Jemena Electricity Networks

JEN 2026-31 PROPOSAL

31 January 2025

Acknowledgement of Country

We acknowledge the many Traditional Owners across this Great Southern Land on which our Group employees and contractors live, work, volunteer, and play.

We pay our respect to the oldest continuing cultures on this planet by way of acknowledging Elders past and present.

We recognise that the First Peoples have lived, travelled on and cared for this Country for thousands of years. Without hesitation, we acknowledge First Peoples connections to the lands and waters of this Country including those relationships with all that is on, above, in, and under the waterways, seascapes, and landscapes.

With an open heart and mind, we are committed to listening and learning from the experiences, traditions, stories, customs, and practices of Australia's First Nations Peoples as we bring our projects to life in many communities where we work. We remain committed to working with First Peoples in co-creating shared futures, and building energy infrastructure, maintenance, and services for new and existing communities.

We honour and pay tribute to the legacy gifts of knowledge, experience and wisdom born from thousands of First Nations generations associated with the lands and waters.

We will work collaboratively with First Nations employees, Elders and Communities to preserve and grow the legacies of the past for the generations to come.

"Wurru Wurru Biik Djirringu – Sky Country of Lightning" by Simone Thomson

Wurru Wurru Biik Djirringu – Sky Country of Lightning

The traditional language of the Wurundjeri People is Woi-Wurrung. In the Woi-Wurrung language, the name Wurundjeri is in two parts. 'Wurun' meaning the manna gum tree, and 'djeri', the white grub that lives in the tree – the witchetty grub. Manna gum leaves float across the sky symbolising deep respects to the traditional custodians of the lands and waterways in which Jemena operates – Wurundjeri Country.

Birrarung, the majestic river of mist and shadows weaves gently across country from its birthplace at the foothills of the Great Dividing Range, to the saltwater Bay of Naarm, the place known as Melbourne. This significant and sacred waterway was a vital food source and means of travel, and the meeting place for inter-clan trade and ceremonies. The flowing water represents our connection to energy and mother earth and the relationship we all have with this vital resource.

Campsites are depicted along the river; they are the arced shaped mounds representing the customer homes within the region that Jemena services. Trees along the waterways represent the growing strength of Jemena and symbolise the intricate root system beneath country linking its customers. A burst of lightning strikes from the sky above, a flicker of light represents its relationship to power and its likeness to the extensive network of tree roots symbolising the distribution of power.

Bunjil the Wedgetail Eagle is the great and mighty creator spirit for the Wurundjeri People and all the Kulin Tribes. He created the lands and sacred waterways and all the flowers, trees and animals. After his creation he took the clay from the earth and moulded it into his people.

He took the string from the stringy bark tree and used it for their hair, then he blew into their mouths so they could breathe. After this, Bunjil was tired. So, he asked Waa the Crow, the Keeper of the Wind and Water if he could open up his bag of wind, he was too tired to use his wings to fly.

Waa did as he was asked and opened up his bag, but the wind was small. Bunjil asked him to open wider for a bigger wind, so Waa did as he was asked and opened his bag wider creating a mighty and powerful whirly wind. It lifted Bunjil into the air and carried him high into the sky right up into the heavens where he became the stars. This is where he remains today watching over his beautiful creation.

In the Aboriginal way, a person is represented by the 'U' and 'n' symbol. From the bird's eye view, this is the shape a person makes whilst sitting on the ground, knees crossed. People are shown around the interconnecting circles representing the many communities across Wurundjeri Country who are customers of Jemena. White dots around these circles symbolise Bunjil's stars in the sky country representing light and power distributed by Jemena.

The large Gathering Circle along Birrarung is the meeting place of Jemena. This is the place where its community gather symbolising the commitment they share in delivering power to its customers, the broader community. It is the place where Bunjil circles from above in his sky country of lightning – *wurru wurru biik djirringu.*

— Simone Thomson, a proud Wurundjeri and Yorta-Yorta woman

The Artist

Simone is a Melbourne based Aboriginal artist and Traditional Owner of Victoria's Woi-Wurrung Wurundjeri and Yorta-Yorta language groups through her mother. Simone also has Irish and Scottish heritage from her father. Simone draws inspiration for her art from the abundant textures and colours of this beautiful land, along with the ancestral bonds she has to the Birrarung (Yarra River) and Dhungala (the Murray River).

The origins of the name Jemena is from the Wagiman people in the Northern Territory (spelt Jemenna in the Wagiman language).

It means “to hear, to listen, to think”.

We have been operating with permission from the Wagiman people under the variant name Jemena since 2008.

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Message from the Board

Every day, we deliver electricity to over 380,000 homes and businesses across north-west Melbourne. We build and operate the infrastructure that transports electricity through over 950 square kilometres, providing energy to support households, businesses and critical infrastructure, such as Melbourne Airport.

The cost of living has increased, and we know our customers' needs and aspirations are rapidly changing. Our customers have told us affordability is a top priority for them, along with maintaining the reliability of the electricity network and increasing resilience to withstand and recover from extreme weather events.

The Board and I are proud of the extensive, comprehensive and meaningful engagement with our customers over the past couple of years. This thorough and broad-based engagement has ensured that we captured the most representative views of our customers as we plan for the upcoming 2026-31 regulatory period. Our plans have been shaped by the preferences, ideas, and recommendations of our residential, commercial, and industrial customers, as well as energy retailers and local councils. Our strategic approach, decision-making and work practices also consider the interests of the communities we serve.

The Board and I will continue to work to deliver affordable, and sustainable electricity network services that provide continued safety and reliability for our customers.

On behalf of the Board, and after taking on our customers' feedback, we are proud to release our Regulatory Proposal for 2026-31.

Jiang Longhua
Chair of the Board
SGSPAA (parent company of Jemena)

Message from the Managing Director

Customers are at the heart of our business. Listening to and understanding our customers' needs has been critical to shaping this Regulatory Proposal.

Over the past two years, Jemena has prioritised understanding how we can provide more affordable services to address our customers' most pressing concern: the rising cost of living. We are working to address this without compromising network safety and reliability.

The extensive engagement and feedback we have received from a diverse range of customers has enhanced our view of the role we play as we transition to a more sustainable energy future. Feedback from our customers has also enriched us as a business, and shaped the initiatives outlined in this Regulatory Proposal.

In response to customer feedback, we have created a strategy centred on affordability, reliability, resilience, energy transformation and education. Our five-year Regulatory Proposal outlines:

- efficient, sustainable solutions required to run a safe and reliable network
- new initiatives to enhance the digital experience and increase the accessibility of our communications with customers
- a commitment to developing a network resilience strategy
- deployment of technologies that enable better management through innovation, providing customers and future generations with service levels that meet their needs.

Despite increased costs and the complexity of managing our electricity network, we are proud to deliver network price reductions to our customers, consistent with our goals in previous regulatory periods. At the same time, our Proposal also outlines a range of benefits aligned to the priorities of the communities we serve such as: addressing concerns around affordability, devising new tariff structures that encourage better network utilisation, our commitment to educating our customers, maintaining current reliability levels and improving price equity between solar and non-solar customers, to name a few.

Finally, I want to thank our customers, stakeholders and community members whose contributions have shaped our plan for 2026-31.

David Gillespie
Managing Director

Summary

Highlights

- In developing our 2026-31 Proposal, we have undertaken an extensive customer and stakeholder engagement program—we purposefully and ambitiously sought to understand the views of our richly diverse customers, including those customers whose voices, without specialist engagement, would not typically be heard.
- We collaborated with our customers to explore how we should prepare for a sustainable energy future while meeting customer and community needs today. The priorities and recommendations of our customers gathered over the course of our 20-month engagement program have been instrumental in shaping our plans.
- The energy transition is fundamentally changing the structure and function of the electricity system and is rapidly transforming the way that we need to plan, manage and operate our network. Our 2026-31 Proposal includes a number of initiatives that will enable us to pre-empt the transformation, mitigate against the potential negative impacts of disruption, and embrace the opportunities that it presents on behalf of our customers.
- Key drivers of our expenditure over the next regulatory period include connecting new customers and catering to growth, maintaining network reliability and improving resilience, accommodating the forecast entry of customer energy resources (such as rooftop solar, electric vehicles and storage batteries) through digitisation and automation and providing ongoing service excellence to our customers.
- To deliver our plans, we forecast that we will need $1,846 million in revenue over the next regulatory period, a 15% increase from our revenue requirement for the current regulatory period.[1]
- Our plan includes a 12% reduction in distribution charges in 2026-27 and a further 5.6% price decrease each year from 2027-28 until the end of the next regulatory period. This price reduction is enabled by an increase in load across our network, driven by data centres and major connections, and increased utilisation by existing customers as they move from using gas to electricity to heat their homes and cook their meals.
- We are proposing changes to our residential tariff structures to reflect our customers' preferences for improving fairness, equity, and cost-reflectivity.

Jemena Electricity Networks (Vic) Ltd (JEN) is an electricity distribution network service provider (DNSP). Every day we help deliver electricity to over 387,000 homes and businesses across north and western Melbourne.

We are subject to economic regulation administered by the Australian Energy Regulator (AER) under the National Electricity Rules (NER).

Our network prices are approved every five years by the AER. Before each new cycle, we submit a proposal to the AER that outlines our plans for the five-year period and how we expect to fund them.

This document and its associated attachments constitute our 2026-31 Proposal for the period 1 July 2026 to 30 June 2031 (the next regulatory period). It sets out the services we will offer, the costs we are likely to incur in providing these services, and the prices we propose during the next regulatory period.

All dollar values in this document are expressed in $2026 unless stated otherwise.

1 The revenue requirement for the current regulatory period includes JEN's reopener application, which we provide more details in Attachment 08-01.

Our 2026-31 Proposal reflects our customers' priorities and how we are responding to a rapidly changing energy market

Our 2026-31 Proposal has been shaped by our customers' expectations and regulatory obligations regarding the safety, reliability, and security of the network as the energy market transitions.

In planning for the next regulatory period we have had to consider and address challenges associated with climate change, policy changes, and the rapid development of technology, all of which have accelerated the rapid transformation of the Australian energy market. We also need to cater for significant growth across our network.

Current cost of living pressures are a concern for all the customers that we engaged with—maintaining affordability alongside reliability was considered essential for equitable energy access.

Our network must respond and adapt to these challenges and this new environment for the long-term interests of our customers. Our 2026-31 Proposal seeks to ensure that we play our role in supporting the transformation of the energy system, whilst meeting the needs of our customers and our community.

Below we set out the key drivers that have shaped our 2026-31 Proposal for the next regulatory period.

Our customers' expectations

Recognising our role as an essential service provider, we are driven to continuously improve our customer-centric culture and strive to understand customer needs and expectations. Our 2026-31 Proposal has provided us with a unique opportunity to allow our customers to help shape the services we offer, and to inspire our teams to improve outcomes for them.

> Our customer engagement goals are to develop a proposal that accurately reflects the preferences of our diverse customers, and to capture the views of customers that without specialist engagement, their voices would not be heard.

With a constantly changing environment and cost of living pressures, providing a fair energy future has never been more important than now. With the increase in customer uptake of renewables and other technologies, people are rapidly changing both how they use electricity and what they expect from the electricity network. This compels us to rethink the best ways to plan for the future and charge for electricity in a way that is fair and equitable and meets the varying expectations of our customers.

Throughout the engagement process, we asked our customers to think about and make suggestions and recommendations on the question:

How should Jemena prepare for a sustainable energy future while meeting customer and community needs today?

Our customers have spoken and we listened. Table S.1 provides a snapshot of our customers' key priorities, while Chapter 2 of our 2026-31 Proposal sets out in detail our ambitious and extensive customer engagement journey, our customers' priorities and recommendations, and how we have responded to this feedback. We are grateful to all the customers who have engaged with us for their invaluable insights and generosity in giving us their time.

Table S.1: Snapshot of our customers' key priorities and expectations

Key themes	Detail
Affordability, equitable and fair tariff reform	Our customers want electricity prices to be affordable. They want us to implement a tariff structure that is fair for different types of customers, such as solar and non-solar.
Reliability, resilience, power quality	Our customers want us to prioritise investment in network reliability to maintain service standards, power quality and customer experience and accommodate new growth. They want us to prioritise investment in network resilience to help us withstand and recover from the effects of natural hazards or disasters.
Sustainability	Our customers want us to facilitate the transition to renewable energy sources and champion renewable energy in new housing and estates. Customers see us playing a leading role in enabling energy storage and incentivising battery take up and they want us to prepare for the increase in electric vehicle (EV) charging. Customers expect our operations to be sustainable and to maximise the use of green energy across the network as much as possible.
Digitisation and automation	Our customers want us to digitise and automate the network to make it smarter, more responsive and more efficient.
Ongoing customer service excellence	Customers strongly want us to take a leading role in empowering and educating them through the energy transition and making communications to them efficient and accessible.
Social and corporate responsibility	Our customers want us to continue to provide support for customers experiencing vulnerability and to help protect the land. Our customers want us to lead by example in reducing emissions and achieving net-zero targets.

Energy transition

Five global megatrends are currently driving the energy transformation, which are likely to fundamentally change the structure and function of the electricity system over the next regulatory period and the long term. These are:

- **Decentralisation.** There has been a gradual decline in demand for electricity from centralised sources like power stations. Conversely, the generation from, and consumption of, electricity from consumer energy resources (CER)[2] has increased.
- **Decarbonisation.** Federal and state governments are implementing policies to decarbonise the economy, and many have accelerated their emissions reduction targets in recent years. In light of this and the expected retirement of the coal generation fleet between now and 2050, significant amounts of intermittent renewable generation—whether large-scale or CER—will likely enter the electricity system in its place.
- **Electrification.** Electrification is likely to be recognised for its environmental benefits by shifting end uses of electricity—including transport and heating—away from fossil-fuel sources. EVs present an opportunity to increase the utilisation of the electricity distribution network, and if the additional electricity used in EV charging can be managed, the expected increase in peak demand can be abated. In addition, the Victorian Government has placed a ban on new reticulated gas network connections. We expect more customers connecting to our electricity network as a result of the Victorian Government's gas policy.

2 CER are small-scale energy resources owned by customers, which can produce, store or vary how they use energy. CER includes rooftop solar, batteries and EVs and more traditional assets such as hot water heaters and pool pumps.

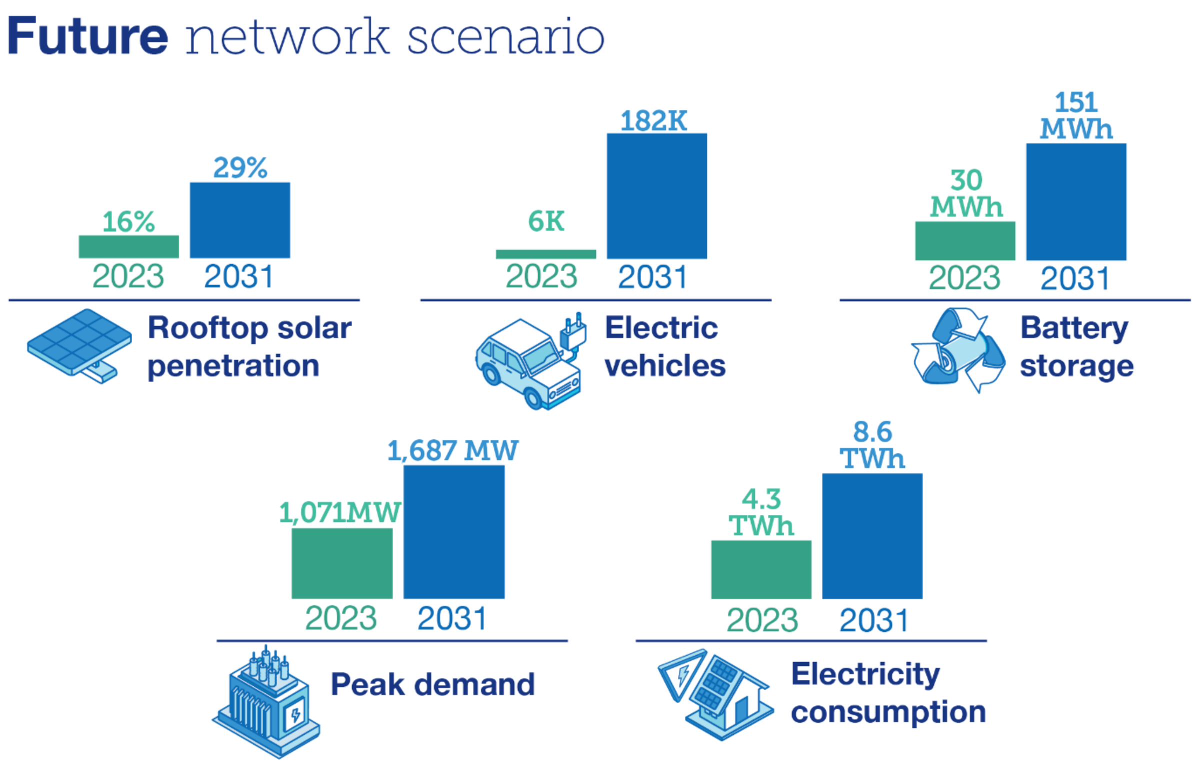
- **The rise of energy storage**. Energy storage is made possible by converting electricity into other forms of energy that can be stored. A growing form of energy storage is batteries. Storage batteries, if managed well, can abate the expected increase in peak demand.
- **Digitisation**. Digital technologies such as smart meters, sensors, automation, machine learning, artificial intelligence and other digital network technologies can create smart integrated networks that better meet customers' needs.

Our analysis shows that due to the energy transformation, our network will be significantly different by 2031. Figure S.1 shows a snapshot of the status of our network by 2031 under a neutral scenario.[3]

From a network perspective, the more variable renewable generation sources that enter the system, the greater the need for flexible, dispatchable capacity to maintain system reliability and security. It could also mean there is a greater need for interconnectedness – both physical and digital – to balance and vary the generation mix. We cannot wait until 2030 or 2040 to address the challenges associated with the energy transition. New capabilities and systems must be added in the next regulatory period.

We have developed a CER Integration Strategy to help us manage the uncertainty and range of risks associated with the transformation.

Figure S.1: Status of our network by 2031 under a neutral scenario



Data centres

Whether you use the internet for online banking, connecting with friends and family, or working from home, you are creating data. While we tend to describe this data as existing 'in the cloud', the websites and apps you

3 Our neutral scenario is consistent with the AEMO's step change scenario (moderate growth, fast change scenario). See Chapter 3 (energy transition) of this document for more details.

interact with store this data in large computer servers. These servers and the systems that keep the data secure are housed in purpose-built buildings called data centres.

It is estimated that over the next five years, trends in internet usage and new technologies like Artificial Intelligence (AI) will generate twice as much data as the past ten years. This means that data centre storage will need to increase by 18.5% per year over the same period.[4]

Data centres are energy-intensive and need to be operational 24/7. They are designed with electricity redundancy to minimise the chance of a power outage. This means that when they connect to the network, costly upgrades are often required to ensure they can get all the electricity they need all the time.

Reopener application

Over the 2021-26 regulatory control period (current regulatory period), we will connect many large data centres to our network.

We anticipate exceeding our capital expenditure allowance in the current regulatory period due to unprecedented growth in data centres and other large customers seeking to connect to our network. The volume and size of large customer connections were unforeseen and were not included in our capital expenditure allowance for the current regulatory period.

In October 2024, we applied to reopen JEN's current regulatory period determination to account for this unforeseen and material increase in capital expenditure. At the time of submitting this proposal, the AER is assessing our reopener application.

In preparing this JEN 2026-31 Proposal, we have assumed that our reopener application will be approved as submitted to the AER. More information on our reopener application is included in Chapters 5 and 7, and Attachment 08-01.

Based on the information shared with us by prospective customers, we forecast that more data centres will apply to connect to our network. Our 2026-31 Proposal has accounted for these intensive data centre projects. Connecting data centres to our network increases our capital expenditure. However, in the long term, their presence on the network will reduce costs for our customers due to economies of scale and the potential to improve network utilisation. The price reductions included within our 2026-31 Proposal are enabled by the significant increase in energy consumption that we expect to see on our network over the next regulatory period, which is largely driven by these data centres. Should actual consumption be greater than we forecast, this will place further downward pressure on distribution bills.

Regulatory obligations

We need to maintain the level of performance provided by our existing assets, or else they will deteriorate and eventually fail. If failure occurs, the quality of service we provide to our customers would decline and we would fail to comply with our regulatory obligations, potentially negatively affecting the stability of the wider electricity grid. Our condition-based and consequence-based risk assessment of our existing assets suggests that we will need to replace several distribution system assets, SCADA,[5] network control and protection systems and assets, and subtransmission assets in the next regulatory period.

Network resilience

Network resilience is the ability of the electricity network to withstand and recover from the effects of a natural hazard or disaster, such as floods, storms and bushfires. The impacts of climate change on electricity distribution are already present and increasing. Our customers have increased expectations about how we perform in extreme situations. Throughout our engagement process, our customers told us that JEN needs to

4 John Rydning, International Data Corporation Document #US49346223, Revelations in the Global Storage Sphere 2023, August 2023.

5 SCADA (supervisory control and data acquisition) is a real-time control system that enables monitoring, and the issuing of process commands to manage the high-voltage network in real time.

prioritise investing in network resilience so it can withstand and recover more quickly from the effects of a natural hazard or disaster.

Following the extreme weather events in Victoria in 2023 and 2024, the Victorian Government has placed additional obligations on electricity distributors to ensure our networks and the communities we serve can withstand and recover from extreme weather events in the future. Due to the timing of the release of some of these new obligations, we have not been able to incorporate the impacts into this 2026-31 Proposal. We will consider the new obligations not currently incorporated into our 2026-31 Proposal in our Revised 2026-31 Proposal, due in late 2025.

We have developed our 2026-31 Proposal using a long-term, whole-system approach

Long-term approach. Many of the required technologies needed to address challenges associated with the energy transition are in their infancy or do not yet exist at scale. We will upgrade our Information and Communication Technology (ICT) networks to ensure we can implement advanced technologies to reduce future network costs and enable consumer participation. Our 2026-31 Proposal is premised on the assumption that these technologies will be increasingly effective beyond 2031 thereby reducing the level of investment we need beyond the next regulatory period.

Whole-of-system approach. Our 2026-31 Proposal considers how we can empower our customers and help them unlock greater value from our network through the various digital technologies we propose to implement to accommodate more CER while meeting our regulatory obligations. We are conscious that if we do nothing, constraints on our network will result in higher costs to consumers by reducing their ability to unlock the advantages of solar and lower-cost electricity for EVs and heating.

Our expenditure forecasts

For the next regulatory period, we forecast an operating expenditure of $615 million, which is 4% lower than our allowance for the current regulatory period (excluding inflation). Our forecast base year operating expenditure is below the efficient level estimated using the AER's benchmarking approach. This is unsurprising as we operate efficiently and benchmark well amongst our peers.

We forecast a gross capital expenditure of around $2.2 billion, a 58% increase from our expected capital expenditure for the current regulatory period. After deducting capital contributions from connecting customers and proceeds from any asset disposals, our forecast net capital expenditure is $1.4 billion. This reflects the costs needed for us to meet our customers' expectations and address the operating challenges we are facing, as outlined above.

Under-investment in network capital expenditure can cause our network to have insufficient capacity to serve the increased load, including from data centres. This will not only lead to higher bills from lower overall utilisation but could lead to increased unreliability during peak times. It will also place limits on network connections, the uptake of CER, and customers moving from gas to electricity for their home heating requirements.

We have assessed the prudency and efficiency of our proposed initiatives against the national energy objectives under the NEL and the AER's various guidelines.

Chapters 5 and 6 set out our forecast expenditure over the next regulatory period, while Chapter 7 provides more information about our incentive schemes.

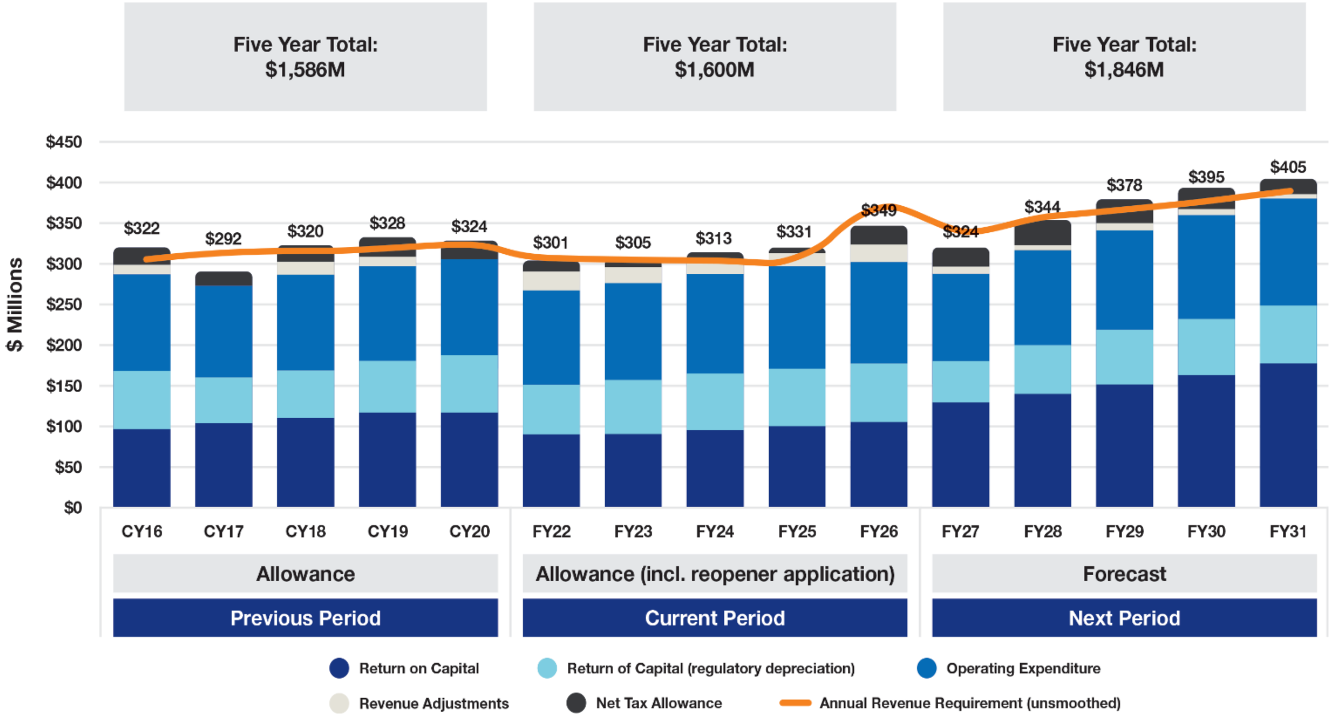
Our required revenue to deliver the 2026-31 Proposal

We forecast that we will need $1,846 million in revenue over the next regulatory period, a 15% increase from our revenue requirement for the current regulatory period[6] (see Figure S.2). Key drivers for the increase are our proposed investments to connect new customers, maintain network reliability and improve resilience, accommodate CER (rooftop solar, EVs and batteries), digitise and automate and provide ongoing service

6 Our revenue requirement for the current regulatory period includes JEN's reopener application, which we provide more details in Attachment 08-01.

excellence to our customers. These initiatives are consistent with and in response to our customers' feedback and recommendations.

Figure S.2: Total revenue requirement – network distribution services, real $2026, millions

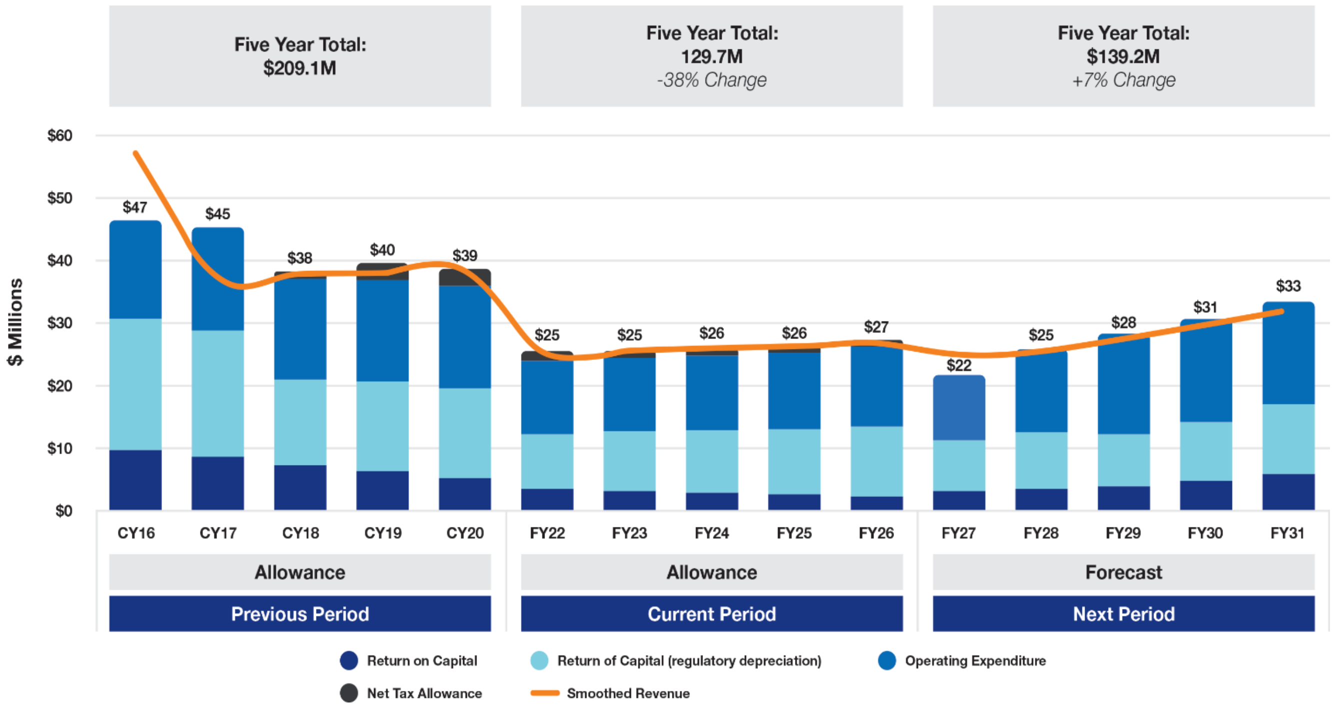


We are also seeking $139 million in revenue over the next regulatory period to deliver advanced metering services to our residential and small business customers, which represents a 7% increase from the current regulatory period (see Figure S.3). Key drivers for our proposed revenue requirement for smart metering services include:

- replacement of smart meters that have reached their 15-year technical lifespan
- in-person inspections of meters as part of our new regulatory obligations.

Chapters 8 and 10 set out how we have estimated our forecast revenue requirements for network distribution charges and smart metering charges, respectively.

Figure S.3: Revenue requirement for smart metering services, real $2026, millions



What our 2026-31 Proposal will deliver for our customers

Figure S.4: Our 2026-31 Proposal will deliver the following benefits for our customers

All customers will receive an average reduction of 12% in 2026-27 and then 5.6% each year for the remaining 4 years (excluding inflation).

A new portal to provide tailored information based on customer preferences and language needs with energy information.

Connect over 33,300 new residential customers and 2,585 businesses in North-west Melbourne.

Broad-based zone-substation redevelopment program to maintain the current reliability levels.

New tariff structures that encourage better network utilisation and improve price equity between solar and non-solar customers.

Large-scale assets to serve new large customers such as data centres and hospitals.

New digital technologies to improve electricity system management and enable new sustainable products and services.

Replacement of fleet vehicles with those that are more environmentally friendly to increase the sustainability of our operations.

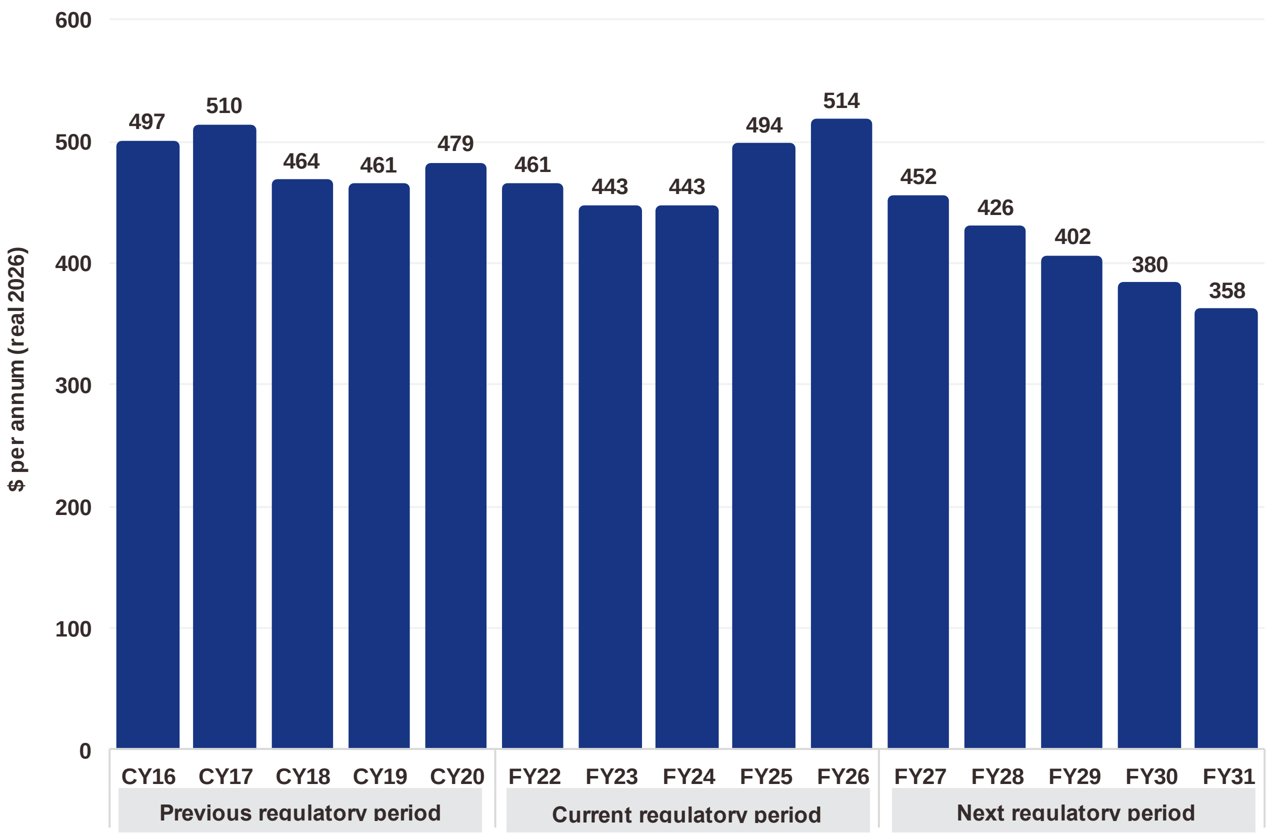
Upgraded systems to keep customers better informed with near real-time information at times they need it the most.

Customer bill impacts

Affordability remains our customers' top concern. We propose to deliver a significant reduction in distribution charges in 2026-27 of 12%, followed by further price decreases of 5.6% each year from 2027-28 until the end of the next regulatory period.

Our proposed price reduction is enabled by an increase in load from data centres, major connections and increased utilisation from existing customers as they move from using gas to electricity to heat their homes and cook their meals. Network distribution costs represent around 35% of a typical residential customer's electricity bills. Figure S.5 shows the historical and forecast distribution charges for a typical residential customer. A typical residential customer's average annual bill is expected to decrease from $471 in the current period to $404 in the next period, which represents a 14% saving in real terms."

Figure S.5: Historical and forecast residential distribution charges per year, $2026



Note: for residential customers consuming around 4300kWh per annum

We are proposing some changes to our tariff structures

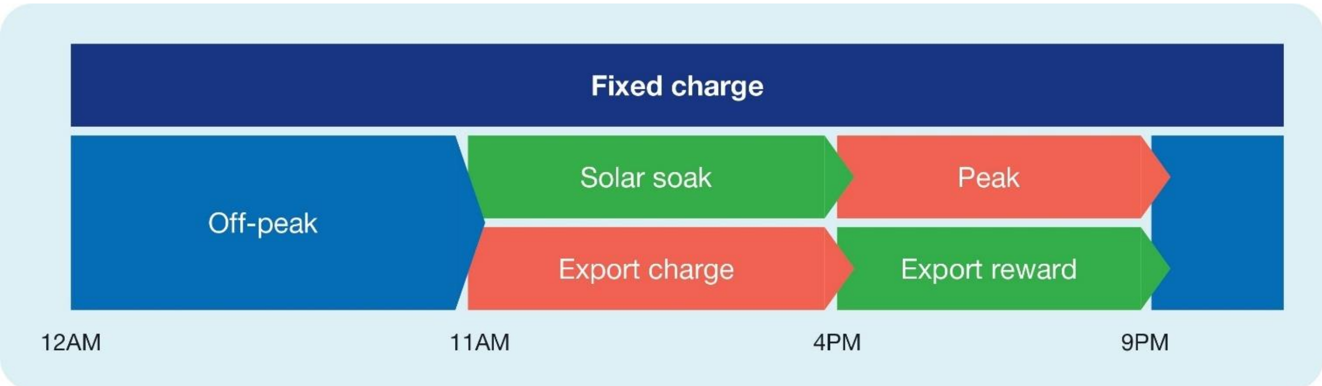
To reflect our customers' preferences for improving fairness, equity, and cost-reflectivity, we want to incentivise customers, with or without solar, to take up more energy created in the middle of the day. For the next regulatory period, we are proposing two new residential tariff structures:

- **Daytime Saver Time of Use.** This tariff will enable all customers to benefit from the energy generated by customers with rooftop solar generating units. We propose to replace our existing Time of Use **(**ToU**)** tariff by introducing a daytime saver period in the middle of the day while maintaining the peak and off-peak components of the previous tariff. This daytime saver period would operate as an additional off-peak period, with cheaper pricing than the off-peak window to encourage consumption (Figure S.6) in the daytime "solar soak" window.

Figure S.6: Daytime Saver

- **Export Tariff**. This tariff includes charges for exporting electricity to the network when the network is constrained,[7] rewards customers who export electricity at a time when the network needs it the most and applies no export charges when exports are expected to have no network impact (Figure S.7). This tariff will be provided on an *opt-in* basis in the next regulatory period.

Figure S.7: Proposed export tariff structure and timing



Network reliability

Throughout this 2026-31 Proposal, we have ensured that our planned expenditures represent the most efficient way of meeting our customers' needs, the objectives we have identified, and our regulatory obligations as the energy market transitions.

Our forecast does not include additional costs to improve network reliability, as our customers have told us they do not see the value in paying for these improvements. They did, however, tell us that we needed to maintain our current levels of service as the energy market transitions and therefore our forecast does include expenditure to ensure that the level of reliability we currently provide does not degrade.

7 For example when the network is at or close to capacity of being able to accept any more electricity generation from customers.

Figure S.8: Reliability over time–unplanned SAIDI (measures the duration of outages)

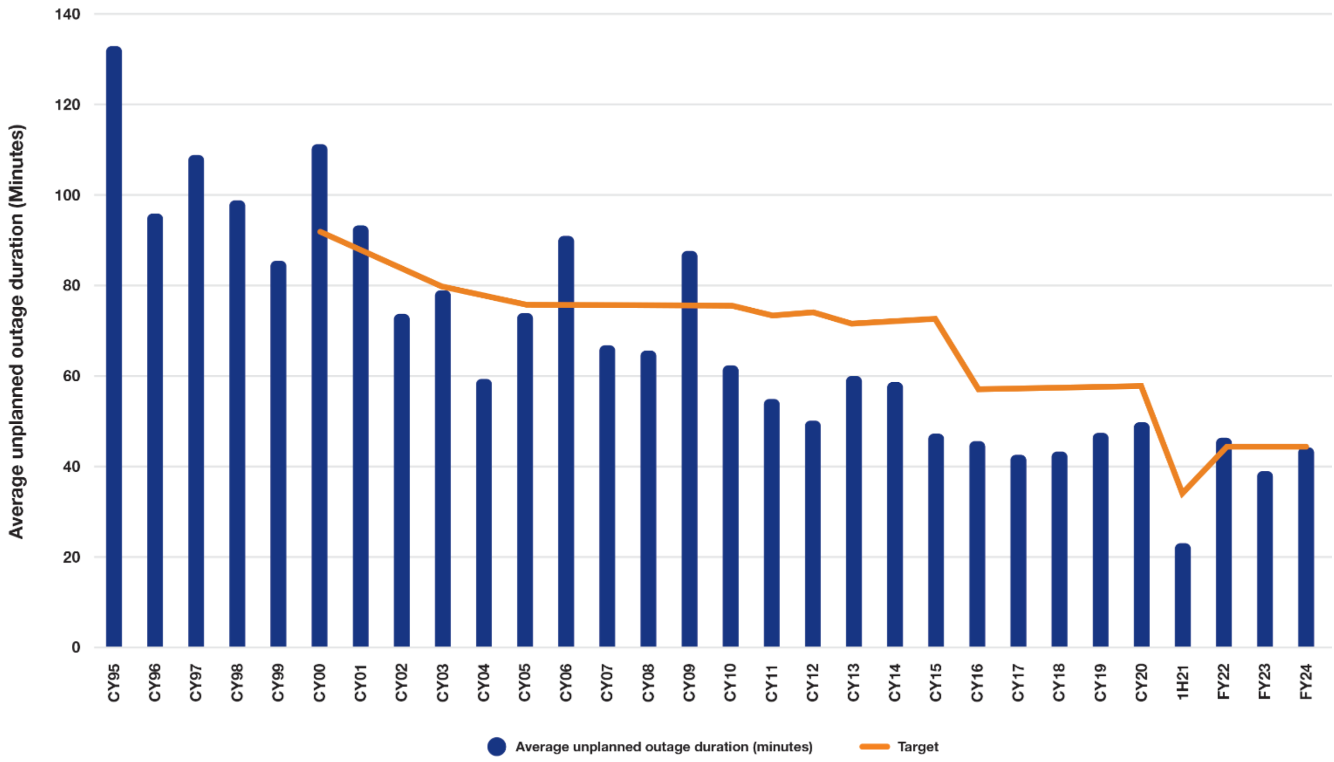
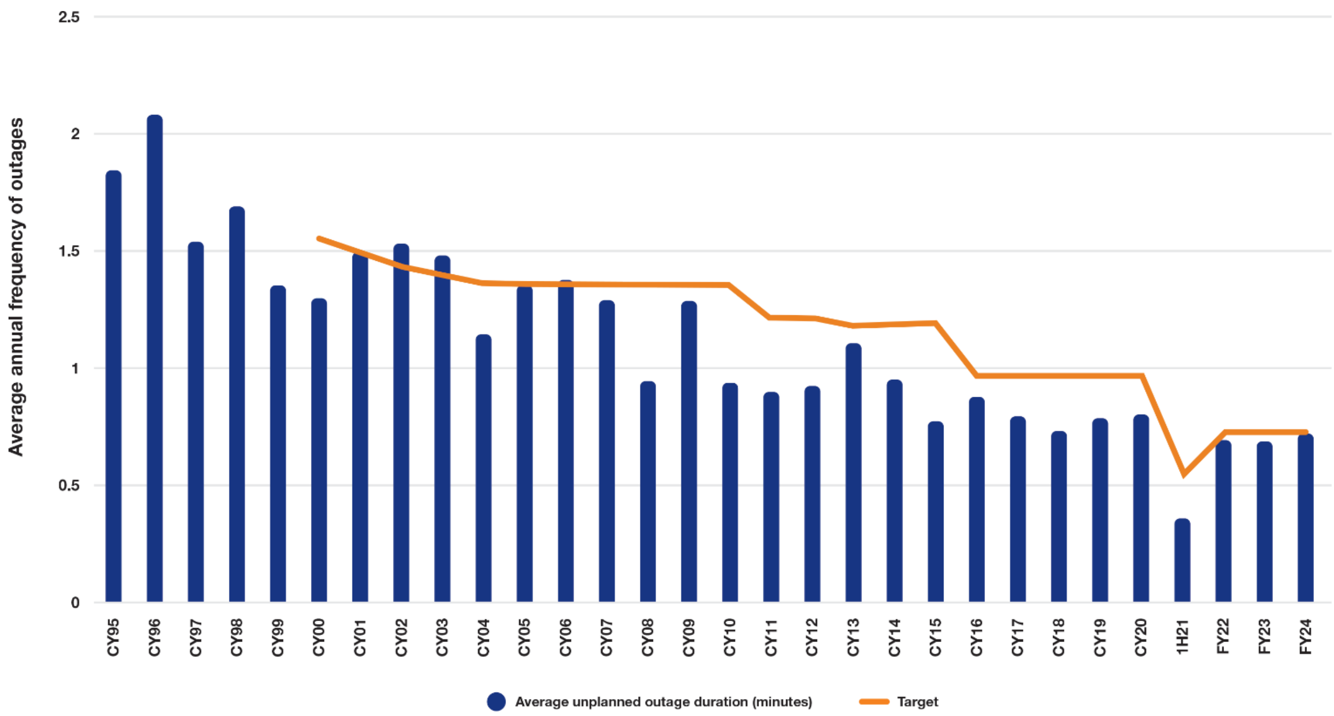


Figure S.9: Reliability over time–unplanned SAIFI (measures the frequency of outages)



2026-31 Proposal risks

Our 2026-31 Proposal is forward-looking, which means we have to forecast a range of activities into the future. These projects may not eventuate, and therefore, our 2026-31 Proposal contains a number of risks. With this in mind, we have developed a range of mitigations to protect against these risks which we have summarised in the table below.

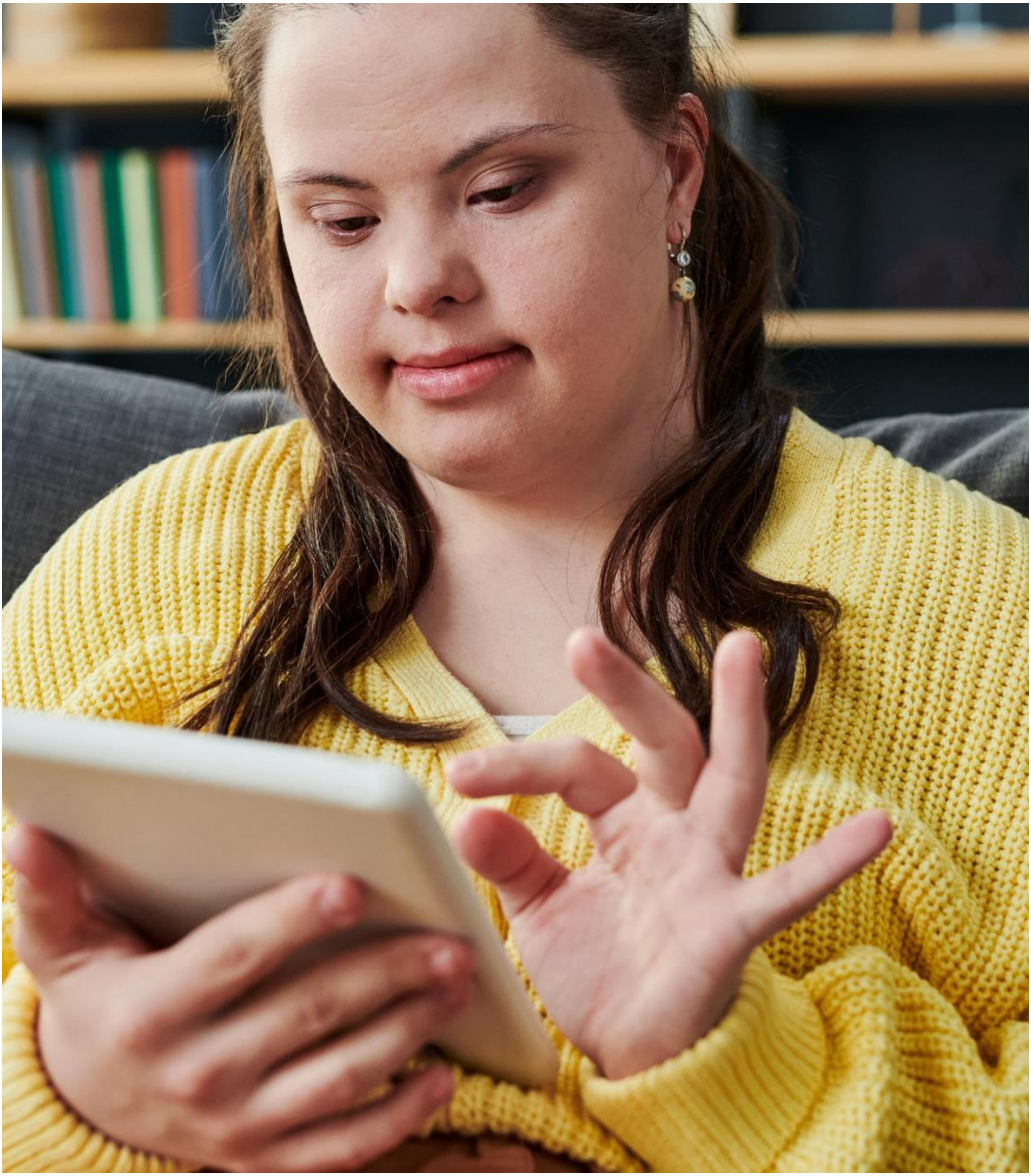
Table S.2: 2026-31 Proposal risks and mitigations

Risk	Mitigation
Retailers are slow to transfer customers to the newly created network tariffs, meaning customers may not get the benefit of lower charges	As part of our 2026-31 Proposal, we have developed a communication and education program to increase customer awareness of opportunities around better tariff selection.
The security of the distribution network is at risk due to the increase in cyber attacks	As part of our 2026-31 Proposal, we have put forward a comprehensive cyber-security program which is in accordance with industry and Government requirements.
An over-emphasis on short-term affordability may have adverse implications on the long-term interests of customers	In all our customer engagement activities we explored the following question with our customers: *“How should Jemena prepare for a sustainable energy future while meeting customer and community needs today?”* This allowed our customers to explore and balance their feedback across both the short and long term. Our 2026-31 Proposal reflects the views of our customers, therefore, also balancing short and long term imperatives. Our business cases and investment briefs have been developed with reference to the long term economic benefits using robust net present value analysis and relies on independent AER inputs such as Value of Customer Reliability and Customer Export Curtailment Values and with reference to the Australian Energy Market Operator (AEMO) forecasts.
If the forecast growth in connections does not eventuate, the distribution charge reductions reduce	We have put protections into our connections agreements to ensure that almost all charges are recovered from major customers irrespective of whether load eventuates or not. This will ensure the benefits flow to all customers.
The export tariff transition strategy does not provide sufficient incentives to modify export behaviours to the distribution network to promote or curtail electricity exports at certain times of the day. This could contribute to the electricity system becoming unstable.	AEMO may need to take action, including activating the Victorian emergency backstop mechanism, which requires us to curtail electricity exports. This would prevent widespread network instability and outages.

Navigating our 2026-31 Proposal

JEN has compiled a comprehensive and detailed 2026-31 Proposal comprising a large body of materials, charts, reports and economic models. To help readers navigate this 2026-31 Proposal, we have developed a document map at Attachment 01-01 that details the materials we have submitted to the AER for its consideration.

1. Background



1.1 About Jemena

Our electricity network is one of five electricity distribution networks operating in Victoria. We are the sole distributor of electricity in north-west greater Melbourne. Every day we help deliver electricity to over 387,000 homes and businesses across north and western Melbourne.

We build and manage the infrastructure that transports electricity across a 950 square kilometre area and provide energy to support businesses and critical infrastructure such as Melbourne Airport, which sits in the middle of our distribution area.

1.2 Operating environment

The distribution area we manage covers a mix of industrial, commercial and residential customers, including established inner suburbs, some major transport routes and Melbourne Airport. Our network covers semi-rural areas around Sydenham, Sunbury and Coolaroo, some of which have a high bushfire risk.

Our network environment is mainly flat land with a few exceptions, such as Greenvale and Reservoir, which have minor undulations. It includes Maribyrnong River, Merri Creek, Darebin Creek, and Steele Creek as waterways and is bordered by the Yarra River in the east and Port Phillip Bay in the south. Underground, Jemena experiences a diverse mix of ground types ranging from soft sand bases to hardened basalt rock.

Our total distribution area covers approximately 12% of the Victorian population.

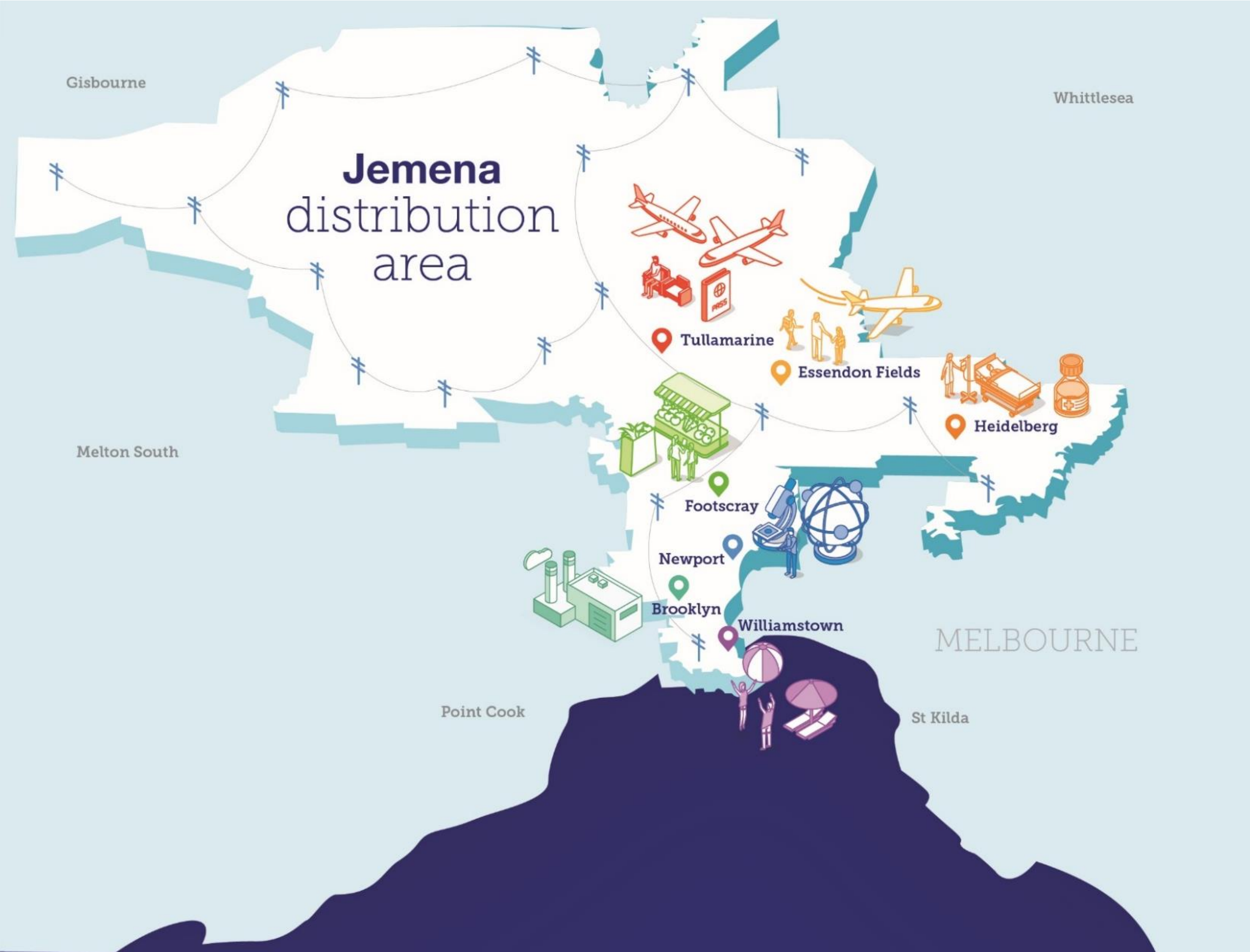
1.3 Our role as an electricity distribution network

As our society increases its reliance on electricity for our day-to-day lives and we progress towards a decarbonised future, the electricity system has and will continue to change. As it transforms, so too does our role as an electricity distribution network provider. We also see an evolution in the workforce we engage with and the technologies we procure to support this change.

Customers want to connect to and interact with the electricity system in many ways, this includes using new technologies such as EVs and community batteries. They also want to generate electricity that can be exported back into the electricity network from rooftop solar and do their bit for the environment. As we move to more electricity use and small-scale generation, we need to manage the congestion of the network and the electricity that flows back to the electricity network.

We are also seeing emerging market trends with new products and services coming online such as virtual power plants where customers can benefit from aggregating exported energy or orchestrating customer electricity usage; we also play a part in transporting electricity with these emerging products and services.

The transition to this new role will be heavily influenced by customers, governments and regulators, as well as other changes in the broader electricity market. With a changing role, we need to pre-empt the transformation, minimise the impact, and embrace the opportunities it presents. We see that greater dependence on data and communications will be necessary, and our interactions with markets, new market players and customers will increase which we need to prepare for.



Key characteristics of the electricity network

387,000+
Number of customers on the network

6,900km
Length of overhead and underground lines

99.99%
Our network is reliable 99.99% of the time

73%
Calls to our faults line are answered within 30 seconds

107,000+
Poles in our network

12.9 billion
Remote meter reads every year

9,000+
New customers connected each year

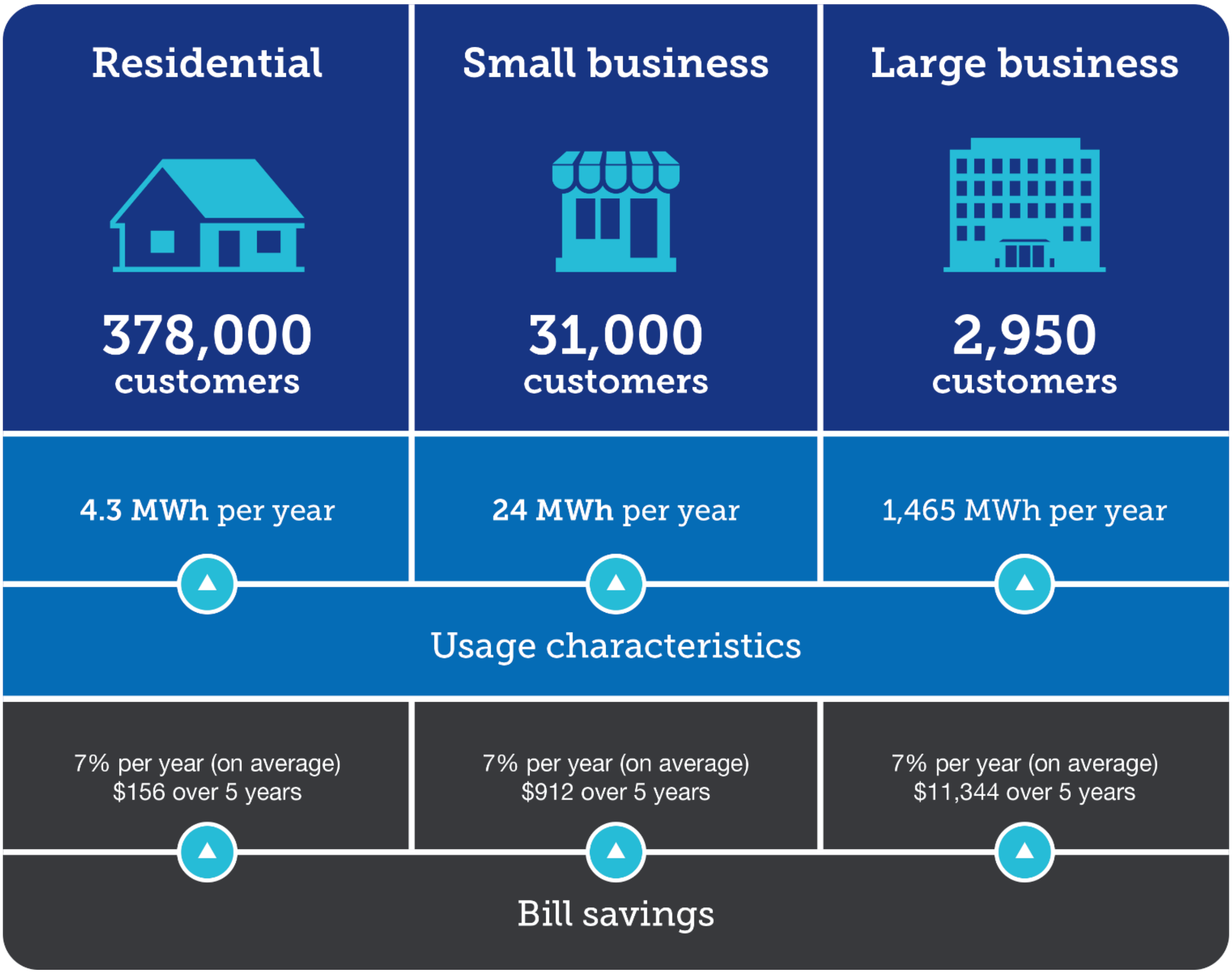
78,500+
Public lights

1.4 Our customers

As a provider of essential services, we have an important relationship with our customers and local communities. Customers are at the heart of our commitment to deliver electricity safely, reliably, and affordably.

Apart from a few very large customers, anyone currently connected to Jemena's electricity distribution network is a customer of ours. We also connect new customers and provide distribution services to other groups like property developers, landlords and businesses of all sizes, from sole traders through to large energy consumers including Melbourne and Essendon airports, industrial customers and hospitals.

Figure 1.1: Jemena's customers and average usage characteristics



1.4.1 Residential customers

We are the sole electricity distributor in northwest greater Melbourne, servicing more than 387,000 households. Our network area's residential customers and communities are diverse, spanning some of Victoria's fastest-growing Local Government Areas including Hume, Merri-bek, Maribyrnong and Moonee Valley.

Our residential customers are made up of diverse households that include:

- Households with solar
- Households with electric vehicles
- Households with batteries
- Dual fuel households with gas and electricity
- Households with electricity only
- Renters and homeowners

- Households of different densities (low, medium and high)
- Households with different socio-economic status
- Customers with lived experience of disability and mental health difficulties
- First Nations peoples
- Seniors
- Young People
- Multicultural households.

1.4.2 Large customers

Our large commercial and industrial customers—made up of over 2,700 customers in north and western Melbourne—consume more than 50% of the electricity that flows through our network. Large customers come from a range of industries including:

- aviation
- transport
- data centres and high-tech industries
- property development
- health and medical
- education
- local councils
- logistics
- food manufacturing
- telecommunications
- other utilities.

Each large customer has different energy priorities that reflect the realities of their industries and the customers they serve.

1.4.3 Small and medium business customers

Small to medium sized businesses in our network are a vital part of our rich and vibrant communities. Our small to medium-sized business customers are made up of over 32,300 diverse customers across north and western Melbourne. Each small and medium business has unique circumstances and ways of operating, including different working environments, retail spaces and office locations.

Small to medium sized businesses include a large mix of sectors and professions, for example:

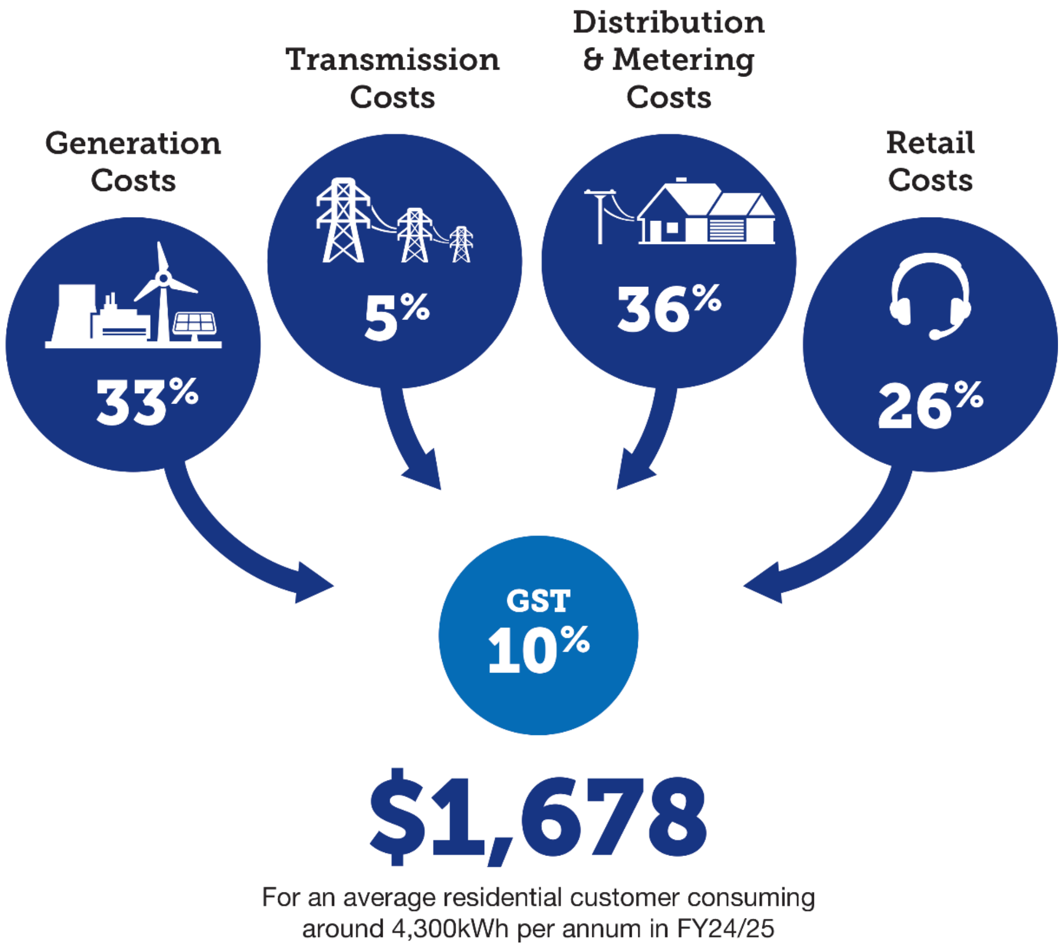
- accommodation and hotels
- florists
- agriculture
- furniture building and restoration
- bars, clubs and breweries.
- printing and design
- cafes, food stalls and restaurants
- real estate
- clothing
- retail
- consultancies
- small goods, delicatessens and butchers.
- entertainment and music.

1.5 Purpose of our regulatory proposal

As an electricity distribution network service provider, we are subject to economic regulation overseen by the AER under the NER. A key function of the AER is to set maximum prices for the services we provide to customers.

The cost of distributing energy across the electricity network is paid for through the network charges included in customers' electricity bills. Typically, network and metering charges make up approximately 35% of a household customer's total bill.

Figure 1.2: Breakdown of charges in an electricity bill



The AER approves our prices in five-year cycles. In the build-up to each new term, we submit a Regulatory Proposal to the AER that outlines our plans for the 2021-26 regulatory control period and how we expect to fund them.

The Regulatory Proposal must outline:

- the services we will offer
- the costs we are likely to incur in providing these services
- the prices we propose to charge during the next regulatory period.

The AER only approves the proposal if it complies with the NER and promotes the long-term interests of our customers.

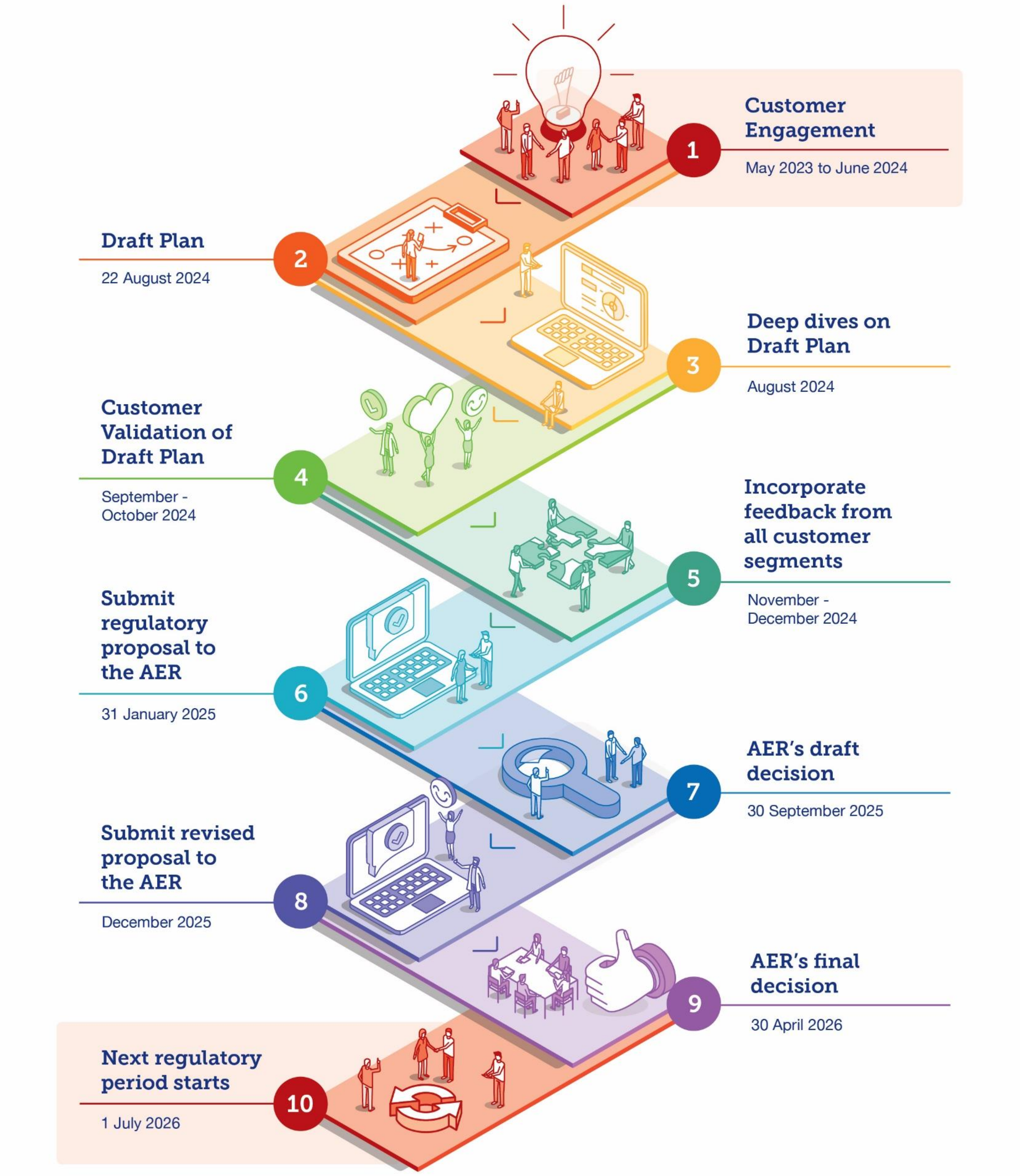
1.6 Customer-centric regulation

The AER regulates energy networks and must ensure that its decisions promote customers' long-term interests.

As part of its five-yearly assessment of the regulatory proposals from each of the electricity distribution network service providers, the AER considers—among other factors—the extent and quality of consumer engagement we have undertaken during the development of this draft proposal. It also looks for evidence that our regulatory proposal reflects the outcomes of that process.

In Chapter 2, we outline how we strive to deliver industry-leading customer engagement that puts customers at the heart of our regulatory proposal, and our business.

1.7 The journey to approval



2. Our customers spoke and we listened

Our customer engagement journey

2023

May

- **Co-design workshop** with residential customers from previous People's Panel
- **Vulnerability Roundtables** Joint VICDB engagement
- **Framework & Approach Workshops** Joint VICDB engagement

Aug

- **Framework & Approach Workshop** Joint VICDB engagement
- **Tariff Workshop** Joint VICDB engagement

Sep

- **Vulnerability Roundtable Joint VICDB engagement**

Oct

- **Energy Reference** Group meeting
- **Resilience Workshop** Joint VICDB engagement
- **Seniors Customer** Voice Group session
- **Mental Health** Customer Voice Group session
- **People's Panel** welcome event
- **Disability** Customer Voice Group session
- **Multicultural** Customer Voice Group session
- **Young People** Customer Voice Group session
- **First Nations** Customer Voice Group session

Nov

- **People's Panel** orientation
- **Energy Reference** Group meeting
- **Cultural Consultation** with Wurundjeri Woi-wurrung Land Council
- **People's Panel** all day forum
- **Seniors** Customer Voice Group session
- **Mental Health** Customer Voice Group session
- **Disability** Customer Voice Group session
- **Multicultural** Customer Voice Group session
- **Young People** Customer Voice Group session
- **First Nations** Customer Voice Group session
- **Energy Reference** Group meeting
- **Tariff Workshop** Joint VICDB engagement

Dec

- **Energy Reference Group meeting**

Our customer engagement journey

2024

Jan
- **Cultural Consultation** with Bunurong Land Council

Feb
- **People's Panel** all day forum
- **Seniors** Customer Voice Group session
- **Mental Health** Customer Voice Group session
- **Disability** Customer Voice Group session
- **Multicultural** Customer Voice Group session
- **Young People** Customer Voice Group session
- **Energy Reference** Group meeting
- **Large commercial and industrial** customer forum
- **First Nations** Customer Voice Group session
- **People's Panel** forum

Mar
- **Seniors** Customer Voice Group session
- **Mental Health** Customer Voice Group session
- **Disability** Customer Voice Group session
- **Multicultural** Customer Voice Group session
- **Young People** Customer Voice Group session
- **Energy Reference** Group meeting
- **People's Panel Day** all day forum with Customer Voice Group members

Apr
- **First Nations** Customer Voice Group session
- **Tariff Workshop** Joint VICDB engagement
- **Energy Reference** Group & **People's Panel** meeting
- **People's Panel Final** all day forum and recommendations provided

May
- **Small and medium business** customer forums
- **Retailer** Forum
- **Local Council** Forum
- **Customer Council Workshop**

Jun
- **Large customer tariffs** online session
- **Large customer survey**
- **Small and medium business** survey
- **Residential** customer research

Jul
- **Energy Reference** Group Meeting
- **Retailer & Large Customer** Forum project update

Aug
- **Draft Plan survey**
- **Energy Reference** Group Meeting
- **People's Panel & Customer Voice Group** Recall Session

Sep
- **Local Council public lighting sessions**
- **Large customer one-on-one sessions**

Oct
- **Energy Reference Group Meeting**

Nov
- **Customer Deep Dive** on expenditure Session 1
- **Customer Deep Dive** on expenditure Session 2
- **Energy Reference** Group Meeting

10,177 visits to GridTalk

7,589 individuals directly engaged (including customers and stakeholders)

282 hours of facetime with customers

4 Board & Senior Management members involved

45 Jemena members involved

6 Customer Voice Group Champions from across the business

80 unique engagement sessions

288 contributions on the GridTalk website

150 residential customers on dedicated engagement groups

7 People's Panel sessions held

24 Customer Voice Group sessions held

2 Cultural consultations with Aboriginal Land Councils held.

2.1 Our approach to customer and stakeholder engagement

Recognising our role as an essential service provider, we are driven to continuously improve our customer-centric culture and strive to understand customer needs and expectations. Our JEN 2026-31 Proposal has provided us with a unique opportunity to allow our customers to help shape the services we offer and to inspire our teams to improve outcomes for them.

With customers at the heart of everything we do, we have sought to engage meaningfully with a broad spectrum of customers in our network. This has included our energy-savvy customers, right through to those who have low energy literacy or face barriers to engaging with energy. Through engagement and open dialogue, we aim to position JEN at the forefront of delivering innovative customer engagement to our diverse range of customers.

Throughout this price reset process, we purposefully and ambitiously set out to understand our customers' views and build the energy capability of those members of the community who need it the most. It is with this sentiment that we sought to reach deep into our community and engage with customer groups experiencing vulnerability, or who may experience issues with accessibility to our services. We aimed to capture the views of customers whose voices, without specialist and purposeful engagement, would not be heard.[8] Where customers were unable to provide their voice, we sought the views of advocates or service providers.

A full summary of our engagement with our customers and interested stakeholders is included within *JEN - Att 02-01 – Customer engagement*. It provides detailed information on our approach to our customer engagement program, including our engagement objectives, how we collaborated with customers and stakeholders to design our engagement program, and how their feedback has shaped our approach to this price reset.

2.1.1 Our engagement objectives

In developing our engagement program, we set out to achieve four clear customer objectives. These objectives, which are shown in Figure 2.1, are underpinned by our engagement values and principles, lessons learned from developing our past energy regulatory proposals, and incorporating energy industry best practice customer engagement.

We recognise that we act as the conduit for our customers' preferences, using their views to shape our plans. To do this, we needed to partner with our customers, listen to the voices that are heard the least, and engage with the customers that need us most.

8 AER - Better Resets Handbook - July 2024.pdf

Figure 2.1: Customer Engagement Objectives

2.1.2 Our customers and stakeholders

JEN has a diverse customer base, with many factors contributing to and influencing their overall experience with electricity and energy. For our residential customers, this includes the type of household they live in, whether they rent or own their own home, age, socio-economic status, cultural background and the diversity of their lived experiences, such as living with a disability or mental health difficulties.

For our small to medium-sized businesses, large businesses, local councils and retailers, this includes the size of their business, the type of business and how they use energy.

Although each customer is unique, they have many overlapping and common factors or circumstances that make up their household. These contribute to our ability to have “cross-customer” impacts within the recommendations and decisions made in our 2026-31 Proposal. They also allow us to have mature and robust conversations on equity and equality that consider a broad range of factors, circumstances, and influences.

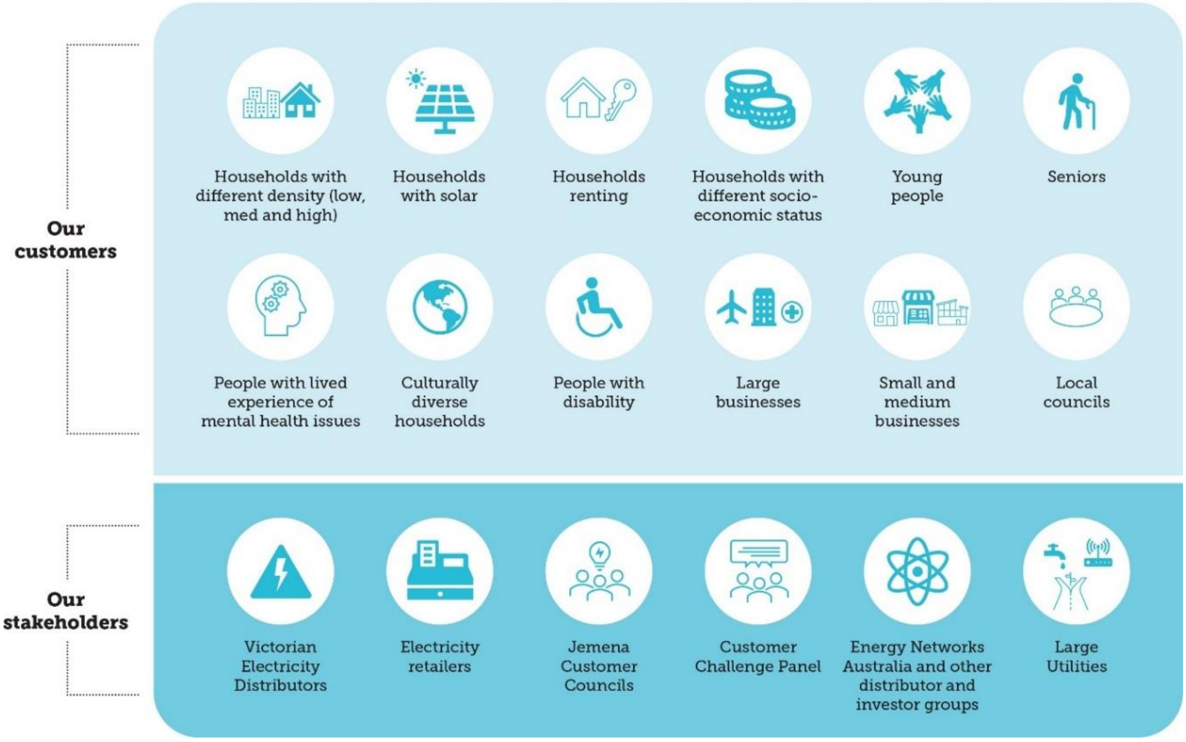
Our engagement program aimed to meet the specific needs of our electricity customers, taking into consideration the following:

- the rich diversity of our customers
- learnings from previous price reset customer engagement processes
- industry best practice
- the unique requirements, issues and challenges our customers face and their growing expectations of JEN and the energy industry
- our desire to engage with customers experiencing vulnerability, and
- dedicated opportunities to create synergies with the other Victorian electricity distribution network service providers for joint engagement, where there are common themes amongst all Victorian customers, enabling consistency and efficiency in our engagement approach across all Victorian networks.

Figure 2.2 outlines our customers and stakeholders identified for engagement.

“Feeling like I’m being listened to is really important and being able to make a small contribution.” - Customer Voice Group member

Figure 2.2: Our Customers & Stakeholders



2.1.3 Collaborating with customers and stakeholders

We place customers at the heart of our decision-making for the future of our electricity network. As set out in our engagement strategy[9], the highest level of engagement we sought through this process of the **International Association for Public Participation's** (IAP2) Engagement Spectrum is ***Collaborate***, and where possible ***Empower***.

Collaborate

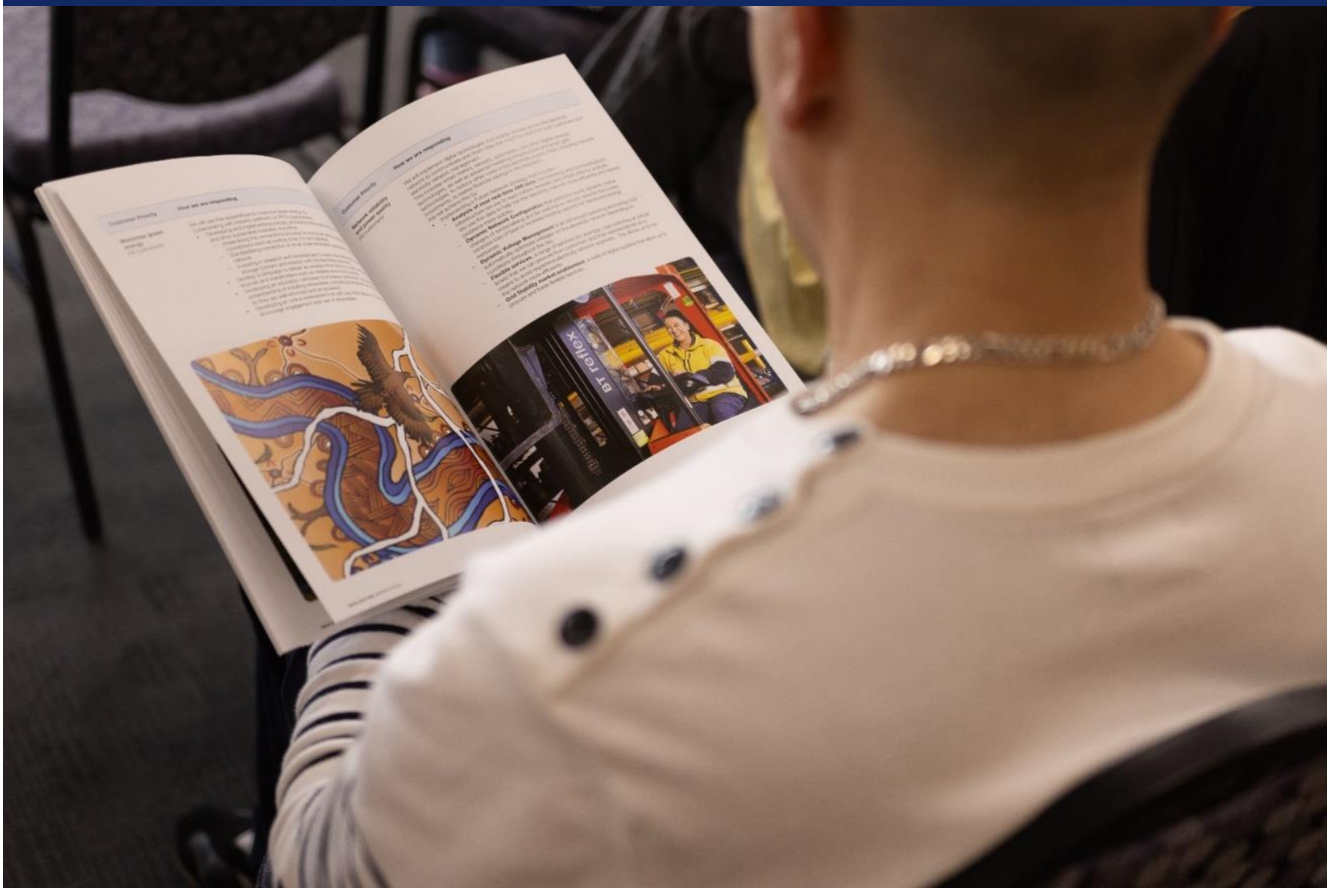
Collaborate means: We will work together with customers to formulate solutions and incorporate your advice and recommendations into the decisions to the maximum extent possible.

9 JEN - Att 02-24 - *Engagement Strategy*

2.1.4 Our challenge and engagement remit

With a constantly changing environment and increase in cost-of-living pressures, providing a fair energy future has never been more important. With the increase in customer adoption of renewables and other technologies, people are rapidly changing both how they use electricity and what they expect from our electricity network. This compels us to rethink the best ways to plan for the future and how to charge for electricity in a way that is fair and equitable for everyone whilst also meeting differing customer expectations. Throughout the engagement process, we asked our customers to think about and make suggestions and recommendations in response to the question:

How should Jemena prepare for a sustainable energy future while meeting customer and community needs today?



2.1.5 Our engagement streams

Our engagement strategy included 11 core engagement streams designed to enable us to deeply understand and engage with the full spectrum of customers we serve in ways that best suit them.

To strengthen and unify the engagement groups, we embedded ways to interconnect groups to cross-pollinate ideas and gather feedback. This included opportunities for groups to:

- meet each other and understand what each brings to the process
- have access to key messages and outcomes reports
- have dedicated connector roles to observe and report back.

This approach enriched the understanding of diverse customer needs and increased the understanding of customer needs and perspectives across all engagement streams.

It also included strong evaluation mechanisms and an independent evaluation of our deliberative customer engagement approach, ensuring that throughout the process, we built in evaluation and monitoring mechanisms to ensure we meet and exceed best practice standards and regulatory requirements.

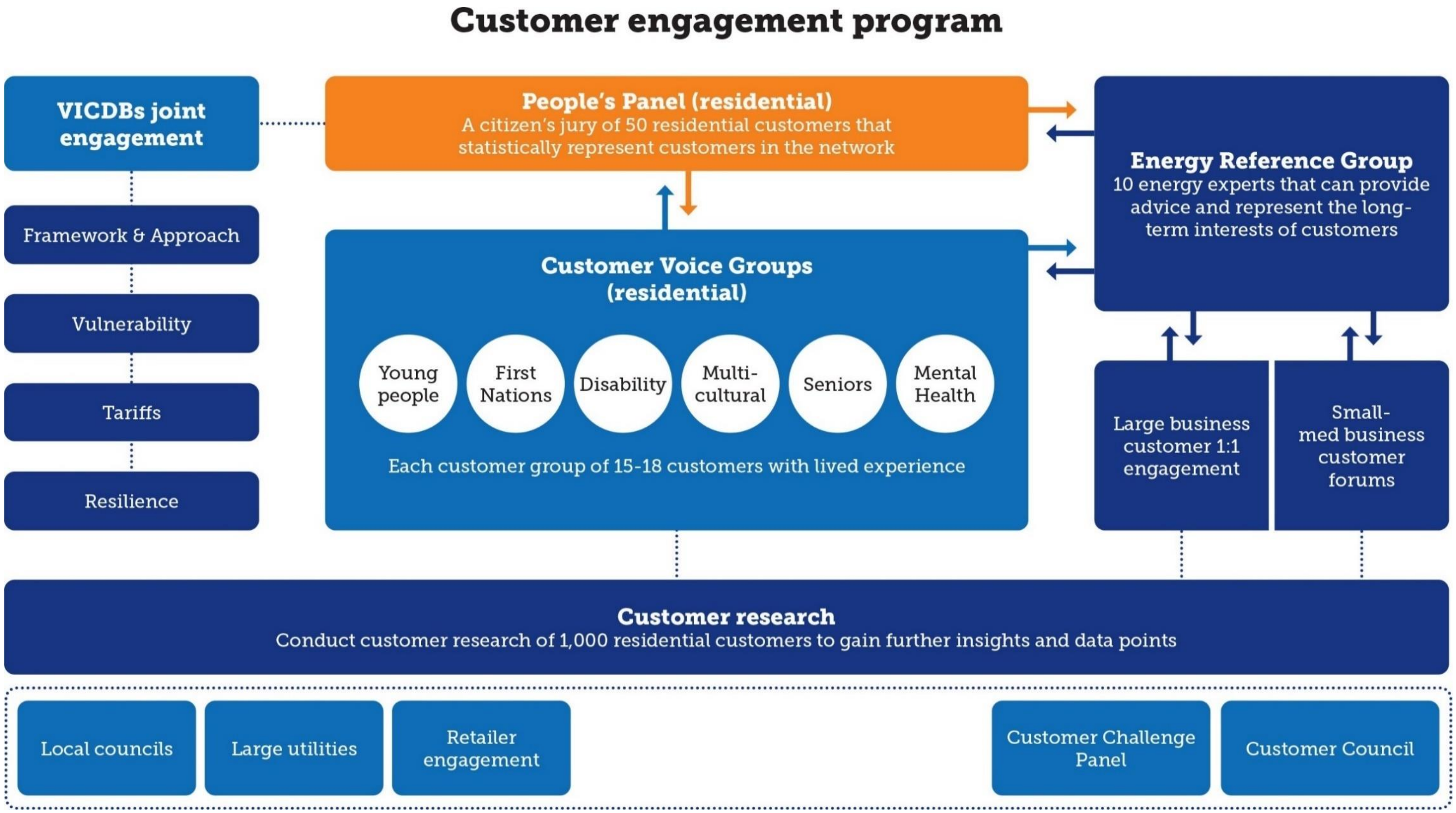
Our core engagement groups included:

- A **People's Panel** – which included approximately 50 diverse customers who make up a statistical representation of customers in our network area. Our People's Panel met between October 2023 to April 2024. After five full days of deliberative engagement, the group made 16 recommendations to us on how we should prepare for a more sustainable energy future while meeting customer and community needs today.
- **Customer Voice Groups** – six customer voice groups, made up of 100 customers, met four times. These groups included customers with different lived experiences. This included customers with disability, customers who experience mental health difficulties, customers from multicultural communities, young people, First Nations Peoples, and seniors. Each group had a senior leader from Jemena to help champion the group to connect, listen and understand their needs. The groups each provided advice and insights to the People's Panel for their consideration in making recommendations given their unique needs.
- **Customer research** – conducting a bespoke survey of more than 1,000 residential customers from across our network to gain a broad spectrum of views and data points. The research aimed to understand the level of importance our residential customers place on the outcomes and priorities of our Customer Voice Groups and People's Panel.
- **Large commercial and industrial customers** – surveys, large user forums and in-depth meetings to engage with large commercial customers.
- **Small to medium sized businesses** – small business forums, surveys and in-depth interviews/meetings with diverse small to medium sized businesses across our network.
- An **Energy Reference Group** – an expert energy panel consisting of 10 energy experts from various industry, commercial, academic, and government sectors. The Energy Reference Group discussed complex issues and provided clear, independent advice and recommendations that have the long-term interests of customers in mind.
- **Local councils** - surveys, in-depth interviews/meetings and Local Council Forums to understand the needs of local councils and the communities they service.
- **Retailers** – bespoke engagement with electricity retailers and retailer bodies, including retailer forums, surveys, in-depth interviews/meetings and engagement with retailers in support of customers affected by family violence.
- **Joint engagement by Victorian electricity distribution network service providers** – joint engagement sessions with Victorian electricity distribution network service providers across the topics of framework and approach, affordability and equity, reliability and resilience, network tariffs and customers experiencing vulnerability.
- Our **Customer Council** – involving our Customer Council members, including providing them ongoing oversight of the engagement program and a dedicated workshop on the price reset.

Figure 2.3 shows our 11 core engagement streams and the interactions between them.

Full details of our engagement with each of the above groups is included within *JEN-Att 02-01 – Customer engagement*.

Figure 2.3: Customer engagement program



Executive and Board Level involvement in engagement

More than 45 Jemena representatives participated in our engagement program, including presenting to customers, answering questions and discussing customer needs. Our Managing Director and a member of our Board were involved in People's Panel sessions to listen to and connect with customers. We also had strong executive team involvement, with executives participating in 282 hours of engagement sessions.

2.2 Customer priorities and recommendations

We understand that our customers and stakeholders have unique circumstances and realities regarding their household, business, organisation, or industry.

Through our engagement, we have spent time deeply listening to and understanding our customers' needs, preferences and priorities.

This section summarises the priorities and recommendations from our core customer engagement groups and customer research, which we have synthesised into common themes. Detailed feedback from each customer group is provided within *JEN – Att 02-01 – Customer engagement*.

Customer Priorities and Recommendations

1. Affordable electricity prices

- Affordable electricity was a top priority for all customer groups, with a specific emphasis on stability to alleviate cost-of-living pressures and reduce financial anxiety.
- Customers across various customer voice groups, including First Nations, Disability, Mental Health, Seniors, Young People, and Multicultural communities, highlighted the critical importance of affordable electricity prices. Many of these groups face financial vulnerabilities, fixed incomes, or significant cost pressures from rising living expenses.
- Seniors and First Nations customers emphasised the need for stable pricing, especially given the increasing costs of living.
- Across all groups, maintaining affordability alongside reliability was considered essential for equitable energy access.

2. Accessible and efficient communication from Jemena to customers

- Clear, transparent, and accessible communication channels were universally requested by many customers.
- Customers emphasised the need for communication tailored to diverse needs, including multiple languages and accommodations for disabilities.
- Multichannel approaches, such as online platforms, phone support, and chat options, were highly valued.
- Enhancing communication accessibility was seen as a way to reduce confusion, increase trust, and improve overall customer satisfaction.

3. Champion renewable energy in new developments & housing estates

- Customers, including the People's Panel and Young People, advocated for Jemena to integrate renewable energy solutions like solar and batteries into new housing developments and estates.
- Small businesses expressed interest in working with Jemena to balance network usage through privately owned solar and battery setups, while retailers called for tariffs and incentives to encourage the adoption of renewables
- Early investments in renewable solutions were viewed as a means to lower long-term operational expenses and promote green living.

4. Collaboration to ensure efficiency

- Collaboration was identified as a critical pathway to achieving efficiency across various stakeholder groups, including the People's Panel, Local Councils, and small businesses.
- Customers recommended that Jemena work with councils, community groups, and peer energy networks to streamline efforts, reduce duplication, and implement best practices.
- Small businesses advocated for stronger partnerships with Jemena to facilitate smoother connections and cost-effective infrastructure upgrades. Retailers highlighted the need for collaboration to align tariff structures and create new opportunities for customers to adopt emerging technologies.
- Local councils proposed partnerships on sustainability initiatives and public lighting projects, while commercial customers recommended joint investments and streamlined processes for renewable energy projects.
- Customers agreed that collaboration could reduce duplication, optimise resources, and achieve cost-effective outcomes.

5. Social and corporate responsibility - addressing sustainability and carbon footprint

- Customers across all segments called on Jemena to lead by example in reducing emissions and achieving net-zero targets.
- Suggestions included electrifying fleet vehicles, adopting sustainable practices, and increasing transparency around sustainability initiatives.
- Young people specifically highlighted the importance of clear communication on the impact of Jemena Electricity Network's investments in driving customer engagement and support for green initiatives.

Customer Priorities and Recommendations

6. Customer education and building energy literacy

- Customer education was a universal priority across many customer groups. They widely emphasised the importance of customer education to empower informed energy usage and investment decisions.
- Key topics included time-of-use tariffs, energy-saving strategies, and the benefits of renewable technologies like solar and batteries.
- Tailored campaigns, culturally relevant materials, and partnerships with community organisations were recommended to address diverse customer needs.
- First Nations groups advocated for culturally specific education, while seniors sought simplified resources.
- Across all groups, accessible and practical information was deemed essential for promoting sustainable energy behaviours.

7. Customer engagement (ongoing)

- Ongoing engagement was valued by all stakeholders, with a strong emphasis on maintaining two-way communication.
- Demonstrating how customer feedback shapes Jemena's plans was seen as crucial to building trust.
- Stakeholders also appreciated opportunities to influence decision-making and suggested regular engagement activities to ensure alignment with customer priorities.

8. Conservation and protection of land

- First Nations groups prioritised the conservation of land and sustainable management of assets to protect cultural heritage.
- They emphasised the importance of incorporating traditional knowledge into land management practices and ensuring that Jemena's operations align with conservation goals to safeguard natural and cultural resources.

9. Cyber security and data protection

- Robust data protection measures were a significant concern across customer groups.
- First Nations communities highlighted the heightened risks associated with sensitive data, particularly in the context of family violence.
- Ensuring customer safety through secure data handling was identified as critical to building trust and protecting vulnerable populations.

10. Digitisation and automation to increase economic efficiency

- Customers supported investments in digital technologies to enhance network management, reduce operational costs, and prepare for future energy challenges.
- Mental health and multicultural customers stressed the importance of adopting advanced systems to improve efficiency and reliability.
- Digitisation was viewed as a vital step toward creating a smarter, more resilient network.

11. Electric Vehicles and preparing for the future

- Preparing for increased electric vehicle adoption was a shared priority among all groups.
- Stakeholders encouraged Jemena to expand charging infrastructure, collaborate with councils and industry partners, and optimise grid usage to accommodate electric vehicle growth.
- Proactive planning and investment were seen as essential to supporting the transition to a greener transport system.

Customer Priorities and Recommendations

12. Empathy in customer service & tailored customer service

- Empathy and personalised service were key themes among residential customers, First Nations communities, and mental health groups.
- Stakeholders emphasised the importance of culturally appropriate support, streamlined interactions, and reducing anxiety through understanding and responsive customer service.
- A dedicated liaison for First Nations customers was suggested to enhance cultural safety and support.

13. Energy storage by distributors

- Energy storage solutions were widely supported as a means to improve grid stability, enhance resilience, and manage solar oversupply.
- Stakeholders recommended exploring communal and distributed battery systems to address these challenges.
- Energy storage was also seen as an opportunity for Jemena to innovate and collaborate with regulators and governments.

14. First Nations Cultural Priorities

- First Nations groups highlighted the importance of cultural training for Jemena staff, increasing employment and procurement opportunities for First Nations peoples, embedding meaningful artwork, and offering specific grants.
- Building strong relationships through ongoing engagement and incorporating cultural knowledge into operations were seen as vital for reconciliation and inclusion.

15. Information and data sharing

- Large commercial customers and other stakeholders requested transparent and proactive data sharing.
- Providing real-time and detailed information on outages, tariff changes, and energy usage was identified as a way to support planning and operational decisions.
- Enhanced data sharing was also seen as a means to build trust and improve customer confidence.
- Large businesses and retailers recommended proactive sharing of technical data and real-time information to improve customer decision-making and operational planning. Retailers also sought greater transparency in data sharing to support vulnerable customers better.

16. Incentivise battery take-up

- Financial incentives for battery adoption were widely supported as a strategy to manage solar oversupply and improve grid efficiency.
- Stakeholders viewed such incentives as beneficial for both customers and the network, enabling better utilisation of renewable energy and reducing peak demand pressures.

17. Maximise green energy

- Customers, including the People’s Panel and Young People, urged Jemena to maximise green energy uptake by upgrading infrastructure and creating a more renewable-friendly grid.
- This included supporting customer participation in green initiatives and investing in technologies to enable greater adoption of solar and other renewable sources.
- Maximising green energy was seen as essential for reducing the carbon footprint and promoting sustainability.

Customer Priorities and Recommendations

18. Network reliability and power quality

- Maintaining high levels of network reliability and power quality was a top priority for all customers.
- Customers stressed the importance of timely outage notifications and resilience planning to minimise disruptions.
- Retailers similarly prioritised reliability as essential to maintaining customer trust and satisfaction.
- Investments in infrastructure to withstand extreme weather events and future demand were seen as crucial for ensuring consistent and reliable energy supply.

19. Network resilience

- Customers, including Local Councils, underscored the importance of investing in resilience to withstand extreme weather events. They called for measures to ensure rapid recovery and minimal impact on customers.
- Small businesses supported network upgrades to better handle operational risks posed by extreme weather.

20. Ongoing service excellence to JEN's customers

- The Energy Reference Group and People's Panel supported Jemena's efforts to maintain service excellence.
- Small businesses called for clear performance metrics to ensure accountability, while retailers encouraged Jemena to benchmark its service against peers and regulatory expectations.

21. Public lighting – Innovative program with smarter technologies and collaborating with Local Councils on trials and grants

- Local Councils advocated for innovative public lighting solutions, such as LEDs and smart systems, to improve safety and efficiency. Collaboration with councils was seen as essential for piloting these initiatives and securing funding.

22. Long-term sustainable operation of JEN's network

- Customers, including Young People and the People's Panel, recommended adopting environmentally sustainable practices to ensure the network remains cost-effective, resilient, and adaptable to future needs.

23. Tariff communications to create clarity and consistency

- Clear and consistent tariff communications were supported by Seniors, Retailers, and Local Councils.
- Customers emphasised the need for transparency to enable customers to make informed choices.

24. Tariffs that are cost-reflective and equitable

- All groups highlighted the importance of equitable tariffs that fairly balance the needs of diverse customer types.
- Small businesses expressed the need for clear, equitable tariffs that enable better budget planning and profitability.
- Retailers highlighted the importance of cost-reflective tariffs to ensure fair pricing across customer types and prevent cross-subsidisation.


Jemena
Instructions:

2.3 Consultation on our Draft Plan

In August 2024, we published our Draft Plan, which was shaped by the feedback from our customers and stakeholders. We promoted our Draft Plan across social media, Jemena and GridTalk websites, via a media release and through direct communication with customers and stakeholders.

Following the release of our Draft Plan, we consulted extensively with our customers and interested stakeholders to determine whether we had adequately understood and actioned their feedback. Based on this feedback, we have refined our plans for the next regulatory period and reflected it within our JEN 2026-31 Proposal.

Our engagement on our Draft Plan included:

- An open online survey to gain feedback on the Draft Plan.
- A recall session for People's Panel and Customer Voice Groups.
- Customer Deep Dives on affordability and expenditure.

We also published a Public Lighting Consultation Paper for Local Councils.

2.3.1 Draft Plan survey

We encouraged and invited customers to have their say through a Draft Plan survey. We promoted the survey across social media, direct customer communications, media and the Jemena and GridTalk websites.

We received 42 survey submissions on the Draft Plan and additional correspondence on key items. We also had 2,770 views[10] of the Draft Plan web page which shows strong engagement with the document.

We asked customers and stakeholders to use a sliding scale from does not meet to meets to exceeds to identify if the Draft Plan met the goal of meeting needs.

The survey results indicated that **83% of customers and stakeholders believed that the Draft Plan either meets or exceeds customer and community needs.**

This reflects that customers have shaped our plans, and that it responds to their priorities and preferences through the initiatives we have proposed.

2.3.2 People's Panel and Customer Voice Group recall session

On 31 August 2024, we hosted a session with 46 residential customers from our People's Panel and Customer Voice Groups to engage them on the Draft Plan and seek feedback on network resilience.

The session:

- Outlined key initiatives in the Draft Plan in response to customer feedback
- Allowed customers to speak to experts to answer their questions on key initiatives
- Tested options on network resilience to understand customers' preferences on investment
- Gave an opportunity to provide feedback on the Draft Plan.

Although we received strong support on our Draft Plan, some customers felt that we needed to work harder to demonstrate how our regulatory proposal is responding to the theme of affordability.

10 Views of the Draft Plan refers to the total number of times a visitor on your sites views any page on your site or project. Page views are recorded each time a page is visited, regardless if the user has previously visited that page.

2.3.3 Customer deep dives on affordability and expenditure

In response to feedback on our Draft Plan, we held two deep dive sessions. The purpose of these sessions was to present the residential bill impacts of our customer education, network resilience, and innovation initiatives. As these programs were developed in response to customer preferences, we wanted to ensure we were appropriately balancing these preferences with customers' affordability concerns and confirm that customers were willing to pay for these services.

Deep dive attendees consisted of a mix of Customer Voice Group and People's Panel participants. The attendees participating in these sessions comprised a representative mix of our customer base across age groups, education, and electricity literacy. They also included customers experiencing vulnerability or who may experience issues with accessibility to our services.

These additional sessions allowed for further meaningful and considered discussions about how JEN's 2026-31 Proposal will address affordability. They also provided an opportunity for JEN to collaborate with our consumers as partners and seek input on operating expenditure step changes.

The key outcomes from the deep dive sessions are captured in the following sections. More detailed information on the deep dives is included within *JEN – Att 02-01 – Customer engagement,* and *JEN - MosaicLab Att 02 - 22 Customer Deep Dive Outcomes Report.*

"Such an interesting group of people to listen to and learn from. I've learnt that a lot goes into keeping the network running and we are lucky to live in Australia and Jemena's network."

"Consulting with its constituents…and valuing their inputs. I definitely feel heard and hopefully added some level of valued input."

— Deep Dive session participants and Jemena customers

Affordability

JEN first explained how we had approached prioritising affordability when developing our Draft Plan and then provided customers with an opportunity to reflect on this issue in small groups. Following the small group discussions, customers were asked what they would like JEN to keep in mind as we considered affordability.

The key themes captured from the customer responses included:

1. Affordability and reliability: Affordability is not solely about cost-cutting but also maintaining consistent and reliable service. It involves balancing affordability with essential priorities like digitisation, sustainability, and climate change mitigation.
2. Efficiency as a path to savings: Emphasis on improving efficiency as a means to achieve affordability. Savings can result from smarter operations rather than direct cost-cutting.
3. Customer-centric equity: The differentiated impact of costs on customer types (e.g., homeowners vs. renters, large vs. small customers). The importance of equitable pricing and addressing diverse customer profiles.
4. Long-term vs. short-term decisions: Concerns about trade-offs between affordability and long-term grid reliability. Highlighting the necessity of forward planning (e.g., investments in substations and climate resilience).
5. Profitability and transparency: Acknowledgment of JEN's right to make profits but emphasis on responsible spending. Requests for clarity on how cost savings are passed on to consumers.
6. Environmental responsibility: Climate change is a priority that requires action despite potential short-term cost increases. Balancing environmental goals with affordability.
7. Consumer trust: JEN's approach to affordability and efficiency should be communicated to gain goodwill. Providing context on challenges (e.g., insurance costs driven by climate change).

The conversation then moved to a discussion around the 'trade-off' between service levels and customer costs.

Customer Education

People's Panel and Customer Voice Group feedback indicated that our customers require accessible, tailored information in multiple languages to make informed decisions about energy usage, reduce costs, and invest in renewable resources. Such information empowers them, enhances energy literacy, and influences behaviour and personal investment choices that contribute to grid stability with minimal infrastructure upgrades. However, current barriers include a lack of readily available information that accommodates disabilities, low literacy rates, and non-English speakers.

In response to customer feedback, we developed three distinct Customer Education packages and quantified the cost of delivering each for a typical residential customer.

After considering each option, attendees spent time discussing their merits. They then voted on their preferred option.

Participants selected **Package 2 – Education & Customer Empowerment**, agreeing it focuses on a balanced approach to education and empowerment - leading to customers who are informed and engaged across all channels.[11] They appreciated this package's attention to increasing their awareness across a range of channels, which makes it more accessible.[12] Participants advised that this package would empower customers to take control and enable them to make more informed decisions.

Based on the preferences expressed by our customers, we have incorporated Package 2 into our JEN 2026-31 Proposal.[13]

11 AER - Better Resets Handbook - July 2024.pdf

12 JEN – MosaicLab Att 02-22 Customer Deep Dive Outcomes Report, November 2024, p9

13 More information on this package is included in JEN – RIN – Support – ICT Investment Brief - Customer education

> *"We prefer it is cost-effective and has push-pull communication topology." – Jemena Deep Dive Participant and Customer*
>
> *— Jemena Deep Dive Session participant and customer*

Innovation Fund

In response to customer feedback about the proactive role JEN should play in the energy transition, we developed four distinct 'Innovation Fund' packages to present to the deep dive session attendees, including a 'no cost' option which would see JEN continue its current approach to innovation.

The packages were presented, reviewed and discussed in working groups. Customers were then tasked with considering the 'trade-off' between the benefits of each package for all customers and the associated bill impacts. Thinking of the full spectrum of customers allowed for deep, considered engagement and offered many varied opinions.

Participants advised that JEN should play a pivotal role in driving sustainability targets and fostering a sustainable energy future[14] and that customers should be empowered to adopt consumer energy resources such as EVs and batteries and believe that JEN should ensure that no customer is left behind.

Customers voted for adopting Package 2 – Innovation with Impact. Deep dive engagement participants appreciated this package's cost-effectiveness and its facilitation of clear, two-way engagement.

> *"Putting our foot in the door for innovation and opportunities from 3rd party investors and / or government grants"*
>
> *— Jemena Deep Dive Session participant and customer*

We have incorporated the package most preferred by customers into our JEN 2026-31 Proposal. More information on this package is included in Attachment 03-02.

Network Resilience

The Draft Plan contained our early thinking on resilience and some estimated costs to deliver these initiatives. During the recall session, we spent time discussing the topic of resilience with our customers to ensure they were fully informed of the climate risks to the network, our proposed initiatives, and the associated costs. This also gave customers the opportunity to ask questions and seek clarification. It also gave JEN the opportunity to understand the nuance of our customers' views on the topic.

Given the complexity of network resilience and the ongoing policy developments in this area, as discussed in Chapter 3, we wanted to ensure customers were willing to pay for these investments despite the associated uncertainty. We therefore revisited to the topic of resilience during the deep dive sessions.

We engaged customers during the deep dive sessions through a structured approach to inform them of developments that had taken place since the previous customer discussions on the topic and to respond to some of the concerns raised during the recall day around a need for further information on these investments.

To ensure improvements aligned with our customers' needs, we presented three packages on network resilience, which focused on our customers' priorities of fairness, reliability, and preparedness.

Customers reflected on these in small groups and then presented their considerations, choosing Package 2—Equitable Resilience. They explained they felt this package took into account resilience efforts for vulnerable and underserved customers and that "no customer was left behind." We have incorporated this package into our JEN 2026-31 Proposal.

14 JEN – MosaicLab Att 02-22 Customer Deep Dive Outcomes Report, November 2024, p16

“This package covers it all off and is more feasible to do other work (that is) outlined in Package 3 later down the track”

— Jemena Deep Dive Session participant and customer

2.3.4 Energy Reference Group feedback

Following the publication of our Draft Plan in November 2024, the Energy Reference Group provided a formal submission on our plans.

The Energy Reference Group provided positive feedback on our Draft Plan, with approximately 90% overall approval of JEN’s plans to support a sustainable energy future while meeting customer and community needs.

The feedback and recommendations from the Energy Reference Group spanned across a range of critical topics of concern for our customers in relation to the Draft Plan and was provided after multiple structured, in-depth cross-collaboration sessions which also included the People’s Panel.

The key feedback from them and our response to these issues are captured in Attachment 02-01.

The Jemena team deserves commendation for their open, constructive engagement and curiosity throughout this process.

— Energy Reference Group Member

“We appreciate the effort put into crafting a proposal that balances affordability, resilience, and the facilitation of the energy transition. The transparent communication of how network investments directly benefit customers will be crucial in maintaining their support for the proposed revenue increase. Additionally, exploring potential efficiency gains and innovations could help manage future costs while ensuring service excellence and resilience.”

— Energy Reference Group

2.4 Evaluation

As a part of our continuous improvement objectives, to be successful throughout our engagement program, and to measure the effectiveness of the engagement process, we:

- built in a feedback loop at the end of each session to identify opportunities for improvement
- provided one-on-one meetings and follow-up with customers who needed more discussion, information or support
- published a Draft Proposal and,
- engaged an independent evaluator (**newDemocracy Foundation**).

The newDemocracy Foundation focuses on the design, oversight, and research of deliberative engagement processes to strive for more trusted decisions informed through deliberative processes.

Internationally, the newDemocracy Foundation offers advice to a range of national governments and parliaments and is a member of the OECD Innovative Citizen Participation Network (where it has contributed to the development of the OECD Evaluation Guidelines for Representative Deliberative Processes).

The newDemocracy Foundation has extensive experience reviewing stakeholder and customer engagement programs and activities for regulated businesses and has worked with and supported many organisations around Australia with similar advice on the design and delivery of deliberative engagement projects.

The newDemocracy Foundation monitored and evaluated JEN's engagement[15] against the International Deliberative Engagement Evaluation Framework and the AER's Better Resets Handbook to provide a customer lens on the effectiveness of our engagement.

The newDemocracy Foundation also set out to measure JEN's engagement against the Better Resets Handbook expectations, the People's Panel and supporting engagement processes.

The newDemocracy Foundation concluded that:

> *Overall, the People's Panel was very well run and allowed participants the opportunity to meaningfully influence Jemena's Business Plan 2026-2031.* ***It met and exceeded all the Better Resets' expectations of customer engagement.***
>
> *Jemena's approach to customer-led decision-making and the integration of deliberative engagement practice into its decision-making processes for the development of the 2026-2031 Business Plan place it at the forefront of global innovation.*[16]

This positive conclusion from the newDemocracy Foundation gives confidence that we have meaningfully engaged with our customers to understand their needs and expectations, and that the feedback that we have obtained throughout our engagement process can be relied upon to shape our 2026-31 Proposal.

Jemena continually maintained sincere and honest engagement demonstrated by regular attendance from senior staff and dialogue between customers and business leadership. Participants were informed, had multiple accessible channels for engagement and ultimately directly influenced the draft plan.

— newDemocracy Foundation

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15 AER - Better Resets Handbook - July 2024
16 JEN - NewDemocracyFoundation *Att 02-20 Independent Evaluation Report*

2.5 Ongoing customer engagement

The engagement we achieved through the price reset process, and building on the strong base established in the last price reset, has continued to highlight the benefits and advantages of engaging with a diverse range of customers.

We have built new relationships with our broad customer base and strengthened existing connections. The engagement process has enriched us with insights into customer needs and elevated our value of placing customers at the heart of our business.

This process has also lead to many other benefits including improved relationships and understanding between networks and consumers, greater faith from all parties in regulatory processes, and the generation of new ideas and regulatory approaches that benefit both consumers and networks.

We have leveraged the learnings and insights gained over past two years to assess our ongoing customer engagement practices. This evaluation aims to:

- strengthen our relationships with First Nations communities both in our network area and across Victoria
- explore new approaches for continuous customer engagement ensuring we cover a diverse range of customers and provide them multiple communication channels and,
- identify opportunities to maintain meaningful connections with our customers and stakeholders who have participated in the engagement process.

3. The Energy Transition

Highlights

- Our customers are acutely aware of the impact their energy choices have on the planet and future generations, and the need to transition the energy system to address these issues.
- In line with government policy, more households and businesses are transitioning towards full electrification and are investing in Consumer Energy Resources (CER).
- These factors will place a higher priority on achieving network reliability that meets community and policy expectations in an operating environment that is expected to become more complex and challenging to manage over time.
- To support this change, JEN’s **CER Integration Strategy** aims to connect its customers to a renewable energy future, by facilitating the integration of CER into the electricity distribution network and facilitating the electrification of the economy.
- In addition to these changes to how our customers interact with JEN’s network, the changing climate is expected to result in increasing disruptions to the electricity network.
- JEN aims to meet customers’ and community resilience expectations and accommodate the increasing divergence between higher maximum demand and lower minimum demand, decentralised energy exports and customer energy storage. This will require increasing the physical capacity of the network to meet these changing expectations. Complementing these upgrades with investments in our digital and operational capabilities will contribute to delivering an efficient outcome for customers and enabling access to renewable energy and new market products and services.
- JEN has identified several programs of work to ensure that it achieves network resilience over the next regulatory period that meet community and government expectations. We discuss these programs of work in Chapters 5 and Chapter 6.

3.1 Leaving the steady state

The National Electricity Market (NEM) and the laws, rules and objectives that underpin its operation have historically incentivised the efficient delivery of electricity to customers in a steady-state environment. This involves balancing affordability and efficient investment, with customer expectations around reliability and quality of service.

However, in recent years consumer preferences, policy changes and the rapid development of technology have led to changes in the way JEN’s customers interact with our network and in some instances, has increased their reliance on the electricity network.

At the same time, climate change and the increasing frequency of extreme weather events is placing an external strain on the electricity network. The poles, transformers and wires we use are coming under increased pressure from extreme weather events resulting in longer and more wide-spread outages.

Our customers have told us they expect JEN to seamlessly meet the challenges of the energy transition in an equitable, cost-effective and timely manner while still providing reliable service in the face of increasing climate pressures. How the market continues to evolve over the next two decades—including the cost of energy, developments in technology, customer needs and expectations, and the regulatory and policy responses—remains unclear, however, what is clear is that the energy system in the long term will be vastly different from that of today. For example, new technologies like battery storage, EVs and home energy management systems to manage their usage and lower their bills. Also, with the cost of solar photovoltaic electricity systems becoming cheaper, it is becoming more common for energy consumers to generate their own energy ‘behind the meter’.

Ruchika Deora, Energy Reference Group member said, "The biggest challenge for Jemena I think facing the future, is actually becoming a technology agnostic enabler of what could look like multiple markets, multiple energy flows and we need to ensure that Jemena is really set up to enable those outcomes in the best interests of consumers."

Our customers told us that they want us to continue to provide affordable and reliable electricity while empowering and supporting customers to take up and utilise more CER.

For the next regulatory period, we aim to continue providing a resilient energy network while developing and deploying digital initiatives that will encourage innovation and support customers' choices when making decisions about managing their own energy needs.

3.2 Emerging challenges

There are five global megatrends that are currently driving the energy transition, and which are likely to fundamentally change the structure and function of the electricity system over the next regulatory period and the long term. Throughout our customer engagement we discussed these megatrends with customers to help build their understanding of the challenges we face while seeking their advice on how we can prepare for the future.

The five global megatrends are:

Decentralisation

In the last decade, there has been a gradual decline in demand for electricity from centralised sources like power stations. Conversely, electricity generation from, and consumption of, electricity from CER[17] has increased.

Digitisation

It is impossible to escape the digital revolution. In the electricity system, digital technologies have enabled devices across the electricity network to communicate and share data that might be useful for both customers and the management of the network. Along with the state-wide smart-meter rollout in Victoria, other smart grid technologies used to digitise electricity distribution, such as sensors, automation, and artificial intelligence, create technologically integrated networks that better meet customer needs. Network operators who are late adopters are likely to be left behind, as they will have less knowledge of their customers, poorer management of their workforces and assets, and will be less prepared for future network changes.

Decarbonisation

Federal and state governments are implementing policies to decarbonise the economy, and many have accelerated their emissions reduction targets in recent years.[18] In May 2023, the Victorian Government set a new emissions reduction target of 75-80% by 2035 and has brought forward its net zero target to 2045.[19]

17 CER are small-scale energy resources owned by customers, which can produce, store or vary how they use energy. CER includes rooftop solar, batteries and electric vehicles and more traditional assets such as hot water heaters and pool pumps. For the purposes of our CER Integration Strategy we refer to CER to also include front of meter batteries.

18 AEMO, 2024 Integrated System Plan for the National Electricity Market: A roadmap for the energy transition, June 2024, p. 31.

19 Victoria State Government, Victoria's 2035 emissions reduction target, May 2023.

It has also set new renewable energy targets of 95% by 2035. To achieve these targets during the transition, the Victorian Government is investing to deliver 4.5GWhs of renewable power (the equivalent replacement of capacity of Loy Yang A power station), reducing fossil fuel gas use, accelerating key transmission infrastructure, driving the development of offshore wind energy projects and continuing its solar homes and EV programs, among other initiatives.

In light of this and the expected retirement of the coal generation fleet between now and 2050, significant amounts of intermittent renewable generation—both large-scale and CER—will likely enter the electricity system in its place.

From a network perspective, the more variable renewable generation sources that enter the system, the greater the need for flexible, dispatchable capacity to maintain system reliability and security. It could also mean there is a greater need for interconnectedness —both physically and digitally—to balance and vary the generation mix.

Electrification

As generation shifts to more renewable sources, electrification is likely to be recognised for its environmental benefits by shifting end uses of electricity—including transport and heating—away from fossil-fuel sources. This shift is already happening in transport, where there has been a strong global increase in EVs since 2010. In addition:

- **Electric Vehicles** – EVs present an opportunity to increase the utilisation of the electricity distribution network and, if the additional electricity used in EV charging can be managed, abate the expected increase in peak demand. With vehicle-to-grid technology, EVs can act like a “battery on wheels” and become a valuable generating resource if coordinated properly.

- **Gas substitution** – The global energy sector is shifting away from the production and consumption of non-renewable fossil fuels and moving towards the use of low-carbon and renewable energy solutions. The Victorian Government has also introduced a gas substitution roadmap, which includes placing a ban on new reticulated gas network connections from 2024.[20] These initiatives are some of the key changes that we expect to significantly change customers' interactions with and use of the electricity distribution network.

The rise of energy storage

Energy storage is made possible by the conversion of electricity into other forms of energy that can be stored. A growing form of energy storage is batteries. The cost of battery storage is rapidly declining and is likely to continue to decrease. The Australian Energy Market Commission (AEMC) also noted that warranted lifetimes for battery storage are increasing, the incentive to store low-cost solar energy and use this energy in peak periods is increasing, and that by 2025, battery installation may be financially viable for a number of households with solar PV installed.[21]

Given these developments and different rebates[22] offered by the federal and state governments to encourage uptake of rooftop solar, battery storage and EVs we expect Australia to see high uptakes of battery storage in coming years.

“I joined the sessions just to connect with other people in the community, to share my voice and hopefully be part of a more sustainable power grid in the future.”

— Mental Health Customer Voice Group member

20 Victorian Government, Gas Substitution Roadmap, Victoria's Gas Substitution Roadmap

21 AEMC, Turning point for incentives to invest in residential batteries.

22 Solar Quotes, Solar & battery rebates, subsidies & incentives – 2024, July 2024.

3.3 Future scenarios for our network

We assessed what our future network will be like in the context of the five global megatrends using the planning scenarios developed by the Australian Energy Market Operator (AEMO) under its draft 2023/24 Integrated System Plan[23]:

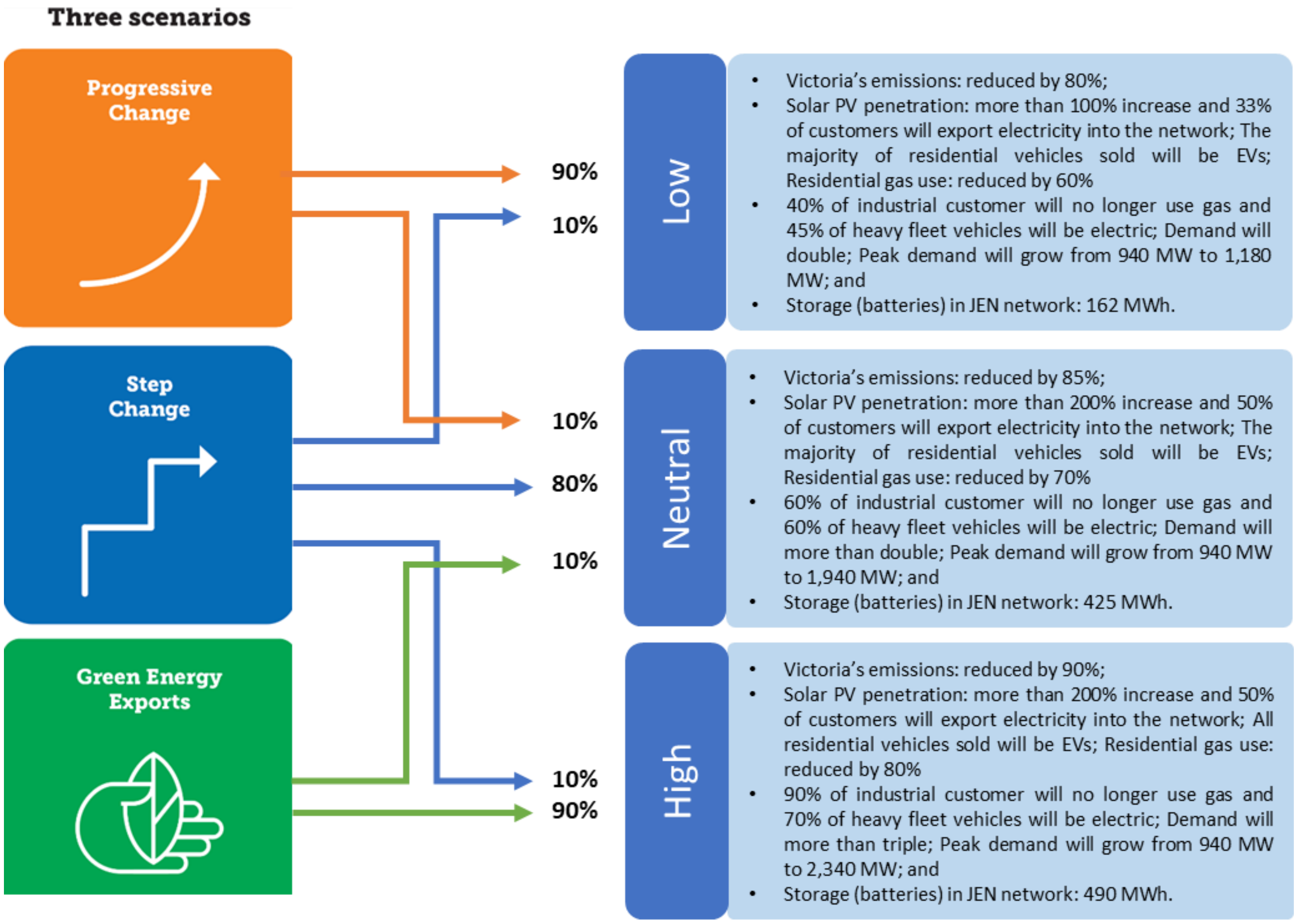
- Progressive change (lower growth scenario) – Australia will fulfil its emission reduction commitment of net zero emissions by 2050 in a growing economy
- Step change (moderate growth, fast change scenario) – achieves a higher level of energy transformation and energy investment
- Green energy exports (high scenario) – very strong industrial decarbonisation and low-emission energy exports.

By applying AEMO's national planning scenarios and methodology to JEN's unique network characteristics and operating environment, we prepared low, neutral and high forecasts that take into account:

- CER uptake
- electrification
- energy consumption
- maximum and minimum demand.

In Figure 3.1, we outline the approach we have taken to develop our forecast by blending these inputs.

Figure 3.1: Jemena Electricity Network's future state scenarios – weighting of AEMO scenarios



23 AEMO, Draft Integrated System Plan for the National Electricity Market: A roadmap for the energy transition, December 2023.

The scenarios are distinguished by different assumed increases in electricity demand and consumption, distributed solar PV systems, plug-in EV usage, and substituting gas in favour of electricity appliances relative to today. Some of the key drivers in our network's forecast are shown below in Figure 3.2 to Figure 3.4.

Figure 3.2: Cumulative capacity of installed solar PV systems[24]

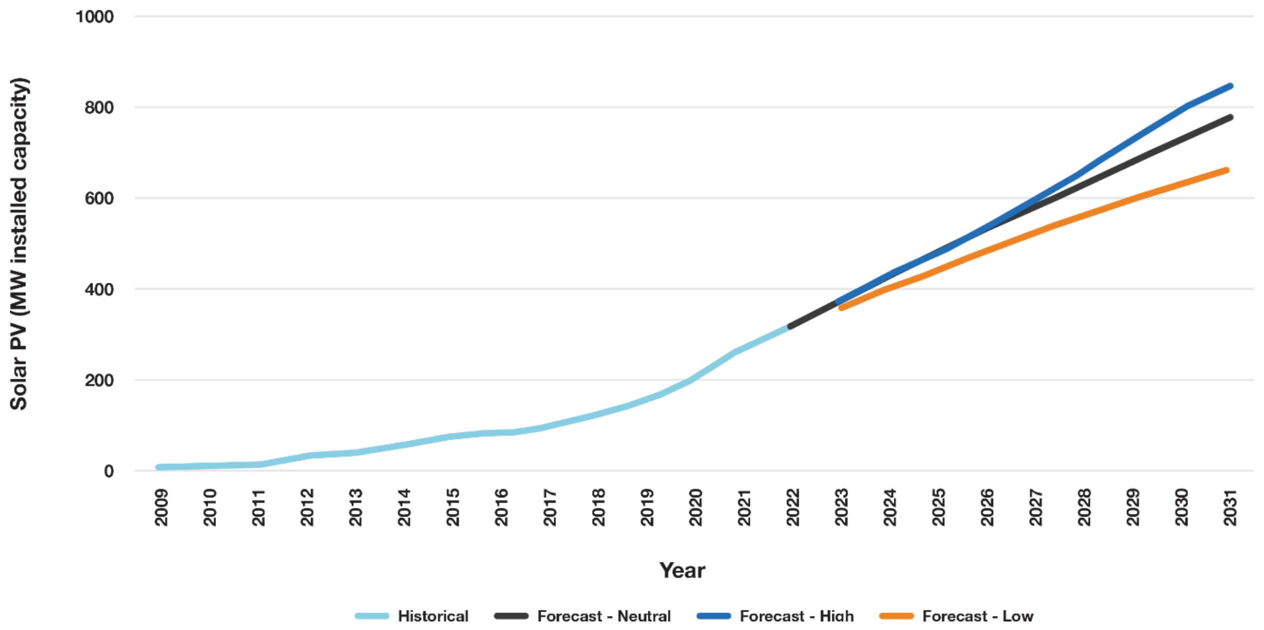
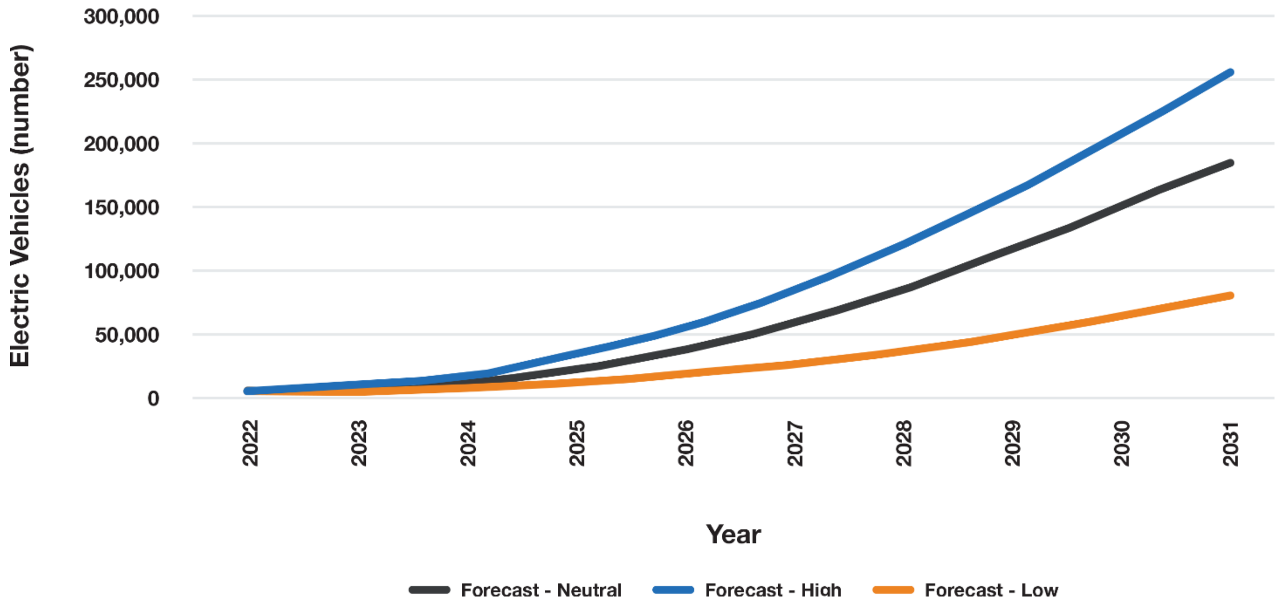


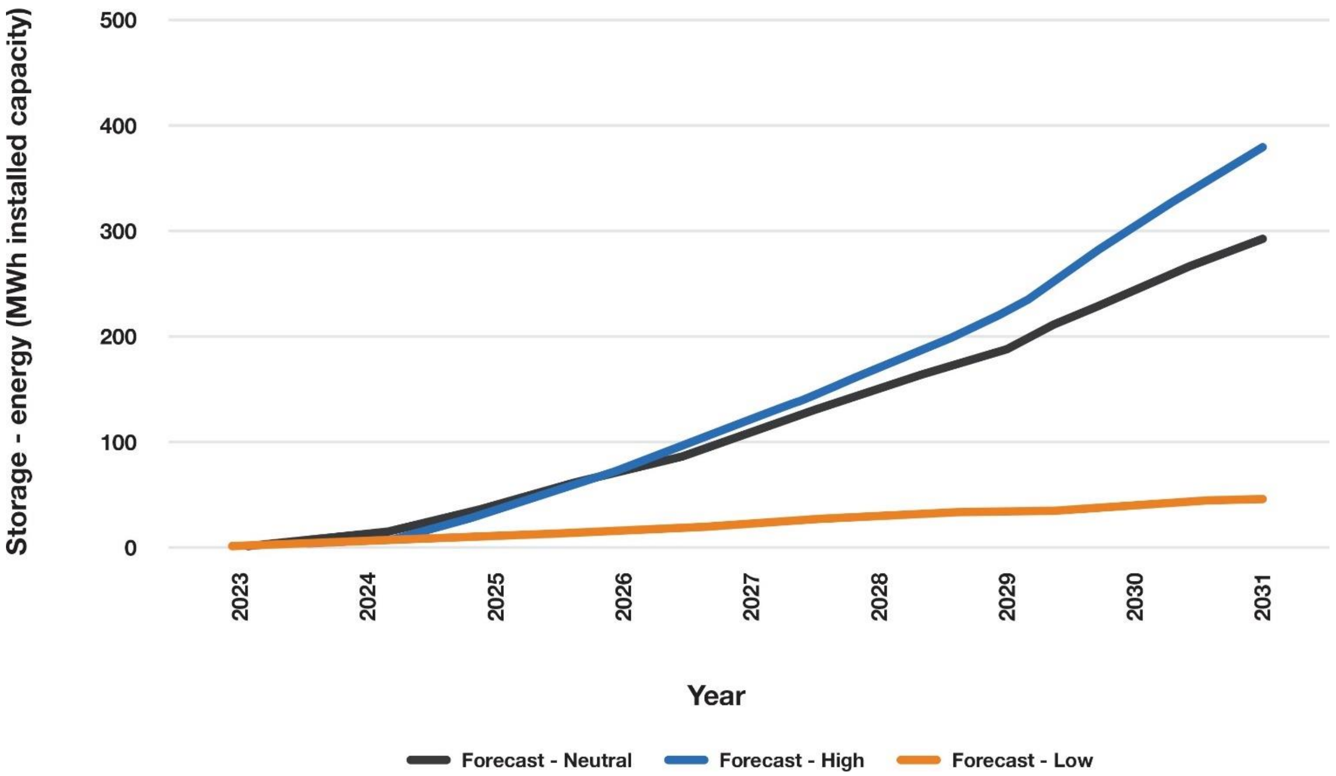
Figure 3.3: Forecast uptake of EVs[25]



24 Source: Source: JEN 2024 demand forecast

25 Source: Source: JEN 2024 demand forecast

Figure 3.4: Forecast uptake of battery storage systems (MWh installed capacity) [26]



The Victorian Government's policy to prevent the growth of reticulated gas networks means customers' energy needs will be increasingly supplied by the electricity network. This policy has significant implications for our electricity forecast because Victorian customers—particularly residential customers—have energy-intensive heating needs during winter, and these will need to be met by the electricity system in the future.

We have considered this change and developed a range of scenarios for what the substitution between gas and electricity energy sources could look like. Table 3.1 below outlines the scenarios we have considered when forecasting the impacts on the electricity distribution network in the future.

Table 3.1: Electrification of gas uptake by customer type, expressed as a percentage of Jemena's total customers

Scenarios	Electrification Residential & Commercial	Electrification Industrial
Low	30% of customers electrified by 2035 (9% brownfield, 21% greenfield)	NA
Neutral	45% of customers electrified by 2035 (24% brownfield, 21% greenfield)	15% of energy electrified by 2035
High	60% of customers electrified by 2035 (38% brownfield, 21% greenfield)	25% of energy electrified by 2035

When we look at the current government policies and megatrends, our analysis shows that—under every scenario—our electricity network will be significantly different by 2035.

26 Source: JEN 2024 demand forecast

3.4 We need a smart and stable network

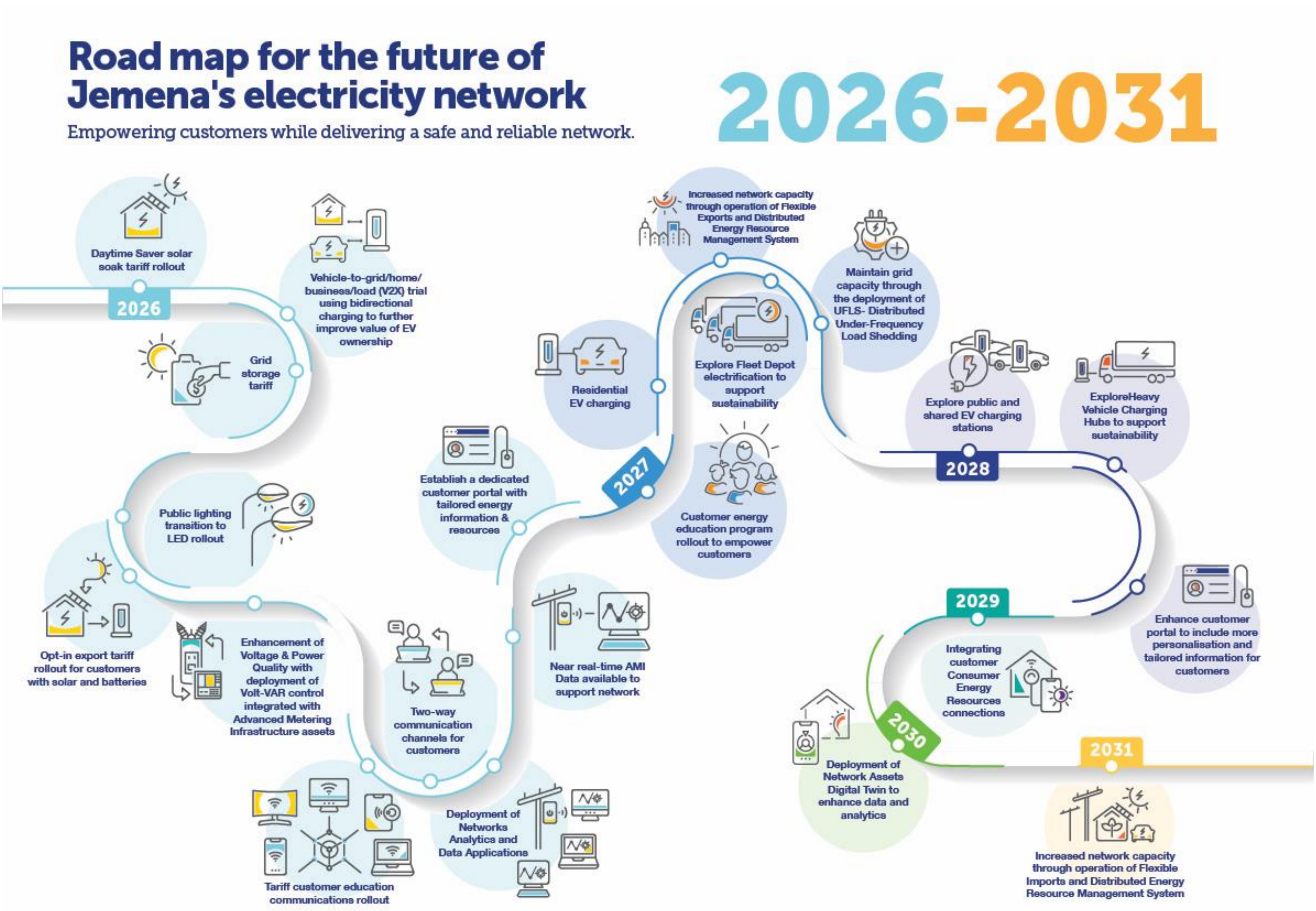
As our society progresses towards a decentralised and decarbonised future, the electricity system will change and as it transforms, so too will our role as an electricity distribution network service provider. With a growing proportion of generation originating from customers and flowing into the network, and with a multitude of customer devices seeking to connect to and interact with the electricity system, we will have to become a sophisticated distribution system operator to intelligently and efficiently distribute electricity to the place it is needed the most. The transition to this new role will be heavily influenced by customers, governments and regulators, as well as other changes in the external electricity market.

To prepare for this change, we need to pre-empt the transformation to mitigate against the potential negative impacts of disruption and embrace the opportunities that it presents on behalf of our customers. We see that digitisation and increased dependence on data and communications will be necessary, and our interactions with markets and customers will be greater. This trend is beginning to emerge through the significant reforms being considered by regulatory bodies such as the AEMC and AEMO.

The term “smart network/smart grid” was coined in the early 2000’s to describe the overlay of an ICT architecture on the physical electricity network infrastructure to improve real-time situation awareness and control as well as collating data for improved asset management planning and customer awareness. As Australia moves towards net zero, “smart networks” enabled by digitisation will play an increasingly important role in preparation for a more responsive and sustainable energy future.

“Ensuring the grid can handle and encourage the shift to renewable energy sources, including electric vehicles, solar power, and batteries. Emphasising the inevitability of this change and the need for infrastructure adaptation.”

— Young People Customer Voice Group member



Road map for the future of Jemena's electricity network
Empowering customers while delivering a safe and reliable network.
2026-2031
2026
Daytime Saver solar soak tariff rollout
Vehicle-to-grid/home/business/load (V2X) trial using bidirectional charging to further improve value of EV ownership
Grid storage tariff
Public lighting transition to LED rollout
Opt-in export tariff rollout for customers with solar and batteries
Enhancement of Voltage & Power Quality with deployment of Volt-VAR control integrated with Advanced Metering Infrastructure assets
Two-way communication channels for customers
Tariff customer education communications rollout
Deployment of Networks Analytics and Data Applications
Near real-time AMI Data available to support network
Establish a dedicated customer portal with tailored energy information & resources
2027
Residential EV charging
Increased network capacity through operation of Flexible Exports and Distributed Energy Resource Management System
Explore Fleet Depot electrification to support sustainability
Customer energy education program rollout to empower customers
Maintain grid capacity through the deployment of UFLS- Distributed Under-Frequency Load Shedding
2028
Explore public and shared EV charging stations
ExploreHeavy Vehicle Charging Hubs to support sustainability
Enhance customer portal to include more personalisation and tailored information for customers
2029
Integrating customer Consumer Energy Resources connections
2030
Deployment of Network Assets Digital Twin to enhance data and analytics
2031
Increased network capacity through operation of Flexible Imports and Distributed Energy Resource Management System

3.4.1 Our CER Integration and roadmap

Our overall mission is to connect our customers to a renewable energy future. While we support individual customer choices, we need to consider those choices to make investment decisions that support the efficiency of the overall electricity system for the benefit of all our customers.

In order to deliver a network of the future to meet the evolving needs of customers and to support Victoria in achieving net zero by 2045, JEN's CER Integration Strategy is driven by opportunities to:

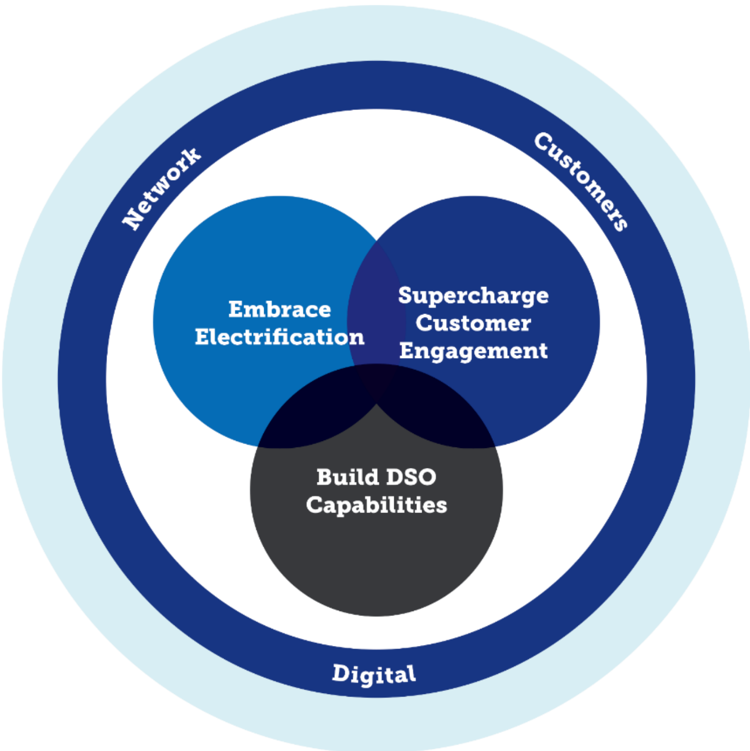
- **Embrace electrification** – Adapt the electricity distribution network to accommodate the additional demands expected from the electrification of the gas and transport sectors and for the evolving needs of our new and existing electricity customers.
- **Build future capabilities** – Continue to adopt digital systems and enhanced distribution services that support the energy transition to enable and facilitate competition and new services for energy market participants using enhanced applications, processes, automation, data and analytics, including functions that support AEMO in its role as a system operator to maintain power system security.

In pursuing initiatives to deliver on the above opportunities that meet our customers' service expectations they require in the transformed energy market, we will supercharge customer engagement. This will involve using a strategic multipronged approach to minimise the costs of adapting the network for the energy transition, maximising the capabilities of our existing network, and using pricing incentives, non-network alternatives and other flexible distribution services that enable and optimise CER. JEN also has a number of customer engagement initiatives planned over the next regulatory control period. These initiatives form part of our regulatory proposal, which includes energy literacy and building a new customer portal that provides tailored information to empower customers to make decisions on sustainable energy usage among other things.

Optimising these themes is necessary to ensure efficient distribution of electricity to our customers.

Figure 3.5 illustrates how these key themes link to customers, the physical electricity distribution network, and digital technology overlays to facilitate a smooth energy transformation at an efficient cost.

Figure 3.5: Our CER Integration strategy themes



Adopting programs of work during the energy transformation that support these key themes will allow us to achieve the following outcomes for customers:

- maintain distribution network reliability and quality of supply
- support power system security, stability and optimisation
- provide equitable and cost-effective distribution network access and CER enablement
- provide and utilise network capacity in an efficient, economic, coordinated and timely manner
- enable and facilitate competition and new services for energy market participants
- meet our regulatory obligations.

Our CER integration strategies

While the energy system evolves towards the goal of net zero by 2045, the time for network reform and investment is coming upon us more quickly than expected. Already, the rapid adoption of CER is putting electricity networks under increased pressure, meaning we need to curtail network exports to maintain the integrity of the electricity system. An increasing number of measures will be required as this pressure increases. We cannot wait until 2030 or 2040 to address these challenges; the timelines of project initiatives will need to be brought forward, and new capabilities and systems may need to be added in the next regulatory period. Our CER Integration Strategy will build and strengthen capabilities outlined in the roadmaps of each of our three programs, as shown in Table 3.2.

Our CER Integration Strategy is based on a scenario-based investment approach to managing the uncertainty and risks associated with the transformation, it is our overarching strategy for our asset management strategies, setting the basis for the strategic direction from which our asset management strategies are informed and developed. This strategy also informs the subsidiary strategies that are directly targeted at supporting the energy transformation (Figure 3.6 and Table 3.2).

"We expect that there will need to be a trade-off between investment in sustainable technologies and the cost impact that customers may incur."

— Energy Reference Group member

Figure 3.6: Our CER integration strategy

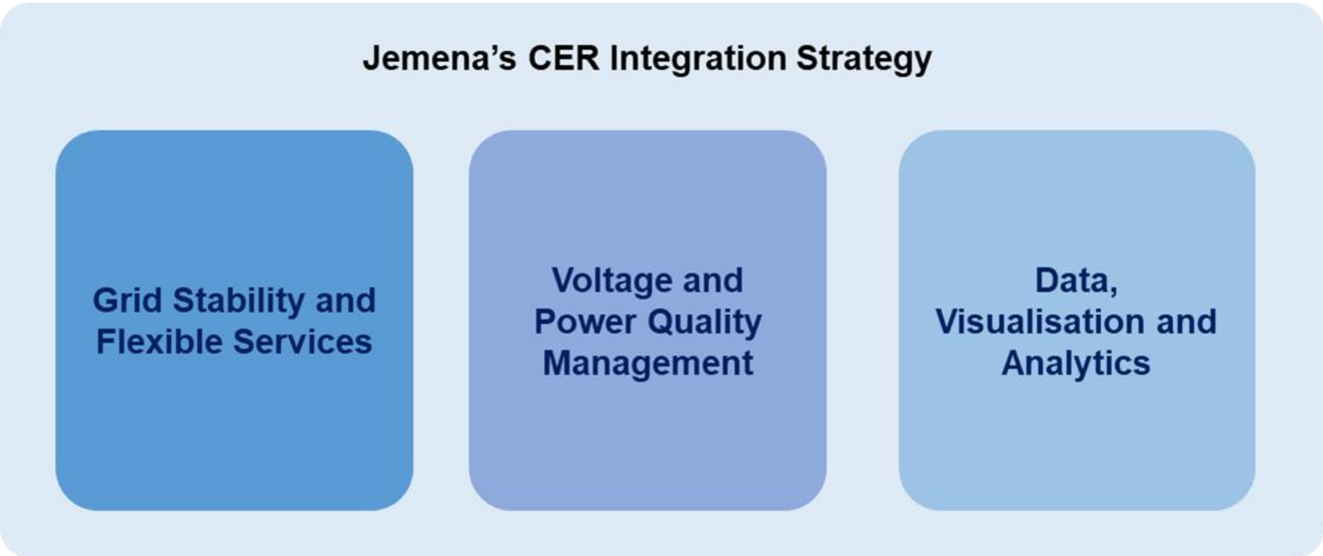


Table 3.2: Brief description of our CER Integration programs

Program	Description
Grid Stability and Flexible Services	A program that articulates the need for JEN to develop a Distributed Solar PV (DPV) Backstop Capability and a Distributed Under-Frequency Load Shedding (Distributed UFLS) Scheme as two distinct grid stability applications to strategically respond to the challenges and opportunities associated with increasing numbers of CER, and their associated influences on power system security and network operating limits. The applications developed from this strategy are supported by a new and staged Distributed Energy Resource Management System (LV-DERMS) platform to achieve near real-time optimised control of CER active power operating envelopes to keep the grid stable and to deliver flexible export and import distribution services using Dynamic Operating Envelopes (DOEs), facilitated by a CSIP-Aus utility server.
Voltage and Power Quality Management	A program to strategically respond to the challenges and opportunities associated with increasing CER penetration and the associated influences on network voltage and power quality. The applications developed from this strategy are supported by a new and staged Dynamic Voltage Management (DVM) system platform to achieve near real-time optimised control of network voltage and reactive power flow to maintain compliant voltages and reduce CER curtailment, using enhanced Volt-VAr control (VVC) integrated with JEN's Advanced Metering Infrastructure (AMI) assets.
Data, Visualisation and Analytics	A program for further digitalisation of network operations functions using network analytics applications. The program includes a network analytics applications program of work, and two application enablers: a Strategic Network Analytics Platform (SNAP) and near real-time AMI data. Network analytics application examples include: simulate new and moved connections, connection approvals, detection of wrong connections, near real-time power quality data for field crews, detect and predict network faults, and regulatory data collection obligations.

The programs of work identified from our CER Integration Strategy set out investment roadmaps, providing a prudent optimum balance between risk, expenditure and uncertainty to meet the identified needs of the energy transformation, delivering several key benefits, including:

- **CER enablement** – improve export capability and reduce CER curtailment calculated using the AER's Customer Export Curtailment Valuation (CECV)[27] methodology.
- **Reliability of supply** – maintain the reliability of supply by managing and adapting to the changes in electricity demand from CER uptake and usage of the network, the electrification of transport and gas substitution, and new and existing customers' requirements for electricity using the AER's Values of Customer Reliability (VCR)[28] methodology.
- **Regulatory compliance** – improved appliance safety and reduced consumption by maintaining voltages within regulatory limits, and satisfy system security through enabling grid stability by AEMO and power quality regulatory requirements using a least-cost approach to achieving our compliance obligations.

3.4.2 Our customers support digitisation and championing renewables

As outlined in the Customer recommendations and priorities (Chapter 2), our customers want an electricity network that uses innovative technologies to create efficiencies and maintain high reliability. Across all our customer groups and stakeholders, most notably residential customers, customers want the benefits achieved through digitisation and automation technologies. They want an electricity network that includes advanced

27 AER, Final customer export curtailment value methodology, June 2022.

28 AER, Values of customer reliability methodology – final decision, December 2019. This is the version is the report that was in force at the time of preparing our proposal.

metering infrastructure and smart network technologies, which can reduce other costs in the electricity supply chain and realise financial savings in the long term.

> *We are considering changing our fleet to electric vehicles, factoring in the current cost of fuel vs lower cost of running EVs, charging during the day etc. Unsure of whether to make the investment if running costs increase in future.*
>
> *— [Small business customer]*

Customers expect us to achieve greater efficiencies through digitisation and automation, increasing economic efficiency through adopting digital technologies and automated processes. Customers also want us to realise the benefits of AI technology, communication, and data sharing across the network, which can improve reliability and respond quickly to disruptions and outages.

Our customers see benefits in the long-term savings that are achieved through less maintenance of assets and less operational manual inputs achieved through digitisation and automation.

Our customers also want us to play a leading role in championing renewables across the network and help incentivise and drive battery take-up as much as possible. Customers see batteries as one of the leading solutions to help redistribute the increasing amount of excess solar generated by more and more households. Customers also see batteries as a means to reduce network stress and create positive outcomes for all customers.

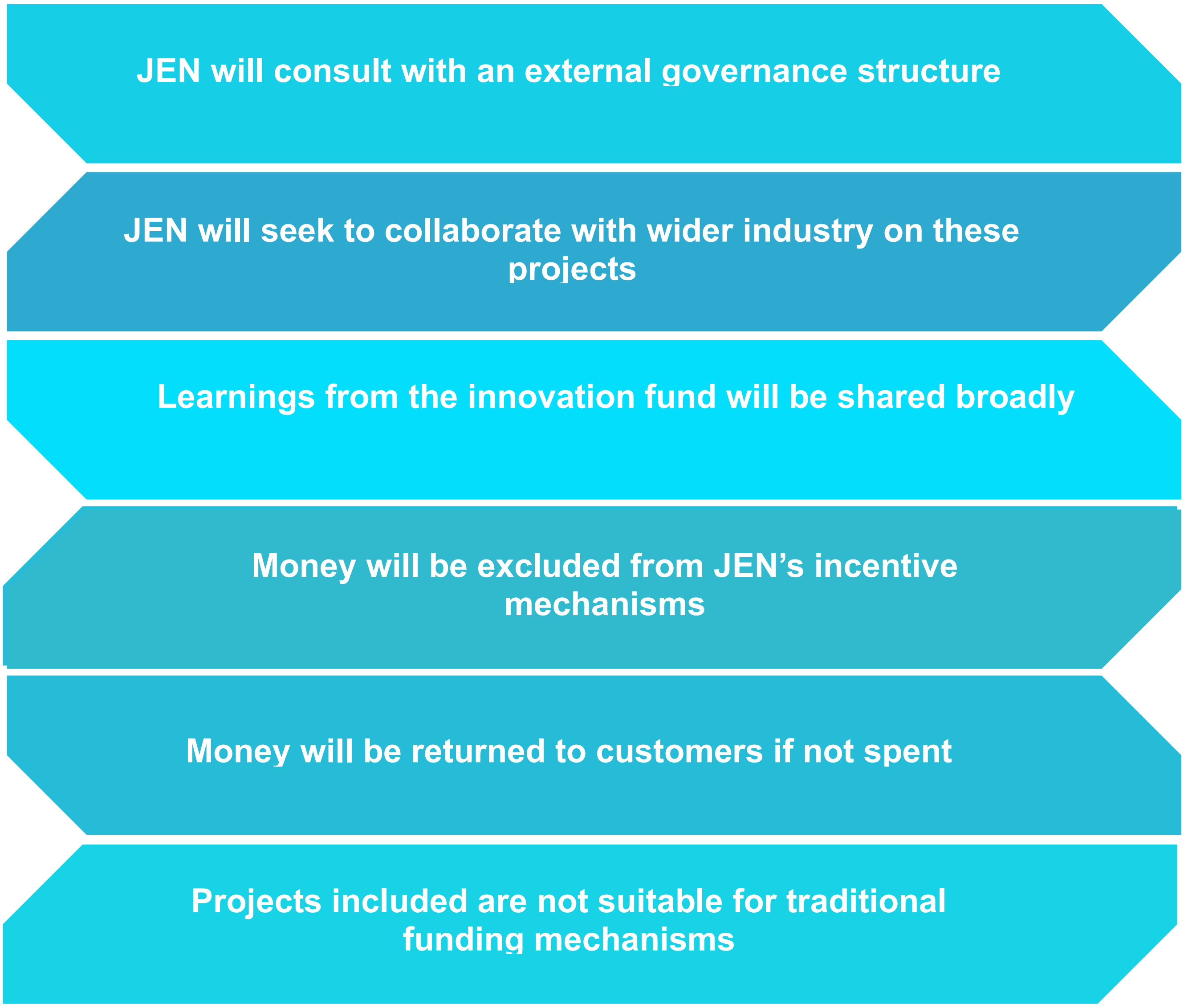
3.4.3 Accounting for ‘known unknowns’

While our CER Integration Strategy has been designed to keep pace with the rapid changes of the energy transition, it is designed based on what we know today. JEN and our customers recognise that there is a lot that we don’t and can’t know about changes in technology and consumer preferences that may take place between today and 2036.

Customers want JEN to be able to react to these changes and support them as they adopt emerging technology.

In response to this, JEN is proposing an $8 million ‘Innovation Fund’. This fund would be used for trials, research and programmes to establish how we can best respond to emerging challenges of the energy transition, before they reach critical mass. To ensure this fund best supports customer outcomes, we are proposing the following ‘core tenets’, based on similar innovation funds proposed by our DNSP colleagues and approved by the AER. Refer Figure 3.7.

Figure 3.7: Innovation Fund core tenets



Additional details on JEN's proposed Innovation Fund are included in '*Attachment 03 – 02 – Innovation Fund'*

3.5 A changing climate

In addition to the changing relationship between our customers and the network, the changing climate is also placing a strain on the network. In 2023 JEN, along with our Victorian DNSP peers, commissioned AECOM to develop a statewide Climate Change study. The purpose of this report was to assess the likely impact of the changing climate on the electricity network assets and to identify areas which could be classified as 'at risk' (refer Table 3.3 below).[29]

Table 3.3: Likely impact of the changing climate on the electricity network assets

Hazard	Exposure risks to JEN's network
Extreme rainfall (flooding) (changes in heavy rainfall events, existing flood hazard area)	Projected changes in heavy rainfall are greatest at Sunbury and Gisborne South. In addition to parts of Sunbury, areas of asset exposure are spread across the southern half of the distribution area, example locations include West Footscray, Hadfield and Heidelberg West. Approximately 5% of JEN's electricity distribution lines (and associated assets), 4% of distribution substations and 10% of zone substations intersect with the existing flood overlays across the distribution area.
Bushfires (existing bushfire management overlay)	Areas of greatest asset exposure include Gisborne South, region surrounding Gisborne South and Woodlands Historic Park. Less than 1% of distribution lines and approximately 1% of distribution substations intersect with the bushfire management overlays across the distribution area.
Extreme heat (heatwaves) (Days over 35°C and/ or days over 40°C)	Frequency and severity of extreme heat days are relatively uniform across the distribution area. Assets are similarly exposed across JEN's distribution area with the frequency and severity of extreme heat events projected to be relatively uniform. The projections do not consider the potential for higher ambient temperatures due to the urban heat island effect.
Extreme wind (Tree extent, wind gust >100 km/h)	Areas of higher exposure as indicated by the vegetation overlay and the concentration of assets include the region surrounding Gisborne South, and in proximity to Merri Creek and Darebin Creek. Approximately 3% of distribution lines intersect with the vegetation overlay across the distribution area.
Sea level rise (Storm surge flooding)	Areas of greater asset exposure include Williamstown. Less than 1% of distribution lines (depending on the voltage levels) and distribution substations intersect with areas that are projected to be inundated by 2040 and areas that projected to be inundated by 2070. Approximately 3% of zone substations intersect with areas that are projected to be inundated by 2070.

Examining AER Regulatory Information Notice (RIN) data illustrates the effect of these events on distribution networks. System Average Interruption Duration Index (SAIDI) measures the average cumulative outages duration for each customer served across the network. Distribution Network Service Providers (DNSPs) are assessed against this metric under the AER's Service Target Performance Incentive Scheme (STPIS). This scheme allows networks to exclude outages which occur on a Major Event Day (MED)[30] or fall under one of the specified exclusion categories as these are deemed to be outside of the control of the DNSP.

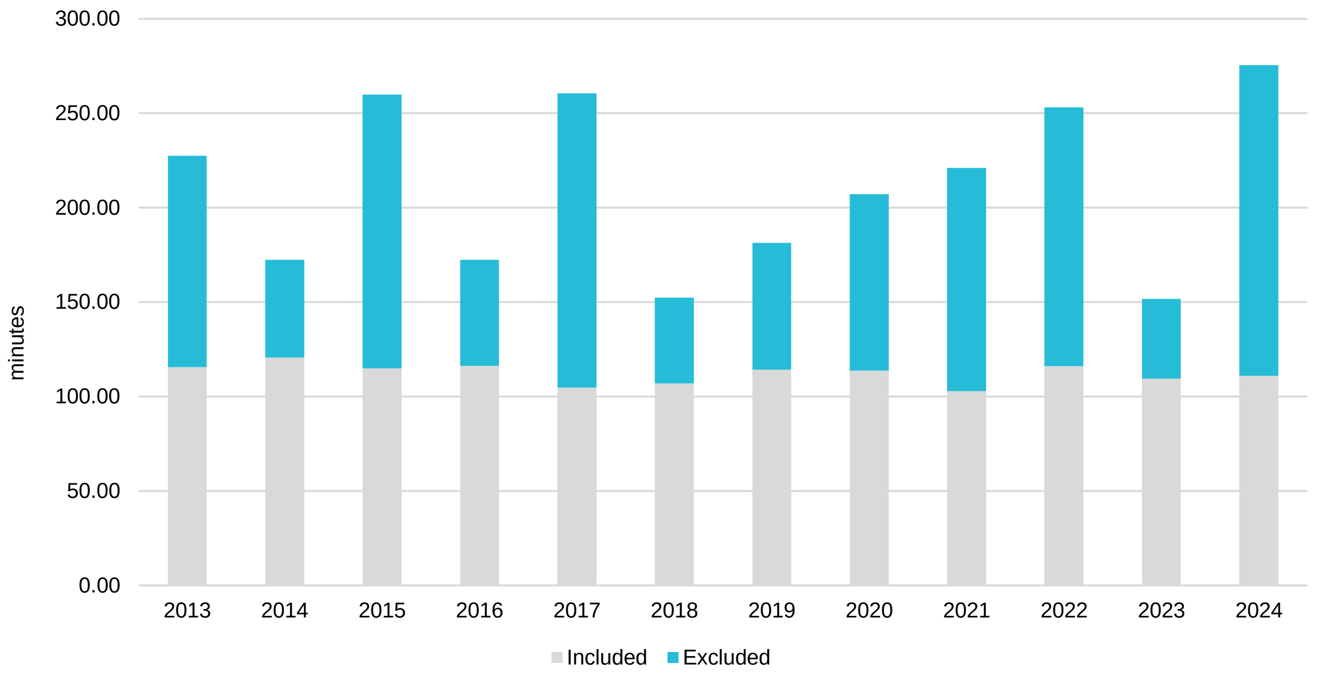
Over the period assessed, while the duration of outages included under the STPIS has generally fallen, the *total* duration of outages has not. This is due to an increase in the duration of outages which are excluded from the STPIS. Due to the changing climate conditions discussed above, historical averages may not be reflective of

29 JEN - AECOM - Att 03-03 - Joint Victorian Climate Change Study Final Report - 20240613

30 A major event day is typically defined as an event where the SAIDI is greater than 2.5 standard deviations from the mean SAIDI of the log normal distribution of five regulatory years' SAIDI data.

future trends however it is reasonable to assume the trends highlighted in Figure 3-8, will continue, if not be exacerbated.

Figure 3.8: Average minutes off supply across the NEM 2013 - 2024[31]



The increasing risk of these long-duration outages has led the Victorian Government, regulators, DNSPs and our customers to consider how best to increase the electricity network's resilience to these extreme events.

3.6 What is network resilience

Network resilience is defined as *"…the network's ability to continue to adequately provide network services and recover those services when subjected to disruptive events"*[32]

Although some initiatives that increase network resilience may also help maintain reliability (for example, replacing wooden poles with steel poles), these are not interchangeable terms or concepts. While reliability relates to how the network performs under normal conditions, resilience measures how the network performs under external strain.

Table 3.4 sets out the definition and measurement of reliability and resilience.

Table 3.4: Reliability and Resilience – definition and measurement

	Reliability	Resilience
Definition	The probability of a system, device, plant or equipment performing its function adequately for the period of time intended, under the operating conditions encountered.	A performance characteristic of a network and its supporting systems (e.g. emergency response processes, etc.). It is the network's ability to continue to adequately provide network services and recover those services when subjected to disruptive events.

31 Source: AER Category Analysis RIN, 6.3

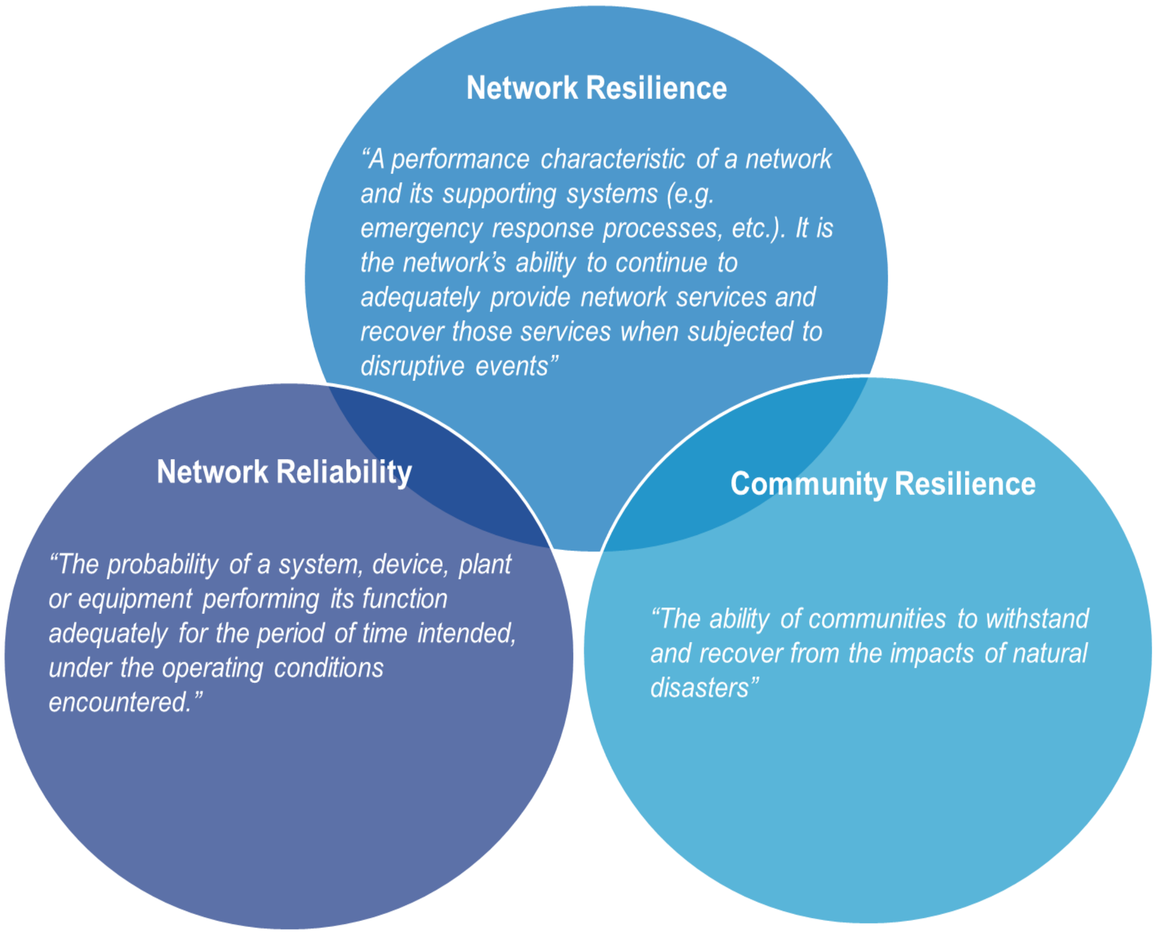
32 s 2.1, AER, Network Resilience - a note on key issues, April 2022

	Reliability	Resilience
Performance Measured By	**System Average Interruption Frequency Index (SAIFI)** The average number of interruptions each year outside of excluded events. **System Average Interruption Duration Index (SAIDI)** The average duration (minutes) of interruptions each year outside of excluded events. **Customer Average Interruption Duration Index (CAIDI)** The total duration of all the Sustained Interruptions (in minutes) divided by the total number of Sustained Interruptions that have occurred during the relevant period	No formal quantification method[33]
Customer Value	Value of Customer Reliability (VCR)	Value of Network Resilience (VNR)
Outage Length	3 minutes – 12 hours (also known as short duration outages)	12 hours + (also known as long duration outages)

While network resilience is an important aspect of responding to major weather events, it is only one part of wider community resilience. Community resilience encompasses how government, communities, households and all critical infrastructure operators respond to natural disasters. Poor network resilience can hinder community resilience by negatively impacting restoration efforts or disrupting the provision of critical services. This also has a flow-on effect on other critical and emergency services, such as hospitals, water treatment plants, and communication networks. Network resilience plays an important role in supporting these emergency agencies, governing bodies, and the communities they serve when faced with a major weather event. The relationship between community resilience, network resilience and reliability is summarised in Figure 3.9.

33 Appendix 3.3 of the AER's Final Decision for Ausgrid 2024 – 2029 Price Determination suggests National Electricity Market wide performance reporting of resilience investments. However, this has not be adopted.

Figure 3.9: The relationship between community resilience, network resilience and reliability



3.6.1 The regulatory framework is changing to include network resilience

Previously it was considered that costs associated with these events were best managed by cost pass through applications made after the event. While this allows networks to recover the efficient costs of repairing the network after the event and reduces costs to customers for unnecessary network hardening, it overlooks the customer and community costs associated with the extreme weather events that could be prevented through appropriate levels of network investment. While this may have previously been an appropriate balancing of risk and cost, there is reason to believe this is no longer the case given:

- The frequency of extreme weather events is increasing, meaning it is becoming more likely that these network investments will be necessary.

  Restoring/repairing the network after an extreme weather event may be more expensive than maintaining the network. For example, the added cost of emergency crews/overtime to replace poles after a storm could be more expensive than replacing timber poles with more resilient composite poles during a regular BAU pole replacement activity.
- As outlined above, customers - particularly residential customers - are increasingly reliant on the electricity network due to both the proliferation of devices and Government policies that encourage electrification. Therefore, the customer costs and impact outages may be increasing.

In response to this changing context, policymakers and regulators have begun investigating and developing adjustments to the regulatory framework to address this emerging challenge. Recent reviews include:

- The Victorian Government's Expert Panel Resilience Review (2021)
- The AER's Guidance Note on Resilience Issues (2022)
- The Victorian Government's Expert Panel Resilience Review (2024)

- The AER's Value of Network Resilience (VNR) (2024)
- Integrating Distribution Network Resilience in the NER (2025)

The resulting recommendation from these reviews is for targeted focus by electricity distribution networks to undertake activities to ensure future resilience and reliability of the electricity network, and to provide customers with access to more information and support when the networks are down.

We provide more information on the outcomes of the above reviews, and how it impacts our likely obligations and activities, and associated costs, in section 6 of *JEN - Att 06-04 Operating expenditure step changes*.

3.6.2 Our customers value network resilience

Early engagement with our customers identified resilience as a top priority.[34] Following the publication of our Draft Plan and our JEN Resilience Addendum, which contained our early thinking on resilience, and some estimated costs to deliver these initiatives, we held a 'recall session' with our customers. Part of the recall session was dedicated to network resilience. We wanted to ensure our customers were fully informed of the climate risks to the network, our proposed initiatives, and the associated costs. This gave customers the opportunity to ask questions and seek clarification. It also gave JEN the opportunity to understand the nuance of our customers' views on the topic.

Given the complexity of network resilience and the ongoing policy developments in this area, we revisited the topic during the deep dive sessions. To ensure improvements aligned with our customers' needs, we presented three packages on network resilience, which focused on our customers' priorities of fairness, reliability, and preparedness.

Customers reflected on these in small groups and then presented their considerations, choosing Package 2—Equitable Resilience. They explained they felt this package took into account resilience efforts for vulnerable and underserved customers and that "no customer was left behind." Customers viewed investment to bolster outage preparedness and response as warranted and they supported the expenditure on this. Customers considered investing in these systems and capabilities as "balanced and pragmatic" and stated, "these are all useful things to spend money on".[35]

Given we are dealing with unknown situations (when, where, how, etc.) it makes sense to future proof in a way that potentially everyone can benefit, not just a few, and still be economically reasonable

— Residential Customer

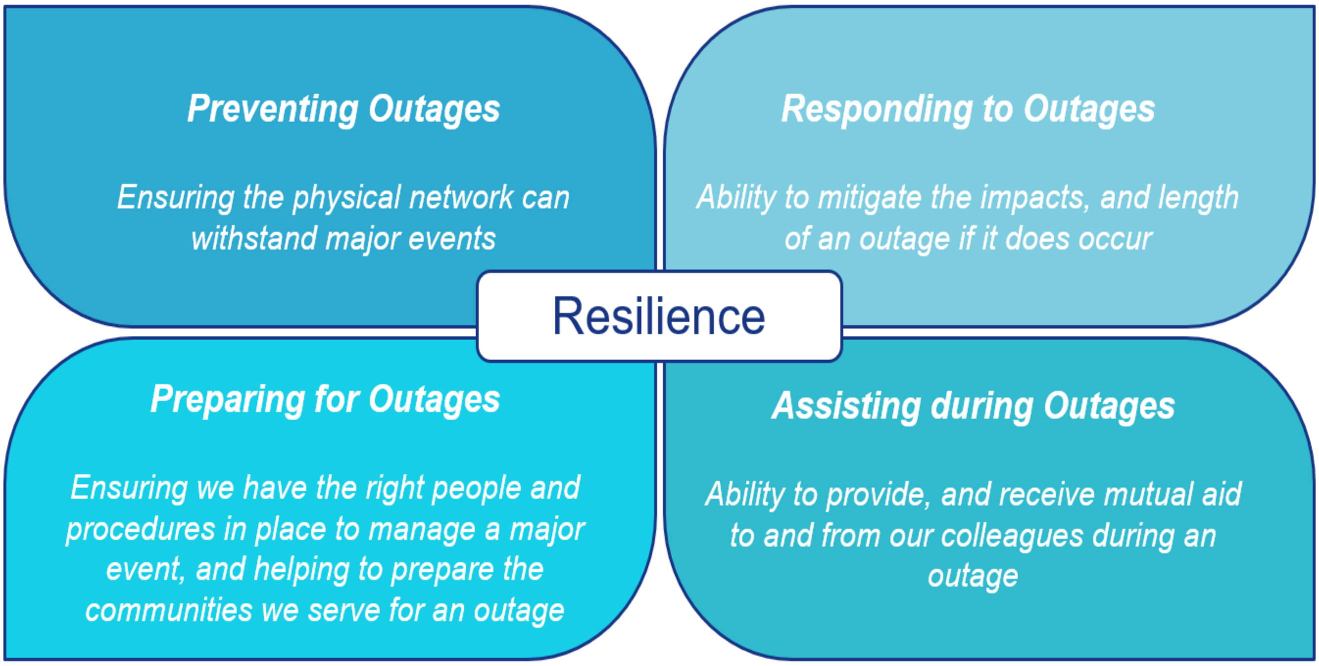
34 JEN, Att 02 – 01: Customer Engagement

35 JEN – MosaicLab Att 02-22 Customer Deep Dive Outcomes

3.7 JEN’s approach to resilience

JEN is committed to providing our customers with sustainable and affordable services. We also want to ensure our resilience plans reflect not only customers’ views but ‘best practice’ as defined by both the AER and the Victorian Government. We have developed a holistic resilience framework to ensure we integrate resilience into our business-as-usual practices in the most efficient and cost effective way possible.

Figure 3.10: JEN's core resilience tenets



This multifaceted view of resilience goes beyond simply hardening the network – which creates the ‘risk of paying twice’[36] and also involves investments in non-network assets, so we can better support customers during an outage. JEN has identified several programs of work that addresses the key resilience tenets above to ensure that it achieves network resilience over the next regulatory period that meet community and government expectations. We discuss these programs of work in Chapter 5 (Our capital investment) and Chapter 6 (Our Operating Expenditure).

36 ‘The risk of paying twice’ stems from the unpredictable nature of storm events. JEN may invest in hardening one area of the network – which is then not effected by a storm event.

4. Our services

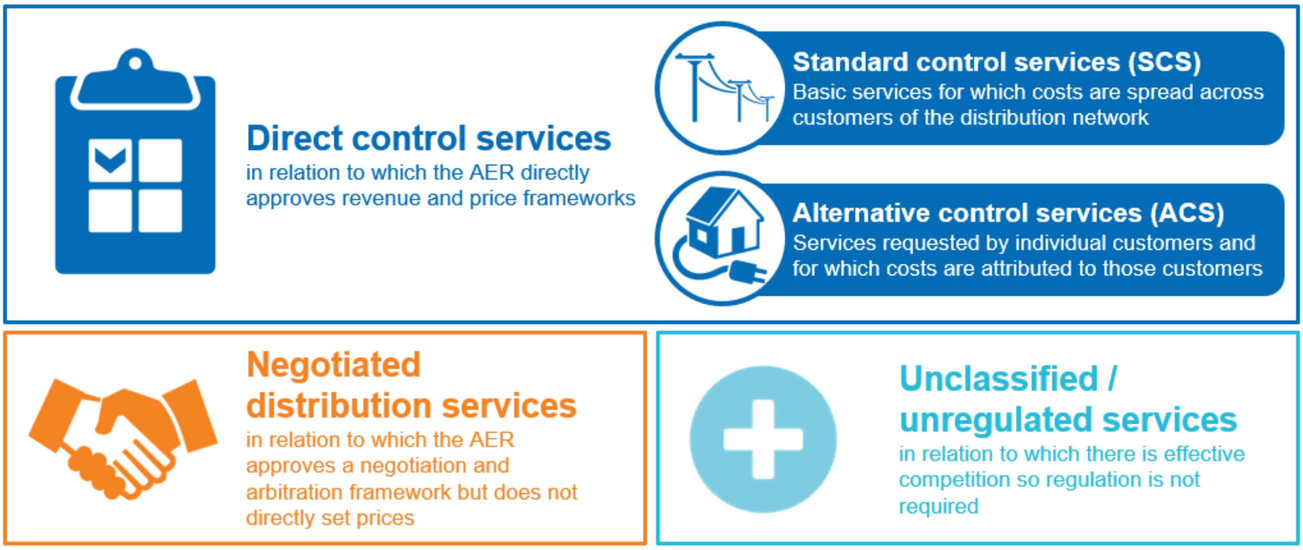
Highlights

- The classification of our current distribution services will continue to apply over the next regulatory period.
- We propose that the following services be introduced and classified as direct control and standard control services:
  - Customer export services
  - Mandatory essential system services
  - Network data sharing and advisory services
  - Standalone power system services
- These new services relate to the energy transition and align with our customers' expectations.
- Through our customer consultation activities, we did not receive any customer feedback or submission specific to the classification of our current distribution services.

4.1 Overview

We provide different types of electricity distribution services. The classification of distribution services defines the type of economic regulation that the AER will apply to the services we provide. The NER set out how the AER is to classify distribution services as shown in Figure 4.1.

Figure 4.1: Distribution service classifications



There are three main classifications of distribution services:

- **Direct control services**. This represents the majority of our electricity distribution services. They are further classified into standard control services and alternative control services. Standard control services relate to the services for which costs are spread across all customers connected to the network. In contrast, alternative control services are those services requested by individual customers and for which costs are attributed to those customers. In 2024, 77% of our total revenue (excluding capital contributions) came from direct control services.[37]
- Whether a distribution service is to be categorised as a standard control service or an alternative control service depends on the AER's consideration of several factors. These factors include whether there is potential for competition in the relevant market, the extent to which costs of providing the service are directly attributable to the person receiving the service, consistency in the regulator's approach within Victoria and among Australian states and territories, and the impacts on administrative costs, among others.

37 The remaining 22% of our total revenue (excluding capital contributions) are pass through revenue related to transmission use of system charges and the other 1% comes from unregulated services.

- **Negotiated distribution services**. The AER does not directly set prices for these services, but it approves the negotiation framework that applies to these services. At this stage, we are not proposing any negotiated distribution services.
- **Unclassified/unregulated services**. The AER does not regulate these services because there is a working competitive market.

JEN – Att 04-01 – Classification of services lists all our current services including the newly classified distribution services approved by the AER.

4.2 We propose only minor changes to classification of our current services

Our current services remain appropriate for the next regulatory period and meet the needs of our customers. However, following engagement with our customers and consideration of the emerging market opportunities, we propose a few minor changes to the existing classification of our current distribution services, network ancillary services, metering services and connection services.[38]

4.3 We propose classifying new services

The AER's Electricity Distribution Service Classification guideline provides a baseline set of distribution services, groupings of services and outlines its preferred approach to classifying distribution services.[39,40] Below, we outline the new services we propose in the next regulatory period, which as noted above have been informed by our customers feedback and consideration of the emerging market opportunities.

38 On 9 May 2023, the Victorian electricity distribution businesses including JEN held a Customer Vulnerability Workshop. The aim of the workshop was to understand how the Victorian electricity distribution businesses can best support customer experiencing vulnerability, amidst the rising cost of living and the ongoing transformation in the electricity market due to the energy transition. For more details about this joint engagement refer to: *Attachments JEN – RPS Att 02-15 – Joint VICDB engagement – Vulnerability report 1 – 20231605* and *JEN – RPS Att 02-16 – Joint VICDB engagement – Vulnerability report 2 – 20230410*.

39 AER, Electricity distribution service classification guideline, 1 August 2022.

40 The AER determines our prices every five years. The first step in the price determination process is to publish Framework and Approach (F&A) papers. The F&A sets out the AER's approach to key elements of the upcoming determinations and facilitates early consultation on these before businesses prepare and submit their pricing proposals. The current F&A for Victorian electricity distribution network service providers was developed in 2019.

4.3.1 Customer export services

Our network is increasingly being used by customers to export the excess electricity generated by their Consumer Energy Resources (CER) to the electricity network for other customers to use. The recognition of export services as a distribution service in the NER will enable us to plan and invest in the network more effectively to support growing customer expectations for CER uptake and electricity exports in the future, helping to unlock the full potential of CER.[41]

Export services involve the use of the shared distribution network to export electricity, hence our view is that these services should be regulated as direct control services and provided for in our standard control service-regulated revenue allowance. This means that the cost of providing these services would be shared across customers in our network, acknowledging the shared benefit that this provides to JEN's customers.

> The AER, in its final Framework and Approach for Victorian electricity distribution network service providers, has accepted our proposal to classify customer export services as direct control and standard control services.[42]

4.3.2 Essential System Services

Essential system services (ESS) are necessary services provided to the National Electricity Market (NEM)[43] to help keep the electricity network safe, reliable, and secure. Some forms of ESS are provided by NEM participants, including utility-scale batteries, large energy users, and some forms of generation. AEMO passes through the costs of these services to NEM participants and electricity customers.

We are permitted to provide the following mandatory ESS when directed by the AEMO:

- interruption or curtailment of distributed/customer energy resources connected to the distribution system to maintain system stability and security where there is critically low demand
- interruption or disconnection of supply at premises to manage under-frequency load risks using our smart control technology.

> The AER, in its final Framework and Approach for Victorian electricity distribution network service providers, has accepted our proposal to classify mandatory ESS as direct control and standard control services.[44]

4.3.3 Network data sharing and advisory services

Electricity distribution network service providers gather and analyse data from network assets such as smart meters, monitoring devices and other systems Our data is also useful for various stakeholders—including customers, NEM participants, investors, developers, governments, community groups and researchers—to support their needs throughout the energy transition. These stakeholders raise data requests with us and other distribution network service providers, such as the examples shown in Figure 4.2.

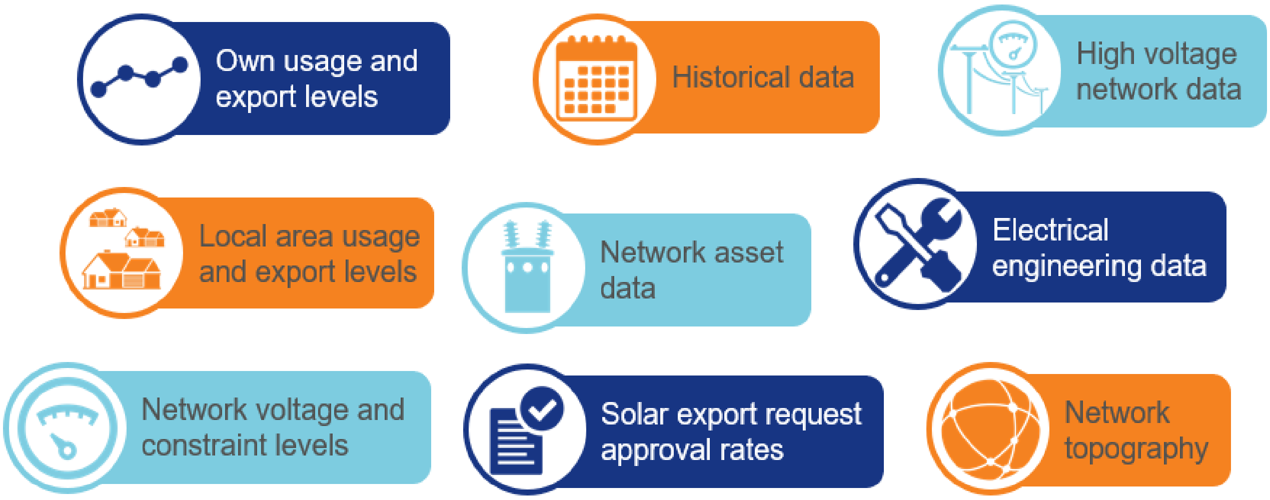
41 AEMC, Access, pricing and incentive arrangements for distributed energy resources, Rule determination, 12 August 2021.

42 AER, Final Framework and Approach Papers for AusNet Services, CitiPower, Jemena, Powercor and United Energy 2026-31, July 2024, p. 4.

43 The wholesale electricity market for eastern Australian states and territories.

44 AER, Final Framework and Approach Papers for AusNet Services, CitiPower, Jemena, Powercor and United Energy 2026-31, July 2024, pp. 5-6.

Figure 4.2: Examples of data requests (non-exhaustive)



We manage a wide variety and significant volume of data requests on an individual, ad-hoc basis. Data requests range in size and complexity and sometimes require dedicated staff to manage. In some cases, customers and other stakeholders requesting data are unsure of the data they require and how to interpret it. The lack of a framework means that there may be inconsistent outcomes, inequitable cost allocations, and consequential impacts on the progress of the energy transition.

In our submission to the AER, we proposed to the AER that it classify the following two services on data provision:

- provision of standardised network data should be classified as direct control and standard control services. This would include data provision services, for example, through a network visibility map or portal that provides public access.
- provision of network data and advice, including data analysis and interpretation, outside the scope of the classified standard control service should be classified as alternative control services. Costs of these bespoke services would be recovered from the stakeholder requesting the data, rather than shared among our customers providing a more equitable outcome.[45]

> The AER, in its final Framework and Approach for Victorian electricity distribution network service providers, has accepted our proposal to classify provision of data services as we have outlined above.[46]

4.3.4 Standalone power system services

Standalone power system services (SAPS) are technology solutions used to provide electricity supply to customers in circumstances where supply via the electricity distribution network is not appropriate—for example, in remote communities out of reach of existing power lines and in communities that have lost access to the electricity distribution network due to line breaks from bushfires or other natural disasters. SAPS are made up of several apparatus, including solar panels, batteries and backup generators, and also include individual power systems and microgrids and operate independently of the electricity network.

45 JEN, Submission for replacement Framework and Approach paper: 2026-31 regulatory control period, October 2023, pp. 22-23

46 AER, Final Framework and Approach Papers for AusNet Services, CitiPower, Jemena, Powercor and United Energy 2026-31, July 2024, pp. 6-7.

Recent reforms to regulatory framework enable us and other electricity distribution network service providers to provide SAPS services to supply electricity to customers who are not connected to the national electricity system. We may provide SAPS services to existing customers and offer to connect new customers to existing regulated SAPS where this is more efficient than connecting them to the electricity distribution network. Under the rule changes, an electricity distribution network service provider's SAPS services are required to be classified as a standard control service so that the costs of providing the services are recovered from across the customer base.[47]

We proposed to the AER to give effect to this change by treating our provision of SAPS services as an activity under the 'common distribution service' grouping.[48]

> The AER, in its final Framework and Approach for Victorian electricity distribution network service providers, has accepted our proposal to classify SAPS.[49]

4.3.5 Connection services

The Victorian Government's Emergency Backstop Mechanism requires us to ensure that newly connected and replaced solar photovoltaic installations can be remotely curtailed in an emergency if there are critical minimum demand risks. This is a mandatory obligation for the Victorian electricity distribution network service providers.[50]

To ensure relevant solar photovoltaic installations are backstop-capable, we will need to undertake a range of activities, including:

- installation of infrastructure to enable backstop capability, for example, inverter technology capable of remote communication with our systems through the internet or other means
- inspection of solar photovoltaic installations at customer sites to check capability and readiness for remote curtailment in case of an emergency
- other activities such as tests and notifications to customers of interruptions or curtailment.

We proposed that the AER consider whether changes to service classifications are necessary to reflect activities we undertake in relation to the mechanism.[51]

We also proposed minor clarifications for the other/enhanced connection services we provide to reflect the potential dynamic network capacity management services outlined above that we may provide to some customers.[52] In its final determination on access, pricing, and incentive arrangements for distributed energy resources, the AEMC recognised the potential for distribution network service providers to provide these services by classifying them as distribution services.[53]

> The AER, in its final Framework and Approach for Victorian electricity distribution network service providers has accepted our proposed change to enhanced connection services which is currently classified as direct control and alternative control. The change includes the addition of 'management of export and load at a customer site that provides the customer greater network capacity than they would otherwise be eligible for'.[54]

47 NER clause 6.2.1A(b).
48 JEN, Submission for replacement Framework and Approach paper: 2026-31 regulatory control period, October 2023, p. 24.
49 AER, Final Framework and Approach Papers for AusNet Services, CitiPower, Jemena, Powercor and United Energy 2026-31, July 2024, pp. 7-8.
50 See Victorian Government, Victoria's emergency backstop mechanism for solar, accessed 7 January 2025. See *Victoria Government Gazette*, No. S 542, 11 October 2023.
51 JEN, Submission for replacement Framework and Approach paper: 2026-31 regulatory control period, October 2023, p. 26.
52 JEN, Submission for replacement Framework and Approach paper: 2026-31 regulatory control period, October 2023, p. 26.
53 AEMC, Access, pricing and incentive arrangements for distributed energy resources, Rule determination, 12 August 2021.
54 AER, Final Framework and Approach Papers for AusNet Services, CitiPower, Jemena, Powercor and United Energy 2026-31, July 2024, pp. 8-9.

5. Our capital investment

Highlights

- We forecast a total gross capital expenditure of $2,229 million in the next regulatory period, a 58% increase from our expected capital expenditure for the current regulatory period. After accounting for capital contributions and disposals, our forecast net capital expenditure will be $1,366 million. This is the amount recovered from our shared network customers.
- 49% of the forecast gross capital expenditure is driven by increased demand for connections, including from large customers (such as data centres). The remaining half of our forecast expenditure will help us to meet and address the key operating challenges we have started to experience during the current regulatory period and will continue to experience during the next regulatory period. Our forecast spend will help us to:
  - invest in asset replacement programs to maintain our network's reliability and manage risk
  - manage the growing challenges associated with maximum and minimum demand and address the greater reliance on the electricity network to support the substitution of reticulated gas and transition to transport electrification
  - facilitate the increase in customer energy resources into our network
  - leverage new technology solutions to use our network more efficiently, respond more quickly to changing customers' expectations and deliver a more efficient service.
- Our forecast addresses our customers' expectations on affordability and the level and quality of service that they expect. We take this to mean our customers will pay no more than necessary for safe and reliable services. We do this by ensuring that our proposed projects and programs are prudent and efficient and based on the option that will give our customers the highest net benefit over the long term.
- Our forecast for each capital expenditure category under the 2026-31 Proposal is lower than what we have proposed in the Draft Plan. This is the result of progressive and various capital expenditure iterations informed by our customers' feedback, the AER's initial feedback on our key capital projects and the latest demand forecast. The exception is the forecast expenditure for connections which has been updated to reflect the latest information and developments on new major connections, including data centres. Nonetheless, despite the increase in costs, our broader customers would benefit even more from increased demand from major customer connections by putting downward pressure on customer bills in the next regulatory period.
- We have developed our forecast consistent with the capital expenditure objectives and criteria contained in the NER and the AER's various guidance and guidelines and also have also been guided by our ISO55001 accredited governance framework ensuring a prudent approach has been followed.

5.1 Overview

Climate change, customer choices, technology and policy changes have all accelerated the transformation of the energy market in Australia. This means electricity distribution network service providers like ours need to adapt and innovate in the way we serve our customers when moving electricity to and from their homes and businesses.

In addition, our decisions are heavily influenced by our customers' expectations and priorities. Our customers' main concern continues to be affordability, but they also want us to focus on reliability, facilitating the energy transition, sustainability and quality customer service. These are all relevant to capital expenditure.

Our customers' priorities and expectations

Affordability

- Our customers expect us to provide distribution services at affordable prices.

Reliability and resilience, power quality

- Our customers expect us to prioritise investment in network reliability and network resilience. In addition to our customers' expectations, the Victorian Government is placing several obligations on electricity distribution network providers, including us, to make the network more resilient.

Digitisation and automation

- Our customers want us to digitise and automate the network to make it smarter, more responsive and more efficient.

Sustainability, decarbonisation and support for renewable energy transition

- Our customers want us to facilitate the transition to renewable energy sources and champion renewable energy in new housing and estates.
- Customers see us playing a leading role in enabling energy storage and incentivising battery take up, and they want us to prepare for the increase in EV charging.
- Customers expect our operations to be sustainable and to connect and maximise the use of green energy across the network as much as possible.

5.1.1 Our capital expenditure objectives

In preparing our 2026-31 Proposal, we developed capital expenditure objectives that reflect our customers' expectations, the capital expenditure drivers (noted above) and capital expenditure objectives and criteria contained in the NER. Our objectives are to:

1. meet customers' expectations that we should maintain our current levels of network reliability at the most efficient cost over the long term
2. meet our customers' expectations that our network and communities are able to withstand and recover from extreme weather events
3. manage safety, environmental, electrical system and security risks to as low as practicable and comply with all applicable regulatory obligations efficiently over the long term
4. connect new customers to the electricity network and meet the changing energy needs of existing customers, ensuring we can meet or manage expected demand for all customers
5. optimise exports and imports from distributed energy resources and CER to the distribution network.

We have developed our capital expenditure forecast with these objectives in mind.

We forecast our capital expenditure through a 'bottom-up' process and followed the AER's expenditure guidelines when developing our capital expenditure forecast.

We note that the capital expenditure forecast in this chapter only relates to our standard control services. Our capital expenditure forecast for our metering services—which are categorised as alternative control services—are discussed separately in Chapter 10.

5.1.2 Our asset management practices

JEN recognises its responsibility to act prudently and efficiently when investing in the distribution network to meet customer and community needs. One way we do this is by adopting asset management practices that put controls in place to test the investment need. Our best practice asset management activities involve balancing costs, opportunities and risks against performance. We do this by managing investment decisions through our ISO55001 accredited systems and processes. Our Asset Management System (AMS) enables a systematic approach to combining management, financial, economic, engineering, and other practices applied to physical network.

Our AMS enables us to effectively direct, coordinate and control asset management activities throughout an asset's entire life cycle. It facilitates an optimal mixture of capital investments, operations, maintenance, resourcing, risks, performance, sustainability and good governance.

JEN is also compliant with the Electricity Distribution Code of Practice (EDCoP) – Good Asset Management practices. This involves JEN developing and implementing plans for the acquisition, creation, maintenance, operation, refurbishment, repair and disposal of our distribution system assets whilst complying with laws and performance obligations to minimise risk and cost to customers.

5.2 Our current period capital expenditure performance

We estimate our total gross capital expenditure for the current regulatory period to be $1,410 million (Figure 5.1), which is 9% higher than our estimated allowance for the current regulatory period.[55]

Our estimated spend for replacement, augmentation and non-network are generally consistent with our original and estimated allowance. Major spending for the first three years of the current regulatory period has been on replacements of primary assets in four of our major zone substations, pole reinforcements and replacements, high voltage (HV) and low voltage (LV) cross arm replacements and feeder augmentation.

We expect to exceed our regulatory allowance for connections largely due to unforeseen growth in major customer and data centre connections. Globally, there has been a surge in data centre investment driven by the deployment of cloud services and the emergence of Artificial Intelligence (AI). This technology was not in existence or anticipate when forecasting the current regulatory period.

Connections are not discretionary or within our control. Various regulatory instruments, including the NER, require us to offer connection services to customers, even if this means spending above the price determination allowance. While expenditure has increased, connecting these customers will bring significant benefits to our local community (through the creation of high-tech jobs) and to the wider economy through the creation of the critical infrastructure required to undermine ongoing innovation and productivity in the digital age.

We anticipate high levels of large customer connections will continue over the next regulatory period. In contrast, our spend for non-network expenditure is estimated to be lower than the allowance for non-network capital expenditure.

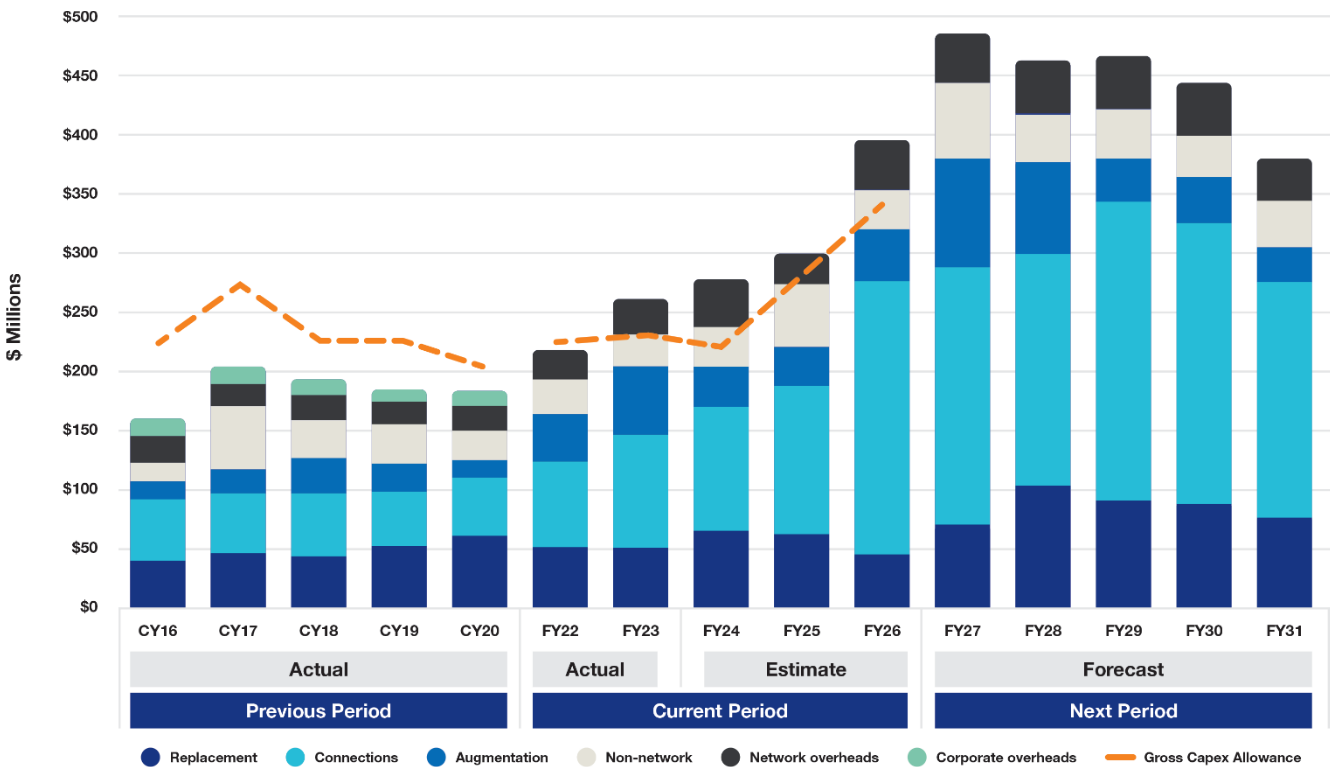
55 The capital expenditure allowance includes expenditure related to cost pass-through application for the Victorian Emergency Backstop Mechanism (approved by the AER in 2024) and the re-opener application (which the AER is currently considering). Excluding these applications, the Gross capital expenditure allowance is $926M. Our allowance is estimated because the AER's decision on our reopener application is outstanding at the time of submitting this JEN 2026-31 Proposal.

5.3 Our forecast capital expenditure

As outlined in Figure 5.1, we forecast a total gross capital expenditure of $2,229 million for the next regulatory period, which is 58% higher than our estimated gross capital expenditure for the current regulatory period. After we account for customer contributions net capex is significantly less at $1,366 million.

About half of our forecast gross capital expenditure is for major customer and data centre connections. We will also need to spend more on replacing our ageing and in poor condition assets. Our forecast also includes critical investments on augmentation, non-network-ICT, CER integration and non-network assets. We discuss the details in the following sections.

Figure 5.1: Historical and forecast gross capital expenditure, $2026, millions



5.4 Replacement capital expenditure

Our assets are ageing and this has contributed to the current poor condition of our assets. Many of our poles and pole top structures have been installed more than 40 years ago which means that a large portion is entering the latter stages of their expected useful life. Poles reinforced as early as the1960s and 1970s cannot be further re-staked given the high risk of failure. Some of our major zone substations' primary and secondary assets are about to exceed their expected useful life. While the age of our assets is not the main basis for replacement and reinforcement, it is a key input to our condition-based assessment of assets.

If failure occurs, the quality of service we provide to our customers would decline and we would fail to comply with our regulatory obligations and potentially negatively impact the stability of the wider electricity system. These are significant risks and therefore we must be proactive in monitoring and managing our asset replacement program.

In this context, we have developed a gross replacement expenditure of $427 million in the next regulatory period. While our forecast is higher than the estimated replacement expenditure for the current regulatory period, our modelled repex is 27% lower than the threshold modelled repex predicted by the AER's model.[56]

Our forecast replacement capital expenditure is guided by the following capital expenditure objectives which are to:

1. meet customers' expectations that we should maintain our current levels of network reliability at the most efficient cost over the long term
2. meet our customers' expectations that our network and communities are able to withstand and recover from extreme weather events
3. manage safety, environmental, electrical system and security risks to as low as practicable and comply with all applicable regulatory obligations efficiently over the long term.

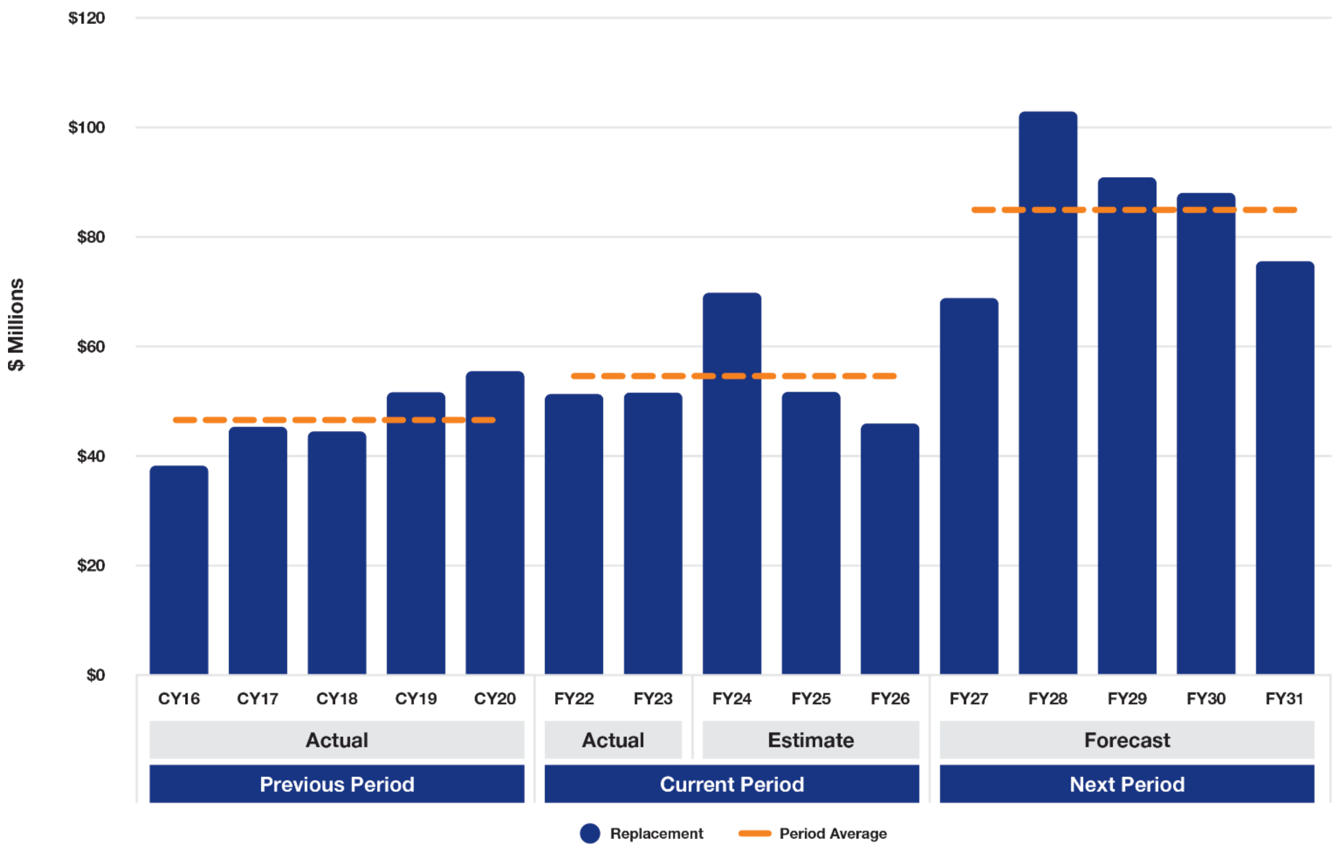
To meet our objectives for the next regulatory period—and over the long term—we will:

- continue our long-term program to replace some large families of assets such as poles, cross arms and overhead services, whose condition continues to degrade. This is to manage safety risks and comply with relevant safety obligations and, at the same time, meet our customers' expectations on network reliability.
- redevelop three major zone substations to address serious safety risks and mitigate supply risks to over 60,000 customers by replacing old and deteriorated equipment with a history of failures and which is non-compliant with current standards, maintenance-intensive or no longer supported by the manufacturer.
- pursue a replacement program for at-risk sub-transmission assets. This is critical to ensure we provide reliable service to our large customers.
- replace some SCADA and network control assets to ensure that we can closely monitor and control the network to maintain the desired operating conditions.

56 Modelled repex includes poles, underground cables, overhead conductors, service lines, transformer and switchgear.

Figure 5.2 shows our historical and forecast replacement capital expenditures.

Figure 5.2: Gross replacement capital expenditure, $2026, millions



5.4.1 Our customers' expectations

Customers have told us to prioritise investing in reliability by assessing, building, and maintaining the network to meet changes in operating conditions and meet future demands. They also want us to prioritise affordability.

"Talking to the guys that actually work on the ground. Just getting a broader picture, what their day to day operations looks like. What kind of infrastructure is actually powering our grid and connect the dots I guess between what is actually happening within Jemena and why they price things a certain way."

— People Panel's member

In response to the Draft Plan, our customers reiterated that they want affordable prices and also expect us to maintain the reliability and reliance of our network.[57] After several progressive iterations, our proposed expenditure for replacements have decreased since the Draft Plan. In developing our regulatory proposal:

- We propose not to spend more than what is needed to maintain the reliability and security of our network, that is, we do not propose to invest more money in order to improve the reliability of our network.
- We only included prudent and efficient replacement programs and projects consistent with the requirements of the NER and the AER.

57 Attachment *JEN – Att 02-18 Draft plan feedback report – 20240924*.

5.4.2 Our approach to asset replacement

Using condition and consequence measures, we take a risk-based approach to determining whether we need to replace our assets. The drivers for replacement capital expenditure include deterioration in the condition of an asset or its environment, and where increases in maintenance costs mean it is more cost-effective to replace an ageing asset than continue to maintain it. We also undertake consequence-based replacement when we undertake a thorough assessment of 'needs' to determine whether a lower-rated asset could satisfy a requirement rather than blanketly apply a like-for-like replacement.

We manage and plan asset replacement by grouping our assets into a set of classes, for which we develop project and program-level forecasts. For some critical assets, we develop a condition-based risk model to support our evaluation of the probability of asset failure and rates of future failures. Once we have identified a need, we develop and evaluate replacement options. We then develop a cost estimate for each option given the scope of works and relevant unit cost schedules for those options.

Our approach ensures that our replacement expenditure is only the amount necessary to continue supplying customers based on their current and likely future requirements.

5.5 Network resilience

Network resilience is the ability of the electricity network to withstand and recover from the effects of a natural hazard or disaster, such as floods, storms and bushfires. this is different to reliability is which is the ability of our network to adequately perform under normal operating conditions.

Our customers have advised us of their increased expectations about how we perform in extreme situations. Throughout our engagement process with our People's Panel, our customers told us that JEN needs to prioritise investing in network resilience so it can withstand and recover more quickly from the effects of a natural hazard or disaster.

In addition to hearing from our customers, we engaged with the other Victorian Distribution Network Service Providers to investigate and better understand the impacts and community expectations for network resilience. We undertook a climate change and customer engagement study with these stakeholders to identify and consider what a resilient network looks like.

Following the extreme storm events on 13 February 2024, the Victorian Government initiated a review by an independent panel (Panel) on network service provider processes and performance through extreme weather events. The Panel has issued a set draft recommendation, however, due to the timing of release, we have not been able to incorporate the impacts into this 2026-31 Proposal. We will consider any new obligations coming from the Panel in our Revised proposal due in late 2025.

For now, our identified network resilience projects will be included in our proposal for the next regulatory period.

"We'd like to see collaboration between Councils and Jemena so it's unified. It would provide the community with a better understanding and produce trust."

— Local council representative

5.6 Connections

Connecting customers to our network accounts for 49% of our gross capital expenditure. Over the 2026-31 regulatory period we expect to incur $1,103 million. Once we account customer contributions towards their connection costs (the proportion of costs not recovered through network charges) this falls to $275 million, about 1% more than current period net capital expenditure.

This program is required to achieve objective 4 connect new customers to the electricity network and meet the changing energy needs of existing customers.

Various regulatory instruments[58] require us to offer connection services to customers on request and accordingly, connections are not discretionary or within our control.

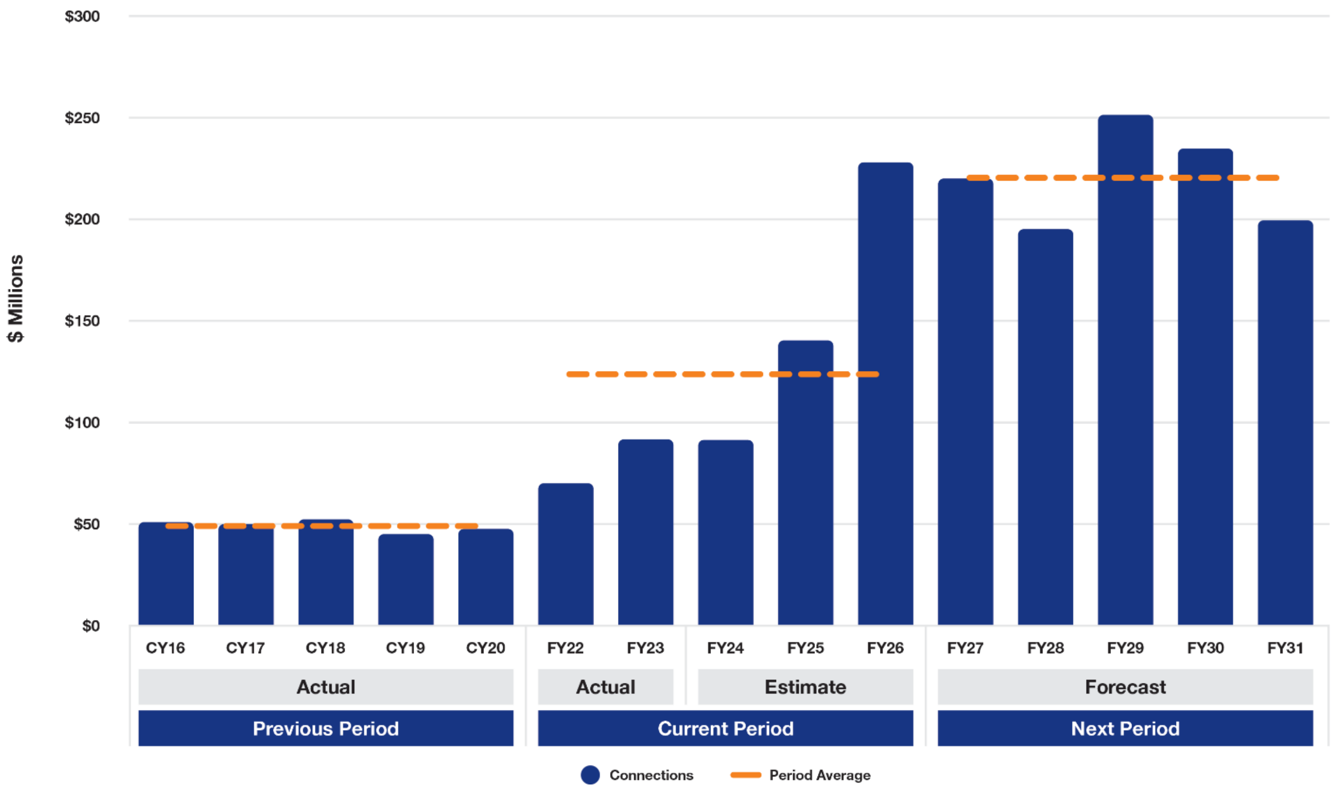
However, connecting new customers brings significant benefits to our local community – connecting new residential dwellings facilitates new housing supply while connecting businesses enhances the productivity capacity of the economy helping to reduce inflation and the cost of living. Connecting data centres will create the critical infrastructure Australia requires to support the ongoing innovation and productivity in the digital age.

This program also delivers substantial benefits to existing customers by facilitating higher volumes of energy delivered, greater utilisation of our existing assets, lower unit costs and in turn lower network bills.

Due to the surge in data centre investment, data centre connection costs already makes up about half of our connections program. This will continue into the next regulatory period requiring expenditure of $704 million or $127 million in after contribution terms.

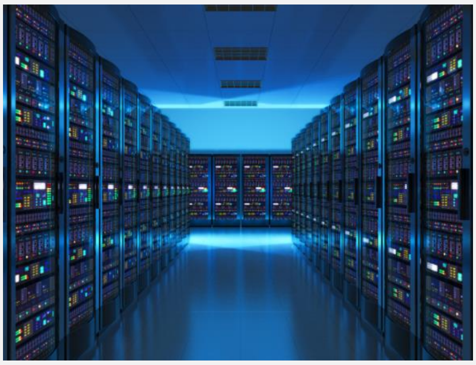
We will also continue to connect other large customers and our, more recurrent program, to connect smaller residential and business customers. We forecast this expenditure using our long-standing approach to project costs based on a three-year average and the application of third-party forecasts relating to business activity and population growth. These programs will cost $399 million, or $148 million net of contributions.

Figure 5.3: Gross connections capital expenditure, $2026, millions



58 Such as NER, clause 5A.F.4 & 5A.F.5

What is a data centre?



Whether you use the internet for online banking, connecting with friends and family, or working from home – you are creating data.

While we tend to describe this data as existing in the 'cloud', the websites and apps you interact with store this data in large computer servers. These servers and the systems that keep the data secure are housed in purpose-built buildings called data centres.

It is estimated that over the next five years, trends in internet usage and new technologies like AI will generate twice as much data than the past 10 years. This means that data centre storage will need to increase by 18.5% every year over the same period.

What does this mean for the electricity network?

Data centres are energy intensive. Not only is a large amount of electricity needed to run the computer servers and keep them cool, but the centres also need to be operational 24/7. They are designed with high levels of electricity redundancy to minimise the chance of a power outage. This means that when they connect to the network, costly upgrades are often required to ensure they can get all the electricity they need, all the time.

What does this mean for our customers?

Connecting these data centres to our network is increasing our capital expenditure. However, in the long term, their presence on the network will reduce costs for all customers due to economies of scale.

In addition, connecting these data centres to the network means our customers can continue to work, scroll social media, order groceries and stream movies online.

5.7 Augmentation

Ongoing growth, the energy transition, and the growth in cloud and artificial intelligence technologies will require our network to expand in size and criticality.

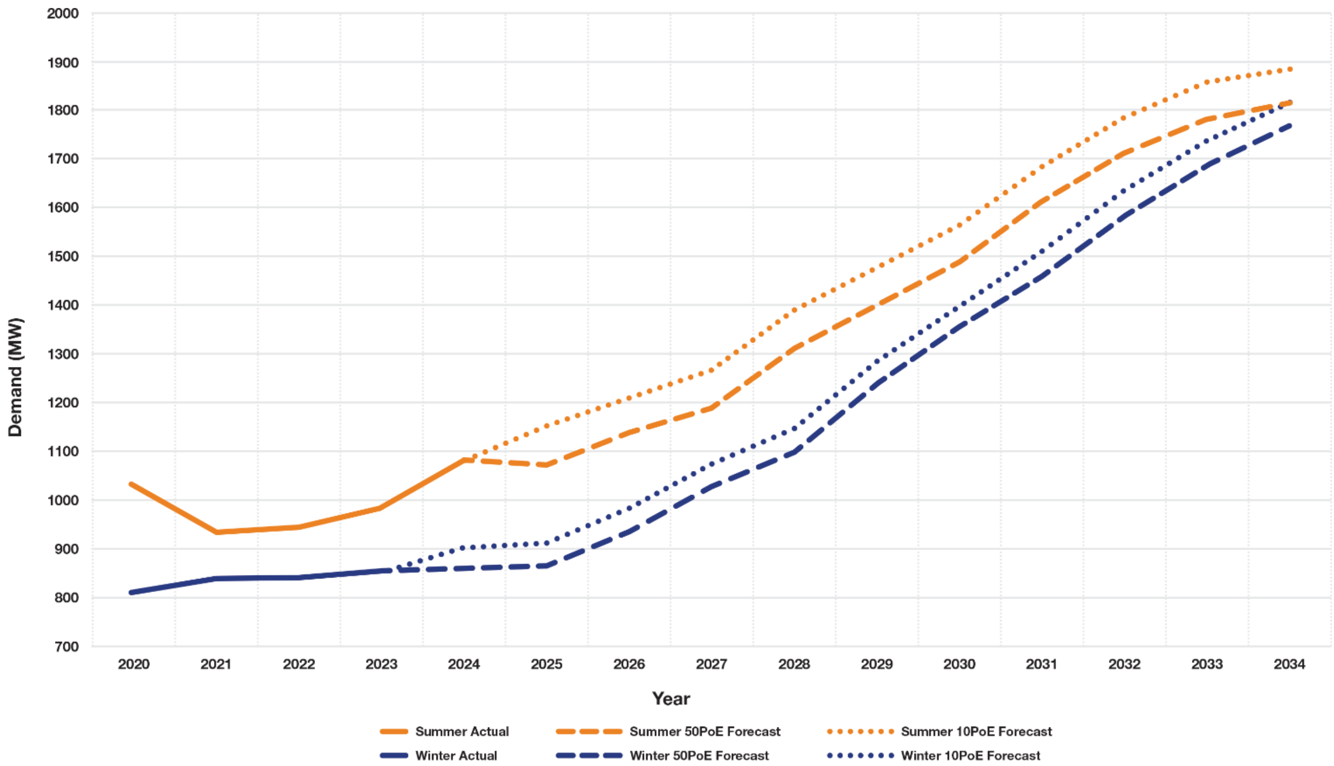
Over the next 10 years, peak demand on our network will almost double. This places substantial pressure on what is already one of the most highly utilised networks in Australia. Despite these pressures, we are proposing a disciplined program of $224 million – only 16% above current period spend – focussed on ensuring sufficient capacity to supply greenfield areas as well as new medium and high-density developments.

5.7.1 Forecast maximum demand

The growth in maximum demand across our network is forecast to increase significantly with the growth in data centre loads. More recent forecasts have highlighted sharper increases in demand, which are expected in future years as decarbonisation initiatives, gas substitution, and electrification start to take effect.

The historical and forecast coincident peak demand growth is outlined in Figure 5.4.

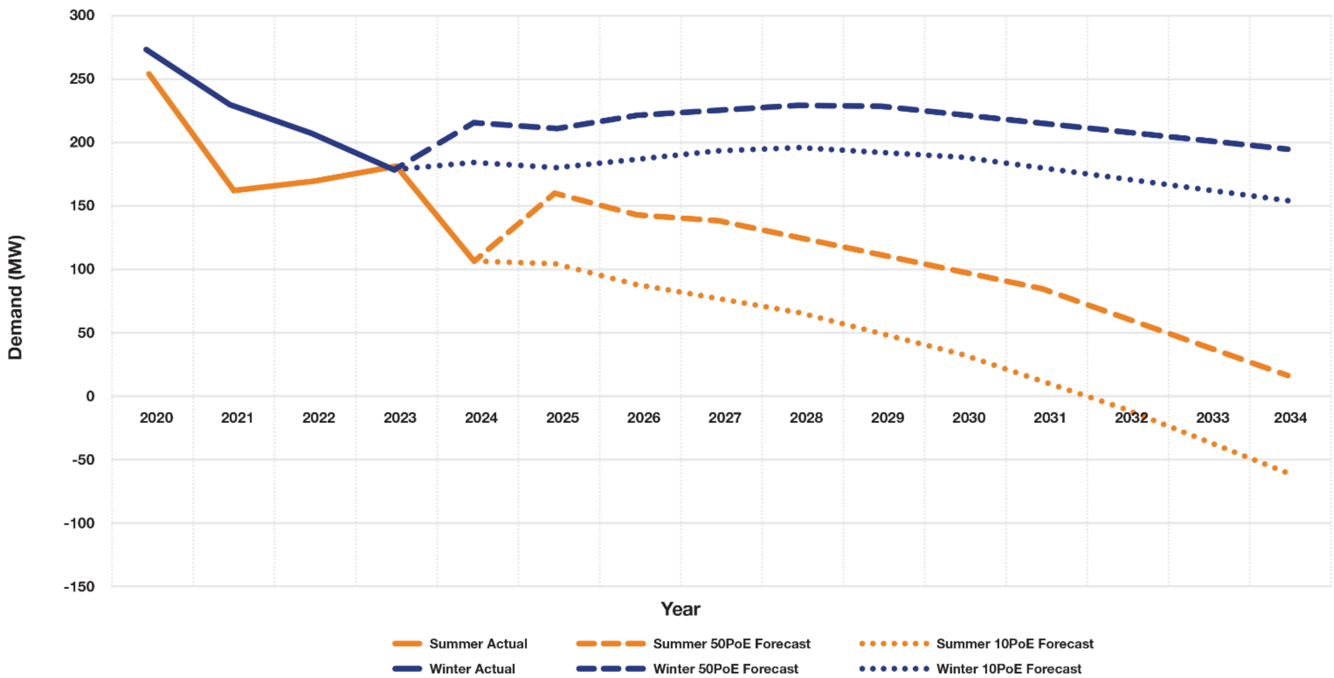
Figure 5.4: Forecast maximum demand (MW), 2024



Despite the general growth in demand at the network level, there are areas within the network where maximum demand is forecast to grow above the network average level. In contrast, in other parts of the network, maximum demand is forecast to decline.

Networks experience minimum demand—the lowest amount of network demand experienced at any point in time—as a result of electricity being produced from rooftop PV generating systems. Minimum demand causes voltage disturbances and ultimately puts a limit on the amount of PV our network can receive. We forecast the levels of minimum demand on our network will continue to decline, imposing system security risks to our network (Figure 5.5).

Figure 5.5: Forecast minimum demand (MW), 2024



In previous price resets, minimum demand was never considered an issue; we were able to manage voltage and other compliance requirements within a tolerable range. However, with the significant growth of customers installing PV generation in recent years, new technical issues have emerged—including the challenges arising with minimum demand. This new phenomenon is something that needs to be managed in the next regulatory period because not acting could compromise the electricity system (see capital expenditure objectives 3 and 5).

While minimum demand is declining, peak demand is increasing due to EV charging loads and other decarbonisation initiatives such as gas substitution. If JEN continues to build distribution infrastructure to cater for the increasing peak demand—while minimum demand is decreasing—the infrastructure will become increasingly underutilised.

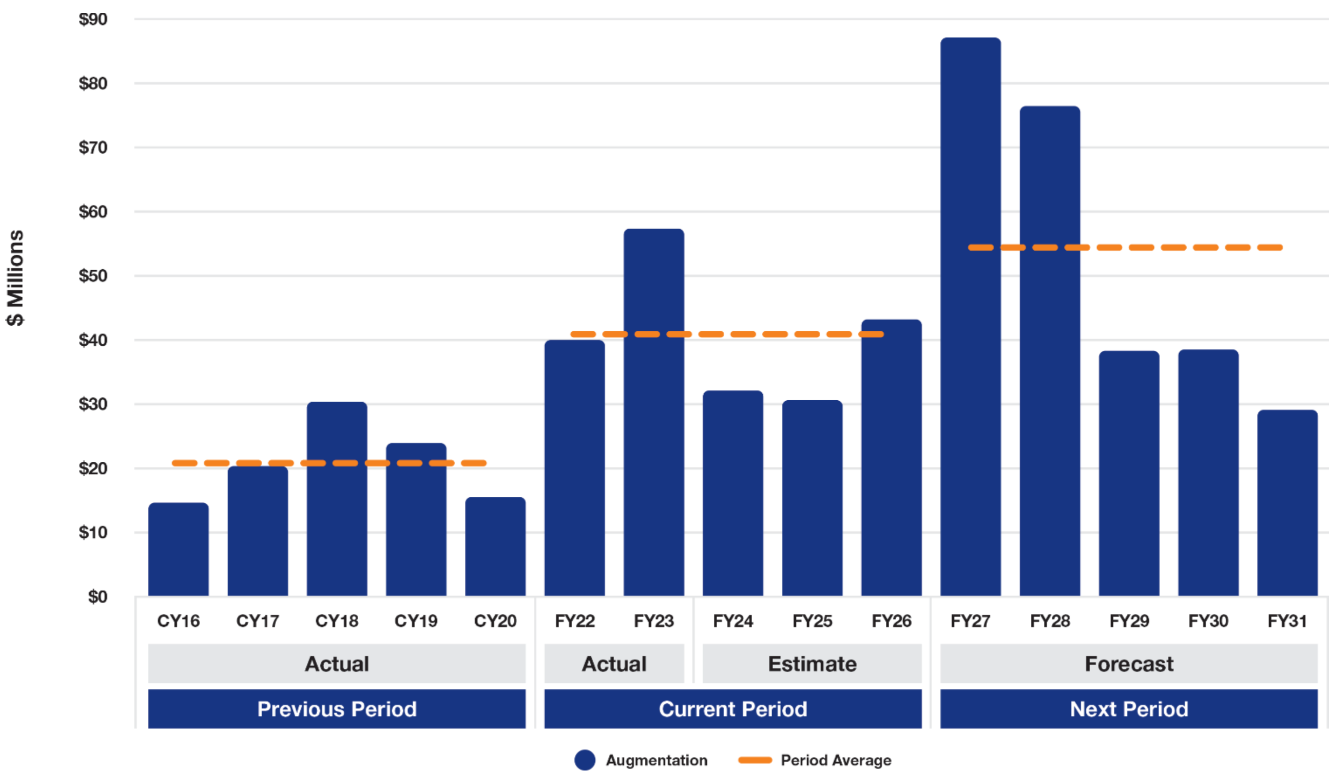
Several options could be implemented to address the challenges of minimum demand (at times of peak export to the distribution network) and maximum demand (at times of peak demand when customers consume the most amount of electricity at the same time). The best options deal with the challenges holistically, not treating peak export and peak demand as separate issues to resolve.

Solutions we are implementing include:

- emergency backstop for distributed photovoltaics to manage minimum peak demand challenge and load shedding to manage maximum demand. These should only be relied upon as a last resort because of their impact on customers.
- customer and market options that may be used more frequently (such as coordinated storage and EV charging, scheduled loads such as pumping load and demand response) to support system security at these times.

We are forecasting an augmentation program (excluding our CER Integration Strategy) of $224 million primarily driven by new loads in greenfield areas as well as medium and high-density developments. Figure 5.6 shows our historical and forecast augmentation costs.

Figure 5.6: Gross augmentation capital expenditure, $2026, millions



Our program is focussed on supporting our radial high-voltage network, where improving utilisation is not a feasible option.

The surge in data centre investment will put significant strain on our network. Based on current information, we expect to require $99 million to strengthen our 66kV sub-transmission backbone. However, as we have time to refine our approach and incorporate new information on the location and size of these loads, we are instead forecasting $19 million in capital expenditure along with two new contingent projects. Our proposal aligns regulatory approval with our decision making and ensures customers do not fund this expenditure until it is required.

Lastly, although the electrification of transport and gas will significantly increase demand, we are not forecasting any material expenditure driven by these new loads. Instead, we will continue our approach, facilitated by our CER Integration Strategy and innovation fund, of using our existing network before building more.

"Addressing fluctuations in demand by allocating funds for network augmentation demonstrates a proactive approach. As the integration of customer energy resources and the adoption of electric vehicles grow, Jemena must be prepared to manage both peak and minimum load scenarios effectively. Augmentation expenditure to address fluctuations in demand is forward-thinking. With more customer energy resources (like rooftop solar) being integrated into the grid and an increase in EV charging, Jemena needs to ensure that it can manage both peak and minimum load scenarios effectively."

— Energy Reference Group

5.8 CER integration

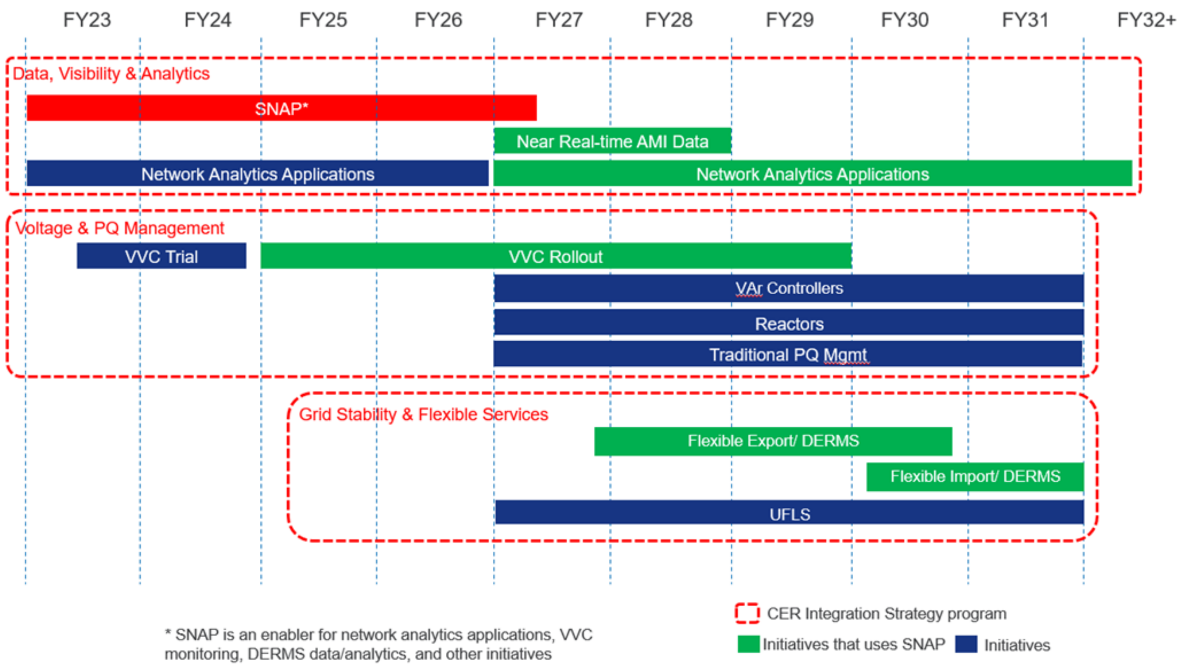
Our customers have told us that it is important to them that JEN connects its customers to a renewable energy future by facilitating the integration of Consumer Energy Resources (CER**)** into the electricity distribution network and facilitating the electrification of the economy.[59] CER includes rooftop solar, batteries, electric vehicles and energy management systems, which are often located on the consumers' side of the electricity meter.[60]

We have developed our CER Integration Strategy which we plan to deliver through a combination of network operations (Asset Management) and new ICT (Digital) capability. Figure 5.7 shows our three proposed programs of work and supporting initiatives to deliver our CER Integration Strategy, and our indicative timing to implement them. Strategic Network Analytics Platform (SNAP) (in red) in the Data Visibility and Analytics program is an enabler for a number of initiatives (in green) in JEN's CER Integration Strategy.

59 JEN – Att 0-01 – Customer engagement – 20250131 – Public

60 CER was previously referred to as Distributed Energy Resources (DER), however CER does not include front of meter batteries DER on our network. For the purposes of our JEN – RIN – Support – Att 03-01 – CER Integration Strategy – 20250131 – Public (CER Integration Strategy) we refer to CER to also include front of meter batteries

Figure 5.7: Proposed programs of work



We forecast a total capital expenditure of $85 million for CER integration in the next regulatory period, of which 54% is network related and 46% is ICT related.[61] This will enable JEN to:

- address the identified needs and existing analytics platform limitations and improve the operational management of the network through the **Data Visibility and Analytics (**DVA**) program**. The DVA program will also help us maintain customer safety and improve operational planning during the energy transition.
- respond to the challenges and opportunities associated with increasing CER penetration and the associated influences on network voltage and power quality though the **Voltage and Power Quality Management (Voltage and PQ) program**. The program will enable us to achieve near real-time optimised control of network voltage and reactive power flow to maintain compliance with Electricity Distribution Code of Practice (EDCoP) standards and reduce CER curtailment.
- respond to the challenges and opportunities associated with increasing numbers of CER, and their associated influences on power system security and network operating limits thought the **Grid Stability and Flexible Services program**. The program will enable us to achieve near real-time optimised control of CER active power operating envelopes to keep the grid stable and to deliver flexible export and import distribution services using dynamic operating envelopes.

Collaboration between the ICT and Network teams is increasingly vital for JEN with the growing digitalisation and complexity of the energy landscape. As the grid modernises with smart technologies and automation, ICT provides the digital infrastructure needed for real-time data collection and analysis, while the Networks team manage the physical infrastructure. Together, they ensure a resilient and adaptable grid capable of accommodating the demands of renewable energy integration, which relies on advanced digital tools to monitor grid health and manage load fluctuations.

61 The ICT related expenditure is captured under our proposed expenditure for Non-network ICT below.

"Building a digital, data-driven infrastructure ensures Jemena can handle the growing complexity of energy systems. The adoption of automation, analytics, and enhanced applications supports power system security and facilitates new market participants, enabling more agile and responsive networks."

— Energy Reference Group

We consider that our forecast expenditure represents the level of funding necessary to achieve the requirements under the NER, efficiently meet our obligations and customers' expectations, and promote their long-term interests. It is also consistent with our capital expenditure objective number 5 which is to optimise exports and imports from distributed energy resources and CER to the distribution network.

5.9 Non-network capital expenditure - Information and Communication Technology

Non-network Information and Communication Technology (ICT) accounts for 7% of our total gross capital expenditure forecast.

ICT enables us to operate a safe and reliable electricity network and keep support services, such as billing and call centres running. ICT plays a critical role in supporting the efficient delivery of services to customers, and their importance grows as the digitisation of the network accelerates. Our ICT also provide platforms that support a wide range of activities for our customers:

- facilitating the real-time monitoring and control of the electricity network
- interacting with customers and other market participants, including receiving service requests and facilitating billing
- planning and managing field operations, including construction, maintenance and outages
- recording, reporting and analysing asset and geospatial information, including for asset management planning
- general corporate support activities for our operations, including finance, reporting, human resources, procurement and compliance with regulatory obligations.

ICT is also playing a more significant role in enabling CER integration during the energy transition over the next ten years (see Chapter 3 – The Energy Transition). We need to deploy technologies that will help us connect our customers to renewable sources of energy in a safe and efficient manner and accommodate more CER without compromising the reliability and security of our network. ICT systems are effective means of meeting the needs of customers in the energy transition and can help defer future investments on network augmentation.

We will also need to deploy other technologies in response to changes in market obligations.

Unlike network assets, which remain relatively static over their long life spans, digital systems have a short lifecycle due to technical obsolescence and changing customer requirements. This, along with increasing digitisation and the pace of change, means our need to invest in digital systems is increasing.

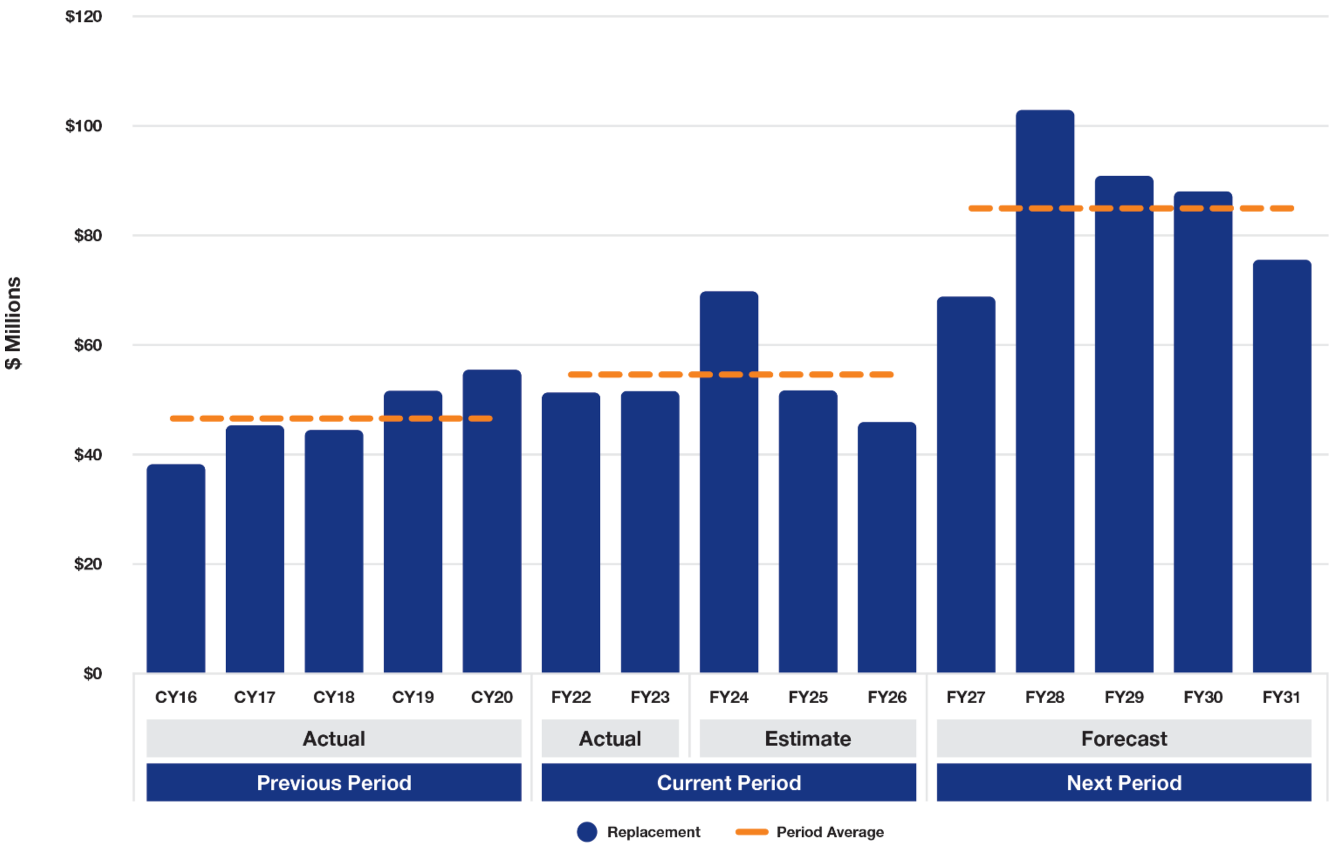
"Key thing is efficiently matching demand to supply in both consumption and export whilst allowing self-determination by customers, and without overbuilding the network"

— Energy Reference Group member

We forecast a capital expenditure of $154 million for ICT in the next regulatory period. This is 32%[62] higher than our expected capital expenditure for the current regulatory period. While there is an overall increase in the ICT requirements, the magnitude of our capital expenditure has decreased relative to the previous regulatory period because of changes in the interpretation of the International Financial Reporting Standards (IFRS) standards, which see a lot of these costs being treated as operating expenditure.

Figure 5.8 shows our capital expenditure over the three regulatory periods.

Figure 5.8: Gross non-network ICT capital expenditure, Real $2026, millions



Our forecast capital expenditure builds on a strong and stable foundational IT landscape which we have developed during the previous and current regulatory periods. Our focus or key drivers for the next regulatory period are:

- to deliver new ICT capabilities as enablers of our CER Integration Strategy and to improve the way we provide information and communication channels to customers. As we move towards a more sustainable energy future, we are investing in new digital capabilities that will support critical areas such as asset health monitoring, grid stability, system flexibility, and market integration, ensuring our infrastructure can adapt to the demands of a renewable energy landscape.

  The alternative to implementing these ICT capabilities is to continue to build out the traditional network, that is, ‘poles and wires’, to alleviate distribution network export and import constraints to avoid the cost of managing overloaded distribution assets. However, this option does not address all the issues; customers will still face the risk of network instability and system collapse, which has unserved energy from supply outages and no access to new market products and services. These ICT systems are the only effective means of meeting the needs of customers in the energy transition.
- to continue the maintenance of IT infrastructure and applications reaching the end of their useful lives—including through our like-for-like (‘base’) recurrent expenditure which is lower than our expected recurrent expenditure during the current regulatory period.

62 32% increase (without SaaS) and 22% increase (with SaaS)

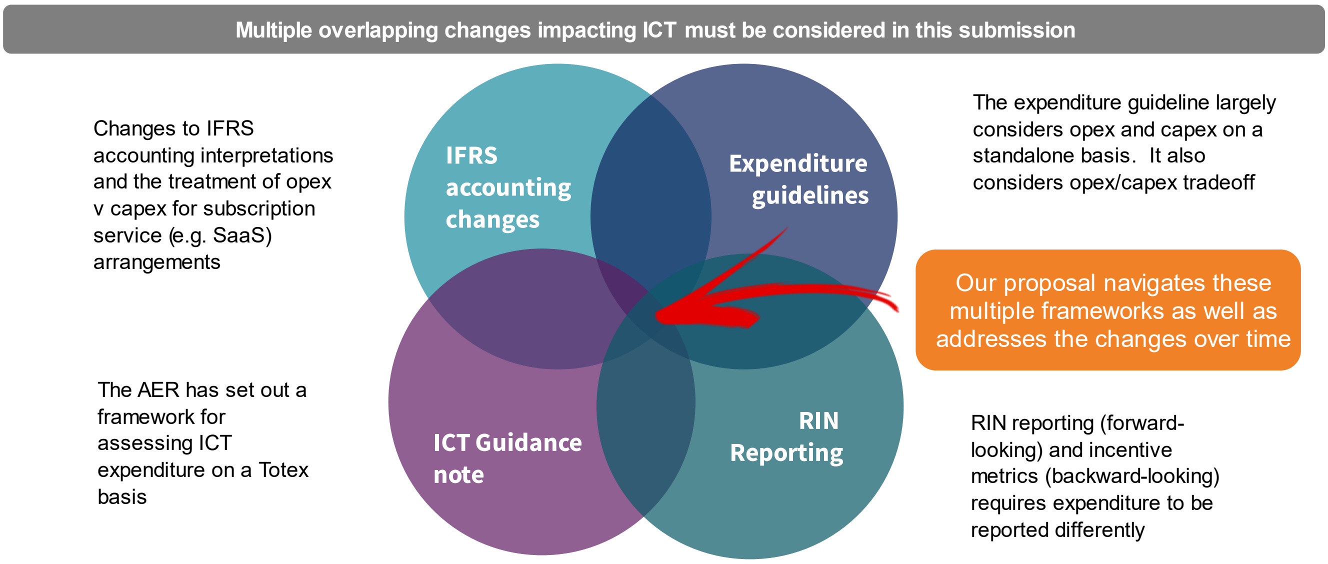
- to comply with new electricity market obligations. With a constantly evolving regulatory landscape, digital technologies will play a vital role in enabling JEN to meet new obligations. In alignment with ongoing Post-2025 NEM market reforms, Market Interface Technology Enhancements, and Flexible Trading Arrangements, our Digital team is enhancing its capabilities to manage the complex new market obligations associated with the energy transition. This increased capability will ensure we can meet regulatory requirements and support a smooth and effective transition to the future energy system, supporting a more modern, secure, and sustainable energy market.
- to protect our IT systems in response to growing cybersecurity threats.
- to address our customers' expectations on affordability, maintaining reliability, automation and digitisation.

Our customers have ranked ICT-related initiatives, such as digitisation and automation, high in terms of priorities but have also reiterated their concerns about affordability. Our forecast expenditure is prudent and efficient. It only includes non-recurrent ICT capital projects that are either based on the least cost or the highest net benefits for our customers over the long term, ensuring efficient costs for our customers. We consider this to be a prudent approach. We provide more detail about how we have addressed our customers' feedback on non-network ICT in the Attachment 05-01.[63]

5.9.1 Our approach to forecasting ICT expenditure

Our forecast non-network ICT capital expenditure is mainly guided by our capital expenditure objectives 3 to 5, however, objectives 1 and 2 are also relevant. We are also guided by several external factors, including regulatory and IFRS requirements, all of which must come together to ensure our ICT forecast is efficient and complies with various obligations. Figure 5.9 below outlines the various standards, obligations, guidelines, and frameworks within which we must operate to develop a compliant ICT forecast.

Figure 5.9: Standards, obligations, guidelines and frameworks we must operate within to develop a compliant ICT forecast



We developed our non-network ICT capital expenditure forecast to:

- manage and maintain our ICT capabilities with a balanced approach to the cost and acceptable level of risk
- ensure ICT capabilities are sustainable and reflect good industry practice
- leverage new technologies to improve operational efficiency and effectiveness
- meet market reform requirements.

63 *JEN – Att 05-01 Capital expenditure*

As noted above, we adopted the approach outlined in the AER's ICT expenditure forecasting assessment approach when forecasting the expenditures involved in delivering the ICT architecture[64] whilst also keeping an eye on the other requirements. Using this framework, we developed capital expenditure forecast proposals based on two categories:

- Recurrent ICT – we set this forecast expenditure by taking the five-year average capital expenditure expected to be incurred between financial years 2020 and 2025 because this is the most recent known capital expenditure and therefore more reflective of our expected capital spend on ICT. The forecasting approach works on the assumption that this type of expenditure occurs on a cyclical (recurrent) basis, with cycles occurring between one and five years. Our approach is consistent with the AER's preferred approach of using a five-year average when undertaking trend analysis on historical recurrent expenditure.[65]
- Non-recurrent ICT – this category of forecast capital expenditure occurs on cycles of more than five years or has not previously occurred. We adopt rigour in developing our forecast non-recurrent capital expenditure and rely on learnings from past projects to develop an efficient forecast. Those, historical projects have been subject to efficiency schemes such as Capital Efficiency Sharing Scheme (CESS) and Efficiency Benefit Sharing Scheme (EBSS), which provides confidence that forecasts are also efficient. Our proposed non-recurrent capital expenditure for the next regulatory period is supported by robust investment briefs for the projects underpinning the forecast non-recurrent spend.

Complying with recent changes to the IFRS accounting standards has meant that much of our ICT expenditure is treated as operating expenditure in the next regulatory period, meaning there is an increased focus on total ICT expenditure to provide services to our customers.

> Refer to *JEN – Att 05-01 Capital expenditure* for our detailed capital expenditure proposal for non-network ICT and *JEN – RIN – Support – Technology Plan* for further justifications.
>
> We elaborate on the ICT operating expenditure in Chapter 6. Refer to *JEN – Att 06-01 Operating expenditure* for a more detailed discussion.

5.10 Non-network - other capital expenditure

Non-network other capital expenditure accounts for 2% of our total gross capital expenditure forecast. Other non-network assets enable the delivery of our services. They predominately comprise the following items:

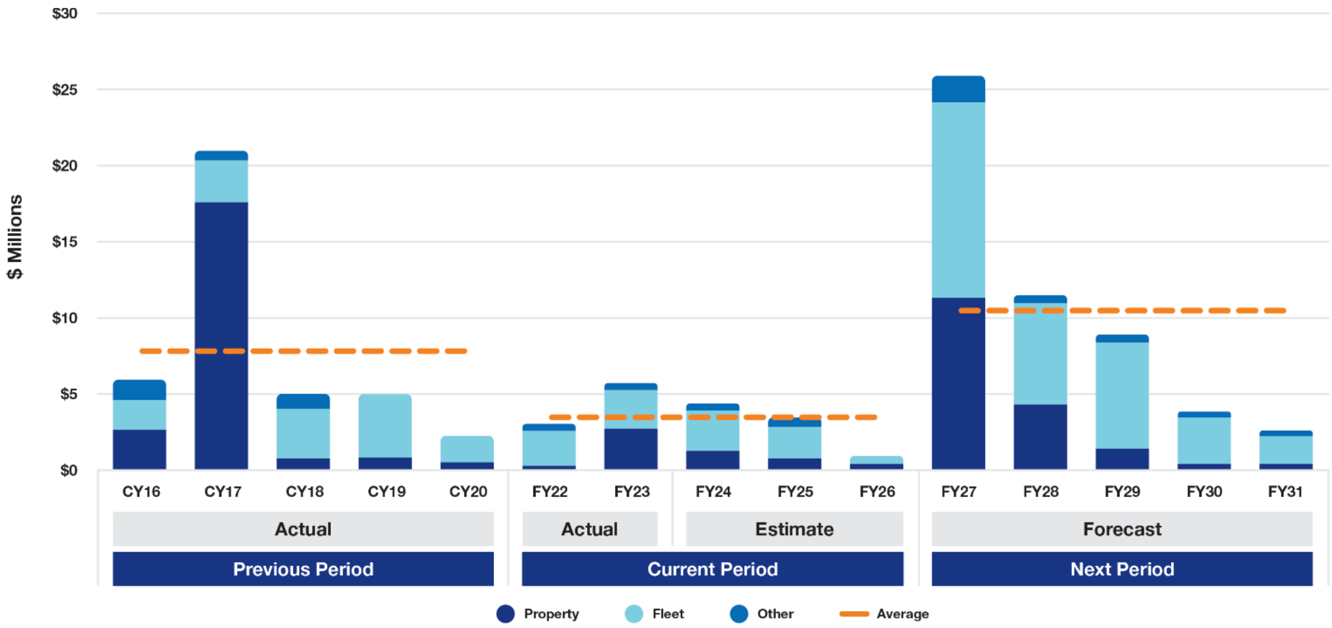
- vehicle fleet
- property and buildings
- tools and equipment.

We forecast a total non-network other capital expenditure of $54 million for the next regulatory period, which is higher than our estimated other expenditure for the current period. Figure 5.10 shows our capital expenditure over the three regulatory periods.

64 AER, *Non-network ICT capex assessment approach*, November 2019.

65 AER, *Non-network ICT capex assessment approach*, November 2019, p. 10.

Figure 5.10: Gross non-network - other capital expenditure, Real $2026, millions



Our forecast spend is higher than our expected expenditure during the current regulatory period but as can be seen in Figure 5.10 we have very minimal spend for the current regulatory period. Key drivers for the forecast expenditure are:

Fleet

The vehicles in our fleet allow personnel, specialised tools and equipment to travel around our electricity network and perform emergency fault response, repair, maintenance, inspection and construction. Our fleet is, therefore, critical to us delivering the services required to maintain a reliable network.

We forecast vehicle fleet capital expenditure in accordance with our fleet asset class strategy. This strategic plan sets out how and when we maintain and replace vehicles to ensure they operate safely and are fit for purpose. Our asset class strategy specifies that elevated work platforms (EWPs) will be rebuilt after 10 years and replaced prior to 15 years of age. EWPs we purchased during the previous regulatory period will reach end-of-life in the next regulatory period.

As per our fleet asset class strategy, light commercial vehicles and passenger vehicles are to be replaced at the earliest of 5 years and 150,000km following a condition assessment. This approach is consistent with good industry practice replacement timeframes. Many of our light commercial vehicles and passenger vehicles are to reach end-of-life in the next regulatory period.

If not replaced, and if operated beyond their lifespan expectations, these vehicles would exhibit condition degradation beyond safe limits. Left unaddressed, this elevated degradation has the potential to result in an increase in fleet maintenance costs in the near future, and unreliable field operations, both of which are not in the long-term interest of our customers.

The significant increase in the unit cost of vehicles since the last price reset has also contributed to the increase in our forecast expenditure. Based on our most recent tender, the cost of EWPs has increased significantly between 2019 and 2024.

Our proposed expenditure is prudent and efficient and addresses our customers' expectation on affordability:

- It is based on an approach that is consistent with the AER's expectation that a distribution network service provider's risk and management standards are aligned with industry standards on good asset and risk management and consistent with well-established relevant Australian industry standards.[66]

66 AER, Industry practice application note: Asset replacement planning, July 2024, p.9.

- It is consistent with the approach used by other distribution network service providers and our assumed replacement cycles for the current regulatory period.
- It is prudent to extend the lives of some of EWPs and heavy commercial vehicles by rebuilding some of them instead of outright replacement.

In addition to affordability, our customers told us—as a top priority—that the replacement of vehicles with those that are more environmentally friendly to increase the sustainability of our operations. We will continue to evaluate the adoption of new technologies, including consideration of hybrid, electric and hydrogen powered vehicles over the next regulatory period, However, our fleet principles of having fit-for purpose-vehicles at an efficient cost will remain to be our primary considerations when evaluating these new vehicle technologies.

Property and building

Our buildings and property capital expenditure forecast covers expenditure on buildings and fixed furnishings at JEN's depots (which we own) and corporate offices (which we lease but are responsible for office fit-outs).

We forecast to increase spending on property in the next regulatory period noting that our capital expenditure allowance for the current regulatory period is minimal and only for refurbishments. Our biggest spend on property will be on Tullamarine depot augmentation. Our forecast expenditure will enable us to increase the operational capacity and functionality. It will help to address the issues we have identified at the depot including those that relate to its design and functionality, ability to support business growth, compliance with relevant regulations and energy efficiency.

Other

This category covers expenditure on non-network assets other than fleet and property. It includes tools and equipment, office furniture and other plant and equipment (such as trailers, forklifts) which does not fall within a motor vehicle category. The main driver for our forecast expenditure is the replacement of plants and trailers consistent with our asset class strategies.

> Refer to *JEN – Att 05-01 Capital expenditure* for our detailed capital expenditure proposal for non-network – Other.

6. Our operating expenditure

Highlights

- Operating expenditure is critical to our ability to deliver our standard control services (SCS). Customer feedback played a crucial role in shaping JEN's operating expenditure forecast, ensuring it aligns with their expectations and needs.
- Our forecast operating expenditure for the next regulatory period is $615 million, which is, 4% lower than our allowance for the current period in real terms.
- Due to the efficiencies we realised through our 2019 operational transformation program, we expect to significantly underspend our current period allowance. Our customers will benefit from these efficiencies through lower forecast operating expenditure in the long term.
- We operate efficiently and benchmark well amongst our peers. Our forecast base year operating expenditure is below the efficient level estimated using the AER's benchmarking approach.
- Whilst most of our operating expenditure is generally recurrent in nature, we are proposing step changes for new obligations and changes in best practice. These include ongoing transition of information communications technology to the cloud, investment in CER, and costs for reliability and safety measures.
- We also incur costs associated with major external factors outside our control associated with our ICT spend for costs that have been treated as capital expenditure in the past but are now treated as operating expenditure.
- At the same time, our network is growing quickly. Significant new load from large connections, including data centres, electrification of transport (e.g., EVs) and gas substitution is putting upward pressure on our forecast expenditure.
- Customer feedback on our Draft Plan reinforced that we were on the right track with our operating expenditure priorities. We have further built on that feedback through deep dive sessions held in November 2024.

6.1 Overview

Our operating expenditure for SCS includes the costs of operating and maintaining our electricity network. These activities include ongoing network maintenance such as inspections, repairs and responding to emergencies, for example, removing trees that have fallen on our electricity power lines. We also perform customer functions like responding to enquiries and providing billing information to retailers.

We also need to continue supporting the development of the network to meet customer requirements and report our compliance with economic and safety regulations. While our customers are concerned with price affordability and fairness, they also want us to focus on and prioritise ongoing service excellence, customer education, digitisation and automation to maintain economic efficiency and network reliability. Our proposed operating expenditure for the next regulatory period reflects the views expressed by our customers.

As noted in Chapter 3, climate change, customer choices, technology, and policy changes have all accelerated the transformation of the energy market in Australia, meaning DNSPs constantly need to adapt and innovate in the way we serve our customers, moving electricity to and from their homes and businesses. While capital expenditure is necessary to build these capabilities, operating expenditure is necessary to maintain and manage them.

We propose a total operating expenditure of $615 million for the next regulatory period. We consider our proposed operating expenditure to be efficient and would allow us to meet our regulatory obligations and customers' expectations.

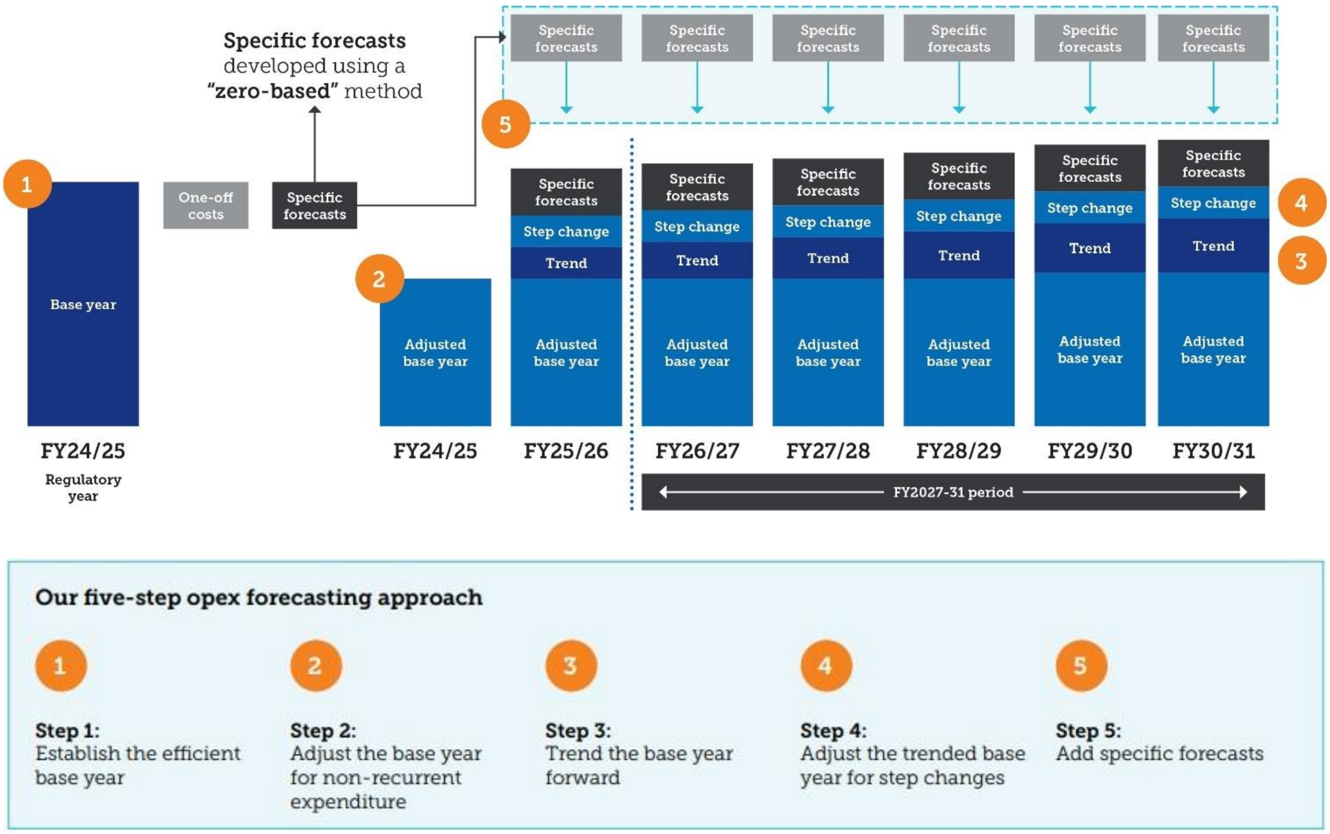
6.1.1 What our customers have told us about operating expenditure

Our customers have told us they want more renewable energy flowing through to the network. To deliver on this expectation, we must invest in advanced systems to manage more complex operations, communications, and data; we outline this further in Chapter 5. As some of these costs are treated as operating expenditure, we must include them in our operating expenditure forecast.

6.2 Our method for forecasting operating expenditure

We use the AER's base-step-trend methodology to forecast SCS operating expenditure (see Figure 6.1). This approach to forecasting operating expenditure assumes the expenditure is relatively stable from year to year but, also allows for adjustments for anticipated changes.

Figure 6.1: The AER's preferred operating expenditure forecasting methodology



First, we establish the efficient base year. We nominate FY25 as our base year, as it is the latest year of actual operating expenditure available at the time of the AER making its final decision for the next regulatory period. It represents the efficient costs necessary to operate and maintain our network and meet regulatory obligations. We then exclude non-recurring operating expenditure and category-specific forecasts, such as government levies, from the base year as they are not forecasted using a base-step-trend approach.

We then trend our base year forward to account for:

- forecast output growth - to ensure sufficient funding for servicing a larger network
- forecast input cost growth - to reflect changes in input costs such as labour and materials
- productivity improvements – to reflect our ongoing commitment to achieving cost reductions over the next regulatory period.

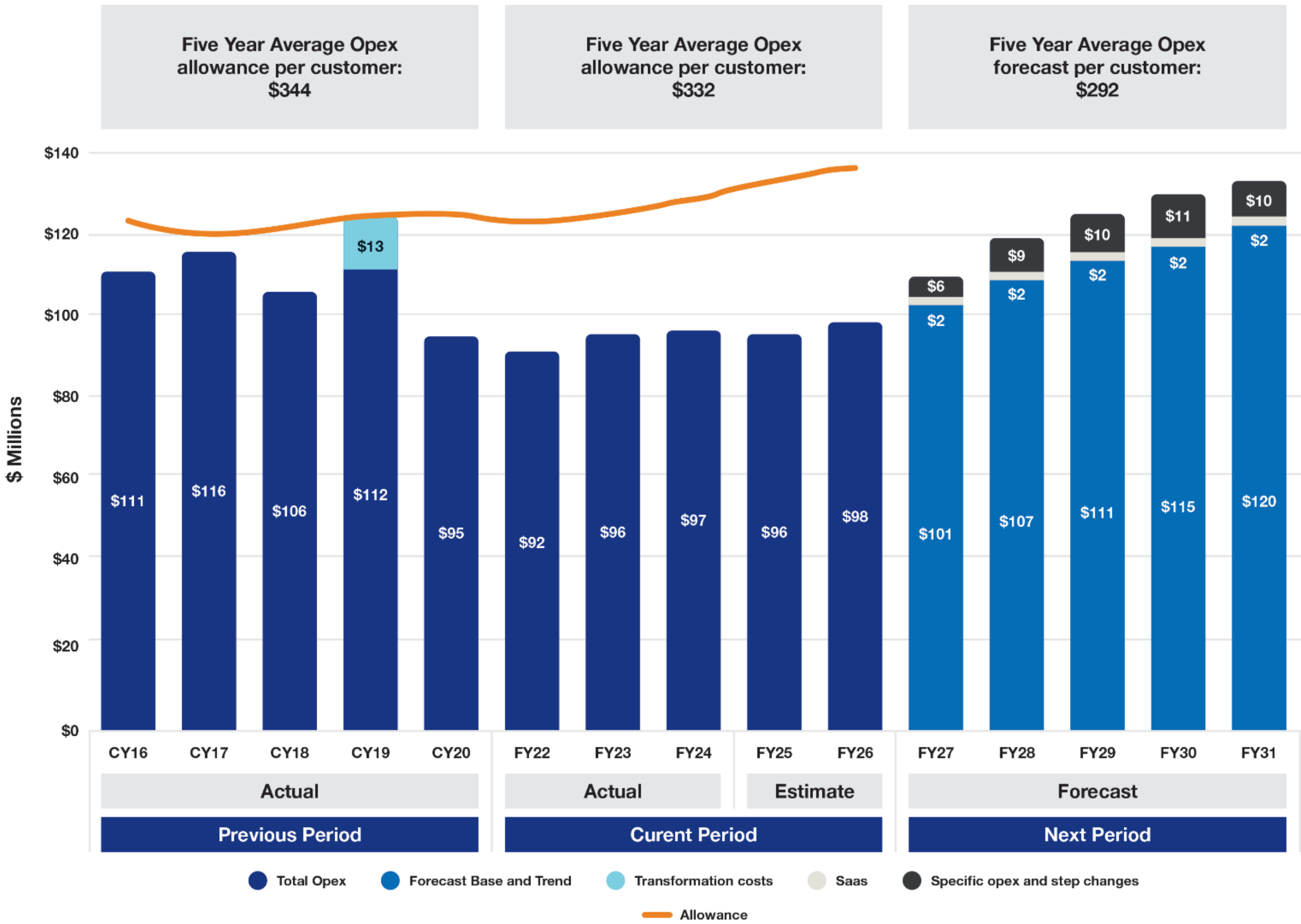
Lastly, we add step changes and specific forecasts to our operating expenditure forecast. This relates to items for which the base year operating expenditure does not provide a reasonable basis to forecast future expenditure requirements. Step changes normally arise from factors such as new regulatory obligations, costs for services that our customers recommended we should prioritise and other major external factors beyond our control such as those related ICT, network resilience and the energy transition.

6.3 Our forecast operating costs

Using the AER's base, step, trend methodology, our total forecast operating expenditure for the next regulatory period is $615 million (including debt-raising costs). This is 4% lower than the operating expenditure allowance in the current regulatory period and 22% higher than our estimated operating expenditure in the current regulatory period (see Figure 6.2). Through deliberate action, we managed to reduce our expenditure below our allowance for the current regulatory period. Our proposed allowance for the next regulatory period builds on this success.

We undertook a thorough assessment to determine that our forecast operating expenditure represents the amount required to efficiently meet our obligations, our customers' expectations and to promote our customers' long-term interests.

Figure 6.2: Historical and forecast operating expenditure, Real $2026, millions



Note: HY21 (Jan to Jun 2021) is not included for visualisation purposes. It does not impact the operating expenditure forecast.

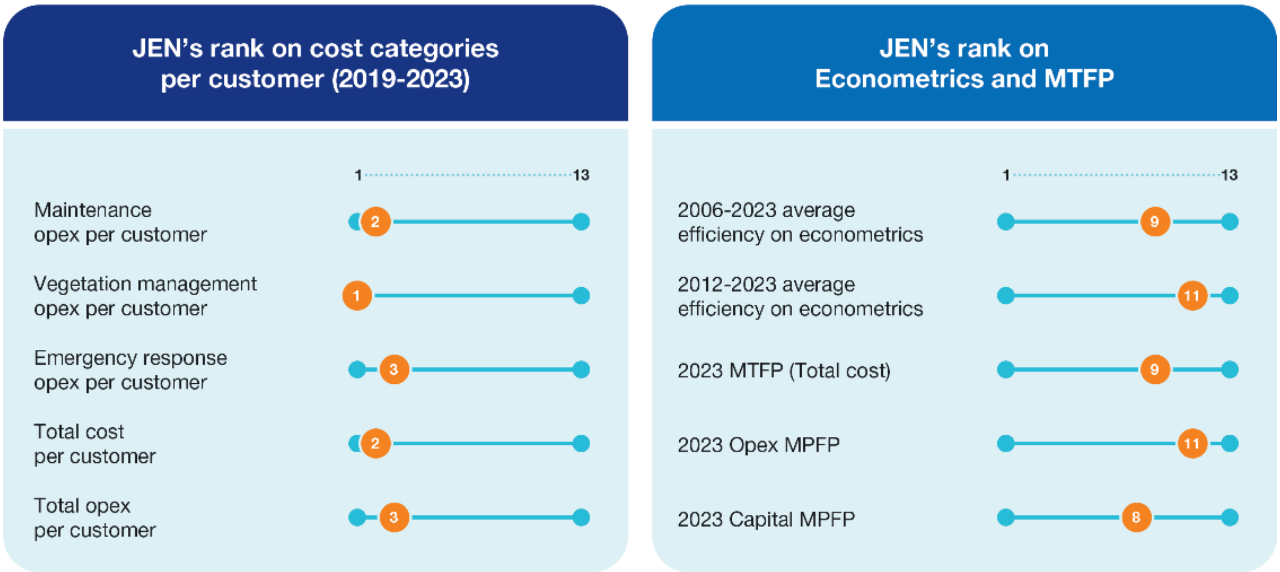
6.4 We benchmark well amongst our peers

The NER requires the AER to have regard to network benchmarking results when assessing capital and operating expenditure and to publish the benchmarking results annually. The aim is to reduce inefficient capital and operating expenditures and to provide customers with useful information about the relative performance of their electricity distributor.

The AER benchmarks the performance of the DNSPs against each other every year. They analyse the audited data we provide to them and process it through various econometric models to form a view of each DNSP's relative efficiency.

The AER employs several techniques to undertake its benchmarking analysis. For most methods we rank well amongst our peers, as illustrated in Figure 6.3 below. These techniques include partial performance indicators (PPI), multilateral total factor productivity (MTFP) and econometric cost functions.

Figure 6.3: JEN's benchmark position against our peers



Source: AER 2024 Annual Benchmarking Report – Electricity distribution network service providers – November 2024

Our cost-category PPIs are among the industry leaders. JEN also had one of the highest increases in productivity in 2021 and 2022, resulting from lower operating expenditure. When considered in the context of overall operations, we remain an efficient DNSP.

"Keeping costs as low as possible, especially for low-income consumers, is the number one priority. Balancing cost with reliability is crucial to meet the high energy needs of people with disabilities without imposing additional financial burdens."

— Disability Customer Voice Group member

6.5 Composition of our forecast operating expenditure

We have developed our forecast operating expenditure using the AER's preferred base-step-trend approach, which we discuss below.

6.5.1 Setting the efficient base year

We propose to use FY25 as our base year to forecast efficient operating expenditure for the next regulatory period. This approach is consistent with the AER's preferred approach. While our audited actual costs for FY25 are not available in time for this submission, they will be available when we submit our revised proposal in December 2025.

We consider our base-year expenditure to be efficient for the following reasons:

- We are subject to a regulatory incentive framework for both operating and capital expenditure and have responded to these incentives.
- Benchmarking analysis supports the efficiency of our expenditure.

Adjustment of SaaS implementation costs

Using FY25 estimated operating costs of $96 million (excluding Software as a Service (SaaS) costs) as our base year, we adjust it by re-allocating SaaS implementation costs of $1.8 million from capital expenditure to operating expenditure in line with the AER's guidance due to a change in the accounting treatment.[67]

The regulatory changes issued by the International Financial Reporting Standards (IFRS) Interpretation Committee in April 2021 have significant implications for the accounting treatment of ICT costs, including SaaS costs. Under the new guidelines, costs associated with configuring or customising SaaS and other software platforms are now classified as operating expenditure when they were previously classified as capital expenditure. Expenses related to software development activities that enhance, modify, or add capability to existing on-premises systems continue to be treated as capital expenditure in relation to intangible software assets. These changes directly impact how we account for ICT-related costs. Specifically, this has led to a significant increase in operating expenditure, which were presented as capital expenditure in the current regulatory period proposal in FY21.

We have adjusted our operating expenditure and capital expenditure accordingly, in line with the AER's guidance for both the current regulatory period and next regulatory periods. The change in accounting treatment of SaaS implementation costs does not increase our total expenditure forecast; our capital expenditure forecast reduces accordingly after re-allocating costs to operating expenditures. This ensures that our customers are not impacted by changes in accounting treatments.

67 In April 2021, the International Financial Reporting Interpretations Committee (IFRIC) released a guidance note requiring SaaS implementation costs to be treated as operating expenditure. When the 2022-26 allowances were determined for Jemena in April 2021, these costs were classified as capital expenditure. To ensure our reported actuals and allowances are comparable based on consistent accounting treatments, the AER provided guidance for us to continue applying the old accounting treatment (i.e. capitalising SaaS implementation costs) for the current regulatory period 2022-26 and apply the new accounting treatment from the 2027-31 period. We have adjusted our operating expenditure and capital expenditure accordingly, in line with the AER's guidance for both the 2022-26 and 2027-31 periods.

6.5.2 Trending the base operating expenditure

We trend our base operating expenditure forward for forecast growth in outputs, input prices and productivity for the next regulatory period consistent with the AER's requirements:

- **Forecast output growth** such as forecast increase in customer numbers, ratcheted maximum demand and circuit line length. This adjustment allows us to meet the increased costs of operating our expanding network.
- **Forecast real input price change** such as wages based on independent expert forecasts from Oxford Economics and Deloitte Access Economics. This adjustment ensures that our costs reflect the expected rate of change in labour and other cost components.
- **Productivity improvement** reflects the efficiency improvements or cost reductions we are committing to deliver as a result of increased automation, process improvements and/or adoption of new technologies. We forecast a 0.5% per annum reduction, which will deliver $9 million cost reductions in the next period.

Trend – growth and productivity

We forecast the trend component of our operating expenditure to be $60.1 million over the next regulatory period.

In Figure 6.2, the forecast base year operating expenditure and trend-related costs are combined.

6.5.3 Step changes

In addition to the base operating expenditure that funds the regular operations necessary to deliver reliable network services today, we anticipate some incremental costs, referred to as step changes, in the next regulatory period due to new regulatory obligations and operating expenditure/capital expenditure trade-off opportunities and requirements. We propose $41 million step changes in total for the next regulatory period.

Step changes

We have proposed the following step changes over the next regulatory period:

- ICT services ($22 million) which include:
  - $9 million of CER Integration Strategy costs (see Chapter 3)
  - $4 million of market reform costs (see Chapter 3)
- Asset management CER Integration Strategy initiatives ($3 million)
- Management of rapid earth fault current limiters (REFCLs) ($5 million)
- Investment in resilience and safety measures ($8 million)
- Investment in Customer Communication and Education ($4 million).

In Figure 6.2, the forecast step changes and costs of raising debts are combined.

ICT step operating expenditure for new projects

The AER defines ICT as all devices, applications, and systems that, together, allow interaction with the digital world.[68] ICT now makes up a significant portion of a distribution network service provider's expenditure, including ours.

68 AER, Non-network ICT capex assessment approach, November 2019, p. 5.

Treatment of ICT expenditure

We manage a wide range of ICT projects within regulatory frameworks and accounting standards. The expenditure treatment of these is determined by various factors, including the types of systems deployed and the expenditure cycles of each system. The diagram below summarises this.

Expenditure Cycle	Operating expenditure	Capital expenditure
Non-Recurrent	>5 years	>5 years
Recurrent	Annually	2 to 5 years

We classify our ICT operating expenditure as:

- Recurrent operating expenditure—from regulatory period to regulatory period—comes from our base expenditure
- Non-recurrent operating expenditure incurred in implementing non-recurrent projects, which is adjusted against the base year operating expenditure
- Recurrent operating expenditure step change for the large non-recurrent projects to be completed in the next regulatory period—which may be new systems or long-cycle upgrades—we will incur additional ongoing recurrent expenditures to support those systems. Ongoing recurrent expenditure is treated as an operating expenditure step change over the next regulatory period.

We are proposing ICT recurrent step operating expenditure for the next regulatory period for several reasons:

- **Integration of new digital capability into the network and dynamic operations.** When implementing new systems, we often need to employ additional human resources and licencing to support the associated ongoing operational activities; this type of expenditure is known as incremental ICT recurrent operating expenditure. These non-recurrent projects are necessary to ensure that our systems remain fit for purpose in a constantly changing technology and network environment where our customers' requirements and expectations continue to evolve. They relate to increasing the data, analytics, systems, and cyber security capabilities required to support our network and the integration of renewable energy.
- **Market Reforms.** When AEMO modifies its systems or the AEMC issues changes to the NER, we need to invest in our ICT systems to comply with the changes. Two current reforms we are considering include Market Interface Technology Enhancement (includes portal consolidation, Identity and Access Management and Industry Data Exchange) and Flexible Trading Arrangements.
- **CER Integration Strategy**. As an electricity distribution network service provider operating in Victoria, JEN plays a key role in facilitating the energy market transformation to renewable energy. Given the uncertainty in the rate of change and direction of the transformation, a least-regrets scenario-based investment approach is needed to manage a smooth transition for customers. Furthermore, Jemena has its own ambitions to work towards net zero. We have therefore developed a CER Integration Strategy and associated programs of work and initiatives to support the energy transition over the next decade.
- **Services shifting from on-premises to cloud-based**. We note the significant shift by users and software vendors away from on-premises systems to cloud computing services. This means that systems and platforms are hosted and maintained by the vendor, and their customers access them via a subscription rather than purchasing a license. Along with the recent changes to interpreting IFRS—which introduced changes that limit what ICT projects can be recognised as assets (capital expenditure)—this has generated a large increase in operating costs that used to be recorded as capital expenditure.

The incremental ICT recurrent costs relate to maintenance, licensing fees, support and ongoing operational activities required to sustain the benefits or functionality delivered by these new projects. They reflect accepted good industry practice, new regulatory obligations and/or external factors outside our control.

More information on these systems and changes can be found in Attachments 6.1 and 6.4 of our proposal.

CER Integration Strategy initiatives

Our proposed step changes for CER Integration Strategy network initiatives relate to the following:

- Strategic Network Analytics Platform (SNAP) – A project will create a strategic platform for analytics, model serving, data integration and other use cases using a modern data lake house, network model, streaming platform and associated application programming interface (API) services to provide foundational capability across the business.
- Variable Voltage Converter (VVC) - The VVC will dynamically and automatically adjust network voltages to maintain compliance with the EDCoP standards during increased solar export to the network.
- Networks Analytics – This program will deliver new network analytics applications (such as CER forecasting tool, the Department of Energy, Environment and Climate Action data & visibility trial, and wrong connections detection) to improve the operational management of the network. These new data and analytics driven applications will improve regulatory compliance, customer safety, and operational planning during the energy transition. It will reduce the future growth of operating expenditure required to manage the network in response to the growth of CERs.
- Grid stability - Implementation of a basic DER Management System (DERMS) solution for curtailing CER such as PV installations on demand to meet the Victorian Government's emergency backstop mandate.
- Key drivers are our CER Integration strategy and customer expectations about ensuring that we can connect our customers to renewables and accommodate more customer energy resources into our network without affecting its reliability (see Chapter 3 for more details). The ongoing operating cost of VVC, SNAP Foundations and Network Analytics is a material change in our operating expenditure requirements.

Regulatory obligations and Victorian Government and customer expectations on network resilience

We propose a step change for the Coolaroo rapid earth fault current limiter (REFCL) annual validation testing. The REFCL was installed and tested in 2023-24; the proposed step change is for the annual testing as part of a new obligation under our bushfire mitigation plan. We are also proposing a step change for the management of hazardous trees in Low Bushfire Rated Areas (LBRA). We currently have a program for High Bushfire Rated Areas and plan on introducing management of hazardous trees in these LBRA. We are proposing to increase response to customer expectations of our network for communities in the LBRA.

Overall, we believe that our forecast operating expenditures represent the level of funding necessary to achieve the requirements under the NER, efficiently meet our obligations and customers' expectations, and promote their long-term interests.

Summary

Our forecast step changes are based on prudent and efficient solutions. They are based on detailed assessments of credible options that can address the need to provide reliable and safe services in a changing environment and meet customer expectations. In addition, our forecast step changes are consistent with our customers' recommendations, priorities and expectations that we:

- prioritise digitisation and automation to increase economic efficiency
- use the latest technology to provide ongoing customer service excellence
- undertake innovative approaches, use digitisation and automation technology and advanced monitoring equipment for determining replacement/upgrading of wires
- commit to environmentally sustainable operations
- champion the use of renewables and energy storage to help reduce network and customer costs
- prioritise investment in network resilience to recover from and withstand extreme weather event.

7. Incentive schemes

Highlights

- Efficiently designed financial incentives for distribution network service providers are in the long-term interests of our customers. They encourage us to be innovative and find ways to spend below our regulatory allowances, leading to reduced prices for customers in the long term.
- We propose to retain the incentive schemes used in the current regulatory period and apply some modifications to the capital expenditure sharing scheme for both the current and next regulatory periods. We consider that expenditure incurred for reasons beyond our reasonable control should not be included in the efficiency assessment of incentive schemes.
- We also propose to introduce a customer service incentive scheme to promote stronger customer service.

The AER applies a range of incentive schemes to electricity distribution network service providers. These schemes incentivise us to operate efficiently, reduce costs, innovate and improve service outcomes for our customers. The incentive schemes are set in a way to balance the tensions between service levels and reduce expenditure.

We propose the following incentive schemes to be applied in the next regulatory period:

1. **The capital expenditure sharing scheme (**CESS**)** incentivises us to be more efficient by rewarding us when we underspend capital expenditure allowances and penalising us when we overspend. The rewards or penalties are shared with our customers:

   a) For underspending, 30% benefit up to 10% underspent of capital expenditure allowance, and then 20% benefit thereafter

   b) For overspending, distribution network service providers will incur a 30% penalty.

   Our consumers benefit from improved efficiencies through a lower regulatory asset base, which is reflected in lower network prices in subsequent regulatory periods. In addition to applying the CESS scheme, we propose removing net connection capital expenditure from its calculation—in both the current and next regulatory periods—to account for non-controllable expenditure.

2. **The efficiency benefit sharing scheme** (EBSS) incentivises us to deliver ongoing improvements to operating expenditure efficiencies relative to the regulatory allowance in a given regulatory period. Any savings we make are shared with our customers; the sharing ratio varies depending on a range of technical factors. However, it is approximately 70% (customers), 30% (JEN) and roughly in line with the CESS. Our consumers benefit from improved efficiencies through lower operating expenditure in subsequent regulatory periods.

3. **The service target performance incentive scheme (**STPIS**)** incentivises us to maintain and improve network reliability performance to the extent that our customers are willing to pay for such improvements. It seeks to ensure that our service levels do not deteriorate because of incentive rewards to pursue efficiency gains under the CESS and EBSS.

4. **The demand management incentive scheme (**DMIS**)** provides a financial incentive to undertake efficient expenditure on non-network solutions to manage peak electricity demand. Reduced peak demand may defer investments in network solutions, leading to lower electricity bills for consumers.

5. **The demand management innovation allowance mechanism (**DMIAM**)** complements the DMIS by providing an annual allowance for research and development in demand management projects that may reduce long-term network costs.

JEN is also proposing to adopt a Customer Services Incentive Scheme **(**CSIS**).** This incentive mechanism seeks to ensure DNSPs are providing holistic customer service at a level consistent with their customers' preferences. The CSIS is designed to ensure that the pursuit of efficiency savings, encouraged by both the EBSS and CESS is not at the expense of customer service

7.1 We propose to retain our current incentive schemes

In 2023, the AER concluded that current incentive schemes have driven significant improvements in distributors' performance through efficiency gains, which reduces prices and outages over time.
It found that:

> *Operating expenditure of Australia's energy network businesses is 30 per cent lower today than it was 10 years ago, and capital expenditure is 50 per cent lower, contributing to significant reductions in network charges.*[69]

We agree and consider that the incentive schemes have played a strong role in achieving this outcome.

We propose to retain our current incentive schemes during the next regulatory period. We consider ongoing efficiencies to be in the long-term interests of our customers, and these can be best achieved with incentives. Nevertheless, we propose several changes to the regulatory approach, which are outlined below.

7.2 Capital Efficiency Sharing Scheme

To calculate the CESS reward or penalty, we take the difference between the allowed and actual capital expenditure within a regulatory period, remove the expenditure relating to any deferred projects and then apply an incentive rate. The CESS amount is then incorporated into the allowed revenue for the following regulatory period.[70]

We anticipate exceeding the AER's approved capital expenditure allowance in the current period (as outlined in Chapter 5). This is due to unprecedented growth in the number of data centres and other large customers seeking to connect to our network. The volume and size of large customer connections were unforeseen and were not included in our capital expenditure allowance for the current regulatory period. Subsequently, we have applied to 'reopen' JEN's current period determination to account for this unforeseen and material increase in expenditure. At the time of submitting this proposal, the AER is assessing our reopener application.

For the purposes of calculating CESS rewards or penalty for the current period capital expenditure, we relied on allowances which incorporated the approved cost pass through application for the Victorian Emergency Backstop Mechanism (VEBM) and assumed that the reopener application is approved as submitted to the AER.

As a result, JEN is projecting a CESS reward of $3 million. If JEN's reopener application is not approved by the AER JEN would incur a CESS penalty of $36 million. This would be driven by an unprecedented increase in volume of large customer connections, rather than any material inefficiencies.

To preserve the incentive for us to continue connecting new customers, we propose excluding the connection capital expenditure in both the allowance and actual amounts in the CESS assessment. This would protect both our customers and JEN from rewards or penalties driven by unforeseen variations in connection volumes that are beyond our control. It would also ensure that the CESS continues to reflect cost efficiencies rather than uncertainties inherent in forecasting.

7.2.1 We propose an update to the CESS

The incentive schemes are designed to give flexibility to distribution network service providers to operate within the total capital expenditure allowance over the subsequent regulatory periods. This encourages distribution network service providers to find innovative and efficient solutions to deliver services to customers and to maximise potential savings. However, when faced with non-controllable items such as new connection volumes, distortions in the incentive framework can arise. We believe these non-controllable components should be excluded from the assessment of incentive schemes.

69 AER, Review finds incentive schemes drive energy network efficiency up and expenditure down | Australian Energy Regulator (AER).
70 NER, cl 6.4.3(a)(5).

Consequently, for the next regulatory period, we propose to continue applying the CESS, as amended by the 2023 Incentive Review.[71] However, we propose to make the following additional changes to the scheme's operation to account for non-controllable factors beyond JEN's control and to ensure consistency with the remaining elements of the regulatory framework.

7.2.2 New connection capital expenditure should be excluded from the CESS

Under the NER, JEN and other DNSPs must issue customers with a connection offer if they seek a connection.[72] While JEN forecasts the volume of connection services that will be required as part of our regulatory proposal, the actual volume of connection services required cannot be predicted with certainty, particularly in the outer years of a regulatory period.

In Victoria, DNSPs are required to undertake market-based testing of works related to connection services made by a connection applicant.[73] This requirement means that the most efficient price will be incorporated into JEN's capital expenditure forecasts for the 2026-31 regulatory period, meaning the opportunity to find further efficiencies does not exist.

As the overarching objective of the CESS is to set incentives for DNSPs to undertake efficient capital expenditure during a regulatory control period. Within this objective, our view is that the CESS should only apply to the part of JEN's capital expenditure program that is within JEN's control. Parts of our capital expenditure program that are outside of our control should be excluded from the CESS. Our proposal will ensure symmetry between the exclusion and inclusion of controllable capital expenditure when calculating rewards and penalties. It also aligns with EBSS where non-controllable components (i.e. specific category forecasts) are excluded from the EBSS assessment.

7.2.3 Changes to the data used in the CESS calculation

To derive actual net capital expenditure, we take gross capital expenditure and deduct the amount of money received from large customers who pay to connect to our electricity distribution network (capital contributions). However, there is a timing difference between recording gross capital expenditure and recognising capital contributions, and this can distort the CESS calculations (see Figure 7.1). This has been highlighted due to the significant increase in the number of major connection customers seeking to connect.

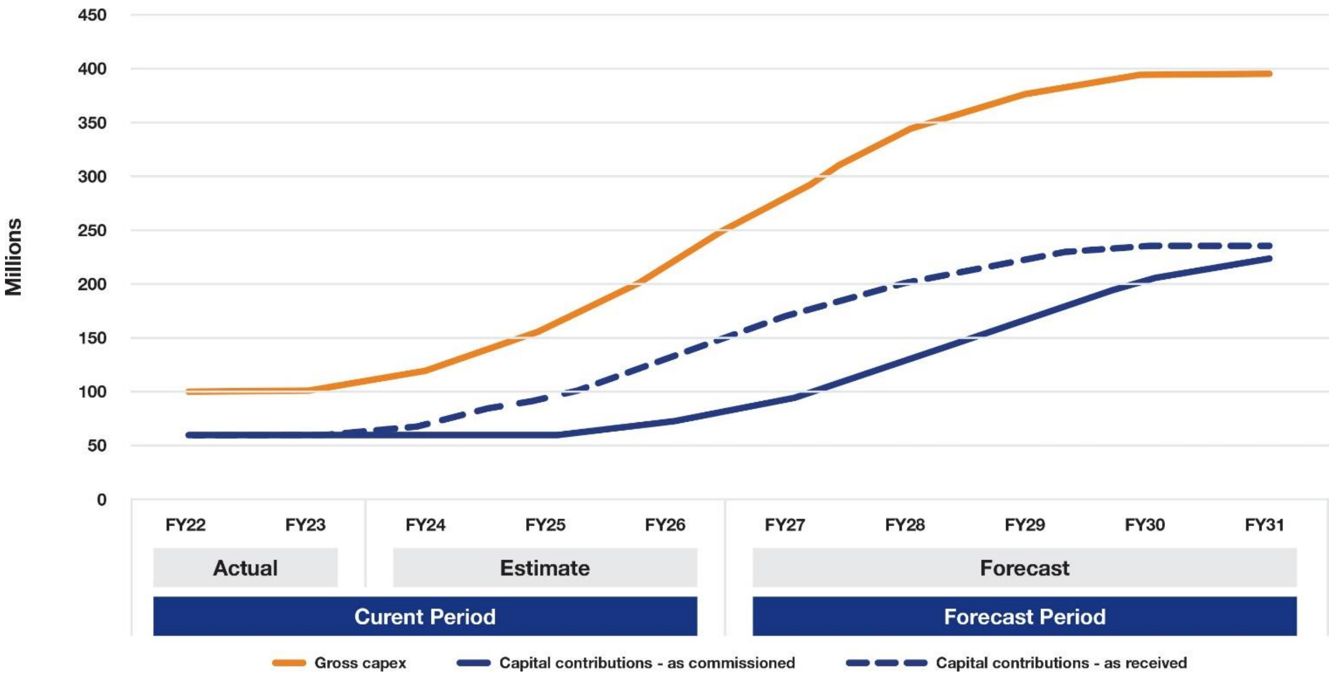
Sometimes the lag between receiving the payment (upfront) and energising the customer site (at the end of the process) can take several years for large customers. This timing difference contributes to higher CESS penalties, particularly where there is a higher growth in new connections, as has been the case for JEN. Figure 7.1 below demonstrates the lag effects of recognising capital contribution under each approach.

71 AER, Final Framework and approach AusNet Services, CitiPower, Jemena, Powercor and United Energy 2026–31, 31 July 2024, section 4.1.

72 NER, Chapter 5A, part C.

73 Essential Services Commission of Victoria, *Electricity Distribution Code of Practice, version 2*, 1 May 2023, s5.2.1(a).

Figure 7.1: Historical and forecast gross capital expenditure and capital contributions, $2026, millions



In November 2024, the AER issued a guidance note clarifying the timing of recognising capital contributions (contributions guidance).[74] It requires cash contributions for connection projects exceeding $200,000 and spanning more than 12 months to be individually reported on an 'as incurred' basis.[75] Details of how we have complied with this guidance are included within Attachment 07-01.

7.3 Efficiency Benefits Sharing Scheme

The EBSS has been in effect for the past five regulatory periods, delivering long-term benefits to customers. Given its success, we propose to continue the scheme to complement the CESS, STPIS and CSIS.

As outlined in Chapter 6, we have spent less than the AER-approved operating expenditure allowance for the current period. As a result, we forecast a total EBSS carryover of $21 million over the next regulatory period. Our customers' share of the EBSS carryover will be reflected in the next period through a reduced base operating expenditure.

JEN proposes to continue to exclude cost categories which are not forecast using single year revealed cost from the EBSS scheme as these costs can vary dramatically, year on year. Costs relating to Guarantee Service Level (GSL) payments and debt raising costs are excluded from the scheme of this basis. Additionally, in the current period the AER has approved exclusions for:

- Energy Safe Victoria (ESV) levies
- Cost pass-throughs and contingent projects
- Demand management innovation allowance (DMIA) opex.

We do not propose to continue to exclude ESV levies in the next regulatory period as these costs are treated as Jurisdictional Scheme amounts[76] and are no longer part of our SCS operating expenditure.

74 AER, *Reporting capital contributions AER Guidance Note for electricity distributors*, November, 2024.

75 meaning qualifying connection projects are to recognise capital contributions in proportion to the connection project capital expenditure spent

76 AER, Jurisdictional scheme determination, Licence fees under Electricity Industry Act 2000 (Vic), July 2024.

We propose that any operating expenditure approved as part of our proposed Innovation Fund be excluded from the EBSS. As discussed in Attachment 03-02, we propose the Innovation Fund be approved on a 'use it or lose it' basis. Therefore, we do not believe it would be appropriate to earn a reward if we underspend this allowance.

7.4 Other Incentives

The rewards available under the DMIS and DMIAM incentive schemes are lower when compared to the CESS, EBSS and STPIS. The AER has granted JEN a DMIAM allowance of $2 million for the current regulatory period. Our DMIAM projects include a dynamic electric vehicle charging trial and a community battery trial, amongst others. Under the scheme, any unspent DMIAM allowance will be returned to our consumers through a lower revenue allowance in the next regulatory period.

The total incentive under the DMIS in any year cannot exceed 1% of the distributor's allowed revenue for that year. We do not have any DMIS projects during the current regulatory period.

7.5 We propose a customer service incentive scheme

In July 2020, the AER published a CSIS[77] to encourage electricity distribution network service providers to engage with their customers and provide customer service in accordance with customer preferences.

77 AER, Review of incentive schemes for networks – Final decision, April 2023.

The CSIS sets financial incentives for distribution network service providers to perform against a range of different customer service targets. It is up to distribution network service providers to develop CSIS proposals to be applied during a regulatory period. To date, we are the only Victorian electricity distributor that has not proposed a CSIS.

Currently, our only customer service measure exists under the STPIS, which is our telephone answering (fault-line) performance. Under this incentive, this parameter has a maximum risk/reward of +/- 0.5% of revenue depending on our performance against the set target.

> Through our engagement process our customers made several recommendations related to customer service and the provision of ongoing service excellence by:
>
> - Ensuring ongoing service standards to our customers in delivering services across the network
> - Ensuring excellence at all levels, benchmarked with our peers
> - Focusing on KPIs that are transparent, monitored, tracked and communicated publicly
> - Providing opportunities for feedback and performing internal reviews to identify opportunities for improvement to service standards.

In light of this, JEN has considered more than 30 candidates for customer service measures using the following criteria:

- the importance to our customers
- we have measurable historical data to develop a target
- we can respond effectively to the signal
- any trend risk (possible known or unknown events that may affect the baseline data)
- can be clearly defined
- any interactions with other incentives/measures.

In July 2024, we presented and discussed the CSIS design, including the measures and weightings, with our Energy Reference Group. The group provided a range of advice and feedback on the approach and assessment criteria, taking into consideration the long-term interests of customers. Feedback from the group on weightings was incorporated into the design to best reflect customers' expectations on how we measure customer service. The group endorsed our approach to the CSIS and recognised that it aligns with customers' expectations to incorporate accountability measures and benchmarking into our customer service, as well as other Victorian electricity distribution network service providers' approach to a CSIS.

Therefore, we are proposing a CSIS measure that comprises the following measures and weightings:

- CSAT planned outages (25%)
- CSAT new connections (25%)
- SMS unplanned outage notification performance (25%)
- Fault-line telephone answering (25%).

Under the CSIS, we propose a maximum risk/reward of +/- 0.5% of revenue.

Further information on JEN's proposed CSIS can be found in Attachment 07-01[78]

78 *JEN – Att 07-01 Incentive Mechanisms.*

8. Our revenue requirement and what it means for our customers

Highlights

- We forecast a total revenue requirement for our standard control services of $1,846 million over the next regulatory period, a 15% increase from the current regulatory period. This revenue requirement will be recovered from all our customers receiving standard control services.
- Despite the increase in our forecast revenue requirements, prices are forecast to decrease due to an even greater increase in forecast energy demand for the next regulatory period.
- Customers' distribution charges are forecast to decrease by an average of 12% in 2026-27 and a further 5.6% each year for the remaining years of the next regulatory period in real dollar terms.
- Our forecast revenue requirements reflect our customers' expectations on affordability, network reliability, digitisation and automation, sustainable future, accessible communication and fairness.

8.1 Our revenue requirement and price impacts

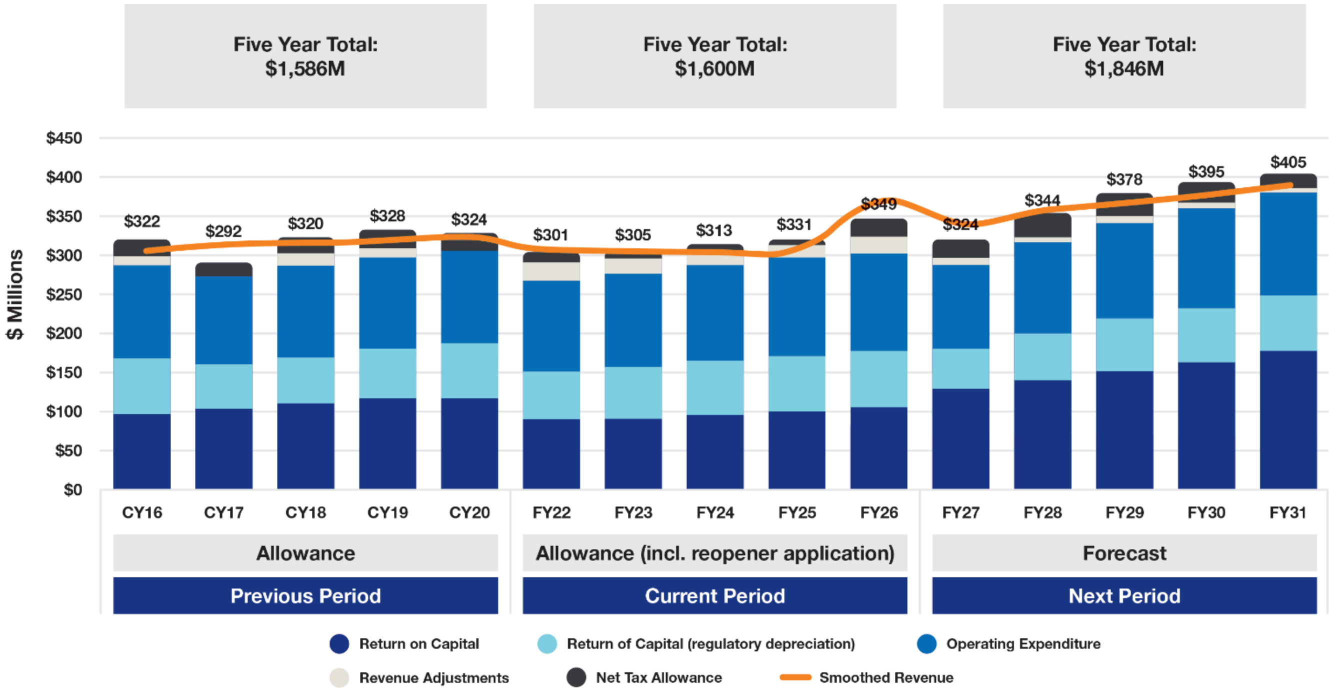
As a regulated business, we are required to estimate the revenue we will need to cover the costs of providing Standard Control Services (SCS), including future investments and a return to our investors.

We forecast that we will need $1,846 million in revenue over the next regulatory period which is a 15% increase from our revenue requirement for the current regulatory period. Key drivers for the increase are our proposed investments to connect new customers, maintain network reliability, accommodate forecast entry of CER (rooftop solar, EVs and batteries) through digitisation and automation and provide ongoing service excellence to our customers. These initiatives are consistent and in response to our customers' feedback and recommendations, as detailed in Chapter 2.

Figure 8.1 below shows our historical and forecast revenue requirement for the next regulatory period. Annual revenue requirements vary from year to year due to lumpy capital expenditure. To avoid volatility, we smooth our revenues to provide a more stable trend, which helps avoid price shocks and volatility for our customers and provides certainty.

Once we derive our smoothed revenue requirement, we apply the principles outlined in our tariff structure statement to derive distribution tariffs that we apply and pass on to our customers' retailers.

Figure 8.1: Total revenue requirement, Real $2026, millions



Price impacts

We receive this revenue from our customers' electricity retailers by charging distribution tariffs.

Affordability remains our customers' top concern. We are able to deliver a reduction in distribution charges by an average of 12% in 2026-27 and a further 5.6% each year from 2027-28 until the end of the next regulatory period (excluding inflation), despite the increase in our forecast revenue for the next regulatory period. Our proposed price reduction was enabled by an increase in network utilisation due to a significant increase in load from data centres, major connections and increased consumption from existing customers as they move from using gas to electricity.

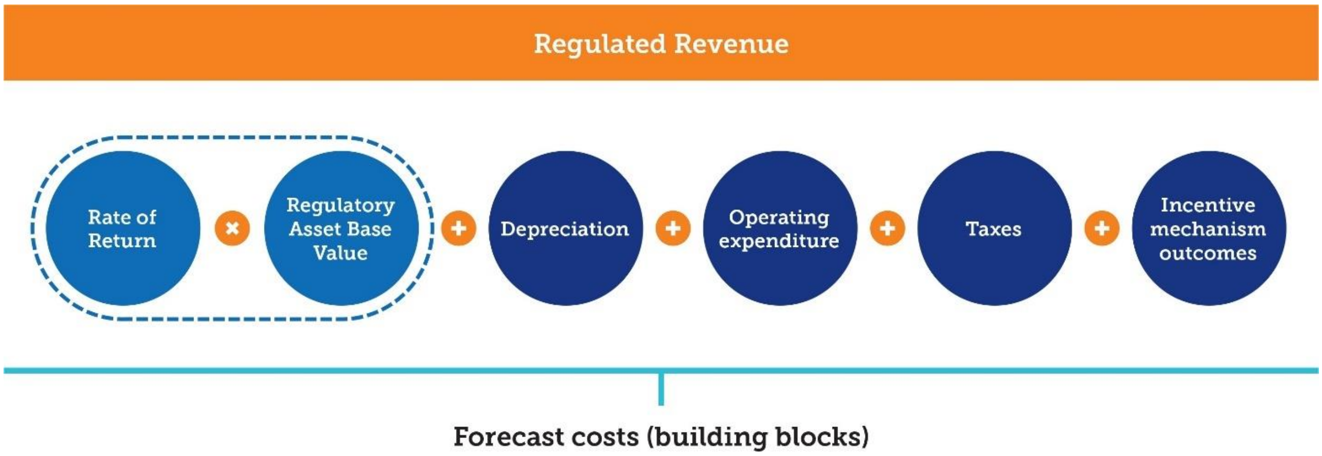
> *"The most important thing for us is how much we can save on our non-negotiables (electricity, gas). Need to see the price change and come down."*
>
> *— Small business customer*

Below, we outline how we estimate our revenue requirements for our Standard Control Services. Our revenue requirement for metering services is outlined separately in Chapter 10.

8.2 What comprises our revenue requirement

We calculate our required revenue to deliver our plan for the next regulatory period using the AER's standard building block approach, as illustrated in Figure 8.2.

Figure 8.2: The revenue building blocks

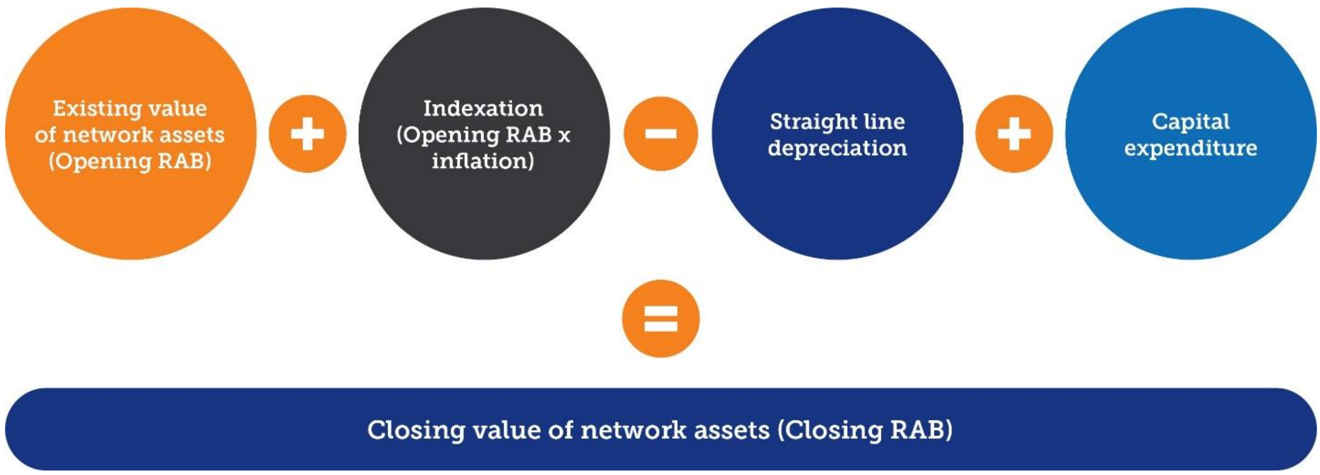


We derive our proposed revenue for the next regulatory period by adding the above building blocks, which we outline below.

8.2.1 Return on capital

Our Regulated Asset Based (RAB) is the total value of our assets used in providing distribution services. This value represents the as-yet unrecovered capital investment we have made in the past to provide services to our customers now and in the future. The value of the RAB changes over time. It increases with every investment in new assets (net of any capital contributions made by connecting customers through our capital contributions policy) and falls as we depreciate existing assets over time. We also adjust the RAB for inflation in accordance with standard regulatory processes. Finally, when customers make capital contributions to these assets[79] or we dispose of them, the proceeds are subtracted from the overall value.

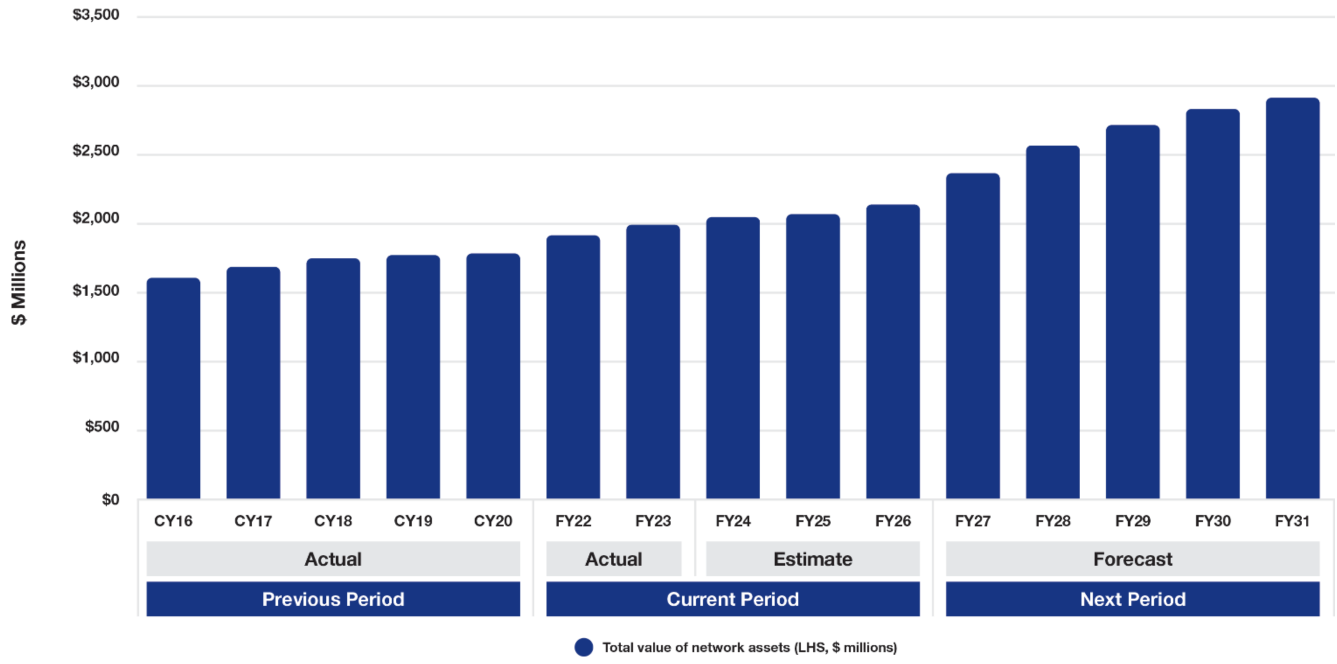
Figure 8.3: How the RAB is calculated



We estimate that the value of our asset base at the start of the next regulatory period will be $2.13 billion and that it will increase to $2.91 billion by the end of the period (Figure 8.4). This increase is mainly due to new capital expenditure investments over the next regulatory period.

79 See Chapter 5 for an explanation of capital contributions.

Figure 8.4: Network RAB trend, Real $2026, millions



Rate of return

The rate of return represents the return our investors require to fund the investments in our network. The RAB is, in effect, the outstanding balance of money we owe to those who financed our capital expenditure. Therefore, the rate of return covers the cost of borrowing that money. For the next regulatory period we have estimated the rate of return based on the AER's 2022 Rate of Return Instrument as outlined in Table 8.1.

Table 8.1: Calculating the rate of return

Parameter	Proposal
Equity beta	0.60
Market risk premium	6.20%
Risk free rate	3.95%
Return on equity	7.67%
Return on debt (5-year average)	5.05%
Gearing	60%
Return on capital (5-year average)	**6.10%**

8.2.2 Depreciation or return of capital

We do not recover our capital expenditure in the year we incur it because of its lumpiness and because the benefits of the deployed assets are delivered over many future years. Instead, we recover these costs over the economic life of these assets. This recovery of investment is referred to as a depreciation or return of capital. It represents the annualised cost of our capital expenditure. We calculated this allowance using an approach that is consistent with the NER and also the AER's standard regulatory models.

8.2.3 Operating expenditure

Operating expenditure is a significant part, about a third, of our building block revenue. We provide our operating expenditure forecast in Chapter 6.

8.2.4 Incentive scheme arrangements

The AER applies a range of incentive schemes to electricity distribution network service providers. As a result of our performance against these incentives, we will either receive a reward or penalty in our revenue. For some schemes, the reward or penalty is received within a regulatory period for other schemes, the rewards and penalties are recovered in the next regulatory period. We have outlined our incentive schemes in Chapter 7.

8.2.5 Corporate income tax

This allowance represents what we forecast our income-tax liabilities will be over the next regulatory period. The amount of corporate tax allowance is estimated by multiplying the corporate tax rate by taxable income and accounting for imputation credits as per the AER’s rate of return guideline.

9. Our tariffs and charges

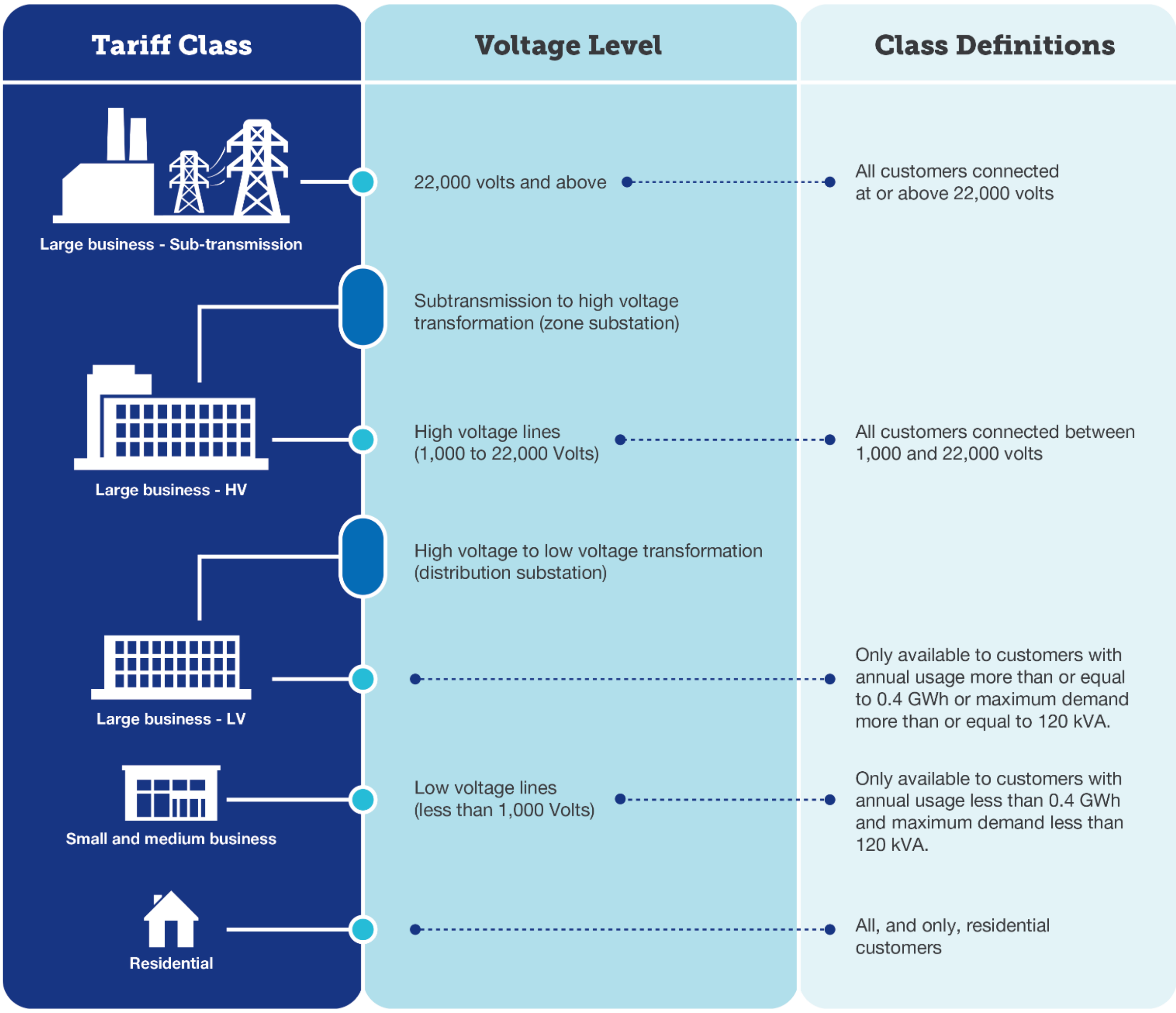
Tariffs are the fees and structures we use to pass pricing signals and to recover our costs from customers. We recover our allowed efficient costs from electricity retailers through network tariffs and electricity retailers recover these costs through the charges they levy on customers through retail bills. To a large extent, our tariff strategy relies on retailers passing on our pricing signals in their charges to customers.

9.1 Our tariff structures

We offer Standard Control Services tariffs to our customers through five tariff classes which correspond with our five major customer segments.

Figure 9.1 shows these tariff classes and their respective definitions:

Figure 9.1: Current regulatory period tariff classes



Within each tariff class, we have multiple tariffs available to meet our customers' varying needs and characteristics. For example, our residential tariff class includes single-rate and time-of-use tariffs, allowing customers to choose their preferred charging structure depending on their circumstances.

Tariff components

Each tariff offered is composed of several components:

- **Fixed charge:** daily supply charge in dollars per day ($/annum). A fixed charge is applied to all of our customers and helps to recover our fixed network costs.
- **Consumption (flat/single-rate) charge:** the price for consuming electricity remains the same at all times of day, charged in cents per kilowatt-hour (c/kWh). This charge applies to our residential and small business customers on single-rate tariffs.
- **Consumption (peak and off-peak) charge:** the price is higher for consuming electricity during network peak demand times and lower outside of peak times, charged in cents per kilowatt-hour (c/kWh). Peak and off-peak tariff components apply to all customers who do not have single-rate tariffs.

- **Consumption (solar soak) charge:** the price (in **c/kWh**) is lower than the off-peak price to incentivise electricity consumption during the 'solar soak' period (11 am to 4 pm) when there is excess energy generation from solar PV in the network. This lower solar soak consumption price is new and only applies to our new residential time-of-use tariff (A130) from the next regulatory period.
- **Peak export reward and solar soak export charge:** Exporting energy during the network's peak period (4 pm to 9 pm) will result in a reward or bill credit. Exporting energy during the solar soak period (11 am to 4 pm) when there is already excess energy in the network will result in an export charge (subject to the basic export level (BEL). These components are charged in cents per kilowatt-hour (c/kWh) and only apply to our opt-in residential customer export tariff (A10E) and our community battery tariff (A30B). These tariff components are new for the next regulatory period.
- **Demand (kW *or* kVA):** based on the maximum demand (rate of consumption of electricity) during peak times and charged in dollars per kilowatt ($/kW) or dollars per kilovolt-ampere ($/kVA). This charge applies to our residential and small business customers who are on demand tariffs, as well as all large business customers.
- **Summer Demand Incentive Charge** (SDIC)**:** a demand charge levied during the evening peak (4 pm to 7 pm), charged in cents per kilovolt-ampere per day (c/kVA/day). This charge applies to all of our large business customers during the hottest months of the year, December to March, and aims to incentivise them to reduce their demand during peak network events.

9.1.1 We operate under a revenue cap

The AER approves our prices at the beginning of a five-year regulatory period, and these are managed under a 'revenue cap' form of price control. During a regulatory period, when we collect more or less revenue than the allowed amount in any given year, we will return the excess or recover the shortfall from customers in the following year. This ensures that our customers do not over-pay or under-pay for their electricity distribution prices over the five-year regulatory period.

9.2 Market changes since the last price reset proposal

The accelerated pace of the energy transition presents both opportunities and uncertainties for JEN and our stakeholders. We are seeing an increase in the number of rooftop solar systems, more batteries, and increased electric vehicles. There's growing interest in communal energy solutions like shared solar installations, virtual power plants, and community batteries. CER are now more accessible than ever.

Federal and state government renewables policies and emissions targets

The Australian and Victorian governments are moving towards net zero, with both jurisdictions targeting net-zero emissions through a diverse range of policies. While the link between tariffs and net-zero targets is not direct, tariffs can encourage consumers to make decisions that would benefit the network and lead towards a net-zero future in the longer term.

Consumer Energy Resources

CER are behind-the-meter resources and technologies that consumers can use in their homes or businesses to manage, generate, and/or store energy. Some common examples of CER include electric vehicles, rooftop solar systems and home batteries.

The adoption of CER has gained momentum in recent years as consumers increasingly seek to control their energy use to lower their energy costs and reduce their environmental impact. However, this introduces new challenges for managing our network and increases the need for network augmentation.

- **Electric Vehicles** have gained significant popularity worldwide. As the rate of vehicle electrification increases, the new demand for EV charging will require network and non-network solutions, such as tariffs, to facilitate this transition.
- **Rooftop solar photovoltaic systems** offer numerous benefits but also pose challenges to grid stability. Excessive solar generation in the middle of the day, for example, can reduce network stability and even cause blackouts.
- **Home and community batteries** store electricity during periods of excess supply or low electricity rates. They can benefit the network by improving network resilience and reducing the need for network augmentation when they are used to export electricity during peak demand times or store electricity during times when excess solar exports might negatively affect grid stability. However, if batteries are used at times that are not favourable for the network, such as charging during peak times, they can put strain on the network.

Tariffs can help address these challenges by encouraging network utilisation at the right times. Through pricing signals, we can encourage consumption at off-peak times. When customers respond to pricing signals passed on from retailers, it could help limit the maximum and minimum demand in the long term, which can result in electricity system benefits.

9.3 What our customers and stakeholders have said

Before commencing our engagement on tariffs, we surveyed retailers and consulted with customers to understand their key priorities. We then completed approximately 80 hours of engagement with a wide range of customers and other stakeholders. We held three joint tariff engagement forums with the other Victorian DNSPs involving customer advocacy groups, retailers, industry experts, and representatives from the AER and the Victorian government to develop our pricing principles, workshop our proposed future tariff structures, and seek feedback.

Tariff design should be customer-centric and our stakeholder groups echoed this view. We also recognise the vital role that retailers play and the importance of aligning tariff structures across Victorian distribution network service providers.

Our Tariff Structure Statement, which lays out our tariff structures and the approach to pricing we will take over the next regulatory period, is included in this proposal as Attachment 09-01. It, along with our explanatory statement, explains how we have balanced the views of these diverse groups of stakeholders and customers with our business needs.

9.3.1 Objectives

When establishing or changing tariffs, we abide by the requirements set out in the NER while also looking to customer and stakeholder groups for further guidance on priorities for the period. We consulted on the pricing principles together with other Victorian distribution network service providers through our joint tariff engagement forum. Table 9.1 displays the pricing principles that we have adopted in developing our tariff structures for the next regulatory period.

Table 9.1: The pricing principles identified through our engagement

Principle	How the principle should be used
Simple	Network tariffs should be simple, consistent, and readily understood by retailers, customers and stakeholders.
Efficient	Network tariffs should incentivise customer behaviours that make network costs more affordable and equitable in the long term.
Adaptable	Network tariffs should be capable of being evolved for future network configurations and emerging technologies, consistent with a net zero future.

9.3.2 Customer preferences

Our residential customers (Customer Voice Groups and People's Panel) also endorsed the above pricing principles. During our discussions with residential customers, two other customer priorities became clear to us:

Fairness and equity

While "equity" was considered part of the "Efficient" principle by our stakeholder groups, it came up repeatedly as a vital and stand-alone consideration for customer groups. Customers find the NER requirement of cost-reflective pricing compelling but have particular concerns for people experiencing vulnerability and customers with rooftop solar who are facing higher bills due to the wind-down of high feed-in tariffs and the possible introduction of export tariffs.

Education

Customers appreciated learning more about JEN and our current tariff structures. They believe that if all customers were more educated about pricing and the need for behavioural change, customer behaviour would be more likely to change, whether to support the network or in response to price signals.

9.4 Proposed changes to our tariff structures

9.4.1 Residential

The primary tariffs we currently offer to our residential customers are outlined in Table 9.2 below.

Table 9.2: Residential customer primary tariffs

Tariff	Tariff details
Single-rate	Includes: – Daily fixed charge ($/day) – Single-rate consumption charge (c/kWh) This tariff's consumption charge is the same, no matter the time of day.
Time of Use	Includes: – Daily fixed charge ($/day) – Peak consumption charge (c/kWh) – Off-peak consumption charge (c/kWh) This tariff's consumption charge varies depending on the time of day, with peak electricity costing more than off-peak electricity.
Demand	Includes: – Daily fixed charge ($/day) – Single-rate consumption charge (c/kWh) – Demand ($/kW) This tariff's consumption charge is the same, no matter the time of day. However, the demand charge is levied based on the customer's demand during peak times.

Our current default residential tariff is Time of Use, which is a cost-reflective tariff. It has a daily fixed charge along with differing charges for peak and off-peak periods, reflecting that our network is predominantly built to meet the peak demand in the 3 pm to 9 pm window. All new and upgrading smart meter-enabled customers are automatically placed on this tariff. Most customers can opt out of the ToU tariff and go on to our residential single-rate tariff (on which customers pay the same rate for electricity throughout the day).

Case for change

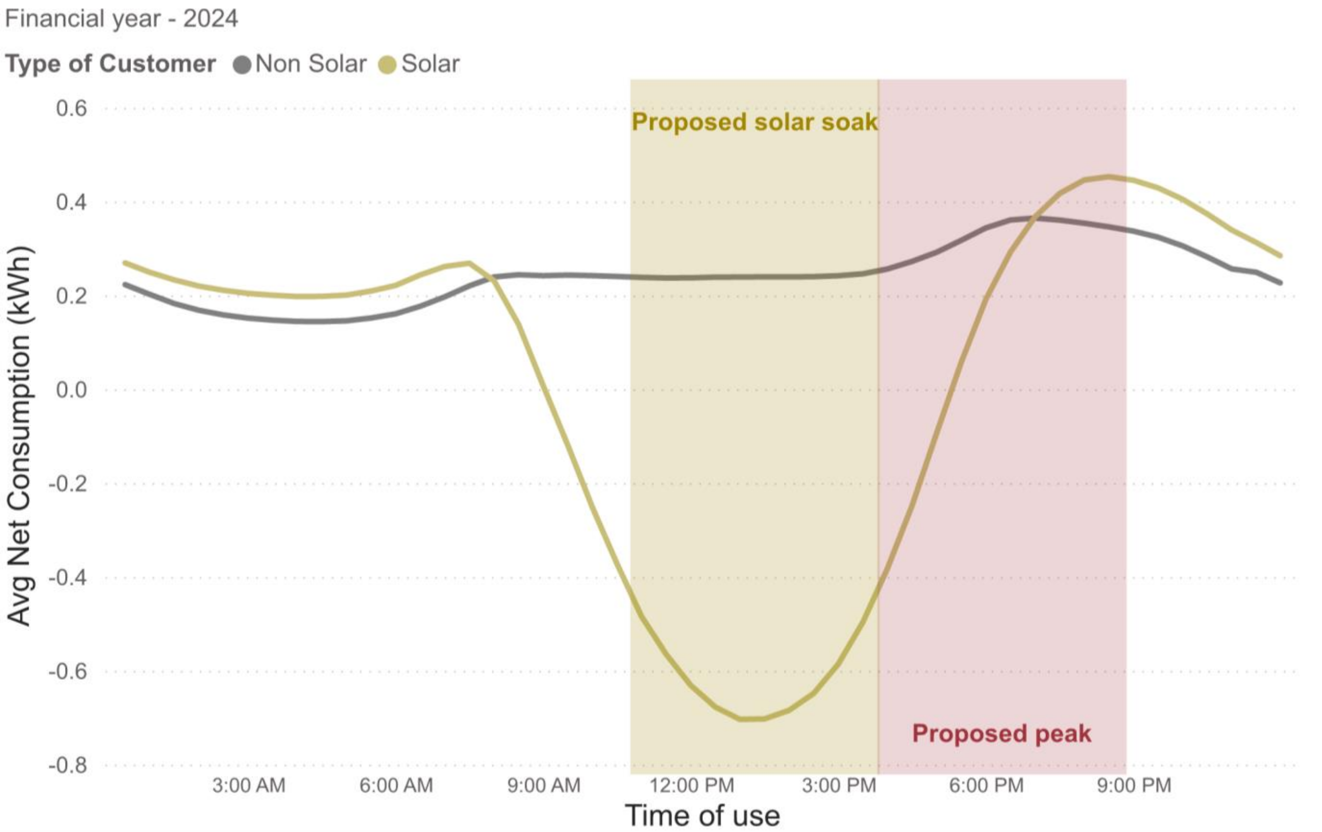
Only 160 of our residential customers are on our demand tariff. These customers pay a charge for their monthly maximum demand. This tariff is poorly understood by customers, and few retailers offer it at all due to the difficulty of explaining it to customers and the need to change retailer billing systems to cater to a very small volume of customers on this tariff. For these reasons, we propose to remove the residential demand tariff in the next regulatory period and move all customers currently on this tariff to our Daytime Saver ToU tariff, which we outline below.

As highlighted earlier, rooftop solar penetration is increasing, which may cause network instability as more customers export their excess energy in the middle of the day.

Figure 9.2 below shows the consumption profiles for residential customers with and without solar exports. They demonstrate the time windows in which issues with excessive solar exports are most likely to occur. With an even greater increase in solar uptake over the next decade, issues caused by excess solar exports in the middle of the day are expected to exacerbate network stability issues.

We are proposing two new residential tariffs to reflect our customers' preferences for improving fairness, equity, and cost-reflectivity and enabling increased penetration of renewables in our network.

Figure 9.2: Average daily electricity consumption of JEN's residential customers



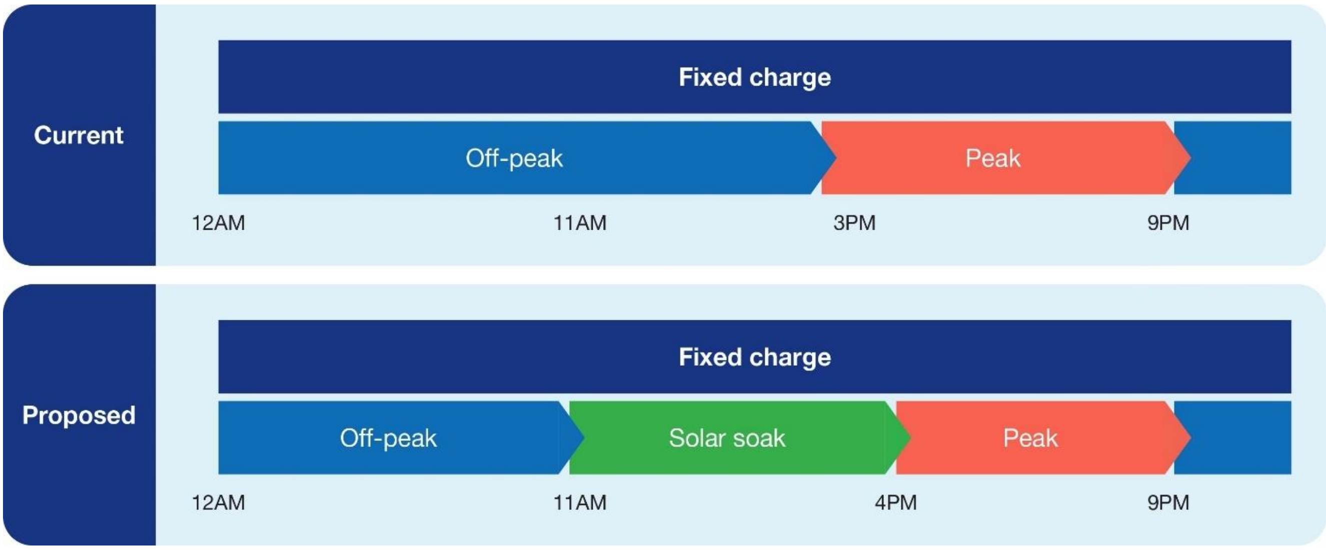
Daytime Saver (solar soak Time of Use)

We want to incentivise customers, with or without solar, to use more energy created in the middle of the day, addressing grid stability issues that may be caused by excess solar exports during this window. A tariff update could enable *all* customers to benefit from the energy generated by customers with solar PV. We propose to replace our existing ToU tariff by adding a "solar soak" period in the middle of the day to the existing ToU tariff structure. This solar soak period would operate as an additional off-peak period, with cheaper pricing than the off-peak window to encourage consumption.

> *"Update tariff language so it is instantly understandable for customers (e.g. 'solar soak' could be 'free' or 'midday discount'."*
>
> *— Electricity retailer representative*

We held a series of joint Victorian distribution network service provider engagement forums to seek feedback on this new tariff structure. Based on this stakeholder feedback, we are proposing the time windows of the solar soak and peak periods as shown in Figure 9.3 consistent with all other Victorian distribution network service providers. These windows will apply to *all* customers in Victoria with a Daytime Saver tariff. Overall, the peak period window for residential customers is reducing from 6 hours in a day (3 pm to 9 pm) to 5 hours (4 pm to 9 pm). We note customer feedback around industry jargon and have chosen to name the tariff a "daytime saver" to give customers the clearest impression of the tariff's purpose.

Figure 9.3: Current and proposed residential Time of Use tariff structure and timing



We propose moving all residential customers on our existing ToU tariff A120 and demand tariff A10D to the new daytime saver ToU tariff.

"I think the new solar soak tariff is a great initiative. The proposed export charge/reward tariffs are establishing appropriate incentives."

— Jemena customer

Export tariff and transition strategy

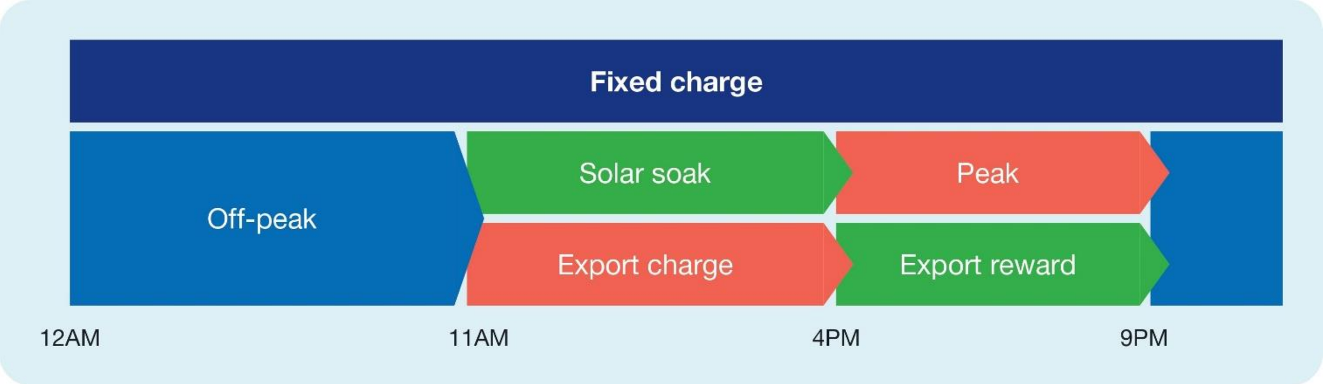
As our customers increasingly adopt CER, such as rooftop solar and batteries, our network will need upgrades to handle the increased energy exported into the grid. The export tariff, like the ToU tariff, is designed to send pricing signals to customers to indicate when certain behaviours are beneficial or costly to the network. This tariff includes charges for exporting to the network when the network is under constraint, rewards when exports benefit the network, and zero export charges when exports are expected to have no network impact, that is, when they are below the Basic Export Level discussed below.

This tariff will be provided on an opt-in basis in the next regulatory period, based on feedback from customers and the Victorian government. This opt-in export tariff for our residential customers is the main pillar of our export tariff transition strategy.

Although revenue recovery from our export tariff is expected to be relatively small in the next regulatory period, introducing this new tariff is an important first step in familiarising JEN's customers with export tariff structures. Further details on our export tariff transition strategy are provided in section 6 of our Tariff Structure Statement.

The proposed timing and structure are shown in Figure 9.4. The periods of export charges and rewards align with the new Daytime Saver ToU tariff.

Figure 9.4: Proposed export tariff structure and timing



The export charge intends to discourage customers from exporting during the middle of the day (11 am to 4 pm) and encourage customer self-consumption. The export reward provides a bill credit for exporting during the evening period of peak demand (4 pm to 9 pm), similar to how feed-in tariffs work for current solar customers, but only during the part of the day when the network needs more electricity. Exporting during other periods is free of charge.

> *"Helping enable tariff flexibility (e.g. opt-in tariffs), so retailers can better meet the needs of different vulnerable residential and business customers"*
>
> *— Electricity retailer representative*

This tariff may appeal to residential customers who can self-consume or store their solar energy between 11 am and 4 pm and export at later times, for instance, customers with home batteries.

Basic export level (BEL)

A basic export level is the amount of electricity that a customer will be able to export to the grid at no cost. We are proposing a basic export limit of 1 kWh per customer per day during the solar soak period (11 am to 4 pm). Above this threshold, customers on the opt-in export tariff will be charged for exporting energy during the solar soak period (11 am to 4 pm). In the event that laws or regulations are introduced to require JEN to impose zero capacity exports, either across some or all of our customers, the BEL will be set to zero.

Customer response

Overall, our residential customers supported the two new suggested residential tariffs. Initially, they expressed a level of concern related to the export tariff, but once clarified it would be an opt-in-only approach for existing solar customers, they were supportive. Residential customers are supportive of the tariff as long as it remains opt-in.

The stakeholder forums conducted by the joint Victorian distribution network service providers spent most of their time building to and workshopping these residential tariffs. Stakeholders were broadly supportive of the proposed structure of the Daytime Saver ToU tariff while noting that customer education and consideration of the effects on customers experiencing vulnerability is crucial.

Stakeholders also supported the export tariff, noting that it may appeal both to sophisticated individual customers and retailers or aggregators who wish to combine their customers' electricity exports to offer to the market. They noted that the pricing levels of this tariff would need to be chosen carefully to avoid cross-subsidisation between customers who have opted into this tariff and other residential customers.

Retailer discussions have confirmed that they do not view the demand tariff as necessary or useful for residential customers, supporting its removal.

9.4.2 Small and medium business

At this point, the only change we are proposing to small and medium business customers' tariff structures is to remove the small business demand tariff, A20D. We heard from our customers that price certainty is particularly important to them. We are therefore proposing to maintain our existing tariffs, except for A20D, which only has 10 customers.

In collaboration with the other Victorian distribution network service providers, we released a small business consultation paper to the community and small business interest groups for consultation in June 2024, with responses received in July 2024. The paper sought views on:

- adjusting peak and off-peak windows for the small business ToU tariff
- reasons for introducing a solar soak period in the middle of the day
- whether customers should still be able to opt in to single-rate tariffs
- whether demand tariffs should be removed for small business customers
- the benefits of introducing export tariffs
- tariff assignment.

Customer response

Based on previous experience, small business customers are very time-poor, and their availability to consult in network tariffs is very limited. Attendees expressed a strong opinion on specific pricing or tariff topics. However, they expressed concern about the pace of change in the energy market, and whether the information they currently received from their retailer was sufficient. They were keen to understand how the energy transition would affect their retail bills, given the uncertainty in this area, the current price sensitivity, and the viability of solar panels, battery storage and the future of EV charging.

In June 2024, the Victorian distribution network service providers released a joint paper seeking input from stakeholders on small business tariffs. The common theme in responses was a suggestion that distribution network service providers consider solar soaks for small business customers. Our view is that most small business customers do not require an incentive to consume more electricity during peak periods of solar export as they consume most of their electricity during the day. Those who do not already consume their electricity during the day (for example, restaurants) will be unable to respond to the pricing signal by shifting their consumption.

9.4.3 Large business

By the end of the current regulatory period, all large customers will have been moved to a fully cost-reflective tariff, including a summer demand incentive charge (SDIC) component[80] as outlined in our current Tariff Structure Statement. This will allow us to remove the transitional tariffs for large customers, leading to an overall simplification of tariff selection for customers.

"We support simpler and more consistent tariffs and guidelines (in partnership with retailers and other Victorian distributors) which can be more easily explained to executive teams (e.g. around maximum demand and energy consumption)."

— Large customer

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80 The Summer Demand Incentive Charge is a tariff component targeted at reducing Large Business demand in the peak times of 4-7pm during the December to March period, the hottest months of the year.

Site-specific tariffs

We have a trial tariff in place to investigate site-specific pricing for our largest customers, connected at the subtransmission level. We will be converting this to permanent tariffs for the large business – HV and large business – subtransmission tariff classes. These tariffs will be available at JEN's discretion to customers whose load and/or usage profiles fall outside of the norms for their tariff class.

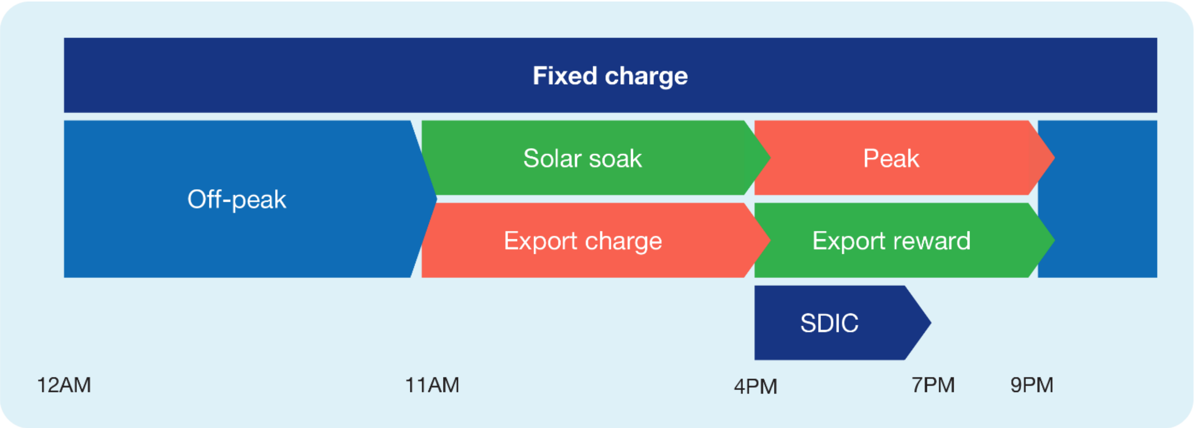
Community battery tariff

Community batteries are shared resources. They can store energy from connected solar customers in the community at times of peak solar output (i.e., in the middle of the day) and return electricity to the same consumers during network peak times when solar energy is less likely to be available and electricity is more expensive. This can also benefit the larger network by reducing network peak demand and preventing excess solar energy from entering the network.

While there has yet to be a widespread take-up of community batteries in Australia, they are on the cusp of becoming more prevalent, with both the Federal and Victorian Governments providing funding for trial community battery projects. As a distribution network service provider, we are interested in exploring community battery opportunities ourselves and supporting the projects of the retailers, councils and energy-focused community groups who have reached out to us for information on these batteries. To facilitate the uptake of community batteries, Jemena has offered a Large Business - LV community battery tariff as a trial since 1 July 2023. No customers are currently on this tariff, but this is expected to change, with four Jemena-owned community batteries and one community group-owned battery expected to come online in 2025. There are also further batteries expected in the pipeline in response to Federal and Victorian Government incentives.
The trial tariff is similar to the residential export tariff in structure, with the addition of a summer demand tariff component to discourage battery charging in times of peak demand, as demonstrated in

Figure 9.5. We note that the solar soak period for community batteries is currently attracting a bill credit, i.e. community battery customers are paid for consuming electricity during this period of peak solar exports. We intend to make this permanent as the large business – battery tariff, with the structure as shown in Figure 9.5.

Figure 9.5: Structure and timing of trial community battery tariff



The additional tariff components in the battery tariff are an export charge and an export reward, both of which are energy consumption components to be charged in *cents per kilowatt-hour (c/kWh)*. The export charge would penalise batteries exporting during the middle of the day solar soak period to encourage the battery operator to store electricity when it's of no use to the network. The export reward would give battery operators a bill credit for exporting during the evening period of peak demand. The SDIC component is intended to disincentivise the battery from charging in periods of peak demand and adding to the costs of our customers. This tariff would be available to customers with batteries up to 500 MVA, at JEN's discretion.

Customer response

In our large customer forums, customers expressed a desire for simple tariffs, with components that are easy to explain to non-experts in each business. Some customers also indicated that they find current tariff components difficult to respond to, meaning that price signals will not change these customers' behaviour.

We note that customers have raised concerns about the SDIC. This tariff component was introduced in the current regulatory period, in response to the AER concerns that our other demand charging components were not sufficiently cost-reflective in periods of peak demand. The SDIC aims to provide an incentive for customers to reduce their demand during the 4 pm – 7 pm peak period from December to March.

As the process of transitioning customers to SDIC tariffs is ongoing, we are not proposing further changes to large customer tariffs in the next regulatory period. We believe that further changing customers' tariffs so soon after implementing a large change would lead to more difficulty for customers, as the SDIC was introduced to ensure cost-reflectivity for large customers and its removal would warrant consideration of alternative tariff components.

10. Smart metering

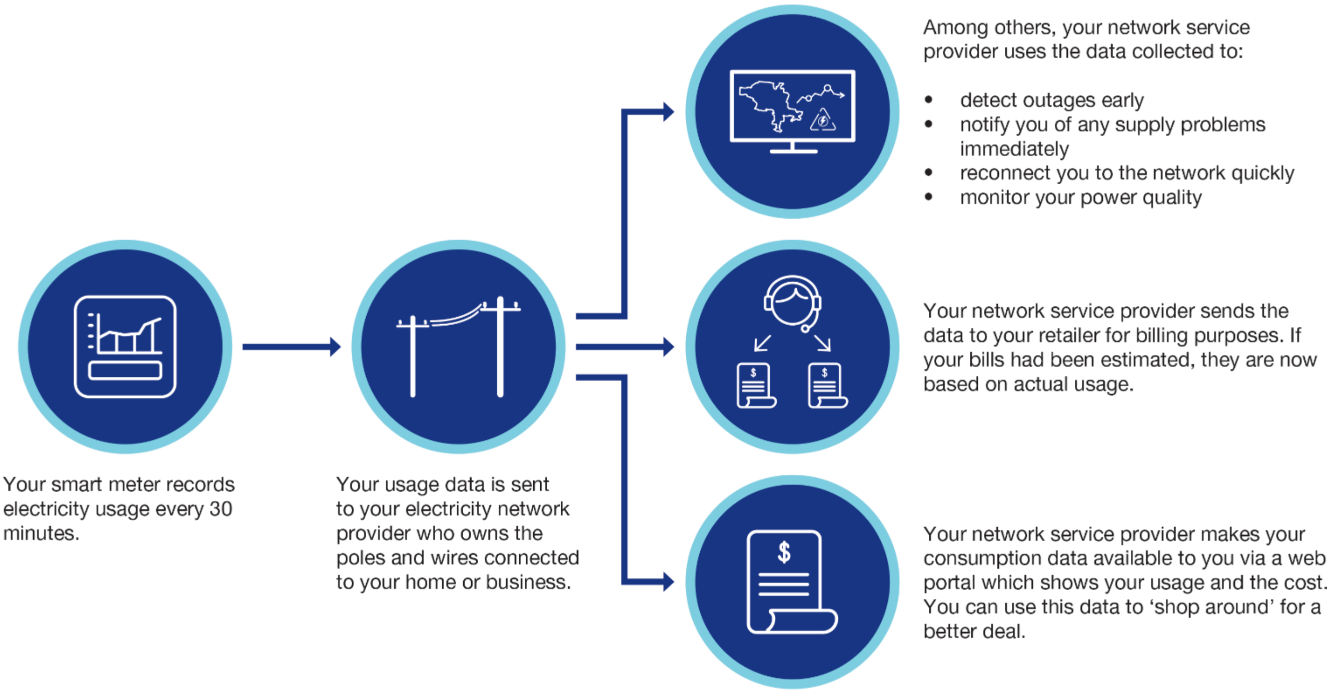
Highlights

- For the next regulatory period, we will provide smart metering services to approximately 387,000 customers. These services provide data for customers' usage and exports, which is used for billing, supporting other products and services, and monitoring the reliability, quality and safety of our network
- During the next regulatory period, we will manage the planned inspection and targeted replacement of aging smart meters to comply with our obligations. This includes inspecting all first-generation smart meters that have reached 15 years of service.
- Option analysis in our smart meter inspections and replacements business case shows that our proposed option of co-optimising our inspection obligations with targeted replacements supports the lowest metering prices by approximately an average of 5%.
- We forecast a total revenue requirement of $139.2 million for our smart metering services in the next regulatory period. This is 7% higher than our revenue requirement for the current regulatory period.

10.1 Overview

Advanced Metering Infrastructure (AMI) consists of a smart meter, which is an electronic meter that records energy consumption in intervals of 30 minutes or 5 minutes (for meters installed after December 2018) and a mesh communications network that transmits meter reading information back to us as the metering data provider for our customers. This meter reading information is then passed on to our customers' electricity retailer for billing purposes and to the Australian Energy Market Operator (AEMO) to settle the electricity market. Customers can also monitor their energy consumption in near real-time to help them better manage energy costs via JEN's portal. Figure 10.1 illustrates this process.

Figure 10.1: How customers, electricity retailers and distributors benefit from smart meters



Smart meters also capture power quality information, which can be used to manage the electricity distribution network more efficiently. For example, it can be used for remote analysis of customer power quality issues, detection of network issues for customer safety, and generation of regulatory compliance reports.

In Victoria, distribution network service providers are responsible for providing metering services for small customers. We own, install, and maintain the smart meters at customers' properties and provide the following metering services. Metering services:

- installation, operation, maintenance and replacement of smart metering installations (type 5, type 6 and AMI meters)[81]
- collection of meter data, processing and storage of meter data, and provision of access to meter data for type 5 and 6 metering installations, including AMI meters.

Only AMI meters connect to our mesh network; for type 5 and type 6 meters, we have dedicated meter reading staffs that attend a customer's site to read the meters manually. Currently, 99.7% of our meters are AMI meters, and we expect this to be 100% by the next regulatory period.

Under the regulatory framework that applies to Victorian distribution network service providers, metering services are categorised as alternative control services.

10.2 Customers benefit from smart meters

When it comes to AMI, we are constantly finding new and innovative ways to realise benefits from the data and services these meters enable, and we will continue to embrace the technological advances that accompany them. We also plan to leverage the infrastructure to further develop a smart, robust and efficient network in conjunction with our CER integration strategy (see Chapter 3) to meet ever-changing customer needs. Table 10.1 provides a summary of the benefits smart meters provide to customers.

81 Type 5 manually read meters record electricity consumption in 30-minute intervals and are manually read by a meter reader. Type 6 meters record accumulated energy data only and are also read manually. AMI meters record customer usage multiple times each day and are remotely read in intervals of 5, 15 or 30 minutes.

Table 10.1: Benefits of the AMI meters

Group Type	Benefit
JEN Customers	Remote meter reading - eliminates the need for manual meter readings, decreases the risk of human error and improves billing accuracy. This leads to more accurate energy bills and improved customer satisfaction.
	Remote connection and disconnection – we can connect and disconnect a customer's electricity supply remotely, reducing the cost and time required to provide these services.
	Enable connection of technology that connects new smart appliances to the AMI meter to facilitate home energy management.
	Enable customers to access their energy consumption data via JEN's Electricity Outlook portal and see how much electricity they are using and when they are using it. This allows customers to compare retail market offers.
	With real-time data on energy consumption, customers can make informed decisions about their energy usage, leading to increased energy efficiency. This helps lower energy bills and promote energy sustainability.
	Allows solar customers to monitor the amount of energy they export back to the electricity network. This provides an accurate measurement of their solar feed-in tariff and enables better energy consumption management.
	Develop and apply smart technologies to the operation of and investment in the electricity network.
JEN - Future Network & Planning	Provide information regarding consumption usage patterns, enhance the demand response, and improve electricity supply chain efficiency.
	Improved demand forecasts on the electricity distribution network allow JEN to target our capital spending more effectively.
	Enable the integration of energy generated by customers through distributed generation to support the energy transition towards a zero-carbon future.
	Advanced analytics – enabled by smart meter data provide JEN with rich data on energy consumption, generation and voltage performance. This data can be analysed to identify patterns, trends, and opportunities for network improvement. This allows JEN to make informed decisions about its operations and improve the overall network performance.
	Real-time monitoring will improve the health of the network, promote the safety to customers' supply services, and ensure ongoing conformance.
JEN- Network Operations	Outage management - Improve responsiveness to supply outages through automated outage notifications. This results in improved supply reliability for customers.
	Reduce hazards by remotely identifying poor connections. The AMI system allows us to detect if a customer has a faulty meter or overhead service that needs replacing.
	Planned switching activities - AMI data is used to verify and update JEN's Geographical Information System (**GIS**) mapping in its operating management system (OMS). This ensures the OMS accurately predicts the scope of JEN's planned network switching activities.
	Enable JEN to calculate outage times and durations. This information improves the calculation accuracy of our reliability metrics (SAIFI and SAIDI). It identifies the best and worst performing circuits enabling JEN to develop the most cost-effective action plan for future grid modernisation investments.
	Allows JEN to comply with regulatory obligations that explicitly call for AMI data as the source for performance reporting

10.3 Key developments that will affect our costs of providing metering services

Several factors will impact the cost of providing metering services in the next regulatory period. 78% of our smart meters will reach the end of their technical design life, which means they will need to be inspected and some of them replaced. Equally important is our customers' feedback on matters that may have direct or indirect implications on our costs of providing smart metering services in the next regulatory period.

10.3.1 Meter inspections and the aging AMI meters

The most significant driver of expected costs on metering services relates to our aging first-generation AMI meters. We deployed our AMI meters starting in 2009 when the Victorian Government mandated distribution network service providers to install smart meters at our small customers' properties. The design life of these first-generation AMI meters is 15 years, which means many of them are now reaching the end of their technical life. This end of design life will affect 78% of our meters over the next regulatory period, requiring that these meters be either:

- Physically inspected, or
- Replaced.

The following sections explain how we have optimised across these two end-of-life options to achieve compliance and meter reliability whilst minimising metering prices.

Compliance with regulatory obligations on meter inspections

JEN must undertake an onsite inspection of all meters that reach 15 years in service to ensure the ongoing integrity of the meter data being recorded and the safety of the electrical connections. For younger meters we do equivalent testing by conducting routine sample testing of meter accuracy and ongoing remote monitoring. Together these approaches mean all JEN's meter installations[82] are subject to periodic time-based inspections.

All current metering installations will be physically visited and technically inspected within the 5 years following the 15-year anniversary of their original installation (unless the meter is scheduled to be replaced in that 5-year period) and every 15 years thereafter.

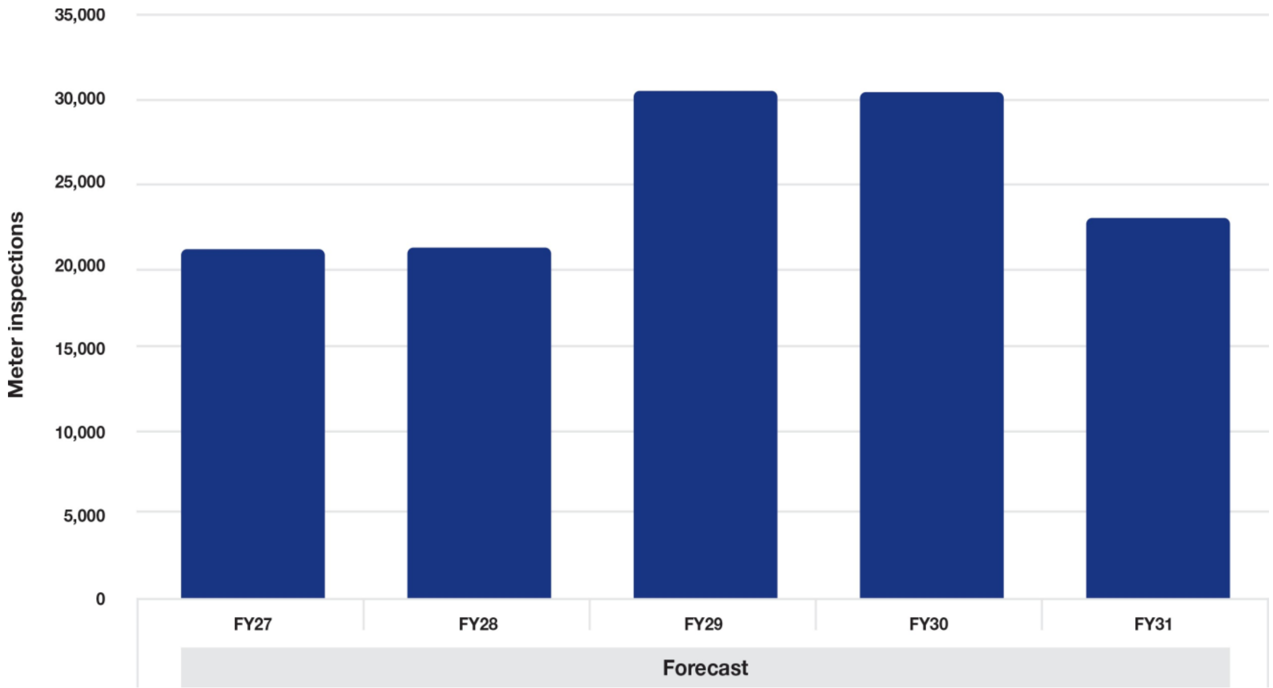
Our meter inspection plan is outlined in JEN's Metering Asset Management Strategy (MAMS) document which is approved by AEMO. We are required to audit our annual compliance with our MAMS and report this to AEMO.

Because JEN's AMI meter population began operating life in 2009 as part of the state-wide AMI rollout, the age profile of our AMI meters indicates that about 127,000 AMI meters are now due for visual inspection over the next regulatory period. This inspection figure is calculated by deducting the number of meter replacements from the number of age-based inspections, and so is less than the number of inspections we would require if we were not undertaking the targeted replacement program discussed below.

Figure 10.2 shows our forecast AMI meter inspections over the next regulatory period.

82 A metering installation comprises the assembly of components, including the instrument transformer, measurement element(s) and processes, recording and display equipment, and communications interface, that are controlled for the purpose of metrology and which lie between the metering point(s) and the point at or near the metering point(s).

Figure 10.2: Forecast AMI meter inspections



Replacement of aging AMI meters

We expect to replace 82,133 ageing AMI meters (22% of our total AMI meters) in the next regulatory period, if not, we expect they will fail by 2030. The 22% failure forecast is informed by:

- JEN's observed growth in the rate of meter failures and the associated analysis of the meter inspection and replacement business case
- the expected increase in failures when JEN starts visual inspections of 15-year-old Victorian AMI meters (which is outlined in the section below)
- detailed quantitative projections of failure rates commissioned from Frontier Economics, and
- review of local and international experience and discussions with meter manufacturers.

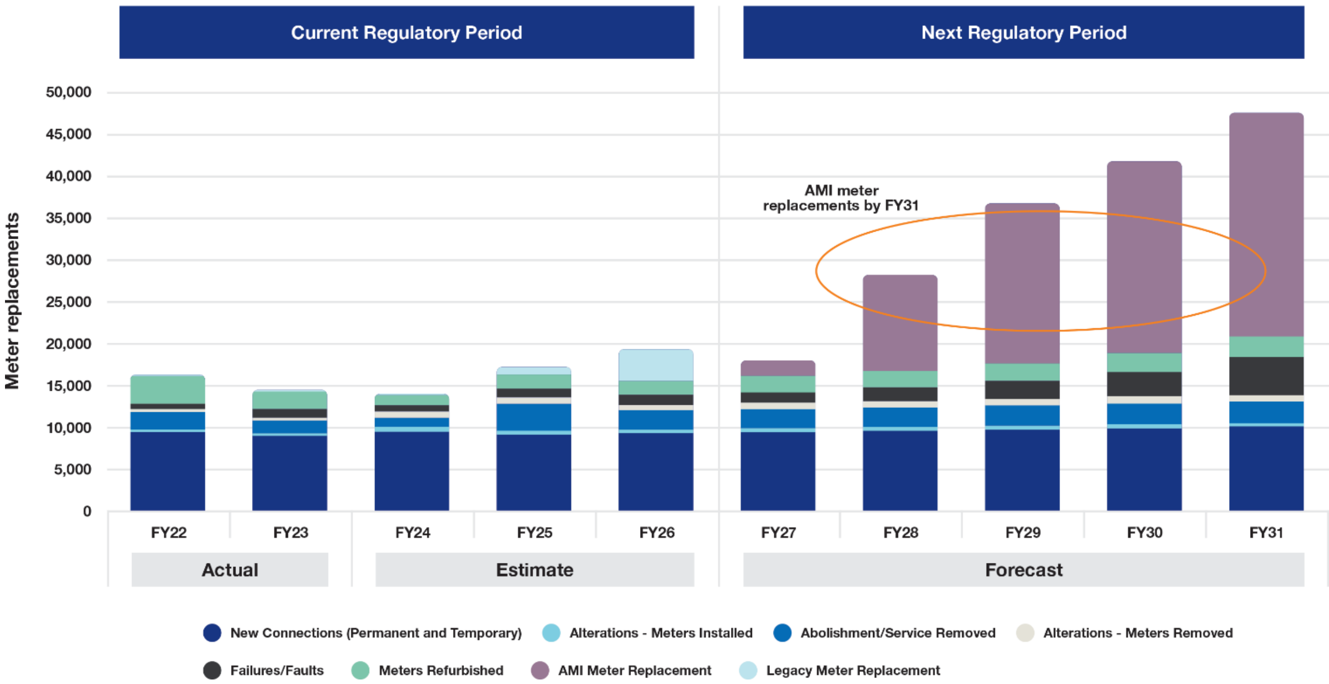
Replacement forecasts include the expected supply upgrades from single to three-phase meters that we anticipate coming from Victoria's electrification of appliances and vehicles that have relied on gas and petrol in the past.

We do not plan to rush out and replace all of our AMI meters on their 15 year anniversary. Instead, we will target replacing those meters that need to be changed.

This means we will extend the technical lives of most of our meters to get the most out of them and defer costs as a result. This approach balances the asset reliability risk and forecast cost risk between JEN and our customers.

Figure 10.3 shows JEN's historical and forecast meter replacements.

Figure 10.3: Historical and forecast meter replacements



To increase efficiency, we have co-optimised physical meter inspections (operating expenditure) and replacement activities (capital expenditure). That is, we will carry out site inspections with a level of proactive and reactive (whilst already on site in the field) AMI meter replacements.

10.3.2 Our customers' recommendations

In its response to our Draft Plan our Energy Reference Group supported our co-optimised approach to jointly meeting our aged meter inspection obligations whilst proactively replacing first generation smart meters that are found to be high failure risk.

While our broader customers did not have specific feedback about metering services, several of their recommendations require our smart metering fleet to remain operational and reliable. These recommendations are outlined in detail in Chapter 2 and include:

- Our Local Councils engagement identified that these stakeholders felt that: 'JEN should be supporting smart networks and providing valuable energy usage data to Councils and communities to inform decision-making'[83]
- Our Customer Voice Group expressed that: 'Young people want us to have fair and equitable tariffs for our customers and that customers who are exporting excess solar energy back into the electricity network, should have appropriate tariffs that reflect their needs versus customers without solar. This is important to young people so that customers without solar do not cross-subsidise those that have the benefits of solar'[84]
- Our People's Panel recommended (recommendation #5) that we implement "*digitisation and automation to increase economic efficiency*".[85] By integrating AMI with other technologies, we are better able to meet the objective of efficient investment and operations of the electricity network.

83 *JEN - Gauge Consulting Att 02-06 Local Council forum report – 20240106,* p.8.

84 *JEN - MosaicLab Att 02-04 Customer Voice Group process report - 20240107, p.20.*

85 *JEN - MosaicLab Att 02-09 Energy Reference Group process report - 20240105, p.44.*

JEN cannot deliver on these customer preferences without a reliable and well-maintained fleet of smart meters, which this proposal seeks to ensure will remain the case until 2031, at which point 78% of our first-generation smart meters will reach the end of their design life.

Many of our future network initiatives, aimed at connecting our customers to renewable sources of energy and accommodating more CER into our network, are integrated with our AMI. We will only realise the benefits of those initiatives with our reliable and functioning smart meters. Given this, we consider that our proposed metering services and annual revenue requirements will address our customers' expectations on digitisation and automation and championing renewable energy generations.

10.4 We are not proposing any changes to how we set our smart metering charges

Similar to our approach for calculating standard control services revenue requirements in the next regulatory period, we have used the AER's building block model to determine our annual revenue requirement for the provision of smart metering services. Our proposed annual revenue requirement is the sum of:

- return on capital (also known as the return on assets), which represents the benchmark return for investing in our AMI system. The return on capital for a given year is calculated by multiplying the rate of return by our forecast metering asset base at the start of that year
- regulatory depreciation (also known as the return of capital), which represents the payback of our investment in our metering system
- operating expenditure allowance, which represents the estimated prudent and efficient costs of operating and maintaining our metering system
- corporate income tax allowance, which represents the estimated cost of corporate income tax for a benchmark firm providing electricity distribution services.

See Chapter 8 on annual revenue requirements for a more detailed discussion of the building block method.

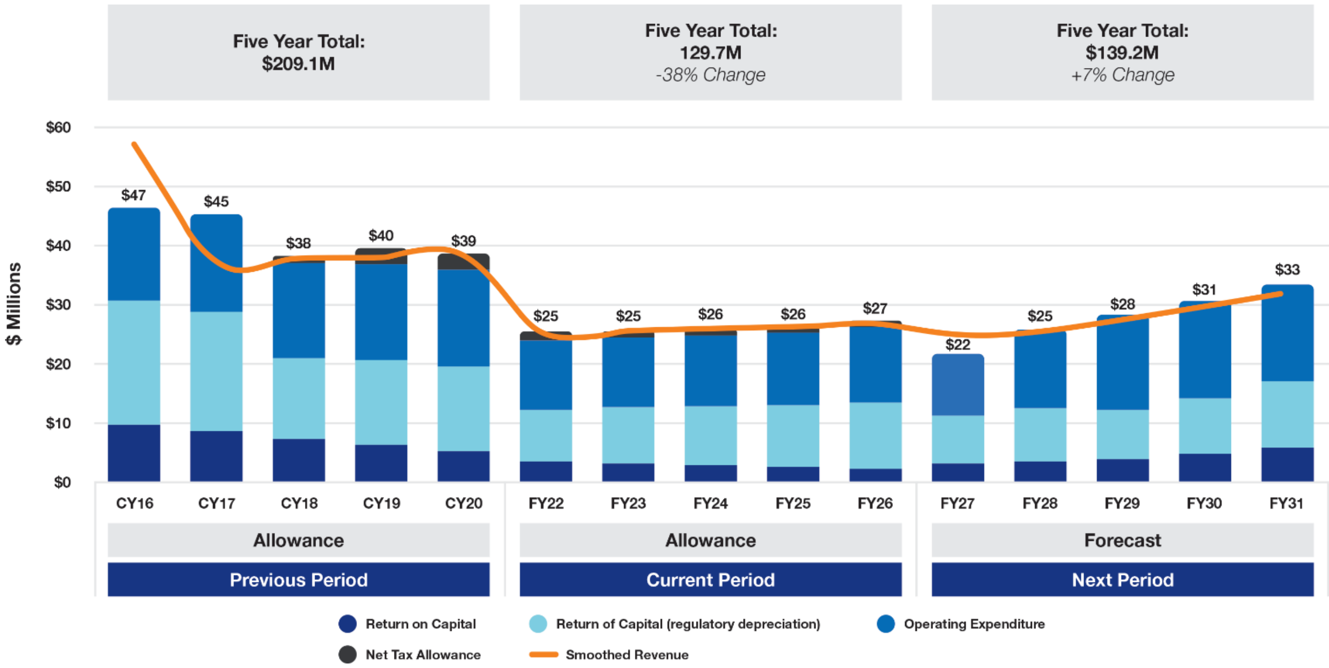
We propose to continue applying a revenue cap form of price control to our annual smart metering charges. Under this form of price control, our annual smart metering services revenue is capped for each year of the next regulatory period. If we under or over-recover our revenue in a regulatory year, we adjust the revenue and prices for the following year to reflect the difference. This ensures that over the five-year regulatory period, even though annual prices may change, the total revenue recovered for the regulatory period will not exceed the regulatory allowance.

Our approach to setting prices for metering services is relatively simple and follows the approach we have used in the current regulatory period. We take the revenue that we have calculated will be required to provide metering services and allocate it across the different meter types and divide it by the number of customers for each metering service.

10.5 Our proposed revenue requirement and what it means for customers

We forecast a total revenue requirement of $139.2 million for our smart metering services in the next regulatory period. This is 7% higher than our revenue requirement for the current period. Analysis of the three options in AMI meter inspections and replacements business case shows that our proposed option of co-optimising our inspection and replacements supports the lowest AMS metering prices. Figure 10.4 shows our historical and forecast revenue requirements for our metering services.

Figure 10.4: Revenue requirement for metering services, Real $2026, millions



The key drivers for our revenue requirement for metering services are meter replacements (capital expenditure) and in-person inspections of meters (operating expenditure). Despite the physical inspection obligations affecting our operating costs for metering, the average metering cost per customer across the five years is forecast to remain at $67 (in real terms) per customer.

> Refer to *JEN – Att 10-01 Advanced Metering Infrastructure* for our detailed advanced metering infrastructure proposal.

11. Other services

Highlights

- Other services include alternative control services other than smart metering services; it includes public lighting and ancillary services.
- We propose to increase the price we charge for Operation, Maintenance and Replacement (OMR) for public lighting by 1.3% for legacy lights and 43.2% for energy efficient lights. The price we propose to charge for council-funded energy efficient lights is forecast to decrease by 10%.
- Our proposed prices reflect our public lighting customers' recommendations that they be allowed to accelerate the LED rollout in a planned, coordinated and cost-effectively. The proposed prices also include the costs of implementing smart streetlighting technologies in the next regulatory period as recommended by our public lighting customers.
- We propose to change our approach to setting prices for public lighting services in the next regulatory period to use the AER's post-tax revenue model rather than the simplified building block model used in the current regulatory period. All else being equal, this change in approach should flatten public lighting prices over a longer period of time.[86]
- We propose to maintain our bottom-up build of costs for setting other services pricing.

11.1 Overview

In this chapter we give an overview of what influences our prices for the following alternative control services:[87]

- Public lighting services
- Ancillary network services, which include basic connection services and connection management services, among others.

The costs associated with providing these services are recovered directly from customers who request them. Depending on the nature of the service, these services are either charged on a fee or quotation basis. We propose to continue applying fixed prices for some services where the scope and cost of providing the service are similar between jobs. For the remaining services, prices will be quoted by way of a cost pass-through using the labour rates, along with material and contractor costs.

86 A key reason for this is that the AER's PTRM uses real straight line depreciation (and indexation) to determine the return of capital. This defers the return on capital when compared with the nominal straight line depreciation approach used in the cost build-up model, all else held constant.

87 Refer to Chapter 4 – Our Services for a full list of services we propose to provide

11.2 Public Lighting Services

We provide the following public lighting services to 13 local councils, and VicRoads:

- operation, maintenance, repair and replacement of public lighting assets in line with the Public Lighting Code (Code) or the relevant legislation[88]
- alteration and relocation of our public lighting assets
- provision of new public lights, including in greenfield sites
- provision, construction and maintenance of emerging public lighting technology.

We propose changing our approach to setting prices for public lighting services in the next regulatory period to use the AER's post-tax revenue model rather than the simplified building block model used in the current regulatory period. All else being equal, this change in approach should flatten public lighting prices over a longer period of time. The change has also allowed us to give effect to requests made by our public lighting customers regarding the accelerated LED rollout.

Notwithstanding this change, we propose to continue to develop the operating expenditure component in the pricing model using a bottom-up cost approach.

11.2.1 Operating, maintaining and replacing existing lights

Currently, we have approximately 78,500 public lights, comprising 19 different light types, installed in our electricity distribution service area, and we are providing public lighting services. These public lights are attached to dedicated poles (usually in newer residential estates) and power poles that are part of our electricity distribution network.

Under our public lighting management program, we plan to replace all our T5 luminaires and mercury vapour luminaires with light emitting diode (LED) and photoelectric (PE) cells over the next regulatory period. We also plan to replace some of our metal halide and sodium high-pressure luminaires with LED luminaires. Our public lighting program and corresponding costs for the next regulatory period have been informed by the following:

Our compliance obligations

The Code prescribes specific timeframes for replacing, repairing and maintaining public lights. The objective of the Code is to ensure that public lighting provides a safe visual environment for pedestrian and vehicular movement during times of inadequate natural light. We support the Code and comply with it. Our proposed replacement of luminaires with standard LEDs and PE cells in the next regulatory period is consistent with the requirements of the Code.

In addition, we must comply with the Minamata Convention, which Australia adopted in 2022. The Minamata Convention is an international convention designed to reduce the use of mercury in all aspects of our daily lives. This has implications for our public lighting service because mercury is present in some of the globes we use. In 2024, we have started replacing our compact fluorescent luminaires (CFL), metal halide (MH) and mercury vapour (MV) luminaires with standard LEDs when they fail. This replacement program will continue into the next regulatory period. Based on our replacement program, there will be no more mercury vapour luminaries by the end of the next regulatory period.

We are also subject to guaranteed service level obligations under the Code, which impose a financial penalty on electricity distribution network service providers if we do not repair a public light within two business days of a fault being reported or a period otherwise agreed with the customer. As such, the guaranteed service level is an important consideration in the development of our replacement and expenditure programs and plans.

88 Essential Services Commission, Public Lighting Code, Version 2, December 2015.

> Our regulatory proposal maintains our view that MV, MH and T5 luminaires should be replaced during the next regulatory period. Our proposal include these replacements. This approach is supported by our public lighting customers.
>
> We also accepted our public lighting customers' recommendations that we treat 3000k lighting as standard offering starting the next regulatory period.

Technology and market developments

Many cities around the world are investing in "smart city" technologies for street lighting, with sensors, cameras, data analytics, and other advanced features integrated into lampposts to improve public safety, monitor air quality, and provide other services, such as EV charging.

LED street lighting has gradually been adopted as LED produces the same level of brightness as high-intensity discharge lighting.[89] LED lighting delivers benefits to customers as it is highly energy-efficient, reducing energy consumption by up to 70% compared to traditional lighting technologies. LED lighting is also highly versatile, with the ability to produce a wide range of colours and lighting effects, and it can be easily controlled and dimmed when it is considered appropriate.

However, our approach to public lighting is customer-driven, which means we work with local councils and VicRoads to ensure that we embrace technological developments that meet our customers' needs. We will work closely with our public lighting customers to understand their preferences for adopting smart technologies and take these into account in our proposed programs and plans for the next regulatory period.

> In response to our public lighting customers' feedback, we propose to implement Street Light Vision (SLV) during the next regulatory period. SLV is a software application that delivers advanced asset management, analytics and control capabilities to improve energy efficiency and optimise smart streetlight system performance. Once implemented, it will allow councils to directly manage its public lighting usage and reduce costs while improving public safety.
>
> Our proposal includes the costs of implementing SLV.
>
> The speed of the implementation of the SLV will depend on the rate of the LED rollout. This is because, the required hardware for the SLV will be installed when existing lights are replaced with LED in order to save on costs.

Our recent operating experiences

Our replacement program in the next regulatory period is also driven partly by emerging operational and performance issues with particular lamp types that have emerged during the current period, such as:

- MV lamps contain excessive quantities of mercury beyond the acceptable limits; therefore, manufacturing and installation of these products will cease in Australia.
- The demand for CFL has reduced, and, as a result, manufacturers are ceasing production of CFL lighting, terminating future supplies.
- MH lamps are being replaced, given their small numbers and inferior performance. Maintaining stock levels is also problematic, as small quantities prove difficult to source from suppliers.
- Latest information from suppliers also indicates that the market is phasing out T5 lamps. While the majority of our T5 luminaires are mid-way through their 20-year expected service life, we consider it prudent and efficient to take a proactive replacement approach, given the supplier issues. We plan to replace all our T5 luminaries with LEDs during the next regulatory period.

89 High-intensity discharge (HID) lamps operate by creating an electrical discharge in the ionised gas. They are generally used in commercial and industrial applications where high levels of light are required, such as warehouses, outdoor lighting, street lighting, and stadium lighting.

We currently have a bulk re-lamping program that schedules lamp replacement on a four-year cycle in accordance with the Code requirements. This timing ensures that lamp replacement occurs at a point-in-time when the light output from the lamp is nearing its minimum required output levels. This approach is lowest cost for our public lighting customers as lights are replaced just in time and not replaced prematurely.

However, our public lighting customers also recommended the accelerated rollout of LED during the next regulatory period. Accelerating the LED rollout means that we will also need to replace over 30,000 legacy lights with LED's during the next regulatory period regardless of their existing asset life and condition.

Our view remains that it is more prudent and efficient to transition the LED rollout during the next regulatory period. This means that we will replace the existing lights with LED under our normal maintenance cycles to help reduce costs. But as we noted in the Draft Plan and public lighting consultation paper, our approach to public lighting is customer-driven and that we would work with local councils and VicRoads to ensure that we meet our customers' needs.[90]

We support our public lighting customers' recommendation for the accelerated LED rollout and propose they fund the accelerated LED rollout program. We have developed a pricing model which reflects this approach. For more details refer to:

- Section 3 of Attachment *JEN – Att 11-02 Public lighting*
- Attachment *JEN – Att 11-05M ACS Public lighting model*
- Attachment *JEN - Att 11-06M ACS Public lighting inputs model*

We will work closely with councils on the process and protocols (regarding specifications, installers and project management) to be followed.

90 JEN, *2026-31 Draft Plan*, August 2024, p.135.

11.2.2 Our proposed approach to public lighting is customer driven

We are strongly focused on understanding and responding to the public lighting needs of local councils and VicRoads. We had a productive workshop and engagements with them starting from August 2023 until November 2024. These engagements helped us to clearly understand our customers' expectations with regards to public lighting services and we have captured these expectations in this regulatory proposal.

We summarised in Table 11.1 our public lighting customers' key recommendations. We discuss their feedback in more detail in Attachment *JEN - Att 11-02 Public lighting services - 20250131 – Public*.

We anticipate further consultation will take place with our public lighting customers throughout 2025 and prior to the AER making its price reset determination for the next regulatory period to refine the services and prices.

Table 11.1: Summary of our public lighting customers' feedback

What our customers told us	Our response
Accelerate LED rollout	Accepted – our price modelling reflects this approach
Implement smart street lighting technologies	Accepted – our price modelling includes the implementation of Street Light Vision
Treat 3000k lighting as standard offering	Accepted – this will be made available during the next regulatory period
Decorative poles should remain non-standard	Accepted – we will continue to recover the incremental costs of decorative poles directly from those councils who require decorative replacement poles
Improve processes for maintenance, share more information and guidance to councils	Accepted. We will review our internal processes and consider changes to address our customers' suggestions

11.2.3 Relative price impacts

We have modelled the OMR prices across the three light classes, these include, Legacy Lights and Energy Efficient Lights, which exist in the current regulatory period, and Customer Funded rollout lights which we are introducing in the next regulation period in response to our public lighting customers' recommendations.

We group charges into these three classes as they are homogeneous and reflect the distinct levels of timing and of investment made by our public lighting customers into the public lighting system. It also reduces cross subsidisation of costs between public lighting customers. The price change across each class of light is outlined in Table 11.2 below.

Table 11.2: Price change (%, nominal)

	FY26	FY27 to FY31
Legacy Lights	1.3%	2.5%
Energy Efficient Lights	43.2%	2.5%
Customer Funded rollout lights	-10.1%	2.5%

Prices across these three lighting classes change significantly in the first year of the next regulatory period for the following reasons:

- **Legacy Lights**. The declining population, relatively low unit costs and low remaining asset value results in a relatively lower asset value to recover.
- **Energy Efficient Lights**. Replacing all legacy lights when attending site results in an acceleration of the replacement capital expenditure for the three years of replacing legacy lights with LED lights.

  The accelerated roll out cost is compounded by a higher unit cost per luminaire and installation of the SLV devices relative to lights in the legacy category.
- **Customer Funded rolled-out lights**. Capital expenditure for this category is very low as all new lights installations are gifted to JEN.

Our forecast expenditure for public lighting also takes into account changes in the real cost of labour, changes in the costs of materials, the failure rate of lights, and an adjustment to the time taken to replace and maintain lights—to better reflect the actual duration of that work.

New public lights

We will make offers to customers requesting new public lighting consistent with the requirements of the Code.

11.3 Ancillary network services

The costs associated with providing ancillary network services are recovered directly from customers who request them, consistent with the AER's Electricity Distribution Services Classification Guideline.[91] Depending on the nature of the service, it is either charged on a fee or quotation basis. We propose to continue to apply fixed prices for some services where the scope and cost of providing the service are similar between jobs. For the remaining services, prices will be quoted by way of a cost recovery using the labour rates, along with material and contractor costs.

Consistent with our current approach, we will charge a fixed fee to cover the costs we incur in completing the work for basic connections, where little or no augmentation of the network is required. This is in line with our responsibilities under Chapter 5A of the NER and the AER's Connection Charge Guideline. We charge a fixed fee for basic connections because the work we must carry out and the costs we incur in doing so are relatively constant.

We developed our proposed ancillary service prices using the AER's standard ancillary services model.

See Attachment *JEN – Att 11-01 Alternative control services*, and *JEN – Att 11-04M ACS Fee based and quoted services model* for more details.

91 AER, Electricity Distribution Service Classification Guideline: Final guidelines, August 2022.

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