Issues Paper

Victorian electricity distribution determination, 2021 to 2026

April 2020

AUSTRALIAN ENERGY REGULATOR

Inquiries about this publication should be addressed to:

Australian Energy Regulator
GPO Box 520
Melbourne Vic 3001

Tel: 1300 585 165
Email: VIC2021-26@aer.gov.au

Amendment record

Update	Date	Page
Published	7 April 2020	
Correction to Figure 1	June 2020	6

Contents

Shortened forms

Shortened form	Extended form
AMI	advanced metering infrastructure
AER	Australian Energy Regulator
augex	augmentation capital expenditure
capex	capital expenditure
CCP/CCP17	Consumer Challenge Panel, sub-panel 17
CESS	Capital Expenditure Sharing Scheme
CSIS	Customer Service Incentive Scheme
CPI	Consumer price index
DER	distributed energy resources
DMIA/DMIAM	Demand Management Innovation Allowance/Demand Management Innovation Allowance Mechanism
DMIS	Demand Management Incentive Scheme
EBSS	Efficiency Benefit Sharing Scheme
HID	high intensity discharge
ICT	information and communications technology
LED	light emitting diode
LIDAR	light detection and ranging
NEL	National Electricity Law
NER	National Electricity Rules
opex	operating expenditure
PV	Solar photovoltaic
PTRM	Post tax revenue model
RAB	Regulatory asset base
Repex	replacement capital expenditure
REFCL	Rapid Earth Fault Current Limiter
STPIS	Service Target Performance Incentive Scheme
TSS	Tariff Structure Statement
VIC	Victoria

1 Introduction

The Australian Energy Regulator (AER) works to make all Australian energy consumers better off, now and in the future. We regulate electricity networks in all jurisdictions except Western Australia. Our work is guided by the National Electricity Objective (NEO) which promotes efficient investment in, and operation and use of, electricity services in the long term interests of consumers.[1] As part of this, we set the maximum revenues that networks are allowed to recover from consumers through their network tariffs (this is known as the 'revenue cap' form of control). The amount of these revenues is based on our assessment of efficient costs and a realistic expectation of forecast electricity demand. By only allowing efficient costs we regulate network tariffs so that consumers pay no more than necessary for the safe and reliable delivery of electricity.

Regulatory determinations usually occur every five years for each regulated business. We use an incentive approach where, once regulated revenues are set for a five year period, networks who keep actual costs below the regulatory forecast of costs retain part of the benefit. This benchmark incentive framework is a foundation of the AER's regulatory approach and promotes the delivery of the NEO. Service providers have an incentive to become more efficient over time, as they retain part of the financial benefit from improved efficiency. Consumers also benefit when efficient costs are revealed and a lower cost benchmark is set in subsequent regulatory periods.

On 31 January 2020, the five Victorian electricity distribution businesses, AusNet Services, CitiPower, Jemena, Powercor and United Energy submitted regulatory proposals for the five years commencing 1 July 2021. The businesses were asked to include in their proposals their response to the AERs guidance on the six month deferral of timing for Victoria.[2]

While the AER has conducted an initial review of the proposals, we have not yet formed a final view on the proposals. We have not yet considered all the materials and evidence that support the claims made by each business or applied all our regulatory tools to test the robustness of the proposals.

The purpose of publishing this paper is to assist stakeholders by identifying those aspects of the proposals which, after our preliminary review, are likely to be relevant to our assessment of the proposal. [3] Stakeholders can assist our process by providing their views on these aspects, but should feel free to comment on any aspect of the regulatory proposals.

There are unique circumstances for this regulatory reset, namely recent bushfires and timing changes for the reset period. The Coronavirus (COVID-19) will impact both our approach to stakeholder consultation and the ability of all market participants to engage. In particular, we cannot hold a traditional public forum and have developed an alternative means of achieving the same outcome. On 22 April 2020 we will put upload on our website, presentations from the businesses and then provide an opportunity for stakeholders to put forward questions. The details of how to participate in this virtual Public Forum will be available on our website.

1 NEL, s.7.

2 Further information regarding the change of timing is at Section 5.

3 As required under NER clause 6.9.3(b)(1)),

In line with the recently released Statement of Expectations, the AER would like to acknowledge the changing operating environment and the potential for this to impact on the five year forecasts in the submissions from the businesses. We are proposing to adopt a greater degree of flexibility in our approach to requesting and receiving information (from all stakeholders) and how we need to consider the extenuating circumstances in our analysis. We will provide the distributors with a chance to submit on the effect of COVID-19 on their proposals and other stakeholders a chance to respond to the businesses submissions. This may also impact on timing of some elements of the process going forward.

1.1 How can you get involved?

A public forum on the proposals will be held via the AER website on 22 April 2020. As part of our review we are also seeking written submissions from stakeholders on the proposals, views on where our assessments should focus, and our approach to the six month deferral.

The decisions we make and the actions we take affect a wide range of individuals, businesses and organisations. Hearing from those affected by our work helps us make better decisions, provides greater transparency and predictability, and builds trust and confidence in the regulatory regime.

Throughout these reviews we will also have the benefit of advice from our Consumer Challenge Panel (CCP17).[4] The expert members of the CCP help us to make better regulatory decisions by providing input on issues of importance to consumers and bringing consumer perspectives to our processes. The table below sets out the key milestones planned for these reviews:

Table 1 Key dates for the Victorian electricity distribution determination

Task	Date
Businesses submit regulatory proposals to AER	31 January 2020
AER to release Issues Paper	7 April 2020
AER to hold virtual public forum on regulatory proposals and issues paper	22 April 2020
Submissions on regulatory proposals due	3 June 2020
AER to make draft decisions	30 September 2020
AER to hold public forum on draft decisions	October 2020
Businesses to submit revised regulatory proposals to AER	December 2020
Submissions on draft decisions and revised proposals due	January 2021
AER to make final decisions	30 April 2021

Note: Given the current circumstances that may impact on the ability of stakeholders to respond, timelines are indicative and subject to change.

4 Consumer Challenge Panel members advising the AER on this review are Mike Swanston, Robyn Robinson, David Prins and Mark Henley. https://www.aer.gov.au/about-us/consumer-challenge-panel

1.2 Our initial observations

The Victorian distributors' regulatory proposals are available on the AER's website.[5] This paper sets out the key issues evident from our initial review of the regulatory proposals. While we welcome submissions on any aspect of the businesses' proposals, we are particularly interested in submissions on the following areas:

- The implications of our comparative analysis of each of the proposals from the Victorian distributors, including the extent to which AusNet's proposal opex and capex are amenable to assessment at the total level with less detailed assessment at the level of capex and opex components, compared to other Victorian DNSPs' proposals, given it compares well with peers, historical allowances and expenditure and the involvement of the consumer forum in settling the proposal — see sections 2 and 3.
- Whether the Victorian distributors' expenditure and tariff reform proposals support the energy system transition including by efficiently integrating distributed energy resources (DER) such as rooftop solar, home batteries and electric vehicles into the grid — section 2.5.1 and section 2.5.2.
- Our preliminary analysis of the drivers of revenue in the regulatory proposals, including the drivers of operating and capital expenditure for standard control services and expenditure and tariffs for alternative control services — see section 4. We are interested in stakeholder views on the following issues:

1. Opex — the increases in expenditure that the distributors are proposing from their base years — set out in sections 3.1 and 4.7.
2. Capex — CitiPower, Powercor, United Energy's forecast increase and justification in replacement expenditure for poles — section 4.8.
3. Capex — The different approaches taken by the Victorian distributors to accommodating the changes to the EPA Act — section 4.8.4
4. Alternative control services — The proposed allocation of a proportion of the costs of metering services to standard control services — section 4.9.1.
5. Alternative control services — The balance struck between costs of phasing out inefficient and/or hazardous lighting and the benefits of more efficient lighting (which could deliver overall savings when considering electricity usage) — section 4.9.2.

- Our proposed approach to accommodate the extension of the regulatory period within our regulatory approach — see section 5.

[5] https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements

2 What do these proposals mean for Victorian consumers?

Below we set out the implications of each of the Victorian distributors' proposals for consumers. This covers the expected impact on revenues and network tariffs, as well as some of the key outcomes that the Victorian distributors will deliver with these revenues, including;

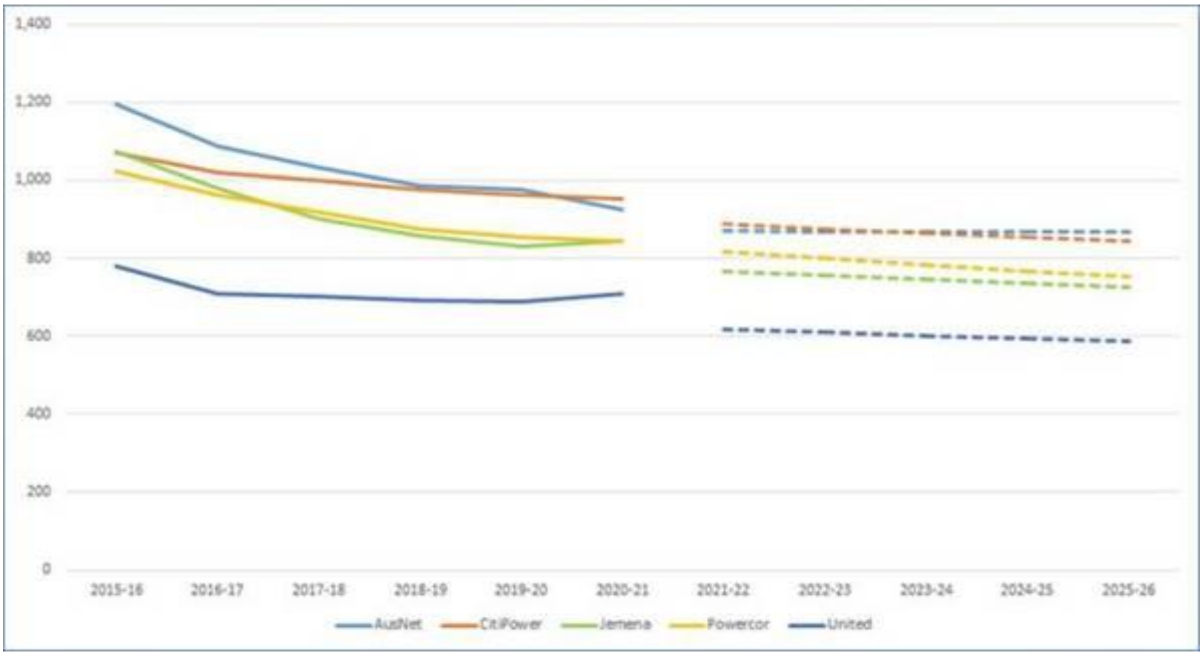
- managing increased demand
- maintaining network reliability
- adapting to the challenges of the energy transition
- addressing the impact of bushfires.

Additionally, the Victorian distributors have engaged with their customers and sought to account for this commitment in shaping their regulatory proposals.

2.1 Proposed revenue

Each of the Victorian distributors is proposing to reduce revenues from the current period. Figure 1 sets out the proposed revenue per customer of each of the distributors which reflects what, on average, a customer will pay for electricity annually. Appendix A sets out the indicative impact on prices for the residential customers and small business customers of each distributor.

Figure 1 Revenue per customer ($Dec 2020)



Source: AER analysis using actual and forecast RIN data.

2.2 Customer engagement and delivering improved outcomes for customers

Below we outline the engagement that each of the distributors undertook, what they heard, and how this has influenced their proposals.

2.2.1 AusNet Services

AusNet Services trialled a new form of customer engagement in the development of its regulatory proposal.[6] This is the 'New Reg' process. New Reg is a joint initiative by the AER, Energy Networks Australia (ENA) and Energy Consumers Australia (ECA). The goal of this initiative is to ensure that customers' preferences drive energy network regulatory proposals and outcomes.[7]

Under the New Reg process an independent Customer Forum was engaged to negotiate aspects of AusNet Services' regulatory proposal. The Customer Forum was comprised of members selected to have relevant skills and experience to ensure they function as an effective and robust counterparty to AusNet Services. It was given autonomy and funding to undertake customer research and was required to evidence positions in its engagement report.[8] .

The operations of the trial were governed by:

- an Early Engagement Plan, reviewed and accepted by the AER on 11 March 2018
- a Memorandum of Understanding between AusNet Services, the AER and the Customer Forum, covering responsibilities and deliverables, funding arrangements and conflict resolution mechanisms.[9]

We supported the Customer Forum to ensure that it could effectively engage with AusNet Services. This included providing the Forum with the technical and economic support during the negotiation process, such as education on the AER's expenditure assessment approaches. AER staff also developed a series of guidance notes on AusNet Services' negotiating positions and draft regulatory proposal.[10] The Customer Forum also met with a large number of expert bodies and agencies throughout the process including CCP17, the Essential Services Commission and Energy Safe Victoria (ESV).[11]

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6 Further details on AusNet Services' consumer engagement is available in its regulatory proposal. Link: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/ausnet-services-determination-2021-26/proposal

7 AER, ECA, ENA, New Reg: Towards Consumer-Centric Energy Network Regulation Approach Paper, March 2018, p. 3.

8 AusNet Services' Customer Forum, *Customer forum final engagement report*, January 2020.

9 Both of these documents have been published on the AER's website, here: https://www.aer.gov.au/networks-pipelines/new-reg/ausnet-services-trial

10 These documents have been published on our website here: https://www.aer.gov.au/networks-pipelines/new-reg/ausnet-services-trial

11 Including the Consumer Action Law Centre, The Energy and Water Ombudsman of Victoria and Energy Consumers Australia, Ref: AusNet Services' Customer Forum, Customer forum final engagement report, January 2020, pp. 69-75.

2.2.1.1 Customer influence on the proposal

> *At the heart of our plans are a range of actions and initiatives designed to deliver our services in the way that our customers have told us they expect. This means:*
>
> *1) Ensuring that services are as affordable as possible;*
>
> *2) Maintaining the quality of the core service customers want from us, which is reliable and safe electricity supply;*
>
> *3) Improving the way that customers experience our services, e.g. when customers need to contact us or when there is an outage; and*
>
> *4) Responding to the changing ways that our customers are using our network, e.g. by installing solar panels and exporting solar energy.*[12]

AusNet Services negotiated a range of outcomes with its Customer Forum.[13] As set out in the Customer Forum's engagement report; adjustments included:

- significant improvements to its customer services, set out in Figure 2 below
- average cost saving per customer rising from $58 ($2021) in February 2019 to $110 ($2021) at the final negotiation
- a 36 per cent reduction in funding for major augex projects
- a 27 per cent reduction to funding for major replacement projects without significantly compromising reliability for customers
- a 31 per cent reduction of metering charges
- proposing significantly fewer step changes compared to the other Victorian distributors. [14]

AusNet Services and the Customer Forum also proposed that the AER develop a customer service incentive scheme (CSIC). We released a draft CSIC in December 2019.

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12 AusNet Services: Delivering better outcomes for customers, Overview of our electricity distribution regulatory proposal 20212–26, January 2020, p. 19.

13 AusNet Services' Customer Forum, Customer forum final engagement report, January 2020. Link: https://www.ausnetservices.com.au/en/Misc-Pages/Links/About-Us/Charges-and-revenues/Electricity-distribution-network/Customer-Forum

14 AusNet Services' Customer Forum, Customer forum final engagement report, January 2020. Link: https://www.ausnetservices.com.au/en/Misc-Pages/Links/About-Us/Charges-and-revenues/Electricity-distribution-network/Customer-Forum

2.2.1.2 Improved customer service outcomes arising from engagement

AusNet Services committed to improvements to its customer services. These are set out in Figure 2 below.

Figure 2 AusNet Services' customer service improvements

Residential customers

- Improving communication and management of planned and unplanned outages
- Making new connections easier
- Continuous improvement of management of life support customers including communication and priority restoration during outages
- Making claims easier if we have inadvertently damaged customer equipment
- Collaborating with communities to improve the experience of our most vulnerable customers

Business customers

- Ensuring customers are on the cheapest network tariff for their usage
- Resourcing of new customer relationship managers to support our business customers and their specific network needs
- Making claims easier if we have inadvertently damaged customer equipment
- Improving communication and management of planned and unplanned outages
- Dedicated staff to support larger electricity generators wanting to connect to our network (such as wind farms)

Solar customers

- Ongoing innovation and collaboration across the industry to unlock the solar resource
- On line pre-approval solar tool (up to 30kW) – 95% approved
- Solar alert so customers know when system not working – over 10,000 alerts
- Dedicated staff to support local communities going solar
- Ongoing programs to improve solar connection processes

All customers

- Incentives to improve customer satisfaction are embedded in the performance measures for senior managers and teams across the organisation
- A new incentive scheme to improve customer satisfaction
- Annual reporting on performance against promised customer improvement outcomes
- Greater customer research and engagement to better understand the key issues being faced by our customers and how best to fix them

Source: AusNet Services: Delivering better outcomes for customers, Overview of our electricity distribution regulatory proposal 20212–26, January 2020, p. 28.

2.2.2 Jemena

Jemena commenced engagement with its Customer Council in 2017 and formed a 'People's Panel'. The People's Panel consisted of 43 people from across Jemena's distribution area with a demographic mix of the customer base to reflect the broader customer base. Jemena described it as 'a highly collaborative and engaging process held over several sessions and based on the concept of a jury'.[15] The People's Panel delivered 25 recommendations to the Jemena Board. Thirteen of these recommendations were for Jemena to action, while 12 issues were beyond Jemena's direct control, but on which it could advocate. Jemena stated that is has adopted all bar one of the People's Panel's recommendations.

Jemena won the Energy Networks Australia (ENA) and Energy Consumers Australia (ECA) 2019 Consumer Engagement Award for its Gas Networks Deliberative Forum in New South Wales as well as its People's Panel citizens' jury in Victoria.

2.2.2.1 Customer influence on the proposal

> *Customers told us that their number one issue was affordability. This Proposal has taken this challenge into account and will help drive down network prices."*
>
> *"Many of our customers want a smarter, more efficient future grid that enables the community to share renewable electricity*[16]

Jemena's People's Panel made a number of recommendations that we consider in this section. These include:

- invest in smart technology across the grid to ensure network equipment is not upgraded too early
- maintain the number and duration of outages as they are today
- adopt monthly maximum demand pricing structure is the best for customers, so long as customers can opt out[17]
- enable increased feed-in of solar (and other renewables) into the grid by improving the performance of the grid through new technologies
- invest in smart technology across the network to ensure network equipment is not upgraded too early. [18]

Jemena has committed to delivering a number of customer service improvements which are outlined in Figure 3 below.

[15] Jemena Electricity Networks, 2021-26 REGULATORY PROPOSAL - OVERVIEW, January 2020, p. iv.
[16] Jemena Electricity Networks, 2021-26 REGULATORY PROPOSAL - OVERVIEW, January 2020, p. i.
[17] Note: Jemena's proposed pricing structure may not currently reflect this recommendation.
[18] Jemena Electricity Networks, 2021-26 REGULATORY PROPOSAL - OVERVIEW, January 2020, pp. 22-23.

Figure 3 Jemena's customer service improvements

Customer interactions

- Improve customer digital channels to meet customer needs and expectations by focusing on the touchpoints that matter
- Build trust - 'Jemena, your local network'
- Increasing services to include mobile apps and using simpler processes
- Sending SMS messages to all customers for unplanned outages with include an estimation of how long it will take to fix the outage
- Improving the information available to customers and the ease of access to smart meter data
- Investigating how customers could be provided with personal usage and bill information for different pricing structures
- Provide email or letter notifications about all planned outages with accurate details of how long the outage will be and suggestions for how to manage the time without electricity
- Continuing to explore using rebates to encourage customers to respond during times of need (for example hot days)
- Increasing investment into energy literacy and awareness in the community by $330 000 per annum

Integrating DER

- Streamline customer experiences when requesting services or information from us

Working with retailers

- To simplify pricing rates to ease complexity and assist consumer choice
- To encourage retailers to keep providing paper bills for customers who want it
- To create an opt-out process for notifications, so all customers can receive notifications via their mobile unless they choose not to

Source: Jemena electricity networks, 2021-26 regulatory proposal – overview, January 2020, pp. 22-23, 30.

A number of Jemena's People's Panel's recommendations related to advocacy that they want Jemena to undertake. This does not directly relate to Jemena's proposal but is worthwhile mentioning. The people's panel wanted Jemena to advocate for:

- increased docking stations for electric vehicles across Jemena's network
- impartial and technically accurate source of information for people who are considering installing solar
- new technologies that make the grid less carbon intensive such as renewable energy storage, efficient technologies and new housing development that enable efficient technologies
- clearer information and engagement with customers about energy options so people know what the best option for them is, and whether it is worth investing in different technologies

- support for vulnerable customers who may get left behind because they cannot take part in new technologies, Government-supported energy literacy programs and educating customers about retailer deals and bills in other languages.

2.2.3 CitiPower, Powercor and United Energy

CitiPower, Powercor and United Energy ran parallel consumer engagement processes. These businesses launched their engagement in 2017, with an overarching strategy that consisted of four phases: 'Customer insights, Possible energy future, Sense checking and Preparing our proposal'. As well as engaging with the businesses' Customer Consultative Committee, a dedicated reference group for the reset was created: Energy Futures Customer Advisory Panel (EFCAP) that participated in the entire engagement program which met every three to four months for two years.

2.2.3.1 Customer influence on the proposal

> *Reliability and cost are the key priorities for all customers and should be an area of focus. Customers are satisfied with reliability and power quality and want levels maintained.*[19] *Customers are not willing to trade off current reliability for cost savings.*
>
> *Affordability is highly valued and many see current electricity prices as too expensive in relation to other utilities.*
>
> *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. They would like a proactive implementation an increase in renewables now. If everyone benefits from investment then customers are willing to pay (solar and non-solar) whereas if just solar customers benefit (e.g. being able to export) then there is a feeling they should pay.*[20]

CitiPower, Powercor and United Energy reported similar feedback from their customers. In response they made the following commitments.

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19 Very satisfied in Citipower's case. Note: C&I (commercial and industrial) customers would like power quality improved.

20 Woolcott Research and engagement, Powercor integrated summary report, August 2019. Woolcott Research and engagement, Citipower integrated summary report, August 2019. Woolcott Research and engagement, United Energy integrated summary report, August 2019.

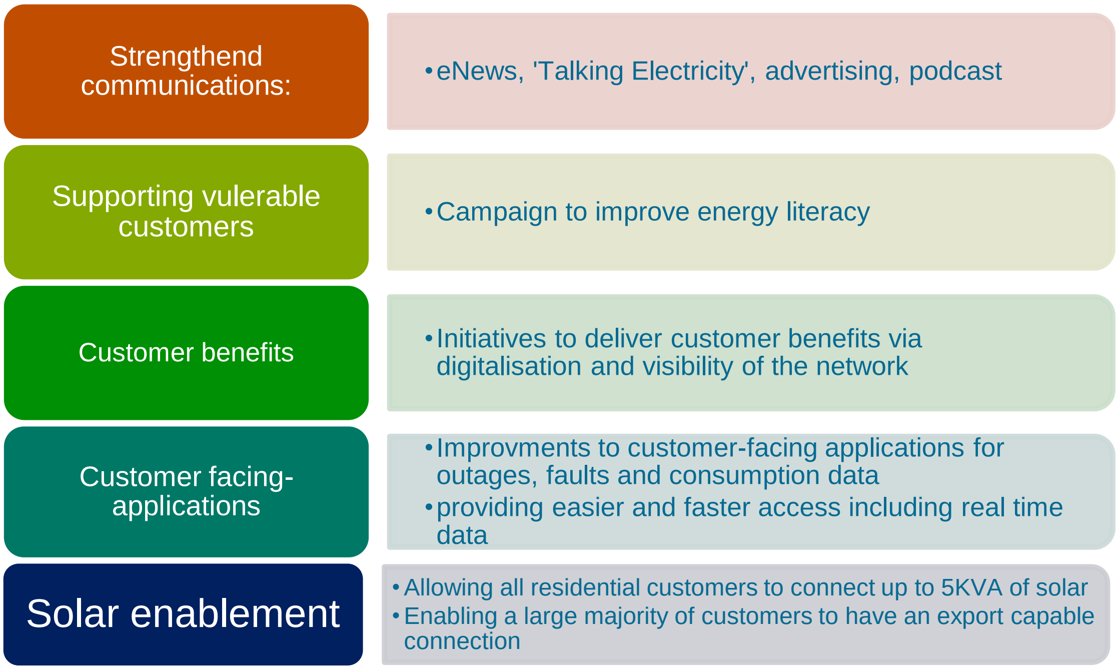
Table 2 CitiPower, Powercor and United Energy's customer commitments[21]

Customer desire	Commitment
"Our customers won't trade off reliability for cost savings."	Maintain their reliability (and reliability relative to other networks).
"Around two-thirds of residential customers perceived their electricity bills as too high."	Ensure that they maintain their high efficiency relative to other networks
"Customers and stakeholders want the power put back into people's hands, with access to real-time data and a customer-centric focus"	Committed to deliver a Customer Service Strategy and improve our customer-facing applications for outages, faults and consumption data.
75% of customers thought the network should be upgraded faster than is planned to allow for renewable energy. A steady and progressive integration of renewable energy with a measured reduction in tariffs by 2026, and improved power quality	Developed a vision for our network that reflects our customers' and 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.

Figure 4 sets out the customer service improvements that CitiPower, Powercor and United Energy have proposed.

21 Citipower, Say hello to our five year plan, January 2020, p.15. Powercor, Say hello to our five year plan, January 2020, p. 15. United Energy, Say hello to our five year plan, p. 15.

Figure 4 CitiPower, Powercor and United Energy's Customer service improvements



Source: CitiPower, Regulatory proposal 2021–2026, January 2020, pp. 19-20. Powercor, Regulatory proposal 2021–2026, January 2020, pp. 19-20. United Energy, Regulatory proposal 2021–2026, January 2020, pp. 34-35.

2.3 Managing increased demand

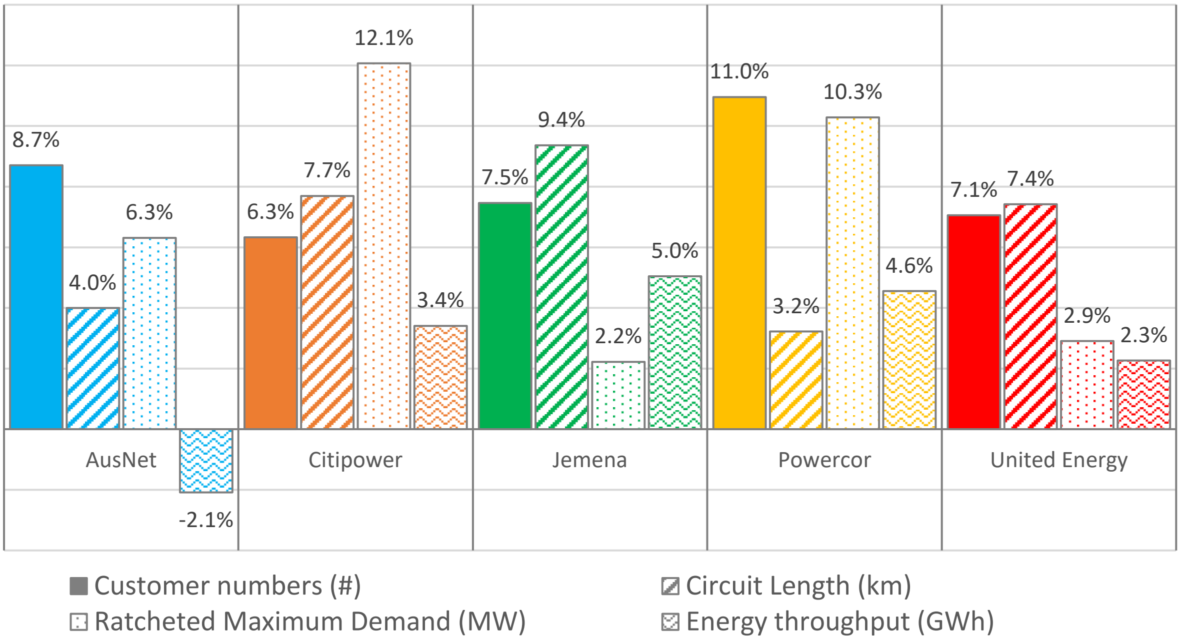
The Victorian distributors develop their regulatory proposals to accommodate increasing demands on their networks. Distributors transport electricity from transmission nodes to customers, sometimes over great distances. In doing so, they need to meet the demand of their customers both over the course of a year and when this demand is greatest. Meeting this demand while maintaining safety and reliability is a key output that distributors deliver to customers.

To measure the aggregate impact of changing demands on the networks, we look at four measures:

- Customer numbers – the number of customers to which distributors supply electricity.
- Circuit length – the distances over which distributors deliver electricity to their customers.
- Energy throughput – the total amount of electricity that distributors deliver to their customers annually.
- Ratcheted maximum demand – the overall peak in energy throughput that distributors have to meet and manage. We use 'ratcheted' maximum demand (the highest maximum demand observed in the sample period up to that point for each distributor) to reflect the increases in demand that distributors have not already invested to meet in the past.

Figure 5 presents the forecast growth in each of these outputs for each of the distributors between the start and the end of the 2021–26 period.[22] These are the forecasts that the distributors submitted to us with their regulatory proposals. These forecasts may need to be revisited in light of the impacts of COVID-19 on the economy.

Figure 5 Output growth from July 2021 to July 2026



Source: AER analysis using regulatory proposal RIN data.

Figure 5 shows that all Victorian distributors are forecasting growth in customer numbers, the circuit length of their networks and in maximum demand in 2021–26. Comparatively distributors are forecasting lower growth in energy throughput, with AusNet Services forecasting a decline in energy throughput over the forthcoming regulatory period.

2.4 Maintaining reliability

Reliability is an important element of the service that distributors deliver to their customers. Our incentive based regulatory framework provides incentives for distributors to maintain and improve reliability. Our Service Target Performance Incentive Scheme (STPIS) provides this incentive.

Table 3 sets out the proposed reliability targets of each distributor under the STPIS. These target levels of the number and duration of interruptions per customer vary according to the locations of the distribution feeder in each distributor's network.

22 These are the outputs that we use in our whole of business benchmarking Multilateral Total Factor Productivity index. For more information see: AER, Annual Benchmarking Report Electricity distribution network service providers, November 2019, p. 2. The rational for the selection of these outputs is set out in: Economic Insights, Economic benchmarking assessment of operating expenditure for NSW and ACT electricity distributors, November 2014, pp. 46–47.

Table 3 Proposed number and duration of interruptions per customer

	AusNet Services	CitiPower	Jemena	Powercor	United Energy
Average number of interruptions per annum (#/customer)					
CBD		0.16			
Urban	0.83	0.41	0.69	0.8	0.66
Short rural	1.98		0.76	1.1	1.61
Long rural	2.58			2.1	
Average duration of interruptions per annum (minutes/customer)					
CBD		10.7			
Urban	76.75	27.6	41.36	67.2	51.5
Short rural	188.10		47.41	99.6	121.5
Long rural	270.87			244.7	

Sources: AusNet Services, STPIS – Target Calculation (Full Year), STPIS targets worksheet. CitiPower, Regulatory proposal 2021-26, January 2020, p. 131. Jemena, Jemena Electricity Networks (Vic) Ltd 2021-26 Electricity Distribution Price Review Regulatory Proposal Attachment 07-05 Incentive mechanisms, p. 11. Powercor, Regulatory proposal 2021-26, January 2020, p. 150. United Energy, Regulatory proposal 2021-26, January 2020, p. 177.

2.5 Facilitating the transition of the energy system

In August 2018, the Victorian government announced the Solar Homes program, which provides support for customers who install solar photovoltaic (PV), solar hot water systems and solar storage batteries.[23] The program is expected to increase the pace of the energy transition in Victoria as more customers invest in DER.

2.5.1 Expenditure to accommodate increased solar exports

The Victorian distributors are predicting a substantial increase in residential solar penetration over the forthcoming regulatory control period, driven by the Solar Homes program. Customers are generally in favour of allowing all households the opportunity to connect to solar, and to export electricity where it is economic to do so.

The Victorian distributors are proposing expenditure to facilitate greater levels of solar export, with some proposals focusing on augmenting networks to allow greater export, and other proposals focusing on managing existing capacity for export within their networks.

23 Solar Victoria, Notice to Market Solar Homes Program, 18 June 2019, p. 4.

CitiPower ($31.5 million), Powercor ($60.7 million) and United Energy ($42.4 million) are proposing a solar enablement program (combined $134.6 million).[24] The majority of the proposed capex is to increase network capacity (i.e. augmentation). This is in addition to expenditures focusing on managing the existing capacity of their networks, similar to businesses in other states. For example, SA Power Networks, which has far higher solar PV penetration rates than the Victorian distributors, has proposed $34 million for its Distributed System Operator transition project.[25] CitiPower, Powercor and United Energy also seek to manage voltages through a Dynamic Voltage Management System (DVMS) and by transformer tapping (an additional $8.5 million).[26] They will use data from the DVMS and advanced metering infrastructure (AMI) to remove constraints to solar exports through network augmentation where it is efficient to do so.[27]

Jemena is proposing information and communications technology (ICT) ($12.7 million) and augmentation capex ($11.4 million) as part of its Future Grid program aimed at enabling DER.[28] Its ICT projects include developing a low voltage (LV) network model, improving data capture processes and implementing new DER assessment functionalities. It also proposes a project to enable dynamic DER export to allow for the control and management of DER. Its augex proposal is aimed at increasing the network's DER hosting capacity by upgrading distribution substations and LV circuits, and installing voltage regulation devices.

AusNet Services is proposing augmentation through its Voltage Compliance and Hosting Capacity for DER programs ($41.5 million augex, $11.4 million IT).[29] These programs are aimed at addressing areas that are currently non-compliant with the Victorian Electricity Distribution Code and those areas forecast to be constrained. It also proposes a DER enablement ICT project to better understand where DER is constrained through improved modelling capability and improved visibility of the LV network. It would also introduce systems to provide customers better price signals that reflect the cost of connecting and managing DER.

2.5.2 The role of tariff reform in supporting the transition

Tariff reform can support the energy system transition such as by enabling more solar PV to be exported in the grid and can facilitate the uptake of electric vehicles while minimising the overall network cost impact on consumers.

In relation to solar PV, the increasing amount of solar generation being exported onto the grid in the middle of the day can lead to voltage rises and consequently some of that solar generation being "curtailed" (i.e. wasted) without network upgrades to manage the voltage problems. Tariff reform can, for example, encourage users to install home batteries to store some of their solar generation and offset their own energy consumption needs at times when the sun is not shining. Reducing the amount of solar generation exported during the middle of

24 $2021
25 SA Power Networks referred to this program as the LV Management program.
26 United Energy has already implemented a DVMS.
27 CitiPower, CP BUS 6.02 – Enabling residential rooftop solar, January 2020.
28 $2019
29 $2021

the day reduces the amount of solar generation which is curtailed while reducing the need for network upgrades.

In relation to electric vehicles (EVs), if a significant uptake of EVs were to occur to Victoria this could require expensive network upgrades if everyone charges their EV as soon as they come home from work. This late afternoon to early evening period is already when the most demand is placed on the grid, and electric vehicle charging could add to that demand. However, tariff reform can lead to smart EV charging. Smart EV charging - either during the middle of the day when there is an increasing amount of excess solar generation available from rooftop PV or overnight when demand on the grid is traditionally low – could enable a significant uptake of EVs while minimising the impact on the grid during peak times.

Rather than adding to the evening peak, EVs might even sell electricity back to the grid at those times and reduce the evening peak. Similarly, customers with solar PV and home batteries could also sell some of their solar generation back to the grid during peak times when it is most highly valued.

We plan to consider the Victorian distributors' tariff reform proposals in the context of their proposals on expenditure, connection policies and demand management initiatives. That is, we plan to review whether the overall package of the distributors' proposals provides a sensible and coherent strategy to address the energy system transition.

We will look at the tariff proposals as an overall package and how they respond to the needs of customers and the challenges facing the networks. While most customers will be on the default or standard tariffs, optional tariffs that provide stronger price signals can also play an important role.

The five Victorian distributors have proposed a largely common tariff strategy across their Tariff Structure Statements (TSS). For residential and small business customers, the distributors propose to focus tariff reform on those customers who install DER such as rooftop solar, a home battery or an electric vehicle. In addition, tariff reform is proposed for retailers of customers with new connections and customers who upgrade from single phase to three phase power.

The proposed default tariff structures for DER customers, new connections and customers with three phase connections are:

- A default time-of-use tariff will be charged to retailers for residential customers, with a peak charging window set as 3pm to 9pm and off-peak rates at all other times.[30]
- For small business customers (<40 MWh pa), retailers will face a default daily time-of-use tariff with the peak set at 9am to 9pm workdays and off-peak rates at all other times.[31]

30 Alternatively, retailers will have the option of being charged a demand tariff targeting the peak period of 3pm to 9pm on workdays. Or the retailer can choose to opt-out of tariff reform and face a single rate tariff.

31 There will be the option for the retailer to be charged a demand tariff targeting the peak period of 10am to 6pm on workdays, or the retailer can choose to opt out of tariff reform and face a single rate tariff. This demand tariff will be the default for small business customers over 40 MWh pa.

Tariffs and demand management

We intend to explore whether the peak periods that constrain each network are sufficiently aligned to the common residential and business customer charging windows proposed by the distributors. For example, it may not be desirable to encourage residential consumers in an urban area with a high concentration of business consumers, and where the network may peak earlier, to shift more consumption from the evening to during the day as this could potentially increase constraints.

On the other hand, we will also consider whether there is merit in exploring a solar sponge charging window for areas with a high concentration of residential consumers to address the falling minimum demand associated with increased penetration of solar (similar to those proposed by South Australian and Queensland distributors).

Alternatively, we recognise that there may be merit in setting a common structure between distributors for simplicity to progress network tariff reform while introducing targeted complementary measures to address location specific issues.[32]

As noted above, we plan to review how the distributors' tariff reform, demand management and other elements of their proposals work together as a package.

Role of retailers in tariff reform

We consider the target audience for cost reflective network tariffs is primarily retailers, not end use customers. This is because retailers are the ones who face network tariffs. Network tariff reform is intended to lead to retailers reforming their retail offers. We consider these new retail offers could fall into three broad categories. End use customers should have a choice between these categories for a retail offer that best suits their needs and preferences. In broad terms, these categories could be described as:

- "Insurance style" — the retailer faces cost reflective network price signals but shields the end customer from this price volatility, for example, by offering the end customer a retail offer with a fixed daily charge and flat kWh energy charge.
- "Pass through" — the network tariff structure is reflected in the retail tariff structure. For example, time-of-use retail rates.
- "Prices for devices" —the retailer manages an end use customer's smart devices to respond to cost reflective network price signals in the background, while keeping simple the retail tariff structure the end use customer actually "sees".[33]

The Victorian distributors' proposed tariff assignment policies are to charge retailers a cost reflective network tariff by default for customers who install DER, are a new connection or upgrade to three phase power. The distributors have proposed alternative cost reflective tariffs

32 This could be done through the sub-threshold clause in the Rules to trial alternative tariffs structures. But it could also be achieved through initiatives such as the procurement of demand response through opex, incentive schemes like the demand management incentive scheme and demand management incentive allowance mechanism (DMIS/DMIAM), or even funding from alternative sources like the Australian Renewable Energy Agency (ARENA). The use of these complementary measures will inform our evaluation of the charging windows for each network.

33 For example, the end use customer might pay a fixed daily charge and a flat kWh retail energy charge, and the retailer manages the charging and discharging of the customer's rooftop solar and home battery or electric vehicle.

that a retailer can choose between - focusing on time-of-use and peak demand tariffs - for residential and small business customers. Apart from AusNet Services, the distributors have proposed that retailers can opt-out of tariff reform and avoid facing a cost reflective network tariff. AusNet Services has proposed that for solar PV customers, the retailer can choose between a time-of-use or demand tariff, but cannot opt-out of tariff reform.

Tariff assignment policy will be a focus of our review. We plan to review whether the proposals provide a sufficient financial incentive for retailers to innovate and reform their offers to meet the needs and preferences of a diverse set of customers and to meet the challenges of the energy system transition at lowest cost to customers overall.

In advance of lodging their regulatory proposals, the Victorian distributors hosted a series of customer forums on tariff reform. This included commissioning and consulting on a report from the Brattle Group.[34] Table 4 sets out the options developed by the Brattle Group. It includes options where the design of the network tariff is targeted towards retailers as the target audience for cost reflective network tariffs, and options where the design is targeted towards end users. As outlined by the Brattle Group:

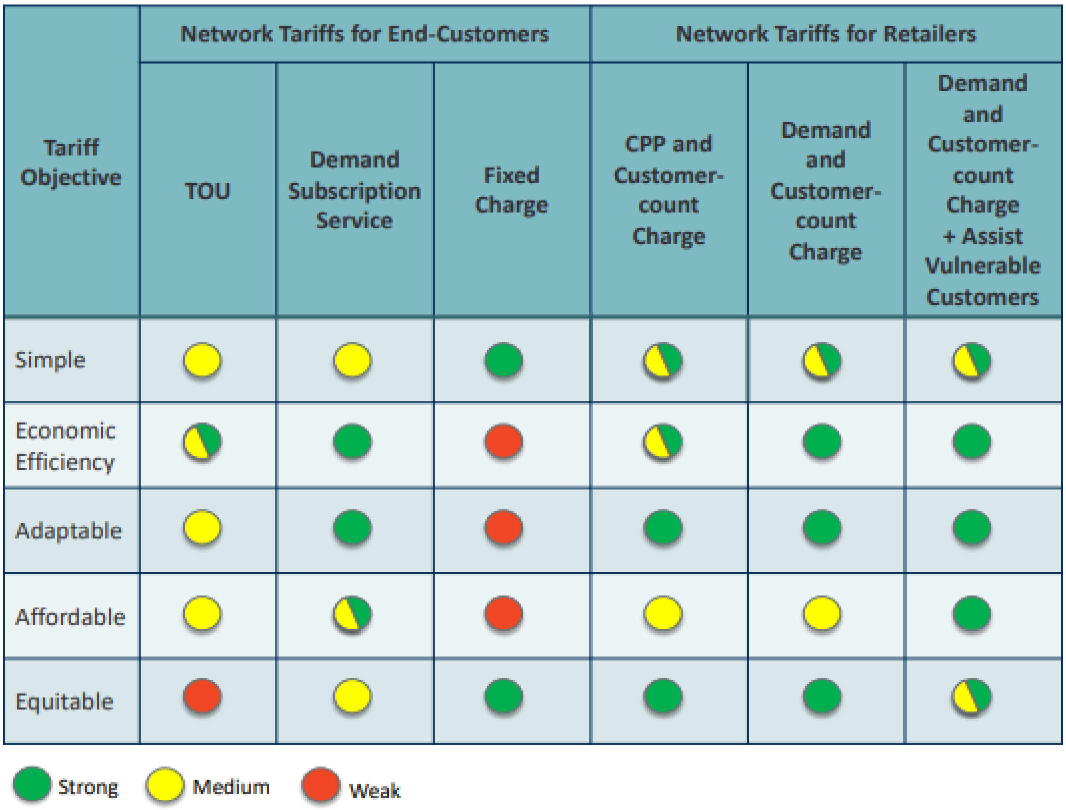
> *If network tariffs are addressed directly to end customers, then retailers are competing with one another over how cheaply they can procure wholesale electricity, but are not competing over the costs of using the network to deliver electricity to customers (since this cost would be transparent to customers).*
>
> *If network tariffs are addressed to retailers, then the retailers can compete over a larger "value stack" which also includes the cost of using the distribution network (which the customer would not see, as is the current case). Retailers could, for example, compete by identifying and targeting customers with consumption patterns that give rise to reduced network charges, or by providing a reward to their customers for adopting such consumption behaviour. In the future retailers, or a third party, could use technologies such as embedded generation and batteries to manage the customers' use of the network in a way that reduces the cost of using the network to deliver electricity to the customer.*[35]

The distributors choose to propose network tariff structures which are simpler and more in line with those targeted towards end customers - in particular, by proposing time-of-use tariffs as the default tariff for residential and small business customers who meet the criteria outlined above. Though for larger users, AusNet Services has proposed to maintain a critical peak price tariff. We seek stakeholder feedback on whether any of these alternative tariff structure options targeted towards retailers should be adopted by the Victorian distributors.

34 Brattle Group, Electricity distribution network tariffs - Principles and analysis of options, April 2018. Available here: https://brattlefiles.blob.core.windows.net/files/14255_electricity_distribution_network_tariffs_-_the_brattle_group.pdf

35 Brattle Group, Electricity distribution network tariffs - Principles and analysis of options, April 2018, p.16.

Table 4 Brattle Group options and assessment - Cost reflective network tariffs



Source: Brattle Group[36]

2.6 Addressing the risk and impact of bushfires

Victoria experienced bushfires in late 2019 and early 2020, which led to the Premier declaring a state of emergency in early January.[37] The bushfires have impacted the electricity distributors that have networks in bushfire-affected areas, particularly that of AusNet Services.[38]

As this event occurred during the current regulatory period, the AER will account for the impact of this current event through the natural disaster pass-through included in the 2016-20 determination.

Within the incentive regulatory framework set out under Chapter 6 of the NER, the regulatory proposals for the 2021-26 period seek funding to address bushfire risk. Additionally, the distributors have proposed natural disaster and insurance cap pass-throughs to accommodate

36 Brattle Group, Electricity distribution network tariffs - Principles and analysis of options, April 2018. Available here: https://brattlefiles.blob.core.windows.net/files/14255_electricity_distribution_network_tariffs_-_the_brattle_group.pdf

37 VIC Emergency, State of disaster - local government areas, News Release, 3 January, http://www.emergency.vic.gov.au/news-and-media/state-of-disaster-local-government-areas

38 AusNet Services, AusNet Services update on the impact of the Victorian Bushfires on Electricity Supply, News Release, 14 January 2020, https://www.ausnetservices.com.au/-/media/Files/AusNet/Media-Releases/Final-2019/Vic-bushfires---media-statement-140120.ashx

the impact of bushfires. Furthermore, the Victorian government has implemented an incentive scheme to reduce fire starts. Some of these measures are set out below:

Rapid Earth Fault Current Limiters (REFCLs)

The Victorian Government's Powerline Bushfire Safety Program has introduced a number of regulatory obligations to prevent or mitigate fire-starts caused by the electricity network.[39] The most significant cost to network businesses and consumers is the installation of REFCLs and related infrastructure. AusNet and Powercor are required to achieve certain technical requirements (referred to as required capacity) at 22 zone substations each and Jemena at one zone substation.

Further to the initial investment, the REFCL program requires ongoing compliance costs. Installation of new high voltage (HV) cables increases network capacitance. When this capacitance exceeds the limits of the existing REFCLs, further expenditure is required to resolve the issue.

Further detail on expenditure proposed by AusNet Services and Powercor to implement the REFCL program is in section 4.8.1 below.

F-factor scheme

The F-factor scheme is a Victorian Government initiative that provides financial incentives to Victorian electricity distributors to reduce the number of fire starts on their networks. Under the scheme, distributors that reduce the number of fire starts relative to annual targets receive an incentive payment (reward). Conversely, if a network business reports a higher number of fire starts relative to its targets, it will face penalties or reduced revenues which are returned to customers. There is no cap on the penalties that can be imposed on a distributor under the scheme.

The Victorian Government is currently reviewing the performance targets for the forthcoming period. Following the review, the Victorian Government is expected to publish a new Order in Council to implement the new performance targets.

The Victorian distributors will be required to continue applying the F-factor scheme during the 2021–26 regulatory period, subject to any new performance targets that may be published by the Victorian Government.

Pass-throughs

During the regulatory control period, a service provider can apply to the AER to pass material changes in its costs arising from pre-defined exogenous events through to customers, in the form of higher or lower network charges. In addition to the prescribed events specified in the NER, other pass through events may be specified (as set out in 6.6.1 of the NER).

The AER included natural disaster and insurance cap pass throughs in the determination for the 2016-20 regulatory period. All of the Victorian distributors have proposed amendments to

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[39] See https://www.energy.vic.gov.au/safety-and-emergencies/powerline-bushfire-safety-program.

the definition of the insurance cap pass through event and the majority of Victorian distributors have proposed amendments to the natural disaster pass through event.

The key concern these amendments are trying to address is potential gaps in the distributors' liability insurance cover due to insurers choosing to reduce their total exposure in the global liability insurance market and withdrawing capacity.

This reduction in liability insurance capacity is reported to be driven from a number of factors including:

- increased wildfire/bushfire activity globally
- other local and global casualty non-fire related losses
- continued consolidation of insurers through merger and acquisition activity
- increased focus by insurers on capital deployment
- changes in insurer risk appetite.

3 Comparative analysis of the proposals

In this section of the issues paper we compare each Victorian distributor's proposals to:

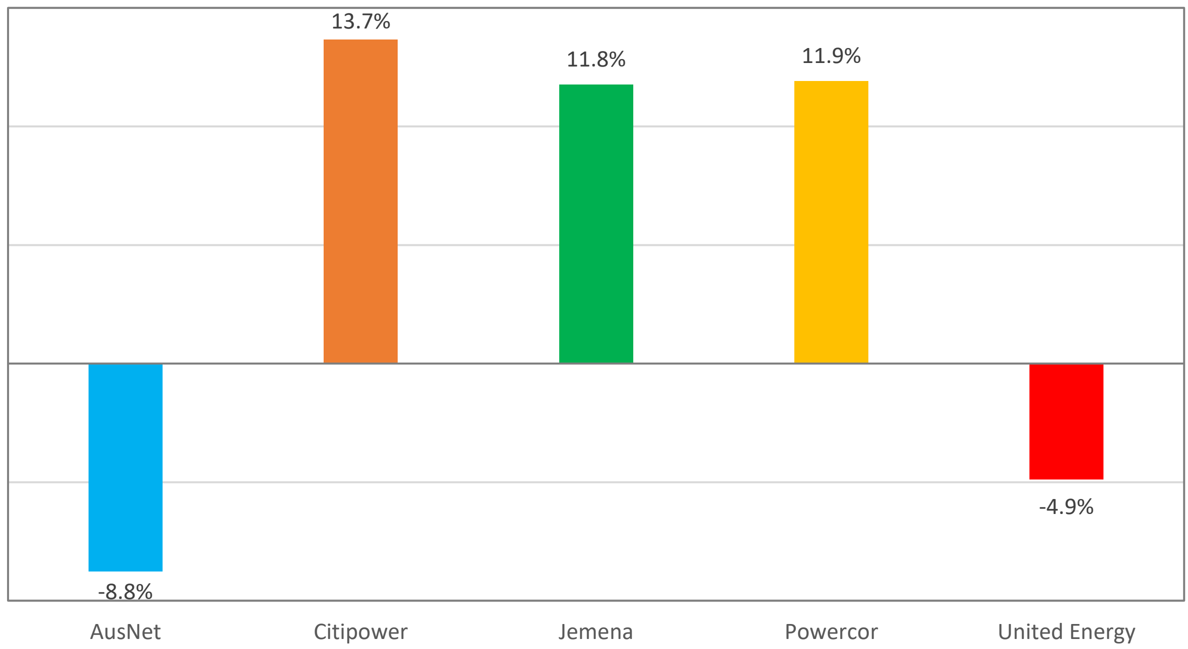
- the proposals of the other Victorian distributors
- the allowances provided in our 2016-20 determinations, and
- the Victorian distributors' actual expenditure.

Our focus in this section is on the proposed opex, capex and depreciation for standard control network services and metering services of each of the distributors as these elements have the largest impact on current and future customers. The rate of return and incentive payments are not a focus as these are have been decided in separate AER processes.[40]

3.1 Operating expenditure

Figure 6 shows the proposed changes in opex from our opex allowances for the 2016–20 period. CitiPower, Powercor and Jemena are proposing increases in opex in excess of 10 per cent.

Figure 6 Change in total opex from 2016–20 determination allowance



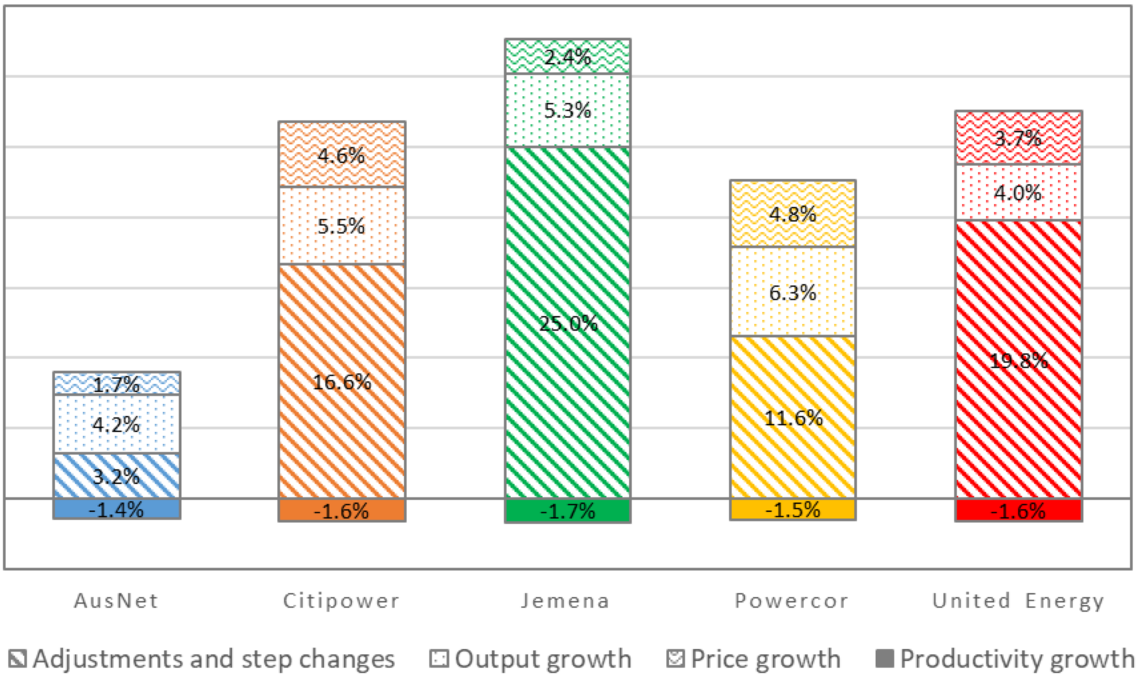
Notes: Total opex includes opex for standard control services and metering services. Changes are determined in real terms – that is, excluding the effects of inflation.

Source: AER analysis using Post tax revenue models (PTRMs) for 2016-20 regulatory period, and regulatory proposal PTRMs for the 2021-26 regulatory period.

40 The rate of return has been largely determined through the 2018 rate of return instrument, while the decision to apply incentive schemes for the current regulatory period was made in the 2016-2020 determination.

Each distributor has proposed to apply our ‘revealed cost’ forecasting approach for opex for standard control services. Under this approach, a recent actual year of opex, a ‘base year’, is used as the basis for forecast revenues. Forecast cost increases (or decreases) are added to the base year to reflect changes in output, price and productivity growth as well as any step changes that are generally related to new obligations or capex/opex trade-offs.

Figure 7 Opex cost changes from the base year



Note: Changes are determined in real terms – that is, excluding the effects of inflation. Step changes only for standard control services.

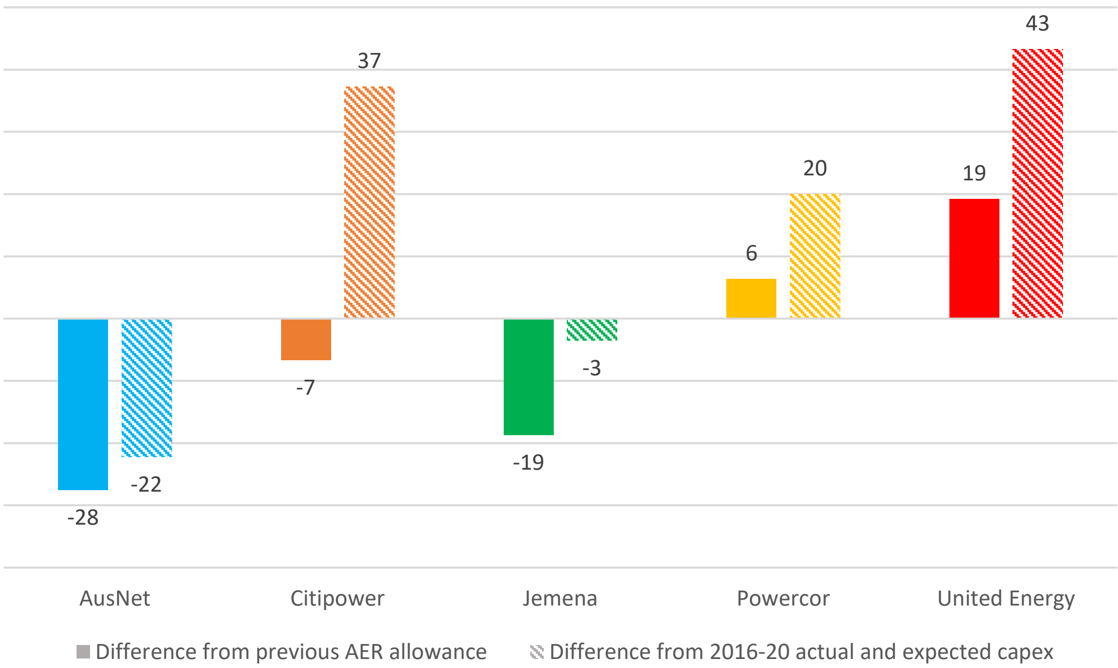
Source: Operating expenditure models for each distributor.

We consider the opex proposals of each of the distributors in greater detail in section 4.7 below.

3.2 Capex

Another significant aspect of each of the proposals is capital expenditure (capex). The costs of capital expenditure are not recovered in the year that they are incurred. Capex is added the regulated asset base (RAB) for each distributor and then the costs are recovered over the expected life of the assets.

Figure 8 Change in capex determination allowance and actual and estimated capex for 2016–20



Source: AER analysis using Post tax revenue models (PTRMs) for 2016-20 regulatory period, and regulatory proposal RINs and PTRMs for the 2021-26 regulatory period.

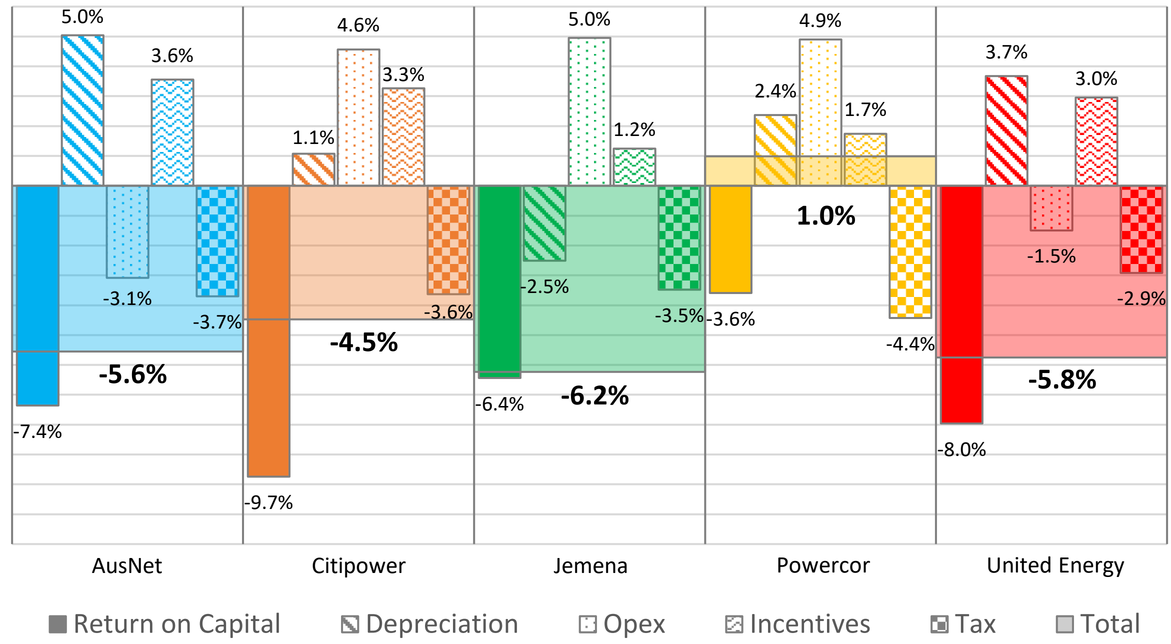
Figure 8 shows the change in proposed capital expenditure from our capex determination and also from each distributor's actual and expected capex for 2016–20.

Figure 8 shows that AusNet Services and Jemena have forecast reductions in capex from both our previous allowance and their actual and estimated expenditure for 2016–20. Powercor and United Energy have proposed increases from both our previous allowance and their actual and estimated expenditure for 2016–20. Citipower is proposing 7 per cent less capex than our previous allowance, but 35 per cent more than actual and expected capex for 2016-20. We outline the different components of the distributors' capex forecasts in section 4.8 below.

3.3 Overall comparison

Figure 9 sets out the change in each distributor's forecast revenue from our previous determination for 2016–20 and the contribution that each forecast 'building block' to the overall change. This figure focuses on what is driving each of the distributor's proposed changes in revenues. In order to measure this we are comparing their proposals against our previous determinations for the 2016–20 period.[41]

Figure 9 Drivers of revenue change (SCS and metering services)



Note: Changes are determined in real terms – that is, excluding the effects of inflation.

Source: AER analysis using Post tax revenue models (PTRMs) for 2016-20 regulatory period, and PTRMs for the 2021-26 regulatory period.

Figure 9 also shows that the return on capital building blocks and tax building blocks are decreasing for each of the networks. This is a result of our binding determinations on the rate of return and tax and current financial market conditions.[42] This figure also shows that each distributor has an increase in incentive payments, reflecting rewards under our Efficiency Benefits Sharing Scheme (EBSS) and Capital Expenditure Sharing Scheme (CESS) for the distributors underspending against our expenditure allowances for the current period.

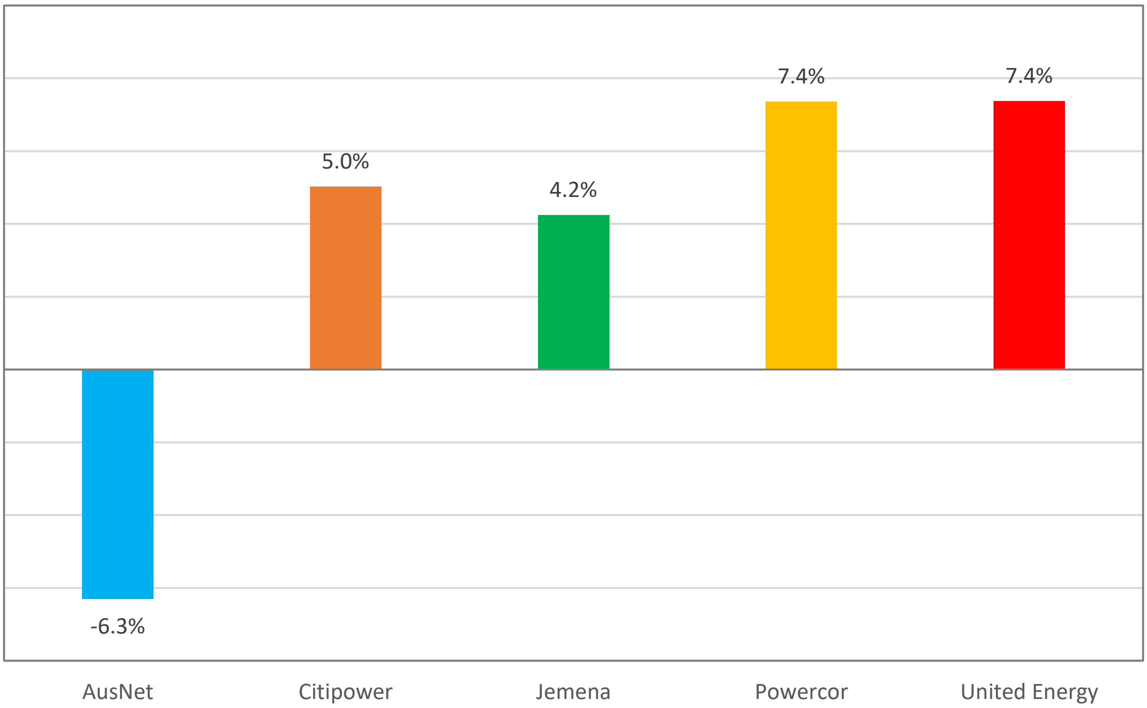
AusNet Services is unusual in that it has the greatest decrease in capex, but the highest increase in depreciation. As set out in section 4.2 below, this is primarily because AusNet Services proposed to depreciate 'protection relays' and 'remote terminal units' over a shorter period, from the current 45 and 50 years respectively down to 10 years.

41 We compare the standard distribution and metering services that account for more than 95% of the revenues earned by the distributors for regulated distribution services.

42 AER, Rate of return instrument, December 2018. AER, Final report Review of regulatory tax approach, December 2018.

Figure 10 shows the proposed change in the each networks RAB per customer over the regulatory period. AusNet Services is the only network to have a declining RAB per customer which will, all else equal, reduce revenues per customer beyond July 2026.

Figure 10 Difference between proposed opening and closing RAB per customer – 1 July 2021 to 30 June 2026 ($real June 2021)



Note: Changes are determined in real terms – that is, excluding the effects of inflation.

Source: AER analysis using PTRMs for the 2021-26 regulatory period.

Table 5 compares the distributors' proposals at an overall level. While CitiPower, Powercor and United Energy and Jemena have improved their customer engagement processes, we consider that their proposals warrant more detailed review given their significant proposed increases in expenditure.

AusNet Service's proposal stands out for the following reasons:

- AusNet Services is the only network to propose decreases in opex, capex and revenues.
- AusNet Services' proposal appears to deliver on the preferences of its customers based on its Customer Forum's Customer Engagement Report
- As set out in section 2.2.1 above, AusNet Services has identified substantial improvements to customer experience with its Customer Forum which it has already started implementing largely within existing budgets.[43]

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43 Aside from those aimed at improving communications with customers which require investment in new information systems.

Table 5 Comparison of the regulatory proposals (in real terms)

	Customer service	Revenue	Opex	Capex	RAB per customer
AusNet	↑ Substantial improvement	↓ 5.6%	↓ 8.8%	↓ 27.5%	↓ 6.3%
CitiPower	↑ Some improvement	↓ 4.5%	↑ 13.7%	↓ 6.7%	↑ 5.0%
Jemena	↑ Some improvement	↓ 6.2%	↑ 11.8%	↓ 18.7%	↑ 4.2%
Powercor	↑ Some improvement	↑ 1.0%	↑ 11.9%	↑ 6.4%	↑ 7.4%
United Energy	↑ Some improvement	↓ 5.8%	↓ 4.9%	↑ 19.2%	↑ 7.4%

Note: Revenue, capex and opex comparisons are relative to our previous determination. Change in RAB per customer reflects the difference between the opening (1 July 2021) and closing (30 June 2026) RABs. Detailed change in customer service is set out in section 2.2.

3.3.1 Implications for AER review of proposals

We have undertaken a comparative analysis of each of the distributor's proposals in order to set out the relative merits of each. We have compared the proposals of against each other, our previous determinations and their previous actual expenditure in this high level assessment.

Our analysis indicates that AusNet Services' proposal opex and capex compares well to their peers, historical allowances and historical expenditure levels. The Consumer Forum and AusNet Services have reached agreed positions on some aspects of the proposal, including on some aspects of capex and opex. In addition, we have developed an understanding of AusNet Services' regulatory proposal by proving input during the trial of the New Reg model through releasing guidance notes for the matters within the scope of the Customer Forum's negotiation as well as making submissions on matters outside the Customer Forum's negotiating scope.

This comparison, and the agreed positions between AusNet Services' and the Consumer Forum, combined with our existing understanding of AusNet Services' proposal gained through the New Reg trial will inform the level of detail needed for our assessment of components of that proposal. In particular, our preliminary view is that compared to other Victorian DNSPs' proposals, we may focus our assessment on total opex and capex, and conduct less extensive assessment of components of capex and opex forecasts in AusNet Services' proposal, compared to other Victorian DNSPs' proposals. That said, AusNet Services is proposing a significant increase in depreciation which warrants further analysis.

4 What is driving the change in proposed revenue?

In this section we set out the key drivers of changes in the building blocks (presented in Figure 9) and proposed revenues over the 2021–26 regulatory period.

4.1 Return on capital

The return (the 'return on capital') each business is to receive on its RAB continues to be a key driver of proposed revenues. We calculate the regulated return on capital by applying a rate of return to the value of the RAB. The allowed rate of return is a forecast of the cost of funds a network business requires to attract investment in the network.

We estimate the rate of return by combining the returns of the two sources of funds for investment: equity and debt. The return on equity is the return shareholders of the business will require for them to continue to invest. The return on debt is the interest rate the network business pays when it borrows money to invest.

We will apply the 2018 rate of return instrument (the instrument) published by us and the values therein to calculate the rate of return for the Victorian distributors.[44]

Table 6 Key rate of return values

	AusNet Services	CitiPower	Jemena	Powercor	United Energy	2018 Instrument
Return on equity	4.92%	4.98%	4.70%	4.98%	4.98%	Risk free rate + 3.66%
Risk free rate	1.26%	1.32%	1.04%	1.32%	1.32%	Based on criteria in the instrument
Market risk premium	All proposed 6.1%			6.1%		
Equity beta	All proposed 0.6			0.6		
Equity risk premium (equity beta*market risk premium)	All proposed 6.1%*0.6=3.66%			6.1*0.6%=3.66%		
Return on debt (nominal pre-tax)	4.79%	4.65%	4.87%	4.65%	4.71%	Based on criteria in the instrument

44 AER, Rate of return instrument, 17 December 2018; AER, Rate of return instrument explanatory statement, December 2018. Available at: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-modelsreviews/rate-of-return-guideline-2018/final-decision.

Gearing	All proposed 60%	60%
Gamma (value of imputation credits)	All proposed 0.585	0.585

Source: AER analysis; AusNet Services Electricity Distribution Price Review 2022-26 Part III, 31 January 2020; CitiPower, Regulatory proposal 2021-2026, January 2020; Jemena, 2021-26 Electricity Distribution Price Review Regulatory Proposal Attachment 07-02 Rate of Return, 31 January 2020; Powercor, Regulatory proposal 2021-2026, January 2020; United Energy, Regulatory proposal 2021-2026, January 2020

The instrument also sets out the process by which we will annually update the return on debt (and therefore the overall rate of return) during the regulatory control period.

In terms of debt raising costs, most distributors have proposed a placeholder rate (around 8 basis points per annum), but noted that there is ongoing work on the AER's benchmark approach to estimating debt raising costs. We obtained actual debt raising cost information from all regulated networks in late 2019, and most businesses noted that they will respond to our considerations in their revised proposal.

There is an additional category of debt raising costs potentially arising as a result of the move to a financial regulatory year, which we label hedging costs. Jemena has proposed transitional return on debt alignment costs of around $1 million.[45] CitiPower, Powercor and United Energy have noted that there may be additional debt raising costs of this type and may include them in the revised proposals if required.[46]

For estimates of expected inflation, all five businesses have proposed our current approach as a placeholder. CitiPower, Powercor and United Energy have noted that their position may change in the revised proposal.[47] Jemena would like us to cross-check our RBA approach and consider alternatives.[48] AusNet Services requested that the AER undertake an inflation review as soon as practical.[49]

4.2 Depreciation

Regulatory depreciation is the allowance provided so capital investors can recover their investment over the economic life of the asset (return of capital). Figure 11 sets out each of the distributors proposed depreciation relative to the total regulatory asset base for the 2021–26 period.

AusNet Services, CitiPower, Powercor and United Energy all included some form of accelerated depreciation in their proposals – whereas Jemena did not.

45 Jemena, 2021-26 Electricity Distribution Price Review Regulatory Proposal Attachment 06-05 Operating expenditure step changes, 31 January 2020, p. 16-18

46 CitiPower, Regulatory proposal 2021-2026, January 2020, p. 126; Powercor, Regulatory proposal 2021-2026, January 2020, p. 145; United Energy, Regulatory proposal 2021-2026, January 2020, p. 173.

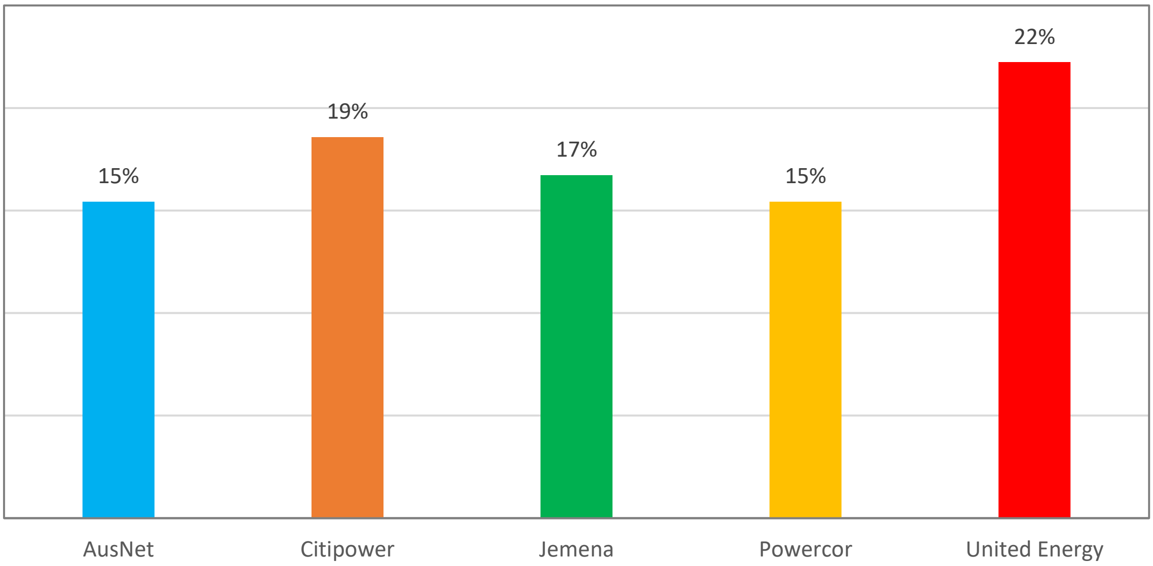
47 CitiPower, Regulatory proposal 2021-2026, January 2020, p. 126; Powercor, Regulatory proposal 2021-2026, January 2020, p. 144-145; United Energy, Regulatory proposal 2021-2026, January 2020, p. 172-173.

48 Jemena, 2021-26 Electricity Distribution Price Review Regulatory Proposal Attachment 07-02 Rate of Return, 31 January 2020, p. 11-13.

49 Ausnet, Electricity Distribution Price Review 2022-26 Part III, 31 January 2020, p. 215-217.

Previously, we have approved accelerated depreciation where assets (with residual values) are replaced and we consider it is no longer economically efficient to use the replaced assets to provide standard control services. In such cases, the depreciation schedules associated with the residual values of the replaced assets are accelerated to reflect their reduced remaining economic life.

Figure 11 Depreciation allowance as a proportion of opening RAB



Note: Changes are determined in real terms – that is, excluding the effects of inflation.

Source: AER analysis using PTRMs for the 2021-26 regulatory period.

AusNet Services

AusNet Services proposed accelerated depreciation of approximately $200 million of existing SCADA/Network control assets (such as protection relays and remote terminal units) over the 2022–26 regulatory control period. These assets have previously been allocated to the 'Sub-transmission' and 'Distribution system' asset classes and depreciated with standard asset lives of 45 and 50 years respectively over the past regulatory control periods. It submitted that these assets have been installed in the network starting from 1997 to replace older assets which have a much longer standard life. AusNet Services stated that these assets typically have a standard life of 10 years similar to the 'SCADA/Network control' asset class which was introduced in the 2011–15 regulatory control period. AusNet Services proposed to transfer the assets into a new asset class, 'Secondary systems – pre 2016', from July 2021 and depreciate them over a calculated weighted average remaining life of 5.3 years. The revenue impact of this change over the 2021–26 regulatory control period is approximately $160 million.[50]

AusNet Services also proposed accelerated depreciation of approximately $4 million of high bushfire risk assets which have been, or are forecast to be, replaced as part of the safety programs approved in the REFCL contingent project applications. These replacement

[50] Calculated based on net change in straight-line depreciation between the proposal and the base-line case where there is no accelerated depreciation.

programs follow from the recommendations of the 2009 Victorian Bushfires Royal Commission. We have approved similar types of accelerated depreciation for such programs in our previous decision for the 2016–20 regulatory control period. As such, we will consider whether this proposed treatment is consistent with our assessment for that period.

Other than the accelerated asset depreciation, AusNet Services also proposed to treat all existing and forecast property and motor vehicle leasing arrangements as capital expenditure from 1 April 2019. It submitted that these lease expenses have been previously treated as opex, but with the change in Australian Accounting Standard AASB 16, leases beginning on 1 January 2019 should be capitalised up-front and amortised over its lease term. It stated that due to this change, it proposed to introduce a new 'Non- Network Leasehold Land & Buildings - 1 Jun 2021' asset class to the roll forward models (RFM) to record the historical expenditure associated with the leasing arrangements for 2019, 2020 and 2021, and to the post tax revenue models (PTRM) for future leasing arrangements. The proposed RFM does not apply any depreciation to this expenditure in rolling forward the opening asset value for this asset class as at 1 July 2021.

Similarly it has proposed to add a new 'Non-network - Metering related IT' asset class for recording existing and forecast metering related IT expenditure starting from 2019. The proposed RFM does not apply any depreciation to this expenditure in rolling forward the opening asset value for this asset class as at 1 July 2021.

CitiPower

CitiPower has proposed $8 million of accelerated depreciation over the 2021–26 regulatory control period. CitiPower's proposal stated that of this, $7 million is for the replacement of older distribution transformers for those with solar enablement and $1 million is for replacement of PVC service cables to address safety concerns.

Jemena

Jemena did not propose any accelerated depreciation but did propose to reduce the standard life for the existing 'Non-network – other' asset class to five years from 24.2 years for the 2021–26 regulatory control period. Jemena submitted that this is because the building related assets which have a longer standard life of 40 years will be re-allocated from the 'Non-network – other' asset class to a new 'Buildings' asset class for the 2021–26 regulatory control period. As a result, the forecast assets in the 'Non-network – other' asset class going forward will be consisting of shorter life assets such as office furniture and vehicles. On balance, the revenue impact of this change over the 2021–26 regulatory control period is approximately $8 million, largely driven by higher regulatory depreciation. [51] Jemena also proposed to reduce the standard life for the existing 'Non-network – IT' asset class to five years from 5.2 years for the 2021–26 regulatory control period.

51 Under the proposed approach, Jemena will recover less forecast depreciation from the buildings related capex over the 2022–26 regulatory period because these assets will now be depreciated over 40 years compared to 24.2 years. This will offset some of the increase to forecast depreciation from reducing the standard life for remaining assets in the 'Non-network – other' asset class to 5 years from 24.2 years.

Powercor

Powercor has proposed $74 million of accelerated depreciation. Of this $39 million relates to the replacement of assets through its REFCL program. While another $35 million relates to replacement of distribution transformers for solar enablement, PVC service cables it has assessed as unsafe, HV aerial bundled cable in bushfire areas, and upgrades to control boxes for 5G network.

United Energy

United Energy proposed $2 million of accelerated depreciation for the replacement of older distribution transformers for those with solar enablement.

4.3 Corporate income tax

The building block approach to calculating the annual revenue requirement includes an allowance for the estimated cost of corporate income tax payable by the business. We calculate the expected allowance consistent with the requirements of the NER.[52]

In December 2018, we completed a review of our regulatory tax approach.[53] The final report presented analysis of the current tax management practices of the regulated networks and identified some required changes to the estimation of the tax expenses. The changes to our regulatory tax approach required amending our models to:

- recognise immediate tax expensing of some capex forecast for a regulatory control period
- adopt the diminishing value (DV) method for tax depreciation to all future capex except for a limited number of assets which must be depreciated using the straight-line (SL) depreciation method under the tax law.[54]

In their proposals, the Victorian distributors have used our latest PTRM template (version 4) which incorporates the immediate expensing and DV changes above. Each distributor's proposal adopted immediate expensing of forecast capex as consistent with its treatment in the current regulatory control period. Additionally each distributor has allocated some capex to be depreciated using the SL method for tax depreciation. We will assess the appropriateness of the proposed amounts of immediate expensing and capex allocated for SL depreciation based on the approach we took in our recent determinations.

Table 7 shows the Victorian distributors' proposed forecast tax allowances. To show the impacts of the changes arising from both the tax review and the change to the value of gamma from the 2018 RoR instrument (section 4.1), the second row of the table contains the calculated tax allowance amounts for each distributor using the proposal inputs entered into our previous PTRM (version 3) template. For this row we used a gamma value of 0.4 which is consistent with that adopted immediately preceding the 2018 RoR instrument.

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52 NER, cl. 6.5.3.

53 AER, Final report: Review of regulatory tax approach, December 2018, p. 76.

54 Capping of gas asset tax lives was also a finding from the final report, but does not require a model change.

Table 7 Forecast tax allowance and impacts of tax review and gamma ($m, nominal)

	AusNet Services	CitiPower	Jemena	Powercor	United Energy
2021–26 proposal	0.0	36.7	30.7	3.3	43.7
2021–26 proposal using PTRM version 3 with 0.4 gamma	139.7	109.8	54.8	169.8	112.9

4.4 Incentive schemes

The AER administers incentive schemes that provide financial rewards for delivering outcomes that are in customers' interests, for example for reducing expenditure and improving reliability. In this section we outline what these schemes are and how they may influence forecast revenues.[55]

4.4.1 Efficiency benefit sharing scheme and capital expenditure sharing scheme

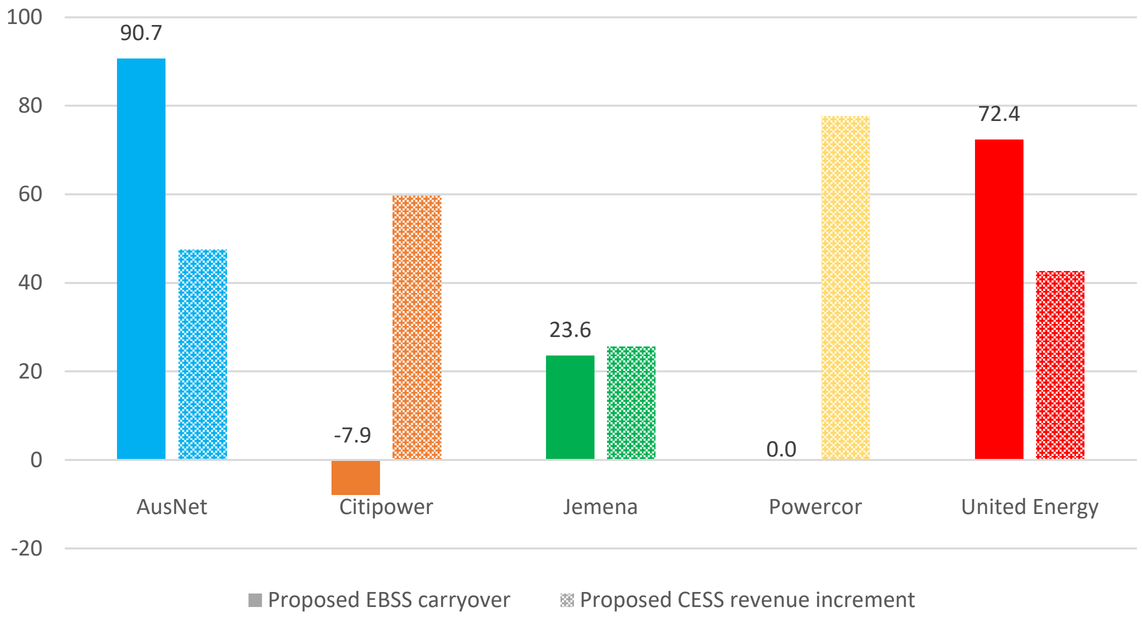
Our efficiency benefit sharing scheme (EBSS) is intended to provide a continuous incentive for distributors to pursue efficiency improvements in opex, and to fairly share these between distributors and consumers. Consumers benefit from improved efficiencies through lower network tariffs in future regulatory control periods.

Our capital expenditure sharing scheme (CESS) aims to incentivise distributors to undertake efficient capex throughout the regulatory control period by rewarding efficiency gains and penalising efficiency losses (each measured by reference to the difference between forecast and actual capex).

Figure 12 summarises the proposed EBSS and CESS revenue increments for each Victorian distributor which reflects the extent to which the Victorian distributors underspent the opex and capex allowances that the AER determined for the 2016–20 regulatory period.

55 This section does not consider the F-Factor scheme as we discuss this in Section 2.6.

Figure 12 Proposed EBSS carryovers and ($million, June 2021) and proposed CESS revenue increment ($ million, June 2021)



Source: Regulatory proposal RINs.

4.4.2 Demand Management Incentive Scheme and Demand management innovation allowance mechanism

The demand management incentive scheme (DMIS) and demand management innovation allowance (DMIAM) encourage businesses to pursue demand side alternatives to opex and capex.

The Victorian distributors' regulatory proposals supported the new DMIS, which operates as an incentive cost uplift of up to 50 percent of the expected cost of each committed demand management project, subject to certain constraints. The total financial incentive that a distributor can obtain across all committed projects in each regulatory year is limited to 1.0 per cent of the annual revenue requirement for that year. The distributors proposed that the new DMIS apply to their individual businesses during the 2021–26 regulatory period, consistent with our proposed approach set out in the final Framework and Approach

The Victorian distributors propose to apply the DMIAM. For each regulatory year, the allowance is calculated as the sum of $200 000 ($2 017) plus 0.075 per cent of the distributor's annual revenue requirement.

4.5 Customer Service Incentive Scheme

In December 2019, we released a draft Customer Service Incentive Scheme (CSIS). This CSIS would allow us to set targets for distributor customer service performance and require distributors to report on performance against those targets. Under the CSIS distributors may be financially penalised or rewarded depending on how they perform against their customer service targets. Submissions on the draft CSIS have been supportive of the development of the scheme. We are currently considering these submissions and intend to publish a final CSIS in May. Penalties and rewards under the CSIS will likely be capped at 0.5 per cent of the annual revenue requirement for that year.

Victorian distributors will be able to apply the CSIS in the 2021–26 regulatory control period. Only Jemena has indicated that it will not seek to apply the CSIS.[56] AusNet Services has submitted an incentive design.[57] CitiPower, Powercor and United Energy have indicated that they intend to continue working with their customers to develop an incentive design to submit with their revised regulatory proposals.[58]

4.6 Service target performance incentive scheme

Our distribution Service target performance incentive scheme (STPIS) provides a financial incentive to distributors to maintain and improve service reliability performance. [59] The scheme aims to ensure that cost efficiencies incentivised under our expenditure schemes do not arise through the deterioration of service quality for customers. [60] Penalties and rewards under the STPIS are calibrated with how willing customers are prepared to pay for improved services. [61] The proposed STPIS targets of each of the distributors is set out in Table 3.

4.7 Operating expenditure

Operating expenditure (opex) refers to the operating, maintenance and other non-capital expenditure incurred in the provision of network services. It includes labour costs and other non-capital costs that a prudent service provider is likely to require during the 2021–26 period for the efficient operation of its network.

4.7.1 Powercor, CitiPower and United Energy

Powercor, CitiPower and United Energy's opex proposals are made up of similar changes and the key drivers are discussed collectively below.

Powercor proposed a total opex allowance of $1524.9 million (real 2021) for the 2021–26 regulatory control period. This is a $242.6 million (18.9 per cent) increase above Powercor's opex allowance and a $332.1 million (27.8 per cent) increase above the estimated opex in the current regulatory period.

56 Jemena, 2021-26 Regulatory Proposal – Overview, January 2020, p. 24.

57 AusNet Services, Electricity Distribution Price Review 2022-26 Part III, January 2020, p 232.

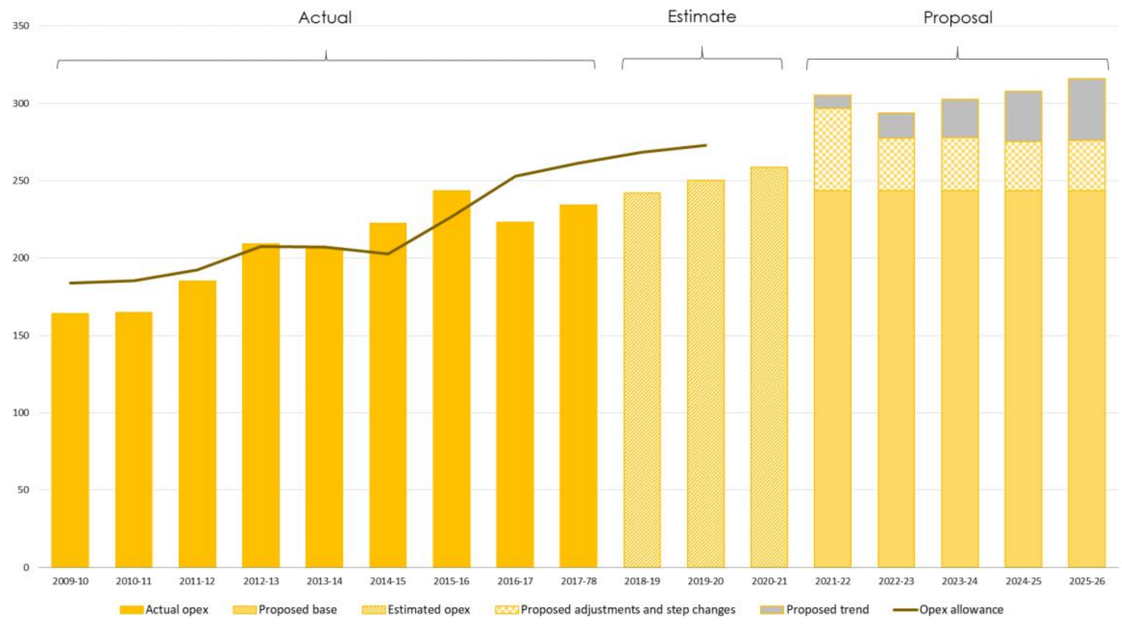
58 CitiPower, Regulatory proposal 2021-2026, January 2020, p. 131. Powercor Australia, Regulatory proposal 2021-2026, January 2020, p. 150. United Energy, Regulatory proposal 2021-2026, January 2020, p. 177.

59 AER, *Electricity distribution network service providers - service target performance incentive scheme V2*, November 2018.

60 Expenditure schemes can include the Efficiency benefits sharing scheme, capital expenditure sharing scheme, Demand management incentive scheme and allowance, Customer service incentive scheme and F-factor scheme.

61 Using the value of customer reliability values.

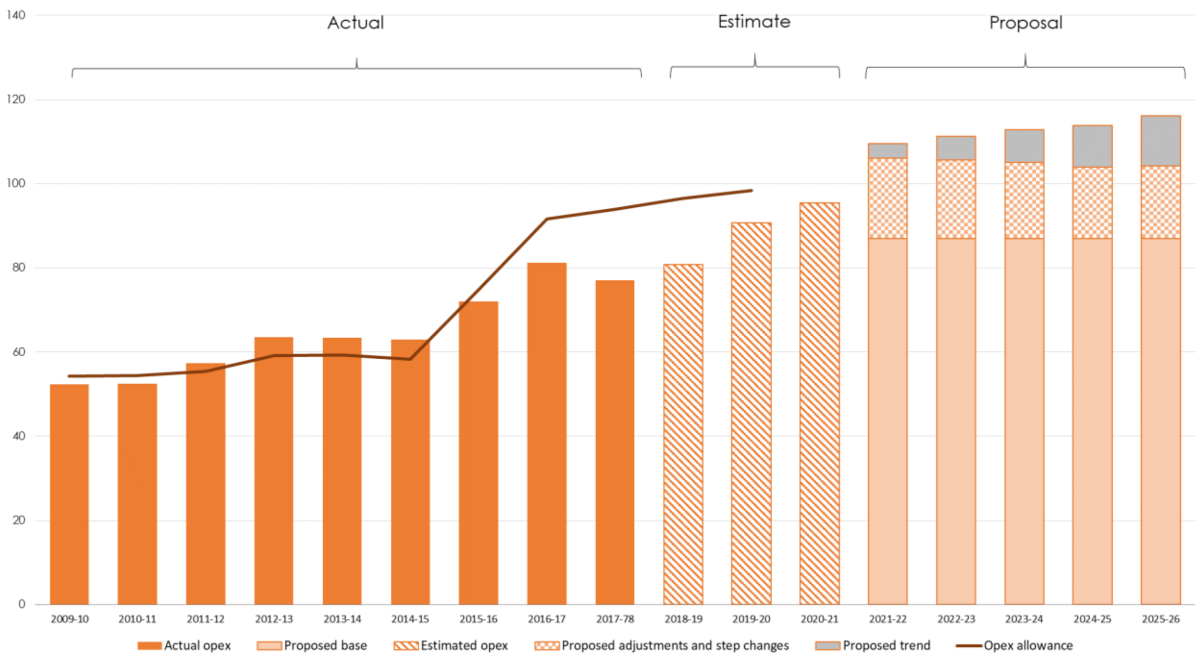
Figure 13 Powercor – operating expenditure ($million, June 2021)



Source: AER analysis from Powercor's regulatory proposal RIN and PTRM.

CitiPower proposed a total opex allowance of $563.7 million (real 2021) for the 2021–26 regulatory control period. This is a $108.4 million (23.8 per cent) increase above CitiPower's opex allowance and a $161.8 million (40.3 per cent) increase above the estimated opex in the current regulatory period.

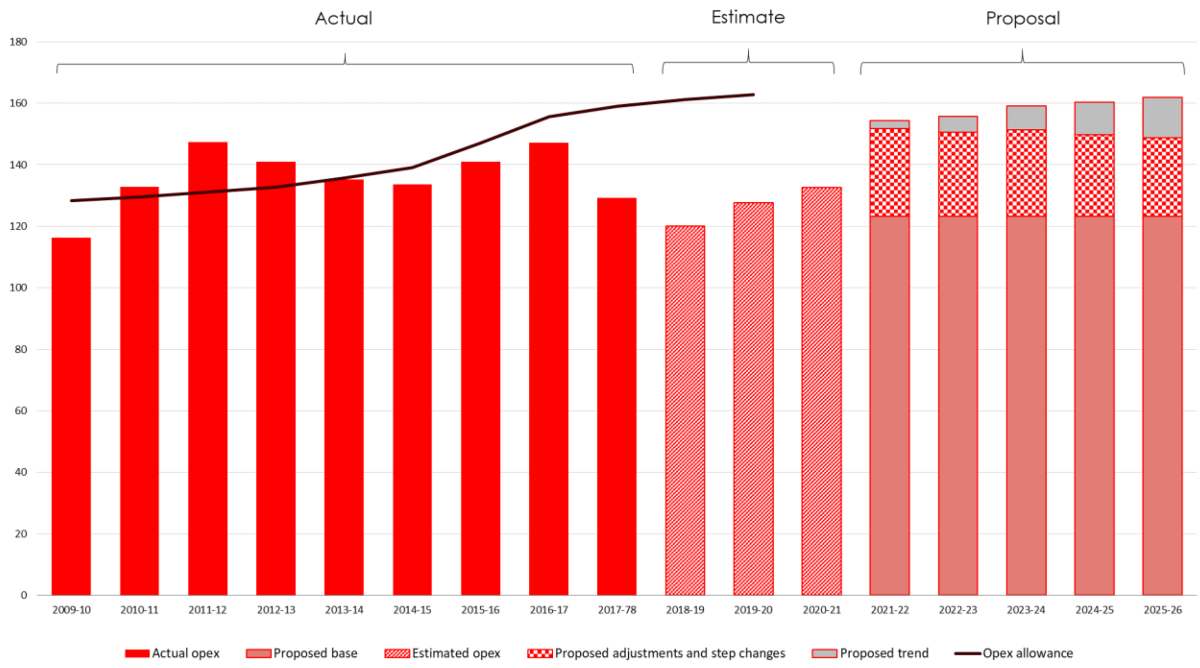
Figure 14 CitiPower – operating expenditure ($million, 2021)



Source: AER analysis from CitiPower's regulatory proposal RIN and PTRM.

United Energy proposed a total opex allowance of $791.3 million (real $2021) for the 2021–26 regulatory control period. This is a $5.7 million (0.7 per cent) increase above United Energy's opex allowance and a $126 million (18.9 per cent) increase above the estimated opex in the current regulatory period.

Figure 15 United Energy – operating expenditure ($million, 2021)



Source: AER analysis from United Energy's regulatory proposal RIN and PTRM.

The key drivers of the proposed increases in base opex for these three distributors, which they consider reflect the efficient costs a prudent operator would incur, are:

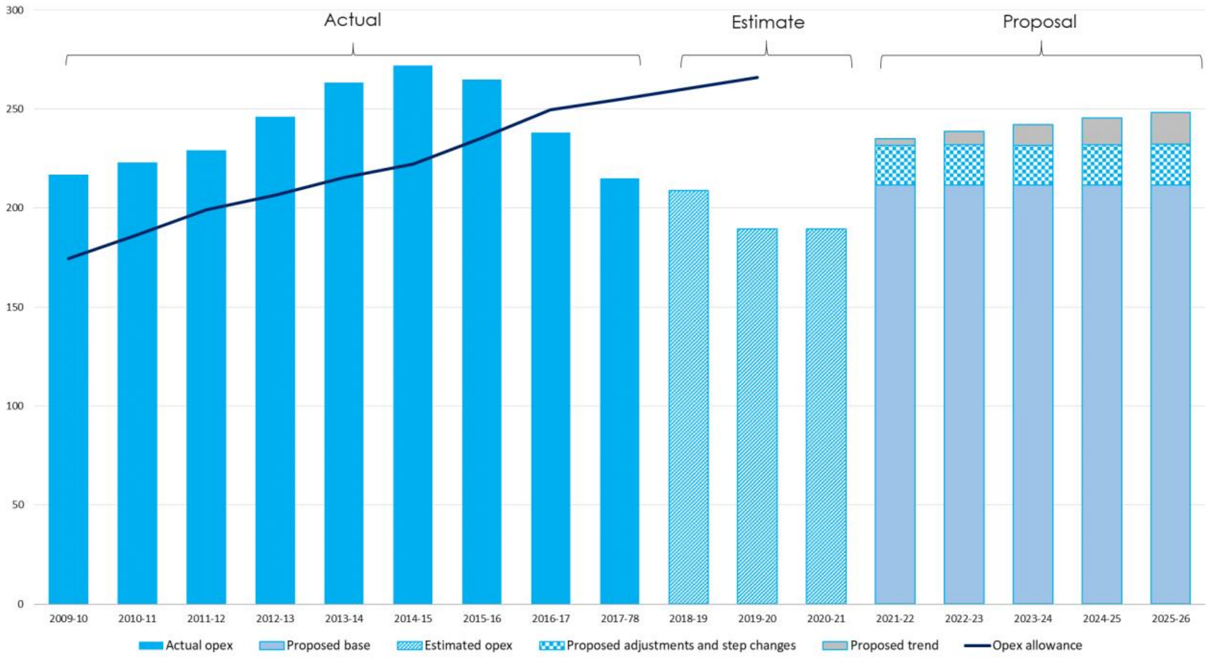
1. Reclassification of costs: The distributors have reallocated a variety of costs to opex, most significantly expenditure on replacement on faults and minor repairs that was previously capitalised. The proposed service reclassifications results in a total increase of $33.5 million for Powercor, $26.8 million for CitiPower and $32 million for United Energy.
2. Step changes: The distributors have proposed a large number of step changes which are a significant driver of the increased costs: $98 million for Powercor, $85.6 million for United Energy and $43.6 million for CitiPower.
    - Across the three proposals there are seven common step changes, with the largest driver related to meeting new regulations concerning system and data controls under the Security of Critical Infrastructure Act.
    - Other material but unique step changes include high bushfire rated area zone reclassifications and replacing expulsion dropout fuses by Powercor, Yarra trams pole relocation by CitiPower, and demand management programs by United Energy.
3. Output growth: To forecast output growth, each distributor has used the average weights of two econometric models. This approach is different to the weights and methodology generally used by the AER.

4. Price growth: To forecast internal labour price growth, each distributor has adopted the wage forecasts developed by BIS Oxford Economics which is different to our standard approach. The distributors also proposed to use an average of our actual efficient input mix over the 2014–2018 period to determine the labour and non-labour weights which is different to our standard approach of using an industry average.
5. Productivity change: all three distributors adopted the AER's productivity change of 0.5 per cent per year.

4.7.2 AusNet Services' operating expenditure proposal

AusNet Services proposed a total opex allowance of $1209.6 million (real $2021) for the 2021–26 regulatory control period. This is a $56.6 million (4.47 per cent) decrease from AusNet Services' opex allowance and a $93.5 million (8.4 per cent) increase above the estimated opex in the current regulatory period.

Figure 16 AusNet Services – operating expenditure ($million, 2021)



Source: AER analysis from AusNet's regulatory proposal RIN and PTRM.

The key drivers of the proposed increases in AusNet Services' base opex, which it considers reflects that of an efficient performance when compared to its peers, are:

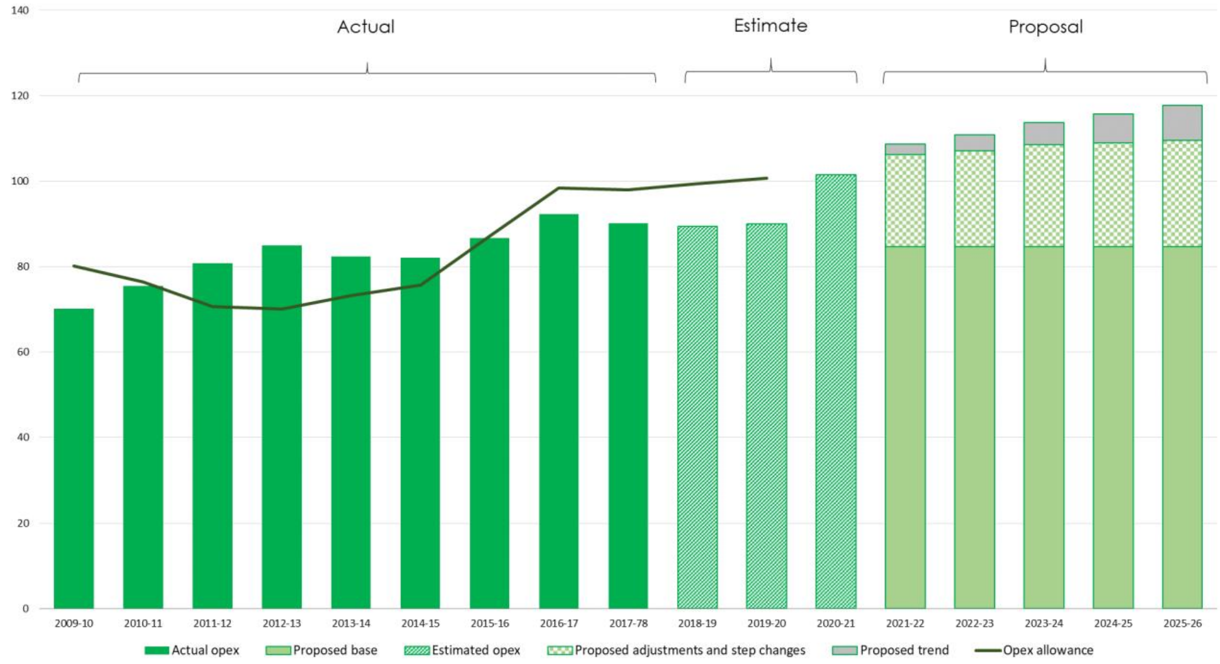
1. Reclassification of costs: the reallocation of smart meter ICT expenditure from alternative control services to standard control services was the largest adjustment to the based proposed.
2. Output growth, price growth and productivity change: AusNet Services have forecast both price and output growth using AER standard approaches, and adopted the AER's productivity change of 0.5 per cent per year.
3. Step changes: AusNet Services proposed five step changes, the largest towards bush fire mitigation with costs associated with annual rebalancing and testing of REFCLs totalling

$5.9 million. We note that AusNet Services is proposing significantly fewer step changes compared to the other Victorian distributors which it considers will result in a productivity saving greater than the AER mandated 0.5 per cent

4.7.3 Jemena's operating expenditure proposal

Jemena's proposed a total opex allowance of $566.6 million (real $2021) for the 2021–26 regulatory control period. This is an $83.1 million (17.2 per cent) increase from Jemena's opex allowance and a $118.2 million (26.4 per cent) increase above the estimated opex in the current regulatory period.

Figure 17 Jemena - operating expenditure ($million, 2021)



Source: AER analysis from Jemena's regulatory proposal RIN and PTRM.

The key drivers of the proposed increases in Jemena's base opex, which it considers is consistent with efficient benchmarks and performance of networks peers, are:

1. Reclassification of costs: A significant driver of Jemena's proposed opex is a change in its cost accounting methodology to expense all corporate overheads opex. This increases opex by $61.5 million over the next regulatory control period.
2. Step changes: Jemena proposed seven step changes, the largest an increase in insurance premiums totalling $28.5 million over the next regulatory control period.
3. Output growth, price growth productivity change: Jemena forecast output growth and price growth using AER standard approaches, and has adopted the AER's productivity change of 0.5 per cent per year.

4.8 Capital expenditure

Capex is an input into the return on capital and return of capital (regulatory depreciation) building block allowances. As such, capex incurred today will affect customers' electricity prices over several decades.

In this section we consider the capital expenditure of each of the distributors in more detail. First we consider some common themes across each of the proposals.

4.8.1 Rapid Earth Fault Current Limiters (REFCLs)

The Victorian Government's Powerline Bushfire Safety Program has introduced a number of regulatory obligations to prevent or mitigate fire-starts caused by the electricity network.[62] The most significant cost to network businesses and consumers is the installation of REFCLs and related infrastructure. AusNet and Powercor are required to achieve certain technical requirements (referred to as required capacity) at 22 zone substations each and Jemena at one zone substation.

For the 2021–26 regulatory control period AusNet proposed $147 million, Jemena proposed $43 million and Powercor proposed $173 million.

We have previously approved $350 million for REFCL-related contingent projects for AusNet Services and $340 million for Powercor. Some of the contingent project allowance for each business will remain unspent prior to the commencement of the 2021–26 regulatory control period.

There are some interrelationships between businesses regarding compliance with the regulatory obligations. For example, Jemena and AusNet Services jointly engaged consultants WSP to conduct options analysis for compliance at Coolaroo and Kalkallo zone substations. Kalkallo zone substation is part of AusNet Services' network, which serves three of Jemena's feeders.

In addition to the exemptions already granted by the Victorian Minister in October and November 2018, each of the businesses have applied for further exemptions from the obligations for a more cost-effective solution. At this stage those further exemptions have not been granted, hence the businesses have proposed the higher cost solutions to meet full compliance.

4.8.2 Poles repex

CitiPower, Powercor and United Energy's three proposals include a substantial increase in poles repex compared with the current period. These three businesses propose an aged-based program in addition to its current asset management practices. It states that its current condition-based replacement program has resulted in its networks having among the lowest wood pole failure rates in Australia.[63] Despite this, its aged-based programs will target lower durability poles located in higher consequence areas.

62 See https://www.energy.vic.gov.au/safety-and-emergencies/powerline-bushfire-safety-program.

63 United Energy says that its pole replacement program "has resulted in our network having amongst the lowest wood pole failure rates in Australia" (United Energy's regulatory proposal, p. 55). Powercor says that it has "pole asset management practices have resulted in relatively low wood pole failure rates (Powercor's regulatory proposal, p. 31). CitiPower says that it experiences an average of around one wood pole failure per annum (CitiPower's regulatory proposal, p. 31).

Our repex model is a statistical tool used to conduct a top-down assessment of a business' repex forecast. A business may use the model before submitting its regulatory proposal as a top-down check of its repex forecast. CitiPower and Powercor's regulatory proposals show that each business' forecast poles repex significantly exceeds their estimated repex model forecasts, while United Energy does not provide this information.[64]

Powercor presents stakeholder support for higher network costs to improve safety. It also discusses some key findings and recommendations from ESV's draft report for its sustainability review into Powercor's wood pole management practices in terms of strategy, inspection, condition and risk assessment, and forecasting and delivery.[65] [66] The review follows from ESV's investigation into the condition of power poles in South West Victoria in response to the 2018 St Patrick's Day fires. ESV will commence similar investigations into pole management practices for the other Victorian distribution businesses in 2020.[67]

CitiPower and United Energy do not provide similar stakeholder views regarding their own networks. Instead, they have proposed changes based on ESV's findings on Powercor's network.

We will look closely at CitiPower, Powercor and United Energy's poles repex programs and come to a view on whether a step-change from current asset management practices is prudent and efficient.[68] We will consider the circumstances for each of the businesses when making our draft decision.

AusNet Services and Jemena's poles repex forecasts are broadly in line with current period spend. Jemena aims to maintain current levels of reliability in addition to targeting poles that do not meet current design standards. AusNet Services is managing its poles repex by increasing its staking rate.[69] However, AusNet Services noted that it may increase its poles replacement rates following the conclusion of the ESV's review.

4.8.3 Distributed energy resources management

The Victorian businesses are predicting a substantial increase in residential solar penetration over the forthcoming regulatory control period, driven by the Victorian Government's Solar Home initiative. Customers are generally in favour of allowing all households the opportunity to connect to solar, and to export electricity where it is economic to do so.

CitiPower, Powercor, and United Energy are proposing a solar enablement program. The majority of the proposed capex is to increase network capacity (i.e. augmentation). This is in addition to expenditures focusing on managing the existing capacity of their networks, similar

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64 CitiPower and Powercor performed their own analysis using the AER's repex modelling approach.

65 Powercor's regulatory proposal, p. 32.

66 Energy Safe Victoria, *Draft report: Powercor wood pole management*, December 2019, esv.vic.gov.au/wp-content/uploads/2019/12/Public-Technical-Report-Powercor-wood-pole-management.pdf

67 Energy Safe Victoria, *Draft report: Powercor wood pole management*, December 2019, p. 2.

68 This is consistent with the requirement for us to provide an expenditure allowance to meet the capital expenditure objectives for maintaining network performance, rather than improving it. See NER, cll. 6.5.7(a)(3)–(4) and 6.5.7(c)–(d).

69 Staking is a refurbishment technique that extends pole life by another 10-15 years. Staking is lower cost alternative to replacement. See AusNet Services, Electricity Distribution Price Review 2022–26, p. 86.

to businesses in other states. For example, SA Power Networks, which has far higher penetration rates than the Victorian distributors, has proposed $34 million for its Distributed System Operator transition project.[70] CitiPower, Powercor and United Energy seek to manage voltages through a Dynamic Voltage Management System (DVMS) and by transformer tapping.[71] They will use data from the DVMS and AMI to remove constraints to solar exports through network augmentation where it is efficient to do so.[72]

Jemena is proposing ICT and augmentation capex as part of its Future Grid program aimed at enabling DER. Its ICT projects include developing an LV network model, to improve data capture processes and implementing new DER assessment functionalities. It also includes a project to enable dynamic DER export to allow for the control and management of DER. Its augex proposal is aimed increasing the network's DER hosting capacity by upgrading distribution substations and LV circuits, and installing voltage regulation devices.

AusNet Services is proposing augmentation through its Voltage Compliance and Hosting Capacity for DER programs. These programs are aimed at addressing areas that are currently non-compliant with the Victorian Electricity Distribution Code and those areas forecast to be constrained. It also proposes a DER enablement ICT project to better understand where DER is constrained through improved modelling capability and improved visibility of the LV network. It would also introduce systems to provide better price signals to customers that would reflect the cost of connecting and managing DER.

4.8.4 New requirements under the Environmental Protection Amendment Act 2018

Changes to the Environmental Protection Amendment Act 2018, that take effect from July 2020 will require businesses to move from a reactive to a proactive approach to preventing waste and pollution impacts of the networks.[73]

CitiPower, Powercor and United Energy proposed investment for oil-leak reduction (bunding) and noise reduction to comply with the new requirements. Proposed investment by business is $71 million for CitiPower, $48 million for Powercor and $83 million for United Energy. The majority of the compliance investment is capex. CitiPower, Powercor, and United Energy used desktop research to select the number of sites for these interventions and forecast their costs.

In contrast, AusNet Services and Jemena did not forecast any compliance capex. Jemena proposed $4 million opex for compliance and AusNet Services stated that it will absorb any costs and has therefore not proposed any capex or opex for compliance.

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70 SA Power Networks referred to this program as the LV Management program.

71 United Energy has already implemented a DVMS.

72 CitiPower, CP BUS 6.02 – Enabling residential rooftop solar, January 2020.

73 See https://www.environment.vic.gov.au/sustainability/environment-protection-reform/ep-bill-2018.

4.8.5 Capex trends

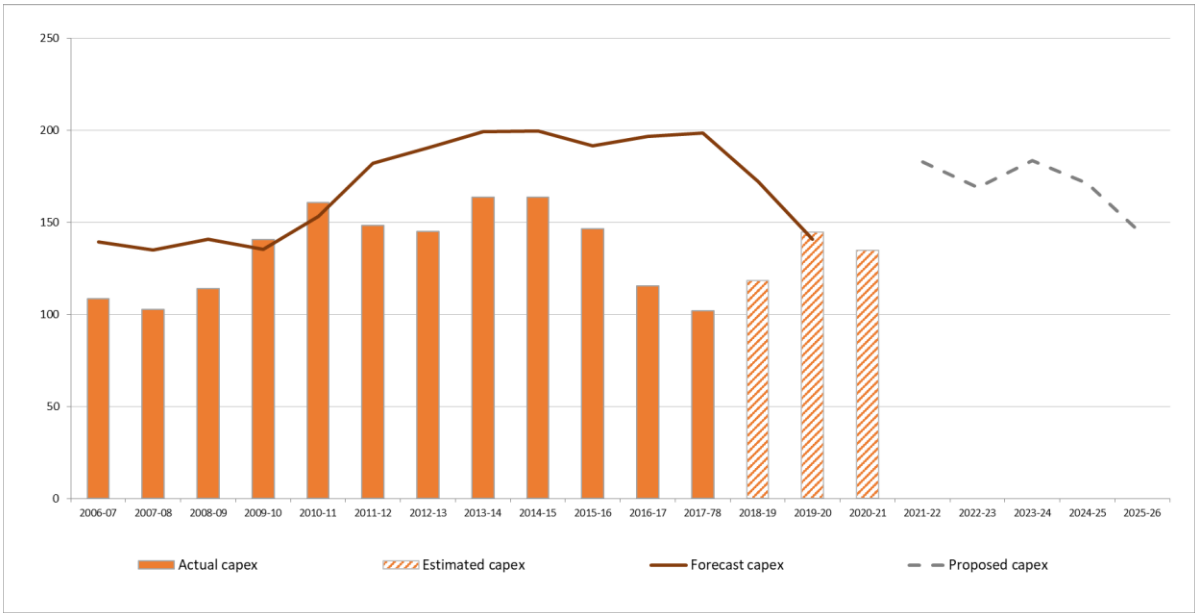
In the following sections we set out the trend in each of the distributors actual, expected and forecast capex. We also outline significant components of each of the distributor's capex forecasts. When considering these trends please take the following into account:

- The Victorian Government's Powerline Bushfire Safety Program has resulted in significant capital expenditure in the current and forecast periods. This compliance-driven capex is generally non-recurrent.
- The Victorian regulatory control period is changing from a calendar year to a financial year basis. As a result disaggregated RIN data does not give a complete time series. The charts below have been compiled a number of different data sources to show a complete trend.

4.8.5.1 Citipower

CitiPower proposed net capex of $846 million for the 2021–26 regulatory control period.[74] Figure 18 shows CitiPower's net capex over time.

Figure 18 Citipower net capital expenditure over time ($ million, June 2021)



Note: Capex excludes asset disposal and equity raising costs.

Source: AER analysis from Citipower's regulatory proposal RIN, RFM and PTRM.

4.8.5.2 Replacement capex (repex)

CitiPower proposed $308 million for replacement and renewal of network assets in 2021–26. This contributes to 36 per cent of CitiPower's total net capex forecast, and is 168 per cent higher than its current period spend.[75] CitiPower proposed the following major projects in its forecast repex for 2021–26:

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74 CitiPower, PTRM, excluding equity raising costs.

75 AER calculations based on data from CitiPower's category analysis and Reset RINs.

- Environmental management program ($71.3 million)
- Wood pole replacement program ($58.9 million).

CitiPower noted that the step-up in proposed repex expenditure from the previous to the forecast regulatory control period is primarily due to investment required to meet new environmental compliance obligations and increases in their pole replacement program in response to external and internal reviews.[76]

4.8.5.3 Augmentation capex (augex)

CitiPower proposed $179 million for augex including distributed energy enablement, an increase of 10 per cent compared with current period spend.[77]

CitiPower noted that the step-up in proposed augex from the previous to the forecast regulatory control period is primarily due to investment in solar enablement ($32 million) to address constraint issues[78] and meeting growing demand which will require off-loading zone substation supply.[79] It also proposed the Brunswick supply area major project ($29 million).

4.8.5.4 ICT capex

CitiPower noted that its proposed step-up in recurrent ICT expenditure from the previous to the forecast regulatory control period is primarily driven by customer feedback that reliability, affordability and the privacy of their data is a top priority, and to maintain the currency of their ICT systems.[80]

4.8.6 Powercor's capex forecast

Powercor proposed net capex of $2 138 million ($2020–21) for the 2021–26 regulatory control period.[81] Figure 19 shows Powercor's net capex over time.

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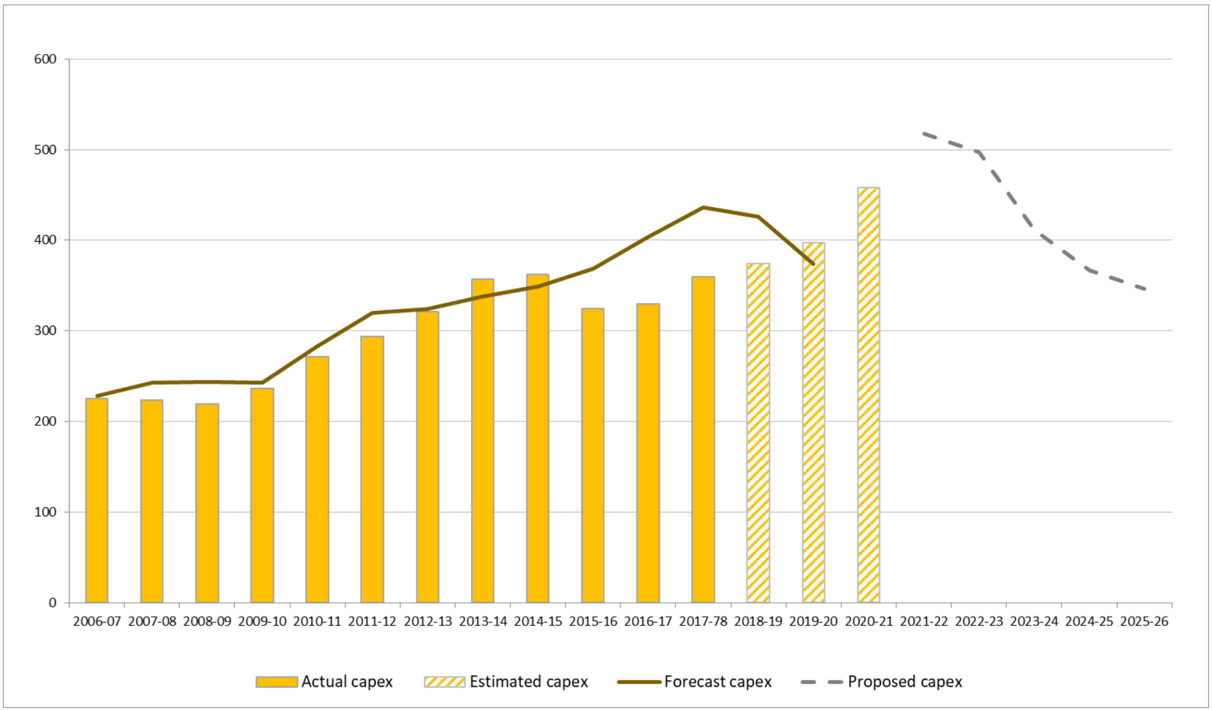
76 CitiPower, Regulatory Proposal, January 2020, p. 28.
77 AER calculations based on data from CitiPower's category analysis and Reset RINs.
78 CitiPower, CP BUS 6.02, Enabling residential rooftop solar, January 2020, p. 30–32.
79 CitiPower, Regulatory Proposal, January 2020, p. 68.
80 CitiPower, Regulatory Proposal, January 2020, p. 79.
81 Powercor, PTRM.

Figure 19 Powercor net capital expenditure over time ($ million, June 2021)



Note: Capex excludes asset disposal and equity raising costs.

4.8.6.1 Repex

Powercor proposed $695 million for replacement and renewal of network assets in 2021–26. This contributes to 32 per cent of Powercor's total net capex forecast, and is 53 per cent higher than its actual and estimated spend over 2016–20.

Powercor's poles repex program ($234 million) is the primary driver for the very large increase in repex in 2021–26. Despite low historical pole failure rates, Powercor states that it is responding to community concerns about pole safety by changing its asset management practices.[82]

Powercor's other forecast major repex projects include EPA compliance ($48 million) and mitigating the reliability impacts of REFCL installations ($13 million).

4.8.6.2 Augex

Powercor proposed $450 million for network augmentation over 2021–26. Major projects include bushfire safety (predominantly REFCL and related capex) and DER enablement.

Remaining augex comprises a large number of projects totalling net $191 million, mostly to meet expected demand growth.

82 Powercor, Regulatory proposal, January 2020, pp. 31–32.

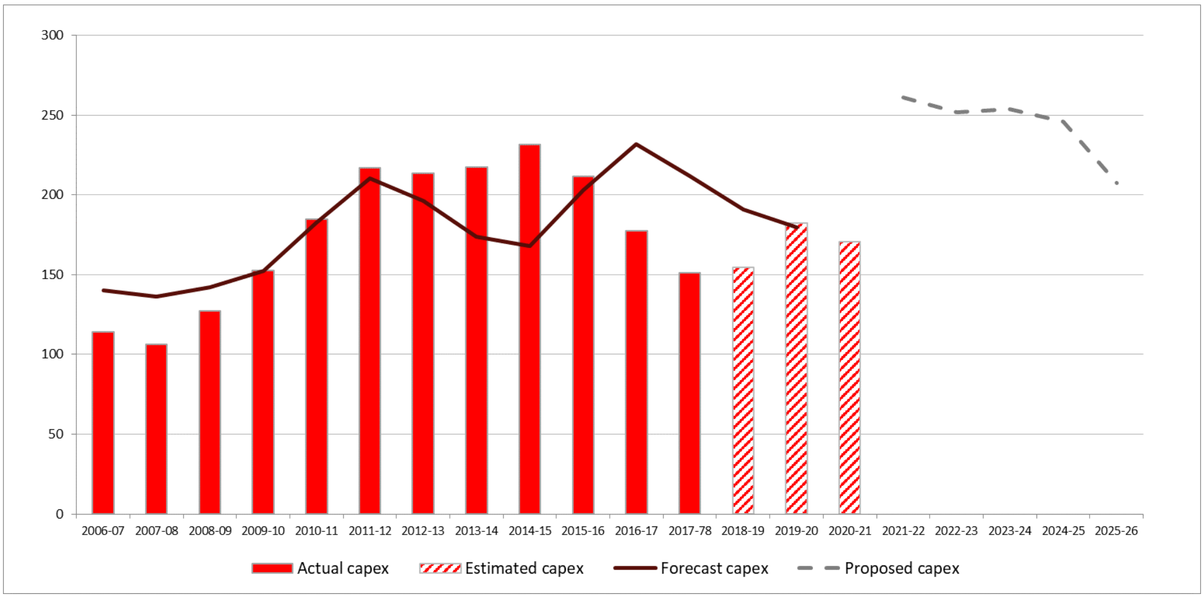
4.8.6.3 Capitalised overheads

Powercor proposed $264 million for capitalised overheads in 2021–26, which is 15 per cent higher than its actual spend in 2016–20. It is not immediately clear what is driving this increase.

4.8.7 United Energy's capex forecast

United Energy proposed net capex of $1 213 million ($2020–21) for the 2021–26 regulatory control period.[83] Figure 20 shows United Energy's net capex over time.

Figure 20 United Energy's net capital expenditure over time ($ million, June 2021)



Note: Capex excludes asset disposal and equity raising costs.

Source: AER analysis from United Energy's regulatory proposal RIN, RFM and PTRM.

4.8.7.1 Non-network capex

United Energy proposed $280 million for non-network capex in 2021–26. This includes $194 million for ICT capex. The step-up from current period spend is due to a number of large non-recurrent ICT programs including SAP upgrade, digital networks (low-voltage management), five-minute settlement programs and customer service initiatives (customer enablement). United Energy notes that the digital networks program will "enhance network safety and reduce the need for augmentation".[84]

United Energy proposed $69 million to upgrade its Burwood and Keysborough depots and to construct a new Mornington depot. This represents a substantial increase in property capex from the current period, although United Energy noted that its historical spend is the lowest in

[83] United Energy, PTRM, excluding equity raising costs.
[84] United Energy, Regulatory proposal, January 2020, p. 118.

the NEM on a per customer basis. United Energy's rationale for this investment is that the size and condition of these depots is no longer adequate.[85]

4.8.7.2 Augex

United Energy proposed $181 augex in 2021–26, which is a significant step-up from its current period spend. The largest forecast augex program is solar enablement ($43 million).

United Energy proposed a number of substation upgrades to resolve expected network constraints, which generally include installing additional transformers and upgrading HV feeders.

United Energy also proposed a number of network modernisation programs. This includes responding to the retirement of Telstra's 3G network and the installation of network monitoring devices which will enable its digital network program.

4.8.7.3 Repex

United Energy proposed $505 million for repex in 2021–26. This contributes to 42 per cent of United Energy's total net capex forecast, and is 47 per cent higher than its actual spend in 2016–20.

United Energy identified the key drivers of the increase in repex as:

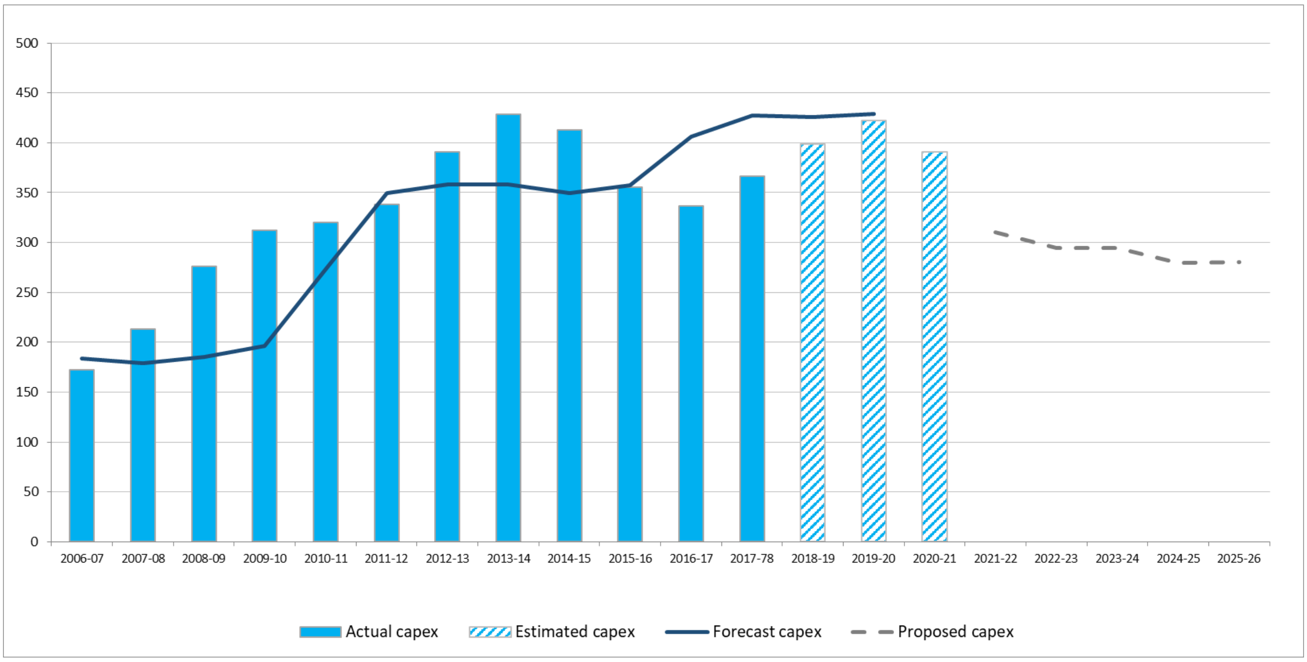
- changes to its pole replacement program (program total $90 million)
- environmental compliance obligations ($83 million)
- greater investment in transformers and switchgear ($42 million).

4.8.8 AusNet Services' capex forecast

AusNet Services proposed net capex of $1460 million ($2020–21) for the 2021–26 regulatory control period is 22 per cent lower than its actual net capex for the current period. Figure 21 shows AusNet Services' net capex over time.

85 United Energy, Regulatory proposal, January 2020, pp. 130–134.

Figure 21 AusNet's Services' net capital expenditure over time ($ million, June 2021)



Note: Capex excludes asset disposal and equity raising costs.

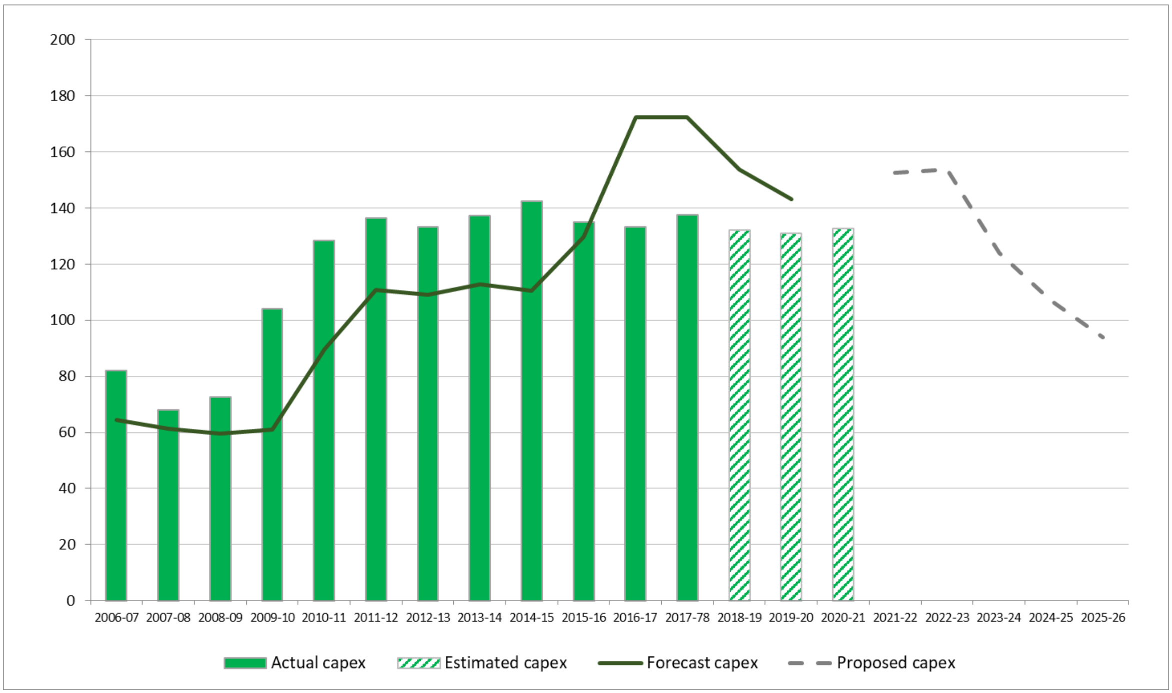
Source: AER analysis from AusNet's regulatory proposal RIN, RFM and PTRM.

AusNet's capex proposal includes $76 million to rebuild major zone substations (this project was the subject of negotiations with AusNet Services' Consumer Forum), $35 million for a safety-driven program to insulate and underground SWER conductors, and a reallocation of $22 million for metering that was previously allocated to ACS metering capex.

4.8.9 Jemena's capex forecast

Jemena has changed its CAM, resulting in all of its corporate overheads being expensed in 2021–26. The effect of this change is that Jemena's forecast capex is around $62 million lower than it would be under its previous CAM. After accounting for this change, Jemena's forecast capex is 6 per cent higher than current spend.

Figure 22 Jemena net capital expenditure over time ($ million, June 2021)



Note: Capex excludes asset disposal and equity raising costs.

Source: AER analysis based on Jemena's regulatory proposal RFM, RIN and PTRM.

Jemena forecast a 10 per cent increase in gross repex (which includes customer-funded repex such as asset relocations). We note that the increase in net repex (i.e. repex which contributes to the RAB) is much higher than this. A contributor to this increase is for emergency recoverable works, which will be reclassified to standard control services in the next regulatory control period.[86] Augex is forecast to increase by 58 per cent compared with the current period, while non-network capex and capitalised overheads (because of the CAM change) are forecast to decrease by 27 per cent and 28 per cent, respectively.

The main projects driving the increase in Jemena's repex and augex include:

- switchgear and relay and protection systems replacements at selected substations; and a program to replace non-preferred service lines to address safety and compliance issues
- augex programs including the Preston conversion program, REFCL-related augex and DER management; and an increase in HV feeders augex.

The decrease in capitalised overheads reflects a change in Jemena's CAM. From January 2021 Jemena will expense all corporate overheads, resulting in a forecast decrease of $62 million in capex and a corresponding increase in forecast opex.[87]

86 Jemena, *Regulatory proposal – attachment 05-01 capital expenditure*, January 2020, p. 62.

87 Jemena, *Regulatory proposal – attachment 06-01 operating expenditure*, January 2020, p. 15.

4.9 Alternative control services

In addition to the general distribution network or 'standard control' services provided to all customers, the Victorian distribution business also provide a range of services to specific customers – 'alternative control' services. The cost of providing these services is typically recovered from those specific customers in accordance with an approved pricing mechanism, rather than through the general cost bucket for 'standard control' services.

4.9.1 Metering services

Victorian distributors are currently the exclusive providers of metering services to residential and small businesses in Victoria.[88] Metering revenue accounts for between five and ten per cent of the Victorian distributors' revenue from regulated distribution services.

The Victorian distribution businesses have proposed decreases in their metering charges for the new regulatory period relative to the current period. Businesses have attributed these decreases to operating efficiencies and the reallocation of certain capital and operating expenditure to standard control services.

As part of their proposals, the distributors have identified spending in relation to the communications devices or networks that support their distribution businesses' advanced metering infrastructure. Examples of this expenditure include Telstra's decision to discontinue its 3G telecommunications network in 2024 and the implementation of five-minute settlement in 2022 (including ongoing costs).

Most of the distributors have proposed to allocate some costs relating to their AMI communications networks to standard control services. This will decrease metering charges while increasing network tariffs. Given the very high penetration of advanced metering infrastructure in Victoria, there will be a substantial degree of overlap between the customer base for both standard control and metering services.

4.9.2 Public lighting services

Public lighting services encompass the provision, construction, and maintenance of public lighting assets. Customers of public lighting services are local government authorities, jurisdictional main roads departments and other Government entities. Public lighting accounts for less than two per cent of the Victorian distributors' revenue from regulated distribution services.

The Victorian distribution businesses have all proposed public lighting charges in the first year that have increased, some significantly. While the distributors' proposals highlight different assumptions or approaches as driving these costs, key themes in the proposals are:

- the transition to energy-efficient LED lighting
- arrangements for phasing out of mercury vapour public lights should Australia ratify the Minamata Convention controlling the use of mercury.

[88] Following an AEMC rule change in 2017, the Victorian Government deferred metering competition in Victoria until at least 1 January 2021 (originally aligning with the start of the new regulatory control period).

The rollout of LED lighting to replace inefficient and/or hazardous lighting can involve a higher capital cost, but can deliver operating and maintenance efficiencies as well as lowering overall energy consumption.

4.9.3 Ancillary network services

Ancillary (or miscellaneous) network services are non-routine services provided to individual customers on an as requested basis. They include connection services and auxiliary metering services. Ancillary network services accounts for less than five per cent of the Victorian distributors' revenue from regulated distribution services.

Ancillary services cover 'fee based' and 'quoted' services. Charges for fee based services are predetermined, based on the cost of providing the service and the average time taken to perform it. These services tend to be homogenous in nature and scope, and can be costed in advance of supply with reasonable certainty. Charges for quoted services are determined at the time of a customer’s enquiry, with most input costs predetermined by us, and reflect the individual requirements of the customer and service requested.

For the first year of the new regulatory period CitiPower, Powercor and United Energy have proposed to keep their fee-based ancillary network services charges constant (in real terms) from the final year of the current period. AusNet Services and Jemena have proposed some changes. AusNet Services reviewed the assumptions underlying some of its ancillary network service fees, resulting in some substantial increases relative to 2020 for after-hours services or those services that they assess as requiring a licensed electrical inspector visit. Jemena’s revised assumptions result in some of their proposed fees increasing relative to 2020 while others decrease.

The Victorian distributors have all proposed that the price control formula for quoted services be amended to include a factor representing a tax allowance. AusNet Services and Jemena have also proposed the inclusion of a profit margin in this price control formula, similar to that previously included for TasNetworks and SA Power Networks.

5 Accommodating the extension of regulatory period within our regulatory approach

The Victorian Minister for Energy indicated her intention to change the timing of the regulatory periods for distribution networks in April 2019 from a calendar year basis to a financial year basis.

The Victorian Government considers there are several benefits in changing the timing for network price updates:

- avoiding bill shock for customers over the Christmas/New year period, when customers may be more affected by cost-of-living pressures
- prompting customers to engage with the market and consider other offers at a time of year when they are more likely to do so (i.e. end of financial year rather than calendar year)
- aligning Victorian price change timing with other jurisdictions.

The Government was clear on its intentions that while the next regulatory period would be delayed by six months, they wanted the current (lower) WACC to apply from the earlier period of 1 January 2021, even though the new period would not start until 1 July 2021.

Since then, AER staff have held regular discussions with the Department of Environment, Land, Water and Planning (VIC) and the businesses on how the change would be given practical effect and what decisions need to be made to do so. Initially, the AER varied the usual timeframes for submission of regulatory proposals as a consequence of the anticipated extension of the regulatory period.

In October 2019 the Victorian Government confirmed its intention to introduce legislation in early 2020 to amend the National Electricity (Victoria) Act 2005 (NEVA) [and National Gas (Victoria) Act 2008 (NGVA)] to give effect to the change. At the time of writing, there was no firm date for introduction of the Bill. Subject to Parliamentary passage, the legislation will extend the current regulatory control period (for electricity) [and current access arrangement period (for gas)] by six months and require distributors to submit pricing proposals in respect of the six-month extension.

Among other matters, the legislation will:

- amend the NEVA to direct the AER to apply the 2018 Rate of Return Instrument (RORI) from 1 January 2021
- validate the AER's actions, retrospectively if required, regarding the process used to apply the RORI and the process for nomination of averaging periods
- amend the NGVA to provide for the application of either the 2018 RORI or the 2022 RORI during the period of the six-month extension for gas, and
- give the AER discretion to make adjustments to the current and following distribution determination or final decision that are necessary or incidental to the date change.

The delay in passing the legislative amendments impacted the AER's intention to conduct consultation on the means of operationalising these changes before the regulatory proposals were due. To give regulatory certainty, the AER provided advice/guidance on the approaches to the various building blocks relevant to the extended period (1 January 2021 to 30 June 2021), to allow distribution businesses to complete their regulatory proposals ahead of submitting them to the AER on 31 January 2020.

The AER recommended a simple trended-forward methodology for establishing most building blocks and applying the 2018 RoR Instrument. This enabled each distributor to specify the relevant inputs to be included in its RFMs and PTRMs for the six month extension period as part of its 2021–26 reset regulatory proposals to the AER.

Under this measure the building block inputs for 1 January 2021 to 30 June 2021 using the amended half year PTRM would be treated as follows:

- Opex: the previous year's allowance trended forward (by the relevant rate of change), then halved.
- Capex: the previous year's allowance halved.
- Opening RAB as at 1 January 2021, based on actual capex/latest estimates for 2016–20, using the standard 5 year RFM for that period.
- Depreciation of capex is based on existing asset classes/lives/methods. For depreciation of existing assets at 1 January 2021, the distributor is to use the depreciation model approved for the current regulatory control period adjusted to reflect the half year.
- No revenue adjustments for 2016–20 EBSS/ CESS calculations—these would be deferred to begin from 1 July 2021.
- Rate of return based on the 2018 Rate of Return Instrument, reflecting the agreed implementation method.
- Corporate income tax is based on the approach used for the current regulatory control period, except for gamma, which is to be based on the 2018 RoR Instrument.

For 1 January 2021 to 30 June 2021, we proposed that in relation to the incentive schemes and tax approach:

- EBSS would apply
- CESS would not apply
- Service target performance incentive scheme (STPIS) would apply, and
- 2018 tax review changes would not apply.

Save for the application of the 2018 Rate of Return Instrument, this approach treats the period of 1 January 2021 to 30 June 2021 as an extension of the current regulatory control period, consistent with the Victorian Government's current stated policy intention. The total revenues for the period 1 July 2021 to 30 June 2026 are to be established using the following models:

- Amended five and a half year RFM (based on extending the standard five year RFM above) to establish the opening RAB as at 1 July 2021.

- A depreciation model that continues the year-by-year tracking approach approved in the current regulatory control period for calculating the depreciation schedules of existing assets at 1 July 2021.
- The standard five year PTRM, which now incorporates the findings of the 2018 tax review.

We recommended that the use of the 'trended-forward placeholders' for 1 January to 30 June 2021 be referenced in the main (full five year) regulatory proposal, where necessary. However, in treating the six month period as 'supplemental', this material might be best placed as an appendix to the regulatory proposal so it is clear to stakeholders who may wish to comment on this approach in their submissions to the proposals. All material would be submitted to us by 31 January 2020.

We will look to finalise its position on these placeholders by August 2020 to enable distributors to submit tariff proposals to give effect to the application of the Rate of Return Instrument on 1 January 2021 (as part of annual pricing proposals). Further, we will make a decision on whether the placeholders should be trued up post 1 July 2021 tariffs as part of our regulatory determination, initially in our draft decision and, having considered all views, in our final decision due in April 2021.

Appendix A: Indicative impact of Victorian distributors proposed 2021–26 revenue

Holding all other bill components constant, Tables 8 to 12 show the impacts of the revenue the respective Victorian distributors' are seeking over the 2021–26 regulatory control period on the distribution network component of a typical bill over that period in nominal dollars.

The tables below present indicative price impacts based on the demand forecasts of each of the distributors. Actual prices are determined using a revenue cap formula and will depend on, amongst other things, actual demand, the outcomes of incentive schemes and any over or under recovery of revenues in previous years.

Table 8 Indicative impact of AusNet Services' proposed 2021–26 revenue on the distribution network component of annual electricity bills ($nominal)

	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	Total 2021–26
Residential customer							
Regulated component	575	563	588	613	638	665	n/a
Annual change		-12	25	25	26	27	90
Small business customer							
Regulated component	987	969	1,013	1,058	1,104	1,151	n/a
Annual change		-17	44	45	46	47	165

Source: AusNet Services Reset RIN, AER analysis.

Table 9 Indicative impact of CitiPower's proposed 2021–26 revenue on the distribution network component of annual electricity bills ($nominal)

	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	Total 2021–26
Residential customer							
Regulated component	360	337	342	348	353	359	n/a
Annual change		-23	5	5	5	6	-1
Small business customer							
Regulated component	1,501	1,439	1,462	1,486	1,510	1,534	n/a
Annual change		-62	23	24	24	25	33

Source: CitiPower Reset RIN, AER analysis.

Table 10 Indicative impact of Jemena's proposed 2021–26 revenue on the distribution network component of annual electricity bills ($nominal)

	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	Total 2021–26
Residential customer							
Regulated component	454	420	424	430	437	444	n/a
Annual change		-34	3	7	7	7	-10
Small business customer							
Regulated component	1,410	1,322	1,333	1,355	1,378	1,401	n/a
Annual change		-88	10	23	23	23	-9

Source: Jemena Reset RIN, AER analysis.

Table 11 Indicative impact of Powercor's proposed 2021–26 revenue on the distribution network component of annual electricity bills ($nominal)

	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	Total 2021–26
Residential customer							
Regulated component	428	425	430	435	441	446	n/a
Annual change		-4	5	5	5	6	18
Small business customer							
Regulated component	1,675	1,681	1,704	1,727	1,750	1,774	n/a
Annual change		6	23	23	23	24	98

Source: Powercor Reset RIN, AER analysis.

Table 12 Indicative impact of United Energy's proposed 2021–26 revenue on the distribution network component of annual electricity bills ($nominal)

	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	Total 2021–26
Residential customer							
Regulated component	381	339	345	351	358	364	n/a
Annual change		-42	6	6	6	6	-17
Small business customer							
Regulated component	1,879	1,698	1,730	1,762	1,795	1,829	-n/a
Annual change		-181	32	32	33	34	-50

Source: United Energy Reset RIN, AER analysis.