Regulatory proposal 2021–2026

Affordable, resilient, flexible

January 2020

CITIPOWER

Good people in power

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1 Executive summary

Welcome to our 2021–2026 regulatory proposal.

We are proud to present a regulatory proposal that offers our customers more value than ever before. We'll deliver more services to supply a network that is resilient and more flexible to the ways our customers are choosing to use electricity. And we'll deliver more for less; our annual charge will fall by $38 for residential customers and $119 for small business customers.

Our operating environment

We've never faced such a challenging operating environment—for example:

- more extreme climatic conditions are making it harder to deliver a safe and dependable network
- a heightened level of cyber threat is underpinning the need to reinforce the systems supporting our network and protect customer data
- a more dynamic market is necessitating an improvement in network visibility and the provision of more data to market operators and our customers
- stricter environmental requirements are resulting in a more proactive approach to oil and noise management.

Our customers are also calling for more flexibility in the way they use our network—to both receive and export electricity—and for more information on their electricity interactions. And they rightfully expect a resilient network to meet their increasing use of electronic appliances and devices.

We are embracing these challenges while still promising to reduce our prices. Our customers can have confidence in our ability to deliver on our promises because we:

- already offer the second lowest network charges in Australia
- are Australia's most reliable network—available for over 99.99% of the year, or less than 20 minutes of unplanned outages for an average customer
- are the second most efficient distributor in Australia according to the Australian Energy Regulator's (**AER**) benchmarking
- provide the most highly utilised central business district (**CBD**) and urban network, meaning we provide more services for less
- will pass on $233 million in savings to our customers from efficiencies we have delivered over 2016–2020.

In addition to our continued productivity enhancing transformation activities, we will also lower our prices by leaning more on technology than ever before to drive further efficiencies and services.

This is also the most balanced proposal we've delivered. We've listened to our customers from across our area to deliver fairer service outcomes, and it is in this context we believe our regulatory proposal should be considered as a package rather than the sum of its parts. We're responding to our community by accommodating new trends in distributed energy resources, reinforcing CBD security and reliability, and upgrading zone substations to accommodate customer growth.

We understand our regulatory proposal may not make it to your summer reading list, but we hope that everyone can take away something positive from it.

Every day we supply electricity to power our customers' activities

Replacement

Our replacement investment program ensures we can maintain our network to dependably power our customers' activities. This is supported by the following programs:

- $59 million for replacing more wood poles—we've changed our policies to better quantify degradation in wood pole strength as these poles age. This followed a review undertaken by Energy Safe Victoria (**ESV**) for our Powercor network, which is equally applicable to CitiPower. These changes will help to deliver a resilient network; a concept developed by our customers that combines safety and reliability.
- $71 million environmental management program—new environmental obligations will require us to proactively prevent waste and pollution impacts. Our forecast includes noise reduction and bunding programs at high-risk zone substations.
- $14 million CBD pits refurbishment—some our underground cable pits, that facilitate the installation and maintenance of our cables, were installed in the 1930s. Corrosion of the supporting steel structures now means there is a risk of pit roof collapse. This could result in injury to the public and so we will be refurbishing them.

Our forecast asset replacement volumes are typically based on risk monetisation modelling, historical defect rates or historical replacement volume trends. This approach follows our asset management framework that aligns to international standards.

We have provided business cases and risk models to support 68% of our investment, particularly where our investment is higher than historical investment.

Connections

Our connections investment is needed to prepare the network for new customers. We are seeing:

- 17,700 new household connections over the 2021–2026 regulatory period
- large infrastructure such as the Victorian Government's Westgate Tunnel project driving gross connections investment until 2022/23.

Our forecast is underpinned by independent and robust construction activity forecasts and historical investment needs.

We are preparing the network to be flexible to our customers' energy needs

Augmentation

Our augmentation investment ensures we can accommodate the ways our customers are choosing to use the network. This includes the following programs:

- $32 million for enabling solar—removing over 95% of the solar constraints (the equivalent output of around 2.4 large scale solar farms across our three networks) to enable more customers to use their solar and support the Victorian Government's solar rebate. We have undertaken advanced modelling using our smart meters to ensure we only remove constraints where the benefits to our customers exceeds the cost.
- $26 million for reinforcing the CBD supply—we're re-developing the Tavistock Place zone substation to ensure customers remain on supply in the event of an asset failure in accordance with our commitments and have the capacity to continue to connect our large customers.
- $48 million to meet growing network demands—we'll undertake offload works to accommodate Brunswick's transition from low-density residential housing to high-density apartment buildings. We'll also undertake works to facilitate the transformation of the Fishermans Bend area from industrial land into a modern development of inner Melbourne. Upon completion in 2050, a residential population in excess of 80,000 with provision of 40,000 jobs are expected.

Our demand driven forecasts are underpinned by a probabilistic planning approach under which we compare the cost to customers of an outage to the cost of an upgrade.

We have developed detailed business cases to explain the need for 71% of our augmentation program.

Information and communications technology

It was only 150 years ago that illumination was met by burning whale oil, a luxury only available to the wealthy. Imagine our electricity needs in another 100 years. The market is evolving quickly and we are leaning more on technology and data to deliver electricity more flexibly and efficiently. Our customers are also asking for a better understanding of their electricity use and interactions with the network. In support of this we will develop:

- $11 million digital network program—we are responding to the transformation underway by building a smarter network that predicts and manages power flows on the low voltage network, ensuring we can run the network safely and more efficiently in the face of changing demands such as electric vehicles.
- $13 million SAP upgrade—our existing SAP program will be nearly 20 years old and unsupported by the vendor. Given the criticality of this program to the operation of our network, we will upgrade this product to ensure the continued functionality of our network programs and corporate functions.
- $9 million for five minute settlement—we will be required to provide five minute interval data for market settlement purposes, improving price efficiency in the generation market. System changes are required for us to collect and validate this data.

All our information and communications technology (**ICT**) investments are supported by business cases demonstrating the customer benefits from the programs and risk monetisation analysis where possible.

Property and fleet

Property and fleet investment is necessary to support the effective operation of the network for our customers. We will undertake:

- $15 million security and compliance upgrade—to protect critical infrastructure in response to heightened risks
- $4 million fleet replacement—in line with historical investment we need to maintain our fleet including cranes, elevated working platforms, trailers, crane borers and fork lifts.

We have undertaken a bottom-up approach to forecast our property requirements.

Operating expenditure

We already operate the second most efficient network in the National Electricity Market (**NEM**). As a result, being part of the CitiPower community means having among the lowest networks charges in Australia. It also means we have limited ability to absorb increases in operating costs. We are seeking a step up in our operating expenditure to manage new legislative and compliance requirements, which include:

- $14 million for new Australian Government obligations to move all customer and employee data related services onshore
- $14 million because Yarra Trams is relocating its poles on which we house assets
- $6 million for new Environment Protection Authority regulations leading to more preventative environmental measures.

Our forecast operating investment is based on the AER's base-step-trend approach with 2019 being our representative 'base' year.

We are maintaining affordability by keeping our prices low

Revenue

We are proposing that real revenue decline in 2021 and thereafter remain constant. This will lower prices by $38 for our residential customers and $119 for small business customers. We will deliver this by:

- lowering our borrowing costs compared to the 2016–2020 regulatory period
- driving efficiencies through leaning on technology to make better decisions about our network
- finding ways to reduce costs in light of the AER's reduction to tax allowances.

We have a strong track record of responding to the AER's incentives to reduce costs, but these are becoming increasingly difficult to find. Specific actions we undertook over 2016–2020 to deliver $233 million in savings to our customers included:

- re-tendering many of our outsourced services such as inspection and vegetation management
- where it was found efficient through market testing, we insourced functions such as some regional field operations and outsourced others such as information technology (**IT**) support and project delivery, and a number of design activities
- automating works scheduling and dispatch to improve the utilisation of our field resources and fleet
- reducing the size of corporate functions including finance, customer service, regulation and human resources
- re-considering our planned investment in a billing system in light of new policy developments and acquiring the United Energy network, which means there is potential to migrate to its system.

The majority of these transformation programs are not repeatable, meaning we will need to consider more innovative and risky ICT solutions in the future. For 2021–2026 we have included a number of these more innovative ICT projects and reduced our investment requirements accordingly.

Metering

We will reduce our metering charges by around 21% and continue to ensure our customers benefit from smart meters through a number of services we already support. These include:

- faster restoration of faults—we receive immediate notification of outages which allows us to dispatch crews often prior to a customer even becoming aware of an outage.
- safer supply of electricity—we have developed an algorithm to identify potential loss of neutral at our customers' homes to prevent 'tingling taps' which pose an electric shock risk. Twice a day (and soon to be every 15 minutes) our algorithm checks all our customers' homes. In just under a year of operation, we have already detected and resolved over 500 deteriorated neutrals.

Over the 2021–2026 regulatory period, we will also implement better network load profiling, identification of safety risks and better enable more distributed energy resources on the network through the voltage data provided from these meters.

These benefits ultimately deliver our customers lower network prices and better services.

We are supporting customers' energy choices through fair and simple charging

Our proposed changes to household tariff structures seek to accelerate the pace of reform without jeopardising the stakeholder support that is crucial to enable change.

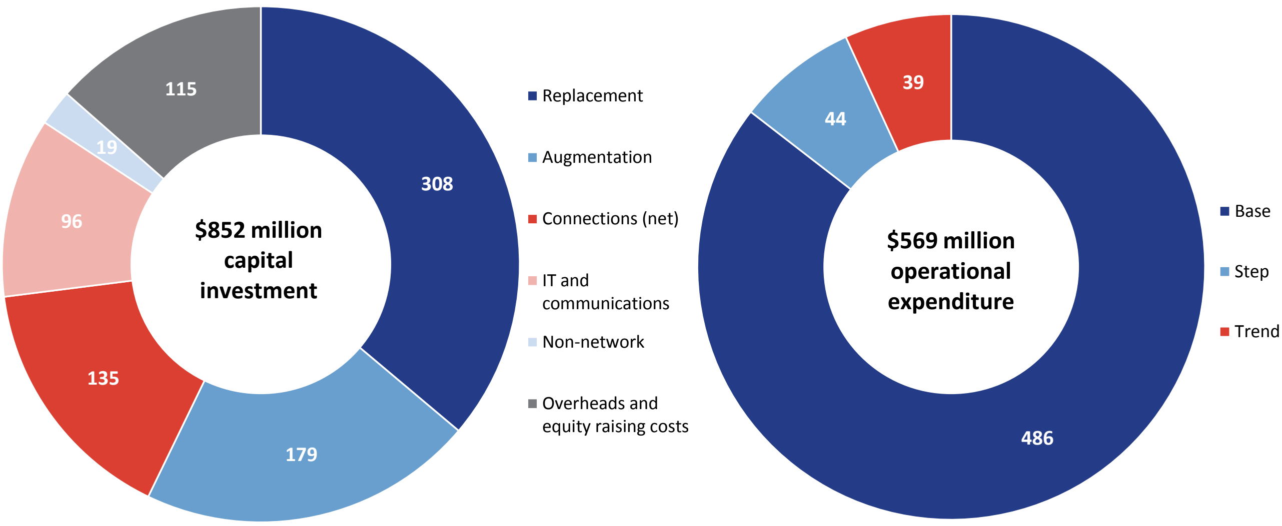
For residential customers, we will introduce a new two-rate tariff for new customer connections, customers seeking supply upgrades to three-phase and customers installing solar or batteries. The objective is to encourage customers to move discretionary electricity use into off-peak periods, when the network is under less pressure. Feedback from our customers strongly preferred the simplicity of a two-rate tariff.

We will change the default tariff for small business customers from a single-rate tariff to a two-rate tariff. And for large business customers on demand tariffs we will change how demand is measured—from ratcheting demand to rolling demand.

Snapshot of our 2021–2026 forecasts

We have considered our forecasts in totality to ensure this proposal delivers the affordability outcomes our customers are seeking. To that end, we are reducing our total revenue compared to the 2016–2020 regulatory period by 5%, while providing more services. Our capital and operating forecasts are summarised below.

Capital and operating expenditure summaries for standard control services ($ million, 2021)



Source: CitiPower
Notes: Includes real escalation. Disposals are netted off non-network investment. Productivity is netted off trend.

Our revenue building blocks are summarised below (modelled in nominal terms, consistent with the AER's revenue models).

Revenue requirement for standard control services ($ million, nominal)

Building blocks	2021/22	2022/23	2023/24	2024/25	2025/26
Return on assets	96.3	99.4	101.4	103.6	104.8
Regulatory depreciation	66.3	73.2	80.4	88.0	95.2
Operating expenditure	113.2	117.8	122.3	126.3	132.0
Incentives	15.4	11.7	7.3	8.1	13.6
Corporate income tax	9.4	7.7	6.0	6.7	6.9
Unsmoothed revenue requirement	300.5	309.8	317.5	332.7	352.4
Revenue X factor (%)	**4.7**	-	-	-	-

Source: CitiPower
Notes: A positive X factor means a real revenue decrease.

This regulatory proposal is for the five year period commencing 1 July 2021, and is supported by the business cases and attachments listed separately in appendix 10 (CP APP10).

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We want customers to choose how they use electricity

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2 Stakeholder engagement

To enable our customers to use electricity in the way they want, we asked them about their preferences.

In today's rapidly changing energy market there's never been a more critical time for us to understand and respond to our customers' needs. We want to move beyond telling our customers what we're doing, to ensuring our proposal delivers what they want and need. This will allow us to anticipate and respond to our customers' changing preferences, support their energy choices, and provide better solutions.

We've been talking to our customers and key stakeholders about the development of our 2021–2026 regulatory proposal through our engagement program called 'Energised 2021–2026'.

Energised 2021–2026 started early, more than three years prior to submitting our regulatory proposal. We wanted to give customers plenty of time to engage with us, talk about their needs and review our plans. Starting early also allowed us to publish our draft proposal 11 months prior to submitting our regulatory proposal.

2.1 Our engagement objectives

Our core objective in designing Energised 2021–2026 has been to listen to our customers and stakeholders more than ever before.

To do this we created a program that reflects the IAP2's inform, consult, involve and collaborate phases of engagement. We have strived to listen and educate, share alternative futures and investment options, support customer choices and provide better solutions.

Our objectives for engagement and integrating feedback into our proposal are outlined in the table below.

Table 2.1 Engagement objectives

	Awareness	Meaningful influence	Improve long-term outcomes
What we wanted to achieve	Achieve a level of awareness of our organisation, our role and the regulatory framework in which we operate.	Gather customer and stakeholder inputs and allow them to have meaningful influence on our proposal.	Actively involve customers and stakeholders in the process so we could understand changing views and preferences, and improve long-term outcomes.
What this meant for our five year plan	Deep insights into customer perspectives on everyday lifestyle changes implicated in different energy futures, both in terms of demand side and supply side changes.	Understanding of the key points of agreement and difference regarding considerations and trade-offs in developing our energy future.	Active involvement of customers and stakeholders to understand changing views and preferences and to improve long term outcomes.

Source: CitiPower

2.2 Our journey with our customers during Energised 2021–2026

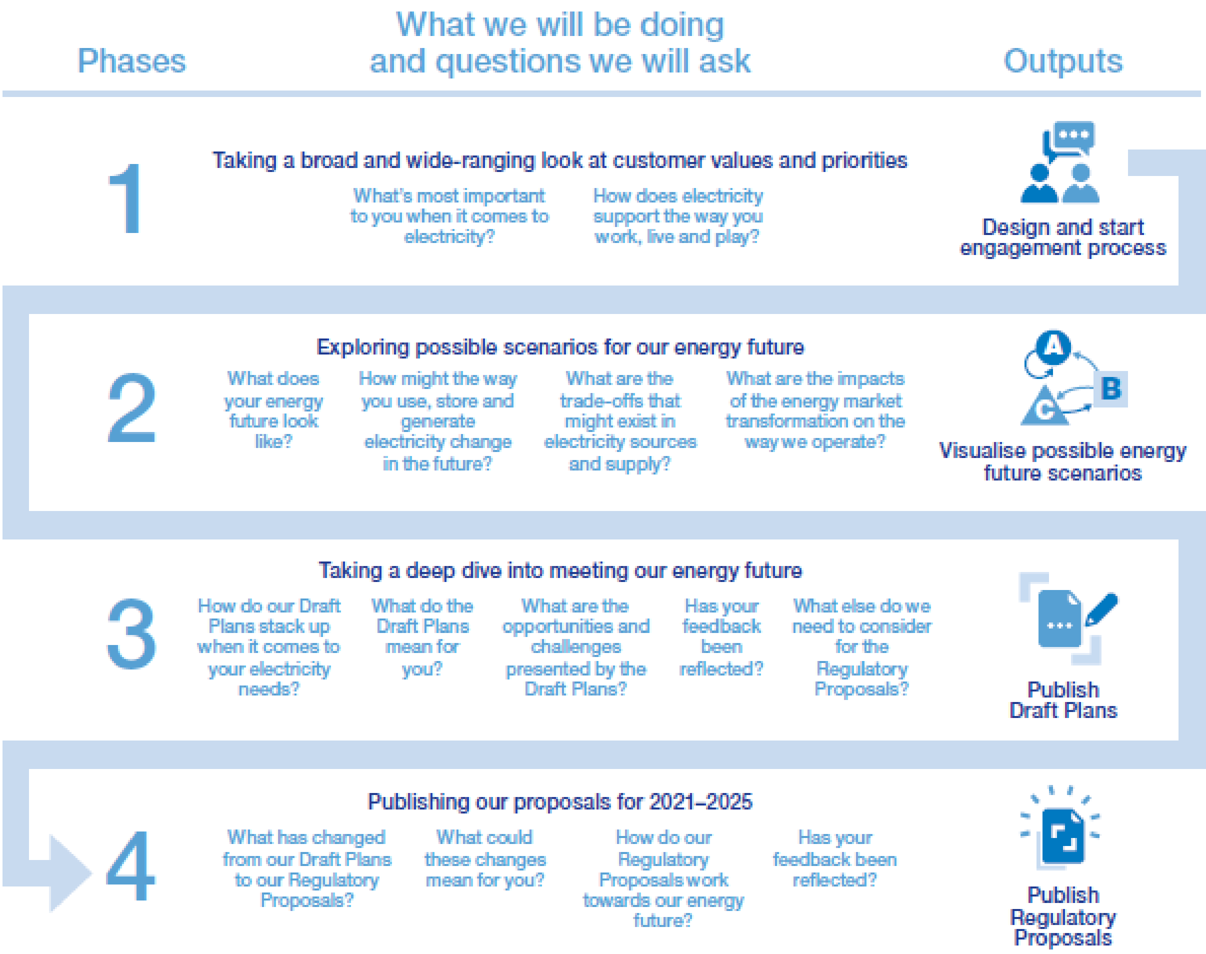
Energised 2021–2026 is designed to take our customers and stakeholders on a journey—sharing their energy values and preferences, deliberating with us on the network's current and future challenges and assessing real-life investment options and trade-offs.

Our approach is innovative—we have used deliberative democracy methods with forums and polling to involve our customers in deep knowledge building, and immerse them in our decision making processes. Our customers have evaluated real world costs and benefits of new or revised approaches to service delivery and network management.

2.2.1 Engagement phases

There were four key phases that guided the design and delivery of the customer and stakeholder engagement as shown in figure 2.1.

Figure 2.1 Engagement process



Source: CitiPower

In the 11 months since we published our draft proposal, we have continued to engage on the various issues, particularly a number of marquee projects such as solar enablement, digital network and customer enablement, which are discussed in our proposal.

2.3 Our engagement activities and reach

We undertook a range of engagement activities and reached out to a large number of our customers. These are summarised in table 2.2.

Table 2.2 **Summary of engagement activities**

Activities	Purpose of engagement	Metrics
Talking Electricity website	A centralised online hub for important information, updates and news about our progress	20,844 page visits
Newsletters	Provide updates on our progress throughout the process	489 subscribers
Pop up displays	Provide information, subscribe new customers and seek insights about energy usage	Pop up display in Melbourne with 220,000 reported foot traffic
Focus groups	Collect exploratory insights on values, customer priorities for the future, renewables, electricity bills and customer impacts	Focus groups held in Richmond and South Melbourne
Interviews	Discuss energy futures, impacts to business, connections, tariffs, energy sources and future investment plans around energy	17 interviews
Surveys	Understand values and preferences on key issues Understand scope, limits and level of support for some of our flagship programs in the proposal	2,656 surveys with residential and businesses with access to insights from 7,793 surveys across our three networks
Meetings	Detailed discussion about our proposal	714 meetings with 2,353 interactions
Workshops	Discuss and decide on the approach to topics like pricing, data, renewables and connections	547 participants over 30 workshops
Citizen led deliberative forums	Dynamic forums for the public to hear from experts about energy futures and provide feedback on their values, the trade-offs, customer impacts and priorities	234 participants during 4 deliberative forums
Future Networks Forums	Co-design energy futures to test with customers and ensure we prepared possible and plausible options for discussion Discuss options to enable solar exports, demand response programs and incentives to encourage customers to shift their energy load	78 participants in two joint network forums
Advisory Panel	Detailed discussion about all elements of the proposal including approach, modelling, insights, market trends, regulation, pricing, connections, community safety, renewables, customer impacts, performance, the draft proposal and our proposal	1,120 interactions with customer reference panel members 18 panel meetings with our customer reference members
Draft proposal and engagement reports	Cover the insights we've collected along the process, how feedback has been considered and how we'll work towards the proposed energy future	Draft proposal published for CitiPower and viewed 1,250 times
Podcast	Inform customers about the proposal purpose and what it includes	319 podcast listens across our three networks
Open house	Opportunity for local government and other community opinion leaders to learn more about the draft proposals and give input	5 community opinion leaders and local government representatives

Source: CitiPower

To help customers engage with us, we also developed a new tool to compare elements of the regulatory proposal and their impact on the average bill. This provided us with insight into customer preferences and priorities in the context of a trade-off between different services and affordability.

2.3.1 A wide range of views

To ensure our engagement process was inclusive, we listened to a range of voices, including the hard to reach and not just the 'usual suspects' such as:

- community leaders to understand their specific issues
- culturally and linguistically diverse, and vulnerable customer groups through a range of bespoke engagements
- small and medium business enterprises participated in surveys and deliberative workshops with our residential customers
- targeted interviews with our commercial and industrial customers.

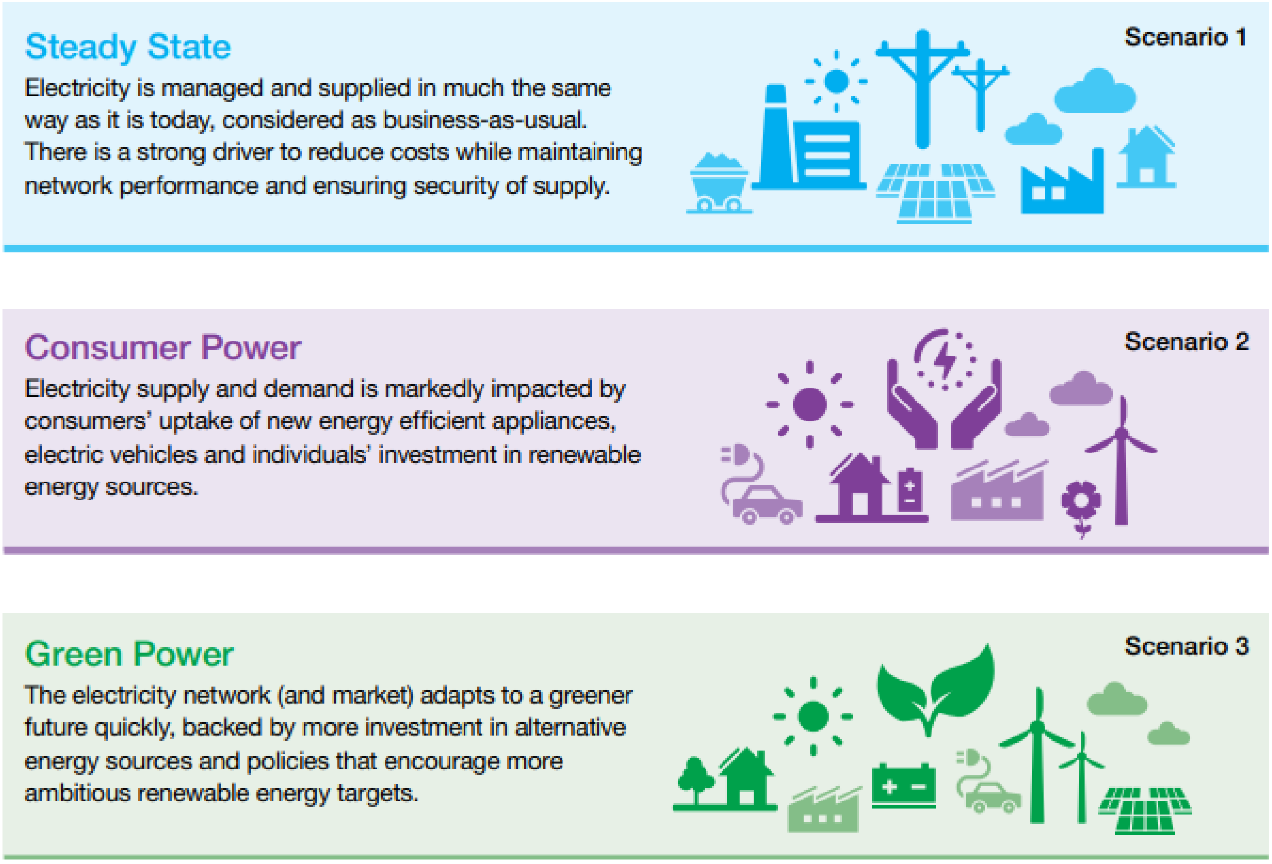
We also recognised the need for a dedicated advisory panel capable of representing the perspective of our customers. Therefore, we established the Energy Futures Customer Advisory Panel (**EFCAP**) in 2017, which consisted of 11 members with a diverse representation of customers and stakeholders. The EFCAP met every three to four months to consider concepts, projects, issues and challenges relating to the development of our proposals.

We also discussed our proposal with our longstanding Customer Consultative Committee (**CCC**) (established over 10 years ago to provide an independent voice in our decision making process), and invited members of the AER's Consumer Challenge Panel (**CCP**) to independently review our engagement approach and provide guidance.

2.4 What we heard

A core component and the starting point of Energised 2021–2026 was establishing a shared energy future that meets the needs of our customers and the communities they live in. To understand how our customers and stakeholders see their energy future, we co-designed three potential energy future scenarios with our customers, consumer advocates and stakeholders and asked them which would best support their lifestyles in the future as shown in figure 2.2.

Figure 2.2 Three energy futures scenarios co-developed with our customers and stakeholders



Source: CitiPower

Ultimately, stakeholders acknowledged Steady State as the immediate priority to reduce costs while maintaining network performance and security of supply. Over time however, increasing consumer power and interest in environmental factors were considered likely to lead to greater investment in alternative energy sources and policies that encourage more ambitious renewable energy targets.

Our proposal reflects feedback by adopting the Steady State scenario while also reflecting the Victorian Government's renewables targets, including policy changes such as Solar Homes, in the most affordable way for our customers. We have also adopted key elements of the Consumer Power scenario by offering more solutions to customers who want to better access their data and use technology to more actively participate in the electricity market.

2.4.1 A safe and dependable, flexible and affordable network

We asked customers about what matters most to them and we heard three common themes in all our feedback, which are summarised in figure 2.3.

Figure 2.3 What we've heard from our research in Energised 2021–2026

Source: CitiPower

Resilient network

Our customers view having a reliable and safe supply as a single key concept; a resilient network. For example:

- customers are not willing to trade off current reliability for cost savings, however, they are willing to pay to improve reliability in areas with poorer service.
- safety is seen as a given, and most trust that we are making the right decisions in this area. Customers want safety to be maintained and improved where possible across the network but balanced with costs.
- residents and small and medium businesses are satisfied with reliability and power quality and want levels maintained. Commercial and industrial customers would like power quality improved.

Affordable network

Affordability permeates every discussion we have about electricity. Participants shared the following:

- affordability is highly-valued and many see current electricity prices as too expensive
- customers are interested in receiving rewards and incentives for participating in demand management, and some commercial and industrial customers would like further dialogue with us about options.

Flexible network

Flexibility revolves around choice and enablement. It means giving customers options to participate with the energy market in a way that suits them most. Our customers:

- have a vision for a greener future, and they expect an increase in the use of renewables (solar and batteries)—both large and small scale.
- want the network to facilitate and cater for this increased renewable uptake—ensuring consistent quality of supply for everyone and enabling solar export. They would like to see us being proactive rather than reactive and implementing plans for an increase in renewables now.
- liked the idea of access to real-time energy usage data but were not willing to pay more for this.
- had some concern around data security and not wanting us to be able to control appliances remotely.

2.5 How this has shaped our proposal

Our customers are at the centre of our 2021–2026 regulatory proposal. Their feedback and how it's used in various elements of the proposal are highlighted and demonstrated throughout this document where most relevant. We summarise how we have incorporated key insights of our customers' wants and needs into our proposal in table 2.3

Table 2.3 Summary of how feedback has shaped our proposal

Topic	Approach	What we heard	Our response to feedback
Phase 1 Exploration of customer values and priorities	Surveys, focus groups, interviews and online tools	Our customers needed to learn more about who we are and what we do. Our customers won't trade off reliability for cost savings. Around two-thirds of residential customers perceived their electricity bills as too high. Customers and stakeholders want the power put back into people's hands, with access to real-time data and a customer-centric focus.	• strengthened our communications to build awareness and a level of trust—eNews, Talking Electricity, advertising and podcast • maintaining our position as the most reliable network in Australia with supply available for over 99.99% • ensuring we maintain our position as the most efficient network • commitment to deliver a customer service strategy and improving our customer-facing applications for outages, faults and consumption data.
Phase 2 Exploring possible scenarios for our energy future	EFCAP, CCC, citizen-led deliberative forums, workshops, surveys and meetings	Customers have a vision for a greener future, and 75% of them thought the network should be upgraded faster than is planned to allow for renewable energy. The preferred energy future was a steady and progressive integration of renewable energy with a measured reduction in tariffs by 2026, and improved power quality.	• began developing a vision for our network that reflects our stakeholders' expectations, including a progressive integration of renewables • identified future technologies that are likely to be integrated into the network • identified how customer choices can be improved, including through enabling access to more useful data • developed pricing principles to guide our decision making for tariffs.
Phase 3 Taking a deep dive into meeting our energy future	EFCAP, CCC, a second round of citizen-led deliberative forums, deep dives with stakeholders, workshops, surveys and meetings	Customers agreed to their values for electricity: • providing a reliable supply of electricity • maintaining affordability • committing to providing a safe environment for customers and workers • using electricity when you want or receive savings for reducing use • keeping your data and our network secure • making it easier for you to export solar and charge your battery • making it easier for you to connect • making it easier for you to use your data to make informed choices.	• combined reliability and safety into resilience • committed to price reductions • commenced consultation on Time-of-Use pricing structures that will support and encourage the integration of new technologies • developed a vulnerable-customer campaign to improve energy literacy • developed initiatives to accommodate renewables and customer-driven technologies • developed initiatives to deliver customer benefits via digitalisation and visibility of the network • developed initiatives to provide customers with easier access to their data and make more informed choices • tested options on how to address customers' needs, including presenting bill impact of each option.

Phase 4 Sense checking our five year plan with customers	Released the draft proposal, deep dives with stakeholders, workshops, surveys, meetings, open house, community displays and a podcast	Draft proposals were generally supported, particularly: • exporting for solar customers • investing in new technology to improve reliability and safety, and encourage renewable generation • providing access to data that tells people how much energy they use at different times of the day and how much each of their appliances cost to run • multi-modal communications about outages, faults, programs and our services.	• finalised our vision for our network that reflects customers' and stakeholders' expectations, including a progressive integration of renewables and maintaining or improving existing services at least cost • redesigned our solar approach and finalised the business case through extensive consultation with stakeholders and analysing customer benefit streams • finalised the business case for improved digitalisation and visibility of network, ensuring we deliver a reliable network at least cost and defer augmentation • finalised our business case for customer enablement using extensive feedback on customer preferences on access to data • finalised our proposal for time-of-use pricing with a slower transition path to ensure all customers are supported.

Source: CitiPower

More information is available in our stakeholder engagement appendix.[1]

[1] CP APP01: CitiPower, *Stakeholder engagement*, January 2020.

3 Our energy future

Our customers are looking to more actively participate in their energy future. They are generating, storing and exporting more electricity back into the network, marking one of the most significant transformations to the electricity industry of recent times. They also want to become more involved in new demand response programs, search more actively for the best energy prices, and expect their electricity requirements will change as electric vehicles (**EV**) become commonplace. New market developments will support customers as they engage in peer-to-peer trading. At the same time, they still expect us to prioritise safety and affordability.

3.1 We are preparing for a shared energy future today

The changes customers are seeking will create more efficient markets and allow them to share in the gains, but will also make network management more complicated. As a result, we are investing to deliver customers the network they need.

We are excited to plan for this shared energy future with our customers. The world does not stand still, and neither are we. Our initiatives to unlock new value are summarised in figure 3.1.

Figure 3.1 Our initiatives are helping to unlock new value for customers now and in the future

Customer outcomes	Ensure safety and reliability	Lower costs through efficient network management	Enable more solar exports	Support prosumers
Example initiatives				
Emerging	• Asset condition monitoring	• EV charging optimisation • Electricity theft detection	• Network optimisation (e.g. transformer tapping) • Phase rebalancing	• Peer-to-peer trading • Solar health notifications • Streamlined customer portals
Developing	• LV asset failure prediction	• Demand response programs	• Dynamic voltage management	• Community energy projects
Existing	• Remote reconnection • Neutral fault detection • Streamlined connection requests	• Remote meter reading • New wood scan practices • Vegetation management using LiDAR	• Voltage and load management	• Energy usage dashboards
Enablers	AMI, new technology, government policies, industry partnerships, engaged consumers			

Source: CitiPower

3.1.1 Building strong foundations for our energy future through smart meters

We are already preparing for our shared energy future by making the most of our smart meter data. We have full penetration of smart meters across our residential and small business customers, which puts us in a unique position compared to distributors in the rest of the world.

Over 89% of our customers support using smart meters to better manage the network. We currently do this, for example, by:

- streamlining the connections process and lowering bills by allowing for remote connections and meter readings
- improving safety by identifying neutral faults at customer premises
- enhancing supply through better automatic detection and dispatch, and rotated load shedding on peak demand days.

Continuing to build the capabilities and experience to operate the network dynamically means we can enhance these existing services, and offer more value to customers in the future. Over the 2021–2026 regulatory period we will build the capabilities to operate the network more efficiently and in real-time to promote the uptake of new technology, optimise load control of customer appliances and enhance the cost reflectivity of pricing. Through managing the network more efficiently, we will lower network costs and put downward pressure on customers' electricity bills.

3.1.2 Supporting the uptake of new technologies

Australia is shifting towards renewable innovations such as solar, EVs and batteries. The uptake of these new innovations presents us with new opportunities and challenges for managing the network.

We have some of the highest uptake of rooftop solar in the world as longstanding blockers to solar uptake are removed by technological innovation, declining costs of renewable generation and battery storage and improvements in the way distributed energy resources (**DER**) are integrated into the network.[2] Customers and governments are increasingly driving this uptake to receive more reliable, affordable and cleaner energy.[3]

Growth in solar uptake is also being supported by government policies. The Victorian Government recently committed $1.2 billion to support the installation of solar panels on 650,000 Victorian households over 10 years.[4] It has also committed to a $40 million program to provide half-price solar batteries for 10,000 Victorian households to encourage uptake and micro-grid development.[5]

However, the higher network voltages caused by solar means that if we do nothing, customers' solar will be automatically constrained by their inverters and they will lose the benefit of solar. We have used advanced analytics and our smart meter data to determine the most efficient way to remove solar constraints in an affordable way so that most customers can export with a 5kVA system. Over the 2021–2026 regulatory period this project will allow us to unlock over 95% of the solar that would otherwise be constrained while maintaining affordability.

This benefits all customers through replacing higher cost generation and deferring network augmentation which places downward pressure on electricity bills for all our customers, regardless of whether they have their own solar panels.

3.1.3 Engaging in demand response

Many of our customers are becoming interested in participating in demand response, whereby distributors incentivise customers to decrease energy usage during peak events to address network constraints and manage assets.

We are taking some exciting new steps as we roll out behavioural and controlled load demand response programs as outlined in table 3.1.

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2 CP ATT171: Marlene Motyka, Andrew Slaughter and Carolyn Amon, *Global renewable energy trends: Solar and wind move from mainstream to preferred*, September 2018.

3 CP ATT171: Marlene Motyka, Andrew Slaughter and Carolyn Amon, *Global renewable energy trends: Solar and wind move from mainstream to preferred*, September 2018.

4 CP ATT173: Office of the Premier, *Cutting Power Bills With Solar Panels For 650,000 Homes*, August 2018.

5 CP ATT174: Department of Premier and Cabinet (Vic), *Victorian Infrastructure Plan*, October 2017.

5 CP ATT172: Office of the Premier, *Cheaper Electricity With Solar Batteries For 10,000 Homes*, September 2018.

Table 3.1 Current period demand response programs

Program name	Solution	Capacity	Target audience
Voltage management	Voltage management at zone substation level to reduce network demand during peak periods. Vulnerable load and life support customers are closely monitored or excluded through events	60MW	Network wide
Commercial customer load control	We are exploring partnerships with commercial customers to reduce network constraints by reducing demand	2MW	Large electricity users with sophisticated energy management strategies

Source: CitiPower

As we learn more about how our customers want to engage in demand response, greater numbers of customers are participating and are consistently using less energy during critical periods.

69% of customers are interested in participating in demand response programs. To maximise the savings these programs can deliver, we are investing in understanding our customers better through various partnerships including:

- RACV channel partnership to test and learn from different brand associations and marketing channels
- CitySmart and Queensland University of Technology research project linking load profile analysis to customer archetypes to refine customer value propositions and messaging for demand response programs.

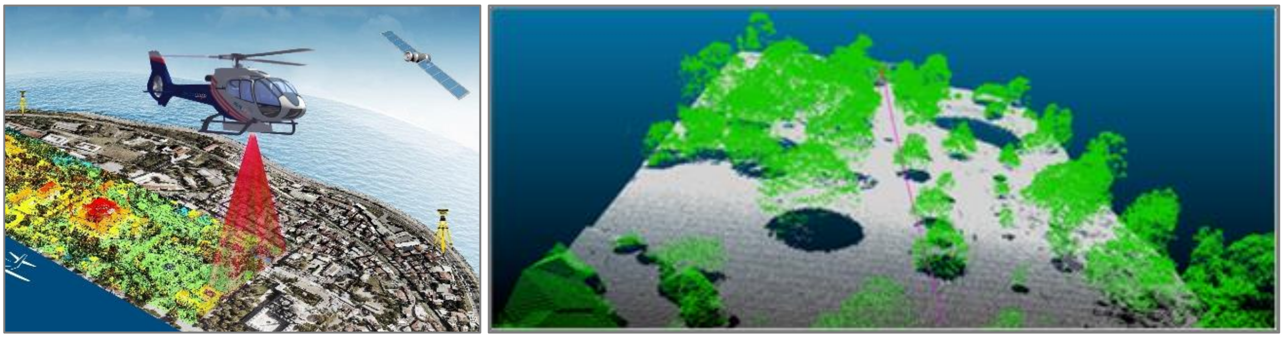
3.1.4 Managing assets in smarter ways

To keep up with changes in our network and our environment we seek out the best in asset management practices. This includes harnessing the opportunities that technology provides and collaborating with industry partners.

For example, we have embarked on a partnership with Swinburne University to find new ways of assessing the health of our limited life poles in less invasive and more effective ways. This will allow us to extend the life of our assets and pass on lower costs to customers while ensuring the safety of our employees and the community.

We have also implemented light detection and ranging (**LiDAR**) to make digital representations of vegetation growth across our entire network. This is done through emitting a laser light and measuring the reflected light pulses. We use this visualisation, in addition to analytics algorithms, to determine where vegetation cutting is required.

Figure 3.2 Example of LiDAR data visualisation to identify vegetation growth



Source: Google images / CitiPower

3.1.5 Empowering more informed customers

Technological development in how organisations capture and display data across a number of industries, including health and finance, means customers can access more information about products and services. Through sharing energy data with our customers, we are helping them to take control of their energy usage.

Our 'myEnergy' dashboard allows business and residential customers to gain visibility about their energy use, see how this compares to their neighbourhood average, and use this data in the Victorian Energy Compare website to get the best energy deal—our customers see a one-stop-shop as simplifying their lives and providing them with information to make better decisions. Our myEnergy dashboard also allows customers with solar to see how much they are exporting back onto our network.

Through our customer enablement program, we will improve customers' ease of access to our online services through consolidating our existing portals into a 'one-stop-shop'. We will also provide new ways for customers to engage with us.

B

Every day we supply electricity to power our customers' activities

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4 Replacement

Summary

We take great pride in the role we play in providing an essential service for our communities—a safe and dependable supply of electricity is critical each and every day. As Australia's most reliable distributor, our network is available for over 99.99% of the year. On average, our customers experience just 20 minutes off supply per annum.

Our replacement investment in the 2021–2026 regulatory period to continue to provide a safe and dependable supply of electricity has been informed by insights from our ongoing stakeholder engagement program:[6]

- we are responding to concerns raised by our communities about the long-term sustainability of our pole replacement volumes by proposing enhancements to our risk-based approach to managing our wood pole population (an outcome of which is that we will intervene on more poles).
- we are leveraging our smart meter network to minimise safety risks as far as practicable. This includes using analytics to proactively detect hazardous assets. The use of meter data allows us to make decisions that prolong the useful life of components of our network, without compromising reliability of supply or network safety.

In addition to leveraging our smart meter network, innovation was something our customers said they expected from us during our stakeholder engagement process.

Our asset management decisions are also increasingly relying on new research and innovation. This helps us make efficient, data-driven decisions to replace our poles, wires and major electrical plant inside our zone substations. For example, we are using new technologies to inspect our assets with non-destructive methods (such as WoodScan for poles) that support the integrity of the existing asset during the inspection process, and are expected to provide more accurate information on asset condition.

Similarly, our current partnerships with a number of universities across Australia are identifying better ways to manage our assets. This includes our work with research partners to develop algorithms that identify vegetation clearance breaches from our state-of-the-art light detection and ranging (**LiDAR**) survey of lines so we can improve safety outcomes. Identifying and implementing new ways to solve network problems leads to safer, more reliable and affordable networks.

Affordability was a common theme from our customers as well. To ensure our regulatory proposal includes efficient replacement investment, we carefully quantify and assess risks to our customers (including safety, reliability, financial, bushfire and environmental impacts). We only invest in replacing assets when the probability weighted cost of these risks exceeds the value of the least-cost intervention.

Our forecast investments are mostly supported by risk monetisation models. This includes all major zone substation asset replacements. Our approach to quantifying risks is consistent with the AER's replacement planning practice note.[7]

As discussed in this chapter, our replacement investment is supported by the assessment approach applied by the AER in its recent decisions for other electricity distributors. Our forecast investment is lower than the AER's repex model estimate.

This chapter outlines our investment in the 2021–2026 regulatory period to replace existing assets:

- in section 4.1, we outline the services our forecast investment will allow us to deliver
- in section 4.2, we provide further detail on our approach to developing our investment forecast, including our asset management practices and risk monetisation process.

The replacement of existing assets occurs as the condition of our network infrastructure deteriorates over time, and investment is required to continue to meet our network safety, reliability and environmental obligations. This is consistent with the capital expenditure objectives, criteria and factors set out in the National Electricity Rules (**Rules**).

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6 As set out in the stakeholder engagement chapter of this regulatory proposal, our engagement program included a series of deliberative forums and customer surveys. These insights were presented in our draft proposal, and discussed during our risk management deep-dive.

7 CP ATT099: Australian Energy Regulator, *Industry practice application note: asset replacement planning*, January 2019.

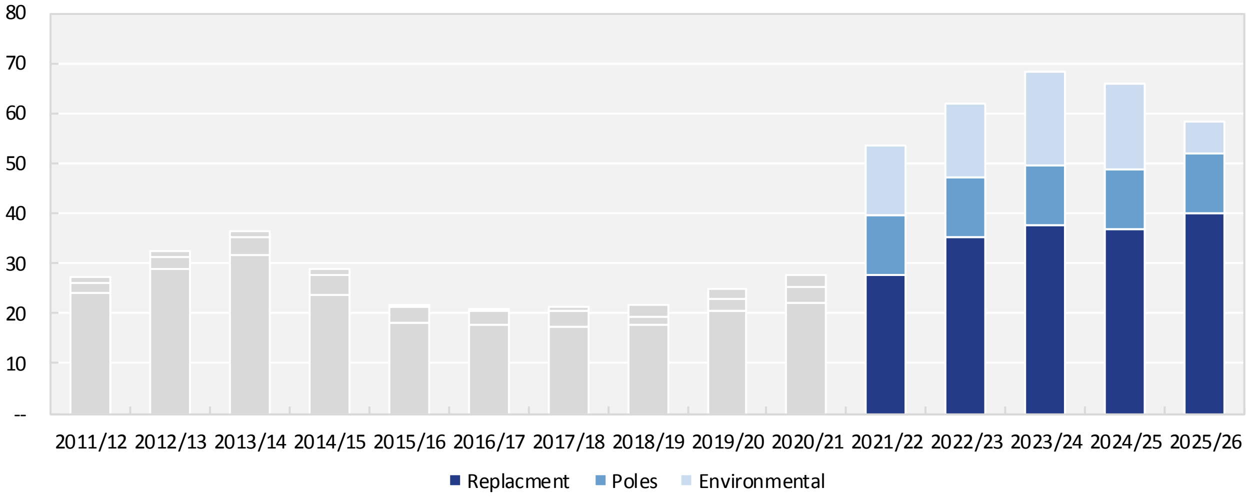
Table 4.1 and figure 4.1 provide an overview of this investment over previous and future regulatory periods.

Table 4.1 Total replacement investment ($ million, 2021)

Description	2016–2020	2021–2026
Replacement total	115.9	308.0

Source: CitiPower

Figure 4.1 Forecast investment to replace existing assets ($ million, 2021)

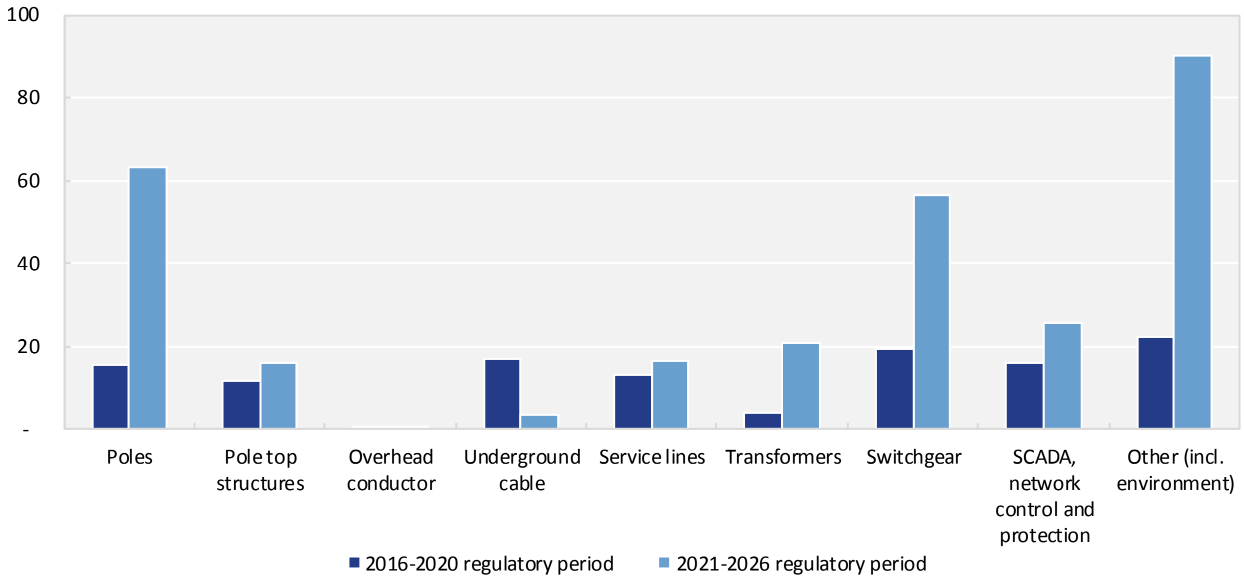


Source: CitiPower
Notes: Forecast shown includes real escalation.

Our forecast investment for replacing existing assets is increasing relative to our historical investment program. This is primarily due to increases in our pole replacement program, transformer and switchgear replacements, and the investment required to meet new environmental compliance obligations.

Our forecast has also increased from our draft proposal, primarily due to the inclusion of additional pole replacements. A comparison between our historical and forecast regulatory periods, at the asset category level, is shown in figure 4.2.

Figure 4.2 Historical and forecast replacement investment by RIN category ($ million, 2021)



Source: CitiPower
Notes: Forecast shown excludes real escalation.

The justification for our forecasts is provided in series of business cases and risk models for our key projects and programs. These are summarised in table 4.2, and cover over 68% of our total replacement investment.

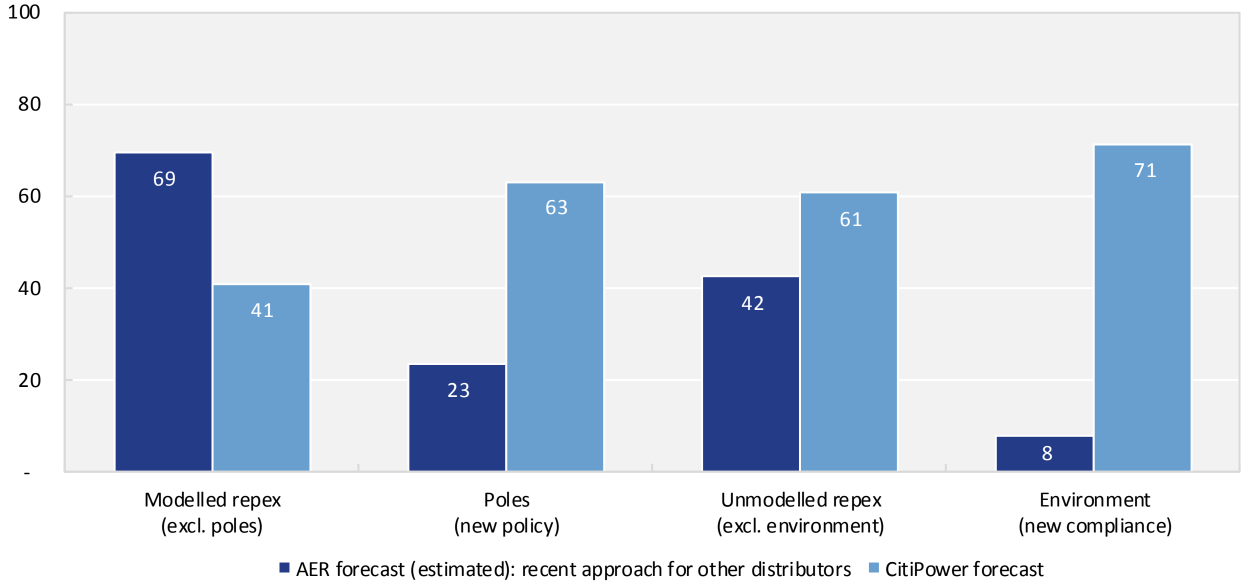
Table 4.2 Summary of material business cases: total forecast investment, 2021–2026 ($ million, 2021)

Description	Investment
Wood pole replacement program (excluding fault response)	58.9
Environmental management program	71.3
Little Queen supply area	19.0
Collingwood supply area	8.5
Transformer replacement program	19.0
J18/J22 circuit breaker replacement program	7.1
CBD cable pit refurbishments	14.1
Total business case	**197.8**

Source: CitiPower
Notes: Forecast shown excludes real escalation.

After accounting for new policy and regulatory compliance obligations (which are not reflected in our historical expenditure), our forecasts are lower than modelled estimates based on the AER's recent assessment approach for other electricity distributors. For example, the first pair of columns in figure 4.3 shows our estimate of the AER's repex model (excluding poles).[8] Our estimate of the AER's repex model is discussed in further detail in section 4.2.5.

Figure 4.3 Comparison of AER's recent approach to our regulatory proposal: total replacement investment ($ million, 2021)



Source: CitiPower
Notes: Forecast shown excludes real escalation.

4.1 What we plan to deliver

To ensure we continue to supply the households and businesses within our communities with the electricity required to power their activities, we commit to providing the following over the 2021–2026 regulatory period:

- safe environment for our customers and workers
- reliable supply of electricity.

4.1.1 Providing a safe environment for our customers and workers

The safety of our communities, and that of our workers, is our first priority—we never compromise on safety. That's why our workers are extremely well trained and our asset management practices are based on international standards.

Some network assets, however, can fail without warning and may pose a safety threat. We undertake a range of activities as part of our asset management practices to reduce the likelihood and impact of asset failures. For example, we undertake proactive, safety-driven replacement programs when we identify deficiencies in families of assets, or when new technology enables us to better mitigate risks. This is consistent with our regulatory

[8] For completeness, expenditure typically treated by the AER as 'unmodelled' is also shown, excluding our environmental investment which is driven by new compliance obligations.

obligations to design, construct, operate, maintain and decommission our network to minimise as far as practicable (**AFAP**) the hazards and risks to the safety of any person arising from the network.[9]

Our forecast replacement investment for the 2021–2026 regulatory period includes our ongoing and proactive safety-driven programs. These programs, which also support the reliable supply of electricity, are discussed below.

Pole replacement program

Poles are essential to an overhead electricity distribution network. Their basic function is to support overhead electrical conductors and other pole mounted assets, and to provide safe clearance from the ground and other adjacent objects (including vegetation).

Our electricity network comprises over 58,000 poles, mostly constructed of wood. We inspect our poles in accordance with our legislated inspection requirements, including the use of innovative technologies, such as Woodscan, to improve the accuracy of our asset intervention decisions.[10]

Our pole asset management practices have resulted in relatively low wood pole failure rates. For example, we have historically experienced around one wood pole failure per annum.

Notwithstanding our low historical wood pole failure rates, we have responded to community feedback and that from key stakeholders to improve our pole asset management practices. Although this feedback was driven primarily by events in our Powercor network, our subsequent asset management response is equally prudent and efficient for CitiPower (recognising that we apply the same asset management approach to both networks).

Our improved asset management practices are summarised below, and set out in detail in our attached pole replacement business strategy.[11]

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9 *Electricity Safety Act* 1998 (Vic), section 98.

10 Woodscan is an ultrasonic scanner measuring pulses travelling between 12 contact points around the pole to detect if there are any defects inside the pole.

11 CP BUS 4.02: CitiPower, *Pole replacement forecast*, January 2020.

Asset management changes: CitiPower and Powercor

We apply the same asset management approach across both our CitiPower and Powercor networks. These networks have the same asset management team and systems, and a risk-based approach is applicable for each business.

We recently amended our pole replacement practices in order to provide our communities with greater assurance regarding the safety of our network, particularly following the St Patricks Day fires in 2018. These amendments included increasing the amount of 'sound wood' required for poles to remain in service. The changes were accepted by Energy Safe Victoria (**ESV**) in Powercor's bushfire mitigation plan (**BMP**), following a review by ESV of the condition of Powercor's poles in the south-west of Victoria.[12]

In the second half of 2019, ESV undertook a further review of the longer-term sustainability of Powercor's wood pole replacement program. This involved a comprehensive end-to-end review of our wood pole asset management life cycle process.

A draft report for ESV's sustainability review was published in December 2019. ESV made a number of recommendations, with three clear conclusions:

- the wood pole management system in place in March 2018, at the time of The Sisters fire at Garvoc, would not deliver sustainable safety outcomes for the future.
- since March 2018, Powercor has improved its wood pole management system, which has the effect of increasing the volume of wood pole replacements and reinforcements. However, these changes alone will not deliver sustainable wood pole safety outcomes for the future.
- Powercor is progressing further improvements to its wood pole management system based on a more comprehensive risk assessment and better inspection practices that, when implemented, will as far as practicable, deliver sustainable safety outcomes to the community.

The draft conclusions from ESV's sustainability review reinforced the findings from our own internal reliability centred maintenance (**RCM**) review conducted in 2019. Our RCM review highlighted the following concerns with the performance of our pole asset class that support the need to change:

- the historical trend in pole failures is increasing, whereas the number of poles classified as 'unserviceable' has declined
- a higher than expected number of poles are transitioning directly from a serviceable to unserviceable state between inspection cycles.

In response to ESV's findings, and our RCM review, we are implementing a risk-based asset management program. We have also changed our pole serviceability assumptions regarding the fibre-strength of wood poles. Specifically, our existing replacement criteria assumes the fibre-strength of a wood pole is the same in year one as it would be in year 100. We have amended this assumption to capture a more robust expectation of age-based degradation.

Our risk-based asset management approach aligns with the conceptual framework set out in the AER's recent asset replacement guidance practice note.[13] For example, we use our existing condition information and revised serviceability criteria as a proxy for the probability of asset failure. Our consequence of failure assumptions reflect a mapping of pole location to our defined bushfire risk zones—for CitiPower, this refers to low bushfire risk areas only.

The changes in our pole management practices will result in a step up in our wood pole replacement and reinforcement volumes. These volumes include compliance driven interventions (i.e. where a pole is assessed as unserviceable, we are required under our safety obligations to intervene) and risk-based interventions. Our intervention response, however, depends on the particular circumstances and risk, rather than being deterministic.[14]

12 CP ATT051: Powercor, *Bushfire mitigation plan*, December 2019.

13 CP ATT099: Australian Energy Regulator, *Industry practice application note: asset replacement planning*, January 2019.

14 For example, our intervention response may be to stake the pole rather than replace. The timeframe for intervention also depends on whether the classification of unserviceable is an immediate priority (i.e. replace in 24 hours, or replace with 32 weeks).

A summary of our forecast wood pole intervention volumes, as well as the required investment in the 2021–2026 regulatory period (excluding fault response) is shown in table 4.3.

Table 4.3 Wood pole replacement volumes and investment, excluding fault response

Description	Replacements	Refurbishments	Investment ($ million, 2021)
Risk based asset management: wood poles	1,863	3,070	58.9

Source: CitiPower
Notes: Forecast shown excludes real escalation; fault response is modelled separately (refer to CP MOD 4.11 - Network faults - Jan2020 - Public).

Other high-volume, low-cost asset replacements

In addition to poles, much of our forecast investment for high-volume, low-cost assets includes the replacement of service lines and pole-top structures (such as cross-arms attached to our poles). We typically replace these assets based on a 'find-and-fix' or reactive approach.

As shown in table 4.4, our total forecast investment for these asset categories is largely consistent with our historical investment.

Table 4.4 Total lines replacement investment ($ million, 2021)

Asset category	2016/17–2020/21	2021/22–2025/26
Service lines	13.2	16.2
Pole-top structures	11.7	15.8
Total	**24.9**	**32.1**

Source: CitiPower
Note: Forecast shown excludes real escalation.

Our investment forecast for these asset categories is estimated using average actual replacement volumes over the four-year period spanning 2014/15–2017/18, and reduced to account for the expected overlap due to our increased pole replacement volumes. Targeted proactive intervention programs are also included in our general lines replacement forecasts for additional safety-driven measures that are consistent with our AFAP obligations. These programs are discussed below.

Stakeholder feedback

As part of our stakeholder engagement program, we undertook a series of deliberative forums with our customers. At these forums, we discussed several safety-driven programs that leveraged our smart meter investment to proactively identify hazardous assets.

To enable customers to fully understand and explore the investment options for delivering these programs, participants were briefed on the key challenges in delivering the program, and three to four options for investment going forward. Two of these safety programs were the replacement of twisted PVC service lines, and our neutral screen testing program (both discussed in further detail below).

The options presented for these programs included a status-quo option (i.e. consistent with our existing asset management approach), and incremental replacements to proactively reduce safety risk. Customers were provided with indicative bill impacts associated with each option, as well as the cumulative impact of selecting multiple safety programs throughout the entire forum.

Our customers were overwhelming supportive of using smart meters to detect faults for repair. Further, our customers wanted us to initiate these programs immediately, rather than wait until the 2021–2026 regulatory period.

Based on our customer feedback, we have brought forward the timing of these projects into the current regulatory period.

Service lines: neutral screen testing program

Since the introduction of smart meters in Victoria in 2009, we now have access to more and better data regarding the performance of our network. We are leveraging our smart meter investment to continuously improve how we manage our network—particularly the safety benefits we can now provide to our customers.

Our neutral screen testing (**NST**) program proactively detects hazardous neutral services by applying an algorithm to smart meter data that identifies particular voltage and current signatures (that are consistent with potentially faulty service connections). Faulty neutral connections can result in electric shocks to customers and have led to serious injuries in the past. As such, where our NST program identifies a potential fault, we remotely de-energise the site and dispatch a fault crew to inspect the connection.

As a result of our NST program, we are forecasting to replace around 113 service lines per annum. These volumes are consistent with those observed since the program began in 2018, but represent a step up relative to our previous inspection method.

Service lines: twisted PVC service line replacement program

Twisted polyvinyl chloride (**PVC**) grey service cables are a common type of service line installed throughout our network. As shown in figure 4.4, these connections use a double ended metal hook that is coated in insulating plastic to hold the service wires into position as they feed from the service span down to the customer's connection.

Figure 4.4 Sample image: twisted PVC service line

Source: CitiPower

The metal hook connection—commonly referred to as a 'dog-bone'—has a failure mode that can lead to a significant safety risk at the premise to which it attaches. With movement of the service over time, the metal hook can pierce the insulation of the service conductors and liven up any attached metal work (such as connected verandas or guttering).

There are over 20,100 PVC twisted grey services installed throughout our network, and when the extent of the safety risk associated with dog-bones was first identified in 2016, we inspected all of them. This inspection resulted in the replacement of over 1,400 high risk services through to 2018. Our asset inspection policy also changed to require visual inspections of all services from underneath both ends of the 'dog-bone', rather than the previous practice of inspecting only from the connecting pole.

We initially presented to stakeholders our intention to continue our twisted PVC service line replacement program from 2021 onwards (for lower priority defects). However, our customers overwhelmingly supported this program, and we have since committed to increasing our replacement rate from 2019. The proposed capital investment across the 2021–2026 regulatory period, therefore, represents the continuation of this program.

Environmental management program

We are subject to both Victorian and Commonwealth environmental obligations, including the *Environment Protection Act* and the State Environment Protection Policies for noise, land, groundwater, surface water and air quality. Our investment forecast includes projects required to continue to meet these obligations.

Historically, we have managed the risks associated with our environmental obligations primarily through a reactive approach consistent with the prevailing legislation. For example, we have investigated noise concerns associated with our zone substation transformers following a customer complaint.

From July 2020, the revised *Environment Protection Amendment Act 2018* will come into effect. As set out in the Regulatory Impact Statement (**RIS**), these revisions establish a modern regulatory approach focusing on preventing waste and pollution impacts, rather than managing any impacts after an event has occurred.[15]

In order to meet these new proactive compliance obligations, our investment forecast for the 2021–2026 regulatory period includes noise reduction and bunding programs at a number of high-risk zone substations. These sites have been identified based on a desktop analysis to determine the following:

- bunding—oil-leak risk rating, based on the likelihood of an oil-leak arising, and the potential damage to the surrounding environment
- noise—decibel exceedance and proximity to residential properties.

The cost for proactively addressing these risks is based on an assessment of least-cost compliance options. For our bunding works, these options typically consider and compare the installation of bunding with or without a stormwater management system. For our noise program, the site options range from enclosing part or all of the site, to asset replacement (as an inner-city network with high-density residential dwellings and space restrictions, suitable site options can be relatively expensive).

The full impact of these regulatory changes, and our monetisation of the likelihood and consequence of all risks, is set out in our attached environmental management business case. The costs are summarised in table 4.5.[16]

Table 4.5 Compliance with new environmental obligations: total forecast investment, 2021–2026 ($ million, 2021)

Description	Investment
Noise compliance program	58.9
Bunding compliance program	12.4
Total	**71.3**

Source: CitiPower
Notes: Increased operational expenditure is also required to meet our new compliance obligations regarding increased monitoring and land contamination management. These costs are discussed in our operating expenditure chapter. Forecast shown excludes real escalation.

15 CP ATT010, DELWP and EPA, *Regulatory Impact Statement: Proposed Environment Protection Regulations*, August 2019, p. 7.

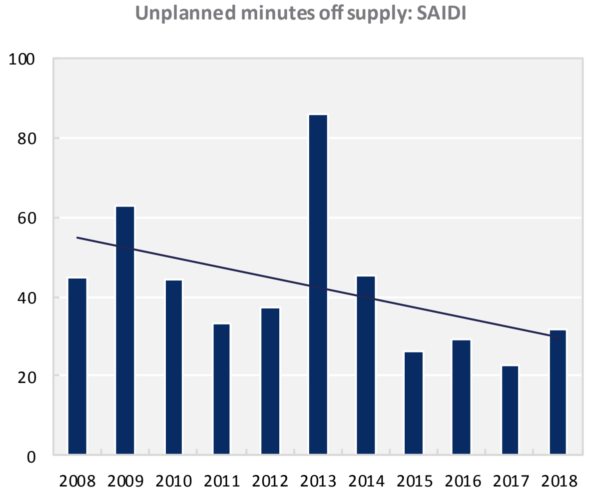
16 CP BUS 4.01: CitiPower, *Environmental Protection Amendment Act 2018*, January 2020.

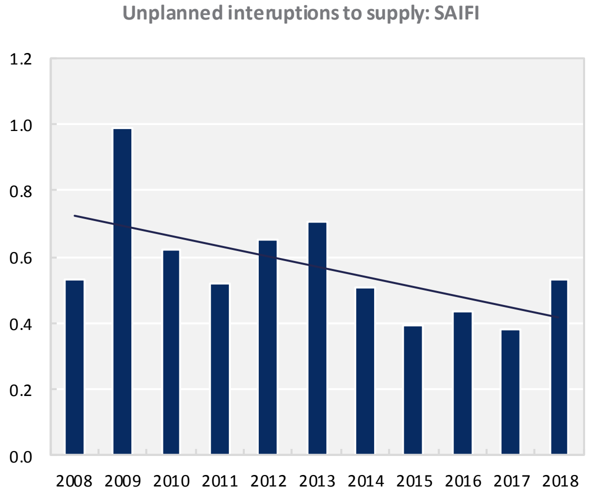
4.1.2 Providing a reliable supply of electricity

Overall, the investments included in our regulatory proposal are designed to maintain both affordability and the long-term health of our electricity assets. This includes investments needed to maintain current reliability levels on average across our network (noting that factors such as the weather will still drive variances each year).

We will also work to improve reliability where our customers value the improvement more than the cost to deliver it, although these works do not form part of our investment forecast. As shown in figure 4.5, we have been improving our reliability and will strive to maintain this trend.

Figure 4.5 Unplanned outages a typical customer experiences (minutes off supply; number of outages)





Source: CitiPower

Stakeholder feedback

We know from talking to our customers that network reliability is important. Along with affordability, it consistently ranked as the key output measure throughout our stakeholder engagement forums.

Specifically, our customers are generally satisfied with the level of reliability currently experienced. Around half our customers were willing to pay more for better reliability, whereas only 16% were prepared to pay less for lower reliability.

Many of our customers also expressed their support for improving reliability for worst-served customers. Although our regulatory proposal does not include such programs—due to balancing other considerations, including affordability—we have improved reliability in the current regulatory period by installing additional switches and monitoring devices. When there is an electricity outage, this equipment helps us restore supply more quickly by remotely identifying and segmenting fault locations for our field crews to attend.

Energy Consumers Australia (**ECA**) were also supportive of a minimum standard of reliability for all customers, and the creation of a 'black-spot' program to relocate our assets in high-risk traffic zones. ECA challenged us to identify creative solutions to these issues, and we will work to operationalise this feedback.

In addition to speaking with our residential and business customers, our engagement included a network risk management workshop with key stakeholders to detail the risk monetisation approach used to justify many of our asset replacements (including zone substation transformers). This workshop was attended by the AER, ECA, and representatives from ESV. As outlined in section 4.2, our risk monetisation approach is consistent with the AER's replacement planning practice note.

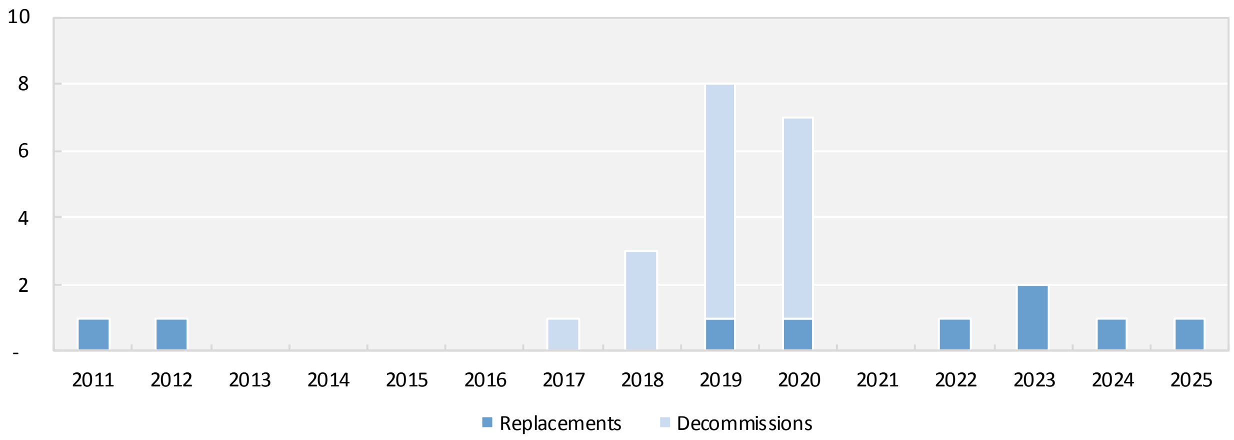
An overview of the key investments we will make over the 2021–2026 regulatory period to ensure we maintain a reliable supply of electricity are discussed below. These include our zone substation transformer and switchboard replacements, our circuit breaker replacement program and refurbishment works for our CBD cable pit population.

Replacement of zone substation transformers

Our electricity network comprises 42 zone substations and 102 power transformers.

In the 2021–2026 regulatory period, we will replace five of these zone substation transformers—two each at our North Richmond and Celestial Avenue zone substations, and one at our Victoria Market zone substation. Figure 4.6 shows our historical and forecast replacement rates, including zone substation decommissions (which have avoided the need to otherwise replace poor-condition transformers).

Figure 4.6 Historical and forecast transformer replacement volumes



Source: CitiPower

Our approach to forecasting replacement investment for major plant is based on a monetisation of risk, and is discussed in detail in section 4.2.2. This approach recognises that should a transformer fail in service, the impact to customers and the community will vary based on the potential consequence in terms of safety, bushfire, environmental and financial impacts, and supply reliability.

Our risk assessment also has regard to the probability of an asset failing, which is a function of the asset's underlying condition. The condition of our assets is characterised by a health index, which is derived from our condition based risk management (**CBRM**) model.[17]

The justification for the replacement of each of the zone substation transformers included in our 2021–2026 replacement program is set out in our attached zone substation transformer risk monetisation justification document and models.[18] A summary of the total investment required for these works is in table 4.6.

17 The CBRM is a proprietary model developed by EA Technologies. The model is an ageing algorithm that takes into account a range of inputs to produce a health index for each asset in a range from zero to 10 (where zero is a new asset and 10 represents end of life). The health index provides a means of comparing similar assets in terms of their calculated probability of failure.

18 CP BUS 4.03: CitiPower, *Transformer evaluation methodology*, January 2020. CP MOD 4.12 - NR transformer no.1 - Jan2020 - Public; CP MOD 4.13 - NR transformer no.2 - Jan2020 - Public; CP MOD 4.14 - VM transformer no.1 - Jan2020 - Public; CP MOD 4.15 - WA transformer no.1 - Jan2020 - Public; CP MOD 4.16 - WA transformer no.2 - Jan2020 - Public.

Table 4.6 Transformer replacements: total forecast investment, 2021–2026 ($ million, 2021)

Description	Investment
North Richmond transformer no.1	3.9
North Richmond transformer no.2	3.9
Victoria Market transformer no.1	3.9
Celestial Avenue transformer no.1	3.5
Celestial Avenue transformer no.2	3.9
Total	**19.0**

Source: CitiPower
Notes: Forecast shown excludes real escalation.

Little Queen supply area: switchboard replacement

Our Little Queen zone substation is located in the heart of Melbourne's CBD. It supplies electricity to over 5,000 major commercial and domestic customers.

Little Queen zone substation was constructed in the early 1970s and most of the original substation equipment remains in service. This includes the existing compound-insulated double bus switchboard and bulk oil-filled switchgear which was designed with no arc fault containment, as shown in figure 4.7.[19]

Figure 4.7 Little Queen zone substation: 11kV switchgear

Source: CitiPower

19 The term 'compound' refers to the insulating medium used to cover bare conductor components and reduce the electrical clearance distances required compared to when insulated by air.

The asset management need (i.e. the need to intervene) at Little Queen zone substation is to maintain a safe and reliable supply of electricity to customers in the Little Queen supply area as the condition of the existing switchboard deteriorates over time. This recognises the risks associated with the existing switchboard, including the increasing probability and consequence of failure—for example:

- deterioration in compound-filled assets is typically monitored by measuring partial discharge activity, with changes in partial discharge activity providing early warnings of impending failure; partial discharges have been detected at multiple locations within the switchboard, including the compound-filled cables and cable boxes, circuit breaker spouts and the B-C bus tie area that includes the compound-filled busbars
- compound-filled switchboards are not designed to contain arc-faults, creating the potential for adverse safety outcomes associated with explosive failures
- the configuration and loading of our Little Queen zone substation are such that a fault would be expected to negatively impact on our ability to supply load to the CBD
- good asset management practice from the broader industry supports the view that compound-filled and non-arc fault contained switchboards pose an increasing safety and reliability risk, and should be progressively removed from service.

Several options were considered including like-for-like replacement, and establishing a new switchboard at an adjacent site; both options were compared to managing the risk at Little Queen zone substation without any major capital intervention. Non-network alternatives were also considered, but would likely require additional at-call generation capacity, which is expected to be prohibitively expensive in the CBD.

Our preferred network solution is to replace the existing Little Queen switchboard in the same building. The decision to replace this switchboard is consistent with standard industry practice, and our asset management approach for other compound-filled switchboards. We have nine compound-insulated switchboards remaining on our network, and all but one are planned for replacement or decommissioning by the end of 2025. The remaining site is currently being reviewed.

The investment required to maintain reliability in the Little Queen supply area over the 2021–2026 regulatory period is shown in table 4.7. Further detail on these works, and our monetisation of the risk of our preferred network option, is provided in our attached business case and risk model.[20]

Table 4.7 Little Queen supply area: total forecast investment, 2021–2026 ($ million, 2021)

Description	Investment
Replacement of existing switchboard at Little Queen zone substation	19.0

Source: CitiPower

Collingwood supply area: switchboard replacement

Our Collingwood zone substation was constructed in the early 1960s, and similar to our Little Queen zone substation, the original air-insulated single bus switchboard and bulk oil-filled switchgear remains in service. These assets were designed with no arc-fault containment.

[20] CP BUS 4.04: CitiPower, *LQ supply area*, January 2020.

The zone substation provides electricity supply to over 6,300 commercial, industrial and domestic customers. Approximately 75% of customers are residential, but major customers include Yarra Trams, St Vincent's Hospital and Carlton United Breweries.

In 2016, a disruptive failure of one of the feeder circuit breakers resulted in damage to the switchboard. The decision to repair (and not replace) the switchboard was a practical, interim response to the immediate problem of reduced system security resulting from the unavailability of part of the switchboard. As the switchboard type is obsolete, the repairs were carried out using reclaimed parts from another decommissioned switchboard.

Figure 4.8 shows the damage to the front and rear of the air-insulated busbar chamber and switch room due to the uncontained arc-fault. The explosive nature of the fault blew the switch room doors open.

Figure 4.8 Damage to busbar chamber and switch room due to explosive failure at Collingwood zone substation (2016)

Source: CitiPower

The asset management need at our Collingwood zone substation is to maintain a safe and reliable supply of electricity to customers in the Collingwood supply area.

As outlined previously, non-arc fault contained assets present a risk of catastrophic failure. Broader industry experience supports the view that non-arc fault rated switchboards pose an increasing safety and reliability risk.

Further, the layout of our Collingwood zone substation is such that the switchgear is situated directly opposite the protection and control equipment, with no form of blast control wall between them or between the bus-sections. As a result, an explosive failure that spreads into the open switch room would result in the loss of all switchgear protection and control equipment.

Our preferred network option to mitigate the safety and reliability risks for our Collingwood supply area is to replace the existing switchboard in the same building using a temporary bus. Alternative offload solutions and managing the risk without any major capital interventions were also assessed.

Table 4.8 sets out the investment required in the 2021–2026 regulatory period for replacing the existing switchboard at our Collingwood zone substation. Further detail on these works, and our risk monetisation of the preferred network option, is provided in our attached business case and risk model.[21]

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21 CP BUS 4.05: CitiPower, *B supply area*, January 2020; CP MOD 4.02 - B supply area - Jan2020 - Public.

Table 4.8 Collingwood supply area: total forecast investment, 2021–2026 ($ million, 2021)

Description	Investment
Replacement of existing switchboard at Collingwood zone substation	8.5

Source: CitiPower
Notes: Forecast shown excludes real escalation.

Replacement of J18/J22 circuit breaker population

We currently own and operate over 1,110 zone substation circuit breakers, the majority of which are 11kV circuit breakers installed within indoor switchboards. These include oil-filled circuit breakers that have been in use on our networks since the 1920s.

In line with many other network operators, we have become increasingly concerned by the material safety and reliability risks posed by oil-filled switchgear. This includes the consequences associated with explosive failures and the lack of arc-fault containment, both of which give rise to potential long-term outages and catastrophic safety outcomes. These risks will increase as the condition of the insulating material within these circuit breakers deteriorates as these assets age.

Our attached J18/J22 circuit breaker replacement business case sets out our proposed asset management plan to progressively remove the highest-risk circuit breakers from service.[22] We have targeted five separate zone substations within our network and applied a risk-monetisation approach to determine the efficient intervention timing.

A summary of the total investment required over the 2021–2026 regulatory period for this program of works is set out in table 4.9.

Table 4.9 J18 circuit breakers: total forecast investment, 2021–2026 ($ million, 2021)

Description	Investment
J18/J22 circuit breaker replacements	7.1

Source: CitiPower
Notes: Forecast shown excludes real escalation.

CBD cable pit refurbishment program

We own and manage a large population of cable pits in the Melbourne CBD. These cable pits allow us to access network and communications cables for installation and repair works without the need to excavate roads and footpaths.

The condition of our cable pit population is deteriorating, and recent inspections have revealed that up to 20% of pits inspected require remediation. The condition of these pits is particularly impacted by the effects of corrosion and increased traffic density (relative to their initial design standards, noting some of these pits were installed in the 1930s). Images of corrosion evident in these pits are shown in figure 4.9.

22 CP BUS 4.07: CitiPower, *J18 circuit breakers*, January 2020.

Figure 4.9 Corrosive damage to supporting steel work inside CBD cable pits

Source: CitiPower

The loss of strength of the supporting steel and reinforcing within the concrete due to corrosion may result in the collapse of the pit roof or pit covers at the surface opening. The consequence of a roof or cover opening failure could be catastrophic in terms of serious injury to the public or our workers, as well as the interruption to electricity supply within the CBD due to damage to the cables within the pit. Further disruption to the CBD could be caused if the failed pit was one of the many which also host telecommunications cables.

Stakeholder feedback

We discussed our CBD cable pit refurbishment plans with our customers during our stakeholder engagement program.

Our customers considered that replacing high-priority pits only, particularly on a reactive basis, was too risky. Instead, our customers had a clear preference for refurbishing both high and moderate priority pits over a five or ten year period.

Our program proposes to undertake these refurbishments over a 15 year timeframe. We consider this reflects the most efficient balance between affordability and risk mitigation.

Previously, we have managed cable pit assets via a reactive approach, whereby remediation work was driven by the immediate need to access a pit to carry out planned works and other operational events. Since 2018, we have adopted a proactive management approach to ensure the safety of our employees and the public, and maintain the reliability of supply in the CBD.

For the 2021–2026 regulatory period, we propose to target the remediation of pits installed in or adjacent to roadways. These pits are subject to high and variable dynamic loadings, which puts greater stress on them. These works will continue our proactive approach to the growing risks carried by these assets.

Justification for continuing our program to refurbish high-risk CBD pits is set out in our attached business case and risk monetisation model.[23] A summary of the investment required over the 2021–2026 regulatory period is shown in table 4.10.

[23] CP BUS 4.06: CitiPower, *CBD cable pits*, January 2020.

Table 4.10 CBD cable pit refurbishments: total forecast investment, 2021–2026 ($ million, 2021)

Description	Investment
CBD cable pit refurbishments	14.1

Source: CitiPower
Notes: Forecast shown excludes real escalation.

4.2 Our forecasting approach

This section provides an overview of how our asset management objectives are reflected in forecast asset replacement volumes and expenditure that are prudent and efficient. Our approach is consistent with the capital expenditure objectives and criteria set out in the Rules, and the AER's expenditure forecast assessment guideline.[24]

4.2.1 Our forecast asset replacements volumes are consistent with our asset management framework

Our asset management framework aligns with the requirements of ISO 55001. This framework is the international standard in asset management.

The asset management framework describes the asset management system that is applied to our network assets. The framework includes our asset management policy, strategic asset management plan (**SAMP**), and detailed network asset management plans and strategies for all asset classes. Our asset management policy and SAMP have been provided as attachments to our regulatory proposal.[25]

Our forecast asset replacement volumes are developed based on these asset management practices. In particular, we forecast asset replacement volumes based on three broad approaches:

- risk modelling/monetisation
- historical defect rates and forecast inspection volumes
- historical volume trends.

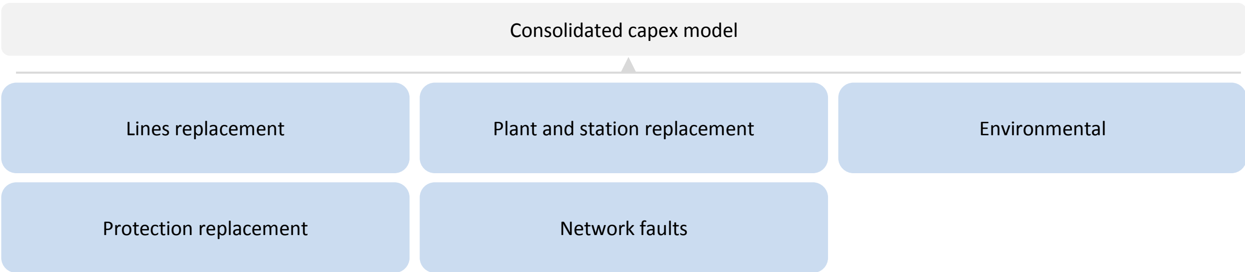
We apply these forecasting approaches to different asset and sub-asset categories based on the characteristics of the underlying asset. For example, we typically forecast high volume, low cost assets using observed historical trends (adjusted for any known change in operational policy or asset specific issues), or based on historical defect rates and forecast inspection volumes. In contrast, low volume, high value assets are typically forecast based on individual risk assessments and options analysis.

An overview map of our modelling approach for our replacement capital investment is shown in figure 4.10.

[24] NER, clause 6.5.7(a) and clause 6.5.7(c).

[25] CP ATT020: CitiPower, *Asset management policy*, March 2018; CP ATT021: CitiPower, *Strategic asset management plan*, December 2019.

Figure 4.10 Capital expenditure model map: replacement investment



Source: CitiPower
Notes: For simplicity, supporting models for individual business cases have not been shown.

4.2.2 Our risk-monetisation modelling is consistent with the AER's asset replacement planning note

Historically, our approach to forecasting replacement investment was based on an assessment of condition. For major plant, this approach was then supplemented with information on the load at a given site.

Our approach to forecasting replacement investment has recently become more sophisticated, and is now based on a monetisation of risk. Our risk-monetisation models ensure we invest only when the cost of replacing existing infrastructure is lower than the total value of the underlying risks. This means our customers pay no more than required on asset replacements.

Specifically, our approach to monetising risk when assessing investment decisions is to determine the annual asset risk cost (as shown in figure 4.11). This approach is taken for all identified failure modes for an asset, and the sum of the annual asset risk cost for all of failure modes is compared to the annualised cost of the preferred option to determine the economic timing for any intervention. This approach is consistent with the AER's recent asset replacement guidance practice note.[26]

Figure 4.11 Calculation of annual asset-risk cost

Source: CitiPower

A summary of how we determine the key input assumptions when calculating the annual asset risk cost is provided below. Further details are also set out in the relevant risk monetisation models for each asset, and/or the corresponding business cases.

Determining the probability of failure

The probability of failure is a key input assumption in any risk monetisation model. In the first instance, we use historical asset failure rates based on our own internal data.

We also use CBRM methodology to inform our probabilities of failure. Under this approach, the probability of failure is a function of an assets health score. The health score is informed by the normal expected life of the

[26] CP ATT099: Australian Energy Regulator, *Industry practice application note: asset replacement planning*, January 2019.

asset, its location and service history, its reliability performance, and observed condition and measured condition.

The relationship between the health score and probability of failure is such that the probability of failure is assumed to be constant for low health scores, but increases exponentially for higher health scores.[27] This is typical of reliability modelling, and represents that increasing degradation in asset condition will result in an escalating likelihood of failure.

The use of the exponential curve, however, can result in an acceleration effect once assets reach a high health score. For assets that are approaching their end of life, this run-away effect may provide a forecast probability of failure that would not reflect the deterioration expected to be observed in real life. To mitigate this impact (i.e. to minimise the potential for overstatement of the forecast probability of failure), an ageing reduction factor is introduced to modify the asset's rate of deterioration. This slows down the forecast ageing rate of any asset by flattening the exponential curve, especially (although not exclusively) where the health score is greater than 5.5.

Further technical detail on the derivation of probabilities of failure and health scores is provided in the risk justification guide supporting our zone substation transformer replacements.[28]

Determining the total expected cost of consequence

The total expected cost of consequence is equal to the likelihood of the consequence of a failure event, and the consequence cost of that failure. Our approach to determining these factors includes estimating outcomes for each potential failure mode across the risk categories set out in table 4.11.

Table 4.11 Monetised network risk categories

Risk category	Example of value of risk
Network performance	Includes the value of unserved energy as a result of an unplanned outage; based on the value of customer reliability (**VCR**) estimated by AEMO (adjusted for inflation)
Safety	Includes potential safety impacts to the public, or our workers, as a result of an asset failure; based on the value of a statistical life, and a disproportionality factor of three
Financial	Includes costs (both capital or operating) associated with the reinstatement or replacement of failed or damaged assets; typically based on expected scope and observed historical costs
Environmental	Includes costs of disposal of hazardous waste or environmental remediation works; typically based on expected scope and observed historical costs

Source: CitiPower

Similar to our approach for estimating the probability of failure, in the first instance, we estimate the likelihood of any consequences of a failure event using our own internal data. For example, we use entry records (i.e. swipe card access) at a particular zone substation to determine the likelihood of our workers being on-site at the time of an asset failure.

27 Specifically, the relationship is based on a Taylor series for an exponential function.

28 See, for example: CP BUS 4.03: CitiPower, *Transformer evaluation methodology*, January 2020.

4.2.3 Our unit cost forecasts are based on recent historical costs

As the second most cost-efficient distributor in Australia based on AER benchmarking, our historical unit costs provide a reasonable basis for forecasting future investment requirements. For high-volume, low-value assets, these costs are typically determined as the average of actual costs over the period 2015/16–2018/19. For low-volume, high-value assets, we typically forecast costs based on recent efficiently delivered projects of similar scope, size and geographic location.

Our historical costs, and therefore our forecast unit rates, also reflect rates from service providers that are derived from periodic tendering where available and appropriate. This includes our materials cost forecasts, which are procured through stringent contracting arrangements.

For clarity, we adjust our historical costs for forecast growth in real input prices over time, such as labour, materials and contracted services. Further discussion on our cost escalators is provided in chapter 9.

4.2.4 We will deliver our replacement program with support from our resource partners

Our labour force is structured to provide flexibility in managing labour resources. This allows us to deliver our total capital program, including the forecast increase in replacement investment. For example, our labour contracts include the following types:

- internal labour—these are permanent employees who provide the base level of labour required to provide a base level of labour services. To operate sustainably over the long term we must ensure we have secure access to a sufficient quantity of labour with the skills and knowledge required to deliver the minimum level of network and corporate services.
- local service area agents (**LSAA**)—these are third party owned and operated franchises that provide network services in specific network areas. LSAAs service different locations across our network and are generally assigned in the lower density network areas. LSAAs are selected through a five-yearly market testing process.
- resource partners—these are third-party businesses, for example Lend Lease and Electrix, that provide additional labour services on an as needs basis. We utilise our resource partners to manage increased workloads that may arise for specific work programs. Resource partners are identified through a three-yearly market testing process.
- contractors—we utilise contractors for skill-specific work including electrical work, fault response, metering works, civil works (i.e. digging works), traffic management, design work and vegetation management. We have different contractual arrangements with our contractors, ranging from longer term contracts with third party businesses to project-specific arrangements with individual Registered Electrical Contractors.

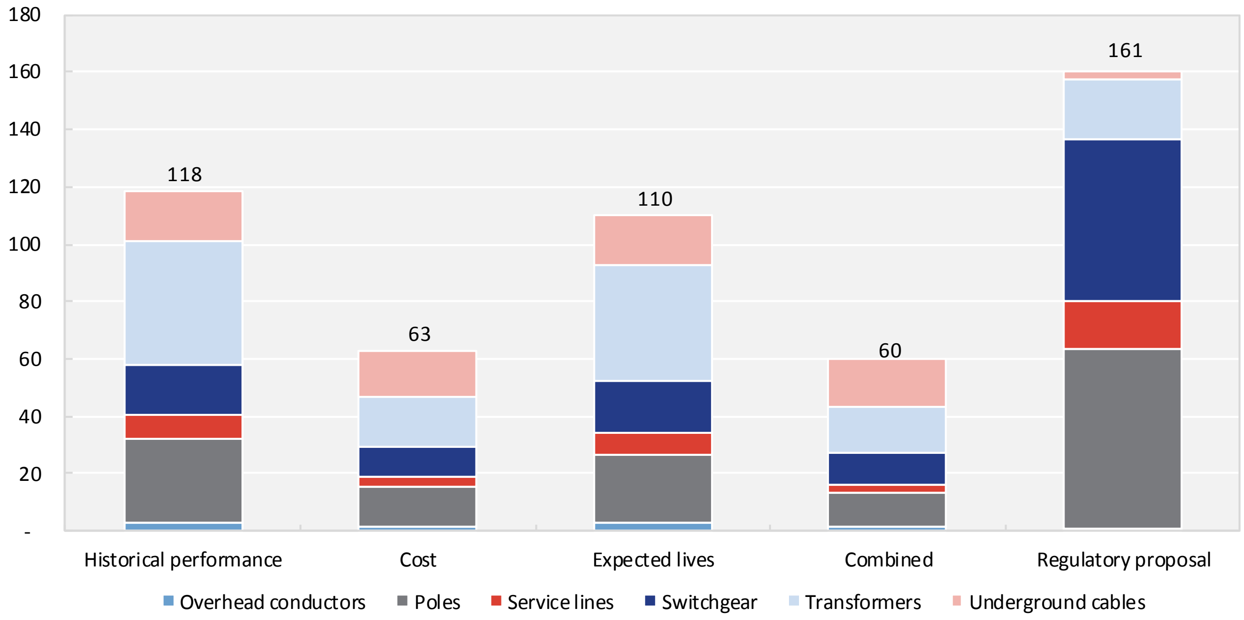
4.2.5 We tested our replacement investment forecast against the AER's repex model

In addition to using a risk-monetisation framework to develop our replacement forecasts, we validated the prudency and efficiency of our replacement investment by comparing our outcomes to estimates from the AER's repex model. The AER's repex model provides a top-down assessment of 55% of our replacement investment forecast.

Modelled replacement investment

Our estimation of the AER's repex model scenarios is provided in figure 4.12. We engaged GHD to validate our application of this model which is available in in the repex modelling review attachment.[29]

Figure 4.12 AER repex model comparison ($ million, 2021)



Source: CitiPower

Based on the approach applied in its most recent draft decision for the South Australian and Queensland electricity distributors, the AER will compare our regulatory proposal forecast to the higher of the expected costs and expected lives scenarios. In the figure above, this will result in a comparison to the expected lives outcome.

Our investment forecasts for the 2021–2026 regulatory period are above the AER's expected lives outcome, particularly for our poles and switchgear categories. We provided an overview of the drivers of our investment for these categories in section 4.1.

We consider our risk monetisation modelling of asset categories and particular projects provides a more robust assessment of the prudency and efficiency of our investment forecast than the AER's repex model. The AER's repex model is a useful tool in identifying areas for further investigation, but it simplifies a complex range of factors to forecast the replacement of assets. In doing so, the AER's repex model has the following inherent limitations:

- the life of assets replaced in the past is assumed to be the same as for assets replacement in the future, such that the replacement investment projections are backward looking and may differ significantly from a truly optimal forward looking replacement program (particularly under an AFAP framework, where technological changes can continually drive further investment)
- the number of units replaced in the past is directly proportional to historical expenditure

[29] CP ATT097: GHD, *Repex modelling review*, December 2019.

- asset age is used as a proxy for the many factors that drive individual asset replacement, where other drivers such as safety or changing community expectations may be the primary driver for particular asset categories.

Unmodeled replacement investment

The AER's repex model is not intended to cover our entire replacement investment forecast. For the 2021–2026 regulatory period, approximately 45% of our forecast replacement investment is 'unmodelled'.

The unmodelled portion of our replacement forecast includes our investment in replacing pole-top structures, protection equipment, environmental management, and miscellaneous plant, station and civil works. A comparison of these costs for our current and forecast regulatory period is outlined in table 4.12.

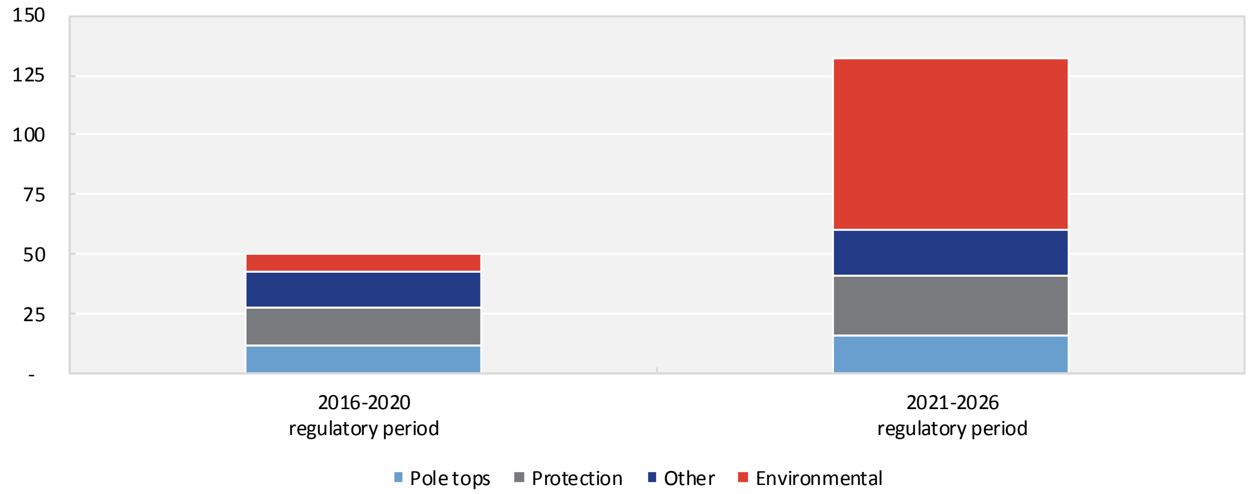
Table 4.12 Comparison of unmodelled replacement investment ($ million, 2021)

Description	2016–2020	2021–2026
Unmodelled replacement investment (total)	50.1	131.9

Source: CitiPowwer

As shown in figure 4.13, the primary driver of the increase in our forecast unmodelled investment is our environmental category (which is driven by new regulatory obligations). The drivers of our environmental investment are set out in our attached environmental business case.[30]

Figure 4.13 Comparison of unmodeled replacement investment with recent actual investment ($ million, 2021)



Source: CitiPower

[30] CP BUS 4.01: CitiPower, *Environmental Protection Amendment Act 2018*, January 2020.

5 Connections

Summary

After speaking with our customers, we have made improvements to our connection processes including reducing timeframes, improving communications and expanding contestability arrangements.

We are forecasting a slowing in high volume connection activity and investment until 2022/23 at which point there will be a modest upturn.

Large infrastructure such as the Victorian Government's Westgate Tunnel project is driving investment in gross connections until 2022/23.

Overall, we have conservatively forecast our net connections investment needs over the 2021–2026 regulatory period to be in line with our historical investment. This is underpinned by independent and robust construction activity forecasts undertaken by the Australian Construction Industry Forum and historical investment needs; an approach previously accepted by the AER.

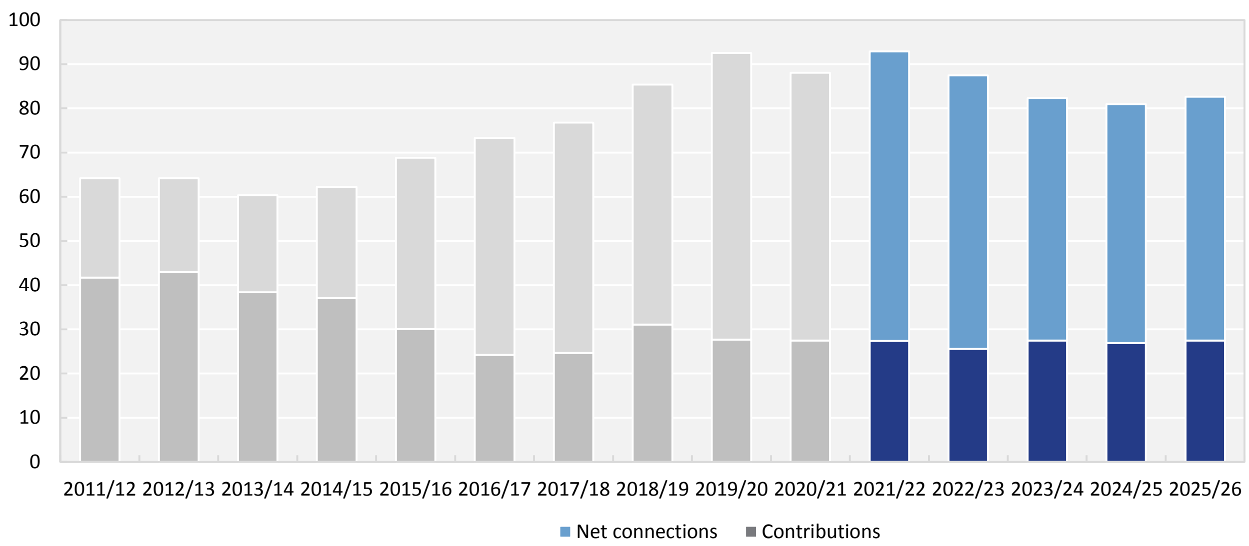
We have cross checked our forecast with a range of other approaches and found ours to be at the lower end.

This chapter sets out the investment we will make over the 2021–2026 regulatory period to meet our customers' connection requirements and support our customers' energy needs:

- in section 5.1 we present our investment forecast and the key drivers in our network
- in section 5.2 we outline our forecast approach and cross check our forecast with other approaches.

Figure 5.1 shows our forecast of gross and net connections. Net connections are net of the contributions we receive from connecting customers.

Figure 5.1 Gross and net connection investment forecast ($ million, 2021)



Source: CitiPower
Notes: 2018/19 is an estimated actual, 2019/20 is the first forecast year. Forecast shown includes real escalation.

Table 5.1 outlines the connection forecast by its components.

Table 5.1 Connection investment forecast ($ million, 2021)

Year	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Gross connections	92.9	87.4	82.3	81.0	82.6	426.3
Gifted assets	1.3	1.4	1.4	1.4	1.4	6.9
Cash contributions	64.1	60.5	53.5	52.7	53.7	284.6
Rebates	-	-	-	-	-	-
Net connections	27.4	25.6	27.5	26.9	27.5	134.8

Source: CitiPower

Notes: Net connections equal gross connections less gifted assets less cash contributions plus rebates. Forecast shown includes real escalation.

5.1 What we plan to deliver

Our focus over the 2021–2026 regulatory period is making efficient and timely connections. This section outlines the way in which:

- stakeholder engagement has driven improvements in our connection processes
- our investments will:
  - deliver more connections to power customers' everyday activities (high volume connections)
  - facilitate infrastructure growth (low volume connections)
- our connection policy will continue to ensure customers pay for their fair share.

5.1.1 Stakeholder engagement has driven improvements in our connection processes

In 2016 we transformed the way we process connections by launching eConnect—our online portal to submit connection requests, seek solar pre-approval and allow us to better manage connections workflow. We also started our online mySupply platform to streamline customer initiated augmentation works. These tools have simplified the connection process and led to operational efficiencies, which have translated into lower costs for our customers.

Stakeholder feedback

From our residential surveys, around 14% of respondents had experienced a connection, of which 74% indicated they were satisfied with the timeframe and process. Unsatisfied respondents sought a quicker connection and better communication.[31] This customer engagement highlighted drawbacks in our online portal, such as system operations that could lead to double booking connection appointments and in turn having to cancel an appointment. We are now fixing this issue. Additionally, we are working to better link multiple connection works at the same site (e.g. an asset relocation and a new connection) within our systems. These changes will ensure we communicate better with our customers.

In 2019 we spoke with developers, who considered connection processes could cause them delay in completing their developments. In response, we have made the following commitments to them and the Essential Services Commission of Victoria:

- connecting developments to our network ('tie-ins') within 20 business days
- undertaking connection audits within 5–8 business days
- undertake design approvals within 20 business days
- offering customers more choice by extending contestability to master designs.

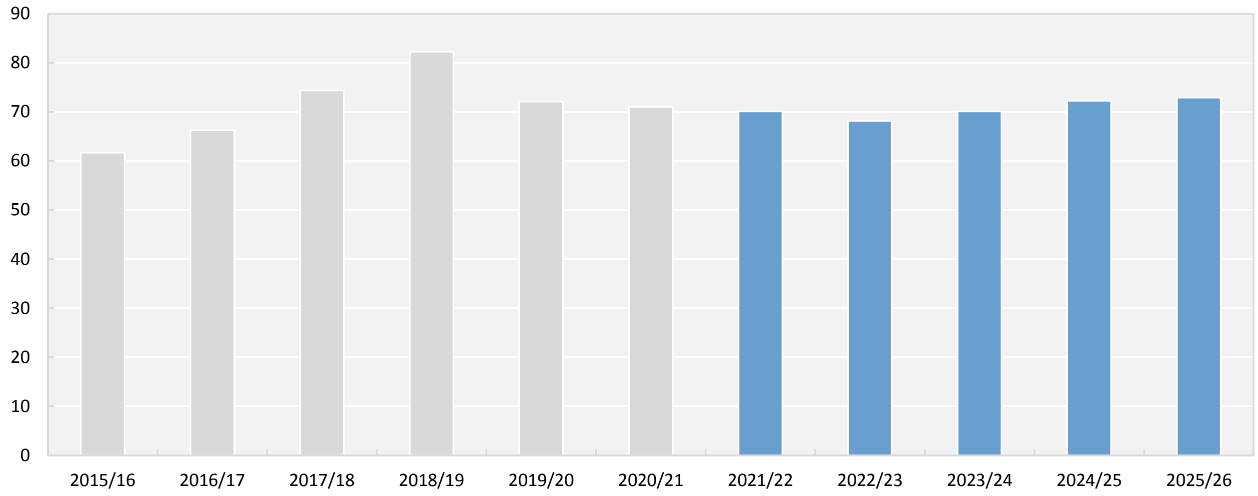
Through responding to customers, we will continue to support their requirements by connecting them faster than ever over 2021–2026.

5.1.2 High volume connections—delivering connections to power customers' everyday activities

Improved services are critical given the sustained connections volume in our network over the 2021–2026 regulatory period. We forecast to connect 17,700 new households over the 2021–2026 regulatory period.[32]

'High volume' connections consist of residential and small to medium business connections. Our high volume connection demand is based on applying construction activity forecasts that have been independently undertaken by the Australian Construction Industry Forum (**ACIF**), as discussed more in section 5.2.1. Figure 5.2 outlines our high volume connection investment trend and forecast.

Figure 5.2 High volume connection investment ($ million, 2021)



Source: CitiPower
Notes: 2018/19 is an estimated actual, 2019/20 is the first forecast year. Forecast shown excludes real escalation.

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31 CP ATT206: Woolcott, *CitiPower Residential Survey*, July 2018, p. 26.

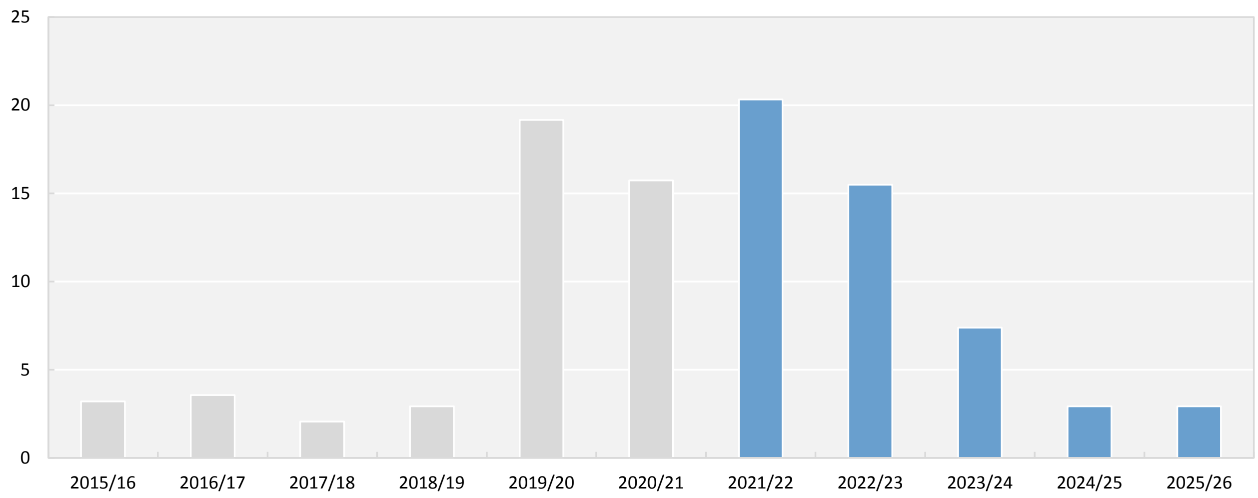
32 Based on applying ACIF growth rates to historical connection volumes. Includes alternative control connections.

Compared to 2015/16 to 2017/18 (actual connection information) we are conservatively forecasting a declining trend in connections investment. In part this is driven by a slowing market for CBD high-rise apartments and fewer building approvals being sought until 2022/23, at which point there is a modest increase in our investment requirements.[33] Further information on construction activity trends is available in ACIF's report (attached).[34]

5.1.3 We are underpinning infrastructure plans

We continue to underpin Victoria's infrastructure plans and the jobs that come with it. Low volume connections are typically used for infrastructure projects and industrial customers. We generally support these projects by making construction supply available, providing permanent supply once the project is completed or relocating existing assets to accommodate the project. Figure 5.3 outlines our low volume connection forecast.

Figure 5.3 Low volume connection investment ($ million, 2021)



Source: CitiPower
Notes: Forecast shown excludes real escalation.

Slower economic growth and low borrowing costs have led to robust public infrastructure spending. Public work grew by 22% in 2017 to reach $67 billion, boosted by sector investment in transport, energy and water infrastructure. There are many new major projects being added to an already solid pipeline. In Victoria, the raft of major infrastructure projects and other public investment activities has been termed 'Victoria’s Big Build'.[35]

From 2019/20 we have seen a step up in the low volume connection investment requirements. This has been driven by:

- the Victorian Governments Westgate Tunnel project—this project will deliver an alternative to the West Gate Bridge by providing a second river crossing between the west and the City. It will also provide new links to the port and is expected to take 9,000 trucks off local streets in the inner west.[36] We are re-locating assets to facilitate the tunnel's construction, which will continue until 2022/23.

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33 CP ATT231: Australian Bureau of Statistics, *8731.0 - Building Approvals*, Australia, March 2019.

34 CP ATT098: ACIF, *Australian construction market report*, May 2019.

35 CP ATT050: ACIF, *Australian construction market report*, November 2018.

36 CP ATT236: Victorian Government, *West Gate Tunnel Project*, 2019.

- Metro rail—continuing to support Melbourne's second underground railway which will free up space in the City Loop.[37] In 2021 we will continue supporting this project by providing supply to the tunnel boring machines.
- connecting a new data centre.

From 2023/24, we are forecasting our connections investment will return to trend.

There is mounting pressure on the Federal Government to ramp-up investment in public infrastructure projects to boost economic activity.[38] While the Federal Government' pledge to bring the budget back into surplus by 2019/20 is currently taking primacy, should the economy continue to slow it will be forced to fill the hole caused by more cautious private infrastructure expenditure. To this end, we consider our forecast based on known projects to be conservative.

5.1.4 We ensure that our customers make fair contributions to their connections

In 2018 we published and sought feedback on our draft connection policies (together with our draft proposal).

Our connection policy has been made in accordance with the AER's Connection Charge Guideline. We have not made material changes to this policy from the 2016–2020 regulatory period. We will continue to offer two types of connection services: basic and negotiated. Customers requiring a basic connection will pay a fixed fee to cover the cost of installing a dedicated service line. Negotiated connections contribute to network upgrade costs based on the capacity of their connection in accordance with the AER's cost-revenue test.[39] This policy also outlines the circumstances when customers (typically developers) build assets and gift them to us and receive a rebate towards their cost of connection.

As part of this regulatory submission we are seeking AER approval of our connection policy and the Model Standing Offers (**MSO**) that most customers agree to when seeking a connection (attached).[40]

5.2 Our forecasting approach

This section outlines our approach to forecasting high volume connections, low volume connections, customer contributions, gifted assets and rebates, and unit costs. We also cross check our forecasts against a number of metrics.

We have applied different forecasting approaches to our high volume and low volume connections. Table 5.2 summarises the approach applied to connections under each of the AER's Regulatory Information Notice (**RIN**) categories.

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[37] CP ATT232: Victorian Government, *Victoria's Big Build*, September 2019.

[38] CP ATT042: Reserve Bank of Australia, *Reserve Bank of Australia annual report 2018*, August 2019.

[39] Compared to our current connection policy, we have escalated the marginal cost of reinforcement (**MCR**) by inflation only. We note that any decrease/increase to the MCR will increase/decrease our net connection forecast.

[40] CP ATT033: CitiPower, *Connection policy*, December 2019; CP ATT034: CitiPower, *Model Standing Offer for Retail Customers who are micro embedded generators*, September 2019; CP ATT035: CitiPower, *Model Standing Offer for Retail Customers other than micro embedded generators*, March 2019.

Table 5.2 Forecast approach

Connection type	Description	Forecast approach
Residential	Simple connection LV	NA—classified as alternative control
	Complex connection LV	High volume—ACIF growth rates
	Complex connection HV	
Commercial/Industrial	Simple connection LV	High volume—ACIF growth rates
	Complex connection HV (customer connected at LV, minor HV works)	
	Complex connection HV (customer connected at LV, upstream asset works)	
	Complex connection HV (customer connected at HV)	Low volume—bottom up build/historical average
	Complex connection sub-transmission	
Subdivision	Complex connection LV	High volume—ACIF growth rates
	Complex connection HV (no upstream asset works)	
	Complex connection HV (with upstream asset works)	
Embedded Generation	Simple connection LV	Low volume—bottom up build/historical average
	Complex connection HV (small capacity)	
	Complex connection HV (large capacity)	
Quoted services[41]	Connection works that are customer funded	High volume—ACIF growth rates and Low volume—bottom up build/historical average

Source: CitiPower

5.2.1 Independent forecasts of connection drivers underpins our high volume forecasts

For high volume connections we have applied forecasts undertaken by ACIF to our historical connection volumes. This approach:

- uses forecasts of construction activity, which underpins high volume connection volumes
- is based on robust, widely used and independent forecasts
- has been accepted by the AER—this approach was proposed by United Energy for its 2016–2020 regulatory period and it was accepted by the AER[42]

41 A standard control connection service that we report as a quoted service for RIN purposes (reset RIN tab 4.4).

- has been applied consistently by CitiPower, Powercor and United Energy in their 2021–2026 regulatory proposals.

The ACIF forecasts are prepared by combining macro-economic forecasts of the domestic and international economy with information about the projected share of construction activity by sector and by region. The forecasts use the latest evidence from the Australian Bureau of Statistics (**ABS**) of Residential Building, Non-Residential Building and Engineering construction.[43] The forecasts are undertaken bi-annually for the two regions—'Melbourne' and 'Rest of Victoria' as defined by the ABS—for 18 sectors of the economy.

Our network falls within the 'Melbourne' region and so these are the forecasts we have adopted.[44] This forecast and accompanying ACIF report are attached.[45]

To determine our connections investment forecast, the ACIF forecast have been applied in the following way:

- we have mapped ACIF's sector forecasts to the connection categories we use within the business, and then to the AER's RIN categories. We have undertaken this mapping in accordance with the main drivers of our connections. For example, ACIF's 'Residential New Houses' subcategory has been matched to our function code '102—LV Supplies to 63kVA'. This in turn is mapped to RIN categories 'Residential Complex Connection LV'. We note our mapping is the same as applied in the 2016–2020 regulatory proposal, which the AER accepted.[46] Our full mapping is outlined in our attached connections model.[47]
- for the first year of forecast connection volumes (2019/20) we have used the average prevailing connection volumes over 2015/16–2018/19. An average has been used for setting the base year because:
  – some connections categories experience relatively low connection volumes meaning a single year may not represent the actual number of expected connections (i.e. smoothing to cater for annual volume volatility)
  – connections may begin in one year and finish in the next meaning any single year may not be a good representation of the connections work undertaken.
- from then onwards, ACIF growth rates have been applied to the preceding year's volumes.
- our unit rates are the actual average prevailing unit rates over 2015/16–2018/19 for high volume connections. These are calculated as connection investment over 2015/16–2018/19 divided by the number of connections over 2015/16–2018/19 for each of our function codes. As with the volumes, an average is used to account for the different mix and hence cost of connections that may occur in a single year. On balance, we consider a longer average would not reflect current market conditions. This averaging period is the same applied across most of our capital expenditure categories.

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42 CP ATT139: Australian Energy Regulator, *Final Decision: United Energy distribution determination 2016 to 2020, Attachment 6 – Capital expenditure*, May 2016, pp. 36, 39, 40. In addition to providing a robust and independent forecast, this approach was selected over that proposed by CitiPower's and Powercor's 2016–2020 regulatory proposal because their forecasts were not accepted by the AER.

43 CP ATT098: ACIF, *Australian construction market report*, May 2019.

44 ACIF's engineering forecast are only made at the Victorian level, which we have applied.

45 CP ATT098: ACIF, *Australian construction market report*, May 2019; CP ATT104: ACIF, *Construction index,* May 2019.

46 CP ATT233: Australian Energy Regulator, *Preliminary decision CitiPower distribution determination 2016−20; Attachment 6 − Capital expenditure*, October 2015, p. 63. The AER stated 'We have assessed the CitiPower mapping of the residential, commercial/industrial and subdivision categories and the descriptions of the internal function codes. Overall we consider that the mapping represents a reasonable allocation between the residential, commercial/industrial and subdivision connection categories and CitiPower's internal function codes'.

47 CP MOD 5.01: CitiPower, *Connections*, January 2020.

Our forecasting approach is further outlined in our connections model.[48]

5.2.2 Our low volume forecasts are underpinned by known connection projects and history

Our low volume categories are the following RIN categories:

- commercial/industrial complex connection HV (where the customer is connected at HV)
- embedded generation complex connection HV (small capacity)
- quoted services.

We have forecast low volume connections based on a bottom up build, however, where connection projects for a particular connection type are unknown, we have used historical investment. This is because we rarely receive inquires for the entire regulatory period by the time of submitting the initial regulatory proposal. The AER has previously considered it appropriate to trend forward connections investment when connection projects are unknown.[49]

Consistent with our previous approach, we have separately forecast the low volume connections below and above $2.5 million.[50] This is because each year there is a relativity steady need for some (even if they cannot yet be identified) low volume projects under $2.5 million, however, projects larger than this are typically driven by specific 'one off' large infrastructure projects. Overall, this approach is preferable to construction activity forecasts because these large and low volume connections are typically not directly related to broader construction activity and are driven by specific policies and customer needs.

We have provided business cases for material projects, which are the Westgate Tunnel and data centre connection investments listed in section 5.1.3 and attached.[51]

Quoted services are generally a high volume forecast category, however for the 2021–2026 regulatory period we have used a mixed forecasting approach. This is due to the presence of once-off major projects falling into this category that are additional to the high volume connection volume we typically experience.

The details of some major connection projects are commercially sensitive and therefore we have provided the full investment breakdown in confidential attachment and a summary in our public connections model.[52]

5.2.3 Forecasting contributions

We have forecast contributions, gifted assets and rebates based on the 2016/17–2018/19 average. We have not included earlier years in the average (as per our volume and unit rate forecasts) because prior to 2016 connections were regulated under the Essential Services Commission (Victoria) guideline 14, under which there was a different approach for calculating these parameters compared to the current approach under Chapter 5A of the Rules.

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48 CP MOD 5.01: CitiPower, *Connections*, January 2020.

49 CP ATT134: Australian Energy Regulator, *Preliminary decision Powercor distribution determination 2016–20; Attachment 6 – Capital expenditure*, October 2015, p. 65.

50 CP ATT096: CitiPower, *2016–2020 Price Reset, Appendix E Capital expenditure*, April 2015, p. 111.

51 CP BUS 5.01: CitiPower, *Data centre connection business case*, January 2020. CP BUS 5.02: CitiPower, *Westgate tunnel business case*, January 2020.

52 CP MOD 5.02: CitiPower, *Connections major projects*, January 2020.

5.2.4 Our connection investment is reviewed as part of our total capital investment program

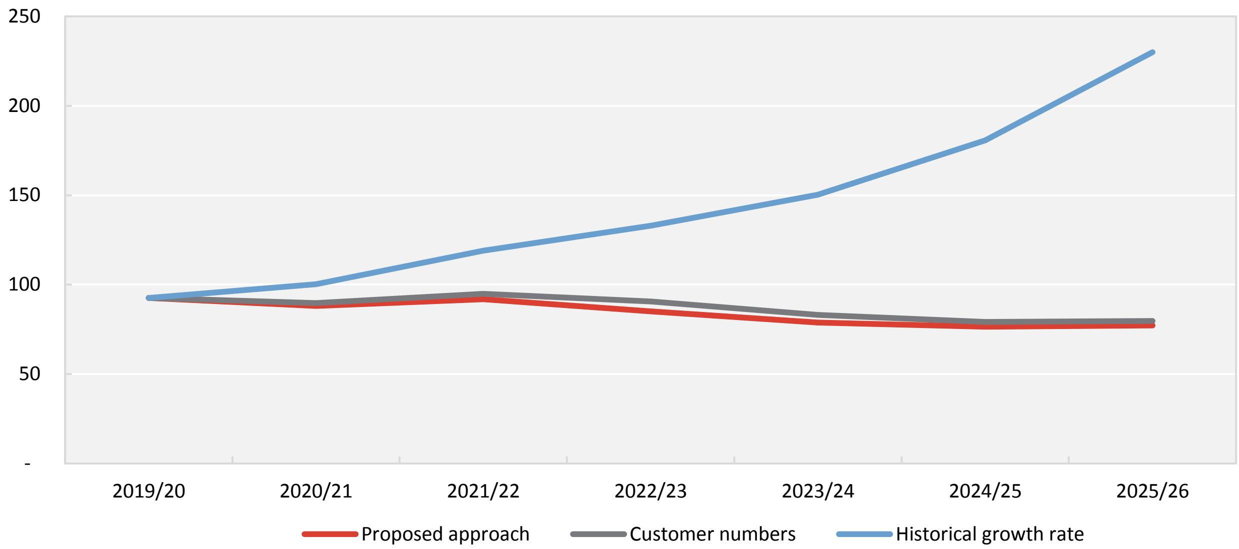
We have cross checked our forecast against alternative forecasting approaches to assess its reasonableness as outlined below:

- our first cross check was to trend forward 2015–2018 average connection growth rates. This approach would assume that historical trends continue.
- our second cross check was to apply the percentage change in customer numbers as forecast by Centre for International Economics (**CIE**) used in forecasting operational expenditure. This approach would not address subdivisions well (i.e. when a dwelling is subdivided it would only show up as one additional customer, however, two connections are required) or commercial customers. Importantly, it would also not provide the detailed sector level forecasts we have used.

In both cross checks, low volume connections have been applied as per our actual forecast approach.

Figure 5.4 outlines our connections forecast under our proposed approach and the cross checks just discussed.

Figure 5.4 Forecast approach cross checks—total investment ($ million, 2021)



Source: CitiPower

The historical growth rate approach would result in a significantly higher forecast. It is evident that ACIF do not expect the rate of growth historically experienced to continue in our network area. On balance, given the historically high growth we have experienced, we agree our forecast would be likely to lie below this cross check. While we would not necessarily expect the alignment of the customer numbers approach with our forecast approach to be as close as it is, we would expect it to be closer match than the historical growth rate. Overall, these cross checks point to our forecasts as being reasonable.

The efficiency of our unit rates is evident through our overall network performance. We are the second most efficient distributor according to the AER's benchmarking (behind Powercor) and have the second lowest network charges in the NEM.[53] This would not be achievable without efficient rates, given gross connections make up around 37% of our capital investment.[54] Further:

- we undertake competitive tenders for source material supplies and labour negotiations with our field resource suppliers have been conducted under strict governance principles.
- our unit rates are based on revealed costs—they are calculated as the average of our connections investment divided by connection volumes. Under the incentive framework, we have a continuous incentive to reduce operational and capital costs meaning our revealed costs are efficient.

5.2.5 Difference from draft proposal

Our connection forecast has reduced from our draft proposal that was published in February 2019 as shown in table 5.3.[55]

Table 5.3 Comparison of forecast to draft proposal ($ million)

Proposal	Gross	Net
Draft proposal	464	157
Regulatory proposal	426	135
Difference	**-38**	**-22**

Source: CitiPower

This has been primarily driven by a change in approach; from an approach driven by customer numbers to the ACIF approach. We consider this more conservative forecast is more robust and better captures the underlying drivers of connections on our network.

53 CP ATT109: Australian Energy Regulator, *Annual Benchmarking Report; Electricity distribution network service providers*, November 2019, p. 31; and distributors' distribution use of system charges for a typical customer consuming 4,200 kWh per annum.

54 Forecast over the 2021–2026 regulatory period.

55 CP ATT234: CitiPower, *Regulatory reset draft proposal 2021–2025*.

We are preparing the network to be flexible to our customers' energy needs

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6 Augmentation

Summary

Our customers are changing the way they use, store and sell electricity. Rooftop solar is already well established, and as the price of technology falls, the take-up of residential batteries is forecast to increase. Likewise, electric vehicles are expected to become more common as their affordability increases.

Our stakeholders have told us they expect we plan for a shared energy future that meets the evolving needs of our customers and the communities they live in. For example:

- our customers want to export their excess solar back into the network so they can lower their bills, have greater energy independence and to help the environment
- over 75% of our customers consider the network should be upgraded faster than is currently planned to allow for renewable energy, and they support both network investment and modernising our technology to better meet customers outcomes
- our residential customers are generally satisfied with our existing reliability and power quality levels; they are not willing to trade these off for cost savings
- our large commercial and industrial customers stressed that a reliable power supply is important, but power quality issues are more frequent and have large and wide-ranging impacts on their businesses—they want us to focus on these concerns, and to provide clear and timely communication during any incidents.

We are also ensuring our network is designed for today's demands and future growth by continuing our program to decommission zone substations in our Port Melbourne and Brunswick supply areas that are connected to our 80 year old sub-transmission network. Our customers told us they expect our planning decisions are forward-looking and accommodate reasonable expectations of population growth. We will upgrade these assets to current, modern standards when the condition of the existing assets deteriorates such that the energy at risk of not being provided becomes uneconomic.

Similarly, we will decommission our inner-city Russell Place zone substation due to the condition of the existing assets and building, and transfer load to our new Waratah Place zone substation. Additionally, our augmentation forecast for the 2021–2026 regulatory period includes investment required to provide capacity in the CBD and meet our security of supply obligations.

In total, our overall augmentation investment forecast supports our customers shared energy future, including enabling our customers' solar investments and the continued demand growth in our network supply area.

This chapter sets out how we are preparing our network to be flexible to accommodate the growing energy needs of our customers:

- in section 6.1, we outline the services our forecast investment will allow us to deliver
- in section 6.2, we provide further detail on our approach to developing our investment forecast, including the drivers of network augmentation, an overview of our planning policies, and how we use non-network and demand management solutions to manage uncertainty or avoid the need for network investment.

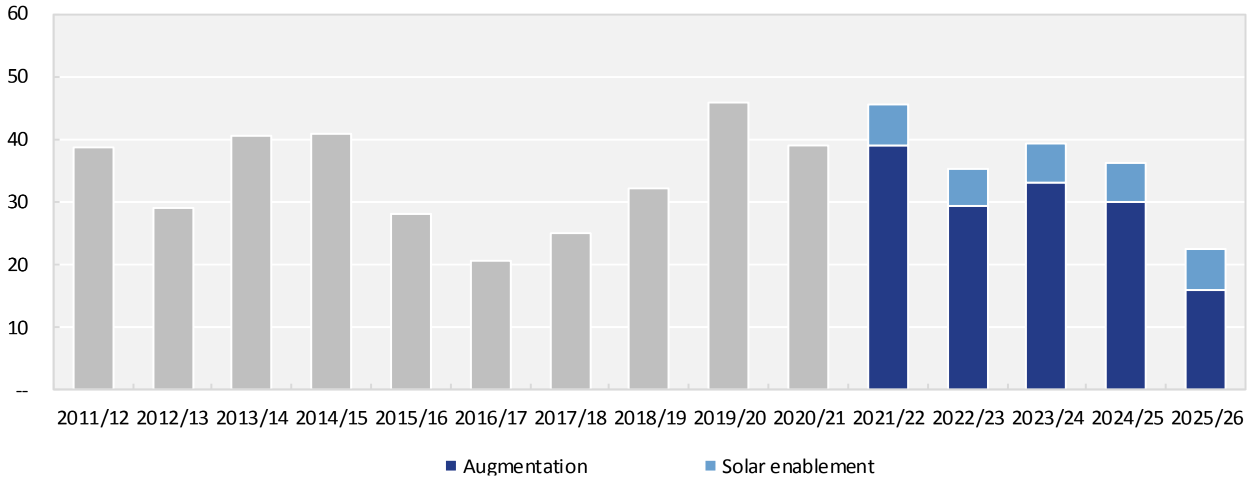
An overview of our forecast augmentation investment in the 2021–2026 regulatory period to support these growing energy needs is shown in table 6.1 and figure 6.1.

Table 6.1 Network investment ($ million, 2021)

Description	2016–2020	2021–2026
Augmentation investment (total)	162	179

Source: CitiPower
Notes: Forecast shown includes real escalation.

Figure 6.1 Forecast investment to augment our network ($ million, 2021)



Source: CitiPower
Notes: Forecast shown includes real escalation.

Our augmentation forecast is consistent with our distribution annual planning report (**DAPR**), and the capital expenditure objectives, criteria and factors set out in the Rules.[56] Our forecasts have decreased relative to our draft proposal, primarily due to refinements to the scope of works required for augmentation projects and the re-allocation of some network communications investment to our replacement category (to better align with the nature of the proposed investment).

Our augmentation forecast is supported by a series of business cases and models for key projects or programs. These business cases are summarised in table 6.2, and cover over 71% of our total augmentation investment.

Table 6.2 Summary of material business cases ($ million, 2021)

Description	Investment
Solar enablement	31.5
CBD supply	25.5
Brunswick area strategy and Brunswick supply area upgrade (RIT-D)	28.7
Port Melbourne area strategy	19.6
Russell Place supply area (RIT-D)	11.2
Digital network: network devices	5.5
Total business case	**121.9**

Source: CitiPower
Notes: Our network devices justification is set out in the digital network business case, included as part of our ICT chapter.
Forecast shown excludes real escalation.

56 CP ATT002: CitiPower, *Distribution annual planning report*, December 2019.

6.1 What we plan to deliver

To ensure our network is flexible to our customers growing energy needs, we commit to providing the following over the 2021–2026 regulatory period:

- enabling solar exports and renewable generation
- reinforcing our network to provide the electricity 'backbone'
- modernising our network to support customer outcomes.

6.1.1 We're enabling solar exports and renewable generation

Our customers have told us we should be taking steps to prepare for a future driven by increased solar, batteries and electric vehicles. These technologies provide opportunities for customers to lower their bills, have greater energy independence and build a sustainable future.

Solar enablement

Between now and 2026, solar capacity on our network is forecast to more than double. Solar panels are becoming more affordable over time, and are supported by the Victorian Government's initiative to subsidise the installation of solar panels on 650,000 homes and 50,000 rental properties over 10 years.

Stakeholder feedback

Since 2017, we have heard from thousands of our customers about their solar expectations. A summary of our engagement is below.

2017	2018	2019	
Initial engagement	Customer preference	Draft proposal	Options paper
Gauged customers' current use and interest in solar: • nine mini-group discussions • online survey of 600 residential and 200 small and medium business customers • seven in-depth interviews with large customers	Asked how we should prepare the network, facilitate solar and who should pay: • two opinion leaders forums • deliberative forum • online survey >800 customers • investment options forum • eight in-depth interviews with large and industrial customers	Received feedback on our proposed solar enablement approach in our draft proposal: • draft proposal forum • deep dive workshops with key industry stakeholders • in-depth interviews with large customers	Sought feedback on solar options paper, which took a more detailed look at different approaches to solar enablement: • online survey • solar online and stakeholder consultation • solar design workshop/report

A key stage of our engagement process was our solar deep dive, where stakeholders told us the approaches to enabling solar we were considering at the time were too limited in scope. As a result, we developed and consulted on an options paper.

The feedback on our options paper was clear that customers can tolerate reasonable constraints (i.e. they supported dynamic control and affordable prices), but the network must be prepared to accommodate more solar and ensure these constraints are not excessive. Our customers also viewed a 'first-in, first-served' approach as unfair; rather, all customers should be able to export some solar.

In our options paper, we also considered how to recover the cost of enabling solar, including:

- connection charge—an upfront charge paid by customers seeking to export solar
- 'quasi export tariff'—a reduction to the feed-in tariff received by solar customers
- tariffs—spread across all customers.

Almost two-thirds of our customers and stakeholders preferred the costs to be paid by those connecting solar. This was also the view from consumer advocates representing financially vulnerable customers. On balance, however, we opted to spread the costs among all customers, including because the benefits from our program will accrue to all. This decision is discussed in detail in our business case.

The feedback we received from our customers and stakeholders, as outlined above, has helped refine our solar enablement program. Consistent with this feedback, we will:

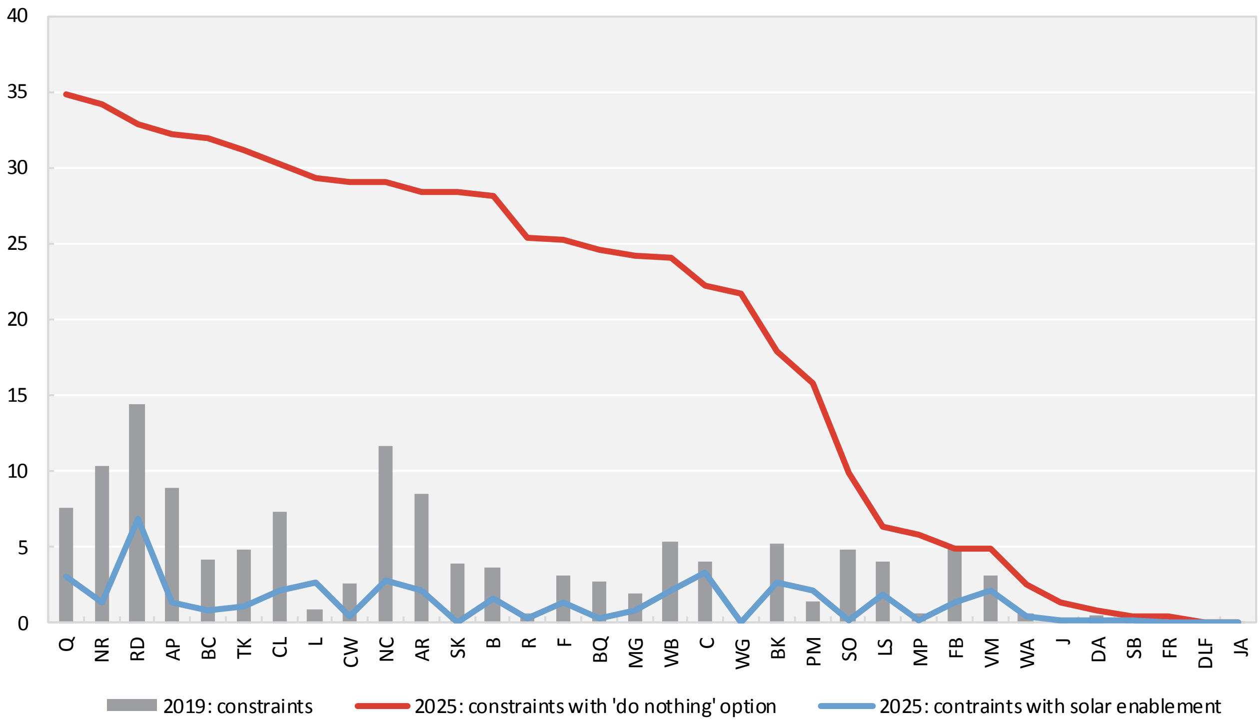
- enable all our customers to connect solar
- enable 5kVA solar systems to be available for export for most of our customers
- remove solar constraints where it is economic to do so (i.e. where the benefits to customers outweigh the costs)
- assist those customers where it is uneconomic to remove constraints to get the most out of their solar.

Our approach is also supported by extensive economic modelling. We have drawn on over 38 billion data points from our smart meters across our three networks (i.e. CitiPower, Powercor and United Energy), and considered the impact on each of our 4,200 distribution transformers.

We understand we are the only distributor to have understood the extent of network constraints for our customers to this level of detail. This has allowed us to understand the percentage of daylight hours for which solar is tripped now and in the future, as shown in figure 6.2:

- the red line indicates the time which solar is forecast to be constrained in 2025 if we undertake no action; this will result in the average customer at 59% of our zone substations experiencing constraints more than 20% of the time
- the blue line represents the outcome after our solar enablement program and the efficient level of constraint; this will result in the average customer only experiencing solar constraints for just over two days of the year in total.

Figure 6.2 Percentage of time solar is constrained by zone substation



Source: CitiPower

We have then compared the cost of removing a voltage constraint with the benefits, as measured by valuing the reduction in wholesale generation fuel costs and carbon reduction benefits from solar. These are benefits that all our customers (even those without solar) will receive. The net benefit to our customers of our program is over $32 million.

By analysing the rich data from our smart meters, we can unlock the value of our customers' solar photovoltaic (**PV**) systems using many low-cost options before we upgrade the local network. The targeted nature of our investment is also consistent with our customer and stakeholder preferences for a proportional program. In table 6.3, we compare the capital investment required under our program to remove most constraints (i.e. the distance between the red and blue lines) to the cost should we attempt to remove all constraints (i.e. the area underneath the blue line).

Table 6.3 Comparison of capital investment alternatives to remove most versus all constraints ($ million, 2021)

Description	Investment
Capital investment required under our solar enablement program	31.5
Capital investment required to remove all solar constraints	99.8

Source: CitiPower
Note: Our solar enablement program also includes an IT and operating component. These are included in the business case and discussed in our ICT and operating expenditure chapters. Forecast shown excludes real escalation.

More broadly, if we do not prepare the network for the volume of solar being connected, the annual amount of constrained solar generation in 2025 across our three networks will be equivalent to the annual output of 2.4 times that produced at the Karadoc solar farm in northern Victoria.[57]

Further detail on our proposed approach to enabling solar investment on our network in the 2021–2026 regulatory period is set out in our attached solar enablement business case.[58]

6.1.2 We're reinforcing our network to provide the electricity 'backbone'

Our network is the most highly used CBD network in the country, and provides the backbone that supports the ongoing growth and development of Melbourne. We serve a diverse range of customers, including cafes and restaurants, major office buildings, sporting precincts like the Melbourne Cricket Ground and tennis centre, and essential services such as hospitals, utilities and public transport network.

Consistent with the capital expenditure objectives in the Rules, we must plan our network to ensure we continue to meet this forecast demand for electricity.[59] This section sets out the key projects we will undertake over the 2021–2026 regulatory period to ensure our network is designed for today's demands and future growth.

Supporting supply in the CBD

Over the past ten years, the south-west of Melbourne's CBD has experienced significant growth. This is being driven by new mixed residential and commercial developments following the redevelopment of the Southern Cross railway station in 2006.

57 Based on the rated capacity of Karadoc, and AEMO's published capacity factor for northern Victorian solar farms.

58 CP BUS 6.02: CitiPower, *Enabling residential rooftop solar*, August 2019.

59 Rules, cl. 6.5.7(a).

This load growth is placing increasing demands on our CBD electrical infrastructure. Specifically, it has driven two separate planning needs:

- consistent with the Electricity Distribution Code, we must provide an 'N-1 secure' level of supply security to CBD load
- consistent with the capital expenditure objectives under the Rules, we must have sufficient capacity to meet expected demand over the 2021–2026 regulatory period.

The Electricity Distribution Code, in effect, requires us to ensure that Melbourne's CBD is 'N-1 secure'. That is, we must be able to maintain electricity supply after the loss of two 66kV cable elements, with an allowance of 30 minutes switching time after the loss of the first element.

The additional load growth in the south-west of the CBD has limited our transfer capability, such that there will be insufficient capacity to meet all demand on our Little Bourke and Little Queen sub-transmission system under the condition when two sub-transmission assets fail. By 2026, an 'N-1 secure' planning standard will not be reached.

Stakeholder feedback

Our CBD security of supply project is vital to the ongoing prosperity of Victoria's economy. The CBD supports 25% of the state's economic value, and over 460,000 jobs—or 15% of Victoria's employment—are based in the CBD. Moreover, almost 20% of the $3.7 billion spent by tourists annually is invested with the CBD's hotels, restaurants, venues, iconic cultural and sports complexes and events.

Throughout the delivery of our security of supply program, we have undertaken significant engagement with our customers. With respect to the program's current works to transform our Waratah Place switching station, the Victorian Minister for Energy, Environment and Climate Change recently stated that 'this upgrade will mean a more secure and reliable electricity supply for Melbourne's CBD and highlights the importance of modernising critical delivery infrastructure'.[60]

Further, our CBD zone substations have a fixed number of feeder exit points available at each site. This is limited by the number and capacity of existing circuit breakers at each zone substation. At our Little Queen and Little Bourke zone substations, which service the south-west of the CBD, the number of feeder connection points is at full capacity, and the number of feeders with sufficient capacity to connect single large loads is nearing capacity.

Any network option to address our N-1 secure standard, or works to enhance feeder capacity in the south-west CBD, will assist the other program. To reach an N-1 secure standard, additional transformers and circuit breakers will need to be developed. This same work is also needed to enhance capacity in the south-west CBD. Accordingly, our options analysis to support our CBD supply considered these two needs in a single, holistic planning solution.

As set out in our attached CBD supply business case, our preferred network solution is to redevelop our Tavistock Place zone substation, and construct new feeders to enable transfers between our Little Bourke and Little Queen zone substations.[61] The investment required to support this approach is set out in table 6.4.

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60 CP ATT213: CitiPower, *Media release - New substation securing power supply in Melbourne CBD*, July 2019.

61 CP BUS 6.01: CitiPower, *CBD supply*, November 2019.

Table 6.4 Supporting supply in the CBD: total forecast investment, 2021–2026 ($ million, 2021)

Description	Investment
Redevelop Tavistock Place zone substation and establish new feeders	25.5

Source: CitiPower
Notes: Forecast shown excludes real escalation.

Ensuring capacity in our Brunswick supply area

Our Brunswick supply area has been transitioning from low-density residential housing to high-density apartment buildings, and this trend is forecast to continue. For example, the Australian Energy Market Operator's (**AEMO**) transmission connection point forecasts show Brunswick as the highest growth area in Victoria, with annual growth rates of around 6%.

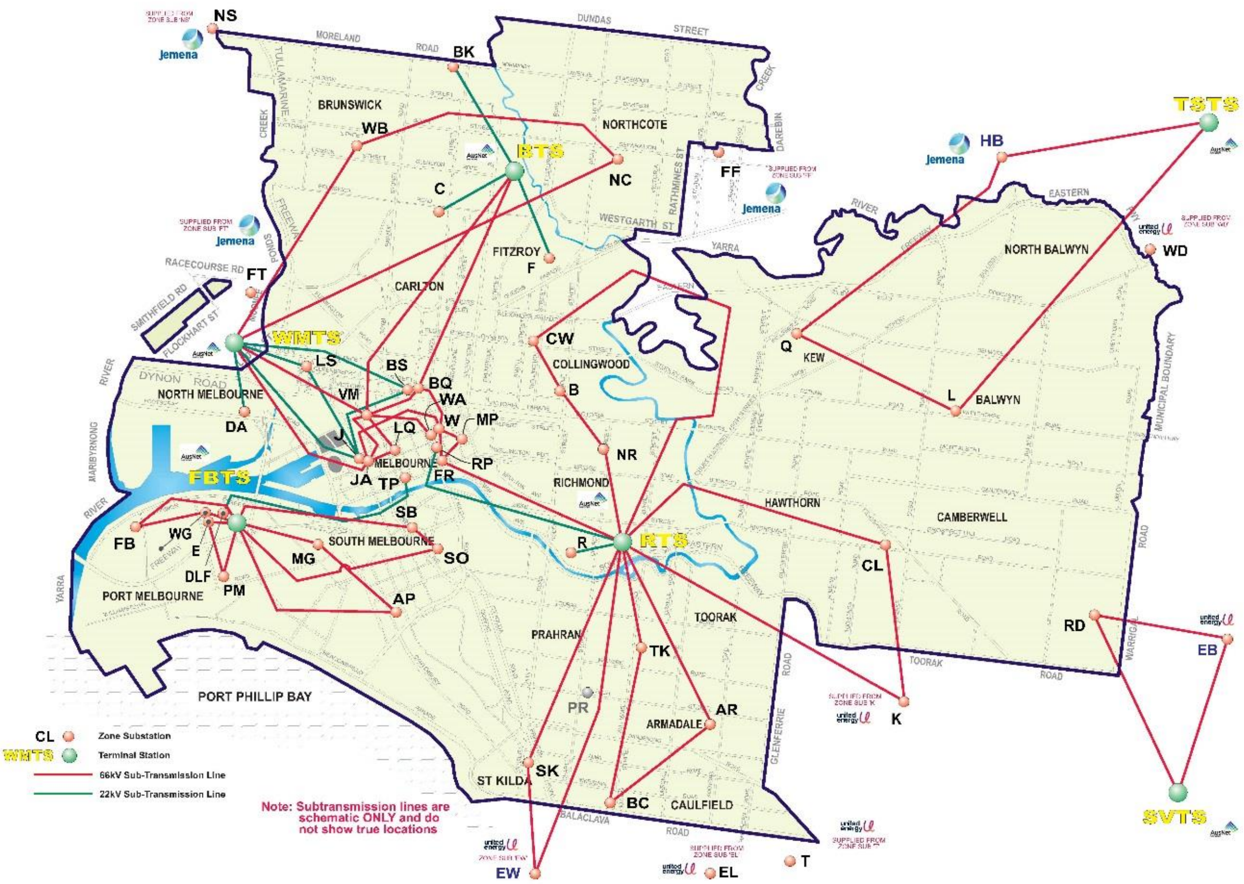
The supply area is currently serviced by a combination of two operating voltages. As shown in figure 6.3:

- our two Brunswick zone substations, and Fitzroy zone substation are supplied by the Brunswick Terminal Station via a 22kV sub-transmission and 6.6kV distribution network (although works are underway to decommission one Brunswick zone substation and transfer load to our West Brunswick zone substation)[62]
- our West Brunswick and Northcote zone substations are supplied by the West Melbourne Terminal Station via a 66kV sub-transmission and 11kV distribution network.

These different operating voltages are a result of evolving industry practice; whereas 22kV/6.6kV is a historical approach, a 66kV/11kV supply is modern industry practice for efficiently servicing areas of greater population density.

[62] The offload and transfer of load from our Brunswick to West Brunswick zone substation has been subject to a RIT-D (published in December 2018). These works are scheduled to be completed in the 2021/2022 financial year.

Figure 6.3 CitiPower supply area (2018)

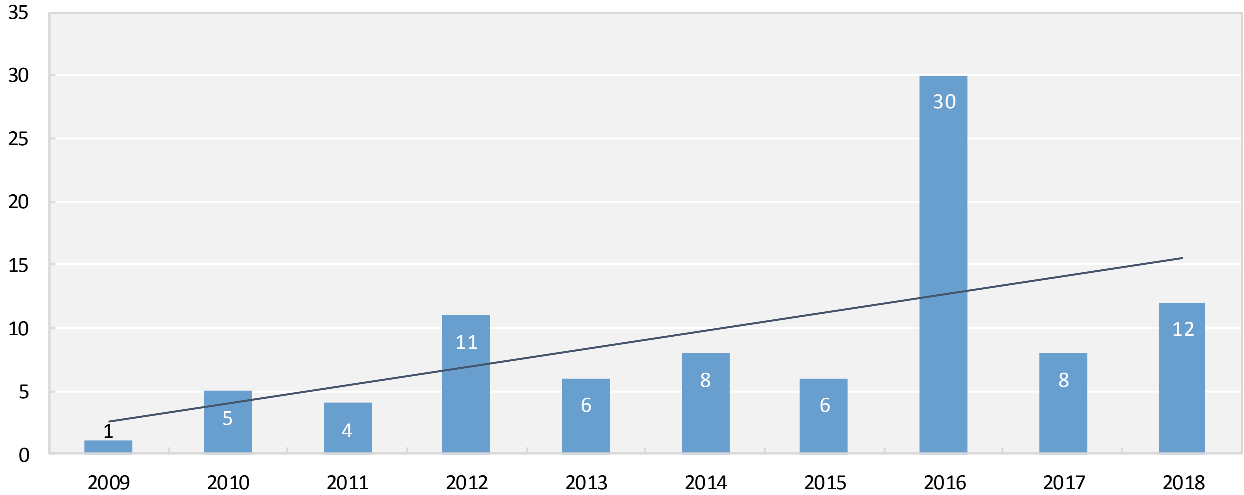


Source: CitiPower

Two of these zone substations—Brunswick and Fitzroy—were constructed almost 80 years ago. The condition of primary plant at both these sites indicates they are approaching the end of their economic lives, with asset ages beyond 55 years. Further, the existing civil buildings are in deteriorating condition and require remediation works.

The poor condition of these zone substations has given rise to an increasing trend in observed defects. This trend is shown in figure 6.4.

Figure 6.4 Number of defects at Brunswick and Fitzroy zone substations



Source: CitiPower

To address the increasing supply and safety risks associated with these zone substations, an independent strategic review of the entire supply area was undertaken by GHD.[63] This recognised that like-for-like replacement of the existing network assets at our Brunswick and Fitzroy zone substations would effectively extend the outdated voltage supply arrangement in the area.

The outcomes of our strategic review of the supply area are set out in our attached business case and risk model.[64] This review compared the cost of alternative network and non-network options to address the identified need against a do-nothing scenario. The evaluation found the most efficient option to maintaining a reliable supply of electricity in the Brunswick supply area is to offload Brunswick to our West Brunswick zone substation, and to offload Fitzroy to our Collingwood zone substation.

Table 6.5 summarises the forecast investment required in the 2021–2026 regulatory period to support these offloads and network reconfiguration, which are all forecast to commence in the current regulatory period.

Table 6.5 Brunswick supply area: total forecast investment, 2021–2026 ($ million, 2021)

Description	Investment
Offload Brunswick zone substation to West Brunswick zone substation	12.0
Offload Fitzroy zone substation to Collingwood zone substation	12.6
Brunswick supply area upgrade (RIT-D)	4.2
Total	**28.7**

Source: CitiPower
Notes: Forecast shown excludes real escalation.

63 CP ATT092: GHD, *GHD report on strategic options evaluation - Brunswick area*, June 2019.

64 CP ATT092: GHD, *GHD report on strategic options evaluation - Brunswick area*, June 2019; CP MOD 6.05 - Brunswick and Port Melbourne - Jan2020 - Public.

Ensuring capacity in the Port Melbourne supply area

Our Port Melbourne supply area is located to the west of the Melbourne CBD. This area is supplied by the Fishermans Bend Terminal Station, and six zone substations.

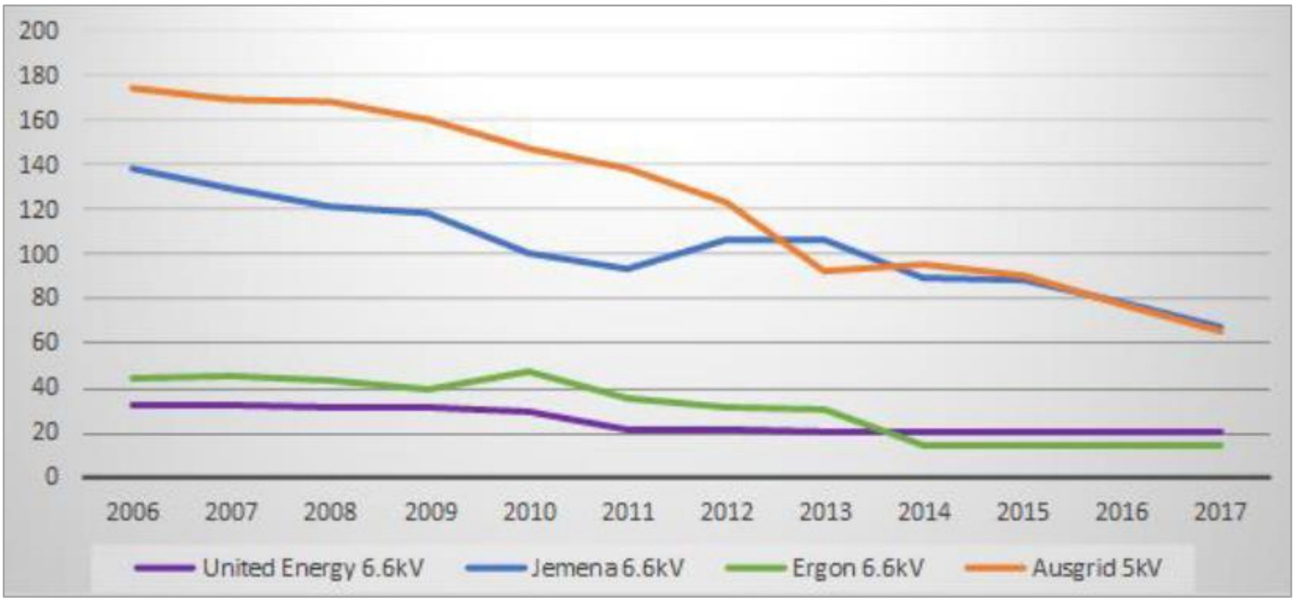
In 2012, the Fishermans Bend area was rezoned from industrial to 'capital city' zone. The stated intent is to transform the Fishermans Bend area of industrial land into a modern development of inner Melbourne. Upon completion of the renewal in 2050, a residential population in excess of 80,000 with provision of 40,000 jobs are expected.[65]

Like our Brunswick supply area, these zone substations are serviced by a combination of two operating voltages—namely, a 66kV/6.6kV and a 66kV/11kV network. Similar concerns also exist regarding the health of the primary plant at our Port Melbourne and Fishermans Bend zone substations, and are again reflected in an increasing trend in observed defects.

The strategic review of our Port Melbourne supply area found that the most efficient option to maintaining a reliable supply of electricity is to offload our Port Melbourne and Fishermans Bend zone substations to our Westgate zone substation. The full justification for this option, including the assessment of alternative options, is provided in our attached business case and model.[66]

The progressive retirement of 6.6kV distribution assets is also consistent with industry practice throughout the NEM. As shown in figure 6.5, other distributors have been replacing these networks with modern equivalents as they reach end-of-life. Our Brunswick and Port Melbourne supply areas are the last remaining locations in our network using these distribution voltages.

Figure 6.5 Progressive retirement of 6.6kV (and 5kV) distribution assets across the NEM



Source: GHD

65 CP ATT230: Melbourne Planning Authority, *Fishermans Bend Strategic Framework*, July 2014, p. 13.

66 CP ATT093: GHD, *GHD report on strategic options evaluation - Port Melbourne area*, December 2018; CP MOD 6.05 - Brunswick and Port Melbourne - Jan2020 - Public.

Stakeholder feedback

Our customers supported the retirement of our assets in Port Melbourne, and the related transfer of load our Westgate zone substation, at our deliberative forums. Specifically, participants at these forums were presented with an overview of the strategic considerations for the supply area, and presented with three investment options:

- option one: continue to maintain and monitor asset condition
- option two: replace existing assets on a like-for-like basis
- option three: retire assets and transfer load to an upgraded Westgate zone substation.

Option three was almost unanimously chosen by customers because it was thought to offer future flexibility, improved safety, power quality and reliability for a slightly lower cost than option two. Some customers wanted reassurance that any unused land would become parklands. If there was a chance that the asset could become derelict, then some customers preferred option two.

A summary of the investment required to offload our Port Melbourne and Fishermans Bend zone substations to our Westgate zone substation is set out in table 6.6.

Table 6.6 Port Melbourne supply area: total forecast investment, 2021–2026 ($ million, 2021)

Description	Investment
Offload Fishermans Bend zone substation to Westgate zone substation	2.4
Offload Port Melbourne zone substation to Westgate zone substation	17.2
Total	**19.6**

Source: CitiPower
Notes: Forecast shown excludes real escalation.

Ensuring capacity in the Russell Place supply area

In December 2019, we published a draft project assessment report for the Russell Place supply area as part of our regulatory investment test for distribution (**RIT-D**) requirements. Our Russell Place zone substation was commissioned in the early 1950s. The zone substation is located in a building basement in the CBD, and supplies approximately 1,022 customers, including the Melbourne Town Hall.

As set out in the draft RIT-D, the identified need is to address the increasing risks to safety and reliability of supply associated with the deterioration of the assets at our zone substation.

Multiple assets, including building structures, transformers, circuit breakers and auxiliary equipment are at the end of their service life. The zone substation is also supplied by aged and unreliable paper lead cables, which are difficult to repair should a fault occur (indeed, previous failures in these cables have resulted in one of the three zone substation transformers being permanently out of service).

The condition of these assets presents an increasing supply and safety risk if they continue in service into the future. As there is limited load transfer capability between Russell Place and the adjacent zone substations, there is a risk that should a major outage occur at Russell Place zone substation, customers will be left without electricity for a sustained period (i.e. as we will be unable to restore supply to all customers until repairs are made and existing assets returned to service or replaced). In addition, in the event of a catastrophic failure of a transformer or circuit breaker, there is a risk of serious injury to staff and major damage to plant and buildings.

The intervention options considered in our draft project assessment report include, for example, a do-nothing option, transferring load to our new Waratah Place zone substation (due for commissioning in 2021), and a like-for-like rebuild of Russell Place zone substation. Non-network options are being sought through the RIT-D process, but given the CBD location, are expected to be uneconomic.

Our detailed economic assessment of these options is set out in our draft RIT-D, attached with our regulatory proposal.[67] The preferred option is to decommission our Russell Place zone substation and transfer load through new HV feeders to our new Waratah Place zone substation.

Table 6.7 sets out the investment required in the 2021–2026 regulatory period to support this option.

Table 6.7 Russell Place supply area: total forecast investment, 2021–2026 ($ million, 2021)

Description	Investment
Russell Place to Waratah Place feeder transfers and de-commissioning	11.2

Source: CitiPower
Notes: Forecast shown excludes real escalation.

Ensuring capacity in our distribution feeder network

In December 2019 the Victorian Government proposed rental housing reforms, including a new minimum standard for all rental properties to have a fixed heater. The accompanying Regulatory Impact Statement expects this will impact on 84,442 rental properties, which will most likely install reverse cycle air-conditions.[68]

These reforms may result in localised load growth that may impact on low voltage (**LV**) network (e.g. feeders). We will continue to assess the impact of these potential reforms for the revised proposal.

Maintaining supply quality

The capital expenditure objectives require that we comply with all applicable regulatory obligations or requirements associated with the provision of standard control services. This includes our quality of supply obligations set out in the Electricity Distribution Code.[69]

Stakeholder feedback

Our stakeholder engagement program found that, generally, our residential customers are satisfied with reliability and power quality, and want existing levels maintained. For example, 56% of residents and 54% of small business customers gave a score greater than nine out of ten when asked if they were satisfied with their existing power quality.

For large commercial and industrial customers, having a reliable power supply is important, but power quality is their biggest concern as these issues are more frequent and have large and wide-ranging impacts on their businesses. Accordingly, they want us to prioritise fixing these issues and to provide clear and timely communication during any incidents.

Our forecast investment required to maintain supply quality in our LV network over the 2021–2026 regulatory period includes the following:

- re-balancing phases to prevent single phase overloads
- upgrades to conductors to prevent voltage drop or allow additional load to be connected
- replacement of transformers that are overloaded (proactively rather than replacing under faults)

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67 CP ATT125: CitiPower, *RIT-D Russell Place zone substation*, January 2020.

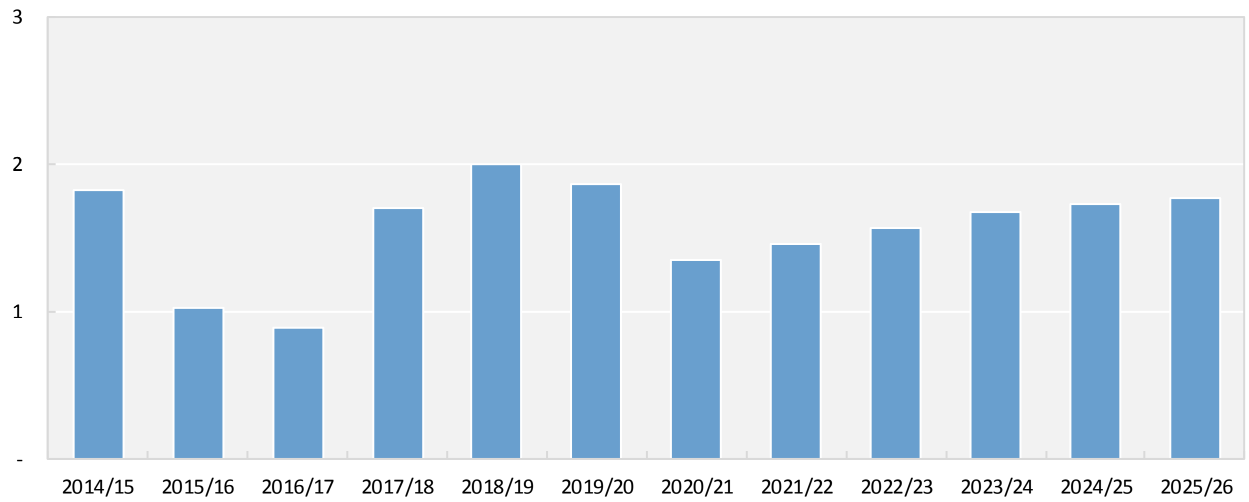
68 CP ATT180: Victorian Government, *Residential Tenancies Regulations 2020 Regulatory Impact Statement*, November 2019, pp. v and 53.

69 CP ATT102: Essential Services Commission, *Electricity Distribution Code*, January 2020, clause 4.

- changing conductors or transformers to address harmonics, flicker or other power quality problems.

We have forecast our supply quality investment based on observed supply quality interventions. As shown in figure 6.6, this investment trends upwards over the 2021–2026 regulatory period in line with load growth expectations for existing and new customers.

Figure 6.6 Supply quality investment ($ million, 2021)



Source: CitiPower

We have also ensured the investment proposed for maintaining supply quality does not overlap with our proposed solar enablement program. Our existing solar policy, whereby we prevent solar export capability if the connection would create a material voltage constraint, ensures that solar driven investment is not included in our historical expenditure or forecasts based on historical expenditure.

Looking forward, although it is conceivable that supply quality and solar enablement works will be required at the same location—meaning only one investment is needed—the potential for any overlap is limited. Our supply quality program will address an average of 23 issues per annum across our population of 4,200 transformers. In turn, our solar enablement program will address 64 sites on average each year. The drivers for these works are fundamentally different, and coupled with the low volumes relative to the total population, the chances of these programs overlapping is minimal.

Our total forecast supply quality investment in the 2021–2026 regulatory period is set out in table 6.8.

Table 6.8 Maintaining supply quality: total forecast investment, 2021–2026 ($ million, 2021)

Description	Investment
LV network augmentation: maintaining supply quality	8.2

Source: CitiPower
Notes: Forecast shown excludes real escalation.

6.1.3 Modernising our network to support customer outcomes

Since 2009, our customers have funded a significant investment in smart meters. We are leveraging this investment to lean more on technology and data than ever before to make smarter network decisions. This facilitates data-driven investments, and helps us better meet customer outcomes at the lowest cost.

As discussed below, the investment required to support smarter network decisions in the 2021–2026 regulatory period includes modernising our communications infrastructure and enabling a digital network.

Supporting a digital network

Distribution networks across the world are currently going through some of their largest transformations in history. These transformations are being driven by changing customer requirements, including increased participation in new demand management programs, and the expected take-up of electric vehicles (**EVs**) and batteries.

During the 2021–2026 regulatory period, we will implement more advanced technology capabilities through our digital network initiative. This will allow us to make smarter and more dynamic network decisions to improve safety outcomes and support customers as they take up new innovations, all while keeping the costs of running the network down.

Most of the investment required to develop a digital network is included in our IT program. This program, however, also includes a network element—specifically, the targeted rollout of network devices at contestable metered sites or distribution transformers—that is captured in the network communications component of our augmentation forecast. These devices will provide real-time consumption and power quality information.

The full justification for this program, including the corresponding options analysis, is set out in our digital network business case.[70] Table 6.9 shows the investment required for the network component of this program.

Table 6.9 Digital network: network device investment, 2021–2026 ($ million, 2021)

Description	Investment
Digital network: network devices	5.5

Source: CitiPower
Notes: Forecast shown excludes real escalation.

6.2 Our forecasting approach

This section outlines how we plan our network to ensure our customers can continue to choose how they use electricity. This includes an overview of the following:

- the drivers of our augmentation investment
- our planning policies, and how these manage risk
- how non-network solutions are assessed through cost-benefit analysis to ensure we only invest where and when it's needed.

Our augmentation forecasts are consolidated in our attached augmentation and communications models.[71]

6.2.1 Our augmentation investment is driven by both demand and non-demand factors

Our forecast augmentation investment includes both demand driven and non-demand driven projects.

[70] CP BUS 7.08: CitiPower, *Digital network*, January 2020.

[71] CP MOD 6.01 - Augex - Jan2020 – Public; CP MOD 6.04 - Network comms - Jan2020 - Public.

Demand-driven augmentation investments

Localised maximum demand on our network is a key driver of our forecast augmentation investment. Where demand is expected to exceed the capacity of our network in a particular area, we look to intervene to ensure we continue to maintain a reliable supply of electricity to our customers. These interventions, which also have regard to risk (as discussed in section 6.2.2) may include reconfiguring our network, additional infrastructure, or implementing non-network solutions.

Our approach to forecasting demand for the 2021–2026 regulatory period combines our own detailed local knowledge with independent economic analysis by the Centre for Independent Economics (**CIE**). A summary of our approach is set out in figure 6.7.

A more detailed discussion is provided in our demand forecasting attachment.[72]

Figure 6.7 Overview of our demand forecasting approach

Top-down forecast
Independent top-down forecasts of terminal station loads were developed by CIE

Post-model adjustments
Post model adjustments, such as for block loads and known embedded generation, and independent technology forecasts (i.e. solar PV) from Oakley Greenwood

Bottom-up forecasts
Zone substation and feeder forecasts developed from local demand/generation characteristics and customer metering data

Bottom-up reconciliation
Our zone substation demand forecasts are reconciled to the top-down terminal station forecasts to ensure consistency

Source: CitiPower

Non-demand driven augmentation investment

We also plan our network to manage non-demand driven factors. These include compliance obligations, considering the impact of future fault currents, voltage levels and voltage quality, and whether these factors are forecast to exceed the levels stipulated by regulatory obligations.

<u>Fault levels</u>

A fault is an event where an abnormally high current occurs as a result of a short circuit somewhere in our network.

We estimate prospective fault current to ensure it is within allowable limits of the electrical equipment installed, and to select and set protective devices that can detect a fault condition. Devices such as circuit breakers, automatic circuit reclosers, sectionalisers and fuses can act to break the fault current to protect the electrical plant, and avoid significant and sustained outages as a result of plant damage.

Fault level mitigation programs are increasingly required on our network as the level of embedded generation being directly connected to our network increases.

72 CP APP03: CitiPower, *Maximum demand and customer numbers*, January 2020.

Voltage levels

We are required to maintain customer voltages within specified thresholds set out in the Electricity Distribution Code.[73]

Voltage levels are important for the operation of all electrical equipment, including home appliances with electric motors or compressors (e.g. washing machines and refrigerators), and farming and other industrial equipment. These appliances are manufactured to operate within certain voltage threshold ranges.

Voltage levels are affected by a number of factors, including the export of electricity onto our network, impedance of transmission and distribution network equipment, length of sub-transmission and distribution feeders, and load and capacitors in our network.

Quality of supply (to other network users)

The connection of embedded generators or large industrial customers to our network may result in a reduction of the quality of supply experienced by other customers on our network. In these circumstances, we may invest to ensure we maintain quality of supply across our network.

These investments are typically undertaken following system studies as part of the new customer connection process.

Compliance with regulatory obligations

As outlined previously, we are subject to requirements set out in the Electricity Distribution Code regarding maintaining the security of supply to the CBD.[74]

6.2.2 Our planning processes prioritise key network risks

We apply a probabilistic approach to planning all our demand-driven investment decisions. This approach involves estimating the probability of an outage occurring within the peak period, and determining the energy at risk of not being supplied.

The energy at risk of not being supplied is assigned a monetary value based on how much customers value reliability. The value of customer reliability (**VCR**) we apply is that determined by AEMO, adjusted for inflation.[75]

Our augmentation forecast only includes capital works where the cost of mitigating a forecast constraint is lower than the monetised value of energy at risk, and a lower cost demand side solution is not feasible.

Ultimately, probabilistic network planning aims to ensure that an economic balance is struck between:

- the cost of providing additional network capacity to remove constraints
- the cost of having some exposure to loading levels beyond the network's capability.

In other words, we recognise that given extreme loading conditions may occur for only a few hours in each year, it may be uneconomic to provide additional capacity to cover the possibility that an outage of an item of network plant may occur under these conditions.

73 CP ATT102: Essential Services Commission, *Electricity Distribution Code*, January 2020, clause 4.

74 CP ATT102: Essential Services Commission, *Electricity Distribution Code*, January 2020, clause 3.1A.

75 The AER is now required to develop an estimate of the VCR, and published new VCRs on 18 December 2019. These VCRs, however, have not been reflected in this regulatory proposal.

6.2.3 We continue to seek non-network solutions

We consider and adopt non-network solutions, including demand management, to avoid or defer the need to invest in network augmentation when it is efficient. We seek non-network solutions through our distribution annual planning report (**DAPR**) and public forums on our entire demand-driven augmentation program, when undertaking a RIT-D for major augmentation works, and through our demand side engagement register.

We are committed to continuing our engagement with the broader industry and our customers to seek further opportunities for growing non-network solutions in the 2021–2026 regulatory period.

6.2.4 Our unit cost forecasts are based on recent historical costs

We forecast costs for capital projects based on recent historical costs for efficiently delivered projects of similar scope, size and geographic locations. As the second most cost-efficient distributor in Australia based on AER benchmarking, we consider our historical costs provide a reasonable basis for forecasting future investment requirements.

We also use rates from service providers that are derived from periodic tendering where available and appropriate. This includes our materials cost forecasts, which are procured through stringent contracting arrangements.

We adjust costs for forecast growth in real input prices over time, such as labour, materials and contracted services.

6.2.5 We will deliver our augmentation program with support from our resource partners

Our labour force is structured to provide flexibility in managing labour resources, including our internal field services staff and arrangements with resource partners. This allows us to deliver our total capital program, including the forecast increases in investment over the 2021–2026 regulatory period.

Further details on our labour contract types are included in section 4.2.4 of our replacement investment chapter.

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7 Information and communication technology

Summary

Information and communications technology (**ICT**) is integral to a modern electricity distribution network. Our customers view reliability, affordability and the privacy of their data as top priorities, and maintaining the currency of our ICT systems allows us to continue to deliver these services effectively and affordably. Our recurrent ICT investment will focus on:

- cyber-security—capabilities to maintain pace with an evolving threat landscape. This includes developing security on access and control of the supervisory control and data acquisition (**SCADA**) system, which is critical to ensuring we maintain security of the distribution system and provide reliable electricity to customers.
- market systems—we will prudently deploy version upgrades to maintain support for our systems which manage the delivery of data to the market including AEMO, retailers and our customers.
- network management systems—we will maintain the currency of the systems that directly manage our network. This is critical to maintaining the safe, reliable, secure and efficient delivery of network services.
- cloud-infrastructure—as part of our continued search for the most efficient approach to delivering IT services, we will migrate some of our existing on premise IT infrastructure to cloud hosting and deliver cost savings for customers.

We will also maintain the currency of other systems, including our facilities security, business intelligence and warehousing, telephony, and enterprise market systems.

Further, our ICT investments will enable us to improve customer experience, respond to changes in the energy market, drive improvements to our network planning and operations, and meet new compliance obligations. This non-recurrent ICT investment will focus on:

- digital network—we will develop a smarter network that responds to the transformation underway in the energy market, ensuring we can run the network safely and more efficiently
- customer enablement—this program will improve the way customers access information, saving them time and effort through unifying customer portals and using artificial intelligence to ensure customers receive better services when they contact us
- SAP upgrade—we will upgrade to the latest SAP product once vendor support on our existing product ends
- five minute settlement—under rule changes determined by the AEMC, we must enhance existing systems to provide five minute interval data for market settlement (by December 2022)
- intelligent engineering—we will improve data accuracy to improve employee and community safety.

At the heart of our success at delivering major ICT projects is a prudent approach to adopting technology that provides tangible benefits to our customers. Throughout the 2021–2026 regulatory period, we will continue to invest in our ICT to help provide safe, secure, reliable and affordable services to our customers.

Technological change is occurring at an accelerated pace and is being impacted by a number of trends. This includes an explosion in available data, the ability to realise new insights through analytics, emerging cyber security threats, rising customer expectations on service provision, more automation and increasingly complex ICT environments. These trends provide opportunities and challenges for us and our customers in the 2021–2026 regulatory period.

Our proposed ICT investment over the 2021–2026 regulatory period is set out in figure 7.1.[76] This includes both recurrent and non-recurrent investments, consistent with the AER's ICT expenditure guideline.[77]

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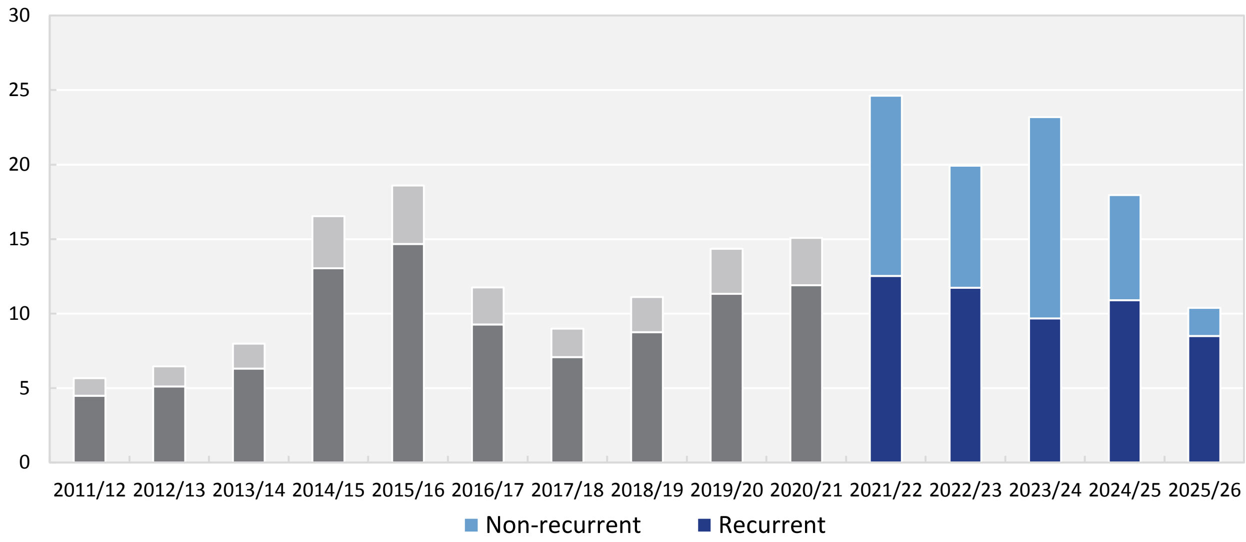
[76] This investment is in alignment with the capital expenditure objectives as stipulated by cl 6.5.7(a) of the Rules and addressing the capital expenditure criteria as specified in cl 6.5.7(c) of the Rules.

[77] While some of our initiatives have both recurrent and non-recurrent investment (as outlined in detail in the respective business cases), below we have outlined them by their primary driver.

Figure 7.1 Forecast ICT investment ($ million, 2021)



Source: CitiPower
Notes: Forecast shown includes real escalation. The peak in expenditure in 2021/22 is a result of large investments to comply with our five-minute settlement obligations.

Table 7.1 also shows our ICT investment for the 2021–2026 regulatory period.

Table 7.1 Forecast ICT investment ($ million, 2021)

Description	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Total	24.6	19.9	23.2	18.0	10.4	96.1

Source: CitiPower
Notes: Forecast shown includes real escalation

7.1 What we plan to deliver

ICT ensures we can efficiently and affordably provide a safe and reliable network, improve the way we deliver services to customers, and support the delivery of new innovations.

This section describes the ICT initiatives we plan to deliver in the 2021–2026 regulatory period, and our track-record in delivering ICT projects. While some of our initiatives have both recurrent and non-recurrent investment (as outlined in detail in the respective business cases), below we have outlined them by their primary driver.

7.1.1 Recurrent investment

Recurrent ICT is investment related to maintaining existing ICT services, functionalities, capability and/or market benefits. Our recurrent investment remains in line with history, reflecting our business-as-usual requirements. Table 7.2 summarises our proposed recurrent ICT investment by project.

Table 7.2 Summary of proposed ICT capital investment for recurrent projects ($ million, 2021)

Project	Investment
Cyber security	8.3
Cloud infrastructure	10.8
Market systems	2.8
Network management systems	8.5
Device replacement	1.1
Business intelligence and warehousing	5.8
Enterprise management systems	4.4
Telephony	1.7
Facilities security	2.6
General compliance	4.6
Total	**50.6**

Source: CitiPower
Notes: Forecast shown excludes real escalation

We will ensure our ICT systems remain secure from cyber threats

We are a key part of Australia's critical infrastructure and deliver services essential for everyday life such as manufacturing, transport, communications, health and finance.

The technologies we use to provide this critical infrastructure are connected and accessible in ways that were not possible even just 10 years ago. In this context, although technology has provided us with many benefits, it exposes us to risks, including corruption to our systems and files from computer viruses, sensitive data being stolen through hacking, and entities attempting to take control of the network. For example, in 2015 in Ukraine, a cyber attack resulted in power being lost to more than 230,000 residents.

The Australian Cyber Security Centre also ranks the energy sector in the top four industries most at risk of a cyber-security threat.[78] Similarly the *Security of Critical Infrastructure Act 2018 (Cth)* was developed in recognition of the evolving national security risks to infrastructure including electricity assets from sabotage, espionage and coercion.

Given the potential consequences of a security breach, we must ensure the security of our IT and systems keep pace with new threats. This is consistent with our stakeholder feedback, where our customers viewed keeping our network data and their privacy secure as a core value proposition.

[78] CP ATT177: Australian Government, Australian Signals Directorate, *ACSC Threat Report 2017*, October 2017.

Our assessment of a range of options for managing these growing risks found that our current security systems can be extended to more effectively prevent cyber security attacks and incidents. This includes refreshing our security for SCADA access to ensure we retain proper authorisations to control the network.

Further information on our options analysis, such as costings for each alternative and our risk monetisation assessment, is available in our cyber security business case.[79]

We will transition to cloud

In the 2016–2020 regulatory period, we embarked on a strategy to migrate core applications supported by on-premise ICT infrastructure to cloud hosting. This arrangement gave us flexibility to choose the right technologies, and to alter services or providers in response to changing business requirements.

With the maturing of cloud offerings, we now have an opportunity to further migrate existing on-premise infrastructure to cloud. A flexible cloud-based approach will lower costs to customers, and provide the following advantages:

- adaptability to changing business requirements, because we can change services more readily
- scalability to ensure we can manage our costs, because cloud services are based on capacity and use
- reduced reliance on vendor support, because we can more easily switch service providers
- avoiding the need to manage maintenance or replacement.

The full justification and risk-monetisation for our proposed migration is available in our cloud infrastructure business case.[80]

We will maintain and support our existing systems

The majority of our ICT investment is to maintain the capabilities of our existing suite of technologies. In the 2021–2026 regulatory period, these investments include:

- market systems—our market systems provide centralised storage and validation of meter reading data, manage market communications and manage customer requests in accordance with our compliance requirements. Technical currency is essential to ensure continued vendor support and compatibility with the integrated software. We have proposed a prudent approach by adopting every second system release, which delivers savings to customers.[81]
- network management system—these comprise core operational systems such as GIS, Outage Management System and Distribution Management system, which are used to manage network operations. Retaining the currency of these systems is essential to continue monitoring and operating the network in real-time, 24 hours a day, as needed to maintain a safe, reliable and secure network.[82]
- business intelligence and business warehousing (**BI/BW**)—we will implement a low cost central data repository to improve the speed and effectiveness of reporting and decision-making, for example in relation to network management, customer service and compliance reporting. The single central data repository will

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79 CP BUS 7.04: CitiPower, *Cyber security*, January 2020.

80 CP BUS 7.10: CitiPower, *Cloud infrastructure*, January 2020.

81 CP BUS 7.06: CitiPower, *Market systems currency*, January 2020.

82 CP BUS 7.05: CitiPower, *Network management systems*, January 2020.

be shared between CitiPower, Powercor and United Energy, consolidating four data warehouses to one, resulting in a near 40% saving across the three businesses.[83]

- devices—we have a highly mobile workforce which needs access to applications to perform their roles and communicate reliably. As a result, our workforce uses computers, phones, mobile tablets, and other devices. These devices require replacement on a periodic basis as the asset reaches the end of its expected life to maintain the current level of operational performance. These devices are essential for retaining the $20 million productivity savings realised through our Click program, which would be lost if our devices are not properly maintained.[84]
- enterprise management systems—ensure we maintain currency of applications relating to asset investment planning, corporate services, customer platforms, data management and field services. These are reaching end of life or will no longer meet business requirements due to changes in technology, customer requirements or cyber security threats.[85]
- telephony—maintain currency of our telephony systems used for contact centre, corporate and control room functions with incremental improvements to the customer experience.[86]
- facilities security—enhance the IT systems underpinning facility security (i.e. CCTV cameras, gates and keys) and maintain the processes that integrate site access with authorisation records in place of manual processes, to prevent safety issues from unauthorised access.[87]
- general compliance—we operate under rules and obligations that impact on the data and support our ICT systems must provide. These obligations are periodically amended. This project investment is in line with current levels and is needed for smaller periodical updates (as opposed to known material structural changes, such as metering contestability or five minute settlement).[88]

Each of the projects above have an associated business case, which provides more detail on the proposed investment, costs, and alternative solutions explored. These proposed measures are all designed to ensure we continue to provide a safe, reliable and secure network for customers while ensuring value and affordability. Our risk monetisation analysis demonstrates the cost to maintain system currency is efficient relative to the high value of risk which would occur if systems are not maintained.

7.1.2 Non-recurrent investment

Our forecast non-recurrent investment is shown in table 7.3. These investments include technologies to unlock new benefits for customers, as well as that required to comply with new regulatory obligations.

83 CP BUS 7.03: CitiPower, *Business intelligence, reporting and data management*, January 2020.

84 CP BUS 7.12: CitiPower, *Device replacement*, January 2020.

85 CP BUS 7.11: CitiPower, *Enterprise management system,* January 2020.

86 CP BUS 7.13: CitiPower, *Telephony,* January 2020.

87 CP BUS 8.01: CitiPower, *Facilities' physical security upgrade*, January 2020.

88 CP BUS 7.14: CitiPower, *General IT compliance*, January 2020.

Table 7.3 Summary of proposed ICT capital investment for non-recurrent projects ($ million, 2021)

Project	Investment
Digital network	11.1
Customer enablement	3.5
Intelligent engineering	4.4
SAP upgrade	12.9
Five minute settlement	8.9
Solar enablement	1.1
Total	**41.9**

Source: CitiPower
Notes: Forecast shown excludes real escalation.

We will develop a more digital network

The energy landscape is changing rapidly with increasing penetration of household solar, batteries, EVs. However, altered usage needs and the reverse power flows created by these innovations will make it more difficult to predict and manage power flows on the network.

In the 2021–2026 regulatory period, we will extend our network devices to customers without smart meters, implement data platforms and conduct new analytics to improve network visibility. Over time, this will allow us to manage the network efficiently in near real-time, through better forecasting, monitoring, diagnosis and eventually through automation. This will enhance network safety, efficiency and reduce network augmentation to lower customer bills over the long term.

Specifically, our digital network initiatives include:

- promoting the uptake of new technologies—by allowing us to monitor the impact of increasing EV penetration on demand and optimise charging away from peak times, we will be positioned to facilitate the uptake of EVs while mitigating the risk of excess demand at peak times (preventing the need for augmentation)
- optimising load control of customer appliances—optimising existing hot water load control and enabling new load control programs (e.g. air conditioners, pool pumps, fridges), including through utilising excess solar in the middle of the day
- enhancing cost reflective pricing—analysing meter data to construct more effective time-of-use tariffs or demand response to reduce peak demand and improve overall utilisation of the distribution network
- improving the equity of energy usage—identifying sites with bypass connections to reduce theft and monitoring variable unmetered supply to ensure energy usage is allocated fairly between customers
- proactively managing asset failures—develop greater predictive capabilities for asset condition to better determine when assets will fail, resulting in less network investment
- avoiding overblown fuses—improving phase balancing, which will allow greater asset utilisation and avoid replacing blown fuses

- looking after vulnerable customers—more accurate mapping of customers to the network to ensure we keep more life support customers connected during outages and provide more accurate communications to customers on planned outages
- keeping customers safe—improving the way we identify loss of neutral at customers' homes, which can pose major safety issues of electric shocks if left unchecked.

We commissioned Jacobs to quantify the benefits of three different implementation options to ensure we provide the maximum benefit to customers. These options involved no additional investment, solely rolling out technology platforms, and rolling out both technology and extending network visibility through additional network devices. Jacobs determined that rolling out both technology and extending our device coverage would provide the largest net benefit to customers.

More information is available in our digital network business case.[89]

We will improve customer enablement

The improvement in customer service across industries means our customers expect to interact with us in a variety of ways, including through better online experiences. We understand customers want simple and customised responses, and for us to proactively provide information.

Stakeholder feedback

We have heard from our customers that they want a streamlined and accessible experience online. When surveyed, 65% of customers stated they were interested in accessing real-time data and just under three-quarters of residents would use this data to seek rebates or savings.

> *'I look at my accounts now and a year ago to see if usage is the same as last year. That is all I do. I feel a bit in the dark at the moment.'*

Many participants in our forums also requested that we invest in a 'one-stop-shop'.

Over the 2016–2020 regulatory period, we steadily improved our customer-facing applications. In the 2021–2026 regulatory period we will continue our journey to provide services that align with our customers' needs and expectations—for example, our customer enablement program includes:

- consolidating our online portals to provide an integrated customer experience such as through a single username, password and interface (i.e. a one-stop-shop)
- improving the capabilities of myEnergy to provide data analytics and customer notifications
- improving the effectiveness of SMS notifications during outages and introducing notifications on the efficiency of customers' rooftop solar output and exports
- providing customers with access to more frequent usage data on a mobile application to better inform their energy choices.

As detailed in our attached business case, our customers will benefit from our customer enablement program through saved time and effort in accessing their information and receiving more targeted notifications about outages and their solar rooftop systems.[90]

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[89] CP BUS 7.08: CitiPower, *Digital network*, January 2020.

[90] CP BUS 7.02: CitiPower, *Customer enablement*, January 2020.

We will establish intelligent engineering capabilities

Our customers view network safety as a core and unquestionable priority.

Our intelligent engineering business case sets out how we will leverage new technology to improve the safety of our employees and the community, and more effectively manage the network.[91] For example, we will improve the accuracy 'dial before you dig' to deliver improved safety outcomes and protect network assets when our customers perform works.

Improving our data management capabilities will also decrease network design planning timeframes, as more accurate data will allow us to automate processes, reduce network planning and design costs.

We will perform a major upgrade to SAP S/4 HANA

We use a SAP system to perform essential business functions that underpin our financial reporting, support our customer connections processes and help maintain the safety of our network by capturing the maintenance activities conducted on our assets. Our existing SAP platform which will reach the end of its lifecycle and end of vendor support by 2025.

We analysed five different options for managing the risks associated with an 'unsupported' system, and determined the lowest cost and risk path involved upgrading SAP (as opposed to moving to new vendors or a third party support model). This analysis was informed by recent experiences with third party support arrangements, which increased complexity and costs in the longer term.

Further, integrating IT systems between the three distribution networks we own and operate—CitiPower, Powercor and United Energy—rather than maintaining them as separate systems, will provide synergies that lower the costs by $5.4 million.

The full justification for our SAP S/4 HANA upgrade is available in our attached SAP business case.[92]

We will meet new five minute settlement compliance requirements

We must enhance our ICT systems to comply with changes to the Rules that require us to provide five minute interval data for NEM settlement. In particular, any smart meter installed after December 2018 must have the capability to record five minute interval energy data by December 2022.

Our current ICT systems do not have the capacity to provide five minute interval energy data to the market. As detailed in our five minute settlement business case, a bottom-up review of the required system changes found that system changes will be required to collect and validate five minute interval data.[93]

We will enable more solar

As outlined in section 6.1.1, we are preparing our network to enable more solar. An important component to ensure this occurs at the least-cost for customers is developing a dynamic voltage management system—an IT system to remotely and dynamically manage network voltages at the zone substation level of our network.

We are investing to develop this system, and more information is available in our solar enablement business case.[94]

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91 CP BUS 7.07: CitiPower, *Intelligent engineering*, January 2020.

92 CP BUS 7.01: CitiPower, *SAP S/4HANA*, January 2020.

93 CP BUS 7.09: CitiPower, *5 minute settlement,* January 2020.

94 CP BUS 6.02: CitiPower, *Solar enablement*, January 2020.

7.1.3 Delivering projects through a rigorous and flexible approach

We have a strong track record of delivering large IT projects within scope, time and budget. Examples include implementing systems to support the rollout of smart meters across our network, upgrading systems to enable meter contestability, establishing 'Click' to optimise field service delivery, and implementing our online portal eConnect to streamline the way we connect customers. As a result, we are highly adaptable to changes in systems and processes, allowing us to realise the benefits of ICT programs swiftly.

A key way we are able to deliver large projects while minimising associated projects risks and costs is through vendor support and third party contractors. We can ramp up resources when a project's workload peaks, before returning labour to normal levels as the project scales down. This is especially advantageous in delivering large-scale IT projects, which require greater and lesser resources at different stages of a project. In this way we ensure we appropriately resource projects to achieve our milestones effectively and efficiently.

We also provide appropriate project oversight through a rigorous governance process. This helps to ensure key strategic decisions about the business remain in-house. Projects are coordinated through our internal project management office to ensure we have the right mix of internal and external skills. Our resources are managed at both the project and program level to ensure we take interdependencies into account.

Further information is available in our attached IT delivery plan.[95]

7.2 Our forecasting approach

We only invest in ICT when there is a clear benefit to customers. Our forecasting approach to support this aim is described below:

- our starting point was to assess our existing ICT capabilities and the services they provide to our customers. As part of this, we identified whether elements of our existing ecosystem were no longer providing value to customers.
- we examined synergy opportunities to integrate our ICT systems with United Energy, weighing up the risks to systems and business processes from such integration activities. This built upon work in the 2016–2020 regulatory period, where we aligned our vegetation management reporting system, ICT issue resolution systems and telephony systems. In the 2021–2026 regulatory period, we identified synergy opportunities where system alignment will reduce overall project implementation costs for our customers as we upgrade SAP and consolidate BI/BW data storage.
- we considered whether existing systems can withstand maturing and emerging cyber-security threats. Unless we maintain and continue to develop our cyber security tools, they quickly become irrelevant and ineffective, risking the security of the network operations and data privacy.
- we then forecast the efficient level of investment needed to retain the effectiveness and security of existing capabilities.

Overall, we found that most of our existing technologies will continue to provide benefits to our customers in the 2021–2026 regulatory period. This reflects the prudency of our investment choices in the past and that our ICT ecosystem has been carefully designed over time.

We also considered whether new technologies can address key business requirements including to enhance safety, ensure compliance and improve service delivery to customers at least cost. In addition to developing

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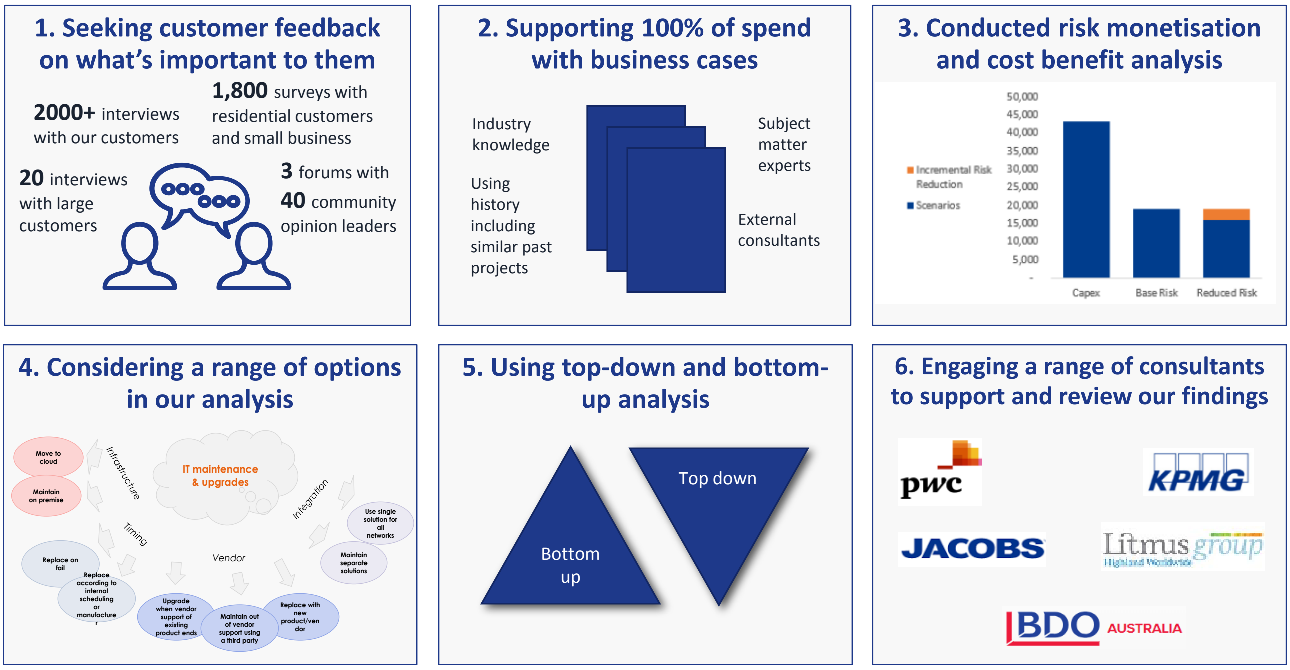
95 CP ATT007: CitiPower, *IT deliverability plan*, January 2020.

robust business cases for these projects, we tested these new projects with customers and other stakeholders, to ensure we prioritised our investments in areas customers most value.

7.2.1 Ensuring a cost-efficient approach

We ensured efficiency was at the cornerstone of developing our forecast through a number of measures as shown and discussed below.

Figure 7.2 Developing forecasts



Source: CitiPower

We weighed up the costs and benefits at a project level to determine the true value of a project for customers, including for recommended options and non-recommended options. We determined expenditure at a granular level, applying unit costs based on past projects of a similar scale and complexity, using external labour rates and known vendor costs, and seeking external validation.[96]

Where we have identified projects that are driven by customer benefits but have potential expenditure savings that may be realised over the 2016–2020 regulatory period, we have taken these savings into account. In the case of operating expenditure savings, we consider these projects contribute toward the 0.5% pre-emptive productivity adjustment. As an efficiency frontier network, we have already achieved considerable productivity improvements through investment in new technologies and changes in operating practices and have limited capacity to achieve the 0.5% productivity adjustment through business as usual activities during the 2021–2026 regulatory period. In the case of capital savings, we have netted these from our 2021–2026 forecasts.

96 CP ATT153: CitiPower, *IT external labour rates*, March 2019.

We also subjected the portfolio to a top down challenge. We engaged PwC Australia (**PwC**) to assess whether individual projects could be better prioritised or delivered more efficiently in order to optimise value for our customers.

7.2.2 We take a risk-based approach to assessing projects

To inform our IT investments, we have started analysing projects through a risk-based framework to help quantify whether a projects risk outweighs its expected cost. In this way we are able to holistically determine the potential costs involved in an investment decision for customers. This work is based on AER guidelines and internal analysis to monetise network risk, but is adapted for the ICT landscape.

Under this approach we use a deterministic view (i.e. we consider the risks at a point in time, instead of considering how risk changes over the years under a probabilistic approach). This is due to a lack of available data to reliably predict the probability of ICT asset failure over time both internally and in the broader ICT community. However, this work provides strong foundations for developing our approach over time.

Approach

Our ICT risk monetisation approach is described as follows:

- quantify the risks involved in a 'do nothing' case of not investing to maintain vendor support, and instead using an unsupported system
- quantify the risks of the proposed and alternative options, including business as usual options
- compare the 'do nothing' case to the proposed and alternative options to determine the highest risk-mitigation option

We have considered two primary risks—ICT risk and business risk—and have not exhaustively covered every risk. More information these two risk categories is discussed in below.

Risks quantified in our ICT risk monetisation

ICT risk considers the immediate risks to ICT teams and users of a system. They are captured through assessing the probability and impact of the following risk types:

- outage—the direct financial consequences incurred by an ICT team in the event of an outage, including the lost productivity from staff being unable to use systems and any remediation or workaround activities required.
- cyber security breach—the direct financial consequences for an ICT team in the event of a breach.
- suitability—the consequences of continuing to use an existing ICT asset that is unable to meet the future needs of the underlying business process it supports. This is driven by changes in process requirements over time, and is typically due to external factors (e.g. introduction of a GST).
- system sustainability—the consequences from not undertaking required maintenance activities, such as internal maintenance or patches to ensure the continued health and stability of ICT assets. This impacts on the health and performance of a system, resulting in lost productivity.

The financial consequences of these ICT risks are valued in terms of lost employee utilisation and rectification costs. Lost employee utilisation is measured according to the estimated employee hours impacted. Rectification costs assess the number of employee or specialist hours, associated fixed costs with identifying and resolving a risk event, implementing workaround activities and activities to prevent the issue occurring again.

Business risk considers the wider risks encountered by the business and the community as follows:

- reliability—the reliability consequence to the network arising from the failure of an ICT asset, as measured via the applicable VCR.
- compliance—the direct financial consequences associated with regulatory or legislative compliance breach arising as a result of failure of an ICT asset. This can be measured by compliance penalties and associated legal or regulatory costs.
- customer experience—the direct financial consequence associated with adverse impacts to customer interactions arising as a result of a failure of an ICT asset. For example, this can be valued according to the value of customer time.

Source: CitiPower

To quantify the ICT and business risks described above, we use the following data sources:

- existing IT data (e.g. outage data, frequency of patches, number of compliance updates required each year)
- other relevant network data (e.g. connection requests, de/energisations)
- documented assumptions where data is not available.

A key source of data has been the result of an incident at United Energy, which reveals how inadequate investment in ICT systems can affect customers and the network. A case study of this experience is provided in figure 7.3.

Figure 7.3 Case study: United Energy supercluster incident

Prior to acquisition, United Energy had a heavily outsourced model

- It consisted of a small management team, overseeing a large number of vendors and contractors
- As a result, a number of key strategic decisions were effectively outsourced

This led to a number of issues, including the 'Supercluster'

An unsuitable vendor solution was implemented, which had:

1. Shared storage, providing a single point of failure and creating poor reliability
2. Low performance of the Disaster Recovery solution
3. Limited connectivity options due to architecture

This had a number of issues impacting customer:

- Suspended meter reading, risking regulatory compliance
- Billing delays impacting ~$12M revenue
- Inability to access work schedules and service orders
- Unavailability of life support reporting
- High call times as front of house call staff had to default to manual service requests
- Extended customer outage times, and delays in Live Line and Tree Clearing

Source: CitiPower

8 Non-network

Summary

Non-network investment includes property, fleet, tools and equipment. This is necessary to support the operation of the network and deliver a safe and reliable service for our customers. In the 2021–2026 regulatory period, we will:

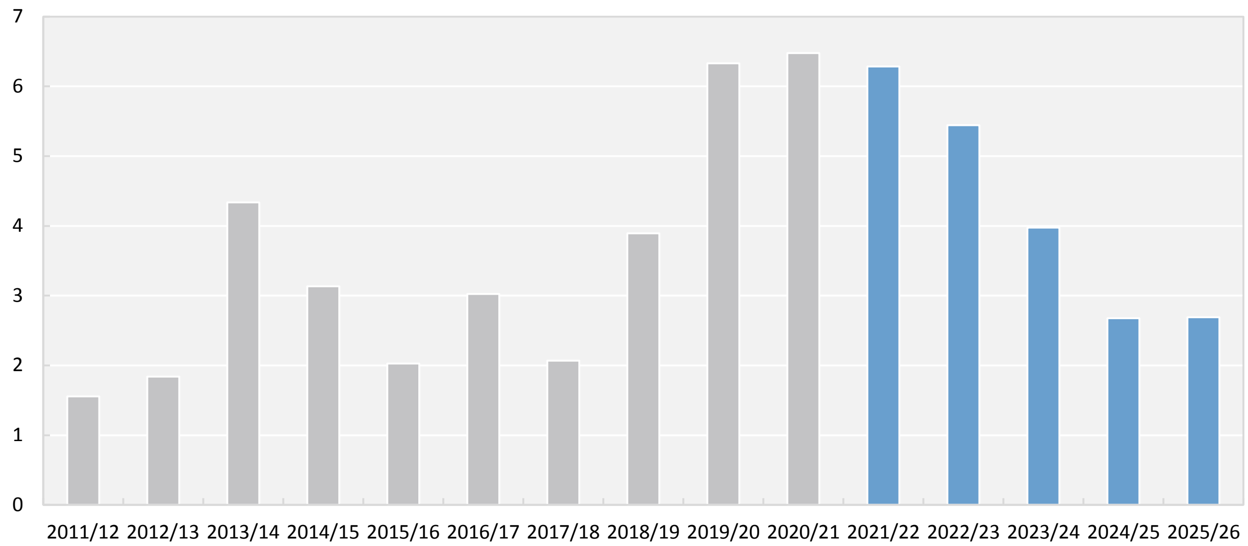
- ensure our buildings are complaint with safety, health, amenity and sustainability obligations
- maintain our fleet and general equipment.

Following a review conducted by Bellrock Group using a risk-based approach, we are increasing the security of our critical assets including zone substations, distribution assets and depots in response to increasing concerns of theft and other unauthorised access.

Our fleet of vehicles are essential to ensuring we can continue to carry out our work efficiently and reliably. Our forecast fleet investment for the 2021–2026 regulatory period reflect our historical level. This is appropriate because our investment drivers are expected to remain unchanged.

Our forecast for non-network is made up of property, fleet, and tools and equipment. We take a prudent approach to non-network investment, adjusting our activities over time to ensure we maintain a balanced portfolio. The profile of our historical and forecast non-network investment is shown in figure 8.1.

Figure 8.1 Non-network investment ($ million, 2021)



Source: CitiPower
Notes: Forecast shown includes real escalation.

The profile of our non-network investment is driven by the need to prioritise works early in the period to ensure the safety of our employees and community, and to meet compliance obligations. In total, our forecast investment is in line with historical levels, as shown in table 8.1.

Table 8.1 Non-network investment ($ million, 2021)

Description	2016–2020	2021–2026
Total investment	20.3	21.1

Source: CitiPower
Notes: Forecast shown includes real escalation.

8.1 What we plan to deliver

Over the 2021–2026 regulatory period, the population of Melbourne is predicted to grow. To meet the associated increased demand on our network, we will:

- ensure our buildings are complaint with safety, health, amenity and sustainability obligations
- maintain our fleet and general equipment.

Our forecast for each year of the regulatory period is outlined in the table 8.2.

Table 8.2 Forecast capital investment for property, fleet and tools and equipment ($ million, 2021)

Description	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Property	4.8	3.9	2.8	2.0	2.0	15.4
Fleet	1.2	1.2	0.8	0.4	0.4	4.2
Tools and equipment	0.2	0.2	0.2	0.2	0.2	1.2
Total	**6.2**	**5.4**	**3.9**	**2.6**	**2.6**	**20.7**

Source: CitiPower
Notes: Forecast shown excludes real escalation.

8.1.1 We will ensure our property investment remains in line with industry standards

Over the 2021–2026 regulatory period, we will enhance the security of our facilities to bring them in line with industry standards. Following a review conducted by Bellrock Group using a risk-based approach, we are increasing the security of our critical assets including zone substations, distribution assets and depots in response to increasing concerns of theft and other unauthorised access. This includes installing new fencing, enhancing monitoring measures such as installing anti-theft alarms and lighting, and establishing a control room to proactively manage security alerts.

We will also conduct an audit of our sites and undertake resulting rectification works to ensure continued compliance with safety, health, amenity and sustainability in building design given that many of our sites were constructed a number of years ago by the State Electricity Commission of Victoria or councils. The cost of these works is based on work conducted by a third party building surveyor, Visionstream Australia, to rectify two sites.

These measures will help ensure the safety of employees, the community and protect our network assets. More information is available in our facilities security and building compliance business cases.[97]

8.1.2 We will maintain our fleet and general equipment capability

Fleet comprises of light or passenger vehicles such as cars and utility vehicles, cranes, elevated working platforms, trailers, crane borers and fork lifts. Our fleet is essential to carrying out our work efficiently and reliably.

Our forecast fleet expenditure for the 2021–2026 regulatory period reflect our average level of expenditure over 2015/16 to 2018/19. Our fleet expenditure is driven by activities including:

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97 CP BUS 8.01: CitiPower, *Facilities' physical security upgrade*, January 2020. CP BUS 8.02: CitiPower, *Building compliance*, January 2020.

- replacing existing motor vehicles in line with industry standards—we purchase, rather than lease, motor vehicles as this to be the most efficient method of sourcing vehicles
- technological developments of in-vehicle monitoring systems, which allows us to track vehicles, in turn improving driver safety
- employee growth or network-related work programs
- compliance with legislation and standards as they apply to varying categories of fleet.

8.2 Our forecasting approach

We have undertaken a bottom-up approach to forecast our property requirements in the 2021–2026 regulatory period.

8.2.1 Physical security of facilities

We assessed the current security risks to sites across our network using the framework provided by Bellrock Group. Given the assets within our network are generally located in more densely populated areas, a number of assets have been identified as having a high level of risk. Upon determining the total security works that needed to be conducted, we scheduled high priority works according to available resources for each year of the 2021–2026 regulatory period. We have already commenced works in the 2016–2020 regulatory period and have used these as the basis for forecast costs.

8.2.2 Building compliance uplift

In April 2019 we engaged third party building surveyor, Visionstream Australia, to conduct an audit of building compliance on a sample of sites. This audit identified a number of items requiring rectification to bring the buildings into line with the Building Code of Australia and the National Construction Code. Many of the items identified are common issues that are likely to be prevalent across a range of our network sites, for example relating to the height of balustrades and guard rails. There are also less common but high priority issues such as those relating to fire safety requirements. We extrapolated from these audit findings to determine the costs of a full audit of network buildings and resulting rectification works.

8.2.3 Our fleet and general equipment forecasts are aligned with historical investment

We have used the average investment from 2015/16–2018/19 to forecast our requirements for fleet in the 2021–2026 regulatory period. Basing our forecasts on average historical fleet investment is appropriate because our investment drivers (noted above) are expected to remain unchanged.

Our forecast expenditure for other general tools and equipment is based on our average historical expenditure over 2015/16–2018/19. This approach ensures our forecasts are efficient as we expect the purchase and replacement of general tools and equipment to remain relatively constant.

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9 Operating expenditure

Summary

Our operating expenditure forecast for the 2021–2026 regulatory period is an efficient, prudent and realistic forecast that allows us to achieve the operating expenditure objectives of the Rules.

We are an efficiency frontier network—we benchmark as the second most efficient distributor in Australia according to the AER's 2019 benchmarking results and we have the lowest operating expenditure per customer. We delivered $59 million in savings during the 2016–2020 regulatory period.

We are facing new challenges and opportunities

As an efficiency frontier network, the ongoing transformation of the energy sector (e.g. the rapid uptake of renewables, and a growing focus on data access and security) is placing upward pressure on our historical operating investment. To successfully transition and manage these challenges proactively and efficiently, our forecasts include incremental investments for targeted step changes, including:

- new obligations under the *Environment Protection Amendment Act 2018* and draft regulations
- strengthened security requirements for the protection of data under the *Security of Critical Infrastructure Act*
- maintaining reliability and safety of electricity supply during extensive Yarra Trams tracks works across the network.

There are also opportunities for us to deliver customer benefits and cost savings during the 2021–2026 regulatory period, including:

- enabling more solar to be connected to the network, delivering economic benefits for all customers and responding to our changing customer needs
- delivering cost savings for customers by migrating on-premise IT infrastructure to cloud hosting.

Our forecasts reflect our efficient operations

We use the AER's the base–step–trend approach to forecast our required operating expenditure. We have selected 2019 as the efficient base year, and have engaged independent consultants to forecast trends in economic factors to be applied to this base.

While we have applied the AER's pre-emptive productivity adjustment to our efficient base operating expenditure, we must be provided funding for implementing new innovative initiatives and productivity-enhancing projects necessary to achieve these productivity improvements. As we have already achieved considerable productivity improvements through investment in new technologies and management practices, we have limited capacity to achieve additional productivity gains through business as usual initiatives in 2021–2026.

Our operating expenditure allows us to run our everyday operations, to meet and manage our compliance obligations and ensure our services meet relevant quality, reliability, safety and security of supply standards. Operating expenditure covers:

- IT maintenance and leasing
- customer and corporate services
- asset inspections, maintenance and repair
- emergency response
- vegetation pruning around our assets
- various other ongoing expenses.

Figure 9.1 shows the largest categories of our operating expenditure in 2019, how we have achieved savings over time and how this meets our customers' priorities.

Figure 9.1 Operating expenditure categories in 2019

40% IT, customer and corporate services	30% Asset inspection, maintenance and repair	8% Vegetation management	8% Emergency response	14% All other operating expenditure
• We have a corporate team that delivers customer service and ensure our business runs efficiently • Customer information and data will soon be handled locally • We've undertaken a 'World Class' savings program to ensure we only employ the staff we need and who are best suited for the job	• As part of our comprehensive asset management strategy, we inspect our assets periodically and maintain or repair assets based on their inspected condition • We prefer to maintain and repair assets where they can still be operational and safe, rather than replace them before their time • We are modernising inspections with lasers, drones and through smart meter data, which will lead to more efficient and accurate results in the future	• We prune trees and other vegetation around power lines periodically to a distance determined by *Electricity Safety (Electric Line Clearance) Regulations 2015* • Our pruning cycle is three years, which controls pruning costs while ensuring visual amenity for our customers • In 2015 we renegotiated our external contract for vegetation management, resulting in on-going savings to customers	• We have a highly trained crew who are available 24/7 for emergency response • Our crew are distributed across the network to minimise travel time in the case of emergency and when conducting other works • We seek to recover the cost of emergency works from third parties as much as possible to minimise the impact on our customers	• Other operating expenditure includes our licence fee, equipment leasing and other smaller on-going expenses • We ensure efficiency in all other operating expenditure by market-testing leasing services and continually reviewing contracts
Data security is very important to our customers	Our customers want us to be more innovative in our operations	Most of our customers are satisfied with our pruning cycles	Our customers rightly expect world-class safety outcomes	Our customers don't want us to spend $1 more than necessary

Source: CitiPower

A summary of the components of our operating expenditure forecast for the 2021–2026 regulatory period is shown in table 9.1.

Table 9.1 Operating expenditure forecasting approach 2021–2026 ($ million, 2021)

Operating expenditure	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Base	86.9	86.9	86.9	86.9	86.9	434.7
Base adjustment	3.9	3.9	3.9	3.9	3.9	19.7
Re-classifications	5.4	5.4	5.4	5.4	5.4	26.8
Output growth	2.6	3.8	4.8	6.0	7.3	24.6
Labour escalation	1.4	2.9	4.5	5.9	7.2	21.9
Productivity	-0.5	-1.0	-1.5	-2.1	-2.6	-7.7
Step changes	9.8	9.4	8.8	7.7	8.0	43.6
Debt raising costs	1.0	1.0	1.0	1.1	1.1	5.2
Total	**110.5**	**112.3**	**113.9**	**114.9**	**117.2**	**568.8**

Source: CitiPower

9.1 What we plan to deliver

Our operating expenditure is among the lowest in the country. Our customers receive value for money as we deliver a safe, reliable and dependable network that meets our customers' needs at the most efficient cost.

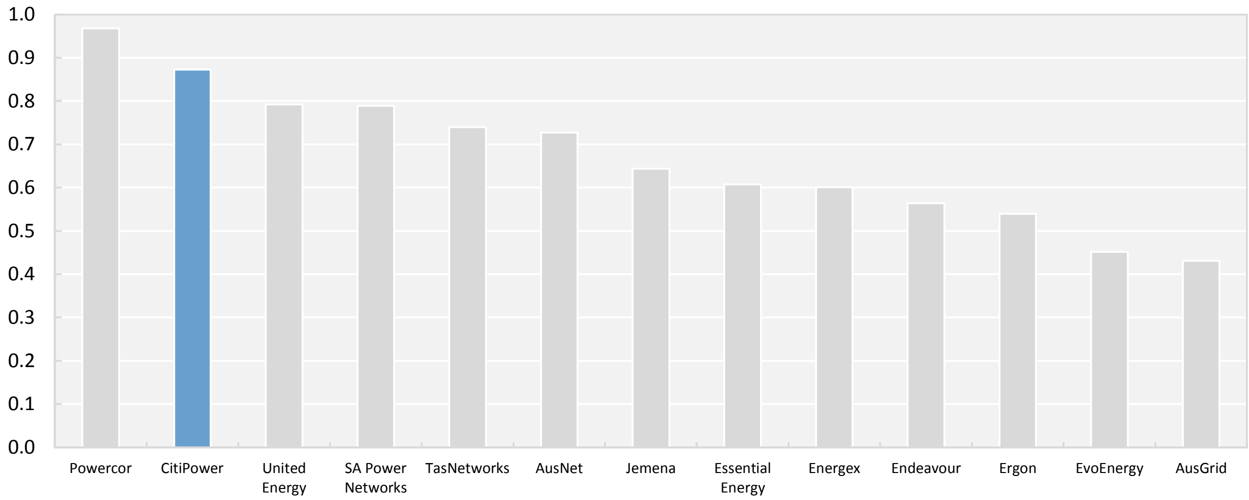
Stakeholder feedback

Our stakeholders and customers have been clear that they expect to not pay a dollar more, nor pay a day earlier than necessary for investments required to maintain our network. We support this view and are striving to do more for less.

As the second most efficient distributor in Australia—along with Powercor and United Energy (distributors we also own and operate)—we set the benchmark for the entire industry on the least-cost way to operate the network. We are proud of this leadership position, and will continue to invest only where prudent and efficient so that we remain at the frontier.

According to AER' operating expenditure benchmarking, our operating expenditure is second most efficient in the NEM. Figure 9.2 summarises the results of the most recent AER benchmarking study.

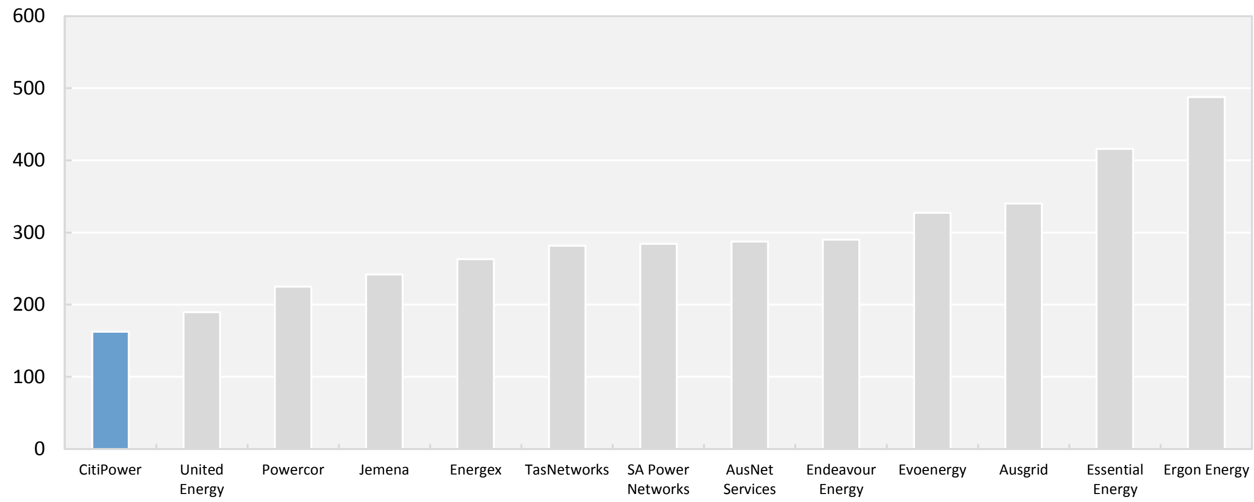
Figure 9.2 Operating expenditure efficiency scores from Cobb-Douglas stochastic frontier analysis (2006–2018)



Source: CP ATT109: AER, *Annual Benchmarking Report for electricity distribution network service providers*, November 2019.

Similarly, our operating expenditure per customer is the lowest across the NEM. In 2018, we ran our operations and serviced our customers with 55% lower operating expenditure per customer than the average distributor in New South Wales and Queensland. Figure 9.3 summarises the operating expenditure per customer across the NEM.

Figure 9.3 Operating expenditure per customer across the NEM, 2018 ($2018)



Source: CP ATT109: AER, *Annual Benchmarking Report for electricity distribution network service providers*, November 2019.

9.1.1 We are investing to ensure we meet new or changed regulatory obligations

Our operating expenditure in our 2019 'base' year reflects the efficient costs a prudent operator in our circumstances would require to achieve the operating expenditure objectives.[98]

Our base operating expenditure reflects our current operating environment, having regard to our current service targets, regulatory obligations and other prevailing environmental circumstances. As an efficiency frontier network, we have no contingency in our operations to absorb increasing costs from growing regulatory and service obligations, or material increases in the cost of complying with existing obligations and delivering services due to changes outside our control.

To achieve the operating expenditure objectives, therefore, we consider it prudent to account for increasing cost pressures from circumstances outside of our control through operating expenditure step changes. Table 9.2 summarises these step changes resulting from new regulatory obligations, and we expand on these below. Section 9.1.2 outlines additional step changes for new services that will allow us to deliver more customer benefits. Our assessment included identifying negative step changes over the 2021–2026 regulatory period, of which no material items were identified.

98 The operating expenditure objectives of the Rules for standard control services require us to meet or manage the expected demand, comply with all applicable regulatory obligations or requirements, maintain the quality, reliability and security of supply, and maintain the safety of the distribution system.

Table 9.2 Step changes resulting from new regulatory obligations or increasing costs of existing obligations ($ million, 2021)

Step change	2021/22	2022/23	2023/24	2024/25	2025/26	2021–2026 total
Five minute settlement	0.2	0.3	0.4	0.5	0.6	1.9
Security of critical infrastructure	3.1	2.8	2.8	2.9	2.9	14.4
EP Amendment Act 2018 and regulations	2.4	2.2	1.2	0.1	0.1	6.1
ESV levy	0.3	0.3	0.3	0.3	0.3	1.5
Financial year RIN	0.4	0.4	0.4	0.4	0.4	1.8
Yarra trams pole relocation	2.8	2.8	2.9	2.9	3.0	14.4
Total	**9.1**	**8.8**	**8.0**	**7.0**	**7.2**	**40.1**

Source: CitiPower
Notes: Forecast shown includes real escalation (not applied to increasing increase in ESV levy step change).

We have also identified two additional regulatory obligations that are likely to result in a step change in costs during 2021–2026:

- electrical line-worker licensing—the Victorian Government at the 2018 Victorian election committed to a licensing scheme for electrical line-workers, expected to commence on 1 January 2021
- Electricity Distribution Code review—the Essential Services Commission of Victoria (**ESCV**) is currently reviewing the Electricity Distribution Code, results of which are expected to be finalised in 2020.

As these changes are still under consideration, we do not have sufficient information to quantify the impact on our operating expenditure. We may propose step changes for these changes in our revised regulatory proposal.

Five minute settlement

On 28 November 2017, the Australian Energy Market Commission (**AEMC**) amended the Rules to change the financial settlement period for the electricity wholesale market from 30 minutes to five minutes to align with the operational dispatch of electricity. This is known as the five minute settlement rule change.[99] As a result of the rule change we are required to capture, store, process and share meter data in five minute intervals for meters installed from 1 December 2018, rather than the current 30 minute intervals.

By December 2022, we must provide five minute data to market for meters installed from December 2018.[100]

To ensure we comply with the rule change, we will incur incremental operating expenditure during the 2021–2026 regulatory period, which is not accounted for in our 2019 base, including for:

- increased wide area network capacity to transport increased volume of meter data between IT systems
- managing the increase in manual validations of meter data exceptions.

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[99] CP ATT222: Australian Energy Market Commission, *Rule determination, National Electricity Amendment (Five Minute Settlement) Rule*, November 2017.

[100] CP ATT222: Australian Energy Market Commission, *Rule determination, National Electricity Amendment (Five Minute Settlement) Rule*, November 2017, p. 121.

Our forecasting approach for these incremental costs, including our options analysis, is set out in our attached step change model and five-minute settlement business case.[101]

Strengthening the security of critical infrastructure

In 2017, the Australian Government introduced a series of requirements to address the national security risks of espionage, sabotage and coercion associated with foreign involvement, through ownership, offshoring, outsourcing and supply chain arrangements, in critical infrastructure. These requirements include our electricity distribution systems.

More specifically, the critical infrastructure requirements include a subset of new requirements concerning system and data controls. To meet these requirements, we must transition to full compliance in accordance with the work plan approved by the Australian Government. The majority of our customers also see data security as vital in an increasingly technology-driven world.

These critical infrastructure system and data control requirements are new 'regulatory obligations or requirements' (within the meaning given to that term by the National Electricity Law) associated with the provision of standard control services.[102] In its draft decision for SA Power Networks in October 2019, the AER also deemed these critical infrastructure system obligations are 'new regulatory obligations or requirements as defined in the [NEL]'.[103]

As a result, we will incur material ongoing operating expenditure in the next regulatory period that is additional to the expenditure reflected in our 2019 base operating expenditure. Further details are provided in our attached step change model and critical infrastructure business case.[104]

New Environment Protection Amendment Act 2018 and draft regulations

We operate a health, safety and environment (**HSE**) management system that sets out a program of works and practices to comply with all HSE legislation and regulatory obligations, including environmental obligations. 91% of our customers supported us managing the network in an environmentally sustainable way.

The current legislation and regulations relevant to our environmental obligations (specific to this business case) are:

- the *Environment Protection Act 1970* (**EP Act 1970**)
- state environment protection policies and waste management policies.

These are administered and managed by the Environment Protection Authority Victoria (**EPAV**).

The *Environment Protection Amendment Act 2018* will repeal the EP Act 1970 from 1 July 2020 to establish a proactive regulatory approach to preventing waste and pollution impacts rather than managing the impacts after they occur. In August 2019, the Victorian Government published the draft Environment Protection Regulations (**draft regulations**), along with the regulatory impact statement (**RIS**). Final regulations are expected in March 2020.

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101 CP MOD 9.01 - Step changes - Jan2020 - Public; CP BUS 7.09: CitiPower, *Five minute settlement rule change*, January 2020.

102 Compliance with those requirements is required in order to achieve the operating expenditure objective set out in clause 6.5.6(a)(2) of the Rules or, in the alternative, clause 6.5.6(a)(1), (a)(3) and/or (a)(4) of the Rules.

103 CP ATT044: Australian Energy Regulator, *Draft Decision SA Power Networks; Distribution Determination 2020 to 2025, attachment 6, Operating expenditure*, January 2019, p. 42.

104 CP MOD 9.01 - Step changes - Jan2020 - Public; CP BUS 9.01: CitiPower, *Security of critical infrastructure*, January 2020.

To comply with the new proactive obligations, we will incur material operating expenditure during 2021–2026 regulatory period incremental to the 2019 base year, related to identifying, assessing and testing potential environmental risks of our operations as well as remediation works for contaminated sites. For remediation of oil contamination on land, which is the largest cost item, we have developed a desktop risk assessment and have ranked the contaminated sites according to level or risk of harm. For our cost estimate, we have included the remediation of the highest risk sites only in the 2021–2026 regulatory period.

Further detail on this change, including information on the highest risk sites are detailed in attached step change model and environmental business case.[105]

Given the estimated costs are based on the preferred option of the draft regulations in the RIS, our forecasts are subject to change when the final regulations are published. We expect to review the implications of the final regulations on our operations, and update the options and the costings with a more detailed assessment for our revised regulatory proposal.

Relocation of our assets on Yarra Trams poles

Yarra Trams, with support of Public Transport Victoria and the Victorian Government, are embarking on a ten year program of substantial tram track renewals and upgrades. As part of the works, Yarra Trams will be relocating or replacing their poles that hold some our pole-top assets and conductors. To maintain reliability and safety of electricity supply, we will be required to relocate our existing assets onto the new or relocated Yarra Trams poles.

The volume of pole relocation works proposed by Yarra Trams for the 2021–2026 represents a fundamental change in our operating environment outside of our control, which necessitates increased expenditure during 2021–2026 to meet the National Electricity Objective.

The proposed relocation program will result in a material increase in our operating expenditure not captured in the 2019 base year.

Further detail on this change is available in attached step change model and Yarra Trams poles business case.[106]

Increase in ESV levy

We are required to make levy payments to ESV. The levy payment schedule is set by ESV on an annual basis. On 30 April 2019, ESV communicated a material increase in its levy, including a 22% increase from 2018/19 to 2021/22 and annual 3% ongoing year on year increases, as shown in ESV's attached fee levy schedule.[107] These material increases in the levy are beyond our control and are not captured in our 2019 base operating expenditure. Further detail on this is detailed in attached step change model.[108]

Financial year RIN

The Victorian Government has changed the next Victorian distributors' regulatory period from calendar years to financial years. We currently prepare financial statements on calendar year basis which is aligned with RIN reporting on a calendar year basis. This means we only incur labour and audit costs for one set of financial accounts.

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105 CP MOD 9.01 - Step changes - Jan2020 - Public; CP BUS 4.01: CitiPower, *EP Amendment Act 2018 and draft regulations*, January 2020.

106 CP MOD 9.01 - Step changes - Jan2020 - Public; CP BUS 9.02: CitiPower, *Relocation of assets on Yarra Trams poles*, January 2020.

107 CP ATT041: Energy Safe Victoria, *General Managers forum; meeting minutes*, February 2019.

108 CP MOD 9.01 - Step changes - Jan2020 - Public.

From 2021/22, we will be required to prepare and have audited a second set of financial accounts each year to enable population of the RINs on a financial year basis. The cost of preparing and auditing a second set of financial accounts is not reflected in our 2019 base operating expenditure.

We forecast the annual cost for preparing and auditing a second set of financial accounts based on our 2018 actual costs. These costs are included in our attached step change model.[109]

9.1.2 We are investing to deliver additional customer benefits

In addition to our compliance-driven step changes, we are investing to deliver new customer benefits. This includes operating expenditure that is not reflected in our 2019 base year, based on the following criteria:

- the benefits to customers exceed the incremental operating expenditure
- the costs cannot be met from existing regulatory allowances or from other elements of the expenditure forecasts
- reflects an efficient trade-off of operating expenditure and capital expenditure
- reflects only the incremental costs above our 2019 base year and the costs are material
- is not productivity enhancing.

Table 9.3 summarises our step changes that deliver new customer benefits.

Table 9.3 Step changes that deliver new customer benefits ($ million, 2021)

Step change	2021/22	2022/23	2023/24	2024/25	2025/26	2021–2026 total
Solar enablement	0.4	0.3	0.3	0.2	0.1	1.3
IT cloud migration	0.3	0.3	0.5	0.6	0.6	2.3
Total	**0.7**	**0.6**	**0.8**	**0.7**	**0.7**	**3.6**

Source CitiPower
Notes: Forecast shown includes real escalation.

Solar enablement

As outlined in section 6.1.1, our customers are seeking to export excess solar back into the network. Where this is efficient (i.e. the benefits exceed the costs) we will enable this.

The net benefit to our customers of this program is over $32 million. The benefits we have calculated are the reduction in wholesale generation fuel costs and carbon reduction benefits from solar; benefits that all our customers (even those without solar) receive.

Delivering these benefits requires a mix of capital, and incremental operating expenditure to remove voltage constraints and enable more exports. Incremental operating expenditure, specifically, is needed to:

- 'tap down' distribution transformer voltages where possible as a less expensive option to, and reduce the need for, capital investment.

109 CP MOD 9.01 - Step changes - Jan2020 – Public.

- compliance and monitoring of customers' inverter settings—if installers fail to apply the required new inverter settings that reduce the voltage rise from exporting solar, voltage rises will be significantly higher than forecast. As a result, the full value of the net benefits will not be realised and there will be inequitable outcomes whereby customers without the inverter settings applied will be able to export more, at the expense of others.

This operating expenditure is incremental to our base year expenditure as our current policy limits solar exports (hence the need to remove constraints) and given the step up in solar installations resulting from the Victorian Government's Solar Homes subsidy program. More information, including our considerations of the incremental nature of these costs, is available in the solar enablement business case.[110]

ICT cloud migration

As discussed in section 7.1.2, we own and maintain the majority of our ICT infrastructure on-premise and we incur capital expenditure to grow and refresh our on-premise infrastructure capabilities. With the maturing market for cloud-based services, there is an opportunity for us to migrate some of our existing ICT infrastructure to cloud-hosting. Under cloud-hosting ICT infrastructure is owned and managed by third party vendors and typically paid for on a subscription basis.

Our proposal represents an efficient trade-off between operating expenditure and capital investment. The proposed migration to cloud-hosting delivers savings to customers through a reduction in ICT capital investment which exceeds the increase in operating expenditure for cloud subscriptions. Our proposed cloud migration also provides longer term benefits of cloud-hosting, such as easy scalability and adaptability of our ICT environment to changing requirements, meaning customers will only pay for the capacity and services we need.

To deliver customer savings through efficiently migrating ICT infrastructure to cloud-hosting, we will incur material incremental operating expenditure which is not reflected in our 2019 base operating expenditure. Further details on this change are detailed in the IT cloud business case and models.[111]

9.2 Our forecasting approach

We have used the 'base–step–trend' approach to develop our proposed operating expenditure for the 2021–2026 regulatory period. This is consistent with the AER's preferred model, as set out in its expenditure forecast assessment guideline. Our approach is as follows:

- nominate 2019 as the efficient revealed base year
- adjust our base year expenditure to include an efficient forecast for activities which are not fully reflected in the base year expenditure, including:
  - review of non-recurrent costs
  - adjustment for services reclassified as standard control
  - adjustment for costs reclassified as operating expenditure
  - adjustment for forecast Guaranteed Service Level (**GSL**) payments rather than actuals in 2019

[110] CP BUS 6.02: CitiPower, *Solar enablement*, January 2020.

[111] CP BUS 7.10: CitiPower, *Cloud infrastructure*, January 2020; CP MOD 7.15 - Cloud infrastructure cost - Jan2020 - Public; CP MOD 7.16 - Cloud infrastructure risk - Jan2020 - Public

- add to the base year the efficient level of operating expenditure determined by applying a rate of change, comprising real price escalation, output growth and productivity
- add the efficient level of forecast step changes for the 2021–2026 regulatory period
- add the efficient forecast of debt raising costs.

We explain the components of our forecasting approach in more detail in the following sections.

9.2.1 Our base year operating expenditure is efficient

We nominate 2019, the fourth year of the 2016–2020 regulatory period, as the efficient base year for our operating expenditure forecast for the 2021–2026 regulatory period. We consider our base year expenditure is efficient for the following reasons:

- the AER has consistently classed us as one of the efficiency frontier networks in the NEM, based on its operating expenditure benchmarking analysis.[112]
- we are subject to an incentive framework to which we have responded and continue to respond.
- our private ownership structure promotes efficient expenditure, evident in savings generated over the past five years.
- we have among the lowest operating expenditure per customer while continuing to provide a safe and dependable network that is available 99.99% of the time.
- a large proportion of our operating expenditure is outsourced to external contractors who benefit from economies of scale.
- we ensure efficiency of our operations by market-testing and engaging competitive contracts where possible. In 2015, we renegotiated our vegetation management contract which resulted in an ongoing saving to customers.
- our labour costs are efficient and competitively priced, and our corporate and field staff are strategically located across the network to minimise travel times and response times in emergency situations.

While we consider every year during the 2016–2020 regulatory period is efficient, we have used 2019 as the base year as it represents the most recent actual audited reported performance that will be available before the AER is required to make its draft decision.[113] The currency of this data (relative to earlier years) ensures our forecasts are based on up-to-date data. The data has been audited to ensure the starting point for our forecasts is robust.

9.2.2 We have adjusted our base year to reflect future ongoing operating expenditure

We have reviewed our base year operating expenditure for any non-recurrent expenditure and future ongoing expenditure that may not be reflected in the base. While no non-recurrent operating expenditure was discovered, we identified several activities for which the 2019 base year does not reflect the expenditure for these activities going forward. A summary of these activities, and the net annual adjustments to our 2019 base year operating expenditure, are set out in table 9.4.

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112 CP ATT109: Australian Energy Regulator, *Annual Benchmarking Report, Electricity distribution network service providers*, November 2019, p. iv.

113 For this regulatory proposal our 2019 operating expenditure is an estimate. Our revised proposal will be updated for our actual audited 2019 operating expenditure.

Table 9.4 Annual base adjustments ($ million, 2021)

Base adjustments	Total (per annum)
GSL adjustment	-0.0
Reclassification of emergency recoverable works	0.2
Reclassification of smart meter communications network operational expenditure	0.6
Reclassification of 'wasted truck visits' for faults on the customer side of the connection point	0.4
Reclassification of minor repairs	4.1
Rate of change for 2020 and half year 2021	4.0
Total	**9.3**

Source: CitiPower

Adjustment for forecast GSL payments rather than actuals in 2019

We are required to make GSL payments to customers who experience reliability that is worse than specified performance thresholds in the Electricity Distribution Code. These payments may exhibit significant volatility across years based on a range of exogenous factors. Given this, we have removed actual GSL payments for 2019 from our base year expenditure and replaced it with a forecast reflecting the average of GSL payments over the period 2014–2019. This approach is consistent with that adopted by the AER in previous regulatory decisions.

Reclassification of emergency recoverable works as standard control

In the 2021–2026 framework and approach paper, the AER reclassified emergency recoverable works as standard control from an unclassified service. Emergency recoverable works are carried out for emergencies that are the fault of third parties. The AER seeks that we recover the cost of the service from third parties, however, this is not always possible due to circumstances outside of our control (including third parties' insolvencies).[114]

While we will continue to seek funding from third parties to recover the cost of emergency recoverable works, our best forecast for the base adjustment reflects the average net cost from emergency recoverable works over the 2014–2018 period. This approach is consistent with that adopted by the AER in Ausgrid's final determination in April 2019.[115] We are only proposing to adjust base operating expenditure for the amount we are historically unable to recover from third parties (which is currently reported as a loss under alternative control services and not included in base year operational expenditure). That way our customers only pay a small portion for the residual cost of emergency recoverable works.

114 CP ATT067: Australian Energy Regulator, *Final framework and approach, AusNet Services, CitiPower, Jemena, Powercor and United Energy Regulatory period commencing 1 January 2021*, January 2019, pp. 26-27.

115 CP ATT235: Australian Energy Regulator, *Final Decision, Ausgrid Distribution Determination 2019 to 2024*, April 2019, pp.32-33.

Reclassification of cost of 'wasted truck visits' for faults on the customer side of the connection point

The AER's 2021–2026 framework and approach paper reclassified 'wasted truck visits' (from an alternative control service).[116] Wasted truck visits are where a distributor sends a truck to a customer's premises after receiving a complaint about a power outage or power quality issue, only to find on arrival that the issue is on the customer side of the connection point. Our forecast base adjustment for these wasted truck visits is estimated using our 2014–2018 actual expenditure.

Reclassification of operating expenditure related to the smart meter communications network

Our use of data analytics with smart meter data has now become part of our business-as-usual network optimisation. Our customers have told us they want us to keep finding more innovative ways for managing the network, and they will continue to benefit through lower costs from managing our network in this manner.

For the 2021–2026 regulatory period, we have allocated 88% of the operating expenditure for maintaining our communications network from metering to standard control services. This amount represents the percentage of data transmitted through the smart meter communications network for network management purposes, the benefits of which are shared by all our customers.

This approach is a fairer outcome for all customers. For more information refer to section 11.2.3 in our metering chapter.

Adjustment for reclassification of minor repairs as operating expenditure

We are proposing to reclassify 'minor repairs' from capital to operating expenditure. Typically minor repairs include labour-intensive work that results from asset failure or identified defects that could result in an imminent asset failure (if not repaired).

Treating minor repair costs as operating expenditure better reflects the nature of the work—the costs are incurred to maintain the age of the asset and the work does not result in the creation of a new asset. We consider these costs to be more akin to maintenance and repair which is immediately expensed, rather than refurbishment or replacement of assets that are depreciated over a longer period.

We have adjusted our base year operating expenditure for the total cost of minor repairs in 2019 and removed forecast minor repairs from our capital replacement forecast. These changes are net present value (**NPV**) neutral, which means customers are no worse-off in the long term.

This is reflected in our updated cost allocation method, and our audited re-cast reset RIN transfers minor repairs from replacement capital expenditure to maintenance.[117]

Rate of change for 2020 and half year 2021

We have added to the base year the efficient level of operating expenditure determined by applying a rate of change, comprising real price escalation, output growth and productivity.

9.2.3 We trend forward our base year for expected changes in economic and network conditions

Our actual operating expenditure in the base year reflects the economic and network conditions that prevailed during 2019. It is reasonable to expect these economic and network conditions to change over the 2021–2026

[116] CP ATT067: Australian Energy Regulator, *Final framework and approach, AusNet Services, CitiPower, Jemena, Powercor and United Energy Regulatory period commencing 1 January 2021*, January 2019, p.32.

[117] CP RIN002 - Workbook 2 - New historical CAT - Jan2020 - Public. CP ATT027 - Cost allocation method - Jan2020 - Public.

regulatory period, and therefore our operating expenditure forecasts must take these changes into account to ensure we continue to achieve the operating expenditure objectives of the Rules.[118]

The AER's expenditure forecast assessment guideline also sets out the following reasons why efficient operating expenditure in the forecast period may differ from the base level of expenditure:[119]

- real price growth—this is changes in the prices we pay for labour and non-labour inputs used in our operations. Real price growth is the growth rate in prices relative to growth in the consumer price index (**CPI**). As real input prices change our efficient level of expenditure will change.
- output growth—this is changes in the network size and demand for network services. It is reasonable that as the scale of operations increases our efficient costs will increase.
- productivity growth—productivity growth reflects shifts in the production possibility frontier delivered through technology advancements or other innovations. It does not reflect reductions in operating expenditure from removing inefficiencies or business as usual IT upgrades.

We have developed forecasts of each of the above components and applied these to develop our efficient operating forecasts. Our approach is described below and in the supporting attachments as indicated in each subsection.

9.2.4 Forecast real price growth

Over the 2021–2026 regulatory period, input prices for labour have been forecast by our independent expert, BIS Oxford Economics (**BIS Oxford**) to grow at a faster rate than CPI.[120] Conversely, we currently have no evidence our non-labour input prices will grow at a greater rate than CPI. We have therefore only included a real price escalation for labour in our forecast.

Real labour price growth

We engaged BIS Oxford to provide independent labour price forecasts for the 2021–2026 regulatory period. BIS Oxford developed forecasts of the Australian Bureau of Statistics (**ABS**) Electricity, Gas, Water and Waste Services (**EGWWS**) Wage Price Index (**WPI**) for Victoria. This is consistent with the AER's preferred approach to forecasting labour price growth.

We engaged Frontier Economics (**Frontier**) to assess the accuracy of BIS Oxford's forecasting history for Victorian real EGWWS WPI. Frontier found that BIS Oxford have been the more accurate forecaster compared to the AER's preferred forecaster Deloitte Access Economics with regards to the real growth in the Victorian EGWWS WPI.

BIS Oxford also provided advice on the calculation of the proposed increases to the superannuation guarantee. As per the Minerals Resource Rent Tax Repeal and Other Measures Bill 2014, Schedule 6—Superannuation Guarantee Charge percentage, the superannuation guarantee is scheduled to increase progressively from 9.5% on 1 July 2020 to 12% on 1 July 2025, as shown in table 9.5.[121]

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118 The operating expenditure objectives of the Rules for standard control services require us to meet or manage the expected demand, comply with all applicable regulatory obligations or requirements, maintain the quality, reliability and security of supply, and maintain the safety of the distribution system.

119 CP ATT163: Australian Energy Regulator, *Expenditure forecast assessment guideline for electricity distribution,* November 2013.

120 CP ATT014: BIS Oxford, *Estimation of opex input weights, A report prepared for CitiPower, Powercor and United Energy*, March 2019.

121 CP ATT211: The Parliament of the Commonwealth of Australia, House of Representatives, *Minerals Resource Rent Tax Repeal and Other Measures Bill 2014 No. 96, 2014, as passed by both Houses*, 2013-2014, p. 37.

Table 9.5 Change in superannuation guarantee charge (%)

Description	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
Charge percentage	9.5	10.0	10.5	11.0	11.5	12.0

Source: The Parliament of the Commonwealth of Australia

According to BIS Oxford's research, the superannuation guarantee charge is not included in the ABS's WPI or the Average Weekly Earnings measures and is treated as a labour 'on-cost'.[122] The superannuation guarantee charge, therefore, needs to be added to the forecast increases in the WPI when escalating labour prices over the forecast regulatory period.

Our labour price growth forecasts include the effect of the change in the superannuation guarantee charge, as added to the BIS Oxford independent forecasts. The forecast real labour price growth rate is shown in table 9.6.

Table 9.6 Labour price growth forecast for 2021–2026 (%)

Description	2021/22	2022/23	2023/24	2024/25	2025/26
Labour price growth forecast	2.00	2.17	2.16	1.91	1.71

Source: BIS Oxford Economics

Labour price growth over the 2021–2026 period will be buoyant as a result of strong population growth and a rebounding economy. Victoria's population, particularly in Melbourne, is expected to be stronger than the national average as migration from interstate increases. Victoria's economy is expected to rebound from stronger population growth, higher exports and household consumption from the weak Australian dollar, and stronger business investment.

EGWWS is a capital-intensive sector with a tight labour market of employees with higher skill and higher wages than most other sectors. Approximately 50% of our workforce is electrical engineers and field staff working on electrical assets. There is also a strong union presence, with around 38% of the workforce under collective agreements. As such, labour price growth in the EGWWS WPI is consistently higher compared to the 'all industry' average WPI.

Demand for skilled labour in the electricity sub-sector is growing at a faster rate compared to the remainder of the EGWWS sector (and compared to the remainder of the economy), as the number and type of services available increases with a transition to renewables and distributed energy resources. Comparatively, Gas, Water and Waste sectors are stable. Industry wage data for 2016–2017 from the ABS shows that average wage levels in the electricity sub-sector are more than 50% higher than employees in the waste sub-sector and 40% higher than those in the water and sewerage sub-sector. As such, the EGWWS WPI forecast is likely to underestimate the labour price growth for the electricity distribution sector alone.

Overall, we expect the labour market for skilled labour will tighten further during the 2021–2026 regulatory period, limiting our ability to negotiate wages, particularly under collective bargaining. The BIS Oxford forecast of the EGWWS WPI reflects a realistic expectation of labour price growth for an efficient, prudent and realistic operating expenditure forecast for the electricity distribution sector.

[122] CP ATT014: BIS Oxford, *Estimation of opex input weights, A report prepared for CitiPower, Powercor and United Energy*, March 2019.

Detailed information on drivers of the Victorian EGWWS WPI, comparisons to other industries and jurisdictions, and assessment of forecasting accuracy is available in BIS Oxford's and Frontier's reports.[123]

Labour and non-labours weights

To develop our real price forecast we assigned weights to the price of labour and non-labour that reflect our efficient mix of labour and non-labour inputs. We propose to use our historical average revealed input mix to define labour and non-labour weights used for forecasting real price growth in 2021–2026, as shown in table 9.7.

Table 9.7 Labour and materials input weights in forecasting real price growth (%)

Input	2021/22	2022/23	2023/24	2024/25	2025/26	2021–2026 average
Labour	70	70	70	70	70	70
Non-labour	30	30	30	30	30	30

Source: CitiPower

Using efficient revealed cost is the most prudent and realistic approach to forecasting future cost. Consistent with its expenditure forecast assessment guideline, the AER accepts the base year revealed operating expenditure as the starting point for forecasting allowances unless its benchmarking analysis identifies that level of operating expenditure to be 'materially inefficient'. Each efficient distributor's revealed operating expenditure in the base year reflects its operating environment, which results in a unique input mix on the productivity frontier. If the AER allows the revealed cost base year but not the corresponding efficient input mix, it will either overcompensate or undercompensate efficient distributors.

The AER's incentive-based regulatory framework incentivises an efficient input mix, which will vary by distributor depending on its operating environment. The efficiency benefit sharing scheme (**EBSS**) incentivises distributors to reduce total operating expenditure and there is a reputational incentive to improve benchmarking performance. If we were to increase expenditure by maintaining an inefficient input mix, we would forgo EBSS rewards and reputational advantage from improved benchmarking results. We will therefore always be seeking an efficient input mix that maximises EBSS rewards and reputational advantage.

We propose to use an average of our actual efficient input mix over the 2014–2018 period to determine the labour and non-labour weights. Using a 5-year average further addresses the AER's concern we would adjust our input mix inefficiently in the base year to favour one input over another. Our input mix over 2014–2018 reflects an efficient, prudent and realistic basis for the forecast of our input mix for 2021–2026.

The AER's preferred approach to forecasting real price growth is to apply an industry average input weight to all distributors. We engaged Frontier to assess the appropriateness of using industry average input weights for forecasting labour price growth for efficient distributors. For the following reasons, Frontier found there is no sound basis for the AER to apply industry average input weights to all distributors when setting operating expenditure allowances, rather than the actual input weights of individual distributors:

- adoption of actual input weights is unlikely to weaken efficiency incentives
- the AER’s approach has not been assessed for prudency and realism and is therefore not consistent with the operating expenditure objectives

[123] CP ATT014: BIS Oxford, *Labour escalation*, April 2019; CP ATT053: Frontier, *Review of labour escalation*, December 2019.

- the AER uses revealed historical costs to set future allowances in some circumstances and it is unclear why the same approach cannot be taken for labour and non-labour weights
- contrary to the AER's claim that using a revealed input mix in setting allowances and an industry average in benchmarking would result in some distributors being found efficient with one measure and inefficient with another, the AER's benchmarking analysis is not materially sensitive to the use of actual input weights.

Using revealed input weights also removes the potential for errors in the calculation of industry averages, or basing the calculations on incomplete datasets, which can lead to inefficient allowances. In its assessment, Frontier found the input weights used by the AER in recent decisions to be unreliable for setting allowances. Frontier found evidence that:

- the data relied upon by the AER to calculate industry average input weights have not been reported consistently by distributors, including a significant number of missing data points, and the AER appears to have undertaken no due diligence to identify this
- there are major shortcomings in the methodology used by the AER to calculate industry average input weights, including:
  - the historical time period the average input weights relate to represents a period of very material cost restructuring for some distributors which may never be repeated
  - the AER has applied an inappropriate 'rule-of-thumb' to fill in missing/unreported data
  - average cost shares are biased towards large distributors and distributors that report data across all categories
- the AER's calculations appear to contain errors.

Frontier concludes the AER's current estimate of input weights should not be used to set operating allowances for distributors. Conversely, our revealed input mix is audited and efficient.

Frontier's findings are available in its report attached to this regulatory proposal.[124]

9.2.5 Forecast output growth

We forecast growth in outputs to capture increases in operating expenditure which are driven by changes in the size of the network and the quantity of services we will supply over the 2021–2026 regulatory period.

To forecast output growth, we:

- model and test various output measures as drivers of operating expenditure
- determine the significant output measures and their weights
- forecast a growth rate for each selected output measure.

Selecting output measures and their weights

To model, test and select appropriate expenditure drivers and their weights, we assessed the models used in AER's benchmarking report, prepared by Economic Insights. Economic Insights prepares four models for the AER:[125]

124 CP ATT053: Frontier, *Review of labour escalation*, December 2019.

125 In the AER's 2019 Annual Benchmarking Report published in November 2019, it also introduced a fifth model a Translog SFA.

- Cobb-Douglas Stochastic Frontier Analysis (**SFA**) (econometric model)
- Cobb-Douglas Least Squares (**LS**) (econometric model)
- Translog LS (econometric model)
- Multilateral Partial Factor Productivity (**MPFP**) (non-parametric model).

We engaged NERA Economic Consulting (**NERA**) and Frontier to independently assess the most appropriate models to be used in determining the weights of each output measure. Both NERA and Frontier found that, while there were challenges with each model, the average of two Cobb-Douglas models—SFA and LS—was the most appropriate estimate of weights for use in forecasting output growth.[126]

<u>MPFP is not an appropriate model for forecasting output growth</u>

NERA found the MPFP is an unreliable measure of drivers of cost of an efficient operator for the following reasons:

- the process for deriving weights from the MPFP modelling is not transparent
- the drivers included in the MPFP modelling were chosen based on tariff structure, not by assessing their effect on distributors' costs
- the weights in the MPFP model are artificially constrained to be positive, masking possible misspecification of the model
- the MPFP weights are estimated with very little data, suggesting the weights are estimated imprecisely.

Frontier agreed with NERA that the AER should discontinue its reliance on the Leontief model (used in MPFP) in the setting of operating expenditure allowances. Frontier came to this conclusion due to severe statistical problems associated with the models estimated by Economic Insights and the multicollinearity between the customer numbers, circuit length and the time trend in the estimating equations.

Frontier also found that based on the statistical evidence, energy throughput is not a material driver of operating expenditure. Their review of the statistical properties of Leontief cost functions estimated by Economic Insights for the Annual Benchmarking Report found no statistical evidence that energy throughput has material impact on operating expenditure.

According to the MPFP model, operating expenditure would decrease with falling energy throughput. This is an inaccurate and misleading representation of actual cost drivers. In fact, the relationship between energy throughput and operating expenditure is likely to be increasingly negative—as the growth in DER reduces energy throughput it also imposes additional distribution costs that are not captured by customer numbers and ratcheted maximum demand.

In its 2019 Benchmarking Report, the AER acknowledged the possibility of the energy throughput measure undercompensating distributors for actual costs:[127]

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126 CP ATT012, NERA, *Review of the AER's Proposed Output Weightings Prepared for CitiPower, Powercor, United Energy and SA Power Networks*, December 2018; CP ATT052: Frontier, *Review Of Econometric Models Used By The Aer To Estimate Output Growth A Report Prepared For Citipower, Powercor And United Energy*, December 2019.

127 CP ATT109: Australian Energy Regulator, *Annual Benchmarking Report, Electricity distribution network service providers*, November 2019, pp. 48-49.

Currently, the energy throughput output variable captures changes in the amount energy delivered to customers over the distribution network as measured at the customer meter. It does not measure energy delivered into the distribution network via distributed energy resources, such as from residential roof-top solar panels. In the extreme, an increase in rooftop solar panels could potentially involve a substitution of different energy sources amongst the same customers without changing the total energy consumed or materially changing the existing network in terms of circuit length or maximum demand. However, a distributor may be required to incur higher opex and/or capital to manage the safety and reliability of its network. In this situation there could be a material increase in inputs without a corresponding increase in any or all of the output measures.

Given analysis from NERA and Frontier, we have excluded the MPFP model from our output growth forecast.

Translog models are not appropriate for forecasting output growth

Frontier also found the translog cost function should only be considered for determining output weights if translog-derived weights are evaluated at output levels that are relevant to the Australian distributors. The approach adopted by the AER is to evaluate the elasticities from the model at the average output levels of all distributors in the international sample. However, these average output levels are vastly different to the output levels of Australian distributors. The elasticities should be evaluated at output levels that are reflective of the operating characteristics of the Australian distributors. However, Frontier concludes if the AER believes the elasticities are constant across all utilities in the sample, then it would be statistically more efficient to estimate these constant elasticities using the Cobb-Douglas cost function.

We are therefore satisfied our approach to forecasting output growth, using an average of the Cobb-Douglas SFA and LS models, results in more efficient, prudent and realistic operating expenditure forecasts compared to the use of the simple average of the four models.

Our proposed forecast output growth uses the output measures from the two models—customer numbers, ratcheted maximum demand and circuit length—and set the weights for each output measure as the average of the weights produced by the two models. Table 9.8 demonstrates the output measures and the weights we used in forecasting output growth.

Table 9.8 Output measures and weights used in forecasting output growth (%)

Output measure	Cobb-Douglas SFA	Cobb-Douglas LS	Average of SFA and LS
Customer numbers	70.80	67.59	69.20
Circuit length	16.81	11.78	14.30
Ratcheted maximum demand	12.39	20.63	16.51

Source: NERA

Further information on NERA's and Frontier's assessments on appropriate output growth is available in their reports attached to this regulatory proposal.[128]

[128] CP ATT012: NERA, *Review of the AER's Proposed Output Weightings Prepared for CitiPower, Powercor, United Energy and SA Power Networks*, December 2018; CP ATT052: Frontier, *Review Of Econometric Models Used By The Aer To Estimate Output Growth A Report Prepared For Citipower, Powercor And United Energy*, December 2019.

Forecasting growth in each output measure

We engaged the Centre of International Economics (**CIE**) to independently develop customer number and maximum demand forecasts. We have used the 2014–2018 historical average to forecast circuit length growth. Their forecasts are shown in table 9.9.

Table 9.9 Forecast growth for output measures (%)

Output measure	2021/22	2022/23	2023/24	2024/25	2025/26	2021–2026 average
Customer numbers	1.4	1.3	1.2	1.2	1.1	1.2
Circuit length	1.5	1.5	1.5	1.5	1.5	1.5
Ratcheted maximum demand	9.6	0.0	0.0	0.9	1.4	2.4

Source: CP ATT019: CIE, *Powercor and CitiPower customer number forecasts*, May 2019; CP ATT022: CIE, *CitiPower and Powercor maximum demand forecast*, March 2019.

Table 9.10 shows our forecast output growth, as a sum–product of the forecast growth rate of each output measure and the weight of each measure.

Table 9.10 Forecast output growth rate (%)

Measure	2021/22	2022/23	2023/24	2024/25	2025/26	2021–2026 average
Output growth	2.8	1.1	1.1	1.2	1.2	1.5

Source CitiPower

Our approach to customer number and maximum demand forecasts, including forecasts of solar penetration, batteries and electric vehicles and their impact on maximum demand, is outlined in the demand appendix.[129]

9.2.6 Productivity growth

We have applied the AER's productivity adjustment in accordance with the AER's final decision on 'Forecasting productivity growth for electricity distributors', as shown in table 9.11. However, as an efficiency frontier network, we have already achieved considerable productivity improvements through investment in new technologies and changes in operating practices, and have limited capacity to achieve the 0.5% productivity adjustment through business as usual activities during the 2021–2026 regulatory period.

Table 9.11 Forecast operating expenditure productivity (%)

Description	2021/22	2022/23	2023/24	2024/25	2025/26
Forecast productivity	0.5	0.5	0.5	0.5	0.5

Source: CitiPower

[129] CP APP03: CitiPower, *Maximum demand and customers*, January 2020.

Shifting the productivity frontier requires investment in innovative technology and practices

In its March 2019 final decision on 'Forecasting productivity growth for electricity distributors', the AER determined 0.5% per year reflects the best estimate of the operating expenditure productivity growth that an electricity distributor on the efficiency frontier should be able to achieve going forward. The AER stated this can come from new technology, changes to management practices and other factors that contribute to improved productivity within the industry over time.

We are one of the four networks on the efficiency frontier in the Australian electricity distribution sector. In its 2019 Benchmarking Report the AER stated:[130]

> *CitiPower, Powercor, United Energy and SA Power Networks have consistently been the most efficient distribution service providers in the NEM. These networks are amongst those service providers that are on the productivity frontier.*

By virtue of being an efficiency frontier network, we have limited capacity to achieve productivity gains through business as usual. This places us in a uniquely challenging position compared with other networks that will more easily achieve the 0.5% per annum productivity through effectively catching-up to the efficiency frontier.

To achieve the 0.5% productivity adjustments, we would need to invest in innovative new technologies which materially change operational processes. This will be challenging given we have already revolutionised a significant portion of our operations through automation and innovation. At this point in time we cannot envisage how we would achieve the full 0.5% productivity adjustment.

We have proposed two ICT projects that are driven by customer benefits, customer enablement and Intelligent Engineering, which also have a modest expectation of operating expenditure benefits.[131] We consider these projects will only marginally contribute towards our ambitious target of 0.5% operating expenditure savings per annum during 2021–2026.

In its ICT Guideline the AER states:[132]

> *non-recurrent ICT capex projects where the main driver are operating expenditure benefits should include a negative operating expenditure step change to at least the same of the cost of those capital expenditure projects, with any additional benefit above this negative step change may contribute to the 0.5% operating expenditure productivity assumption*

We disagree the 0.5% productivity assumption can be reached without funding for capital investment required to achieve the savings. In forecasting the 0.5% pre-emptive productivity adjustment, the AER relied on evidence that included productivity growth attributable to non-recurrent ICT expenditure. If the AER makes a further adjustment to reduce allowed operating expenditure to reflect productivity that is expected to result from non-recurrent ICT expenditure, this will result in over-estimation of the forecast productivity growth rate and an operating expenditure allowance below efficient and prudent costs.

It is particularly important to acknowledge the expenditure necessary to achieve future savings for efficient frontier networks. We have already automated our processes and in doing so, have de-risked the industry with regard to new and innovative ICT by introducing it to the Australian energy market. We have lean operations and do not have the contingency to absorb further risky and costly initiatives without reasonable reward. We can

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130 CP ATT109: Australian Energy Regulator, *2019 Benchmarking Report*, November 2019, p.18.

131 CP BUS 7.02: CitiPower, *Customer enablement*, January 2020; CP BUS 7.07: CitiPower, *Intelligent engineering*, January 2020.

132 CP ATT164: Australian Energy Regulator, *Non-network ICT capex assessment approach*, November 2019, p.12.

only envisage future savings coming from investment in new and risky technology—we therefore consider it crucial we receive sufficient funding for the productivity-enhancing projects to allow us to achieve the operating expenditure objectives.

Relationship between productivity and step changes for regulatory obligations

The AER's decision to apply a 0.5% per year pre-emptive productivity adjustment is a shift from its previous approach of applying a 0% productivity adjustment at a time of negative measured productivity. In the past, the AER has never compensated distributors for growing cost pressures through the productivity adjustment (i.e. allowing distributors to recover more allowance by applying an adjustment for negative productivity). Rather, the AER compensated distributors for negative productivity by allowing step changes related to new or growing regulatory obligations.

According to the AER's final decision, the period of growing regulatory obligations ended between 2011 and 2012 on average across Australia. As a result, the AER based its new approach to measuring productivity on electricity distribution data post-2011. This approach was applied to econometric models as well as the MPFP model.

The AER's measure of electricity distribution productivity during 2011–2017 removes the impact of regulatory obligations on operating expenditure productivity by assuming minimal or no growth in obligations during that period. By virtue, any change in regulatory obligations should be considered in isolation of measured productivity, whether historically or forecast. This is consistent with the AER's previous approach to measuring productivity where distributors were compensated for growing regulatory obligations through step changes and not through a productivity adjustment.

By isolating the impact of regulatory obligations on productivity, the 'rate of change' calculation for forecasting operating expenditure does not account for change in regulatory obligations. To ensure we are able to achieve our operating expenditure objective of the Rules, the AER must allow step changes for regulatory obligations during 2021–2026.

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We are maintaining affordability by keeping our prices low

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10 Revenue

Summary

We will be reducing our charges for residential and small business customers over the 2021–2026 regulatory period. This reflects the efficiencies we will deliver to customers, such as through our new ICT initiatives and lower borrowing costs.

We have also applied the rate of return consistent with the AER's guideline.

We propose to apply the following incentive schemes to ensure we face the right incentives to continue to drive efficiencies—efficiency benefit sharing scheme, capital expenditure sharing scheme, demand management incentive scheme and innovation allowance, service target performance incentive scheme and the F-factor scheme.

10.1 What we plan to deliver

The revenue we propose to recover from our customers, and the affordability we strive to deliver, are key concepts we have sought to balance in our regulatory proposal. As discussed in our respective capital and operating expenditure chapters, we have considered whether the programs we intend to deliver are needed, will result in customer benefits, and are delivered in the least-cost way. Importantly, we have also considered whether in totality this proposal delivers the affordability outcomes our customers are seeking.

Stakeholder feedback

Throughout our research, the affordability of energy has been 'top of mind' for our customers and stakeholders. Customers have made it very clear they want a resilient and flexible network but also one that is affordable. Only a third of customers felt electricity is affordable, with a fifth of all customers finding it very expensive. For our commercial and industrial customers, energy affordability is seen as a key factor in the success of large businesses and the likelihood of these businesses staying in Australia or moving offshore.

Overwhelmingly, customers want us to provide value for money rather than reduce services to increase price cuts:

> *'Value for money – if I am paying I expect it to be reliable. Expect it to work when I flick the switch. I agree with those values.'*

> *'Want to find a good balance between investment and affordability.'*

Our proposal provides value for money for customers—we will continue to run the most reliable network in the country at affordable prices while meeting new challenges and regulatory obligations. We will also deliver new customer benefits and cost savings to our customers while improving productivity and continuing to shift the yard-stick of efficiency in the industry.

Consistent with our stakeholder feedback, we will be reducing our charges for residential and small business customers over the 2021–2026 regulatory period, compared to the current period. The average estimated bill impact is outlined in table 10.1.[133]

Table 10.1 Average bill impact ($)

Type	Average estimated bill impact
Residential	-38
Small business	-119

Source: CitiPower

[133] This comparison is based on the 2020 charges compared to the average charges over the 2021–2026 regulatory period. For simplicity, it excludes the transitional six month period. It includes the impact of metering. More information on the transitional period is available in CP APP07: CitiPower, *Transitional arrangements 1 January to 30 June 2021*, January 2020.

We note the final impact to customers will depend on factors such as the willingness of electricity retailers to reflect our price reductions in their pricing, actual energy consumption and the impacts of incentive schemes.

With respect to our charging structures, we are proposing changes to residential and small business structures to accelerate the pace of reform without jeopardising the stakeholder support that is crucial to enable change. We will introduce a new two-rate tariff for new customer connections, customers seeking supply upgrades to three-phase and customers installing solar or batteries. The objective is to encourage customers to move discretionary electricity use into off-peak periods, when the network is under less pressure. Feedback from our customers strongly preferred the simplicity of a two-rate tariff. Further information on our pricing structures is available in our tariff structure statement attachments.[134]

To achieve our forecast price reductions, we are reducing the total revenue we will recover from our customers compared to the 2016–2020 regulatory period by 5%. We are able to constrain our revenue requirement while providing more services through the range of activities discussed below.

10.1.1 We have created efficiencies for our customers and responded to incentives

We have a strong track record of responding to the AER's incentive framework to reduce costs. This is important because when we reduce our costs, customers receive 70% of these savings through lowering the revenue we recover, and hence customer bills. Table 10.2 outlines the efficiencies we have made over the 2016–2020 regulatory period.

Table 10.2 Efficiencies over the 2016–2020 regulatory period ($ million, 2021)

Investment type	Efficiencies
Capital	273.7
Operating	59.1
Total	**332.8**

Source: CitiPower

The specific actions we undertook over 2016–2020 to deliver savings to our customers included:

- automated, centralised and optimised works scheduling, remote crew dispatch, live on-site reporting of works and live fault monitoring
- re-negotiated contracts with service providers
- restructured corporate and network management services
- leveraged smart meter data to better manage the network and reduce capital expenditure
- deferred transformer replacement projects through the introduction of risk monetisation and calibration of our condition based risk model to take account of recent performance of comparable assets

134 CP APP05: CitiPower, *Tariff structure statement reasons*, January 2020. CP APP06: CitiPower, *Tariff structure statement technical*, January 2020. CP ATT032: CitiPower, *Indicative tariffs*, January 2020.

- not proceeded with upgrading our billing system as a result of the Victorian Government's decision to only allow opt-in demand tariffs (which diluted the customer benefits case), and the future opportunity to consider migrating to United Energy's system.

It is through implementing these types of initiates that we consistently rank among the lowest cost distribution networks in Australia. However, as is the nature of continuous improvement, it is becoming increasingly difficult to find these efficiencies—the majority of our transformation programs over the 2016–2020 regulatory period are not repeatable.

To continue to driving efficiency, we will need to consider more innovative and risky ICT solutions in the future. For the 2021–2026 regulatory period, we have included a number of these initiatives and reduced our expenditure forecasts to reflect this. This means customers will receive these savings quicker.

More information on how we have delivered customer savings, and their impact on the operation of the incentives schemes, is included in an appendix to this proposal.[135]

10.1.2 We are responding to lower borrowing costs

The rate of return set by the AER seeks to reflect the cost of funds required by an efficient entity to fund network investment. The rate of return set by the AER has decreased relative to our 2016–2020 regulatory period, and all things being equal, this reduces revenues.

We have applied the AER's rate of return instrument in developing our regulatory proposal, and will seek to reduce our business costs accordingly.

We also recognise the impact of depreciation on long-term prices. As outlined in section 10.2.2, we will accelerate the deprecation of selected assets that will be removed from our network in the 2021–2026 regulatory period due to technical obsolescence. While this approach reflects common regulatory and accounting practice, accelerating depreciation while borrowing costs are low is akin to paying off more of a home loan when interest rates are low. The benefits of this include the following:

- it is possible to reduce the size of the loan (or RAB) without increasing overall prices
- when borrowing rates increase, there is less mortgage (or RAB) to be paid.

10.2 Our forecasting approach

This section sets our forecast approach for the development of our revenue requirement over the 2021–2026 regulatory period for standard control services.[136] This includes the building block approach required by the Rules, our use of the AER's roll forward model (**RFM**) and post-tax revenue model (**PTRM**), and the application of various incentive schemes for the current and future regulatory period. We have prepared our regulatory proposal in accordance with our proposed cost allocation method.[137]

In general, we have adopted the standard approach outlined by the AER for previous regulatory decisions. A summary of our forecast revenue requirements is shown in table 10.3. As outlined above, our proposed X factors have been calculated to hold expected smoothed revenue constant in real terms over the regulatory period.

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135 CP APP02: CitiPower, *What we have delivered*, January 2020.

136 We have classified our services in accordance with the AER's framework and approach paper published in January 2019.

137 CP ATT027: CitiPower, *Cost Allocation Method*, January 2020.

Table 10.3 Revenue requirement ($ million, nominal)

Building blocks	2021/22	2022/23	2023/24	2024/25	2025/26
Return on assets	96.3	99.4	101.4	103.6	104.8
Regulatory depreciation	66.3	73.2	80.4	88.0	95.2
Operating expenditure	113.2	117.8	122.3	126.3	132.0
EBSS	3.0	-1.0	-5.6	-5.2	-
CESS	12.2	12.5	12.8	13.1	13.4
Other adjustments	0.1	0.1	0.1	0.1	0.1
Corporate income tax	9.4	7.7	6.0	6.7	6.9
Unsmoothed revenue requirement	300.5	309.8	317.5	332.7	352.4
Smoothed revenue requirement	307.1	314.4	322.0	329.7	337.6
Forecast CPI (%)	2.4	2.4	2.4	2.4	2.4
Revenue X factor (%)	**4.7**	-	-	-	-

Source: CitiPower

Notes: A positive revenue X factor means a real revenue decrease and a negative revenue X factor means a real revenue increase.

10.2.1 Roll forward of the RAB

We have used the AER's RFM to calculate the opening RAB from 1 July 2021:

- capital expenditure rolled into the RAB has been reduced by customer contributions and disposals
- net capital expenditure includes a half year’s weighted average cost of capital (**WACC**)
- straight-line depreciation based on forecast capital expenditure has been deducted in accordance with the AER’s 2016–2020 final determination
- the RAB has been adjusted for actual inflation, consistent with the method used for the indexation of the control mechanism.

The estimated opening value of the RAB for standard control services as at 1 July 2021 is shown in table 10.4, and in our attached RFM.[138]

[138] CP MOD 10.01 - RFM 5.5 year 2016-21 - Jan2020 - Public.

Table 10.4 Roll forward of the RAB from 1 January 2016 to 1 July 2021 ($ million, nominal)

Description	Total
1 January 2016 opening RAB from previous determination	1,763
Add: True-up for 2015 capital	-1
Add: Actual/estimated net capital for 2016–2021 (including half-year WACC)	690
Less: Forecast straight-line depreciation for 2016–2021	-607
Add: Adjustment for actual inflation for 2016–2021	168
1 July 2021 opening RAB	**2,013**

Source: CitiPower

To roll forward the RAB from 2021 to 2026, we have applied the following approach:

- the RAB has been rolled forward from 2021 to 2026 in accordance with the Rules using the AER's PTRM
- forecast net capital expenditure for the roll forward of the RAB over the 2021–2026 regulatory period has been reduced by forecast customer contributions and by forecast disposals which are based on average historical disposals
- forecast net capital expenditure includes a half year's WACC.

The roll forward of the RAB is shown in table 10.5, and in our attached PTRM.[139]

Table 10.5 Roll forward of the RAB over 2021–2026 ($ million, nominal)

Description	2021/22	2022/23	2023/24	2024/25	2025/26
Opening RAB	2,013.4	2,137	2,243	2,361	2,464
Forecast net capital	190	179	199	190	163
Depreciation	-115	-124	-134	-145	-154
Inflation on opening RAB	48	51	54	57	59
Closing RAB	**2,137**	**2,243**	**2,361**	**2,464**	**2,531**

Source: CitiPower

139 CP MOD 10.02 - PTRM 2021-26 - Jan2020 - Public.

10.2.2 Regulatory depreciation

Straight-line depreciation has been calculated using year-by-year asset tracking from 2011, consistent with the approach taken in the AER's 2016–2020 final determination (and shown in the attached model).[140] Our proposed standard asset lives are shown in table 10.6.

Table 10.6 Standard and remaining asset lives (years)

Asset	Standard life
Sub-transmission	50
Distribution system assets	49
SCADA/network control	13
Non-network general assets: IT	6
Non-network general assets: other	10
VBRC	21.6
In-house software	5
Equity raising costs	42

Source: CitiPower

We have also separated asset classes covering assets that will become redundant before 2026, so that they receive the appropriate economic lives. This includes:

- replacement of distribution transformers to enable greater capacity of solar generation on our networks by 2026. The replacement on distribution transformers is to remove old models that do not have appropriate tapping functionality and/or to increase the transformer capacity.
- twisted PVC grey service cables which will be replaced by 2026. Due to safety concerns associated with the cables, a proactive program has commenced to replace cables that pose a risk to the community and this program will continue through the 2021–2026 regulatory period.

Further information is available in our depreciation model.[141]

Regulatory depreciation for each year of the 2021–2026 regulatory period is shown in table 10.7.

140 CP MOD 10.03 - Depreciation 2021-26 - Jan2020 Public.

141 CP MOD 10.03 - Depreciation 2021-26 - Jan2020 Public.

Table 10.7 Regulatory depreciation ($ million, nominal)

Description	2021/22	2022/23	2023/24	2024/25	2025/26
Straight-line depreciation	114.6	124.5	134.3	144.7	154.3
Less: Inflation adjustment	48.3	51.3	53.8	56.7	59.1
Regulatory depreciation	**66.3**	**73.2**	**80.4**	**88.0**	**95.2**

Source: CitiPower

10.2.3 Rate of return

Our rate of return has been prepared consistent with the 2018 Rate of Return Instrument (**2018 RORI**), modified in accordance with AER instructions to accommodate the Victorian Government's intent to extend the current regulatory period by six months. Our placeholder rate of return is shown in table 10.8.

Table 10.8 Placeholder rate of return

Description	2021/22	2022/23	2023/24	2024/25	2025/26	Average
Nominal risk free rate (%)	1.32	1.32	1.32	1.32	1.32	1.32
Market risk premium (%)	6.10	6.10	6.10	6.10	6.10	6.10
Equity beta	0.6	0.6	0.6	0.6	0.6	0.6
Return on equity (%)	4.98	4.98	4.98	4.98	4.98	4.98
Return on debt (%)	4.65	4.43	4.21	3.99	3.77	4.21
Gearing (%)	60	60	60	60	60	60
Nominal rate of return (%)	**4.79**	**4.65**	**4.52**	**4.39**	**4.26**	**4.52**

Source: CitiPower

Return on debt

The 2018 RORI requires the return on debt to be calculated as a ten-year trailing average, updated annually. The AER has provided us with modified weightings to be used to accommodate the six-month extension to the current regulatory period.

We estimate the ten-year trailing average annual return on debt based on the placeholder averaging period of the last 20 business days in July 2019.

The ten-year trailing average debt rates will be updated in accordance with the 2018 RORI based on observations during the agreed risk-free rate averaging periods.

Return on equity

Under the 2018 RORI, the return on equity must be calculated as the risk free rate plus a market risk premium multiplied by an equity beta. The risk free rate must be calculated as the ten-year yield to maturity on Commonwealth Government Securities, measured over the agreed risk free rate averaging period.

We have calculated the return on equity using a placeholder risk free rate of 1.32% based on the placeholder averaging period of the last 20 business days in July 2019. The risk free rate will be updated based on observations during the agreed risk free rate averaging period, calculated in accordance with the 2018 RORI.

Averaging periods

The 2018 RORI proposes there be a averaging period set for each year of the relevant regulatory period from which the data for the allowed return on debt will be drawn, and a single averaging period from which risk free rate data for the allowed return on equity will be drawn.

The 2018 RORI states we can propose the period no later than the lodgement date of the regulatory proposal and agreed by the AER on a confidential basis. We have proposed our averaging periods confidentially to the AER in accordance with the 2018 RORI.

10.2.4 Expected inflation

In the PTRM, the AER specifies a methodology to estimate inflation. The method is to calculate the geometric average based on the inflation forecasts for two years sourced from the latest available Reserve Bank of Australia’s (**RBA**) Statement of monetary policy and the mid-point of the RBA’s target inflation band for eight years.

Our estimate of expected inflation, for the purposes of a placeholder for this proposal, is 2.40% using the PTRM method, assuming an RBA inflation forecast of 2.00% for the first two years and 2.50% for the remaining eight years. The energy networks recently raised concerns with the AER about the current PTRM method, and potentially the inflation framework. Based on the AER's consideration of these concerns, we may amend the method used to calculate expected inflation in our revised proposal.

10.2.5 Debt raising costs

Debt raising costs are transaction costs incurred each time debt is raised or refinanced. These costs may include arrangement fees, legal fees, company credit rating fees and other transaction costs.

There is now some uncertainty associated with debt raising costs for the following reasons:

- in the SA Power Networks draft decision the AER based the debt raising cost allowance on a report from Chairmont which updated the estimate previously provided by PwC in 2013. SA Power Networks have submitted a report from CEG to the AER in its response to the AER draft decision which contends that one component of debt raising costs—arranger fees—should be 6.88 basis points per annum (**bppa**) rather than the 3.97 bppa calculated by Chairmont and adopted in the AER draft decision.
- the AER collected actual debt raising cost information from all regulated networks in November 2019 but it is not yet clear whether consideration of this data will result in the AER modifying its debt raising cost estimates or approach.

We have applied a placeholder debt raising cost of 8 bppa. We will respond to the AER's draft decision in which the AER would have had the opportunity to consider the data recently collected by the AER and the CEG report submitted by SA Power Networks.

The interest rate swaps which we currently have in place mature at the end of each calendar year over the next ten years. Due to the transition from calendar to financial regulatory years, there will be a mismatch between the maturity date of each existing interest rate swap over the next ten years and the commencement date for rates that need to be hedged in the future. The most efficient solution for dealing with this mismatch depends on many factors including the shape of the yield curve. It is premature for us to select a solution prior to the submission of this proposal and therefore we have not yet been able to cost a solution. Should the efficient cost be material, we will propose a cost in the revised proposal.

10.2.6 Equity raising costs

Equity raising costs are transaction costs incurred when a network raises new equity to fund capital investment. The AER provides a benchmark allowance to recover an efficient amount of equity raising costs, when a network's capital expenditure forecast requires an equity injection to maintain the benchmark gearing of 60%.

Our calculation of equity raising costs is contained in the PTRM.[142] This calculation includes the latest AER parameters, including an imputation credit distribution rate consistent with the 2018 RORI.

10.2.7 Shared asset revenue reduction

Shared assets are those used to provide both regulated and unregulated services. The AER may reduce our annual revenue requirement for a regulatory year to share unregulated revenue with customers. In making this decision, the AER must have regard to the shared asset principles and the Shared Asset Guideline.[143]

One of the shared asset principles is that a shared asset cost reduction should be applied where the use of the assets other than for standard control services is material. The AER's shared asset guideline outlines the use of shared asset is material when a distributor's annual unregulated revenue is expected to be greater than 1% of its total smoothed revenue requirement for a particular regulatory year. If this materiality threshold is exceeded, then 10% of forecast unregulated revenue earned from shared assets is deducted from the revenue building blocks and otherwise no shared asset revenue reduction applies.

Our shared asset revenue is primarily earned from renting poles and ducts to telecommunications companies. The calculation of materiality and shared asset revenue reduction for each year of the 2021–2026 regulatory period is shown in table 10.9.

Table 10.9 Shared asset revenue reduction ($ million, nominal)

Description	2021/22	2022/23	2023/24	2024/25	2025/26
Forecast unregulated revenue from shared assets	3.1	3.2	3.3	3.3	3.4
Smoothed revenue (prior to shared asset reduction)	307.4	314.7	322.3	330.0	338.0
Materiality percentage (%)	1.0	1.0	1.0	1.0	1.0
Shared asset revenue reduction	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**

Source: CitiPower

10.2.8 Estimated cost of corporate income tax

The estimated cost of corporate income tax for each year of the 2021–2026 regulatory period have been calculated using the AER's PTRM. The tax opening asset values, remaining lives and standard lives inputs for the PTRM have been calculated in the AER's RFM. The standard tax asset lives are consistent with the Australian Tax Office ruling Income tax: effective life of depreciating assets (applicable from 1 July 2019).[144]

142 CP MOD 10.02 - PTRM 2021-26 - Jan2020 - Public.

143 CP ATT159: Australian Energy Regulator, *Shared Asset Guideline*, November 2013.

144 CP ATT158: Australian Tax Office, *Taxation ruling 2019/5*, May 2019.

We have forecast immediately deductible capital expenditure based on the average actual amount of immediately deductible capital expenditure claimed over the 2016–2018 as reported in the reset RIN. It is appropriate to use an average since the mix of capital expenditure can vary from year to year.

We have applied a value of 0.585 for the value of imputation credits consistent with the 2018 Rate of Return Instrument. The estimate cost of corporate income tax is shown in table 10.10.

Table 10.10 Estimated cost of corporate income tax ($ million, nominal)

Description	2021/22	2022/23	2023/24	2024/25	2025/26
Estimated cost of corporate income tax	9.4	7.7	6.0	6.7	6.9

Source: CitiPower

10.2.9 Incentive schemes

This section outlines the revenue increments and decrements arising from the incentive scheme that applied over the 2016–2020 regulatory period and outlines our application of these over the 2021–2026 regulatory period.

Efficiency benefit sharing scheme

The efficiency benefit sharing scheme (**EBSS**) provides incentives for us to drive efficiencies in operating expenditure. The benefits of efficiency savings are shared between us and our customers.

We have applied the AER's EBSS to calculate the revenue increments and decrements, as outlined in the attached model and shown in table 10.11.[145] In line with the EBSS guideline, debt raising costs, the demand management innovation allowance and GSLs have been excluded.

Table 10.11 EBSS calculation ($ million, 2021)

Description	2016	2017	2018	2019	2020
Adjusted benchmark EBSS operating expenditure	90.0	91.3	94.7	96.3	98.5
Actual EBSS operating expenditure	79.6	80.7	75.7	86.7	88.9
Incremental efficiency	7.6	0.2	8.4	-9.4	-
Carryover year	2021/22	2022/23	2023/24	2024/25	2025/26
EBSS carryover	**3.0**	**-0.9**	**-5.2**	**-4.7**	**-**

Source: CitiPower

We propose to continue to apply the EBSS to standard control operating expenditure over the 2021–2026 regulatory period to ensure we have strong incentives to pursue innovations which deliver lower costs to customers over the long term. We propose to continue applying the EBSS in accordance with the AER's EBSS

145 CP RIN005 - Workbook 5 - EBSS - Jan2020 - Public.

guideline and exclude debt raising costs, demand management innovation allowance and GSL payments from the calculation of the 2021–2026 carryover.[146]

Applying the EBSS is consistent with the AER's framework and approach paper and our forecast operating expenditure for 2021–2026 which is based on our actual efficient 2019 operating expenditure.

Capital expenditure sharing scheme

The capital expenditure sharing scheme (**CESS**) provides financial rewards for distributors whose capital investments becomes more efficient and financial penalties for those that become less efficient. The scheme ensures savings are shared between customers and distributors.

We calculate the 2021–2026 CESS revenue increment or decrement as follows:

- calculate the cumulative underspend or overspend for the current regulatory period in net present value terms
- apply the network sharing ratio of 30% to the cumulative underspend or overspend to work out our share of the underspend or overspend
- deduct the 2016–2020 financing benefit or cost of the underspends or overspends.

We have identified projects deferred from the 2016–2020 regulatory period and reproposed for the 2021–2026 period as outlined in the appendix to this proposal.[147] We have not adjusted the CESS calculation to exclude the deferred projects because these do not materially increase our capital expenditure forecasts.

The CESS outcome is shown in table 10.12 and more detail is available in the attached model and incentives appendix.[148]

Table 10.12 CESS calculation ($ million, 2021)

Description	Present Value
Total efficiency gain	273.7
Network service provider share (30%)	82.1
Financing benefit	26.1
CESS payment in 2021–2026	**56.0**

Source: CitiPower

Over the 2021–2026 regulatory period, we propose to continue applying the CESS to standard control expenditure in accordance with the AER's CESS guideline.[149] This ensures we have incentives to minimise project costs and pass on a proportion back to customers.

146 These exclusions are consistent with the AER's 2016–2020 final determination for calculating the EBSS carryover.

147 CP APP02: CitiPower, *What we have delivered*, January 2020.

148 CP RIN006 - Workbook 6 - CESS - Jan2020 - Public.

149 CP ATT157: Australian Energy Regulator, *Capital Expenditure Incentives Guideline for Electricity Network Service Providers*, November 2013.

Consistent with the CESS guideline and the AER's framework and approach paper we propose using forecast depreciation to establish the opening RAB for the following regulatory period 2026–2031.

Demand management incentive scheme and allowance

The Demand Management Incentive Scheme (**DMIS**) and demand management innovation allowance (**DMIA**) mechanism provide incentives for us to explore demand management alternatives to network capital investment. We are provided with an annual fixed allowance in the form of additional revenue for each regulatory year of the regulatory period.

During the 2016–2020 regulatory period we commenced the following demand management initiatives:[150]

- we dynamically manage voltage levels on the network on peak demand days to manage supply imbalances in the wholesale energy market
- we are assessing the potential to partner with commercial customers to alleviate network constraints by reducing demand during peak periods and targeted load shedding.

We propose to apply the DMIS and DMIA in the 2021–2026 regulatory period. Applying these satisfies the requirements of the National Electricity Law (**NEL**) by providing an incentive to use more demand management, which can defer augmentation and create option value, potentially lowering costs in the long term.[151]

In December 2017 the AER revised the way that the DMIA would be calculated, which is the sum of:

- $200,000 (in the dollars of the distributor's regulatory year that ends in 2017), escalated for inflation
- 0.075% of the distributor's annual revenue requirement.

Table 10.13 provides our proposed DMIA, calculated in accordance with the AER's guidelines.

Table 10.13 DMIA ($ million, 2021)

Description	2021/22	2022/23	2023/24	2024/25	2025/26
DMIA	0.4	0.4	0.4	0.4	0.4

Source: CitiPower

Service target performance incentive scheme

The Service Target Performance Incentive Scheme (**STPIS**) provides incentives for us to improve network reliability and customer service when the benefits exceed the costs.

Over the 2021–2026 regulatory period we propose calculating the STPIS targets, incentive rates and major event day (**MED**) threshold in accordance with the AER's 2018 STPIS guideline as follows:

- use historical performance data over the five year period from 1 January 2015 to 31 December 2019[152]

150 We did not seek a DMIA for these initiatives.

151 DMIS, 2.1 (b) The distributor's regulatory proposal must include a description, including relevant explanatory material, of how it proposes this scheme should apply for the relevant regulatory period. The distributor's regulatory proposal must also detail how its proposed approach would satisfy the requirements of the National Electricity Law and NER.

152 We have only used 2015-2018 audited data for the regulatory proposal. We will provide 2019 data and updated targets in April 2020.

- recast our historical data to align with the new definitions in the AER's Distribution Reliability Measures Guideline[153]
- apply the updated VCR as determined by the AER to determine the incentive rate[154]
- calculate the MED threshold in accordance with the STPIS guideline
- apply the revenue at risk of 0.5% in accordance with the guideline.

We do not propose to apply the GSL component of the STPIS scheme as we are subject to the Victorian jurisdictional GSL scheme.

Our proposed STPIS targets, incentive rates MED threshold are set out in table 10.14.

Table 10.14 STPIS targets and incentive rates for 2021–2026 regulatory period

STPIS parameter	Network segment	Target	Incentive rate (%)
Unplanned SAIDI	CBD	10.689	0.0206
	Urban	27.621	0.0873
Unplanned SAIFI	CBD	0.157	0.9361
	Urban	0.408	3.9368
MAIFIe	CBD	0.003	0.0749
	Urban	0.229	0.3149
Telephone answering (fault calls)	Network	87.2%	-0.0400
MED threshold	Network	2.328	-

Source: CitiPower

More information is available in our incentives and targets models.[155]

Customer service incentive scheme

We support the AER's draft customer service incentive scheme which enables distributors to propose a new incentive around customer service under the small scale incentive scheme framework. In accordance with the AER's draft scheme, we intend to continue working with our customers to develop an incentive scheme which targets services they value. We intend to submit the details of this scheme with our revised regulatory proposal.

F-factor scheme

The F-factor scheme provides incentives for us to reduce the risk of fire starts from our assets. Figure 10.1 demonstrates we have very few fire starts on our network.

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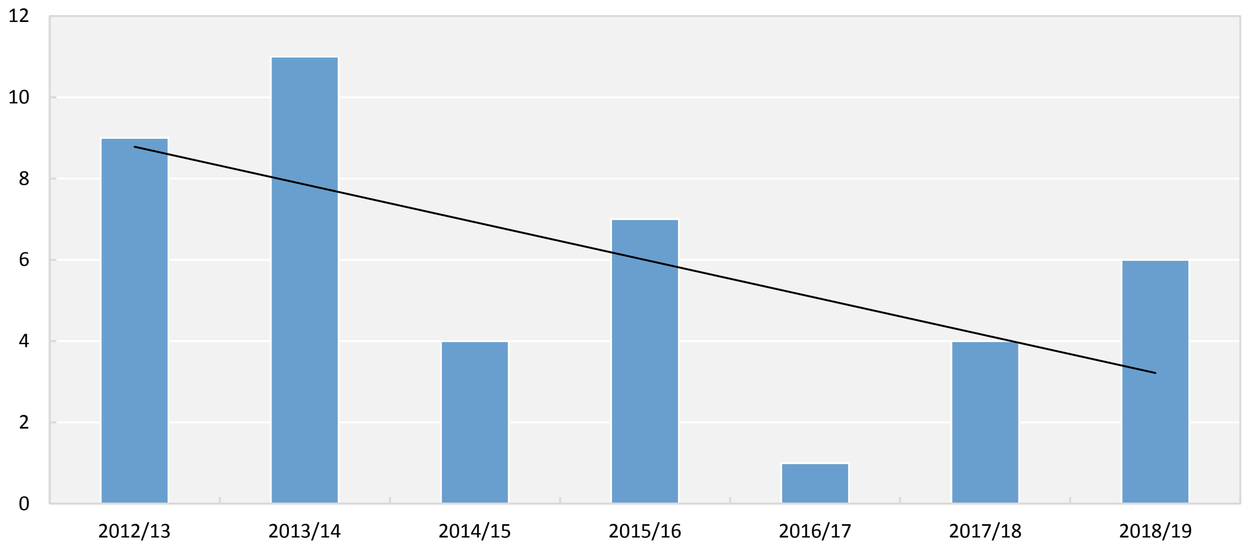
153 CP ATT155: Australian Energy Regulator, *Distribution Reliability Measures Guideline*, November 2018.

154 CP ATT156: Australian Energy Regulator, *Values of customer reliability*, December 2019.

155 CP MOD 10.12: CitiPower, *Targets*, January 2020. CP MOD 10.11: CitiPower, *Incentives*, January 2020.

Figure 10.1 Number of fire starts



Source: CitiPower

We propose to continue to apply the F-factor scheme during the 2021–2026 regulatory period, consistent with the AER's framework and approach paper.

The Victorian government is presently reviewing the approach for setting the F-factor scheme targets and is expected to publish a revised F-factor Order in Council in 2020. Once published, we propose applying the revised F-factor order and subsequent revised AER's F-factor scheme determination.

10.2.10 Control mechanisms

The control mechanism imposes limits on the prices that we can charge. More information on this is available in our control mechanism appendix.[156]

156 CP APP08: CitiPower, Price *control formula*, January 2020.

11 Metering

Summary

The rollout of smart meters in Victoria is a success story. We delivered an efficient rollout of the meters, communications network and IT infrastructure, on time and on budget.

The Victorian smart meters are a rich source of data that we use to deliver better services to our customers and manage the network more efficiently. We have embedded the use of smart meter data and services in our daily operations and have revolutionised network operations. This has resulted in improved network reliability and safety, and reduced network operating costs, delivering major benefits for customers.

Our customers will continue to benefit from us providing metering services in the 2021–2026 regulatory period. We will reduce our average metering charges by 21%. As we lower charges we will ensure customers continue to receive existing smart meter benefits as well as additional services.

11.1 What we will deliver

We provide an efficient metering service to our residential and small business customers. The service involves installing and maintaining smart meters for customers who consume less than 160MWh, and remotely collecting and processing energy data from these meters. It also includes the maintenance and reads of the remaining fleet of manually-read meters.

Victoria has been a pioneer in the NEM for adopting smart meter technology. In 2009, the Victorian Government required distributors to install smart meters for all residential and small business customers. This reflected the significant benefits for customers from smart meters, including the synergies from a mass rollout.

We currently have more than 341,000 smart meters across our network, covering 97.5% of our residential customers. We also have a web of communication devices that allow us to remotely operate and collect data from the meters. Our IT systems allow us to process and validate smart meter data.

11.1.1 Customers benefit from smart meters

Customers have benefited, and continue to benefit, from our smart meter infrastructure. Key benefits are outlined in figure 11.1.

Figure 11.1 Benefits to customers from smart meters across the lifecycle of our services

CONNECT

Timely connection

Ongoing savings from remote meter read
Customers no longer have to pay for site visits for meter reads and tests

Streamlining connections
Connect customers and install meters in a single appointment, rather than multiple visits

Reconnecting remotely
Remotely reconnect a customer without having to visit the customer's site

Connecting solar
Remotely reconfigure smart meters for solar exports

SUPPLY

Better electricity supply

Improving safety at customers premise
Remotely identify neutral integrity issues in a customer's home that may have led to electric shocks

Integrating solar and batteries
Help us understand when it is safe to export electricity into the network

Improving security
Reduce load by managing voltage at times of peak demand, avoiding potential blackouts

RESTORE

Fix outages quicker

Shorter outages
Detect outages quicker, so we can get power back on for our customers in a shorter time

Rotating load in emergencies
Share and rotate energy among our customers in times of emergency. We can prioritise life-support customers and critical infrastructure in these cases

Identifying faults at home
Provide information on whether an outage is caused by the network or a customer's home

BILLING

Efficient billing

Real time usage
Provide next-day insights into usage patterns to help customers manage their bills and compare tariff options

Improved data accuracy
Provide more than 99% accurate data each day, minimising data errors

Notification if a meter fails
Customers are at less risk of a incorrect bill from a faulty meter, as we receive a signal when a meter has failed

EFFICIENCY

Lower long-term costs

Reducing peak demand
Control and distribute load among customers efficiently to reduce peak demand and need for augmentation

Improving power quality
Monitor voltage and reduce any potential issues before they occur

Improved visibility
Visibility of much if the low voltage network, including load data

Source: CitiPower

The smart meters in Victoria and other states differ markedly. While all customers with smart meters benefit from the savings of moving from manually to remotely read meters, Victorian customers also benefit from the rich source of power quality data for network management and optimisation. Only Victorian smart meters are required to be installed with functionality that means this data is collected.

Victorian smart meter functionality is essential to meeting our technology vision for our network including providing full visibility of the LV network as outlined in our digital networks proposal, and managing the increasing penetration of rooftop solar (and other technologies) that will lead to more exports on the network and the need to manage two-way flow and voltage variations.

Therefore, the continuation and realisation of the full range of smart meter customer benefits is highly dependent on key functions that are required under the Victorian functional specification. Some of the new benefits that will continue to be generated by smart meters are discussed below.

We will make it easier for customers to use their smart meter data

We will be streamlining customers' access to smart mater data during the 2021–2026 regulatory period. As detailed in our ICT chapter, we will be introducing a new one-stop-shop portal and mobile application where customers can easily access their usage data in 15-minute snapshots, helping them better understand their usage patterns and track the usage of individual appliances by isolating appliances through usage patterns.

We will be exploring innovative ways to present this data, including measuring the efficiency of customers' exports. This will empower customers to make informed choices on energy use, explore the benefits of participating in demand management and energy markets, and choose suitable tariff offerings.

Stakeholder feedback

Throughout our research, our customers have told us they are interested in accessing more data on their energy use, using the data to make more informed choices and participate in demand response programs. Most engaged customers expressed interest in taking steps to manage their own demand through use of real or near real-time data:

> *'I would be very interested in using my data. I want to know what I am using, how I am being charged… What difference it makes if I don't have my TV on for a week.'*
>
> *'Only if [data] it's easy to use… it needs to be effective!'*

The smart meters are a rich source of data that our customers can use to shape their energy use. As owners and operators of the smart meter infrastructure we will continue to empower customers by improving meter data accessibility.

We will use smart meter data to assist the DER register

To better understand the level of penetration of DER across Australia, AEMO will manage a DER register from December 2019 with assistance from distributors. As the penetration of solar rooftop and batteries grows, we will use the smart meter export data to locate premises with exports, to assist AEMO in maintaining the register.

Expanding our analytical capabilities

We are only at the beginning of our journey in uncovering the analytical possibilities of the rich power quality data provided by smart meters. We expect that complimentary investments in our digital networks initiative will allow us to leverage the data in smart meters to drive innovation in our business.

11.1.2 We will reduce our meter charge in 2021–2026

We will reduce our average metering charge by 21%. We operate an efficient business that continually looks for ways to keep the price as low as possible. Our customers are now sharing the benefits associated with the mass rollout. Table 11.1 summarises our annual metering charges from 2020 to 2025/26.

Table 11.1 Metering charges from 2020 to 2025/26 ($ per NMI, 2021)

Meter type	2020	2021/22	2022/23	2023/24	2024/25	2025/26
Singe phase	72.2	56.6	55.9	55.2	54.5	53.9
Three phase direct connected meter	89.2	70.0	69.1	68.2	67.4	66.6
Three phase (current transformer) connected meter	112.1	88.0	86.9	85.8	84.7	83.8

Source: CitiPower

A key advantage of a distributor provided metering service is our natural economies of scale, efficiencies from bulk purchases and storage, and synergies from operating the communication infrastructure. It also means customers have a single point of contact as the same crew can handle connections, faults and meter installations, all in one visit to achieve much lower meter installation timeframes.

As we lower charges we will ensure customers continue to receive existing smart meter benefits and additional services. More customers will also have smart meters, as we continue to replace legacy manually-read meters on the network.

11.2 Our forecasting approach

Our proposed meter charges for the 2021–2026 regulatory period seek to recover the efficient costs of providing the metering service. Similar to standard control services, we use a post-tax revenue model (**PTRM**) to calculate the revenue based on key inputs such as the metering RAB, new capital expenditure, rate of return, operating expenditure and tax. We then determine a charge for an individual type of meter. In the sections below we identify our method and key inputs to forecast metering charges.

11.2.1 Our forecast meter volumes reflect the experience on our network

The majority of our forecast metering investment in the 2021–2026 regulatory period will be procuring and installing smart meters. We forecast volumes of new and upgraded customer connections, together with volumes of replacement for faulty smart meters and older accumulation meters as follows:

- new customer connections are based on economic advice provided by the Centre for International Economics and volumes of smart meters for customer requested additions and alterations based on historical trends.
- volumes of meter replacement due to network faults are based on historical fault rates (we reactively replace meters when they fail due to a network fault).
- volumes of replacement due to meter faults are based on meter type, estimated asset life and condition. We proactively replace meters when we recognise a systematic failure mode impacting a specific type of smart meter or a family of meters.
- replacement volumes for accumulation meters—at the time of our rollout there were a small number of premises that either opted out of installing smart meters or were inaccessible. Over time, we have been replacing these meters as customers request a smart meter, or where the accumulation meter has failed. Our forecast approach is based on volumes of accumulation meters and experience with previous rollouts.

Table 11.2 sets out the volumes of smart meters we expect to procure and install on the network in 2021–2026. More information is available in the metering cost model.[157]

Table 11.2 Forecast volumes of smart meters installations in the 2021–2026 regulatory period

Driver	Volumes
New connections	36,682
Supply upgrades (additions and alterations)	2,925
Replacements due to network fault	1,012
Meter fault replacement	19,457
Accumulation meter replacement	4,569
Total smart meters	**64,644**

Source: CitiPower

157 CP MOD 11.04 - Metering cost model - Jan2020 - Public.

11.2.2 Our costs are market tested

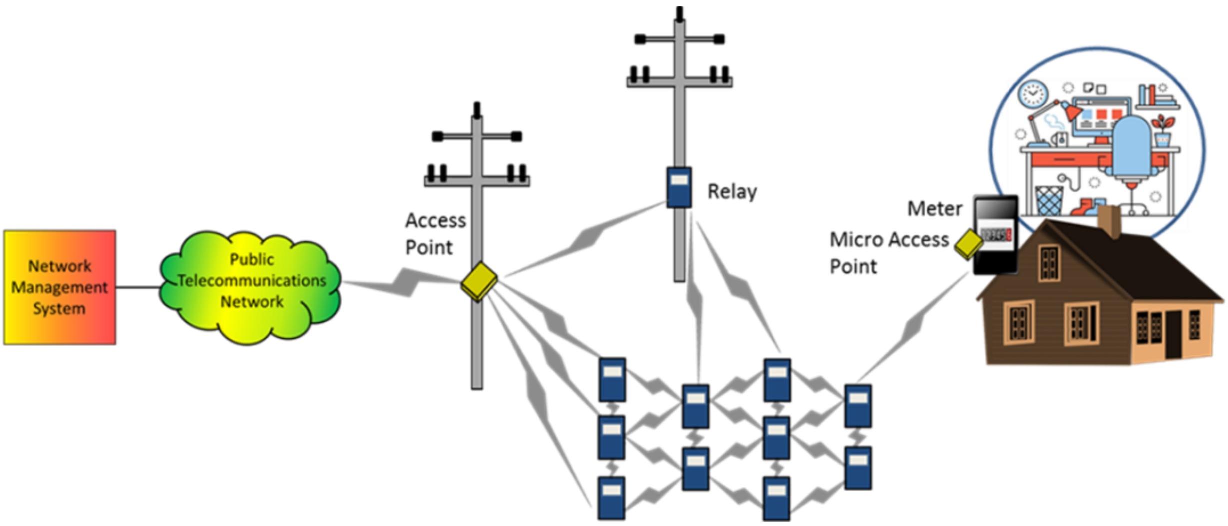
We procure smart meters and communication devices from competitive service providers. This provides confidence that the cost of undertaking the capital works are efficient and market tested. In our forecast, we have used:

- unit rates to procure smart meters and communication devices based on current supplier prices. The unit rates reflect the market-tested cost of hardware.
- for installation costs, we have used rates based on current contracts with suppliers. We have sufficient data to identify the forecast hours and complexity for undertaking different jobs. For example, meter fault replacement has a lower labour cost than replacement caused by network fault, due to the ability to plan ahead.

11.2.3 All customers benefit from our smart meter communications network

Our smart meter communications network comprises a series of communications devices—mainly access points and relays—and a network management system that communicate via the public telecommunications network as depicted in figure 11.2. Other smaller devices comprise of modems, antennas and batteries.

Figure 11.2 Communication devices



Source: CitiPower

The communications network transmits smart meter data at various intervals, depending on the use of that data. Currently we collect data at the following intervals:

- usage data every 30 minutes
- power quality data every 15 minutes
- additional power quality data from various sites for advanced data analytics every 5 minutes.

In 2018, power quality data accounted for 88% of all data collected and transmitted through the smart meter communications network. We expect this share to remain relatively constant by 2025/26.

Given the smart meter communications network mainly transmits data used for network management and optimisation, the benefits of the communications network investment is largely shared by all our customers. As we continue to develop our smart meter data analytics to develop innovative ways to optimise the network and defer network augmentation, all our customers will continue to benefit from the smart meter communications network, including those with contestable meters.

For the 2021–2026 regulatory period, therefore, we have allocated future capital investment for communications device replacements, and operating expenditure related to maintaining the communications network, as follows:

- 88% to standard control services
- 12% to metering services.

Our forecast of the total capital volumes for communications devices is based on historical fault rates, and new growth based on customer numbers, which are outlined in the communications model.[158]

11.2.4 We use the base-step-trend approach to forecast operating expenditure

We incur operating expenditure to collect and verify metering data, to maintain and test meters, to provide customer services and to operate our communication devices.

We use the AER's preferred base-step-trend approach to forecast metering operating expenditure whereby we:

- nominate 2019 as our efficient revealed base year
- adjust our base to remove operating expenditure related to the maintenance of the smart meter communications network
- add to the base year the efficient level of operating expenditure determined by applying a rate of change that comprises labour price escalation and an increase in scale
- add a negative step change to reflect the reduction in the cost of manual meter reads resulting from the expected replacement of legacy meters.

This is outlined in more detail in our metering model.[159]

11.2.5 Our revenue forecast is based on the PTRM model

We have used the AER's PTRM model to calculate the forecast revenue necessary for the efficient provision of metering services during the 2021–2026 regulatory period. Table 11.3 shows the building blocks.

[158] CP MOD 6.03 - AMI comms - Jan2020 - Public.

[159] CP MOD 11.04 - Metering cost model - Jan2020 - Public.

Table 11.3 Building blocks of revenue requirement for metering services for 2021–2026 ($ million, nominal)

Revenue requirement building blocks	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Return on capital	3.6	3.3	3.1	2.7	2.4	15.0
Regulatory depreciation	9.5	10.3	11.1	12.0	12.5	55.5
Operating expenditure	5.5	5.8	6.1	6.4	6.7	30.7
Net tax allowance	1.1	1.1	1.1	1.1	1.1	5.5
Unsmoothed revenue requirement	19.7	20.5	21.4	22.3	22.8	106.8
Smoothed metering revenue	**20.3**	**20.8**	**21.3**	**21.8**	**22.3**	**106.6**

Source: CitiPower

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12 Alternative control services

Summary

Alternative control services (**ACS**) are our customer requested services that are directly recovered from customers seeking the service. They include network ancillary services, such as customer connections, as well as public lighting services. Metering provision services are covered separately.

Our ACS proposal for the 2021–2026 regulatory period incorporates service classifications made in the AER's framework and approach paper. This includes the reclassification of some service trucks to standard control services, introduction of new services previously labelled as service trucks, and the reclassification of previously negotiated services. We will also be abolishing remote re-energisation and de-energisation, providing these services to our customers with smart meters without charge.

We have heard our customers' top concern is affordability and so we are proposing to keep our prices constant in real terms.

With more quoted services from 2021, we are proposing three new labour types for quoted labour rates—increasing quoted labour types from two to five. Our labour rates are based on our efficient 2019 actual rates, inclusive of overheads, escalated by our independently sourced labour price growth forecasts.

Our proposal for public lighting services for the 2021–2026 regulatory period reflects customer preferences for a rapid move to more efficient light alternatives, as well as the need to improve the accuracy of cost allocation across different light types.

12.1 What we will deliver

In the following sections we discuss our network ancillary services and public lighting services.

12.1.1 Network ancillary services

Network ancillary services are non-routine services provided to customers on an 'as needs basis'. Depending on the service, the charge we apply may be a fixed (fee based) charge or variable (quoted) charge based on time and materials to complete the activity.

Fee based services

Fee based services are activities which are fixed in nature and are charged on a per activity basis. For the 2021–2026 regulatory period we will make changes to our fee based services consistent with the AER's framework and approach paper.

We have abolished the service truck visit charge because the framework and approach paper outlines that this is not a distribution service, but rather an input in delivering a distribution service. As such, the service truck visit charge requires reclassifying.

There is a wide variety of services that fall under the service truck visit task that applies in the 2016–2020 regulatory period and which must now be reclassified. To ensure cost-reflectivity and simplicity, we have adopted an approach of classifying the service according to the length of the task:

- isolation of supply or reconnection, excluding HV (usually less than 30 minutes)
- standard alteration (usually between 30 and 60 minutes)
- complex alteration (usually longer than 60 minutes).

We have also created a single charge for short jobs commonly carried out on the same day. For example, a customer may request an isolation and a reconnection within a short space of time. Rather than levying two short services, we will introduce a single charge that includes two visits in the same day and is around 10% lower than the combined two short charges together.

For the 2021–2026 regulatory period, the 'wasted service truck visits' will be reclassified as standard control according to the framework and approach paper. As such, we have created a new charge 'failed field visit' for circumstances when the crew are sent to conduct works that are classified as ACS but are unable to carry out their works due to conditions within the customers' control.

Our customers are already benefiting from smart meters by having access to remote services without the need for site visits, including remote meter reads, remote re-energisation and remote de-energisation. As owners and operators of smart meters, we have the economies of scale to offer these services affordably and at almost no cost. For the 2021–2026 regulatory period, we will continue to provide benefits to our smart meter customers by abolishing remote re-energisation and remote de-energisation fees—providing these services to our customers free of charge.

We already provide a number of services free of charge to our customers, including:

- abolishments under 100 amps (or non-complex)
- desktop and site assessments for No Go Zones.

We are also abolishing a fixed-fee charge for access to meter data and propose to create a quoted charge for meter and network data access for cumbersome requests only.

The abolished charges for the 2021–2026 regulatory period are outlined in table 12.1.

Table 12.1 Abolished charges for the 2021–2026 regulatory period

Service group	Description
Service truck visits	To align with the framework and approach paper
Remote re-energisations / de-energisations	Immaterial costs and so these services will be offered free of charge
Access to meter data	This charge will become a quoted service charge

Source: CitiPower

Our proposed fee based services over the 2021–2026 regulatory period are outlined in table 12.2. Our charges are available in the ACS appendix and more detail is provided in our model.[160]

[160] CP APP09: CitiPower, *ACS charges*, January 2020; CP MOD 12.01 - Fee based - Jan2020 - Public.

Table 12.2 Description of fee based services for the 2021–2026 regulatory period

Service group	Fee based service	Description
Existing charges that will remain		
	Basic connections (BH/AH)	This charge applies for retail customers seeking a basic connection service or proposes to become a micro-embedded generator.
	Meter/NMI/site investigation	This charge applies when a request is received to investigate the metering/connection at a given supply point. This request may be initiated by either the retailer or a customer.
	Remote meter re-configuration	This charge applies when a request is received to reconfigure a smart meter and has the related infrastructure in place.
	Field-based special read	This charge applies when a request is received to manually read a meter outside of the cycle.
	Meter testing	This charge applies when a request is made to test the accuracy of a meter (or meters) at a given supply point.
	Manual re-energisation	This charge applies when a request is received to re-energise a supply point for fuses less than 100 amps by a field visit. The two options for re-energisations available: • reconnections (same day) business hours only • reconnections (including customer transfers) business hours
	Manual de-energisation	This charge applies when a request is received to de-energise (including disconnections for non-payment) a supply for fuses less than 100 amps by a field visit.
New charges		
	Isolation of supply or reconnection, excluding HV (single) (BH/AH)	This charge applies when a customer requests an isolation of supply (e.g. to allow customer and/or contractor to perform maintenance on the customer's assets, work close to or for safe approach), or a reconnection of supply after the isolation, excluding high-voltage (**HV**) assets. It also includes requests for disconnection at the point of supply (i.e. pole or pit) and also includes service line isolations in association with No Go Zone applications.
	Isolation of supply and reconnection after isolation, excluding HV (same day) (BH)	This charge applies when a customer requests both an isolation of supply and a reconnection of the same point of supply on the same day during business hours, excluding HV assets.
	Standard alteration, 30-60 minutes (BH/AH)	This charge is for alteration services expected to last 30 to 60 minutes, including but not limited to the following services: • install or remove controlled load • move meter to new position • relocate point of attachment or service • replace meter panel • re-route mains to new pit • upgrade maximum demand or change supply capacity control • replacing fascia board. If multiple of the above services are required for the customer's alteration, this may be deemed a complex alteration.

Complex alteration, > 60 minutes (BH/AH)	This charge is for alteration services expected to be more than 60 minutes, including but not limited to the following services: • change overhead to underground • change to group metering panel • upgrade phase. It also includes multiple services during the same site visit, for example a customer requests a metering panel replacement and moving a meter to a new position in the same visit.
Failed field visit (unable to perform customer requested task) (BH/AH)	This charge applies when a fixed–fee ancillary service is requested by the customer or a third party but the field crew cannot perform the task once arriving at the site due to customer fault. For example, the site is locked with a non-industry lock preventing access for our crews. Other examples are available in our attached pricing proposal.[161]

Source: CitiPower
Notes: BH refers to business hours and AH refers to after hours.

Quoted services

Quoted services are variable in nature and levied on a time and materials basis. Table 12.3 presents a description of our quoted services for the 2021–2026 regulatory period. The quoted services have been updated to reflect new classifications in the AER's framework and approach paper. Our pricing formula for quoted services and our quoted labour rates are attached.[162]

161 See for further examples: CP ATT144: Australian Energy Regulator, *Pricing proposal 2020*, November 2019.

162 CP APP08: CitiPower, *Price control formula*, January 2020. CP APP09: CitiPower, *ACS charges,* January 2020.

Table 12.3 Proposed quoted services for the 2021–2026 regulatory period

Quoted services	Description
Complex supply abolishment	This charge applies when a customer requests permanent removal of our supply assets on a complex site. For example, when supply is directly from a sub-station, when the abolishment requires a design to be completed safely, or when the supply is more than 100 amps.
Rearrangement of network assets at customer request, excluding public lighting assets	This charge applies when a customer requests capital work for which the prime purpose is to satisfy a customer requirement other than new or increased supply, other than where Guideline 14 applies. For example, a customer requests a removal or relocation of service to allow work on private installation.
Audit design and construction	This charge applies when either a third party requests or we deem it necessary to review, approve or accept work undertaken by a third party. Examples include: • customer provided buildings, conduits or ducts used to house our electrical assets • customer provided connection facilities including switchboards used in the connection of an electricity supply to their installation • any electrical distribution work completed by our approved contractor that has been engaged by a customer • provision of system plans and system planning scopes, for designers engaged by the customer • reviewing and/or approving plans submitted by designers engaged by the customer.
Specification and design enquiry	This charge applies when design or network planning is required to fairly assess the costs so that an offer can be issued to a customer. Examples include: • the route of the network extension required to reach the customer's property • the location of other utility assets • environmental considerations including tree clearing • obtaining necessary permits from State and Local Government bodies • assessment of design and network planning options • specialist services (which may involve design related activities and oversight/inspection works) where the design or construction in is non-standard, technically complex or environmentally sensitive and any enquiries related to distributor assets.
Elective undergrounding	This charge applies when a customer could receive an overhead service but requests an underground service, other than where Guideline 14 applies. For example, a customer requests an underground service where we would consider it safe and prudent to install an overhead service.
High load escorts–surveying and lifting overhead lines	This charge applies when a third party requires safe clearance of overhead lines to allow high load vehicles to pass along roads. This includes surveying and lifting of overhead lines.
High profile antenna installation	This charge applies when customers request to install a high profile antenna to an existing smart meter.
No-go zone safety-related services	This charge applies when a customer or third party requests services related to ensuring safety of no-go zone around our assets, including a supply isolation, covering assets with tiger tails and aerial markers, and other related works. For example, a customer/third party is conducting building works at a site near our assets where visual markers (tiger tails) are required for safety.
Reserve feeder maintenance	This charge applies when a customer requests continuity of electricity supply should the feeder providing normal supply to their connection experience interruption. The fee covers the maintenance of the service, it does not include the capital required to implement or replace the service as this is a negotiated connection service.

Alteration and relocation of public lighting assets	This charge applies when a customer or a third party requests alteration, rearrangement or relocation of public lighting assets.
New public lighting services including greenfield sites and new light types	This charge applies when a customer or a third party request an installation of new public lighting assets, including new light types and emerging light technologies.
Access to network data	This charge applies when a customer or a third party requests electricity network data, including aggregates smart meter data, outside of legislative obligations. For example, a third party requests large quantities of aggregated data outside of our standard practices of legislative obligations.
Complex isolations and alterations, including HV	This charge applies when a customer requests an isolation of supply (e.g. to allow customer and/or contractor to perform maintenance on the customer's assets, work close to or for safe approach) of HV assets or where there are more complex/larger scale works isolation or alternations. This also includes where works are requested to be perform after hours for multi-occupancy or complex sites. For example, after-hours isolation for customer side works at a large multi-occupancy site, such as a caravan park.
Alterations to the shared distribution network assets	This charge applies when a customer or third party initiates alterations or other improvements to the shared distribution network to enable the third party infrastructure (e.g. NBN Co telecommunications assets) to be installed/altered on the shared distribution network.

Source: CitiPower

We are proposing five regulated labour types for quoted services to reflect the varying type of labour requirements across quoted service jobs. Table 12.4 summarises our proposed labour type for quoted service for the 2021–2026 regulatory period. Our charges are available in the ACS charge appendix and more detail is provided in our model.[163]

Table 12.4 Description of quoted labour type and rates for the 2021–2026 regulatory period

Labour type	Description
Administration	Business support officers, project creation and close-out, project administration
Field worker	Trade skilled worker, asset locators, customer connection officers, compliance officers, substation construction, maintenance, testing
Technical	Metering services, SCADA, telecommunication officers, network facilities, quality of supply officers, telecommunications network operating, network standards, network access, substation estimators, surveyors
Engineer	Designers, project engineers
Senior engineer	Senior and principal engineers, senior designers, network planning, network protection

Source: CitiPower

163 CP APP09: CitiPower, *ACS charges*, January 2020; CP MOD 12.02 - Quoted services labour rate - Jan2020 - Public.

12.1.2 Public lighting

We provide public lighting services for local councils and Victorian Department of Transport. The provision of public lighting services and the respective obligations of our business and public lighting customers are regulated by the Victorian Public Lighting Code.[164]

Table 12.5 summarises the changes to the treatment of public lighting services for the 2016–2020 regulatory period as per AER's framework and approach paper. Our public lighting charges are available in the ACS attachment and more detail is provided in our model.[165]

Table 12.5 Changes in classification of public lighting services

Service group	2016–2020	2021–2026
Operation, maintenance, repair and replacement of public lighting assets	Alternative control service, fee based	Alternative control service, fee based
Alteration and relocation of public lighting assets	Negotiated	Alternative control service, quoted
Provision of new public lighting	Negotiated	Alternative control service, quoted

Source: CitiPower

Operation, maintenance, repair and replacement of public lighting

We own and maintain more than 52,800 public lighting across our network. This includes ensuring the lights are operational and safe, periodically replacing lamps and repairing or replacing any luminaires, poles and brackets before or after they fail. The local councils and the Department of Transport pay a fixed annual fee per light—the operation, maintenance, repair and replacement (**OM&R**) charge.

We have around 30 types of approved lights on our network, including minor and major road lights, with more councils opting for efficient light alternatives. In 2019, around 65% of all public lights on our network were efficient alternatives, with more than 95% of these in minor roads. Table 12.6 summarises the existing stock of public lights on our network per reference light type (each reference light type has multiple light types within it).

164 CP ATT005: Essential Services Commission of Victoria, *Public lighting code*, December 2015.

165 CP APP09: CitiPower, *ACS charges*, January 2020; CP MOD 13.01 - Public lighting - Jan2020 - Public.

Table 12.6 **Current public lighting stock we manage per reference light type, 2019**

Light category	Description	Number
MV80	Minor road lights with gas discharge lamps that use an electric arc through vaporised mercury to produce light. These are the least efficient public lights	1,972
High pressure sodium (**SHP**) 150W	Major road high pressures lights with gas discharge lamps. These are the least efficient major road lights	10,631
SHP250W	Major road high pressures lights with gas discharge lamps	3,583
Fluorescent lamps T5	Minor road lights with MV gas discharge lamps that are more efficient than MV80s as they use fluorescence to produce visible light	14,734
Compact fluorescent (**CF**)	Minor road lights that are more efficient than MV80s by running electricity through gas inside the coils, exciting that gas, and producing light	1,046
Light emitting diode (**LED**) Category P	Efficient minor road lights with LED lamps with a longer lifespan than most lights are more efficient than fluorescent lights	11,329
LED Category V	Efficient major road lights with LED lamps.	9,538
Total		**52,833**

Source: CitiPower

Moving to efficient lights

Together with our customers, we are committed to replacing inefficient lights with more efficient alternatives as quickly as possible. Efficient light alternatives result in lower electricity bills and present an opportunity to install smart controls that will enable further savings and control of lights in the future.

The majority of our minor road lights have been replaced by efficient light alternatives in bulk council replacements. Major road lights however remain mostly inefficient. Over time, it will become more difficult and potentially costly to source inefficient lights and there will be declining community support.

We have already changed our practices to reflect the declining market for inefficient lights. If a luminaire fails today, we will only replace it with the most efficient LED alternative. That means failing MV80s or T5s will only be replaced with Cat P LEDs and failing SHPs will be replaced with Cat V LEDs. We propose to continue this approach during the 2021–2026 regulatory period to help our customers reach their efficiency goals sooner. The only exception is the replacement of decorative lights where the councils choose what luminaire we install.[166]

To minimise costs to all customers, we only replace those lights if they fail or if the replacement is necessary. Our customers will make the decision if they wish to replace the remaining inefficient lights in bulk.

In the future, if Australia ratifies the United Nations Minamata Convention on Mercury, the importation of mercury vapour lamps will be banned after 2020. This will require a change in our processes where we either use a LED lamp in inefficient luminaires (similar to decorative light trial below) or we replace the luminaires.

166 Installation of new or repaired decorative lights must comply with current standards which prohibit the use of mercury vapour lanterns.

Stakeholder feedback

In September 2019, we held an Open House engagement with our councils, the Victorian Government and the Northern Alliance for Greenhouse Action where we presented our public lighting proposals. The forum participants strongly supported a complete phase-out of inefficient lights and a change in practice where all failed lights are replaced by the efficient LED alternatives. Customers also supported replacement of lamps in decorative lights with efficient photo-electric cells.

For more details on outcomes of the Open House engagement refer to our stakeholder engagement attachment.[167]

Decorative light trial

We have approved the use of a replacement LED lamp for decorative/historical lights as a trial. Early results are positive however this is only a short term solution. Despite installing a LED lamp, these lights are expected to have higher failure rates compared to LED luminaires and would therefore still be treated as inefficient lights with respect to maintenance and replacement. However, there would be energy savings for councils from use of more efficient lamps.

12.2 Our forecasting approach

12.2.1 Network ancillary fee based services

Our proposed methodology for revising our ACS fixed charges for the 2021–2026 regulatory period has been to escalate each of our existing charges by labour escalation and CPI. For new fee based services, we used a revenue-neutral volume weighted approach to develop the charges for each of the newly created services. This method has been chosen to align the approaches between existing and new charges.

12.2.2 Public lighting fee based services

We use the AER's public lighting model to forecast the OM&R charge for each light type across our network. We have updated the following key assumptions in the model:

- labour escalation for 2021–2026
- fault and failure rates for each light type, measured as an average of actual fault and failure rates during 2016–2018 where available
- the cost of replacing a pole, to better reflect the actual cost incurred.

We have also made a structural change to the model, based on a change in internal asset management practices and international best-practices:

- we have introduced a new light type: major road category V LED light.
- we have assumed that by 1 July 2021, we will no longer be replacing inefficient light luminaires like-for-like. Rather, all fault or failure replacements will be with efficient LED alternatives (category P LED for minor roads and category V LED for major roads). This excludes decorative light luminaires which require non-standard fittings.
- for decorative lights we have assumed lamp replacements will be with efficient LED alternatives.
- we have smoothed the charges to be constant over the regulatory period.

167 CP ATT071: CitiPower, *Open house findings report*, October 2019.

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13 Managing uncertainty

Summary

We operate in an uncertain environment in which uncontrollable external events can alter the quantity and nature of services required to be provided to our customers. While our forecasts have been prepared based on the best information currently available for what we will need to do during the 2021–2026 regulatory period, we are unable to predict each and every event that will occur.

This chapter sets out our proposed nominated pass through events for the 2021–2026 regulatory period.

The uncertainty regime under the Rules comprises pass through events, capital expenditure reopeners and contingent projects. These mechanisms deal with expenditure that may be required during a regulatory period but which are not able to be predicted with reasonable certainty at the time of preparing or submitting a regulatory proposal to the AER.

Rather than building up our expenditure forecasts to cover every possible eventuality, we propose nominated pass through events in this regulatory proposal so as to enable us to request extra funding from the AER during the regulatory period if a large unexpected event occurs, or where we are unable to cost an anticipated event given limitations on the works we may be required to undertake. The exclusion of the costs of these uncertain events from our regulatory proposal ensures our customers face the lowest possible prices.

13.1 Pass through events

The pass through mechanism in the Rules recognises that a distributor can be exposed to risks beyond its control, which may have a material impact on its costs. A cost pass through enables a distributor to recover the costs of defined unpredictable, high cost events not built into the AER's distribution determination.

In addition to the pass through events specified in the Rules, an event may be defined by the AER in a distribution determination. We propose the following nominated pass through events be accepted by the AER in our distribution determination.

Table 13.1 Proposed nominated pass through events

Type of event	Changes from current definition / definition in recent regulatory decisions
Insurer credit risk event	Consistent with current definition and definition accepted by AER in recent regulatory decisions
Insurance coverage event	Amendment from the current 'insurance cap event' having regard to the changes and challenges in the global insurance market that have increased the risk of inability to obtain the full level or scope of cover under relevant insurance policy or policies
Natural disaster event	Minor amendment to current definition and consistent with recent AER regulatory decisions
A terrorism event	Current definition amended to include specific reference to cyber terrorism
Retailer insolvency event	Minor amendment from current definition having regard to the current definition of the retailer insolvency event in the Rules
Major cyber event	Additional event with definition that addresses AER reservations expressed in recent decisions
Act of aggression event	Additional event added with definition that addresses AER reservations with this event expressed in recent regulatory decisions
Electric vehicle event	Additional event added to address the uncertainty with electric vehicle uptake

Source: CitiPower

Each of these proposed nominated pass through events is consistent with the nominated pass through event considerations. In particular, each event:

- can be clearly identified and defined
- is not covered by the pass through events specified by the Rules
- has a low probability of occurrence but the potential to have a significant cost impact
- is beyond a distributor's ability to prevent, substantially mitigate, commercially insure or self-insure acting prudently and efficiently
- identifies any additional factors that it is known will be relevant in assessing the amount to be passed through for the purpose of a pass through application for the event.[168]

Further, with the exception only of the major cyber event, the act of aggression and the electric vehicle event, each of the proposed nominated pass through events is consistent with the nominated pass through events accepted by the AER in its recent decisions for other service providers.

Further information on our nominated pass through events is set out in our attached managing uncertainty appendix.[169]

13.2 Application of cost pass throughs to alternative control services

We also propose the AER apply the pass through provisions for the Rules' specified and nominated pass through events to alternative control services. We propose applying a modified materiality threshold and that an approved pass through amount (or part thereof) that relates to the increased costs of providing alternative control services be recovered through alternative control services pricing, rather than standard control services charges as set out in the managing uncertainty appendix.

168 Clause 6.6.1(j) of the Rules.

169 CP APP04: CitiPower, *Uncertainty appendix*, January 2020.

A Glossary

Term	Definition
2018 RORI	2018 Rate of Return Instrument
ABS	Australian Bureau of Statistics
ACIF	Australian Construction Industry Forum
ACS	Alternative control services
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AFAP	As far as practicable
BI/BW	Business intelligence and business warehousing
BIS Oxford	BIS Oxford Economics
BMP	Bushfire Mitigation Plan
Bpaa	Basis points per annum
CBD	Central Business District
CBRM	Condition based risk management
CCC	Customer Consultative Committee
CCP	Consumer Challenge Panel
CCTV	Closed-circuit television
CESS	Capital Expenditure Sharing Scheme
CIE	Centre for International Economics
CPI	Consumer Price Index
CT meters	Meters with current transformers
DAPR	Distribution Annual Planning Report
DELWP	Department of Environment, Land, Water and Planning
DER	Distributed energy resources
DMIA	Demand Management Innovation Allowance

DMIS	Demand Management Incentive Scheme
Draft regulations	Environment Protection Regulations
DUoS	Distribution Use of System
EBSS	Efficiency Benefit Sharing Scheme
ECA	Energy Consumers Australia
EFCAP	Energy Futures Customer Advisory Panel
EGWWS	Electricity Gas Water and Waste Services
EPA	Environment Protection Authority Victoria
EP Act 1970	Environment Protection Act 1970
ESCV	Essential Services Commission of Victoria
ESV	Energy Safe Victoria
EV	Electric vehicle
Frontier	Frontier Economics
GSL	Guaranteed Service Level
GST	Goods and services tax
HSE	Health, safety and environment
HV	High voltage
IAP2	International Association for Public Participation
ICT	Information and communications technology
IT	Information technology
kV	Kilovolt
kVA	Kilovolt amperes
kWh	Kilowatt hour
LiDAR	Light detection and ranging
LS	Least Squares
LSAA	Local service area agents

LV	Low voltage
MAIFI(e)	Momentary average interruption frequency index (event)
MCR	Marginal cost of reinforcement
MED	Major event day
MPFP	Multilateral Partial Factor Productivity
MSO	Model Standing Offers
MW	Megawatts
MWh	Megawatt hour
NEL	National Electricity Law
NEM	National Electricity Market
NERA	NERA Economic Consulting
NPV	Net present value
NST	Neutral screen testing
OM&R	Operation, maintenance, repair and replacement
PTRM	Post tax revenue model
PVC	Polyvinyl chloride
PwC	PwC Australia
RAB	Regulatory asset base
RBA	Reserve Bank of Australia
Repex	Replacement expenditure
Reset RIN	Price Reset Regulatory Information Notice
RFM	Roll forward model
RIN	Regulatory information notice
RIS	Regulatory Impact Statement
RIT-D	Regulatory investment test – distribution
Rules	National Electricity Rules

SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
SAMP	Strategic asset management plan
SCADA	Supervisory control and data acquisition
SFA	Stochastic Frontier Analysis
STPIS	Service Target Performance Incentive Scheme
VCR	Value of customer reliability
WPI	Wage Price Index

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