak Plus pilot project, which was a collaboration between a metering provider and ten retailers to proactively transition off-peak hot water customers in the Albion Park Zone Substation supply area to smart meters, offering excellent customer benefits while saving investment in old ripple control technology.

We provided a financial incentive to the meter provider / retailers to expedite the bulk meter exchange (under the DMIS framework) on the basis that it avoided network investment in a replacement load control system as well as enabled additional benefits such as hot water solar soaking and improved network visibility.

This project transitioned hot water control from a network owned ripple control system to the smart meter. The ripple control system is used to turn on/off all units connected to a zone substation together as a batch with the same time schedule used for all.

Smart meter control allows for more flexible control of the heating times at the individual customer level by sending control signals direct to each meter through the meter provider's remote API control interface. Both the network and retailer have access to control each meter, allowing both network management and retailer delivered market services (allowing for new customer offers).

The Off Peak Plus program provides tremendous benefits to customers by soaking up excess solar energy during the day, providing a discount tariff. In addition to the benefits that solar soaking can provide this investment is also an alternate to:

- replacing like for like end-of-life off-peak ripple control systems in existing substations
- installing new ripple control systems in a new substation that partially supplies an existing brownfield area where not all customers have transitioned to smart meters yet.

This initiative is scalable to other services such as EV charging and provides us with smart meter information to help guide future investment. As such, we propose a step change of $5.8 million (real, 2023-24), to avoid $12 million of network investment / cost and improve hosting capacity valued at $2 million. Refer to Attachment 10.39 and 10.40 for the details of this business case.

Similar to the above step change, our underlying assumptions and business case have been updated for the AEMC's draft metering review and will be revised further following the final outcomes. Currently, the opex component of this project is a payment to accelerate the roll-out of smart meters in target locations, procuring PQD (non-basic) and device control (for a 5-year period) for network support purposes.

The AEMC rule change will likely allow us to target desired locations as part of our yet-to-be-confirmed Legacy Meter Retirement Plan (LMRP). However, it remains unclear whether support payments will still be required to achieve replacement in our required timelines for network purposes. The funding arrangements for PQD access remain uncertain along with whether there will be Government support for site remediation costs. It also remains the case that we would need to procure ongoing control for network support purposes.

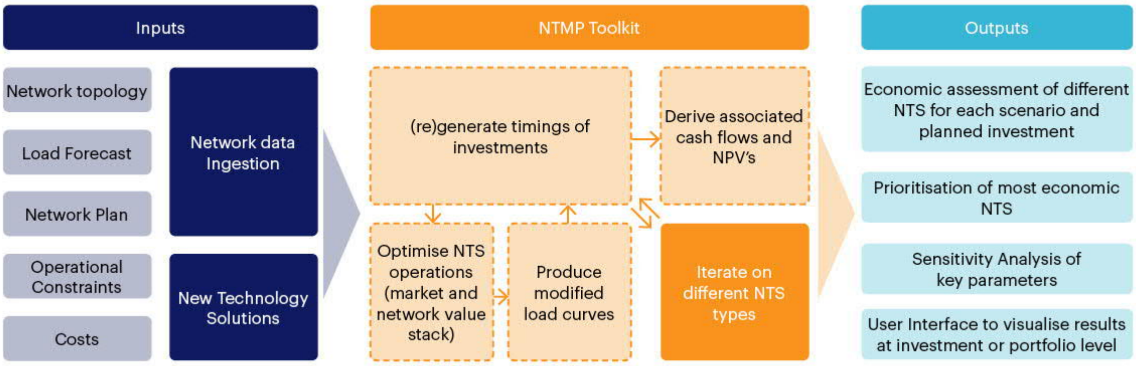
Based on the draft report we have reduced and accelerated the support payments required in anticipation of the smart meter rollout increasing over the 2024-29 period. We will review and update our business case accordingly for this step change in our Revised Proposal once the AEMC's review and any associated reforms to address site remediation are finalised.

Demand Management

As part of our augex decision making framework described in Chapter 10, we screen potential network investments for non-network and new technology solutions to identify and evaluate credible solutions.

To do this, we use our NTMP tool as depicted in the figure below.

Figure 11-6 Overview of NTMP



This tool is consistent with the RIT-D guidelines and evaluation methods. It allows us to assess network support options such as embedded generation Virtual Power Plants (VPPS), Grid-scale Batteries, Commercial direct load control and residential behavioural demand response.

As discussed in Chapter 10, we have constrained our Augex proposal from a bottom-up forecast in excess of $550 million to $413 million. Achieving the latter will require the realisation of delivery efficiencies, favourable timing differences and the implementation of non-network solutions. Based on our initial assessment of Augex projects using the NTMP we have identified the following projects that are likely to be candidates for non-network solutions:

- South Penrith Zone Substation
- North Bomaderry Zone Substation
- Culburra Beach Zone Substation
- Catherine Park Zone Substation Stage 2
- Calderwood Zone Substation Stage 2.

We estimate the likely deferral value of these projects (noting the deferral achieved will vary per project) to be approximately $7 million and our augex listing has been adjusted to reflect these deferrals (i.e., reduced by tens of millions of dollars). Whilst our base year opex (2022-23), and therefore our trended opex forecast, is not inclusive of demand management related expenditure. Consistent with our approach of constraining our step changes and in recognition of forecasting uncertainty we therefore propose a step change of $3.4 million for the 2024-29 period. We anticipate that demand management opex will become part of our recurrent opex in future periods.

NSW GSL Scheme

The NSW Government will amend our Distribution Licence Conditions to, amongst other things, introduce a new customer GSL to apply from 1 July 2025.

For Endeavour Energy, this will involve:

- **Level 1:** a $120 payment (to be escalated by CPI annually) for customers who experience 20 hours of outage(s) or 10 outages per calendar year.
- **Level 2:** a refund of the distribution component of the average residential bill for customers who experience 48 hours of outage(s) or 20 outages per calendar year.

This Scheme is likely to see a material increase in the number of claims for compensation made by residential and small business customers. We anticipate this to be in the order of $6 million if 50% of estimated eligible customers take-up the opportunity and accounting for the associated administration costs (0.2 FTE).

In accordance with our obligations, we routinely assess options to improve service for worst served feeders. However, network upgrades are often impracticable and/or more costly than a modest and recurrent level of non-compliance.

Whilst this cost relates to a new obligation and efficient capex/opex trade-off (in part) it is subject to a degree of uncertainty as to the level of take-up. We have therefore decided not to propose a step change amount for the 2024-29 period at this stage.

11.7 Rate of change

Actual opex in the base year reflects the prevailing economic and network conditions. It is reasonable to expect that known changes in conditions are incorporated in the forecast to ensure it remains efficient over the course of the period. For example, increases in demand and customer numbers result in additional network investment which in turn increases our opex (such as increased inspection and maintenance work). We have sought to account for these known changes through the trend factors that are applied as part of the AER's preferred base-step-trend forecasting methodology.

The AER's Expenditure Assessment Forecast Guideline sets out the following reasons why efficient opex in the forecast period may differ from the base level of expenditure[70]:

- **real price growth:** this relates to changes in the prices of the key inputs we use in our operations including labour, materials and contractors. Real price growth is the growth in the rate of prices relative to growth in the CPI;
- **output growth:** this relates to changes in the scale of the network over time in response to customer and demand growth. It is reasonable that as the scale of operations increases our efficient costs will increase; and
- **productivity growth:** this relates to changes in the level of expenditure required to deliver the same level of services to customers. Productivity growth may be a result of productive, allocative or dynamic efficiency improvements.

We have developed forecasts for each of these components and applied these to develop our opex forecasts. Our trend factors are discussed in the below sections:

11.7.1 Price growth

Labour price growth

We have engaged BIS Oxford Economics to estimate cost escalation factors in order to assist us in forecasting future opex based on changes in input costs for the 2024-29 regulatory period.

We have found that over the 2024-29 period input prices for labour and contracts (which are mostly labour based) are forecast to grow at a faster rate than CPI. We have therefore included real escalators for these inputs in the AER's Opex model (and our capex forecast). We outline our approach to labour escalation and some of the key issues in more detail below.

There are a number of issues to address in developing a forecast of labour price growth. Based on advice received from BIS Oxford Economics we have taken the following positions:

- **Wage Growth:** our EBA wage growth outcomes reflect efficient and robust negotiations in accordance with the Fair Work Act 2009 (Cth). However, we have used a Wage Price index (WPI) for the EGWWS sector to estimate both EBA and non-EBA wage growth as this is the AER's preferred efficient benchmark.
- **Labour/Non-labour weightings:** to date the AER has utilised a benchmark labour/non-labour split to account for wage growth. We have used the proportion of labour (59.2%) used by the AER in recent determinations.

We discuss some of these issues below in further detail.

Total labour price growth

The labour escalators in the table below represent the real cost escalators to be applied in developing forecast opex by financial year. These forecasts are based on the forecast wage price index for the utilities sector in NSW as provided by BIS Oxford Economics. The BIS Oxford Economics report and calculation methodology are provided at Attachment 0.10. We have also:

[70] AER, Expenditure forecast assessment guideline for electricity distribution, November 2013, p. 34.

- used a placeholder AER estimate from recent decisions consistent with the AER's approach of blending two expert forecasts.
- incorporated the impacts of legislated superannuation guaranteed increases, the impacts of which are not included in either BIS or the AER's expert forecasts.

Table 11-5 Real labour escalators for FY25-FY29

Real cost escalators (%)	2024-25	2025-26	2026-27	2027-28	2028-29
Labour – AER forecast	1.10	0.85	0.47	0.48	0.48
Labour – BIS Forecast	1.21	1.14	0.86	0.52	0.93
Labour - Average	**1.15**	**1.00**	**0.66**	**0.50**	**0.71**
Superannuation guarantee increases	0.50	0.50	0.00	0.00	0.00
Labour price growth	**1.65**	**1.50**	**0.66**	**0.50**	**0.71**
Proportion of labour	59.2	59.2	59.2	59.2	59.2
Total labour price growth	**0.98**	**0.89**	**0.39**	**0.30**	**0.42**

In line with AER preferences, we will continue to use an industry wage price index to forecast opex rather than known EBA figures.

We also note that the WPI is a conservative estimate of labour price growth as it assumes that wage increases associated with changes in job classification are perfectly offset by increases in productivity. This is incorrect as some wage increases are necessary to retain staff in a competitive labour market rather than simply acknowledging productivity improvements. Furthermore, we note that labour price growth in the Electricity industry is generally higher than other utilities meaning the combined EGWWS WPI is likely to understate our likely wage growth.

Material price growth

We use a range of electricity distribution equipment such as transformers, conductors, poles and circuit breakers. Forecast price changes in the commodities that this equipment is derived from like steel, oil and copper were examined. Based on this analysis, we expect our material input prices will grow substantively over the remainder of the 2019-24 period on account of Covid-19 followed by the war in Ukraine. We expect these costs to decline from these extreme highs over the course of the 2024-29 period.

Despite this substantive growth over the remainder of the period, and consistent with feedback from stakeholders, we have not included real price escalation in the materials component of our opex (and capex) forecast for the 2024-29 period.

11.7.2 Output growth

Output growth relates to changes in the size of the network and the quantity of services that we are required to provide. Growth in the scale of our network is a result of growth in our customer numbers and network demand. As previously mentioned, it is important to consider output growth to ensure the total opex forecast is dynamically efficient. Dynamic efficiency refers to remaining efficient in a changing environment. Accounting for step changes and output growth are the primary way of ensuring the base year is appropriately adjusted so that the resulting opex forecast reasonably reflects the expenditure criteria.

To measure output growth, the AER has developed three industry standard weighted output variables that align to economic benchmarking variables used by Economic Insights. These measures, and their respective weights across the four models, average as follows:

- customer numbers (49%);
- circuit length (13%); and

Endeavour Energy

- ratcheted maximum demand (38%).

The AER considers these measures are appropriate as they align with the objectives contained in the NEL and Rules, they reflect the services provided to customers, and they are material. The core operating cost is maintaining and operating the network which involves inspections, vegetation management, maintenance (preventative and broad-based) and fault and emergency response. These activities are self-evidently highly variable and dependent on the physical size of the network.

We accept these outputs measures and the industry standard weightings the AER apply. We do not have any evidence at this stage that suggests additional factors or alternate weightings should be considered. As the scale of the network increases the cost of maintaining our service quality across a larger network will increase. We therefore consider the above measures are appropriate for estimating the impacts of output growth on opex over the period. We note that to avoid the potential for double counting, economies of scale are considered as part of the assessment of total productivity change.

In Table 11-6 we summarised how we estimated each of the output change measures listed above. Estimates for each of these are contained in the Reset RIN and included below for reference:

Table 11-6 Forecast growth rates in output variables (%)

Annual growth rate (%)	2024-25	2025-26	2026-27	2027-28	2028-29
Customer numbers	2.17	2.02	1.97	2.00	2.01
Ratcheted maximum demand	1.76	0.21	0.96	1.23	1.02
Circuit line length	1.37	1.37	1.37	1.37	1.37
Weighted output growth rate	**1.91**	**1.25**	**1.51**	**1.63**	**1.55**

We note for ratcheted maximum demand we have adopted a lower forecast for opex forecasting purposes. Our demand forecast, inclusive of data centre's and/or spot loads produces a higher growth rate and in turn would materially increase our opex forecast. Whilst a consistent forecast should generally be used, as part of our commitment to constraint we have adopted a lower forecast as an additional productivity factor. We have therefore adopted our underlying demand forecast, inclusive of lot releases but exclusive of data centres and spot loads, for opex purposes.

Our forecasting methodology for each of these output factors is described in Chapter 7 of this proposal or our Reset RIN Basis of Preparation, Attachment RIN0.06.

11.7.3 Productivity factors

Productivity change can result from technical change, efficiency improvements and economies of scale and is important to consider in developing a forecast opex that is dynamically efficient.

In our previous Proposal we raised concerns with the AER's approach to calculating the productivity factor. Whilst these concerns remain, we note the standard practice is to apply the AER's benchmark assumption of 0.5% and we have applied this to our opex forecast in accordance with the expectations of the AER and stakeholders.

We also note that our opex MPFP ranks 4th in the NEM and the benchmark productivity factor applies equally to all networks. For more efficient networks this represents a more material challenge as unlocking harder to achieve productivities becomes more costly and risky.

12. Rate Of Return

12.1 Overview

We have applied the AER's 2018 Rate of Return Guideline in full in deriving our estimated rate of return whilst we await the outcome of the AER's 2022 Rate of Return Instrument review.

We propose an average rate of return on capital of 5.99% for the 2024-29 period. This rate of return has been developed using the AER's prevailing 2018 Rate of Return Instrument ('RORI').

We have applied the 2018 RORI as a regulatory proposal must comply with the RORI in force at the time of lodging our Proposal. In November 2022, the AER released a Market notice[71] advising that there would be a delay to releasing the 2022 RORI and it is now expected to be published in February 2023. Consistent with AER advice following this announcement, the 2018 RORI remains in force. We note the final 2022 (2023) RORI will apply to the remaining stages of our determination process.

The proposed rate of return considers the need to promote efficient pricing and long-term stability for customers and equity holders while maintaining stability and predictability of the regulatory outcomes.

The clear message from our stakeholders is that our rate of return estimate must be efficient in order to put downward pressure on electricity prices. To achieve this, stakeholders are clear in their expectation that we apply the methodologies, models and estimates contained in the AER's RORI.

We have aligned with these expectations and our obligations by applying the AER's 2018 RORI. The proposed rate of return complies with the Rules. In particular, it:

- reflects the financing costs of a benchmark firm with a similar degree of risk;
- has been calculated using a weighted average of the return on equity and the return on debt;
- is determined on a nominal vanilla basis;
- incorporates an estimate of the value of imputation credits ('gamma') consistent with the market's valuation; and
- reflects prevailing market conditions for equity funding and historical market conditions for debt funding.

Table 12-1 Proposed rate of return, inflation and tax estimate parameters

Parameter	Proposed value (%)
Inflation	2.87
Return on debt (5-year average)	4.85
Return on equity	7.69
Gearing	60
Gamma	59.5
Corporate tax rate	30

Despite our best endeavours, we note that factors outside of the control of both ourselves and the AER are placing significant upward pressure on the WACC and as a result, our required revenue. The global economic downturn has resulted in material increases in observable parameters such as the risk-free rate and cost of debt over the last 12 months. For instance, between January and October

[71] Australian Energy Regulator - AER delays 2022 Rate of Return Instrument until February 2023 – Issued 14 November 2022

2022 the risk-free rate increased by over 200 basis points. As a result, the rate of return is now over 50 basis points higher than that determined for the 2019-24 period on average.

12.2 Cost of debt

Endeavour Energy proposes an average cost of debt of 4.85% based on the application of the 10-year trailing average approach consistent with the AER RORI using observations from the most recent averaging period for debt to inform future expectations. This value will be updated with data obtained in the five averaging periods nominated by Endeavour Energy consistent with the AER RORI.

12.2.1 Our proposed cost of debt follows the AER's preferred methodology

The proposed cost of debt was derived using:

- application of a simple 10-year trailing average approach with a 10% weighting for each of the ten years;
- 10-year benchmark debt term;
- Australian corporate bond yield data from Bloomberg;
- yields for BBB+ rated bonds estimated through a weighted average of B (two thirds) and A (one-third) rated yield curves; and
- annual updates to cost of debt allowance.

We note that for our Proposal, a placeholder estimate is used based on a placeholder averaging period. As noted above, the AER will update this at the time of its decision and then at each annual pricing proposal process based on the accepted averaging period. Our placeholder estimation window is the 10 days commencing 4 October 2022.

12.2.2 Debt raising costs

The process of raising debt finance incurs significant transaction costs that should be recognised in regulated revenue allowances over the 2024-29 regulatory period. The AER's standard practice has been to recognise these costs as benchmark efficient operating expenditure, and this is reflected in the AER's post-tax revenue model (PTRM). The AER's PTRM requires input of benchmark efficient debt raising costs in basis points per annum (bppa) that is applied to the regulatory asset base.[72]

The AER's approach for forecasting debt raising costs first divides the benchmark debt share (60%) of the RAB by a benchmark bond size ($250 million). The upfront costs associated with issuing these bonds are then amortised using the nominal vanilla WACC from the PTRM, to be expressed in basis points per annum.[73]

Endeavour Energy has adopted the AER's approach for determining the 8.2 bppa benchmark debt raising cost. Consistent with the AER's approach, this benchmark debt estimate will then be multiplied by the debt component of the projected RAB in order to determine the debt raising cost allowance.

[72] AER, Electricity distribution network service providers: Post-tax revenue model handbook, June 2008, pp. 8-9.
[73] See: AER, AusNet Services Gas access arrangement 2018 to 2022, Attachment 3 – Rate of return, Draft Decision, July 2017, pp. 3-445 to 3-446.

12.3 Cost of equity

Endeavour Energy has applied the Guideline methodology and used the point estimates as per the AER's 2018 RORI within the Sharpe-Lintner (SL) CAPM framework to determine the benchmark efficient cost of equity of 7.69%.

In estimating our proposed cost of equity of 7.69% we have:

- used the SL CAPM as the foundation model;
- updated the risk-free rate using a placeholder averaging period[74];
- applied the AER's equity beta point estimate of 0.60;
- applied the AER's MRP point estimate of 6.1%; and
- adopted a gamma estimate of 0.585.

We have adopted a nominal risk-free rate of 4.03% for the purposes of this Proposal based on recent observations. This will be updated to reflect the risk-free rate measured over the averaging period proposed to the AER. In accordance with normal practice the nominated averaging period is for a future period and will remain confidential until such time as the averaging period has passed. The proposed approach is consistent with the RORI methodology.

12.3.1 Equity raising costs

Raising equity finance incurs costs that should be recognised in regulated revenue allowances over the 2024-29 regulatory period. The AER's standard practice has been to recognise equity raising costs as capex within the PTRM and amortise these costs over the life of the assets that they are used to fund.[75] In applying the AER's standard cash flow analysis sheet within the PTRM we estimate no benchmark equity raising costs over the 2024-29 regulatory period.

[74] 10-year CGS Yields sourced from RBA Indicative Mid Rates of Australian Government Securities – F16. Treasury Bonds 158 and 165 from 16 September to 17 October 2022.

[75] See for example AER, Final decision, ElectraNet 2013-14 to 2017-18 transmission determination 2013-14 to 2017-18, p. 87; AER, Final Distribution Determination Aurora Energy Pty Ltd, 2012-13 to 2016-17, April 2012, p. 78; AER, Final decision, Powerlink transmission determination 2012-13 to 2016-17, April 2012, pp. 107-108; AER, Final decision, Victorian distribution determinations 2011-2015, Appendix O, pp. 505–506; AER, Final decision, Qld Distribution determination 2010-11 to 2014-15, May 2010, p. 201;

13. Building Blocks

13.1 Overview

We will continue to keep our component of the electricity bill stable and efficient by using the building block approach prescribed in the Rules.

We provide a range of services that are classified by the AER as standard control services. These are attributable to the shared network and are central to providing access to safe and continuous supply of electricity from the grid. We propose a regulatory control period of five years commencing on 1 July 2024 with a proposed total revenue requirement for this period of $5.1 billion (real, 2023-24).

To calculate the revenue required to provide these services we have used the building block approach prescribed in the Rules. The building blocks relate to return on and of capital, operating and tax costs and other revenue adjustments (such as incentive scheme benefits). Our approach and forecasts for each respective building block are detailed in Chapters 8 to 12 of this Proposal.

Based on our forecast plans, and application of the AER's 2018 RORI in prevailing market conditions, we expect our average annual contribution to customers' bills to increase by approximately ten percent in real terms over the 2024-29 period compared to our expected price at the end of the 2019-24 period (i.e., FY24).

The building block components of our proposed indicative annual revenue requirements (unsmoothed) for 2024-25 to 2028-29 are outlined in Table 13-1 below:

Table 13-1 Forecast standard control revenue requirement over the FY25-FY29 regulatory control period

$m; Real FY24	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Return on capital	469.3	470.1	474.1	476.9	481.9	**2,372.3**
Return of capital	267.7	218.7	199.4	170.7	165.9	**1,022.4**
Operating expenditure	287.8	294.7	298.2	305.0	312.0	**1,497.6**
Cost of corporate tax	25.2	18.1	16.8	14.9	14.5	**89.5**
Revenue adjustments	57.1	22.6	36.9	31.4	3.6	**151.6**
Total unsmoothed revenue	1,107.1	1,024.2	1,025.3	998.9	977.9	**5,133.4**
Smoothed revenue	1,028.4	1,028.4	1,028.4	1,028.4	1,028.4	**5,141.9**

13.2 Proposed revenue requirements and indicative prices

13.2.1 Annual revenue requirements

We set out our proposed building blocks above. By adding these building blocks together, we derive our proposed total unsmoothed annual revenue requirement (ARR) for the 2024-29 regulatory period. This revenue will be recovered from our customers via network tariffs (or charges). These charges reflect the recovery of the efficient expenditure we need to invest in our network, to operate and maintain it and comply with our regulatory obligations. They also provide a reasonable return on our investment in the network.

To smooth the lumpy profile of these revenue requirements and limit customer price volatility between years, the Rules allow the AER to constrain revenues to follow a CPI-X path. The section below outlines our proposed X-factors to deliver sustainable pricing outcomes over the 2024-29 period.

Proposed smoothed revenue and X-factors

Our customer engagement activities have consistently revealed stakeholder preference for stable, smooth price movements between years.

To minimise price variations over time we need to take into account fluctuations in the ARR over the course of the regulatory period. In deciding on the proposed smoothed revenues and the resultant X-factors we have derived an adjustment that complies with the Rules and consistent with principles ensuring the:

- net present value of smoothed and unsmoothed revenue over the 2024-29 period are equal;
- pricing impact is as smooth and consistent as practicable over the period; and
- difference between smoothed and unsmoothed revenue in 2028-29 is as low as reasonably possible in order to minimise pricing volatility between regulatory periods[76].

The resulting revenue X-factors are provided in the PTRM, Attachment 0.04. The revenue requirement and X-factors that underpin them are provided in Table 13-2 below.

Table 13-2 Proposed unsmoothed and smoothed annual revenue requirement for FY25-FY29

$m; Real FY24	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Unsmoothed revenue requirement	1,107.1	1,024.2	1,025.3	998.9	977.9	**5,133.4**
Revenue X-Factors*	-14.12%	0.00%	0.00%	0.00%	0.00%	
Smoothed revenue requirement	1,028.4	1,028.4	1,028.4	1,028.4	1,028.4	**5,141.9**

* A negative revenue X-factor denotes a real revenue increase.

As discussed in the sections below, in proposing X-factors that result in the smoothed revenue profile, we have carefully considered:

- forecast changes in energy consumption over time (see Chapter 7); and
- the final year difference between smoothed and unsmoothed revenues;

Final year pricing difference 2024-29 period

As aforementioned, the Rules require that the difference between smoothed and unsmoothed revenue in the final year of a regulatory control period be as low as reasonably practicable in order to minimise pricing volatility between periods.

The Rules do not set a percentage band but the AER's more recent practice has been to limit the final year difference to ±3%. We note the AER has previously adhered to a ±5% band and we have

[76] NER, cl. 6.5.9(b)(1)

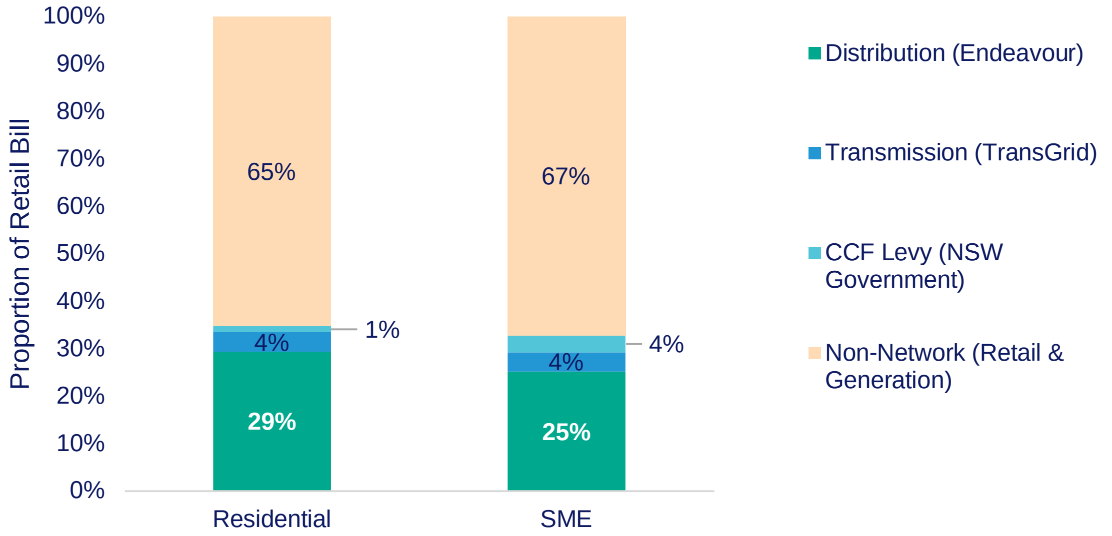
adopted this for our Proposal as we consider it provides a more stable revenue profile from a pricing perspective for the 2024-29 period.

As such, we consider we have complied with this requirement in smoothing our forecast revenue for the 2024-29 period. The final year difference between smoothed and unsmoothed revenue in the final year for the 2024-29 period is 5.2%, which we consider to be reasonable.

13.2.2 Indicative charges and bill impacts

Our contribution to the average electricity bill is less than 30% for residential and small business customers.

Figure 13-1 Breakdown of component parts of average electricity bill



We have worked hard over the previous and current regulatory periods to keep downward pressure on our contribution to electricity prices. By focusing on making broad and targeted improvements to make our business more efficient, network charges for the average residential customer's bill have fallen by 32.4% over the last 10 years and by 23.8% for small business customers.

Figure 13-2 Average (consuming 4,900kW p.a.) Annual Residential DUOS Bill ($; FY24)

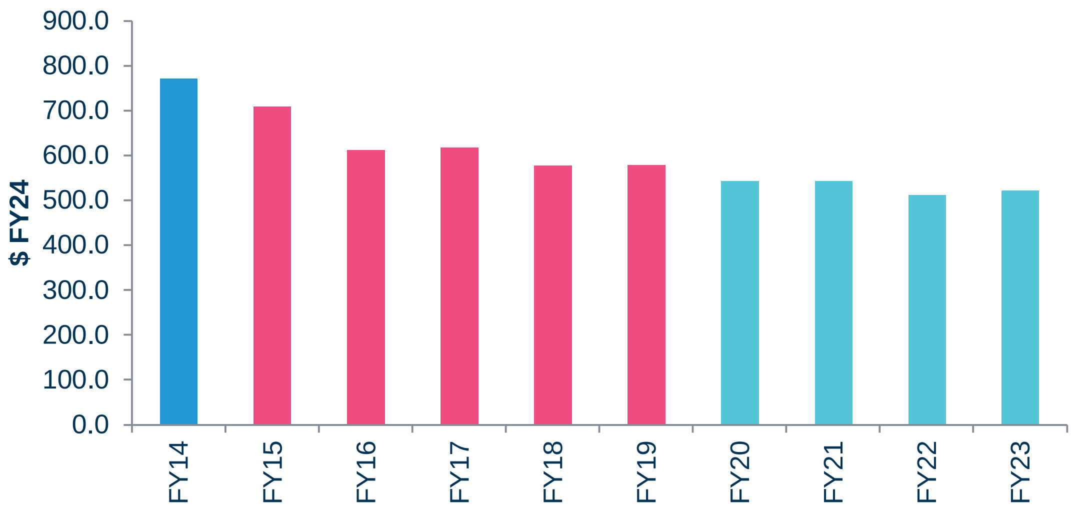
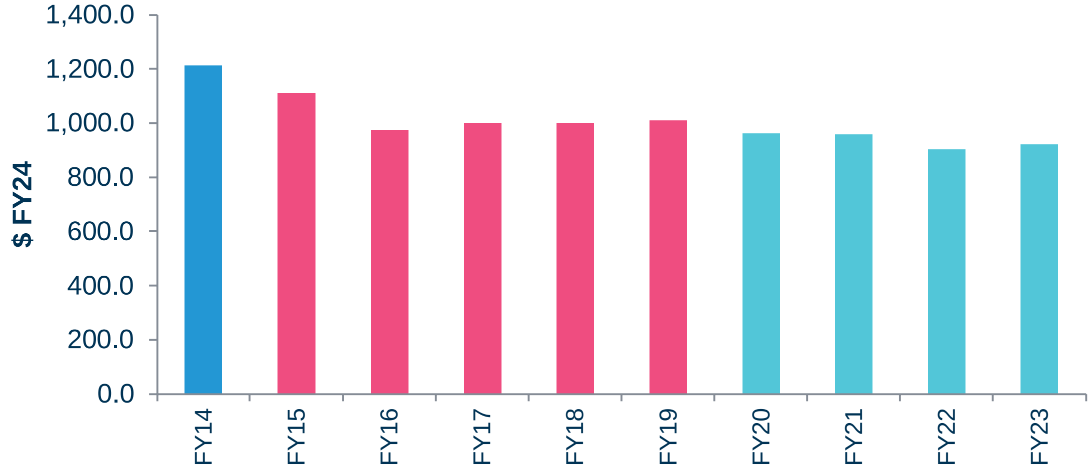
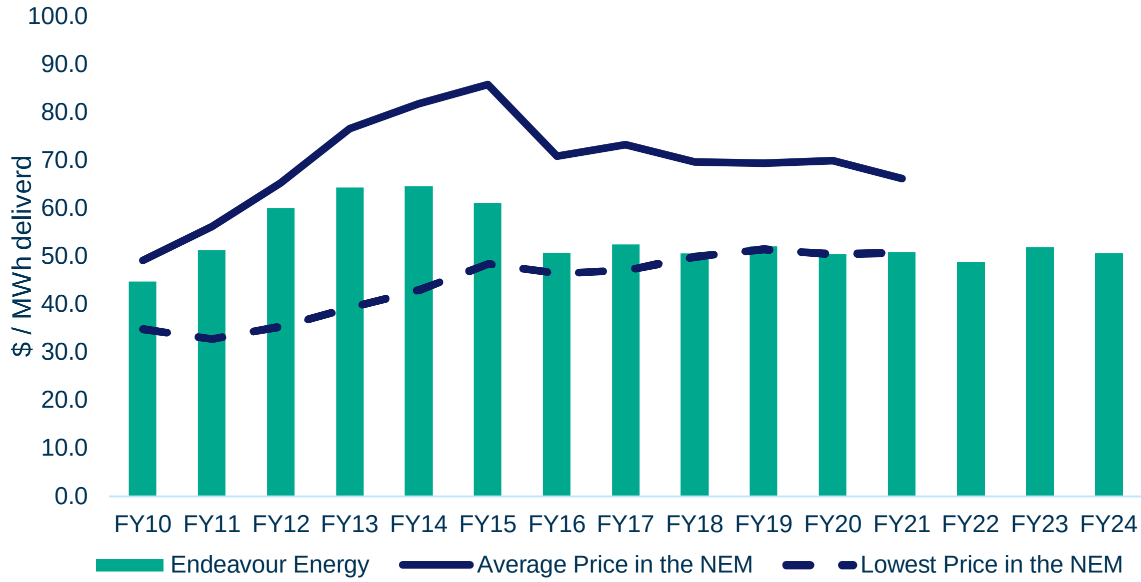


Figure 13-3 Average (consuming 10,000kW p.a.) Annual General Supply DUOS Bill ($; FY24)



As a result of these significant reductions our price, per unit of energy delivered, now ranks as the lowest in the NEM as per the AER's most recently published network performance data. This reflects our commitment to alleviate price pressures and our ongoing effort to be effective and efficient in everything we do, without compromising the safe, sustainable and reliable supply of electricity.

Figure 13-4 Average price per MWh ($; FY24)



Indicative DUOS prices for 2024-29 based on our proposed bundled revenue and our latest forecast of energy volumes are provided in Table 13-3 below.[77]

Table 13-3 Indicative average DUOS for FY23-FY29 (exclusive of metering)

$; Real FY24	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29
Residential customer consuming 4.9MWh p.a.	521.9	494.9	563.3	559.1	543.3	531.4	519.4
Small business customer consuming 10MWh p.a.	885.7	839.8	955.9	948.8	922.1	901.8	881.5

[77] For a full listing of indicative prices and bill impacts for the 2024-29 period, refer to table 7.7 of the Reset RIN attached to this proposal.

We note these increases (relative to FY24) are driven almost entirely by factors outside of our control. Namely, the economic downturn has materially increased the cost of capital that is derived by applying the RORI. The expected WACC has increased by over 150 bps in less than a year based on movements in observable parameters.

We also note that the prices outlined above are only a portion of the total network use of system (NUOS) charge to customers. NUOS charges include the cost of the services provided by the NSW Transmission Network Service Provider (TransGrid) as well as the recovery of an amount to satisfy obligations under the NSW Climate Change Fund (CCF) and NSW Electricity Infrastructure Roadmap. These components are also outside our control.

We have constrained all factors wholly within our control as much as reasonably practicable to limit the impacts of the WACC and expected increases in other components of electricity bills.

The prices outlined above are indicative only and will be updated in our Pricing Proposal for each year of the 2024-29 period to reflect:

- updated energy consumption forecasts;
- actual CPI;
- updated cost of debt;
- incentive scheme performance; and
- any changes in the relative portion of revenues recovered from each tariff and tariff component.

14. Alternative Control Services

14.1 Overview

We have responded to customer feedback and adopted a more cost reflective approach to pricing alternative control services. This has led to real savings for public lighting and metering customers.

Alternative control services (ACS) are distribution services that are attributable to a single customer or location or have the potential to be provided on a competitive basis. The costs of providing these services are recovered directly from individual customers and does not form part of our revenue requirements as proposed through the building block approach.

For public lighting, we have engaged with our customers to understand their priorities and concerns. Based on this feedback we have simplified our modelling approach, including the latest street lighting technologies, in our pricing model and updated our assumptions to reflect the benefits LED technology provides to offer a differential pricing option to traditional technologies. We have made these changes while reducing our overall forecast public lighting revenue requirements[78].

For metering we engaged HoustonKemp to develop assumptions on the transition to full metering contestability which commenced 1 December 2017. Our prices have been derived using the AER's standardised models and reflect a cost-reflective and simple metering charge that supports the transition to metering contestability.

For ancillary services, we have used the AER's standardised model, simplified our listing by reducing the number of applicable labour rates and used benchmark labour rates in setting fees for the 2024-29 period.

[78] Exclusive of non-LED lights noting we expect our network to fully transition to LED prior to the commencement of the 2024-29 period

14.2 Public lighting

We are committed to providing public lighting services that effectively and efficiently meet the needs of our customers. In response to favourable customer feedback, our proposed approach to public lighting services is consistent with that of the current regulatory period, meeting at least the minimum standards detailed in the NSW Public Lighting Code continues to guide our public lighting service plans.

In this section, we identify the method by which we have developed prices for the public lighting services we provide our customers.

14.2.1 Public lighting services

Public lighting is important in providing safety and security for pedestrians and vehicle traffic as well as enhancing the visual environment. Public lights are typically installed in street locations including residential streets and main roads using either existing electricity poles or dedicated public lighting poles (often referred to as "columns"). The type of lighting required depends upon the road type and customer requirements.

The vast majority of public lighting construction projects are contestable, in which case the public lights may be installed by a customer or gifted through land development protocols. Once completed and operating, we are responsible for the ongoing maintenance and repair of the lights. These activities are not contestable and can only be provided by Endeavour Energy. We also directly undertake the construction of minor public lighting works and other public lighting projects at the customer's request.

Legislation, regulations, standards and codes

We abide by the following legislation, regulations, standards and codes when installing and maintaining public lighting:

- NSW Public Lighting Code which we must comply with as part of our distribution licence conditions;
- Customer nominated requirements within the range of services offered;
- AS/NZS1158 series of standards for lighting of roads and public places;
- Electricity Supply Act 1995;
- Endeavour Energy electrical safety rules; and
- Endeavour Energy General Terms and Conditions for connection of public lighting assets.

NSW Public Lighting Code

The service performance standard agreed between providers and public lighting customers is set out in the NSW Public Lighting Code. This Code seeks to provide a basis for expected service quality by DNSPs with reference to the Australian Standard (AS1158) for public lighting which details illumination and other technical requirements. The Code provides a basis from which DNSPs, and public lighting customers may wish to negotiate alternative service performance outcomes.

Our public lighting forecasts reflects our adherence to the current minimum standards and guaranteed service levels set out in the Code in accordance with our obligations.

Public Lighting Management Plan

A requirement of the Code is for each public lighting provider to prepare a Public Lighting Management Plan (PLMP). Our PLMP (Attachment 14.08) has been developed to provide an overview of the business structure, processes and decision support systems we have in place to manage and operate a safe and reliable public lighting network. It also provides an overview of strategies we have put in place for continuous improvement in the standard of public lighting services provided to customers.

Engaging with our customers

We currently serve 28 public lighting customers, including 23 local councils, with approximately 230,000 installed lights, of which 111,000 are LED and 119,000 are old technology. It should be noted that we expect our network to fully transition to LED technology before June 2024. The number of public lights is steadily increasing due mainly to installations in several rapidly expanding growth areas within our network.

We consult extensively with our public lighting customers as part of BAU activities. This consultation has been extended beyond the regular meetings with each council in our network area in preparing this Proposal, to understand the specific needs of our customers and receive feedback on our performance.

As summarised in Attachments 5.07 and 5.08, our customers wanted us to:

- Simplify our pricing model to reduce the number of tariffs, make it easier to forecast costs and improve the transparency of the model.
- Embed cost savings, particularly in ongoing maintenance costs, between LED and non-LED technology.
- Implement a process to better support and facilitate the quick adoption of new technologies.

Overall, affordability remains their primary concern and customers see transitioning to new technologies as a way of realising cost savings and improving service offerings.

Consequently, we have adopted a new public lighting pricing model with simplified network charging schedules and reduced the number of tariffs. These simplifications include merging TC2 and TC4 maintenance tariffs, reducing price points of LED maintenance to two and replacing the cost recovery for TC1 with a capital annuity tariff.

In addition, following our engagement activities we updated our public lighting model to:

- adopt the latest available benchmark labour rates and fleet rates; and
- reduce our LED cleaning maintenance cycle from 10 years to 6 years to bring it into alignment with the new NSW Public Lighting Code that comes into effect from 1 July 2023.

These revisions further reduce our proposed public lighting prices for the 2024-29 period whilst also improving our compliance to the NSW Public Lighting Code. Our customers were largely supportive of these outcomes as presented during our engagement process.

We discuss these changes further below.

14.2.2 Public lighting objectives

Our public lighting decisions are made with reference to key objectives that ensure investments are in the best interest of customers and in accordance with the NSW Public Lighting Code.

Support new Lighting Technology

Our customers continue to express their desire to benefit from technological developments in lighting. Energy efficient light sources with longer life expectancy may result in:

- Reduced frequency of bulk replacement programs;
- Increased periods between scheduled maintenance;
- Reduced energy consumption;
- Lower lamp failure rates;
- Lower light output deterioration rates; and
- Improved environmentally sustainable outcomes.

We support the introduction of new street lighting technology and conversion to LED streetlights that can deliver these benefits to our customers. LED luminaires now account for almost 50% of all our public lighting installations and we expect this to grow to 100% over the remainder of this period.

We work closely with our public lighting customers to identify opportunities to introduce new equipment. We conduct product assessments including field trials which monitor equipment performance including failure rates; deterioration of light output over time and colour shift. Other factors such as cost, energy efficiency and environmental impact are also considered and public lighting customers are kept informed about the progress of the trials through regular meetings.

To improve the cost reflectivity of our public lighting prices and incentivise the adoption of more efficient LED lighting technology, we have developed differential LED public lighting prices. We note key assumptions underpinning this differential is an LED useful life of 16 years and a cleaning cycle of 6 years. On the latter, we revised our original position of 10 years to better align our Proposal with the revised NSW Public Lighting Code due to commence from 1 July 2023.

Minimum Service Levels

As part of this Proposal, we propose to continue targeting the standards set out by the NSW Public Lighting Code.

Based on the feedback received from our customers, we are satisfied that our service performance is commensurate with our pricing offerings and their expectations. We propose to continue the existing arrangements to the extent possible where they satisfy our customers' needs.

Minimise total lifetime cost

In our efforts to reduce public lighting costs over the complete asset lifetime, we continue to focus on offering and promoting energy efficient lighting options to customers. Increased service life and reliability performance from LED technology can lead to reduced replacement and maintenance requirements, putting downward pressure on future costs. The potential long term cost savings offered by energy efficient lighting are incorporated in our public lighting prices. Furthermore, our focus on containing costs and driving productivity improvements through increased use of market delivered solutions will continue into the next regulatory period.

Maintaining network performance

The Public Lighting Code outlines the principle obligations for public lighting service performance. Our public lighting systems and processes are designed to satisfy the Public Lighting Code.

We have implemented a public lighting compliance framework to satisfy the service standards described in the Code. Elements of the framework include:

- operating a 24-hour call centre and online form to receive fault reports from customers;
- establishing a management plan and reporting system for the design and construction of public lighting assets;
- cleaning, inspecting and repairing luminaires during re-lamping;
- ensuring that repairs of public lighting assets are undertaken within an average of eight working days per customer per year from receipt of the reported fault;
- endeavouring to provide repairs more quickly in high priority cases; and
- supplying reports to all major customers.

14.2.3 Pricing methodology

We have used our Public Lighting Pricing Model for the purposes of determining the public lighting charges for the 2024-29 regulatory period (Attachment 14.06). The model contains the proposed unit cost inputs for labour and material categories used to calculate these charges.

Costs

There are three main costs in providing public lighting services: capital, operating costs and corporate overheads.

- **Capital costs:** These refer to costs relating to the installation of public lighting assets either for new connections or replacing assets due to poor performance or being made obsolete due to new technology. Capital costs include the purchase of the physical items being installed and the capitalisation of labour costs required to undertake the installation;
- **Operational costs:** These refer to the ongoing costs to maintain/repair the installed assets as well as the replacement of lamps for each installation at appropriate intervals; and
- **Overheads:** These relate to the operational and strategic support costs such as IT systems to support asset and billing information, safety management, procurement activities etc.

These cost categories are most influenced by labour and material unit costs.

- **Labour:** consistent with our ANS model, we use benchmark labour rates derived by applying the AER and Marsden Jacobs approach using the most recently available Hays 2022-23 salary guide. This gives us confidence that our current labour unit costs are efficient.
- **Materials:** A variety of direct materials, such as luminaries, brackets, outreaches, etc. are required to provide public lighting services. The prices in our public lighting model reflect the current contracted market price for these materials; and
- **Rate of Return:** We have used a rate of return consistent with that applied to standard control services.

Price tariffs

We propose to continue applying the current tariff structures and component-based pricing over the next regulatory period with two key amendments. The tariff classes are broken down into two key subgroups, tariffs for assets installed before 8 August 2009 and those after this date:[79]

- **Tariff class 1 (TC1):** is an aggregate capital recovery and maintenance tariff. This applies where the asset was initially funded by us and was included as part of the RAB determined by IPART prior to 8 August 2009. Capital cost recovery built into this tariff class will trend in line with the residual RAB value reducing over time and historical price escalation constraints. Assets priced under TC1 may sometimes also be referred to as legacy assets. No new public lighting installations are covered by this tariff class;

  We propose that the TC1 (non-luminaire) asset base is converted to a capital annuity tariff using a 10-year remaining useful life. This will significantly reduce the number of tariffs and complexity of our previous pricing model.

- **Tariff class 2 (TC2):** is a maintenance cost recovery only tariff. This applies to assets where we did not fund the initial construction which occurred prior to 8 August 2009. As we did not fund the construction, we are not entitled to any capital recovery charges for these assets. Similarly with TC1, assets priced under TC2 may sometimes also be referred to as legacy assets. No new public lighting installations are covered by this tariff class;

  We propose that this tariff is merged with the TC4 maintenance tariff, again to improve the simplicity of our pricing model.

- **Tariff class 3 (TC3):** is an aggregate capital recovery and maintenance tariff similar to TC1, however this tariff class is priced using an annuity approach and only applies to assets installed after 8 August 2009. Unlike TC1 there is no RAB value driving variable prices over time and is specific to the asset installed;
- **Tariff class 4 (TC4):** is a two-part tariff; the first element is a maintenance cost recovery only charge similar to TC2. This applies to assets where we did not fund their initial construction which

[79] Even though the AER cut-off date for switchover of charges from legacy rates to annuity rates was 1 July 2009, on demand from its Public Lighting Customers and ASPs, Endeavour Energy agreed to a date of 8 August 2009 to cater for completion of projects that were already under way and to give time for Public Lighting Customers and ASPs to understand the new rates.

occurred after 8 August 2009. As we did not fund the construction, we are not entitled to any capital recovery charges for these assets. However, we are required to pay income tax on assets gifted to us in this manner. The second element of TC4 is a tax cost recovery charge that is paid through an annual amount over the life of an asset that is gifted to us by our customers after 8 August 2009; and

- **Tariff class 5 (TC5):** is a pure capital recovery tariff that is paid in a lump sum at the time of agreeing to replace an asset before the end of its useful life. This tariff class does not have specified prices but rather a specified formula for calculating the residual unrecovered capital and tax costs when a customer requests an early replacement of assets paid for by us.

Compliance with control mechanism

In compliance with the Rules, we propose the following forms of control for public lighting services over the 2024-29 regulatory period consistent with the AER's F&A decision:

- a schedule of fixed prices for public lighting services for the first year of the regulatory period; and
- a price path for the remaining years of the regulatory control period, based on the CPI-X methodology contained in the submitted public lighting model.

14.3 Metering services

Historically, as a DNSP we had the sole responsibility of providing small customers with metering services in our network area. Following the AEMC Rule change which sought to establish a competitive market for metering services throughout the NEM, metering contestability (Power of Choice) came into full effect on 1 December 2017.

The suite of changes made under the Power of Choice reforms have contributed to the decentralisation of several metering related activities from distribution networks. Through technological and regulatory changes, customers are increasingly able to access a wider range of metering services to help them make better decisions on their energy usage.

In anticipation of these changes, for the 2014-19 period metering services were reclassified from standard control services to alternative control services and separately priced so that customers could make efficient decisions when metering contestability was introduced.

Under the Power of Choice reforms metering contestability are being introduced on a gradual basis. All new meters installed from 1 December 2017 are provided by a Metering Coordinator on a contestable basis[80]. This means many customers will retain their existing metering until it fails, or they agree to replace it. Endeavour Energy will therefore continue to provide metering services for these existing meters as a transitional Metering Coordinator.

14.3.1 Type 5 & 6 metering

Existing meters are referred to as either Type 5 and 6 meters, which are defined as follows:

- Type 6 meters are the most commonly installed type of meter in our network and are a basic accumulation meter that is manually read on a quarterly basis; and
- Type 5 meters are less common in our network and are an interval meter that can be read remotely.

Metering customer volumes

We expect over time, the proportion of Type 5 and 6 meters will decline as they are steadily replaced with Type 4 ("smart meter') equivalents after either failure or through mutual consent between customers and their respective retailer. New installations will also increase the penetration of smart Type 4 metering.

HoustonKemp have provided an estimate of the likely churn in our metering customer base based on a number of factors. On average, they forecast an average annual churn rate of almost 65,000 of our Type 5 and 6 meter customer base. However, we have observed higher churn amounts in the most recent years and consider this higher level will be sustained over the coming 2024-29 period. Particularly in light of the AEMC's ongoing metering review which is exploring opportunities to accelerate the smart meter roll out.

We have therefore adopted an average annual churn rate of over 91,000 metering customers per annum for the 2024-29 period noting this will likely need to be revised to account for the AEMC's final metering review recommendations which are expected in early-mid 2023.

This piecemeal transition of customers to contestable metering can create asset stranding risks and diseconomies of scale in our operating activities. We discuss the impact of this on our capex and opex forecasts below.

Recovery of capital costs

For all Type 5 and 6 meters installed after July 1, 2015 we recovered the capital costs upfront rather than requiring an annual capital payment. However, there are replacement costs over the 2014-19 period and unrecovered amounts from previous periods that remain outstanding. Our opening metering asset base for the 2024-29 period is forecast to be $14.1 million (nominal).

Our pricing approach has been to recover these costs from all customers (through their retailers) that had an Endeavour Energy meter prior to 1 July 2015. We propose to continue with this pricing approach as we consider it to be fair, simple and practical. However, the technical remaining life for

[80] We note that due to implementation difficulties, Metering Coordinators may elect for the LNSP to continue to provide metering services alongside competitive metering service providers temporarily until March 2018.

the asset base at the commencement of the 2024-29 period is 13 years. We note the transition to competitive metering is likely to accelerate in coming years and a shorter lifespan may be appropriate. To address this issue, we consider the metering asset base recovery options are as follows:

- **Existing approach:** continue to recover the metering asset base from pre-1 July 2015 customers over the remaining technical life of the assets. For the 2024-29 period this equates to an annual capital charge of approximately $1.86 (real, 2023-24) per annum on average;
- **Accelerated approach:** as above with an adjustment to the remaining life of the assets to 5 years to better reflect their likely economic life. For the 2024-29 period this equates to an annual capital charge of approximately $3.57 (real, 2023-24) per annum on average;
- **Standard control recovery:** for the 2014-19 period, we suggest the remaining metering asset base is recovered as part of the standard control services RAB as these investments were made as a standard control service at the time. However, the AER considered this approach was not permissible under the transitional Rules which applied to the 2014-19 determination. We would be interested in exploring this option further if the AER considers it is viable; and
- **Exit fee:** for the 2014-19 period, we also proposed an exit fee of approximately $64 to recover our outstanding metering asset base. The AER and stakeholders considered this fee would present a barrier to competition. We have not proposed an exit fee for the 2024-29 Proposal on this basis.

We note the existing approach is likely to become untenable following the AEMC's final metering review which is likely to accelerate the rollout by several years. Our preference, as it was at the time of the 2014-19 Proposal, is to exit the metering market as quickly, as reasonably and as affordably as practicable to facilitate the transition to metering competition. We have based our proposal on the existing approach consistent with the AER's recent decisions. However, we would be interested in the views of stakeholders on which option is preferable and whether the AER considers any of the alternative options are appropriate.

Our capex forecast for the 2024-29 relates to supporting ICT systems given we will be required to continue data capture and processing meter populations until their replacement. Our capex forecast for the 2024-29 period is $1.9 million (real; 23-24) and is required to:

- Improve data collection and scheduling;
- Maintain currency to software security and market optimisation;
- Improve the accuracy and time spent doing meter reads; and
- SAP automation and upgrades (relating to meter reading) to interface into market B2B systems.

Metering operating costs

As a transitional Metering Coordinator for existing Type 5 and 6 meters we will continue to have meter operating, data storage and reading costs. Similar to standard control service opex, we have applied the base-step-trend methodology for forecasting our metering opex. Our proposed metering opex, using 2022-23 as the base year, for the 2024-29 period is set out in Table 14-1 below.

Table 14-1 Proposed metering opex for the FY25-FY29 period (including debt raising costs)

$m; Real 2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Metering opex	17.7	16.4	15.0	13.4	11.7	**74.1**

We engaged HoustonKemp to provide a forecast of opex accounting for the diseconomies of scale associated with a decline in our metering customer numbers following Power of Choice. Their analysis involved compiling a dataset comprising six variables for six DNSPs:

- the level of scheduled metering expenditure, expressed in 2021-dollar terms;
- the number of type 5 meters;

- the number of type 6 meters;
- the length of each network;
- the total number of customers; and
- the total number of residential customers.

The principal challenge associated with drawing out the relationship between meter reading costs and meter stock is that geospatially disaggregated records of meter reading costs are not available. HoustonKemp also tested a number of model specifications and estimation techniques as detailed in Attachment 14.05 to this proposal.

They concluded from their extensive evaluation of alternative models and estimation techniques that there is no evidence of a statistically significant, positive relationship between the stock of legacy meters and the cost of scheduled meter reading.

This finding is consistent with the untargeted, dispersed replacement of legacy meters by responsible third parties to date. This ad-hoc rollout has limited the scope for route optimisation and, in turn, the cost efficiencies that be achieved. However, HoustonKemp note that it is intuitive that at some point, even an ad-hoc replacement program will enable cost savings through route optimisation. It is unclear though when this point will be reached.

Despite these findings, which we support, we have decided to maintain the existing diseconomies of scale factor that the AER applied in our 2019-24 determination in the absence of a valid alternative. We note this is a conservative position and one that requires us to achieve cost savings that the rollout to date has not enabled.

14.3.2 Proposed prices for the 2024-29 period

Our proposed pricing approach is the same as that which applied for the 2019-24 period for the same reasons. Noting we have adopted the AER’s standardised metering models for consistency, transparency and simplicity.

To summarise, we have split metering services between primary and secondary categories. The latter are metering services that are in addition to the basic network service most customers receive, such as off-peak hot water or solar PV meter services. These additional services result in only marginally higher overall costs and therefore attract a lower incremental charge.

This means that a customer will pay a greater amount for their first metering service as this creates the majority of costs we incur as their meter provider. This approach also ensures that customers who have more metering services than a basic accumulation service will pay more to reflect the additional services being provided. We consider this balances the need for cost reflectivity and fairness. Our approach involves the following:

- **Existing metering assets:** We will seek to recover the existing capital costs for Type 5 and 6 meters during the course of the 2024-29 period. The collection of existing meter costs will be on a per-customer basis to avoid penalising customers for past decisions. The average charge will be $1.86 (real, 2023-24) p.a. for each customer; and
- **Opex:** Ongoing costs such as maintenance, meter reading, meter testing and data services will be recovered via a cents per day charge. The prices for ongoing opex have been developed on a per-service basis. This means that each unique data stream will attract a price. For example, a basic metering charge and an off-peak metering charge equates to two data streams and two services.

As aforementioned, our metering customer numbers are forecast to decrease by over 91,000 metering customers per annum on average over the course of the 2024-29 period due to the ongoing transition to metering contestability.

Metering is subject to a price cap form of control meaning prices to recover the forecast costs from the expected customer base are set for each year of the period. As metering customer numbers are declining at a faster rate than our costs this means primary metering prices will increase compared to the 2023-24 base year charges by approximately $18 and $27 (both real, 2023-24) across residential and small business customers by the end of 2024-29.

We consider this is an unfortunate by-product of the introduction of metering contestability. However, it is important that we provide a price signal that reflects the growing diseconomies associated with regulated metering services. This will encourage customers to electively transfer to a contestable metering service where it is efficient to do so. We have smoothed our metering prices to manage this issue as best as possible. Our resulting prices are as follows:

Table 14-2 Ongoing metering prices (capital plus non-capital charges)

$m; Real 2023-24	2024-25	2025-26	2026-27	2027-28	2028-29
Residential anytime	31.76	34.05	36.55	39.25	42.18
Small business anytime	47.10	50.62	54.43	58.56	63.03
Controlled load	9.57	10.09	10.66	11.29	11.99
Solar	9.57	10.09	10.66	11.29	11.99

Compliance with control mechanism

The Rules require that a regulatory proposal include:

- the proposed control mechanism;
- a demonstration of the application of the proposed control mechanism; and
- the necessary supporting information for alternative control services.

In compliance with the Rules, we propose the following forms of control for metering services over the 2024-29 regulatory period consistent with the AER's F&A decision:

- a schedule of fixed prices for metering services for the first year of the regulatory period; and
- a price path for the remaining years of the regulatory control period, based on the CPI-X methodology contained in the submitted metering services model.

Please see Attachment 14.04 for our pricing model and price list inclusive of our proposed pricing x-factors.

14.4 Ancillary network services

Ancillary network services are services which involve a variety of non-routine activities that are provided to customers on an 'as needs' basis. As with other alternative control services, the AER will regulate ancillary network services through establishing price caps for each year of the 2024-29 regulatory period. The prices we will directly charge our customers for each ancillary network service activity is required to reflect the efficient cost of providing these activities.

Ancillary network service prices are provided to customers as either of the following:

- **Fee based services:** The work involved in some ancillary network service activities are relatively homogenous. The costs involved performing these activities are generally the same and are charged at a fixed price on a per activity basis. Fees are derived from the relevant labour rates and average time required to perform the task and are charged irrespective of the actual time taken to complete the activity; and
- **Quoted services:** Costs for some ancillary network service activities may vary considerably between jobs. This is often the case for one-off activities that are specific to a particular customer's request. For quoted services, charges are levied on a time and materials basis. Prior to commencing work, customers are informed of the per hour cost with the final total charge payable dependent on the time taken to complete the respective activity.

For the 2024-29 period, we propose to provide the ancillary network service activities that were provided to customers in the current regulatory period. We have also proposed to provide some new activities to our customers. See Attachment 14.07 for a full listing of our ancillary services for 2024-29.

14.4.1 Our ancillary network services prices

Our ancillary network services (ANS) prices are required to reflect the efficient cost of providing these services. To ensure our prices are considered efficient we have adopted benchmark labour rates to set our prices for the 2024-29 period.

These labour rates were derived by firstly applying raw labour rates from the most recently available Hays 2022-23 Salary Guide, consistent with the approach used by the AER and their consultant Marsden Jacob in previous regulatory determinations. We note the Marsden Jacob benchmarks include a significant number of labour markets that we do not have access to and therefore do not reflect a realistic expectation of our cost inputs in NSW. However, we adopted the benchmark raw labour rates in the interests of affordability and continuity for our customers.

To derive total labour rates, we then applied a fixed oncost factor to each of the raw labour rates consistent with the AER's 2019-24 final decision. This reflects costs related to a variety of leave entitlements as well superannuation, workers compensation and payroll tax. We also applied an overhead rate which reflects our allocation of network and corporate overheads to ancillary network services plus a rounded 6% regulatory WACC. In combination, this results in an overhead factor that is in line with the implied overhead rate from the AER's 2019-24 final decision.

On the latter, we also note that we have not applied a margin, or associated tax recovery, to our ANS prices. This is consistent with our approach in the current period and because the AER typically assesses the overhead and margin factor applied collectively and our overhead rate is already at the AER's benchmark limit for these factors combined.

Finally, we have applied a vehicle cost that is consistent with the AER's 2019-24 final decision for labour types where vehicle use is inherent in the activities performed. Also, we have not applied a travel time component in the price build-up of our fee-based prices as a measure to keep downward pressure on ANS prices.

The process we followed for developing our ANS prices can be summarised as follows:

Step 1: Transition our existing ANS model to the AER's standardised ANS model. This involved listing all available fees as per the 2019-24 ANS model and working with internal stakeholders for inputs such as hours by labour category, and materials required to execute the list of ANS fees.

These inputs were also compared to the categories of the 2019-24 model to identify variances to ensure the transition did not result in any unreasonable variances.

Step 2: Review our ANS model for opportunities to rationalise our price list to improve comparability and simplify our pricing approach for customers. Our 2019-24 ANS price list contained over 300 individual quoted and fee services, many of which were slight variations of other ANS services. We reviewed under-utilised and/or comparable services for opportunities to reduce our listing. As a result, the following amendments were made:

- **Reduction in fee-based services with similar descriptions and prices:** We found 22 fees involving a similar service (Access Permits, Substation Commission Fee, Notification of Arrangement) but separated for customer type (Asset Relocation, Industrial Commercial, Non-Urban etc) at the same price. We therefore combined these fees reducing the number to 7 by adjusting the descriptions (68% reduction).
- **Reduction in quote-based services with similar descriptions and rates:** We identified 64 fees involving a similar service (Administration Fee, Design Certification fee, Design Information Fee etc) but separated for customer type (Asset Relocation, Industrial Commercial, Non-Urban etc) and/or separating between an Engineer or an inspector at the same price. We consolidated these 64 fees to 18 by adjusting and/or combining the descriptions (71% reduction).
- **Reduction in fee-based services by removing tiered pricing:** We identified 75 fees that have ASP Gradings such as A, B or C. This approach is a long-standing carryover of practices from when these fees were regulated by IPART (i.e., prior to AER regulation) and may have been to be tiered to incentivise higher quality ASP submissions. We do not consider this practice is required any longer or reflective of our current relationship with ASPs. As a result, these 75 fees have been reduced to 25 through consolidation (67% reduction).

We also decided to consolidate our existing 18 labour rates to 8 labour rates to be more consistent with the practices of most other DNSPs[81]. Our 18 labour rates were a vestige of our bottom-up, cost-reflective prices proposed for the 2014-19 period. To rationalise our labour rates, we checked that the 8 labour categories were consistent with the types of positions that we use to deliver ANS services.

Step 3: Review whether any new services were required and develop prices using the benchmark labour rates applied to an assumed quantity of labour and/or materials estimate. Specifically, this exercise resulted in the addition of the following ANS services:

- Network Tariff Change Request (fee): This would apply when a customer or retailer requests an alteration to an existing network tariff and may require us to conduct tariff and load analysis to determine whether the customer meets the relevant tariff criteria.
- High Loads Escorts Preliminary Study (quote): This often involves studies for transport companies that have particularly high loads, where an escort requires us to plan a path for them to drive through our network without affecting any low hanging mains.
- Pole Holds (quote): This involves us sending pole supports when an external ASP is performing boring works close to an existing electricity pole.
- Data Request Fee (quote): As more and more data points are captured on our network, this involves providing various types of data requests by customers for use in their projects/planning.

We have also made minor amendments relating to the names of the disconnection and reconnection service fees below to clarify that a separate fee will be charged for the disconnection and for the subsequent reconnection. This change is required to remove ambiguity regarding the application of these fees and brings us into alignment with our peers.

- Disconnections or Reconnections (Meter Box);
- Disconnections or Reconnections (Pole Top / Pillar Box);

[81] We have applied an 'after hours' factor of 1.75 to each of our 8 standard labour rates to reflect the cost of providing ANS services outside of normal working hours. This results in 16 labour rates being included in the ANS pricing model.

- Disconnections or Reconnections (Site Visit); and
- Disconnections or Reconnections at Pole Top / Pillar Box - Site Visit.

Step 4: Review whether any of the following assumptions have changed:

- The type of tasks involved in performing each service;
- The type and number of personnel and skills required to undertake each task;
- The time taken to complete individual tasks; and
- The type and number of non-labour resources/materials.

This review involved reviewing the hours and materials allowed in the existing model and discussion with internal stakeholders to confirm their validity. Based on this review we adjusted the time taken to perform 'Termination of cable at zone substation – distributor required performance' and 'Cable ID & Spike' to better reflect the time taken to perform the task and/or the materials required.

Overall, we consider these changes will simplify our pricing approach for ANS customers, improve its comparability and ensure our fees remain cost-reflective so that ANS customers are not cross-subsidised by SCS customers.

Security lights

Security lighting for private customers is similar to public lighting with installations typically attached to existing distribution network poles and structures. From the 2019-24 regulatory period, prices for security lighting services were regulated by the AER as Ancillary Network Services. This was seen as necessary to avoid the need to have this service ring-fenced from regulated distribution network services. The rationale behind this decision was that this service could only reasonably be provided by us as access to distribution assets is restricted and not practically provided by a different provider – ring-fenced or otherwise.

Until the commencement of the 2019-24 regulatory control period these services have been provided as an unregulated service with the price set at each site being directly negotiated with the prospective customer. Customers have been under no obligation to acquire the service offered, nor has Endeavour Energy been under any obligation to supply.

During the 2019-24 period, substitute services (such as privately owned LED lights and columns) have become increasingly available. In addition our energy costs, which are set in accordance with unmetered supply requirements, have increased substantively. As a result of our increasing costs and the possible emergence of a contestable market for private lighting, we intend to review our ongoing provision of this service for the 2024-29 period prior to the lodgement of our Revised Proposal.

At this stage, we propose to continue the 2019-24 pricing approach, a forward-looking pricing methodology similar to that of public lighting tariff 3, for the 2024-29 period. Under this approach, customers are required to pay a one-off installation cost and a monthly rental charge. These charges will vary depending on the type of lighting service requested and length of the contractual period. The ongoing charge will cover the costs of operating, maintaining and replacing the assets as required. As an unmetered supply of electricity, the charge is also inclusive of an estimated amount of electricity consumption calculated in accordance with published load tables and our contracted energy rates.

For simplicity, we have set prices based on the service provided to a customer i.e., the amount of illumination required. This allows us to maintain a common set of service outcomes for customers over time while providing flexibility to adopt different technologies to suit the location and/or different technologies as they become cost competitive.

Compliance with control mechanism

In compliance with the Rules, we propose the following forms of control for ancillary network services over the 2024-29 regulatory period consistent with the AER's F&A decision:

- a schedule of fixed prices for ancillary network services for the first year of the regulatory period; and

- a price path for the remaining years of the regulatory control period, based on the CPI-X methodology contained in the submitted ancillary network services model.

Please see Attachment 14.07 for our pricing models, pricing x-factors and price list.

15. Glossary

TERM	DEFINITION
AASB	Australian Accounting Standards Board
ABR	Annual Benchmarking Report
ACS	Alternative control service
ADMD	After Diversity Maximum Demand
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AER CCP	Australian Energy Regulator’s Consumer Challenge Panel
ANS	Ancillary Network service
ARR	Annual Revenue Requirement
AS	Australian Standards
ATO	Australian Taxation Office
BASIX	Building sustainability index
BESS	Battery Energy Storage System
BSC	Blacktown Solar Cities
Capex	Capital Expenditure
CAM	Cost Allocation Methodology
CAPM	Capital Asset Pricing Model
CBD	Central Business District
CCC	Customer consultative committee
CCF	Climate Change Fund
CEG	Competition Economists Group
CER	Customer Energy Resources (previously referred to as DER)
CESS	Capital Efficiency Sharing Scheme
COAG	Council of Australian Governments
CPI	Consumer Price Index
CSIRO	Commonwealth Scientific and Industrial Research Organisation

TERM	DEFINITION
DAPR	Distribution Annual Planning Report
DER	Distributed Energy Resources
DFA	Dual Function Assets
DGM	Dividend growth model
DMIA	Demand management innovation allowance
DMIS	Demand management incentive scheme
DMS	Distribution management system
DNSP	Distribution network service provider
DOE	Dynamic operating envelope
DRED	Demand response enabling devices
DRP	Debt risk premium
DUOS	Distribution use of system
EBA	Enterprise Bargaining Agreement
EBSS	Efficiency benefit sharing scheme
ECCNSW	Ethnic Communities Council of NSW
EGWWS	Electricity, Gas, Water and Waste services
EMM	Energy Ministers' Meetings
ENA	Energy Networks Australia
ENCRC	Energy National Cabinet Reform Committee
EnergyCo	Energy Corporation of NSW
ENTR	Electricity Network Transformation Roadmap
ESS	Energy Saving Scheme
EV	Electric vehicle
F&A	Framework and approach
FSC	Field Service Centre
FR	Frequency rate
GDP	Gross Domestic Product

TERM	DEFINITION
GSL	Guaranteed service levels
GWh	Gigawatt Hour
HV	High Voltage
ICT	Information and Communications Technology
IPART	Independent Pricing and Regulatory Tribunal of NSW
ISO	International organisation for standardisation
ISSC	NSW Industry Safety Steering Committee
kV	Kilovolt
kVA	Kilovolt Ampere
kWh	Kilowatt Hour
LED	Light-emitting diode
LiDAR	light detection and ranging
LTI	Lost Time Injury
MAMP	Metering asset management plan
MAPE	Mean absolute percentage error
MAR	Maximum Allowable Revenue
MED	Major Event Day
MEPS	Minimum energy performance standards
MPFP	Multi-Partial Factor Productivity
MPU	Major Projects Unit
MRP	Market risk premium
MTFP	Multi-Total Factor Productivity
MVA	Mega Volt Amperes
MWh	Megawatt Hour
NECF	National Energy Customer Framework
NEL	National Electricity Law
NEM	National Electricity Market

TERM	DEFINITION
NEO	National Electricity Objective
NIEIR	National Institute of Economic and Industry Research
NPV	Net present value
NRF	National Reconstruction Fund
NSW	New South Wales
NUOS	Network use of system
OECC	Office of Environment and Climate Change (NSW)
OEF	Operating environment factor
Opex	Operating expenditure
OT	Operational technology
PCSC	Peak Customer and Stakeholder Committee
PIAC	Public Interest Advocacy Centre
PLMP	Public Lighting Management Plan
PMA	Post-modelling adjustment
PoE	Probability of Exceedance
PoF	Probability of Failure
PPI	Partial Productivity Indicator
PQD	Power Quality Data
PTRM	Post tax revenue model
PV	Photovoltaic
RAB	Regulatory asset base
RBA	Reserve Bank of Australia
REZ	Renewable Energy Zone
RFM	Roll-forward model
RIN	Regulatory Information Notice
RIT-D	Regulatory investment test for distribution
RNC	Rewiring the Nation Corporation

TERM	DEFINITION
RRG	Regulatory Reference Group
Rules	National Electricity Rules
SAPS	Stand alone power system
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
SCADA	Supervisory control and data acquisition
STPIS	Service target performance incentive scheme
TCMD	Temperature corrected maximum demand
TOU	Time of Use
TRI	Total Recordable Injuries
TSI	Total system import
TSS	Tariff Structure Statement
UDIA	Urban Development Institute of Australia
VCR	Value of customer reliability
VDA	Value Development Algorithm
WACC	Weighted Average Cost of Capital
WARL	Weighted Average Remaining Life
WPI	Wage Price Index
WSA Co	Western Sydney Airport corporation
WSROC	Western Sydney Regional Organisation of Councils
ZS	Zone Substation

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Endeavour Energy

POWER together