Consumer
Challenge
Panel

CCP17

Advice to the AER on the Victorian Electricity Distributors' Regulatory Proposals for the Regulatory Determination 2021-26

AER Consumer Challenge Panel – Sub-Panel CCP17

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CCP17 wishes to thank and acknowledge the staff from AusNet Services, CitiPower, Jemena, Powercor and United Energy, as well as members of the AusNet Services Customer Forum, who have been so generous with their time and so willing to share insights into each business and their respective Regulatory Proposals.

We also thank the AER technical, NewReg and co-ordination staff for their support and guidance during this process.

Confidentiality

We wish to advise that to the best of our knowledge this advice neither presents any confidential information nor relies on confidential information for the comments.

The Consumer Challenge Panel sub-panel CCP17

The AER established the Consumer Challenge Panel (CCP) in July 2013 as part of its Better Regulation reforms. These reforms aimed to deliver an improved regulatory framework focused on the long-term interests of consumers.

The CCP assists the AER to make better regulatory determinations by providing input on issues of importance to consumers. The expert members of the CCP bring consumer perspectives to the AER to better balance the range of views considered as part of the AER's decisions.

CCP17 is a sub-panel of the AER's Consumer Challenge Panel. The AER established the sub-panel to focus specifically on the AER's regulatory determination of the five Victorian electricity distributors for 2021-2026. CCP17 has provided advice related to these determinations throughout 2018-20, which can be found on the AER website.

1 Executive Summary

We recognise the traditional owners of the land on which the Victorian electricity distribution businesses operate. We respect the elders of these nations, past and present along with the emerging leaders.

The AER is guided by the National Energy Objective (NEO): "to promote efficient investment in, and efficient operation and use of, energy services for the long term interests of consumers of energy with respect to price, quality, safety, reliability and security of supply of energy.

This submission responds to the Regulatory Proposals for the period 2021-26 from the 5 Victorian electricity distribution businesses: AusNet Services, CitiPower, Jemena, Powercor and United Energy and the AER's Issues Paper responding to issues raised in the proposals.

As the AER's Consumer Challenge Panel subpanel for this reset, CCP17 has considered the proposals against the questions:

- How prudent and efficient is proposed capex/opex expenditure?
- How does the proposal reflect the changing electricity market, current and longer-term issues?
- Do the proposals reflect effective consumer and stakeholder engagement?

Consumer Engagement

All Victorian DNSPs embarked on an early engagement program with their customers and undertook innovative approaches, including negotiation with a Customer Forum (through the NewReg trial), Energy Futures Customer Advisory Panel utilising scenario planning and a Peoples' Panel.

There has been an observable shift in engagement intent along the IAP2 Spectrum from the inform/consult levels of the spectrum to the involve/collaborate levels, demonstrating increasing levels of consumer engagement maturity by all businesses.

The common themes identified through a diversity of engagement activities, including Draft Proposals for each business included:

- ***Affordability*** – Consumer sentiment is that current electricity prices are too expensive. Customers do not perceive that they are receiving value for money. There is an expectation that businesses should improve their efficiency to reduce prices for consumers.

- ***Reliability*** – Consumers are generally satisfied with current levels of reliability and do not want to pay more for reliability improvements.

- ***Solar enablement*** – Perhaps driven by the Victorian Government's Solar Homes program, but also reflective of general community attitudes towards sustainability, there is strong support for networks to enable the increased installation of solar PV. The question of who should pay for the required investment by networks was debated frequently.

- ***Access to meter data*** - There was general interest from consumers in obtaining access to their data.

- ***Consumer Choice and Control*** – Consumers are wanting to retain control of their participation in the energy system.

- ***Demand Response*** – Consumers were generally supportive of demand response schemes, so it is surprising that there is minimal consideration of Demand Response approaches in the Regulatory Proposals.

Revenue Change

There are significant cost reductions driven by external to business factors, such as allowable Return on Capital and the tax allowance, while the businesses' controllable costs are rising. Without these external factors, we highlight that there would be an increase in prices paid for customers.

Incentive Schemes

Efficiency Benefit Sharing Scheme (EBSS) and Capital Expenditure Sharing Scheme (CESS)

There is $419m from EBSS and CESS incentive payments accruing to the Victorian distribution businesses from the current regulatory period. CCP17 submits that the observed outcomes of the efficiency incentive schemes are not reflective of expected results for businesses at the efficiency frontier. We suggest that a holistic review of incentive schemes is required with a focus on:

- Ensuring that schemes are meeting intended objectives,
- Simplifying and reducing the number of schemes,
- Eliminating overlaps and interdependencies,
- Delivering value for money for customers.

Customer Service Incentive Scheme

In December 2019, the AER published a draft CSIS and is continuing to consult on a final design for the scheme. Throughout the process, we have consistently supported the introduction of a CSIS as proposed by the AusNet Services Customer Forum.

CCP17 looks forward to a decision on the final scheme design being released as soon as possible to provide certainty to the DNSPs who wish to take advantage of the CSIS to support their customer service improvement initiatives.

Operating Costs (Opex)

All networks are seeking significant increases for opex allowance in the 2021-26 period, above what they are likely to spend in the current period, we also observe that:

- Opex allowances have increased for all 5 businesses over the last 2 regulatory periods, some increases have been significant. Although there have also been some efforts to reign in opex costs.
- All Victorian DNSPs have underspent their opex allowances during the current period. Prompting us to ask how this should be understood against the bids for higher opex cost allowances for the next period?
- When compared with the regulated opex allowance for the current period, only AusNet services is seeking less.
- Main drivers are step changes, cost reclassifications, demand growth (in particular, outer Melbourne residential) and "Solar enablement."
- Our main focus is on step change proposals which have been adjusted in response to recent developments, particularly related to COVID-19. Many of the proposed step changes are responses to external factors and so are supported.
- In response to some step change proposals for existing cost items, we have considered the question of 'materiality' of cost increases, including insurance costs which are likely to increase beyond a level that would previously have been regarded as likely. Material increases in existing

costs are also supported as step changes. Proposal that we do not support are those we consider to be one-off costs, items that are capital costs and existing cost items that are unlikely to have 'material' cost increases.

- Base Year - there is some concern about the efficiency of the base year for AusNet Services and Jemena, while 2019 is supported as the preferred base year

Forecasts

All Victorian distributors are forecasting growth in customer numbers, the circuit length of their networks and in maximum demand in 2021-26. They are also forecasting lower growth in energy throughput, with AusNet Services forecasting a decline in energy throughput over the forthcoming regulatory period.

In general, the forecasted peak demand increase may be overstated. Any impact of the expanded uptake of time-of-use for customers installing rooftop solar may counteract peak demand growth. Conversely, the use of reverse-cycle air conditioners, especially in new subdivisions, may also impact demand growth. It is recognised that the emerging economic challenges will have an effect on forecasts, and we expect in the revised proposal utilities will revise forecasts and the impact on connections, large connections, solar enablement and demand-driven augmentation.

We also observe that there are some deviations between AEMO demand forecasts and those of the utilities. AusNet Services highlights some reservations with recent changes to AEMO forecasting methodology (proposal s7.6.3), but the conclusions agree regarding their growth augex projects.

Forecasts of energy usage, peak demands and connections (new connections, and existing connections disconnecting) will need to be revisited in light of the impacts of COVID-19 on the economy. AEMO forecasts are also likely to be revised in light of COVID-19.

Capital Costs (Capex)

CCP17 supports the majority of the planned capital investment by the five DNSPs. There are a few expenditure proposals that require more detailed consideration and analysis, including considering taking these issues back to consumers to confirm their position now that more detailed information is available. These key areas of concern are:

- The value of the Regulated Asset Base (particularly per customer) has been increasing steeply over recent regulatory periods. RAB per customer growth tends to stabilise or fall in the next regulatory period in the case of Jemena and AusNet Services, which is to be commended, yet continues to grow markedly for the CPU distributors.

There is a strong case for approaching capital as a finite resource, asking at every point "what impact will this expenditure have on affordability for all customers over the longer term?"

- Asset Replacement is the major driver of capex in Victoria.

  The Victorian DNSPs plan to spend more on asset replacement than in the 2016-20 period. Specifically, we see the significant change in pole replacement strategy for the CPU group as the single largest issue of capital investment to be scrutinised across the proposals, noting the significant departures from the AER repex models. Detailed analysis and close scrutiny of the repex proposals of Powercor, CitiPower and United Energy, particularly poles, is a high priority.

- Network augmentation focuses on accommodating significant growth in Distributed Energy Resources (DER). While acknowledging the strong consumer support for networks to support environmental sustainability, we see some risks and perhaps even a level of misinterpretation of customer sentiment inherent in the investment cases. This may result in the DNSPs overstating their capital requirements. In essence, it would be prudent for the level of investment to meet DER growth to be reduced slightly, prioritised and staged in this upcoming period.

- Distributors have regularly underspent their allowances, suggesting there are continually emerging opportunities for improving the efficient delivery of asset replacement needs. This pattern of under-expenditure, then asking for increased repex the following period, needs to be scrutinised closely by the AER, as does the CESS framework, as it is difficult for consumers to support.
- Capital investment on non-network assets, in particular Information and Communications Technology (ICT), has accelerated over recent regulatory periods, and continues at historically high levels. The recent work by the AER to separate ICT into recurrent and non-recurrent expenditure is useful, however the expected cycles of investment are not apparent. Consumers remain concerned at the way ICT investment continues to become a larger proportion of the overall capital investment.

Future Networks and Distributed Energy Resources (DER)

CCP17 is a strong supporter of any initiative to improve the falling load factors and network utilisation seen in modern networks. The challenge to use existing assets as productively as possible, managing peak demand and facilitating the local consumption of solar PV is an admirable objective.

With a strong focus on "solar enablement" and other future network uncertainties, we see considerable value in the DNSPs each publishing a 'future operating model' document into the public arena. This would allow future network investment to be discussed more widely, to encompass the many aspects of efficient and customer-focused energy use in a vision document, which would consider matters such as:

- How networks are planned to evolve in the medium term to meet the power supply needs to remote and regional communities, considering microgrids, local energy autonomy, 'thin connections' and a high proportion of renewable energy;
- The role of energy storage, both in the grid and at customer's premises;
- The application of active and passive demand response by customers;
- A position on changing energy mix, including gas;
- A strategic view of the distributors' role in the many aspects of demand response;
- The role of advanced tariffs in meeting peak demand, encouraging best use of DER and helping mitigate any peak demand risks from electric vehicles;
- How actions at the sub-transmission and distribution network level integrate with the broader transmission system operating requirements and emerging new planning criteria.

Driven by the Victorian Solar Homes programme, customers are likely to invest in large amounts of rooftop solar PV over the next few years. The five Victorian DNSPs are gearing up to meet this increase in distributed generation. Indeed, facilitating the export of excess energy from rooftop solar PV is the centrepiece of all five proposals in respect to Future Networks. Overall, we estimate a remarkable $209M in capital and $3.5M annually in operating costs is proposed to be invested in new technologies and network capacity by the five distributors over the next five years related to the challenge to meet this expected growth.

In this advice, we strongly support the DNSPs investing in three types of investment – optimising the existing network; establishing better tools to bring innovation to the management the low voltage network and new DER connections, and refining 'non-asset' approaches.

The issue of constraint and restriction regarding new solar connections and the ability to feed excess energy from rooftop solar was the focus of most workshops related to Future Networks and received strong customer support. While we do not deny that such response was evident in the engagement, the way the case was presented and how the response has been interpreted in underpinning the DNSPs' investment plans may have led to the DNSPs overstating their customers' expectations, including the level of exports that individual customers can reasonably expect to generate.

Tariffs

The Victorian DNSPs agreed to work together on issues of common interest. Victorian network tariffs were one such area, where the businesses had established a joint program to progress network tariff reform in Victoria. We commended the businesses for implementing this initiative.

The AER view is supported that the tariff proposals need to be considered in the context of their proposals on expenditure, connection policies and demand management initiatives, and whether the overall package of the DNSPs' proposals provides a sensible and coherent strategy to address the energy system transition.

We are concerned regarding the effects of tariff reform on vulnerable customers. Research conducted by ACIL Allen showed that, while on average vulnerable customers would receive lower bills, there would still be around 27% of vulnerable customers who would be negatively impacted by more than $10 per annum. Across the population of Victorian vulnerable customers, this is of concern.

CCP17 supports the AER's intent 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. On the other hand, we also see that there is merit in setting a common structure between distributors for simplicity to progress network tariff reform, as long as this does not create perverse effects that would be mitigated if the tariffs were separately designed for each distribution area.

Six-month transitional period

CCP17 recognises that the regulatory treatment and the practical implementation of the six-month transitional period need to be as simple as possible and continue to give good outcomes for consumers. We consider that the approach outlined by the AER is sensible and support the simple trended forward methodology and the other measures outlined by the AER in the Issues Paper.

We also accept that ex-post adjustments may be required should unforeseen circumstances arise. We expect that there is a high probability that some aspects of the 2021-26 decisions will need to be "re-opened" particularly due to the COVID-19 induced uncertainties.

COVID-19 Reponses

COVID-19 requires a holistic approach and we recognise that many of the responses to the pandemic need to be "NEM wide", while there are some responses that have more immediate application to the Victorian regulatory resets.

The AER has said that they 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 business's submissions. This may also impact on timing of some elements of the process going forward.

We agree that the impacts of COVID-19 have been and will be significant and cannot be reasonably predicted, therefore all stakeholders involved with this reset will wrestle with uncertainty where previously there was at least a reasonable degree of predictability, even if it didn't seem to be the case, at the time.

We are proposing the following COVID-19 responses:

- Engagement needs to continue, but differently;

- Regular updates in the interest of ‘no surprises’;
- Be flexible and note that the standard processes may not work as well due to exogenous factors;
- Review processes for “re-openings” of determinations and think about when, why and how they might be needed.

2 Introduction & Context

2.1 Introduction

Historically, revenues for the five Victorian electricity distribution businesses (DNSPs) have been set on a calendar year basis, with the current regulatory period covering January 2016 until December 2020. In April 2019, the Victorian Minister for Energy indicated her intention to change the timing of the regulatory periods for these networks from a calendar year basis to a financial year basis.

The Victorian Government has identified 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 result of this decision is to defer the start of the next regulatory period by 6 months. The new regulatory period will now commence on 1 July 2021, and extend until June 2026.

In this Advice, we have referred to the period between January and June 2021 as the "6-month transitional period".

On 31 January 2020, the five Victorian electricity distribution businesses, AusNet Services, CitiPower, Jemena, Powercor and United Energy submitted Regulatory Proposals for the July 2021 to June 2026 regulatory period, as well as for the "6-month transitional period" to the AER. In combination, the proposals set out the revenue each business proposes to collect from its customers through distribution charges from 1 January 2021 to 30 June 2026.

In this document, CCP17 provides advice to the AER on the Regulatory Proposals for each of the Victorian electricity distribution businesses.

2.2 Context

The context in which the Victorian electricity distribution businesses have lodged their regulatory proposals for the 2021-26 period is important and we identify some of the key factors impinging on this regulatory process.

<u>Natural Disasters</u>

Nationally, years of drought have left many rural Australian communities struggling emotionally and financially which has impacted on the capacity of some to be able to meet their electricity costs. The drought impacts were seriously exacerbated in many regions by the dreadful fires over the spring and summer of 2019-20. Energy businesses across Australia, including Victorian energy businesses have rallied strongly to support impacted households, producers and businesses. The responses of the Victorian electricity distribution businesses, to be specific to this process, have been prompt, compassionate and constructive.

<u>COVID-19</u>

After the DNSPs finalised their regulatory proposals, the COVID-19 virus spread throughout the world leading to a strong public health response in Australia in mid-March 2020, with the Australian public being advised to self-isolate and to minimise any public engagement. This meant that many businesses have been closed down awaiting an easing of restrictions. The responses to the COVID-19 pandemic have had many impacts across Australian communities and have impacted significantly on demand for electricity with reduced capacity to pay for many businesses and households, while reliability of the essential service electricity has remained paramount.

We recognise that COVID-19 has created greater uncertainty for network businesses about energy demand in the immediate as well as mid-term future. It is also recognised that consumer engagement and customer responsiveness can be more difficult without face-to-face activities. However, uncertainty cannot be dealt with by waiting. Section 14 of this submission deals with responding to the pandemic and responses that we think are appropriate to deal with the uncertainty.

The form and influence of engagement

The Victorian DNSPs commenced their consumer and stakeholder engagement up to 3 years ago, and all have utilised innovative approaches in their engagement. We are satisfied that the COVID-19 pandemic has had minimal impact on engagement activities to date and that the networks all commenced their engagement with plenty of lead time. The feedback has been very clear that affordability is the prime issue for customers and that there are clear expectations that network businesses along with other businesses in the electricity supply chain are making every effort to reduce the electricity price that customers pay.

Future network / DER

Energy markets around the world are rapidly changing as energy production and use changes. In particular goals to decarbonise energy systems as a response to climate change induced by global warming from carbon emissions have contributed to a significant increase in the application of renewable energy sources to energy markets, particularly electricity. Wind and solar electricity generation and particularly small-scale solar PV are impacting on electricity networks. Responses to the uncertainty of the future network and the rapid uptake of rooftop solar PV have been significant issues for consumer engagement as well as policy debate and network engineering. This Advice includes sections dealing with “future networks” (section 8) and “enabling distributed resources” (section 9) in response to the significant issues which are highly relevant to this group of regulatory proposals.

Capable of Acceptance

The term ‘capable of acceptance’ has been used frequently during engagement in the period leading up to the businesses lodging their proposals. We have strongly supported the goal of having lodged proposals being capable of acceptance by the AER because the consumer input and support for lodged proposals is compelling. We continue to regard the idea of a regulatory proposal being capable of acceptance as an important aspirational goal.

Basis for Analysis

Our analysis in this submission uses data from the Regulatory Information Notices (RINs) and other information provided by each of the five DNSPs at the time the proposals were lodged in January 2020. We have made effort to note the changes proposed by the companies after that time, due significantly to COVID-19 impacts, and highlight that our analysis does not include the impact of the changes unless specifically noted.

The case for restraint

As we emerge into a post-COVID19 environment, we recognise the significant economic challenges that will be faced by many parts of our community. The long- term benefit of electricity consumers lies not in the provision of the best levels of customer service, or the most elegant response to future network needs, but in the spirit of the proposals to have affordability and balance as the uppermost priority.

In the short term, that means finding the compromise between the business cases with strong NPVs and the question ‘can customers afford this change?’

Over the longer term, we also consider the impact on the Regulated Asset Base (RAB). Growth in the RAB has the potential to result in significantly increased prices for customers in the future when allowable return on assets increases from the current low levels. Therefore, despite capital investment having only a moderate impact on prices within the regulatory period, we place an extra level of scrutiny to consider what may be facing customers over the longer term.

In much of the consumer engagement – which was almost exclusively undertaken before COVID-19 was evident, the case for capital investment is presented as 'only a few dollars per customer per year'. We acknowledge this data is factual, but in some cases it trivialises the nature of the investment. It is important to present the costs of capital programmes as total, and as the cost to customers over the life of the investment, including the returns to the distributor, and in the context of all other investments, price changes and risks of exogenous variables that may support or destroy the value from the investment.

Therefore, we consider affordability as the highest priority in forming our opinions regarding capital investment, challenging some expenditure as not being prudent even if it shows a strong positive business case. With affordability such a significant issue in customers' minds now and in the future, there is an imperative to view capital funds as a finite resource.

<u>Adjustments to the Environment Protection Amendment Act 2018</u>

We acknowledge CPU's letter to the AER of 15 May 2020 advising of some changes to their Regulatory Proposal, including the reduction in planned expenditure resulting from the EP Amendment Act 2018 and draft regulations.

We had intended to query this expenditure item, so we therefore support the change in approach taken by CPU in reducing this estimate significantly. The remaining amount, we understand, is to undertake data gathering regarding compliance with the proposed change to the legislation. We view this as being prudent and reasonable.

3 Consumer and Stakeholder engagement

3.1 CCP17 involvement

Consumer Challenge Panel sub-panel 17 (CCP17) was established by the AER in November 2017 to provide advice on the 2021-26 Victorian Electricity Distribution Revenue Determination.

During 2018 and 2019, CCP17:

- observed multiple consumer engagement events conducted by each of the businesses (approximately 50 in total),
- met 5 times with each of the businesses to discuss development of regulatory proposals and understand the issues impacting on each business,
- met 4 times with the AusNet Customer Forum,
- attended 5 joint DNSP meetings on tariffs,
- held regular discussions with AER coordination and stream teams,
- held discussions with consumer representatives and other stakeholders.

To date, CCP17 has provided the following advice to the AER:

- Response to the Preliminary Framework and Approach (F&A) for Victorian Distribution Businesses – November 2018
- Comments on the AusNet Services Customer Forum Interim Engagement Report - 6 February 2019
- Progress Report on Consumer Engagement by the Victorian Electricity Distribution Businesses for the 2021-2025 Regulatory Reset – March 2019
- Comments on the Draft Regulatory Proposals (Draft Plans) – July 2019 (for each business)
- Customer Service Incentive Scheme Issues Paper – August 2019
- Draft Customer Service Incentive Scheme – February 2020

CCP17 submitted a presentation to and participated in the virtual Stakeholder Forum conducted by the AER in April 2020.

3.2 General comments on the engagement

All Victorian DNSPs embarked on an early engagement program with their customers to ensure that customer needs were well understood by the business and that the final regulatory proposals were shaped by customer requirements and choices. Generally, the businesses commenced their engagement activities around the end of 2017 with a view to submitting their regulatory proposals in July 2019, some 18 months later. There was an observable level of improvement in the quality of the engagement compared with what had been implemented for the previous regulatory reset.

There has also been an observable shift in engagement intent along the IAP2 Spectrum from the inform/consult levels of the spectrum to the involve/collaborate levels, demonstrating increasing levels of consumer engagement maturity by all businesses.

This reference to participation level is based on the IAP2 (International Association of Public Participation) Public Participation Spectrum[1] which provides a useful framework for consideration of the consumer engagement (which we regard as synonymous with the public participation language of IAP2) undertaken by a business or organisation.

In its simplest form, the spectrum summarises increased levels of consumer engagement in moving from left to right:

INFORM – CONSULT – INVOLVE – COLLABORATE – EMPOWER

It has been pleasing to see the variety of different methodologies applied by the businesses (e.g. scenario planning, People's Panel, Customer Forum), and the thoughtfulness with which each business tailored their chosen methodology to the characteristics of their business and customer base.

During 2017, all of the Victorian DBs worked proactively to develop a joint engagement strategy on residential pricing, culminating in the joint Victorian Electricity Networks Household Network Pricing Consultation Program. This was aimed at formulating a consistent approach to tariff reform in Victoria that would ultimately be acceptable to the Victorian Government. Three one-day tariff forums were conducted jointly by the five businesses and involved a broad group of stakeholders including consumer representatives, retailers, government representatives and regulators. Active participation by retailer representatives was a notable feature of these events. The engagement resulted in a shared position on residential network pricing which is reflected in all Victorian DB Tariff Structure Statements. This process was welcomed as an efficient use of resources and a sensible outcome by all stakeholders.

In accordance with current practice for most regulated networks in the NEM, the Victorian DBs all released Draft Regulatory proposals at the beginning of 2019, approximately six months in advance of the expected date for lodgement of Regulatory Proposals. The Draft Proposals varied in coverage and the level of detail included, but each of them provided stakeholders with an earlier insight into the business plans and intentions than had been available in previous resets. CCP17 commends this significant step towards greater transparency and openness in the regulatory process.

Common Themes for the consumer and stakeholder engagement

Key aspects of each of the five Victorian DNSPs' consumer and stakeholder engagement activities are described in the remainder of this section. However, CCP17 observed a set of common themes across the various engagement programs, methodologies and customer cohorts. Most of these themes were introduced by the business as part of a targeted engagement program seeking to shape particular components of their Regulatory Proposals, however some themes arose through direct consumer input.

The common themes are summarised as follows:

Affordability – Consumer sentiment is that affordability remains the top priority concern for all consumers, and particularly for vulnerable consumers. Many see current electricity prices as being too expensive, and do not perceive that they are receiving value for money. There is an expectation that businesses should improve their efficiency to reduce prices for consumers.

Reliability – Consumers are generally satisfied with current levels of reliability and do not want to pay more for reliability improvements. There were exceptions for some business customers, and for consumers in areas experiencing poorer service levels.

Solar enablement – Perhaps driven by the Victorian Government's Solar Homes programme, but also reflective of general community attitudes towards sustainability, there is strong support for networks to enable the increased installation of solar PV. The question of who should pay for the required investment by networks was debated frequently. Options discussed included payment by solar PV owners only, payment by all customers, contributions from Government and self-funding by the businesses. There was not a consensus view on the preferred approach.

Access to meter data – The Victorian rollout of Advanced Metering Infrastructure (AMI) provides an opportunity for usage data to be made available to consumers. There was general interest from consumers in obtaining access to this data (at no additional cost), but less clarity about the purposes for which it might be used and what the benefits would be.

Consumer Choice and Control – There was a strong message from consumers about wanting to retain control of their participation in the energy system. This is possibly a continuing reflection of consumers' lack of trust in the industry. There was resistance to proposals from network businesses to constrain the export capacity of solar PV installations, or to be able to manage air-conditioner settings remotely. Consumers want simple tariff structures, and assistance to determine which is the best tariff to match their individual circumstances, but do not want networks or retailers to make that decision on their behalf.

Demand Response – Consumers were generally supportive of demand response schemes, so it is surprising that there is minimal consideration of Demand Response approaches in the Regulatory Proposals. Discussion of energy efficiency programs and their potential link to affordability was also absent.

Effect of the six-month deferral

This six-month delay resulted in a noticeable lull in engagement momentum for the businesses as they strove to re-cast their proposals to match the new timeframes. While a small number of engagement activities were carried out during this time, they were typically business-as -usual activities, rather than events focused on influencing the final Regulatory Proposals.

The impact of the six-month deferral is discussed in more detail in section 12 of this advice.

3.3 AusNet Services

Approach to Consumer Engagement

As part of a trial of the NewReg process[1] which is aimed at enabling consumer perspectives to be better reflected in regulatory proposals, the AusNet Services Customer Forum[2] commenced work in late March 2018 with the objective of negotiating with AusNet Services on behalf of customers to ensure their needs and expectations were considered in the Regulatory Proposal AusNet Services presented to the AER.

In parallel with the work of the Customer Forum AusNet Services continued its own consumer and stakeholder engagement program. A key focus was to elicit insights that would assist in building the Customer Forum's understanding of AusNet Services' customers and stakeholders. In this section we examine the consumer engagement undertaken by AusNet Services. We discuss the role of the Customer Forum in Section 3.4 below.

EDPR 2021-26 Engagement

In January 2018, prior to the appointment of the Customer Forum, AusNet Services commenced its consumer engagement program for the 2021-26 Revenue Determination. Between January and April 2018, AusNet Services commissioned and / or undertook in-house, a series of qualitative research initiatives involving interviews and surveys aimed at 'developing an in-depth understanding of key customer and stakeholder needs and future expectations regarding our services to inform the development of our

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[1] For information about the NewReg trial, see https://www.aer.gov.au/networks-pipelines/new-reg/ausnet-services-trial

[2] For information about the AusNet Services Customer Forum, its appointment and role, see https://www.ausnetservices.com.au/Misc-Pages/Links/About-Us/Charges-and-revenues/Electricity-distribution-network/Customer-Forum

expenditure proposals'.[3] Large and small business customers, residential customers, local councils, consumer advocates and community energy groups were included in these studies. Key themes discussed with stakeholders included:

- Affordability & value for money
- Reliability & outages
- Demand management
- New technology
- Energy efficiency
- Smart meters and smart meter data
- Communication preferences

This research identified priorities and concerns to frame the development of the Regulatory Proposal.

Community-focused research was carried out in July 2018 when AusNet Services commissioned Newgate Research Group to conduct 10 focus groups at five locations across AusNet Services' electricity distribution network (Lilydale, Benalla, Bright, Philip Island and Sale). The study involved a broadly representative mix of customers with a diverse spectrum of demographic and sociodemographic traits, with primary segmentation by levels of financial vulnerability[4]. The purpose of the research was to provide a deeper understanding of customers' awareness, perceptions, knowledge and preferences across a range of electricity related issues.

AusNet Services also organised three community meetings in August 2018 (Chiltern, Clyde North and Doreen). The purpose of these sessions was to explore community preferences and priorities in areas of the network expected to be directly impacted by the 2021-26 distribution price review. The Clyde North meeting was poorly attended (with only two customers attending),[5] and the Doreen meeting was subsequently cancelled.

In October 2018, leading up to the publication of the Draft Regulatory Proposal, AusNet Services hosted small workshops for each of four key stakeholder groups – advocates for vulnerable consumers, residential consumer advocates (3), large energy users (2), and environmental interest groups (3) to test the negotiating positions to be included in the Draft Proposal. Customer Forum representatives also attended these workshops. The topics tested in these workshops were not restricted to those in-scope for the Customer Forum. They included:

- Customer experience
- DER Integration
- Innovation allowance
- Tariff Structure Statement
- Opex
- Capex
- Revenue requirements

[3] AusNet Services, Electricity Distribution Price Review 2022-26, Part I & II, p36
[4] Ibid, p37
[5] The forum was held in a school staff room. In view of the low attendance, the school principal agreed to participate as well, thus bringing the number of customers attending up to three.

AusNet Services also participated in the joint Victorian Electricity Networks Household Network Pricing consultation program conducted between November 2017 and October 2019.

Consistent with current best-practice approaches to regulatory determinations, AusNet Services' published a Draft Regulatory Proposal in February 2019. It was intended that the document be released for review approximately six months prior to submission of the 2021-26 EDPR Proposal. Due to a later decision by the Victorian Government to amend the regulatory period (see Section 12), the Draft Regulatory Proposal was actually published 1 year in advance of the 2021-26 EDPR Proposal.

Through a program of five Deep Dives, AusNet Services facilitated feedback from key stakeholders on the Draft Proposal. The Deep Dives were held between February and May 2019 and covered:

1. Customer experience, operating expenditure including step changes, and innovation
2. Public Lighting
3. Major repex projects; Pole and conductor replacement programs
4. Innovation; Distributed Energy Resources
5. Information and Communications Technology (ICT)

AusNet Services sought feedback on its Draft Proposal and received 6 formal submissions as well as verbal feedback from 5 other stakeholders. The consultation process on the Draft Proposal highlighted the need for further clarification of customers' preferences and expectations relating to solar integration and innovation expenditure proposals. An additional round of four face-to-face and online focus groups investigated support for innovation expenditure, proposed DER uptake and the question of who should pay for network DER augmentation.

<u>Business as Usual Engagement</u>

AusNet Services created a Customer Consultative Committee (CCC) in 2016 to generate insights that would guide decision-making within the business, and to serve as a direct channel for external customer perspectives. The CCC comprises seven AusNet Services personnel and up to eleven external representatives from a range of customer interests and community groups. The CCC meets quarterly, and its sphere of interest encompasses AusNet Services' regulated energy services (electricity distribution, transmission and gas networks), as well as its commercial energy services. The CCC has continued as a business-as-usual activity during the tenure of the Customer Forum.

A new Customer Satisfaction Survey conducted by Customer Satisfaction Benchmarking Australia, was introduced in April 2018, and is ongoing. The target is to sample 1800 customers who have interacted with AusNet Services each year. This initiative commenced prior to the appointment of the Customer Forum.

We understand that various customers and stakeholders are also being invited to participate in the re-design and implementation of important customer-facing processes such as the solar PV connection processes. CCP17 strongly supports this approach to ensuring that customer and stakeholder preferences and priorities are incorporated in high-volume, high-impact customer interactions.

<u>CCP17 Involvement in AusNet Services' Consumer Engagement</u>

Following appointment of the Customer Forum, it took some time to clarify the agreed scope for the Customer Forum's negotiations, and CCP17's role in the trial of the NewReg process. In July 2018, the AER determined that:

> *CCP17 would observe AusNet Services' consultation on its draft revenue proposal with consumer and other stakeholder groups, but focusing on issues that are out-of-scope of the*

Forum's negotiation—e.g. CCP17 would be free to engage in issues that were not in scope per AusNet Services' request.[6]

As a result, CCP17 were not able to observe any of the 10 focus groups conducted by Newgate Research during July 2018. We did, however, attend one Community Forum at Clyde North. We did not have the opportunity to attend the 4 face-to-face and online focus groups held in September 2019. CCP17 representatives were invited to observe three of the four stakeholder workshops in October 2018, and also participated in four of the five Deep Dives on the Draft Proposal. CCP17 provided Advice to the AER on AusNet Services' Draft Proposal.[7]

Compared with our involvement in other Victorian DNSPs' Consumer Engagement programs, CCP17 has had limited opportunities to witness AusNet's consumer engagement program in practice. As a result, our observations are largely based on documented outcomes.

CCP17 Observations

Strengths of the AusNet Services engagement activity have included:

- Over an 18-month timeframe, multiple & diverse engagement approaches have been used including one-on-interviews with stakeholders, online surveys, community focus groups, advocate workshops and Deep Dives on the Draft Proposal. Key EDPR documents were posted on the AusNet Services website.
- Views were sought from a range of customer cohorts including large and small businesses, local councils, consumer advocates, community energy groups, and residential consumers. In some cases, specific residential consumer groups such as older consumers, or more vulnerable consumers were targeted.
- A comprehensive Draft Proposal with a significant level of quantitative detail was released for review by stakeholders initially 5 months, and eventually 11 months, prior to lodgement of the Regulatory Proposal – a major achievement.
- The Customer Forum's Final Engagement Report contains multiple references to aspects of AusNet Services' engagement activities to support their negotiating position, demonstrating that AusNet Services has successfully 'elicited insights that would assist in building the Customer Forum's understanding of AusNet Services' customers and stakeholders'.

Gaps and opportunities

a) Consumer Engagement Strategy

The AER's Consumer Engagement Guideline for Network Service Providers[8] sets out the requirement that:

We expect service providers to (1) identify consumer cohorts, and the current views of those cohorts and their service provider, (2) outline their engagement objectives, and (3) discuss the processes to best achieve those objectives. To this end, we expect service providers to develop and undertake a process for identifying issues and setting priorities for consumer engagement.

[6] https://www.aer.gov.au/networks-pipelines/new-reg/ausnet-services-trial

[7] https://www.aer.gov.au/system/files/CCP%20subpanel%2017%20-%20Comments%20on%20AusNet%20Services%20draft%20regulatory%20proposal%20-%2030%20July%202019.pdf

[8] https://www.aer.gov.au/system/files/AER%20-%20Consumer%20engagement%20guideline%20for%20network%20service%20providers%20-%20November%202013.docx

CCP17 is not aware of an overarching Consumer Engagement Strategy developed by AusNet Services identifying customer cohorts, engagement objectives, engagement processes and priorities. In addition, we are not aware of plans to measure AusNet Services' engagement strategies and activities. Without an overall strategy and implementation plan, the consumer engagement activity undertaken by AusNet Services appears to be somewhat ad-hoc and reactive, and not as effective as it could have been. CCP17 understands that the appointment of the Customer Forum may have led to confusion over responsibility for engaging with consumers and other stakeholders leading up to the lodgement of the 2021-26 EDPR.

We suggest that early agreement on an overall Consumer Engagement strategy would have been helpful, particularly for those issues outside scope for the Customer Forum. The lack of an overarching strategy is having a continuing impact. AusNet Services did not conduct a structured community engagement follow-up program after release of the Draft Proposal. AusNet Services has also not provided clear plans for engaging with consumers during the remainder of the EDPR process in the absence of the Customer Forum.[9]

Engagement on issues which were out of scope for the Customer Forum was problematic. For example, CCP17 is not aware of broad consumer engagement by AusNet Services on important issues such as tariff design and accelerated depreciation which is presented in the Regulatory Proposal as an 'intergenerational issue' for customers as much as a cash-flow issue for the business.

b) Customer Consultative Committee

The AusNet Services Customer Consultative Committee's proceedings are not made public, and CCP17 did not get to observe any CCC meetings during this process. There is an opportunity for more transparency around the involvement of the CCC in the EDPR process, and their support or otherwise for the outcomes reflected in the Regulatory Proposal. Comments made by the Customer Forum that 'the insights it obtained from the CCC were limited as meetings were not always well attended and some key customer segments were poorly represented on the CCC'[10], suggest that there is an opportunity for AusNet Services to review the issues raised.

c) Further areas for future consideration include:

- AusNet Services' website has been used in a rudimentary fashion for this EDPR process, whereas there are contemporary opportunities to employ websites as more interactive engagement tools,
- Customer and stakeholder views are not homogeneous. There was a tendency in AusNet Services' reporting to focus on a single 'majority' view, rather than explore the range of perceptions and desired outcomes by different customer and stakeholder groups,
- The 2016 Census revealed that more than a quarter of Victoria's population speak a language other than English at home.[11] It would be appropriate for AusNet Services' consumer engagement program to pay particular attention to the perceptions and needs of CALD communities, and
- Compared with other regulated network businesses, a relatively high proportion of AusNet Services' Regulatory Proposal documents are flagged as 'confidential'. This can create a real barrier to stakeholder engagement and can also lead to a lack of trust in the process and the

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[9] https://www.aer.gov.au/system/files/AusNet%20Services%20-%20Victorian%20EDPR%202021-26%20-%20online%20public%20forum%20question%20and%20response%20-%20May%202020.pdf

[10] AusNet Services 2021-2025 Electricity Distribution Price Review, Customer Forum Final Engagement Report, p189

[11] https://www.vic.gov.au/discover-victorias-diverse-population

outcome. CCP17 encourages AusNet Services to review its approach to document classification to ensure that the 'confidential' label is only used where necessary.

3.4 The AusNet Services Customer Forum

Approach to Consumer Engagement

The Customer Forum's role was to represent AusNet Services' customer base and negotiate aspects of the Regulatory Proposal on their behalf. Members of the Customer Forum were well-qualified for the role, bringing to the task a broad range of experience including consumer advocacy, market research, finance and communications.

In early discussions between AusNet Services, the AER and the Customer Forum a defined scope of interest for the Customer Forum was agreed.

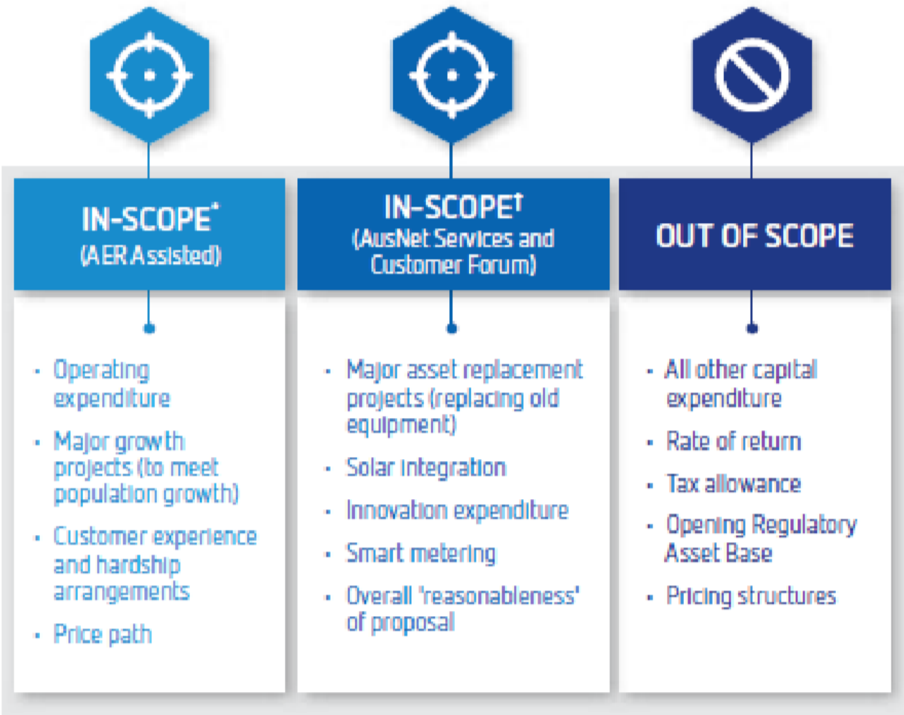

Figure 1: Scope of Customer Forum negotiations (Source: AusNet Services)

Note: ** AER assisting Customer Forum by providing information and independent advice.*
† Not in scope of the AER's assistance to the Customer Forum.

For topics designated within scope by the AER, AER staff have provided formal Guidance Notes.[12]

Working within the framework of 'In-scope, AER assisted' and 'In-scope, AusNet Services and Customer Forum', the Customer Forum has directly negotiated around 40% of the forecast revenue for AusNet's distribution services and all revenue for metering services[13]. This engagement is consistent with operating at the 'Collaborate' level of the IAP2 Public Participation Spectrum[14]

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[12] See https://www.aer.gov.au/networks-pipelines/new-reg/ausnet-services-trial
[13] AusNet Services, Overview of our Electricity Distribution Regulatory Proposal 2022-26, p10
[14] See https://www.iap2.org.au/resources/spectrum/

The Customer Forum's negotiating position was informed by customer research initiated by AusNet Services (refer to section 3.3 above) as well as a very extensive program of individual contacts with AusNet Services customers and other stakeholders[15]. The Customer Forum also initiated, designed and managed five customer surveys as follows[16]:

- Business Customer Survey (July 2018) – telephone survey of 300 small to medium businesses to better understand the issues and challenges facing businesses,
- Major Projects Customer Survey (March 2019) – telephone survey of 506 customers residing in locations serviced by zone substations identified for replacement in 2021-26 to understand perceptions of reliability,
- Clyde North and Doreen Customer Survey (April 2019) – telephone survey of 300 residential consumers in Clyde North and Doreen exploring reliability issues,
- Healesville – Bundoora Customer Survey (July 2019) – telephone survey of 42 customers affected by a high voltage incident,
- 'Who Should Pay Survey' (Sept 2019) – a telephone survey with 300 customers to establish views as to who should pay for network upgrades to cater for growth in rooftop solar PV.

Coincident with the release of AusNet Services' Draft proposal, the customer Forum issued an *Interim Engagement Report*[17] to explain the rationale for decisions made to that point, and outline areas for further work in development of the Regulatory Proposal. The Customer Forum attended the stakeholder Deep Dives on the Draft Regulatory Proposal, using the feedback obtained to support its views in the final round of negotiations with AusNet Services. To accompany the lodgement of AusNet Services' Regulatory Proposal the Customer Forum released its Final Engagement Report in January 2020.[18]

CCP17 Involvement with the Customer Forum

In relation to the Customer Forum, the AER has determined the role of CCP17 to be:

> *… (to) assist the Customer Forum, where requested, in preparing its initial and final Engagement Reports. This has involved meetings between the Customer Forum and CCP17 to test their thinking on issues that are in scope and access the broader perspective of the CCP*[19]*.*

CCP17 participated in four meetings with the Customer Forum (three face-to-face, and one teleconference), to assist the Customer Forum in forming its views on issues in-scope, and to share perspectives on issues that are common across all network businesses.

CCP17 Observations

CCP17 congratulates AusNet Services and the Customer Forum for their willingness to trial this approach to consumer participation in a regulatory reset process, a first in the Australian energy industry. We recognise that this trial has exposed AusNet Services to a degree of transparency and scrutiny of its operations beyond that which has been observed in any other regulatory process to date. CCP17

[15] Customer Forum Final Engagement Report, Appendix C
[16] AusNet Services, Electricity Distribution Price Review 2022-26, Part I&II, p37
[17] https://www.ausnetservices.com.au/-/media/Files/AusNet/About-Us/Determining-Revenues/Distribution-Network/Customer-Forum/Final-AST-Customer-Forum-Interim-Engagement-Report---Feb-2019.ashx?la=en
[18] https://www.aer.gov.au/system/files/AusNet%20Services%20-%20Customer%20Forum%20Final%20Engagement%20Report%20-%2031%20January%202020.pdf
[19] https://www.aer.gov.au/networks-pipelines/new-reg/ausnet-services-trial

commends both AusNet Services and the Customer Forum for their openness, goodwill and preparedness to tackle tough issues together.

It is our view that the AusNet Services' Regulatory Proposal strongly reflects customer perspectives for those aspects within scope for the Customer Forum. It is also clear that the Customer Forum, with its laser-like focus on customer service, has influenced and accelerated a major change in culture and approach within the AusNet Services business. We have observed a genuine commitment by AusNet Services to drive the necessary changes through the business which will deliver better service outcomes for customers.

The customer experience initiatives outlined in the Regulatory Proposal[20],both those already implemented and those planned for the next regulatory period will be particularly welcomed by AusNet Services' customers. CCP17 acknowledges AusNet Services' commitment to this work and agreement to implementing many of these changes with no additional cost to customers.

AusNet Services has agreed to produce an annual Customer Interaction and Monitoring Report to hold itself to account with respect to its customer experience improvements, with the first report to be produced by the end of March 2020. At the time of writing, it is understood that preparation of the report has been delayed by the unprecedented impacts on the business imposed by bushfires and responding to the COVID-19 pandemic. We urge AusNet Services to ensure that this report is made available as soon as possible.

Opportunities

Evaluation of the AusNet Services NewReg trial is out of scope for CCP17, so we look forward to the trial review being conducted by the NewReg Project Team.

Nevertheless, we offer one comment related to the Customer Forum's endorsed scope. In CCP17's 'Progress Report on Consumer Engagement by the Victorian Electricity Distribution Businesses for the 2021-2025 Regulatory Reset'[21] we stated that 'we have concerns that limiting scope for the Customer Forum could restrict its ability to contribute to important aspects of the regulatory proposal on an holistic basis'.[22] For the AusNet Services Regulatory Proposal, the application of accelerated depreciation will have a significant impact on the regulated revenue outcome and hence on prices for customers, yet depreciation is not in-scope for the Customer Forum. We question whether the Customer Forum is in a position to assess the 'Overall Reasonableness' of the Revenue proposal without being able to consider such a significant factor.

3.5 Jemena Electricity Networks

Approach to Consumer Engagement

On 17th May 2017, JEN shared the following summary of their consumer engagement strategy with CCP17. At the time this was just over two years before the regulatory proposal was due to be lodged.

Jemena were very clear in advising us that their three core objectives from engagement are:

a) To let our customers' views shape our regulatory proposals,

b) To build customer trust in our regulatory proposals, and

c) To support growth of Jemena's customer focus culture.

[20] AusNet Services, Electricity Distribution Pricing Review 2022-26, sections 5.2,5.3
[21] https://www.aer.gov.au/system/files/CCP17%20Progress%20Report%20on%20Vic%20DB%20Consumer%20Engagement%20-%20Final%20-%2027%20March%202019.pdf
[22] Ibid, p10

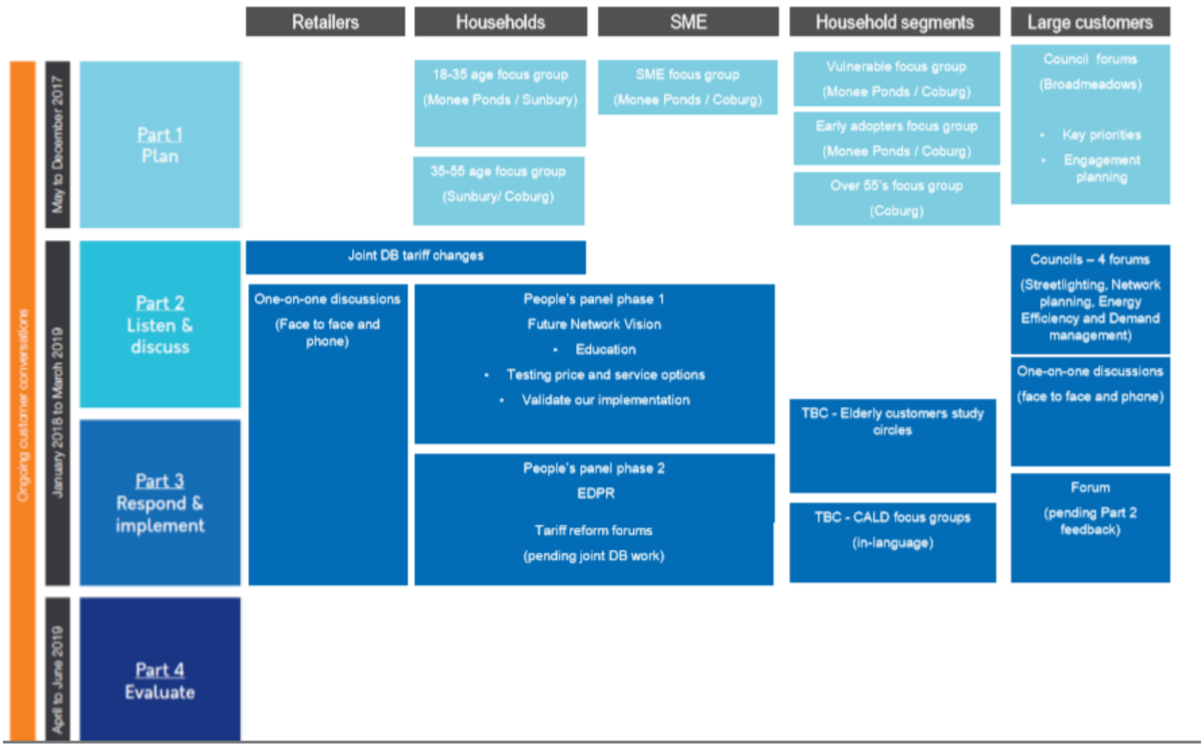


Figure 2: Jemena engagement framework (Source: Jemena)

We were also surprised that Jemena aimed for a level of consumer engagement that would be set at the IAP2 Participation level of engagement of – Collaborate

This reference to participation level is based on the IAP2 (International Association of Public Participation) Public Participation Spectrum[23] which provides a useful framework for consideration of the consumer engagement (which we regard as synonymous with the public participation language of IAP2) undertaken by a business or organisation.

In its simplest form, the spectrum summarises increased levels of consumer engagement in moving from left to right:

INFORM – CONSULT – INVOLVE – COLLABORATE – EMPOWER

The IAP2 spectrum also provides "promises to the public" appropriate to each element of the spectrum. The promise to the public / consumers for the "Collaborate" level is:

> *"We will look to you for advice and innovation in formulating solutions and incorporate your advice and recommendations into the decisions to the maximum extent possible."*

At the time of our initial advice of the AER we said that "to claim to be operating at the 'collaborate' level of the IAP2 spectrum is a significant claim by JEN particularly when considering our observation that many energy network companies are still operating at the 'inform' and 'consult' levels of the spectrum." We stand by this earlier statement.

We also observed that Part 1 of the engagement plan primarily dealt with the first part of the "collaborate" promise to the public *"we will look to you for advice and innovation …"* The subsequent parts of the plan dealt more with *"formulating solutions and incorporating advice and recommendations into decisions…"*

[23] https://www.iap2.org.au/About-Us/About-IAP2-Australasia-/Spectrum

One of the early tables produced by JEN in honing their engagement strategy is shown as Figure 3, which both shows the range of consumer and stakeholder groups to be consulted and a diversity of methods for engagement. We remain strongly supportive of this diversity in approach.

The following table shows what they said we needed to do to engage effectively with them.

Table 2.1 How our customers wanted to engage with us

Residential and small business customers	— Provide simple documents that are easy to understand. — Structure engagement in a way that is designed specifically for customers. — Start any discussion from the customer's perspective, not ours. — Take customers through a journey over multiple sessions.
Large business customers	— Preferred a one-on-one meeting rather than a time-consuming forum.
Local councils	— Workshops are a good way of engaging. — Structure events around key milestones in the regulatory process. — Engage with representatives from different teams in their organisations to obtain different perspectives. — Hold different 'streams' of events for different interest groups.
Retailers	— Stated a preference for individual conversations.

This information was invaluable during the execution of our formal engagement program and ensured that what we delivered met the needs of the whole community.

Figure 3: Jemena engagement cohorts (Source: Jemena)

<u>Early Engagement - 2017</u>

As an example of the plurality of engagement approaches undertaken, the following activities were undertaken during November and December 2017

- Household – Sunbury 18-35 age focus group 35-55 age focus group
- Retailers and stakeholders Joint Victorian DNSP tariff forum
- Large customers – Broadmeadows Council Forum Key priorities – Engagement planning
- Household segments – Moonee Ponds Vulnerable focus group Early adopters focus group 18-35 age focus group
- Small and medium enterprise – Moonee Ponds Focus group
- Household segments – Coburg Vulnerable focus group Early adopters focus group Over 55's focus group
- Small and medium enterprise – Coburg Focus group Household – Coburg 35-55 age focus group.

<u>The People's Panel - 2018</u>

This has been a significant component of the JEN consumer engagement lexicon and, we suggest, an important development in consumer engagement methodology by Australian network businesses. The People's Panel was one of the engagement approaches used by JEN during 2018, but it was (arguably) the most significant and so we review aspects this engagement below.

At its core, the People's Panel was a group of 43 people, selected from across the Jemena region to demographically reflect JEN's customer base. The group was recruited by market research company, Capire and was brought together on 6 occasions (initially) to consider a selection of the main issues with which

JEN was grappling in preparing its regulatory proposal. The sessions were either all of Saturday workshops or extended evening events of about 3 hours. Topics considered included:

- Introductions and initial briefing.
- Energy literacy and customer preferences.
- The future of energy.
- Fairness and network initiatives.
- Reliability and introducing electricity pricing
- Final, wrap up pricing followed by a presentation of recommendations to JEN Board Members.

In our observation of these sessions we were impressed by how much fun people were having and the high level of ‘energy’ that was maintained throughout the (comparatively long) sessions. Participants were involved in a variety of individual, small group and larger group activities. Information was presented through a variety of engaging approaches including interesting guest speakers, Jemena staff as “Mythbusters,” videos and through material online. Feedback was collected using a diversity of approaches, including personal written responses, visual mapping, the inevitable ‘post-it’ notes, and table facilitator reporting.

The People’s Panel produced two main sets of advice / feedback. The first involved suggestions and proposals made during the sessions and which were recorded by Jemena, resulting in a table being produced after the first 5 sessions that provided a summary of the feedback and proposals from the Panel and JEN’s response.

The People’s Panel also produced a list of 25 recommendations to go to the JEN Board, 13 for Jemena specific action and a further 12 issues that were beyond JEN’s direct control but issues they could advocate about. This list of recommendations is attached as appendix 2.

CCP17 members were extremely impressed with the People’s Panel approach both for the range of advice delivered to Jemena and to the focus and a high degree of unanimity with the 25 recommendations.

<u>Draft proposal</u>

JEN produced a draft proposal as the next step in their engagement strategy and regulatory proposal development. Our initial observation was that the proposal actively considered the views of consumers as expressed through the various engagement approaches and in line with the “IAP2 promise to the public” associated with the “collaborate’ level of the spectrum.

<u>Final, Pre-Lodgement Engagement 2019</u>

The Victorian government decided to change the timing of the regulated period for Victorian distribution businesses from calendar-year to financial year, meaning that regulatory proposals were lodged by Jemena and the other four Victorian distribution businesses, in January 2020 rather than July 2019.

Partly in response to this and partly to maintain momentum of engagement, further engagement was undertaken during 2019 including through the extension period, some of that engagement is summarised in the graphic segment below, which is taken from the JEN revenue proposal.

Figure 4 shows that further sessions of the People’s panel were conducted, and that engagement continued with the customer Council, a constant throughout Jemena’s ongoing consumer connection. Large customers were also consulted, using the preferred approach in September as the revenue proposal was being finalised

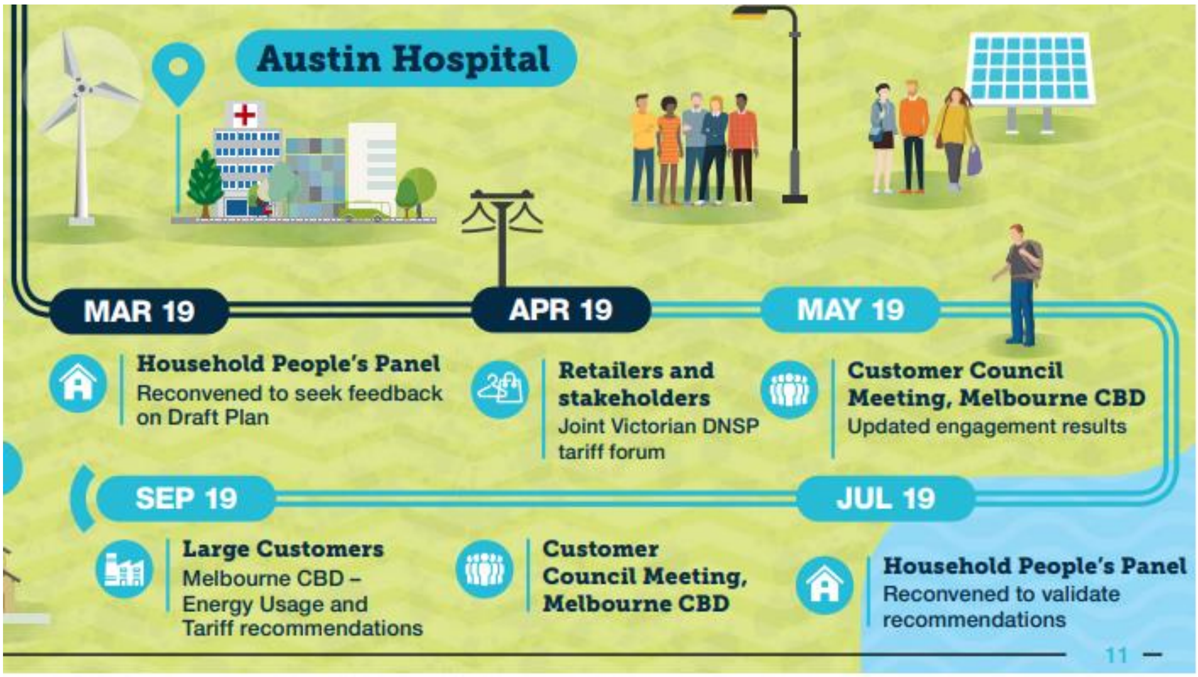


Figure 4: Continuing engagement plans (Source: Jemena)

<u>Pricing / Bills</u>

Jemena also worked closely with their Victorian distribution business peers to consult on a state-wide pricing strategy. The outcomes of which are discussed in a separate section of this submission that deals with tariffs.

<u>Engagement in summary</u>

The People's Panel engagement strategy was recognised by the ENA / ECA Consumer Engagement Awards in 2019 with Jemena winning the award for its work in both New South Wales with consumer engagement for the gas network and in Victoria, in large part for the People's Panel approach.

CCP17 thinks that the diversity of engagement by JEN over an extended period of time (nearly 2 ½ years) is as significant as the People's Panel process, as good as that was.

JEN provided the following summary statistics for its engagement, as part of their regulatory proposal. These figures bear out the extent of their engagement:

- 43 residential customers involved with the People's panel over nine sessions
- 13 focus groups
- 319 online surveys completed
- 7,400 visitors to the JEN website for aspects of their regulatory proposal development engagement
- 87 direct "contact hours" of engagement activity (excluding online)
- 10 board and senior management members attended various engagement activities

<u>Gaps or major issues</u>

Our observation is that Jemena is at the forefront of both development and application of consumer engagement approaches. They maintained engagement, with some ebbs and flows, for 2½ years and innovated with the People's Panel.

The following observations are thoughts about some areas where further engagement could occur rather than criticisms of gaps in process:

- COVID-19 responses will require ongoing engagement. This is detailed elsewhere in this submission.
- We anticipate that there will be some further consideration of issues pertinent to vulnerable customers, including with the shared discussions regarding pricing.
- The "future network" session during the People's Panel attracted considerable interest, and we expect this to be a topic of some further debate and engagement.
- The JEN area comprises people from several different cultural backgrounds and we are aware that Jemena plans to engage with CALD communities as part of further engagement.

<u>Observations</u>

The engagement we have observed has many strengths including:

1. A range of engagement strategies have been used.
2. There has been strong intent to engage with diversity of customer segments including lower income household customers, small business, local government, large businesses and energy retailers.
3. A clear desire to listen to customer input and to "incorporate advice and recommendations into decisions to the maximum possible extent".
4. Willingness to try new approaches with the preparedness to accept that some approaches might not "work" but that there will be learnings whatever happens.
5. Preparedness to talk about innovation and not claim to have all the answers
6. Real attempt to make engagement 'fun' which is a challenge in the energy space!

Jemena claims to be operating their consumer engagement at or near the "collaborate" level of the IAP2 spectrum. From engagement that we have observed so far, we are inclined to accept this claim as being real in practice as well as aspiration.

3.6 CitiPower, Powercor and United Energy

<u>Progress report on consumer engagement March 2019</u>

CCP17 provided a Progress Report on Consumer Engagement by the Victorian Electricity Distribution Businesses for the 2021-2025 Regulatory Reset to the AER in March 2019.

This included an overview of the consumer engagement activity undertaken by CP, PC and UE, it set out CCP17 involvement to date, and summarised what we saw to be strengths of the approach, as well as gaps or major issues, and set out future directions.

<u>Our presentation to the AER public forum in April 2020</u>

Our presentation to the AER public forum in April 2020 summarised the three businesses' consumer engagement activities as follows:[24]

CitiPower, Powercor and United Energy ran their consumer engagement based on a consistent approach and using the same Melbourne based staff for each engagement activity.

[24] See slides 12 and 13

Much of the material used and timelines for consumer engagement activities was published on a single website, where customers could also:

- Read information regarding the businesses and their consumer engagement activities
- Find out about the 2021-25 reset process
- Download key documents
- Provide comments on a 'Contact us' form

The consumer engagement activities regarding the upcoming regulatory proposals were branded "Energised 2021-2025".

The consumer engagement activities commenced with the publication of a single Regulatory Reset 2021-2025 Stakeholder Engagement Plan in November 2017 that covered all three businesses – CitiPower, Powercor and United Energy.

This Engagement Plan set out four phases of activities that the businesses would be undertaking. These phases included:

- Understanding customer preferences (2017)
- Exploring future energy scenarios (2018)
- Engagement on the Draft Plans (2019)

The Engagement Plan also set out the engagement platforms that the businesses would be using, which included newsletters, the Talking Electricity website, pop up displays, focus groups, interviews, surveys, meetings, workshops, an advisory panel, and communication around the businesses' Draft Plans.

Since its inception in November 2017, CCP17 has liaised closely with the three businesses.

We sent at least one CCP17 representative to most of the events to which we were invited, but clearly did not have the resource to attend every event. We have generally encouraged the businesses on the paths that they have chosen, on the shared understanding that not every consumer engagement activity will prove successful. The businesses were on a steep learning curve, and much learning came from trial and error.

<u>Strengths of the approach as documented in March 2019</u>

In March 2019, we summarised the strengths of the CP-PC-UE approach to be as follows:

The range of consumer engagement activities that the businesses have undertaken is a strength of the approach. It has enabled a large number of customers to participate in a variety of different ways. The events that we have observed have been well run, with discussions and activities to maintain interest levels of participants. Participants have largely been engaged, and have had free range to say what they want, to present their own views without undue pressure from others, and also to ask subject matter experts from the businesses for clarification where some things were not clear. This avoided discussions going down a wrong track simply though misunderstandings.

Phase 3 of engagement used a "scenario planning" approach which we consider to be a helpful methodological development initiated by this group of businesses. Under the auspice of the Energy Futures Customer Advisory Panel (EFCAP) these sessions encouraged participants to consider the strengths and challenges of three stylised electricity future scenarios. The uncertainty about energy market futures makes the scenario planning approach particularly relevant.

The use of independent facilitators (from Woolcott Research) assisted in the above.

For later forums, Woolcott chose participants from the first larger deliberative forum, which seems to have worked well. They were chosen on the basis of the participants being active, and across a range of demographic characteristics. In this way, they have taken a group of customers on a journey. Overall, the consumer engagement has enabled the business to look at things from a customer perspective.

<u>Gaps or major issues as documented in March 2019</u>

In March 2019, we documented:

> *"We have no major issues with the consumer engagement, which is not to say that everything ran totally smoothly leaving no room for improvement. On the contrary, we witnessed several occasions where staff of the business realised that something was causing confusion or could be improved and made a note to do things slightly differently at the next event.*
>
> *We are pleased that the independent reports from Woolcott do not paint a picture of perfect understanding of customers. There are several examples in the published reports where Woolcott highlights that customer understanding of the options on which they were being asked to "vote" could have been improved."*[25]

CCP17 considers that the Energy Futures Customer Advisory Panel (EFCAP) process is an especially useful approach, which was well implemented, and generated considerable engagement in its initial application. However, over the past 12 months, the role of the EFCAP process and the learning gleaned by the businesses from the EFCAP members has not been clear. As such, it is probably an opportunity that has 'slipped'. Over time, it became unclear whether the group was really still "advising" the businesses as an "Advisory Panel", or rather spending most of its time getting feedback on what the business was doing.

Some EFCAP members were clearly frustrated because they were participating in order to "make a difference" for customers but could not see evidence of that. EFCAP members requested more frequent (monthly) meetings so that they could provide an advisory role, but this did not eventuate. EFCAP met a total of three times during 2018, and the impact on the businesses' activities remains unclear.

We wait with interest to see how the EFCAP process will be reinvigorated, to provide a more pro-active advisory role in the coming months leading up to the regulatory proposals.

<u>Future directions as documented in March 2019</u>

We wrote in March 2019:

> *"The businesses have published their draft proposals, which we have not yet reviewed. We understand that following publication of the draft proposals, the businesses are embarking on Phase 4 of their Engagement Plan, which will comprise further significant consumer engagement, leading up to publication of the regulatory proposals in July 2019."*

The proposed activities include:

- Forums with customers to present what is in the draft proposals and to determine the level of support for the draft proposals,
- further online surveys,
- deep dives with industry stakeholders,
- in-depth interviews with large customers, and

[25] In March 2019, at this point in our Progress Report, we listed a few small examples of this, which are not repeated here.

- ongoing Talking Electricity online customer engagement.

It remains to be seen the extent to which consumer engagement will change the businesses' regulatory proposals or influence their ongoing "business as usual" behaviour.

Our comments on the businesses' draft plans

We commented in July 2019 on the businesses' draft plans.

In our comments on the draft proposal, we noted that each of the businesses had embarked on an early engagement programme with its customers in order that customer needs were well understood by the business. We commended the Victorian DBs for this early engagement approach, and we were supportive of the way they had made these Draft Plans available to Victorian energy consumers and other stakeholders. At that time, we commented that over the next few months, we would keenly observe the way the DBs consider the feedback from the range of stakeholders, interact with their Customer Consultative Panels and Reference Groups, and take this excellent opportunity to best reflect the needs, thinking and suggestions from the community.

CP-PC-UE consumer engagement activities since our March 2019 progress report

Our March 2019 progress report was timed to cover the businesses' activities up to release of their draft plans in January 2019.

At the time, the businesses' regulatory proposals were due to be lodged with the Australian Energy Regulator (AER) by 31 July 2019. Since then, the date for lodgement was delayed by six months until 31 January 2020. The business lodged their regulatory proposals with the AER on 31 January 2020.

Since the consumer engagement described in our March 2019 progress report and before lodgement of the regulatory proposals, we have

- Attended meetings where the businesses presented their draft plans to customer forums and obtained further feedback on how the customers felt their inputs had been reflected in the draft plans,
- Attended deep dives on risk and capex, DER and peer to peer trading, and IT capex,
- Attended joint DB TSS meetings, including one hosted by the Victorian Government,
- Attended Energy Futures Customer Advisory Panel (EFCAP) meetings,
- Attended a meeting with the *VicUtilities* Forum,
- Visited a CP "pop-up" at Melbourne Central, and
- Held several meetings with each of the businesses.

When the businesses lodged their regulatory proposals with the AER on 31 January 2020, the formal consumer engagement pre-lodgement was completed.

Post-lodgement stakeholder engagement

After COVID-19 started to affect meetings in Australia in March 2020, we continued engagement via telephone and electronic remote meeting apps. We engaged directly with the businesses on their regulatory proposals submitted in January 2020, participated in the AER's virtual public forum in April 2020, and had follow-up discussions with the businesses after that forum.

We understand that COVID-19 makes it more difficult for the businesses to engage with consumers. CP-PC-UE have been using electronic means, including placing an interactive multi-media version of their AER Public Forum presentations and their regulatory proposal documents on their 'Talking Electricity' website.

Looking to the future

The businesses' stakeholder engagement attachments[26] to the regulatory proposals set out how feedback from the consumer engagement was used in the businesses' final proposals.

At the completion of the engagement process, the businesses reviewed their process against their evaluation indicators. The businesses summarised this review including network specific indicators collected and whole of Energise 2021-2026 program indicators, and engagement process evaluation outcomes.

We agree with the businesses' conclusion:

> *"We are committed to ongoing engagement with our customers and stakeholders. Engagement does not stop after the regulatory reset process. We are committed to improve our engagement process with customers and stakeholders now and into the future."*

The businesses' stakeholder engagement appendices end with recommendations for the next reset. Engagement does not stop after the regulatory reset process and should be continued as 'business as usual'. We look forward to seeing the businesses' plans for business as usual stakeholder engagement.

[26] CP APP01, PAL APP01 and UE APPP01

4 Revenue

4.1 Forecast Revenue & Bill Changes

With the exception of Powercor, revenues for each of the DNSPs is projected to decrease over the next regulatory period by between 4.5% (CitiPower) and 6.2% (Jemena). Powercor's revenue is forecast to increase by approximately 1%. Excluding Powercor, this is expected to translate into modest bill reductions for residential and small business consumers in 2021-22 ranging from $12 to $181. Bills for Powercor's customers will remain stable with a $4 reduction for residential consumers offset by a $6 increase for small business consumers[27]. Whilst price reductions are welcome for consumers, CCP17 questions whether these businesses could deliver more significant bill reductions for consumers.

4.2 Drivers of Revenue Change – comparative analysis

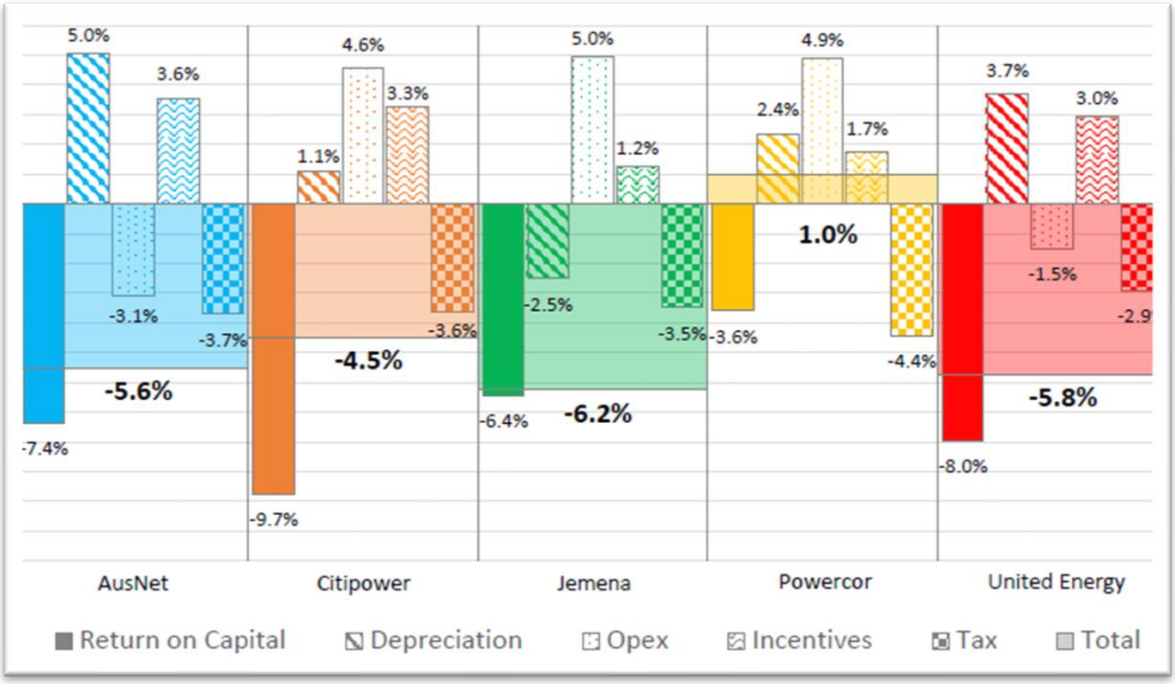


Figure 5: Revenue changes from current regulatory period (Source: AER issues paper)

There are significant factors external to the businesses, such as allowable Return on Capital and the tax allowance which are driving down revenues compared with the current regulatory period. Without these external factors, we highlight that there would be an increase in total revenue and likely subsequent price increases as a result of these proposals.

CCP17 notes that:

- the declining Return on Capital, which generates the biggest price reduction impacts for all businesses except Powercor (tax allowance reductions are bigger);
- opex is the main driver of pressure for price increases for Jemena, CitiPower, Powercor;

[27] AER, Issues Paper, Victorian electricity distribution determination, 2021-26

- depreciation is the main upward price pressure for AusNet Services and United Energy;
- opex is reducing for United Energy and AusNet Services;
- the lower Return on Capital for Powercor at 3.6 % does not align with other businesses, we wonder why?

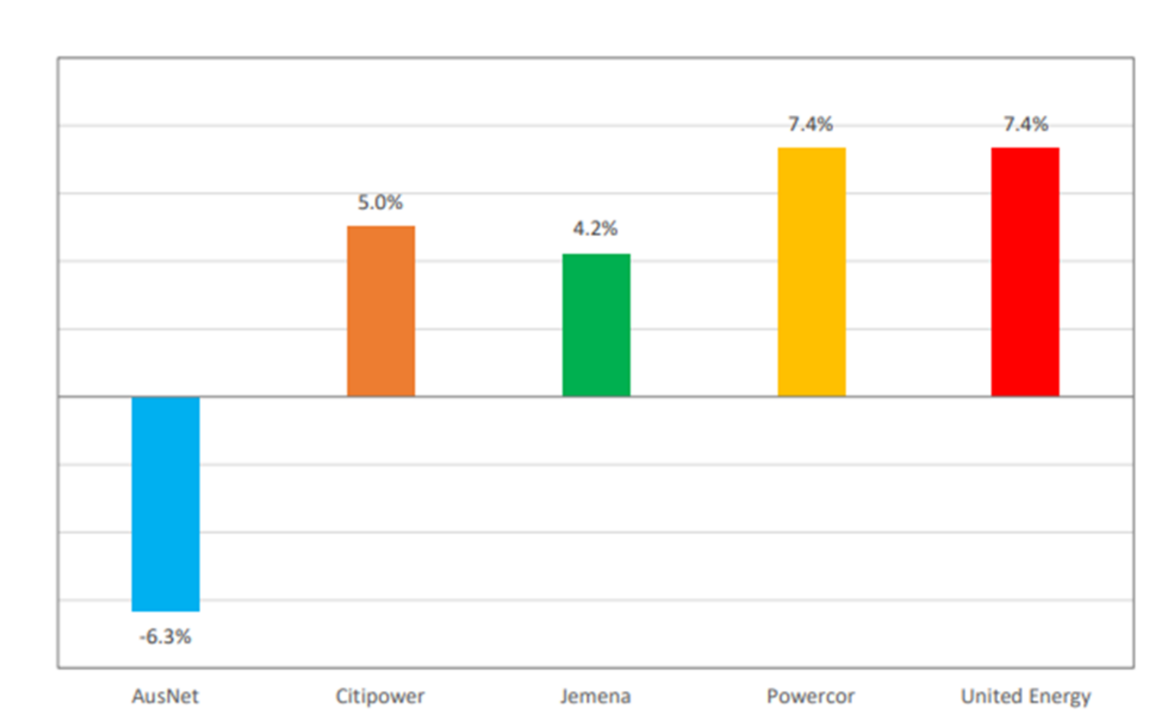
These issues will be discussed elsewhere in this report, however CCP17 contends that, based on the revenue reductions delivered through the lower Return on Capital and tax allowances, further bill reductions should be possible.

4.3 Regulatory Asset Base (RAB)

All networks note in their engagement, the strong preference by consumers to restrict price rises.

However, the level of investment, leading to the increase in the regulated asset base per customer (for all but AusNet), raises real risks of significant prices in the future if and when the allowable return on assets increases. In our assessment, we look for evidence where utilities have considered a revised risk position, the application of innovative solutions and the fact that 'not every NPV positive project needs to go ahead' in order to respect the customers' desire to restrict future price rises.

The RAB, and consequently the allowed economic return to be earned from those assets, are a major component of electricity costs for consumers. A growing RAB locks in costs for decades ahead, with the underlying risk of significant price rises should the allowable rate of return increase. Investment that contributes to an increase the RAB should be considered carefully, in terms of demonstrated requirement as well as efficiency.



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.

Figure 6: Proposed RAB increase per customer (Source: AER issues paper, fig 10)

The RAB for all five DNSPs has increased significantly since 2006, and is proposed to continue to climb into the next regulatory period for all by AusNet Services, as shown in Figure 6.

Much of this historical RAB growth has reasonably occurred as both customer numbers and energy demand rise. The Victorian DNSPs were somewhat insulated from the rapid rise in the value of the assets as a result of investment driven by the aggressive network security standards introduced in most other jurisdictions over a decade ago.

The current proposals apply for further RAB growth. When normalised against the number of customers, RAB continues to grow per customer for all distributors other than AusNet Services as shown in Figure 7.

We have already suggested that the distributors operate under a similar capital-constrained paradigm that almost all major private companies must respect. Such an environment would lead to an inherent focus on managing RAB growth in customer's interests.

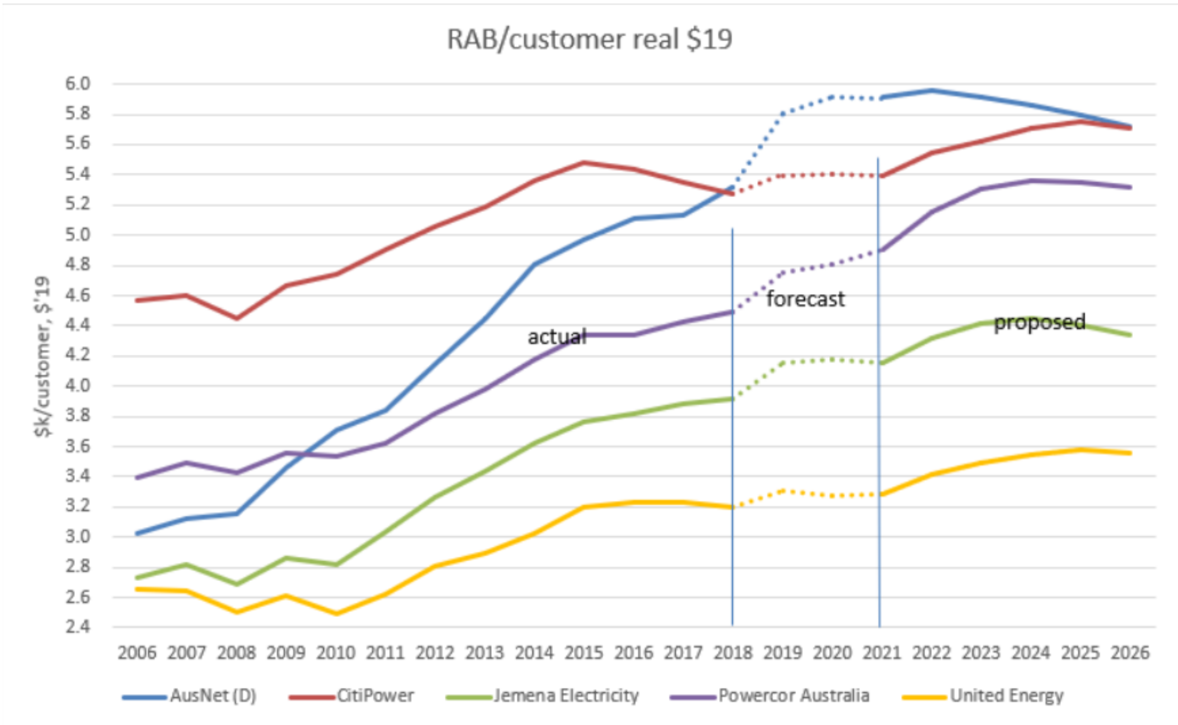


Figure 7: Regulated Asset Base growth (Source: BSL analysis) [28]

4.4 Depreciation

The treatment of depreciation is well established by Australian network regulatory practice, although there is a growing (probably) level of debate about application of accelerated depreciation

Figure 8 shows the depreciation allowance as a proportion of opening RAB for each of the five Victorian distribution businesses with a range of 15%-22%. Depreciation is accepted as a significant component of network business revenue.

[28] CCP17 acknowledges the analysis undertaken by The Brotherhood of St Lawrence, Renew and VCOSS in their presentation to the AER Public Forum, April 2020

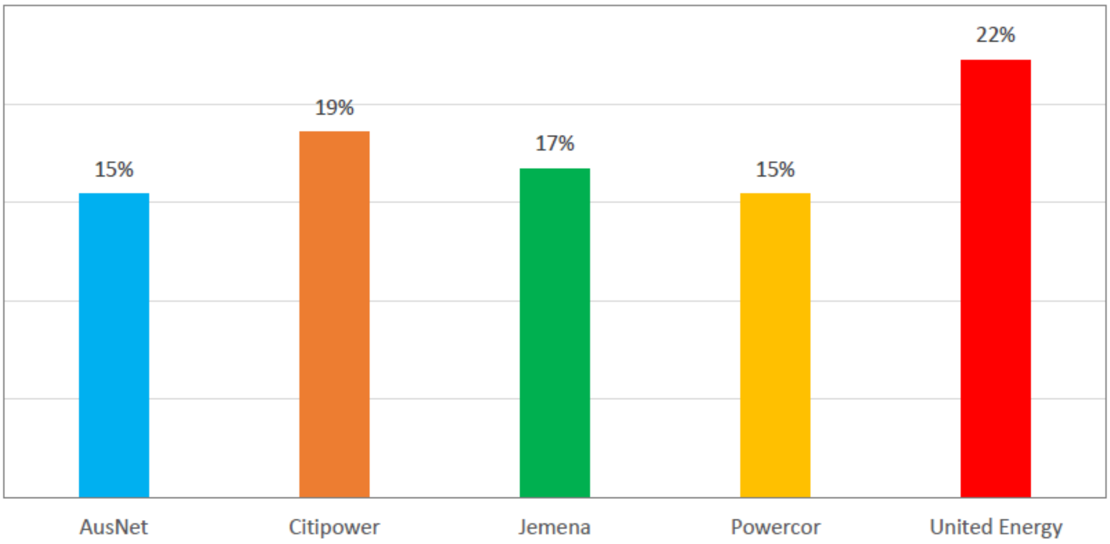


Figure 8: Depreciation Allowance as a proportion of opening RAB (Source AER Issues Paper, Figure 11)

Each of the Victorian distribution businesses have proposed elements for "Accelerated Depreciation," though the language changes from business to business, Jemena for example uses the language of "reducing life" or "re-allocation" for some asset classes. We understand accelerated depreciation to mean that assets have their residual value reduced. We regard that the end impact for customers is much the same as the application of "accelerated depreciation," irrespective of the language used.

The accelerated depreciation proposals for each of the businesses are:

- AusNet is proposing to depreciate 'protection relays' / 'remote terminal units' over 10 years; currently its over 45-50 years. ($200m)
- CitiPower, $7 million to replace older transformers for solar enablement. $1 million to replace PVC service cables ($8m)
- Jemena, no accelerated depreciation but proposing to reduce life for the existing 'Non-network – other' asset class to 5 years from 24. ($8m)
- Powercor, $39 million to replace REFCL assets. $35 million to replace distribution transformers for solar enablement. ($74M)
- United Energy, replacement of older transformers for solar enablement. ($2M)

The AER's most recent consideration of accelerated depreciation has been with the Jemena Gas (JGN) final determination[29] that was made public on 5 June 2020. We recognise that accelerated depreciation is arguably more pressing for gas network businesses than for electricity and that some of the issues are different, however we regard the JGN final decision as pertinent, the AER says:

> *"We have carefully considered JGN's submissions, but we do not agree that its proposed reductions to the standard asset lives are warranted in this final decision. We have allowed accelerated depreciation under the National Gas Rules (NGR) where assets have become stranded in the past. We have also allowed a more limited number of cases where assets were expected to become stranded at a given date.*

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29 https://www.aer.gov.au/system/files/AER%20%20Final%20decision%20%20JGN%20access%20arrangement%202020-25%20-%20Attachment%204%20-%20Regulatory%20depreciation%20-%20June%202020.pdf

> *Having considered JGN's revised proposal, we confirm our position in the draft decision to not accept the reductions to the standard asset lives for new expenditure associated with the 'Trunks', 'HP mains', 'MP mains', and 'MP services' asset classes. We do not consider the evidence of demand and costs outcomes that JGN projected to 2050 and beyond as sufficiently robust. Nor do we consider the proposed solution is well targeted or consistent with the depreciation criteria. Given this, we consider these standard asset lives should continue to be based on their technical lives."*

The critical question is to ask whether consumers are getting good value for accelerated depreciation elements. CCP17 is not convinced by the large time changes for some assets proposed by some businesses, e.g. devices currently depreciated over 45-50 years being depreciated over 10 years, or 24-year current life to 5 year. We do not regard the proposed depreciation lives as relating will to the AER "roll forward model". Solar enablement depreciation also needs further justification.

We suggest that if there are circumstances where reducing lives of assets makes sense, then the adjustment should be made over 2 periods, rather than one.

The JGN final decision effectively dismisses application of accelerated depreciation to that gas network business. We support this approach also being applied to the Victorian electricity distribution businesses, thereby retaining the standard, and reasonable, current approach to depreciation.

4.5 Incentive Schemes

<u>Overview</u>

The Victorian DNSPs are subject to and have proposed a combination of efficiency incentive schemes and performance incentive schemes as shown in Table 1.

Incentive Scheme	AusNet Services	CitiPower	Jemena	Powercor	United Energy
Efficiency Benefit Sharing Scheme (EBSS)	✓	✓	✓	✓	✓
Capital Expenditure Sharing Scheme (CESS)	✓	✓	✓	✓	✓
Demand Management Incentive Scheme and Demand Management Innovation Allowance Mechanism	✓	✓	✓	✓	✓
Customer Service Incentive Scheme (CSIS)*	✓	?	✗	?	?
Service Target Performance Incentive Scheme (STPIS)	✓	✓	✓	✓	✓
F-factor Scheme (Jurisdictional Scheme)	✓	✓	✓	✓	✓
Guaranteed Service Levels (GSL) - Jurisdictional Scheme	✓	✓	✓	✓	✓

* *Jemena has elected not to implement a CSIS for the next regulatory period. CPU are engaging with customers to develop a CSIS for inclusion in their Revised Regulatory Proposal.*

Table 1: Application of Incentive Schemes to Victorian DNSPs

EBSS and CESS

EBSS and CESS are the primary efficiency incentive mechanisms utilised within the regulatory framework. Both schemes applied to each of the Victorian DNSPs during the 2016-21 regulatory period. Proposed carryover amounts to be included in regulated revenues for the 2021-26 period are summarised below.

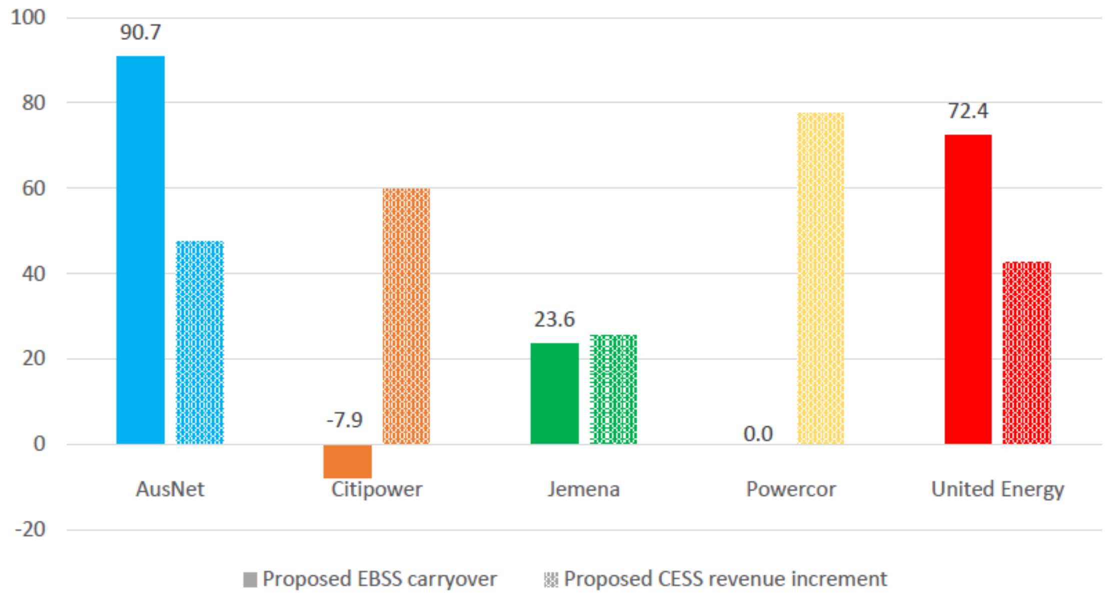

Figure 9: Proposed EBSS carryover amounts Source: AER Issues Paper, fig 12, p37

It can be seen in Table 2 that these schemes are expected to deliver a substantial contribution to regulated revenues for the Victorian DNSPs in the next regulatory period. This is detailed in the following table.

($million, June 2021)	Proposed Revenue	EBSS carryover	CESS carryover	Total Benefit	% of Proposed Revenue
AusNet Services	3186	90.7	44.5	135.2	4.2%
CitiPower	1599	-7.8	56	48.2	3.0%
Jemena	1285	24	26	50	3.9%
Powercor	3695	0.6	72.8	73.2	2.0%
United Energy	2245	72.4	40	112.4	5.0%
Total				419	

Table 2: Analysis of Proposed Carryover Benefits (Source: DNSP Proposals, CCP Analysis)

This analysis immediately prompts questions regarding the structure and application of the efficiency incentive mechanisms, including:

- Are these outcomes consistent with expected outcomes for the Victorian DNSPs which are working at or near the 'efficiency frontier'?
- 9 out of 10 scheme outcomes are positive. There is one relatively small negative result. Is this consistent with establishing efficient regulatory benchmarks?
- Is it appropriate for a business to significantly underspend a capex allowance in one period to achieve a large CESS carryover, and then propose an even higher capex allowance in the following period?
- Is it appropriate for a business to significantly underspend an opex allowance in one period to achieve a large EBSS carryover, and then propose large opex step changes in the next period?
- Combined with outcomes from the STPIS scheme, Victorian DNSPs can be recovering 5-10% of their revenues from customers through the application of incentive schemes. Is this a price premium that customers are willing to pay? Discussion of efficiency incentive schemes did not feature in the Victorian DNSPs' engagement programs.

The following specific matters are highlighted:

- CCP17 notes that EBSS and CESS carryover amounts for some Victorian DNSPs are influenced by changes to the business's capitalisation policy or cost allocation methodology. In their response to CCP17 questions posed in the Victorian EDPR 2021-26 Public Forum, the AER stated that '*Our opex efficiency analysis may also be impacted by changes in cost allocation and capitalisation practices by businesses*'. We urge the AER to examine these practices to ensure that efficiency scheme carryover payments result from true business efficiencies rather than clever accounting practices.
- United Energy's $72.4m EBSS carryover, followed by a $45m opex step change for cybersecurity – could some of this expenditure be brought forward to the current period?
- Powercor's $72.8m CESS carryover, followed by an increase in proposed capex allowance – could some of this expenditure be brought forward to the current period?
- A factor in CitiPower's significant underspend in the 2016-21 regulatory period was the decision not to proceed with upgrading the billing system (valued at $50 million).[30] We question whether this should be excluded from the CESS scheme on the basis that it was not a true efficiency improvement.
- We recognise that a change to accounting standards resulted in operating leases being reclassified as capex from 2018. We question AusNet Services' removal of $4.6m from the 2018-year opex for EBSS purposes, on the basis that the 2018 allowance would have included the operating lease costs.

CCP17 submits that the observed outcomes of the efficiency incentive schemes are not reflective of expected results for businesses at the efficiency frontier. We suggest that a holistic review of incentive schemes is required with a focus on:

- Ensuring that schemes are meeting intended objectives,
- Simplifying and reducing the number of schemes,
- Eliminating overlaps and interdependencies,
- Delivering value for money for customers.

[30] CitiPower, CP APP02, p9

Customer Service Incentive Scheme

CCP17 notes that in December 2019, the AER published a draft CSIS and is continuing to consult on a final design for the scheme. Throughout the process, we have consistently supported the introduction of a CSIS as proposed by the AusNet Services Customer Forum.

In our most recent advice on the CSIS Draft Decision, CCP17 outlined the following concerns relating to the draft CSIS design:

- The need to include maintaining a 'social licence to operate' as an objective,
- Addition of a robust feedback loop in the overall process,
- Ensuring that there are not opportunities for 'double dipping', when combined with other regulatory allowances or incentives,
- Ensuring that the CSIS 'trial' is formally evaluated.

CCP17 looks forward to a decision on the final scheme design being released as soon as possible to provide certainty to the DNSPs who wish to take advantage of the CSIS to support their customer service improvement initiatives.

Consumer Perspectives

CCP17 recognises that as part of AusNet Services' trial of the New Reg process, the Customer Forum have identified areas where AusNet could improve its customer service. AusNet Services and the Customer Forum proposed that the AER develop a CSIS to replace the current incentive for DNSPs to answer telephone calls within 30 seconds. From its origins, it is evident that customer perspectives are inherent in the CSIS proposal from AusNet Services. AusNet Services has put forward a CSIS design based on customer satisfaction measurements for four parameters: unplanned outages; planned outages; new connections; and complaints. CCP17 supports AusNet Services' proposal.

We also support CPU's expressed intention to implement a CSIS. Since lodgement of Regulatory Proposals in January 2020, CCP17 has observed online engagement with CPU's customers in relation to customer service issues via online discussion boards. We encourage CPU to consolidate feedback, including customer support for adoption of a CSIS, and finalise a CSIS proposal as part of their Revised Regulatory Proposals.

CCP17 respects Jemena's decision not to proceed with a CSIS proposal based on feedback from their People's Panel.

CCP17 Observations

CCP17 notes that both the STPIS and the proposed CSIS have a focus on unplanned outages. We advise the AER to examine the correlation between unplanned outage duration and customer satisfaction with unplanned outages and consider whether the combined schemes may be 'double counting' the impact of unplanned outages.

It is our understanding that the CSIS is to be proposed as a 'trial'. Consequently, we expect a formal evaluation of the trial to be conducted in due course. For the DNSPs seeking to adopt the CSIS, CCP17 understand that there is an intention to replace the existing STPIS 'telephone answering' measure with a suite of measures better reflecting priority consumer concerns. Telephone answering remains an important service for many consumers. As part of a trial, we seek to be reassured that speed of telephone answering will continue to be an important metric for DNSPs, even if it does not contribute to their incentive rewards. For this reason, we encourage the AER to require telephone answering metrics to continue to be reported, and for evaluation of the trial to assess any degradation of this service.

Other Incentive Schemes

CCP17 notes that:

- The Victorian Government is currently consulting on changes to the Victorian GSL scheme, which may lead to any changes being reflected in the Revised Regulatory Proposal.
- F-factor targets for 2021 are expected to be announced by the Victorian Government in June 2020.
- All 5 DNSPs have indicated that they will make use of the Demand Management Incentive Allowance Mechanism, although only AusNet Services has nominated a list of specific DM Innovation projects. It is not clear that this scheme is a strong driver of Demand Management programs for the Victorian DNSPs.

We commend AusNet Services for its agreement with the Customer Forum that they will self-fund approximately $750,000 of GSL payments if they do not achieve performance targets for events which are within the control of AusNet Services staff. CCP17 considers this action to be strongly reflective of customer centricity and encourage other Victorian DNSPs to do likewise.

5 Operating Expenditure

5.1 Overview

The operating expenditure criteria (NER 6.5.6(c)), require that costs be prudent, efficient and realistic. Across the proposals:

a) All networks are seeking significant increases for opex allowance in the 2021-26 period, above what they are likely to spend in the current period.

b) Opex allowances have increased for all 5 businesses over the last 2 regulatory periods, some increases have been significant, although there have also been some efforts to reign in opex costs.

c) All Victorian DNSPs have underspent their opex allowances during the current period. How should this be understood against the bids for higher opex cost allowances for the next period?

d) When compared with the regulated opex allowance for the current period, only AusNet Services is seeking less.

e) Main drivers are step changes, cost reclassifications, demand growth (in particular, outer Melbourne residential) and “Solar enablement”.

f) Our main focus is on step change proposals, noting that there are some recurring step changes from the May 2016 final determinations, for example; increased costs for producing RIN data was accepted for the current period (except for AusNet Services), have RIN costs increased to warrant another step change?

g) Base Year: There is some concern about the efficiency of the base year for AusNet Services and JEN (see benchmarking data)

h) Labour cost escalators: There have been no real income increases for many customers in a very low-income growth environment, so proposed labour rises seem out of balance with customer incomes. The economic slowdown implications of COVID19 also mean that these cost escalators will have to be revised.

i) Opex / Capex trade-offs, what are the implications for customers? There has been active consideration and application of a range of opex / capex trade-offs for several years. Is there evidence to show that customers are benefitting from these trade-offs, in reality?

j) The opex productivity improvement (minimum 0.5 of a percent improvement) is not obvious

k) Responding to bushfire risk: Victorian DNSPs have spent considerable effort responding to the horrific 2009 fires and a decade later – another horrific bushfire summer. We expect some revision of recent bush fire impacts in the revised revenue proposals and expect detailed engagement with consumer groups about any changes.

l) Impact of COVID19, this is still largely unknown and is another topic that we expect will be carefully considered in consultation for the revised revenue proposal.

(Note: Consumers have welcomed energy business responsiveness to COVID, for example through the ENA and Energy Charter, provided these initiatives are properly targeted. How these initiatives are funded in the longer term is also of concern.)

5.2 What the Businesses are Proposing

All of the Victorian DNSPs are proposing increases in operating cost expenditure over the next regulatory period when compared with current levels of expenditure.

The following five figures show actual forecast and proposed opex expenditure for each of the businesses.

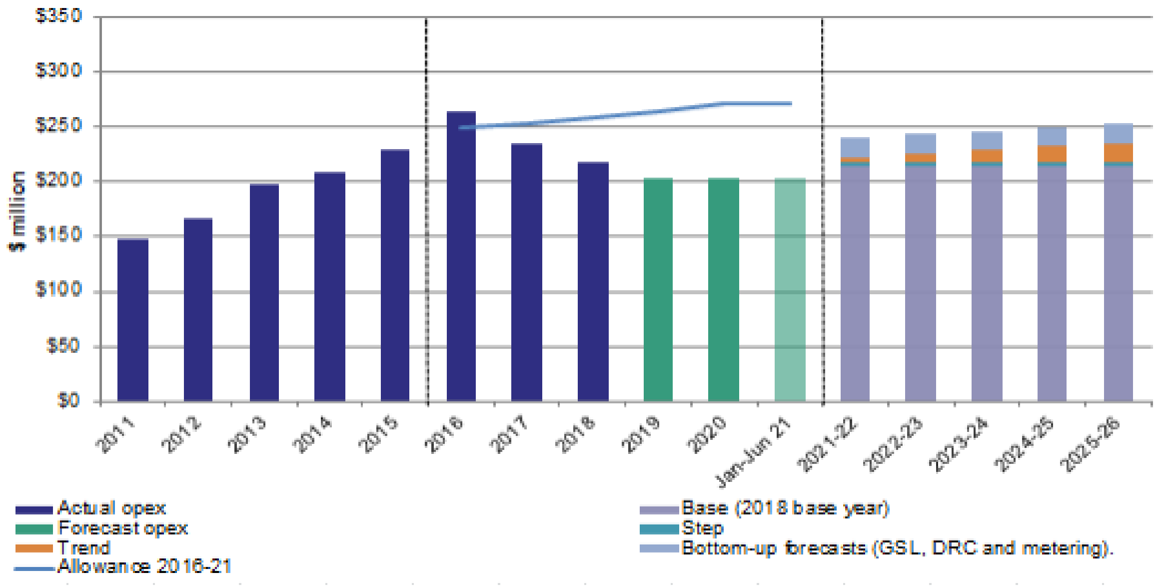

Figure 10: Operating expenditure trend and forecast, AusNet Services (Source: AusNet proposal, part 3)

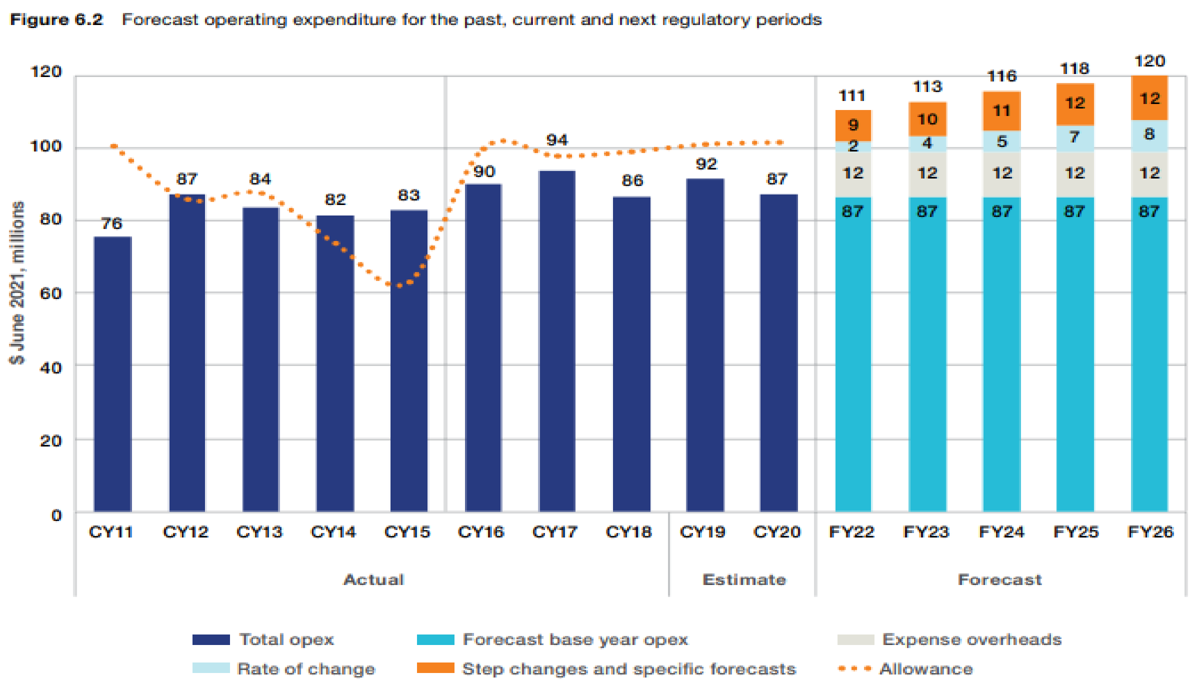

Figure 11: Operating expenditure trend and forecast, Jemena Services (Source: Jemena proposal)

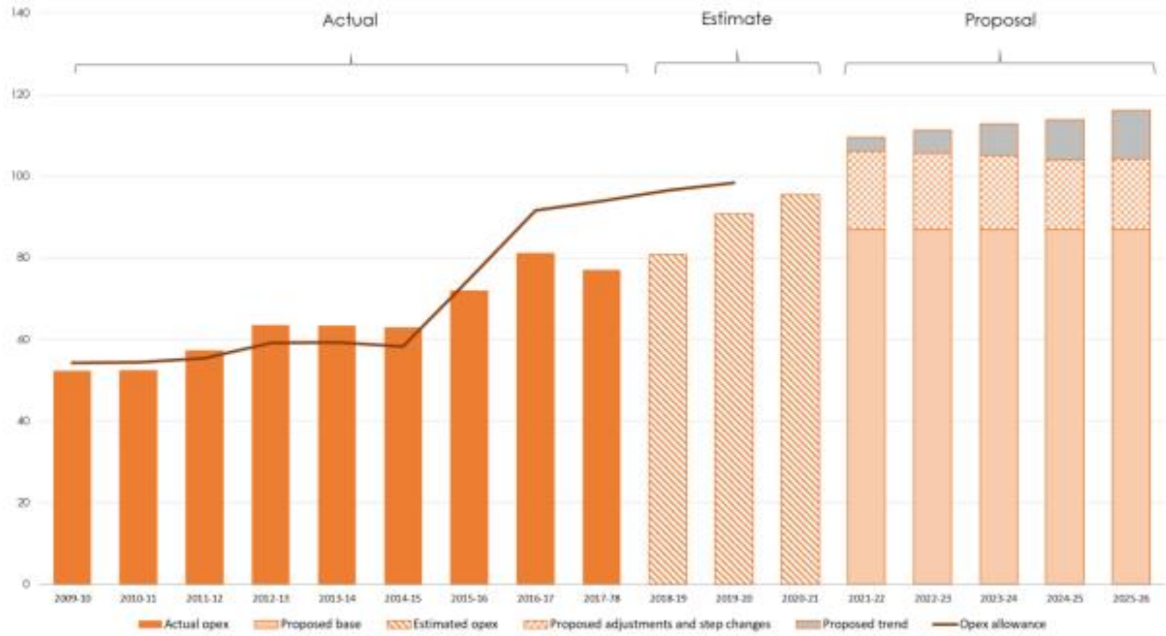

Figure 12: Operating expenditure trend and forecast, CitiPower(Source: AER issues paper)

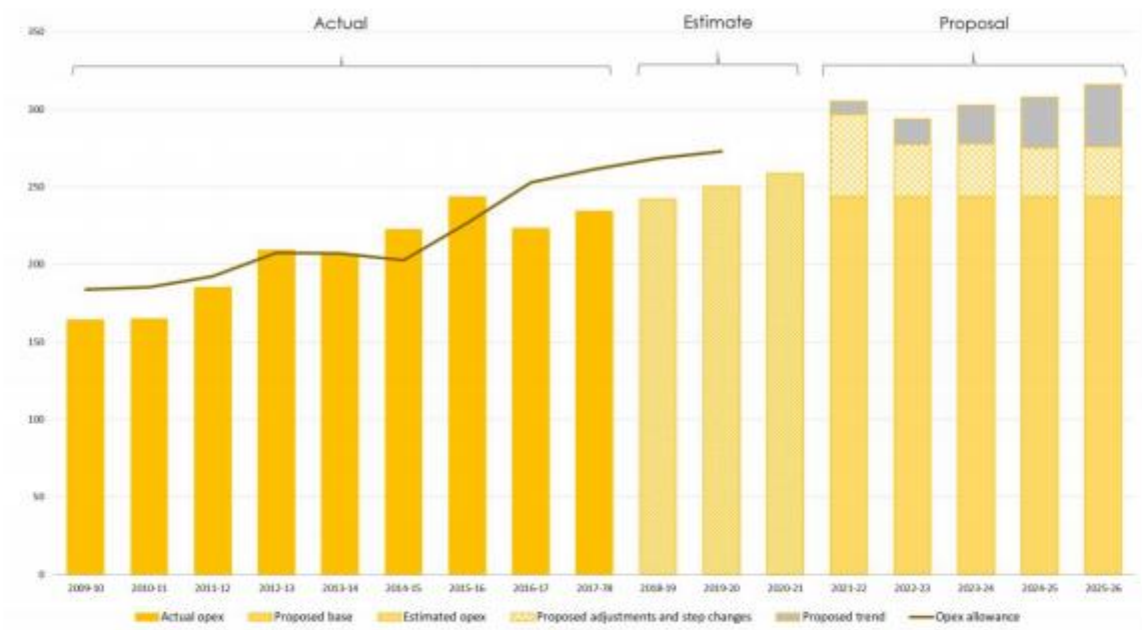

Figure 13: Operating expenditure trend and forecast, Powercor(Source: AER issues paper)

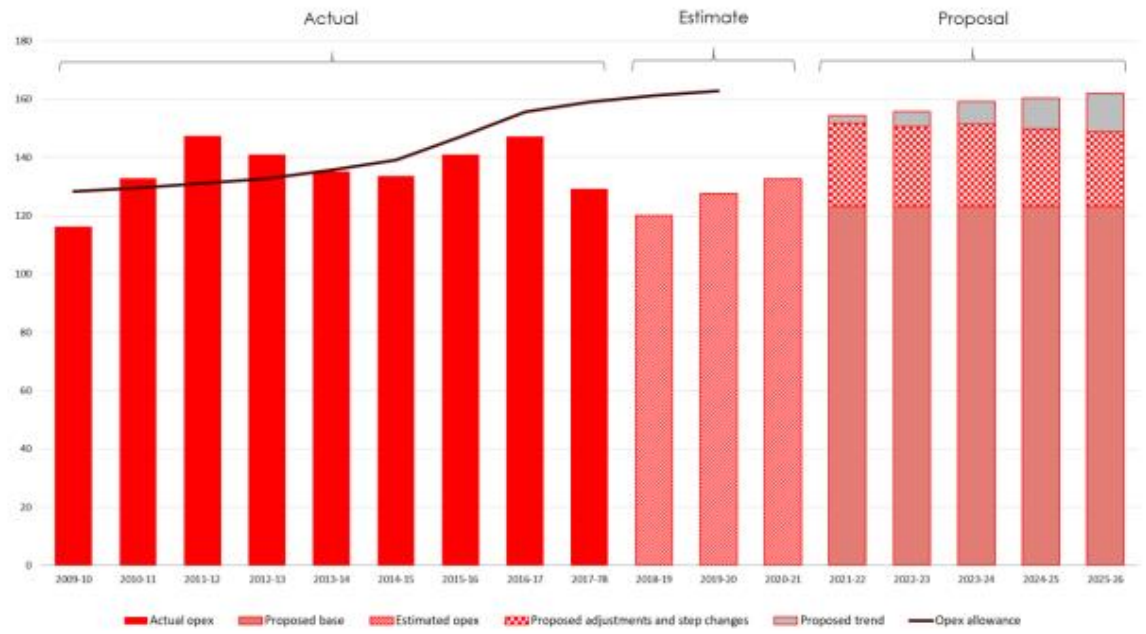

Figure 14: Operating expenditure trend and forecast, United Energy (Source: AER issues paper)

Table 3 summarises the operating costs revenue proposals for the next period with each business proposing real increases over the five years of the regulatory period.

$June 21 (real)	AusNet Services	Jemena	CitiPower	Powercor	United Energy
2021/22	240	111	111	307	156
2022/23	243	112	112	296	157
2023/24	247	116	114	305	160
2024/25	250	118	115	310	162
2025/26	253	120	117	318	163
Total	**1,233**	**577**	**566**	**1,534**	**798**

Table 3: Operating expenditure proposals, 2021-26

Figure 15 below shows operating expenditure proposals.

Each business has underspent against the regulatory allowance for the current period, translating into EBSS payments, while all but AusNet Services are seeking more revenue for the next period than was allowed or spent in the current period. AusNet Services are seeking less than the allowance but more than actual expenditure from the current period.

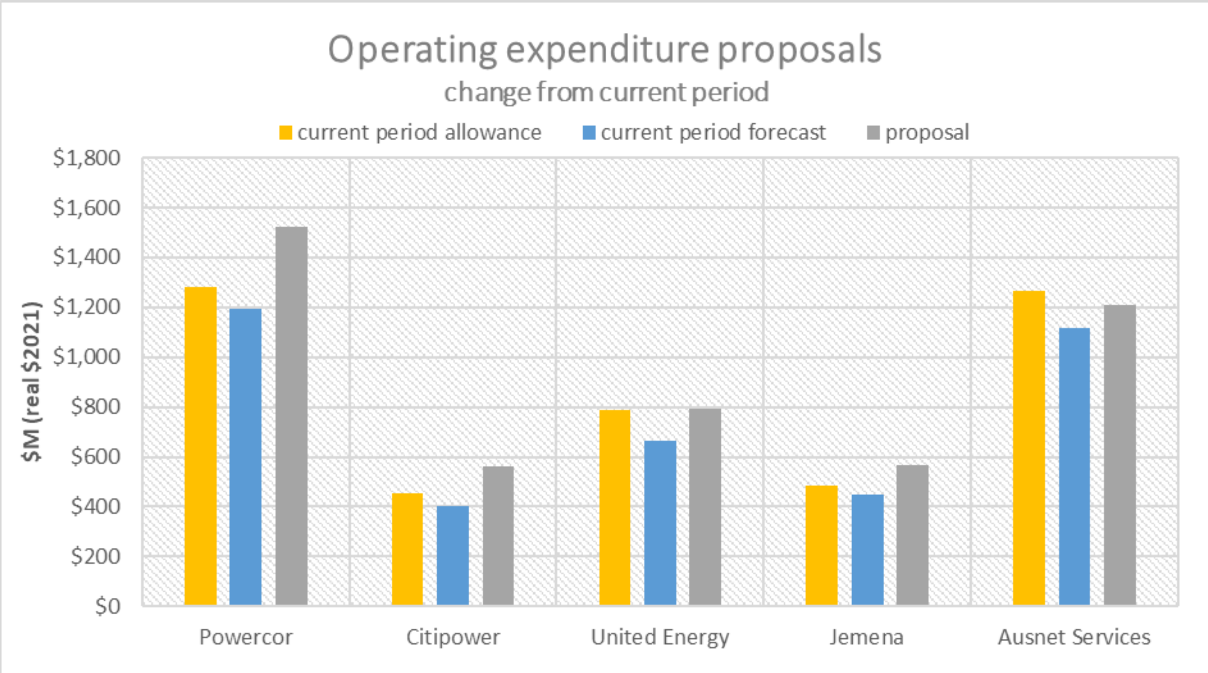

Figure 15: Operating expenditure trends (Source: CCP analysis)

The situation shown in the table above is translated into percentage changes for the proposed allowance compared to both current period allowance and actual forecast expenditure for the current period, shown below in Figure 16.

United Energy is seeking a modest increase compared to the current period allowance but still a 19% increase on actual expenditure. AusNet Services shows a reduction in proposed allowance compared to the current period allowance but an 8.4% increase against actual and forecast expenditure for this period.

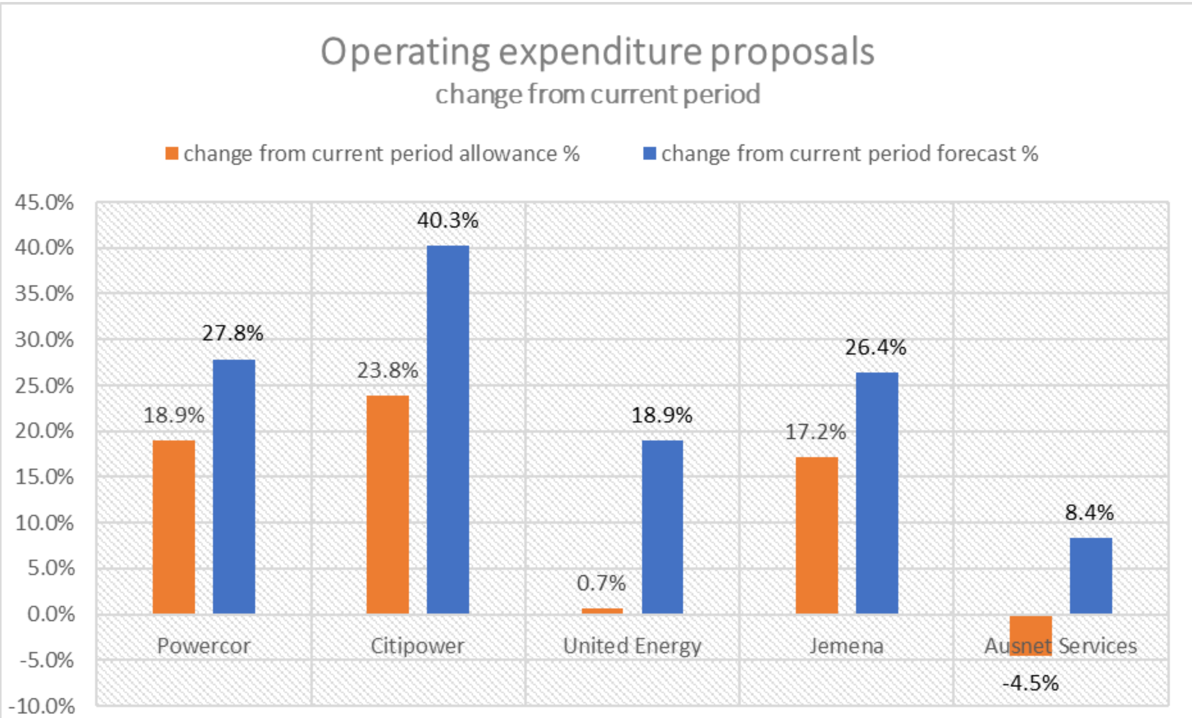

Figure 16: Operating expenditure proposals – change from current period (Source: CCP analysis)

5.3 Operating Expenditure – Base Year and Adjustments

Australian energy network regulation utilises a *Base – Step - Trend* methodology in establishing operating cost allowances, with consideration commencing with establishing the base year expenditure to start the next regulatory period. This is established by choosing an efficient base year from the current period and making category specific adjustments to remove any one-off items and add in adjustments for ongoing costs. The next section considers the choice of base year for each of the five businesses and then considers the category specific adjustments that are proposed.

<u>Opex base year</u>

Two of the network businesses, AusNet Services and Jemena have proposed the 2018 calendar year as the base year while the CPU group have nominated the 2019 calendar year for establishing operating costs for the 2021 - 26 regulatory period. CCP17 has questioned the 2018 choice mainly because of the significant amount of time between 2018 and the commencement of the next regulatory period in July 2021. The extra six months between regulatory periods also gives a sense of a lengthy time lag. In the period of change we have postulated that a base year closer to the commencement of the next regulatory period might give a better outcome for consumers through knowledge of costs closer to the start of the next period.

An alternative would be to use the fourth year of the current regulatory period, rather than the third year as base year, particularly now that 2019 operating costs are known.

For AusNet Services the operating costs for 2019 are lower than those for 2018, while Jemena spent $4 million less in 2018 than 2019. Revealed costs do not indicate a significant variance between the two main base year options for the businesses choosing 2018 as the base year.

Another way of considering the relative efficiency of proposed base years is by consideration of the Opex multilateral partial factor productivity (MPFP) from AER benchmarking.

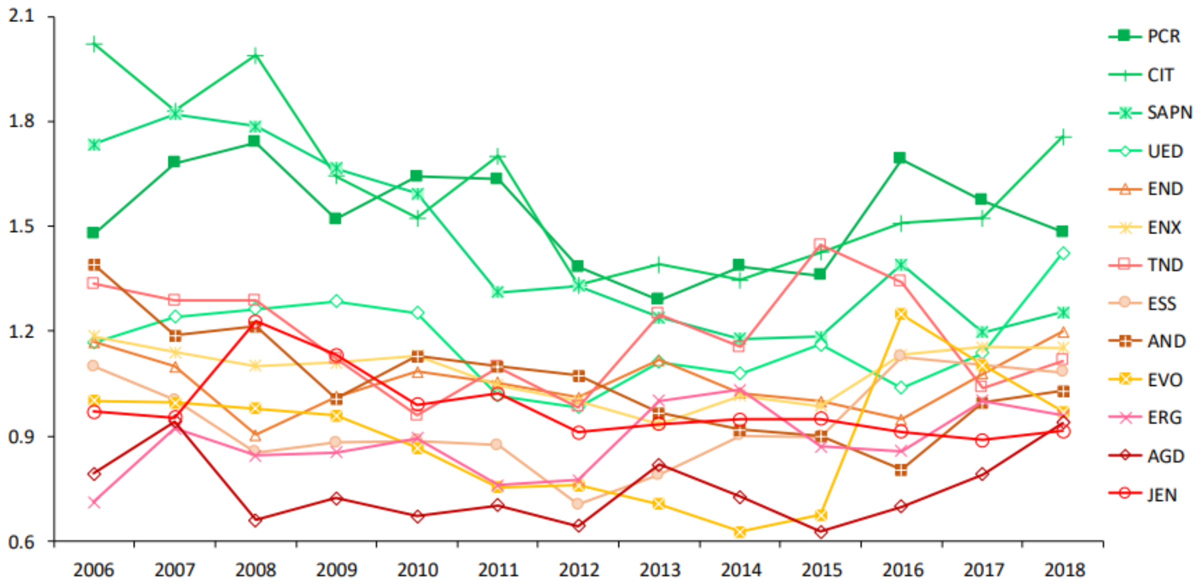

Figure 17: DNSP opex MFP indexes (Source: AER Annual benchmarking Report, Nov 2019)

The 2019 report shows:

- Jemena & AusNet are in the lower range re opex efficiency, though improving over recent years.
- ‘CPU’ group are in ‘best 4’, though United Energy’s MPFP is declining.

- Jemena, who do not rate as well as CPU in efficiency benchmarking

These results have led us to question whether the proposed base year is efficient for all Victorian DNSPs, particularly AusNet Services and Jemena. We asked this question through the public forum process that was conducted remotely rather than it being a face-to-face forum, (due to COVID-19 isolation requirements.)

AusNet Services Opex base year

AusNet Services responded by highlighting that *"The Customer Forum accepted 2018 as a base year, subject to AER confirmation that it regarded 2018 as "efficient" for the purposes of the EDPR process.*"

They also explained that 2018 "*has a lower level of opex compared to the previous two years due to cost reductions arising from a cost savings program we have been implementing for the last two years. This will deliver ongoing savings for customers*."

As part of their input to the public forum EUAA did not support the AusNet Services opex proposal, questioned whether the 2018 base year was efficient. The EUAA commented that "The proposed reductions in opex and capex for the 2020-25 period are relatively small with the price reductions driven as much by falls in WACC than they are by actions actually taken by AusNet." AusNet Services responded that they consider their basic topics to be efficient stating that "Our opex has fallen in 2017 and 2018 and was a 3% positive contributor to our TFP in 2018. While our productivity did decline in 2018, this was due to a poor year of reliability. The AER's 2019 benchmarking report confirms that we are a reasonably efficient DNSP."

The business also said that *"Importantly, the AER has committed to reviewing bushfire risk as an operating environment factor that is not yet incorporated into the benchmarking analysis as well as considering DNSPs capitalisation policies. These issues mean that our relative efficiency is greater than that shown by the AER's benchmarking report*."

AusNet Services also responded to public forum questions saying that "*Since the EUAA's submission, we have also committed to absorbing additional costs within our existing base year allowance. We have also adopted the AER's final decision on opex productivity, which reduces our allowance by 0.5% per annum. Taken together, we are now proposing an annual productivity saving of over 1%."*

In our public forum comments, we stated that we expect to see explicit reference to savings that have been made through the smart meter benefits. AusNet Services responded: *"We are now utilising these systems to carry out numerous distribution functions including, network planning, call centre operations, and outage management. Any cost savings from these activities would be captured by our base year expenditure but are not explicitly quantified."*

ECA said that AusNet Services should use latest data for its base year. AusNet services responded by saying "*At this stage, that would be 2019, which would be the latest full year of data available to the AER. 2018 audited data is the most recent full calendar year data that we available for our regulatory proposal. We are indifferent to the selection of the base year due to the interactions between the opex forecast and the EBSS."*

In our discussions with AusNet Services they described the efforts that have been made to improve their opex efficiency over the current regulatory period, evidence of which is borne out in Figure 10 above which shows an opex cost reduction of over 20% during the current regulatory period. This is a commendable reduction which carries through to the next period along with the annual productivity saving of over 1% that AusNet Services have highlighted in the public forum responses.

While AusNet Services still does not rate well using opex MPFP benchmarking we are satisfied with AusNet Services using either 2018 or 2019 as their base year for reasons including:

- the relative minor difference between operating costs for the two years;
- Customer Forum support for 2018. We understand that the Customer Forum applied significant scrutiny to the question of efficient base year;
- the substantial improvements in operating costs over the current period;
- commitment to operating cost productivity savings of "over 1%" per year for the next regulatory period;
- the role of EBSS in ameliorating the risk of inefficiencies.

Jemena Opex base year

We also asked Jemena about their opex base year selection through the Public Forum process and their response was:

> *"Jemena applied AER's benchmarking techniques (including partial performance indicators, multilateral productivity and econometric methods) as well as performing a comparison to its regulatory allowances to ensure that the base year proposed is efficient and suitable for forecasting opex for the next regulatory period. (Refer to section 4.4 of our opex chapter for more details)."*

Expanding on this response, section 4.4 from the regulatory proposal includes: "*In response to customers' affordability concerns, we have an existing and extensive program underway to optimise the performance of current assets. This program includes targeted measures to reduce costs and improve how our performance stacks up against other distribution networks in Australia.*

For example, when assessing whether a part of the network needs replacing, our first question is whether an asset of a smaller capacity will meet the needs of customers into the foreseeable future. This means we will only invest in the network when absolutely necessary. We are also unlocking network benefits from advance metering infrastructure (AMI)—we outline these benefits in detail later in this document."

We do not find this response compelling nor are we convinced that Jemena's base year is efficient. The business performs poorly against its peers on MPFP benchmarking and does not have the evident opex cost reduction history over the current period that AusNet Services is able to demonstrate. We encourage the AER to evaluate the efficiency of the JEN opex base year.

CPU Opex base year

Each of the three businesses in this group have nominated 2019 as the base year and have given the following reasons, each stating that they "*consider our base year expenditure is efficient*" for the following reasons:

- the AER has consistently classed Powercor as one of the efficiency frontier networks in the NEM, based on its operating expenditure benchmarking analysis.
- the group are subject to an incentive framework to which we have responded and continue to respond.
- The private ownership structure promotes efficient expenditure, evident in savings generated over the past five years.
- The group has among the lowest operating expenditure per customer while continuing to provide a safe and dependable network that is available 99.99% of the time.
- a large proportion of the operating expenditure is outsourced to external contractors who benefit from economies of scale.

- the ensure efficiency of our operations by market-testing and engaging competitive contracts where possible. In 2015, we renegotiated our vegetation management contract which resulted in an ongoing saving to customers.
- labour costs are efficient and competitively priced, and our corporate and field staff are strategically located across the network to minimise travel times and response times in emergency situations.

While we consider every year during the 2016-2020 regulatory period is efficient, we have used 2019 as the base year as it represents the most recent actual audited reported performance that will be available before the AER is required to make its draft decision."

CCP17 agrees that the proposed base year for each of these businesses is efficient for the purposes of applying the building block approach to their regulatory proposals.

5.4 Comparative analysis

Each of the five Victorian DNSPs claims that it is efficient. CCP has had a strong interest in efficiency for some years arguing that genuinely efficient businesses are in the best interests of customers. We have also argued that efficiency is a dynamic process that requires continuous improvement once the efficiency frontier has been reached. Efficiency is often regarded as a more static concept so that businesses that benchmark well, in the AER's benchmarking report, will claim that they are on or near the efficiency frontier and therefore efficient.

- The most recent benchmarking data reinforces the claim by the CPU group that they are efficient though we highlight the need for them to continue to be dynamically efficient and so constantly seek improvement.
- Both Jemena and AusNet Services benchmark as being among the less efficient electricity network businesses in Australia and have made significant efforts in the current regulatory period to improve their efficiency, with the results being more tangible for AusNet Services.
- In nominating the base year for determining operating costs for the next regulatory period, our preference is for the calendar-year 2019 as these results are known and are closer to the commencement of the 2021-26 period, we accept that the application of the efficiency benefit sharing scheme (EBSS) means that expenditure in any year should be efficient.

5.5 Base Year Adjustments

All networks are seeking significant increases in their opex allowances through category specific adjustments and step changes as shown in the following chart. Note that for AusNet Services, most of their proposed operating costs changes are through category specific adjustments, the other four businesses seek greater levels of adjustment through step changes.

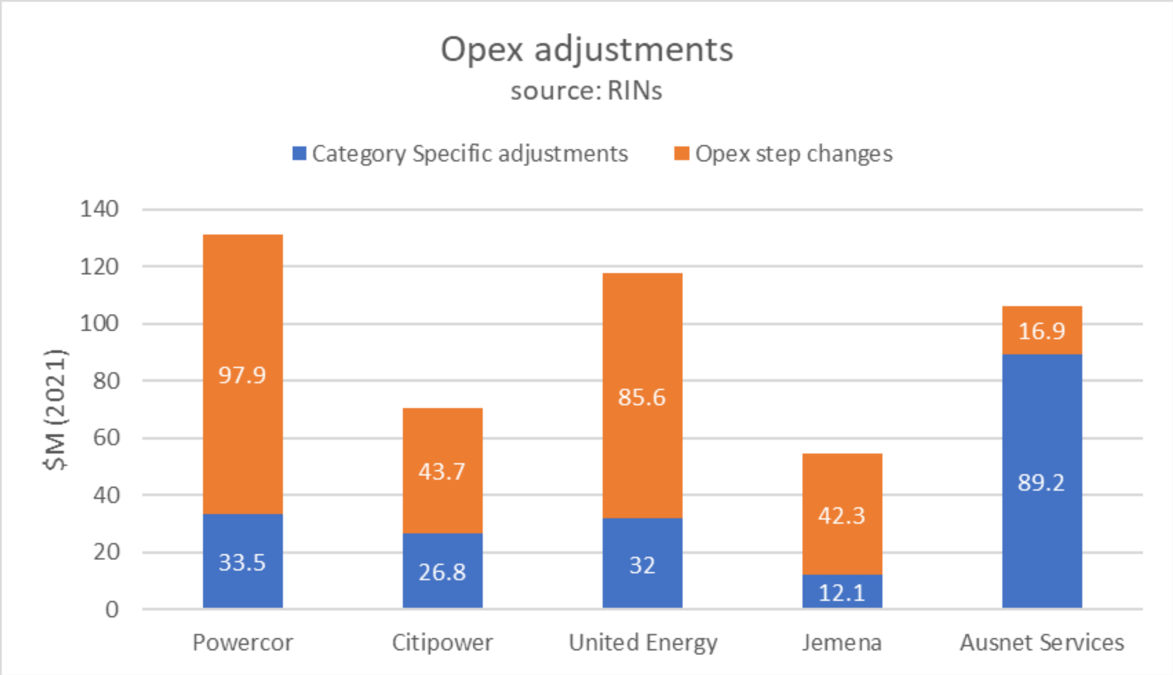

Figure 18: Opex adjustments (Source: RINs)

5.6 Category Specific Adjustments

This proposed category specific adjustments are summarised in the following Table 4.

Category Specific Adjustments $M $2021	AusNet Services	CitiPower	Jemena	Powercor	United Energy
GSL Adjustment	46.7		0.8	1.5	1
Reclass emergency recoverable works		1		1.5	
Reclass AMI and Coms		3		7.5	4.5
Wasted Truck Visits		2		6.1	1.1
Reclass minor repairs to opex		20.8		18.8	26
Emergency recoverable works		1		1.25	
Innovation	1.2				
Rate of change2020 & half 2021		20		50.5	17
Energy Safe Levy			6.9		
Debt raising Costs	11.8		4.4		
Metering reallocation	29.5				
Total	**89.2**	**46.5**	**12.1**	**86**	**49.5**

Table 4: Category-specific adjustments (Source: RINs)

The total value of proposed category specific adjustments is $276m in category specific adjustments over the five-year regulatory period, a significant adjustment particularly when taken in aggregate.

The four most substantial adjustments are:

- GSL adjustments for AusNet Services,
- rate of change for 2020 in the first half of 2021 for the CPU group particularly for Powercor,
- reclassification of minor repairs to operating costs (from capital costs),
- metering reallocation for AusNet Services.

We consider these four adjustments in turn.

GSL Adjustment

AusNet states that "We propose category specific forecasts for two categories of our opex, which are the GSL scheme and the debt raising costs. We removed $6.6 million from the base year expenditure, reflecting actual expenditure in 2018. A bottom-up forecast of these costs is then included in our opex forecast. The bottom-up approach is consistent with the approach taken in the 2016-20 regulatory period as well as more recent AER revenue determinations. We consider that bottom-up forecasts remain the appropriate approach to forecasting these costs".

CCP17 understands that the Victorian Essential Services Commission is undertaking a review of the GSL framework so this may impact provisions for the revised revenue proposal.

We also understand that different businesses have used different approaches in adjusting for GSL payments. AusNet Services in setting 2018 as their base year had a lower than average level of GSL payments so bringing forward average costs provides a larger increase than would otherwise be the case. AusNet Services also remove the full GSL payment value from their base year and add in the new amount giving a larger figure than the CPU group who simply add in the difference in GSL to their base year.

We understand that AusNet Services and the Customer Forum negotiated an approach to GSL payments where AusNet Services will self-fund GSL payments for aspects that it regards as controllable. CCP17 is not convinced that the increase to the base year to adjust for some GSL self-funding correlates with the GSL category specific adjustment that AusNet Services have proposed.

We are satisfied that the other businesses proposed adjustments are reasonable at the time of lodging this submission (10th June 2020), recognising that there may be subsequent changes from the Victorian Government.

Rate of Change for 2020 and half year 2021

Powercor explain this adjustment "we have added to the base year the efficient level of operating expenditure determined by applying a rate of change, comprising the real price escalation, output growth and productivity. In accordance with the AER's approach, the rate of change is used to trend forward our base year expenditure to the start of the new regulatory period.

Reclassification of minor repairs to opex

AER 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.

CPU group explain the adjustments as follows:

"*We are proposing to reclassify 'minor repairs' from capital to operating expenditure.*

Typically, minor repairs include labour-intensive work that results from asset failure or identified defects that could result in an imminent asset failure (if not repaired). Treating minor repair costs as operating expenditure better reflects the nature of the work—the costs are incurred to maintain the age of the asset and the work does not result in the creation of a new asset.

We consider these costs to be more akin to maintenance and repair which is immediately expensed, rather than refurbishment or replacement of assets that are depreciated over a longer period. We have adjusted our base year operating expenditure for the total cost of minor repairs in 2019 and removed forecast minor repairs from our capital replacement forecast.

These changes are net present value (NPV) neutral, which means customers are no worse-off in the long term."

We note the trend to reallocate some restorative work, particularly on overhead lines, as repairs rather than asset replacement. Given that the work does not impact the value of the asset in any appreciable way, we agree with the proposal to reclassify a portion of cable and conductor minor repairs from capex to opex.

We encourage the AER to examine the value of these adjustments.

Metering reallocation

AusNet Services explains this proposed adjustment as follows:

> *"We are leveraging our AMI data to enhance the delivery of our standard control services, including through improving network planning, demand forecasting and network operations. For the current regulatory period, the AER accepted that a portion (36%) of our metering system costs should be allocated to standard control services.*
>
> *However, the trend to using this data in the delivery of standard control services is continuing to increase. Consequently, we do not consider the apportionment used in the 2016-20 decision will reflect the usage in the 2021-26 regulatory period.*
>
> *Therefore, the allocation used in the 2016-20 regulatory period needs to be updated. Additionally, we consider that the AER's decision should allow for a more flexible approach to allocating these costs within the 2022-25 regulatory period, which is consistent with our Cost Allocation Methodology.*
>
> *Our proposed approach will ensure that the allocation of costs accurately reflects the usage of the systems as it changes over time. As already explained, while this reallocation of increases our opex allowance it is offset by an equivalent reduction in the cost of our metering services."*

Noting that there was an allocation for a share of metering costs to be allocated to standard control services in the current period, we look to the AER's technical expertise to assess the reasonable reallocation for the next period.

Other -innovation fund

While the cost adjustment for the innovation fund proposed by AusNet Services is modest, the concept is really important and supported in concept by CCP17. We also understand that it was supported by the Customer Forum which we regard as significant. The question is more the best way to treat the innovation fund from the point of view of efficient management and so that customers get the best outcomes. We note that Ausgrid has an innovation program that is overseen by stakeholder reference group. There is merit in this approach.

A key question is whether the innovation fund is a one-off or recurrent expenditure? We also ask whether the Innovation fund is an allowance sought or are there specific innovation projects that should be considered as part of opex or capex expenditures, or a mix of both?

Perhaps an Innovation Fund should be regarded as a category specific forecast so that it does not get lost simply in recurrent costs. We also question whether the innovation fund should be tied more directly to specific proposed innovation projects?

Comparative analysis

There are some notable issues in the approaches across businesses, such as:

CPU choosing to reclassify some minor line repex as repairs, this will require further investigation about best approach by the AER.

AusNet is seeking a significant GSL adjustment of $46M, noted in the RIN as 'payments for failure to meet GSLs'. There are adjustments to the base year that warrant consideration by AER, noting that AusNet Services is self-funding what it considered to be the controllable aspects of their GSL payments. We also note and give credence to the Customer Forum for their negation on these aspects of GSL payments.

5.7 Step Changes

Jemena sums up the general view of the five DNSPs, in saying: "For each step change proposed, we have only included new obligations that we cannot avoid or change in the market where Jemena has no ability to influence. In all case, we have considered the options available, through market testing and options analysis, and have only included those costs that we believe meet the operating expenditure criteria."

CCP17 has considered that there are three criteria for assessing whether a proposed expenditure meets the requirements for a step change:

- Legitimate obligations or capex / opex trade-offs.
- Something that is new and exogenous, meaning that is imposed from outside of the business.
- Recurrent, or likely to be recurrent, it cannot be a one-off cost.

A proposed expenditure that meets either the first or second criterion, as well as the third criterion, is highly likely to be justified as a step change, being an increase in operating expenditure that customers will pay for. Step changes can be negative, providing savings customers, but in practice there are very few examples of a negative step change.

Materiality

In considering the significant number of step changes that were proposed by the five Victorian network businesses for the forthcoming regulatory period, we observed that there were proposed step changes that did not meet strict interpretation of either the first criterion or the second criterion, because they are existing costs and recurrent. However, the rate of increase is likely to be much higher than could reasonably have been expected by the business when considering past and current costs. Externally imposed levies and insurance premiums are a couple of examples from the proposed step changes.

This gives rise to a fourth criterion: materiality. By this we mean increases in costs for an existing recurrent item that an efficient business could not readily absorb into their cost structure. This is perhaps a function of the AER and consumer expectations that a 0.5% operating cost productivity 'dividend' be provided by network businesses to incentivise dynamic operating cost efficiency.

We then ask to what level of increase on the existing operating cost would be material enough for to be considered a step change?

The short answer of course is that no single percentage figure can be applied as a hard and fast rule. To apply some guidance to our thinking was started with the view that material increases could only apply to items with a cost of over $1 million per year.

We then considered that an increase of CPI and probably a doubling of CPI would be expected to be absorbed as a standard operating cost increase, so rounding up, any increase under 5% per annum could be expected to be absorbed by business in the current economic climate.

We then considered that any recurrent cost item that increased by more than 50% could be readily regarded as material.

This then leaves a fairly large band of "grey". We consider that materiality increases as the shade of grey increases from about a 5% increase to 50% increase with the decree of materiality being a lower percentage for higher cost expenditure. While very much a "rule of thumb" we have considered that the scale provides some basis for initial consideration of materiality with each expenditure increase being then reviewed from a reasonableness perspective.

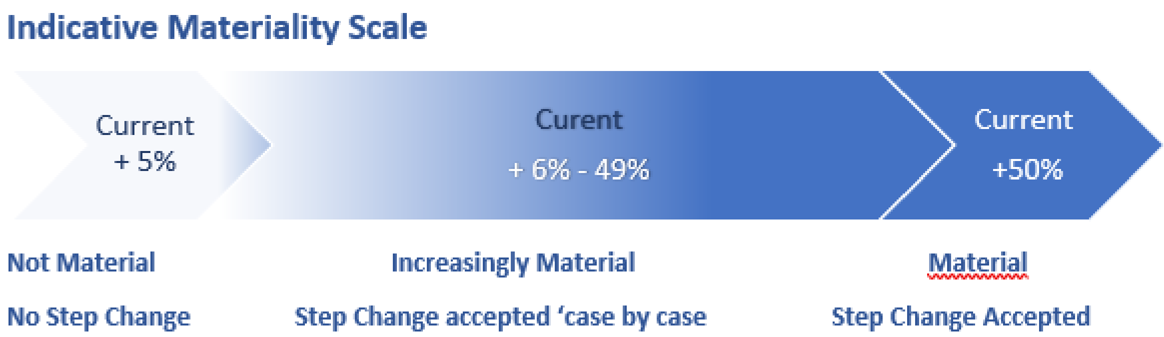

Figure 19: Operating expense materiality scale (proposed)

<u>Proposed Step Changes 2021-26</u>

Over the course of about 2 ½ years, while these recent proposals have been developed, the step changes 'story' has been one of ongoing evolution. Circumstances have changed between the development of draft plans and the recent proposals lodged and have continued to change since lodgement of the proposals.

As a starting point for considering step changes proposed we commence with the step changes listed in the regulatory proposals as initially lodged. These are summarised in the following Table 5.

Step Changes	Powercor	CitiPower	United Energy	Jemena	AusNet Services
5 Minute Settlement	4.9	1.9	3.9		3.6
Cybersecurity	14.5	14.4	45.9	2.9	4.7
EP amendment	9.6	6.1	11.8	4.2	
ESV Levy	4	1.5	2.5	6.9	
Financial Year RIN	1.8	1.8	1.8	0.5	
Yarra Trams		14.4			
Insurance Premiums	5		2.2	28.8	

Step Changes	Powercor	CitiPower	United Energy	Jemena	AusNet Services
REFCL ongoing	13.3			1.3	5.9
Reclassification of HBRA	21.5				
Debt raising Costs				4.3	11.8
Solar / future grid	6.2	1.3	4.2	3.8	
IT cloud migration	5.9	2.3	4.7		2.6
EDO fuse replacement	11.2				
Other			8.6	0.9	
Total	**97.9**	**43.7**	**85.6**	**42.3**	**16.9**

Table 5: Proposed step changes, 2021-26 (Source – RINs)

Circumstances have changed since the step changes were proposed in the January 2020 regulatory proposals, in particular the arrival of COVID-19. While the implications of this pandemic are not fully known, there have been revisions to some of the proposed step changes. At the date for the submission, we were aware of the following changes.

The CPU group has written to the AER saying "*Our proposals, as submitted in January 2020, are based on regulatory obligations assumed to be in effect during 2021–2026. Since the submission of our proposals, a number of presumed regulatory obligations have changed or been deferred. We have assessed the impact of these changes and have consequently made the following amendments to our 2021–2026 proposals"*

Those changes are, in summary:

- withdrawal of the step change, and a significant reduction in the capital expenditure program, related to meeting the new obligations of Environmental Protection (EP) Amendment Act 2018—for CitiPower, Powercor and United Energy
- withdrawal of the reclassification of the 'food belt' to high bushfire rated area (HBRA) step change—for Powercor
- reduction in the Rapid Earth Fault Current Limiter (REFCL) incremental ongoing operating costs step change—for Powercor."

The reduction in the Powercor REFCL incremental cost step change has been amended from $13.3 million to $8.4 million.

We are also aware of likely reductions in step change costs in the areas of:

- Victorian government / essential services commission of Victoria licenses and fees
- deferral of five-minute settlement implementation timing

The following considers the various step changes in turn including CCP17 opinions about those that meet the criteria listed above and those that do not.

5 Minute Settlement

The Australian Energy Market Commission (AEMC) has advised that the implementation of the five-minute settlement and global settlement programs be delayed.

Implementation of the five-minute settlement process meets the criterion of being new, exogenous and ongoing and so qualifies as being an acceptable step change. The unknown question at time of writing is the extent of downward revision of the initial costs proposed due to the delay in implementation.

The information on the AEMC website regarding the delay is shown in Table 6.

Delayed implementation of five minute and global settlement *Rule Change: Open* *Overview:* *On 9 April 2020, the Australian Energy Market Operator (AEMO) submitted to the Commission proposing an urgent rule be made to delay the commencement of the Five-minute settlement (5MS) and Global settlement and market reconciliation (GS) rule changes by 12 months.* *AEMO has proposed the delay in response to the potential impact of COVID-19 on the energy industry. AEMO suggests that a delay to 5MS and GS would free up both human and financial resources which would be under strain during this period, ensuring the ongoing supply of energy and appropriate customer support.* *Consultation paper:* *On 14 May 2020 the AEMC published a consultation paper seeking feedback on the proposal. Key issues the Commission are seeking feedback on include:* *a) How has COVID-9 impacted participant cash flows and capacity, and what would be the impact of a delay on participant cashflow and capacity?* *b) How would a delay impact the contract market and participant risk management?* *c) What would be the impact of delaying the benefits of 5MS and GS by 12 months?* *d) If there were to be a delay, is 12 months the most optimal delay length, or is there another delay length that is more appropriate?* *e) Are there any implications for other parts of the National Electricity Rules or AEMO/AER/Information Exchange Committee procedures and guidelines?"*

Table 6: AEMC website advice - delay to 5-minute settlement rule

Cybersecurity

The actions proposed under the heading of cybersecurity appear to be legitimate obligations that are imposed by the Commonwealth Government. The step change meets the criterion of being new and exogenous. We expect that there will be ongoing operating cost elements associated with cybersecurity but that these will diminish from initial implementation.

Our interest is in the most efficient meeting of the obligation and the process to review one-off and ongoing costs for application to base year calculations for future regulatory proposals.

Environmental Management legislation

This proposal has been withdrawn by the CPU group and retained by Jemena, who state that the step change that they have proposed in based on known information that continue to apply in their situation.

ESV levy

We observe that some businesses have proposed this is a step change whereas AusNet Services regard it as a change to their base. We also regard this as an exogenous and ongoing operating cost, we see merit in uniformity of approach in dealing with it across the five businesses. We expect the AER to determine whether this is a step change or adjustment to opex base year.

Financial Year RIN

We understand that this step change relates to additional work required to prepare the Regulatory Impact Notices for the six-month extension to the current regulatory period. Step changes for RINS were approved for Jemena, CitiPower, Powercor and United Energy at the start of the current regulatory period so given that additional ongoing costs for RIN production is already included in the base year, the question is whether this is a new or externally imposed cost and whether the cost increases for a one off additional period are material?

The CCP17 view is that this proposed step change is not an ongoing cost, because the recurrent costs for RIN development were incorporated into the current regulatory allowance. We do not consider this step change proposal to be ongoing nor material enough to warrant it being regarded as a step change.

Yarra Trams

This proposal relates to the relocation of poles used by Yarra Trams that are also used by the electricity network, CitiPower. This is a one-off cost and so does not meet the step change criterion of being recurrent. However, without having examined the costs in detail, we are satisfied that in principle the proposal is an efficient expenditure. Therefore, the question is more about how to treat it from a regulatory point of view rather than the merit of the project

We suggest that probably a better way to treat this project is for it to be regarded as a category specific adjustment.

Insurance Premiums

CCP17 accepts that insurance premiums will rise significantly and that the step change proposal is one that is primarily about materiality given that insurance is an ongoing cost with well-established business processes for managing it. We also note that JEN observes that they are different in this category to the CPU group, who quite possibly had a significant increase in premiums as result of the last round bushfires and the subsequent Royal Commission. Perhaps Jemena has only been impacted more recently?

Insurance premiums are factored into operating cost and a prudent business would expect growth in premiums.

CCP17 also understands that the global insurance market for energy networks is highly constrained with a small number of potential providers. We are also aware of global disruptions to energy network insurance markets, particularly as result of California bushfires, there is also growing nervousness in insurance industry about heightened bushfire risk in Australia. Consequently, we accept the network arguments that insurance premiums will almost certainly be dramatically higher than for past years. We also accept that insurance is a necessary business cost.

Consequently, the CCP view is to accept that any reasonable materiality threshold will almost certainly be exceeded in the next regulatory period and therefore accept this as a step change, to be reviewed in the revised revenue proposal by which time we expect businesses will have more information from their insurance brokers.

REFCL ongoing

Some aspects of this have already been approved as contingent projects and it is a legislated requirement. The AER role is to check efficiency of implementation

Debt Raising Costs

CCP17 regard debt raising costs as an ongoing expense for any network business and so question whether this can be justified as a step change, considering the criteria summarised above. Based on our understanding of this proposal, we do not accept it as a step change.

Solar / Future Grid

All except AusNet Services have this is a step change, JEN called it future grid. The AER observed that it is not a regulatory obligation so what is the driver? Of relevance is the recent SAPN proposal, where $3-$4 million was sought for low-voltage network management, so the SAPN final decision will be relevant here. AusNet Services seem to be the outlier.

IT Cloud migration

This is considered as part of a capex /opex trade-off and is acceptable as a step change where there is net benefit to customers.

EDO fuse replacement

The CCP17 view is that this is a capital cost, not an operating cost and so should not be built into the operating cost base. This should not be regarded as a step change.

Step Change Revised	Powercor	CitiPower	United Energy	Jemena	AusNet Services
5 Minute Settlement	4.9 ✓	1.9 ✓	3.9 ✓		3.6 ✓
Cybersecurity	14.5 ✓	14.4 ✓	45.9 ✓	2.9 ✓	4.7 ✓
EP amendment				4.2 ✓	
ESV Levy	4 ✓	1.5 ✓	2.5 ✓	6.9 ?	
Financial Year RIN	1.8 ✘	1.8 ✘	1.8 ✘	0.5 ✘	
Yarra Trams		14.4 ✘			
Insurance Premiums	5 ✓		2.2 ✓	28.8 ?	
REFCL ongoing	8.4			1.3 ?	5.9 ?
Debt raising Costs				4.3 ?	11.8 ?
Solar / future grid	6.2 ✓	1.3 ✓	4.2 ✓	3.8 ✓	
IT cloud migration	5.9 ✓		4.7 ✓		2.6 ✓
EDO fuse replacement	11.2 ✘				
Other			8.6	0.9	
Total	**61.9**	**35.3**	**73.8**	**53.6**	**28.6**

✓ CCP agrees, subject to analysis	✘CCP does not support	? no position

Table 7: Opex step changes - CCP view (summarised)

<u>Comparative analysis</u>

There are some notable issues in the approaches across businesses, such as:

- The cost to undergo operational changes to meet cybersecurity obligations can vary significantly based on current organisational arrangements
- Some AMI costs are being transferred to standard control services
- Most utilities continue to invest in ICT cloud services. The capital savings from this action are not clear as ICT capex reductions, while opex costs are maintained and often extended. This is another adjustment that will require AER attention, alongside other ICT costs and trade-offs.
- REFCL systems require ongoing attention, such as tuning, representing opex costs of up to $13M in Powercor's case.
- CCP recognises that many of these changes result from legislative and industry requirements, although we seek further clarification that some of the proposed adjustments are valid, efficient and demonstrably a recurring operating cost of the business.

5.8 Trend Forecasts

All Victorian distributors are forecasting growth in customer numbers, the circuit length of their networks and in maximum demand in 2021-26, and the businesses are forecasting lower growth in energy throughput, with AusNet Services forecasting a decline in energy throughput over the forthcoming regulatory period.

In general, the forecasted peak demand increase may be overstated. Any impact of the expanded uptake of time-of-use for customers installing rooftop solar may counteract peak demand growth. Conversely, the use of reverse-cycle air conditioners, especially in new subdivisions, may also impact demand growth. It is recognised that the emerging economic challenges will have an effect on forecasts, and we expect in the revised proposal utilities will revise forecasts and the impact on connections, large connections, solar enablement and demand-driven augmentation.

Forecasts of energy usage, peak demands and connections (new connections, and existing connections disconnecting) will need to be revisited in light of the impacts of COVID-19 on the economy. AEMO forecasts are also likely to be revised in light of COVID-19.

<u>Labour real price growth</u>

In the past the AER has used an average of the forecasts from the networks' forecaster (usually BIS Oxford) and the AER's forecaster (Deloitte) to assess real cost escalation. In earlier CCP reports in other jurisdictions, we encouraged the AER to review this averaging approach, particularly in the light of the evidence provided by Business SA on subdued growth among its members.

Based on the latest forecasts by the two consultants, Figure 20 shows that the AER's approach results in an average of about 0.5% lower annual increase in real labour costs[31].

[31] See Revised Proposal Attachment 3 p. 23

	2020/21	2021/22	2022/23	2023/24	2024/25
BIS Oxford Economics %	1.11%	1.28%	1.44%	1.60%	1.33%
Deloitte Access Economics %[56]	0.41%	0.37%	0.34%	0.45%	0.44%
Average %	**0.76%**	**0.83%**	**0.89%**	**1.02%**	**0.89%**

Figure 20: Real Labour Cost Escalators (Source – Revised Proposal Attachment 3 p.30)

This averaging approach was changed by the AER as part of the Draft Decisions for SAPN and EQ processes where comparison of the relative accuracy of the two forecasts led to the conclusion[32]:

"Based on this analysis, we now consider that Deloitte's utilities industry real WPI growth forecast, rather than BIS Oxford Economics', or an average of the two, better reflects actual Australian utilities real WPI growth."

The AER's approach is supported as it better reflects the actual growth that has been observed and the advice received from stakeholder groups regarding expected growth.

Very recently the AER has updated their thinking in the Energy Queensland and SAPN final decisions [33] that were made public on Friday 5th June 2020.

The AER says *"to forecast labour real price growth we have used an average of the forecasts of growth in the utilities WPI for South Australia as forecast by Deloitte and BIS Oxford Economics. SA Power Networks also used an average of utilities WPI growth forecasts for South Australia from BIS Oxford Economics and Deloitte.31 This is a change from the approach we used for our draft decision, for which we only used the forecasts from Deloitte."*

This decision on labour price escalator is further explained in the comments:

> *"We have applied a forecast non-labour real price growth rate of zero. This is consistent with our draft decision and SA Power Networks' initial and revised proposals.*
>
> *We applied benchmark input price weights of 59.7 per cent and 40.3 per cent for labour and non-labour, respectively. These are the weights we use for our econometric modelling in our annual benchmarking report. This is consistent with our draft decision and SA Power Networks' initial and revised proposals.*
>
> *Consequently, we and SA Power Networks have applied the same approach to forecast price growth. The only difference between our real price growth forecasts and SA Power Networks' is that we have used more recent forecasts from Deloitte. An average of Deloitte's and BIS Oxford Economics forecasts reflects the best estimate of labour real price growth."*

We have not had time to fully absorb these most recent final decisions and expect that the economic follow-on from COVID-19 will challenge again forecasts for movement in labour prices. We note the following graph from the SAPN Final decision explanation:

[32] See p. 6.-32 https://www.aer.gov.au/system/files/AER%20-%20SA%20Power%20Networks%202020-25%20-%20Draft%20decision%20-%20Attachment%206%20-%20Operating%20expenditure%20-%20October%202019_0.pdf

[33] https://www.aer.gov.au/system/files/Final%20decision%20-%20SA%20Power%20Networks%20distribution%20determination%202020-25%20-%20Attachment%206%20-%20Operating%20expenditure%20-%20June%202020.pdf

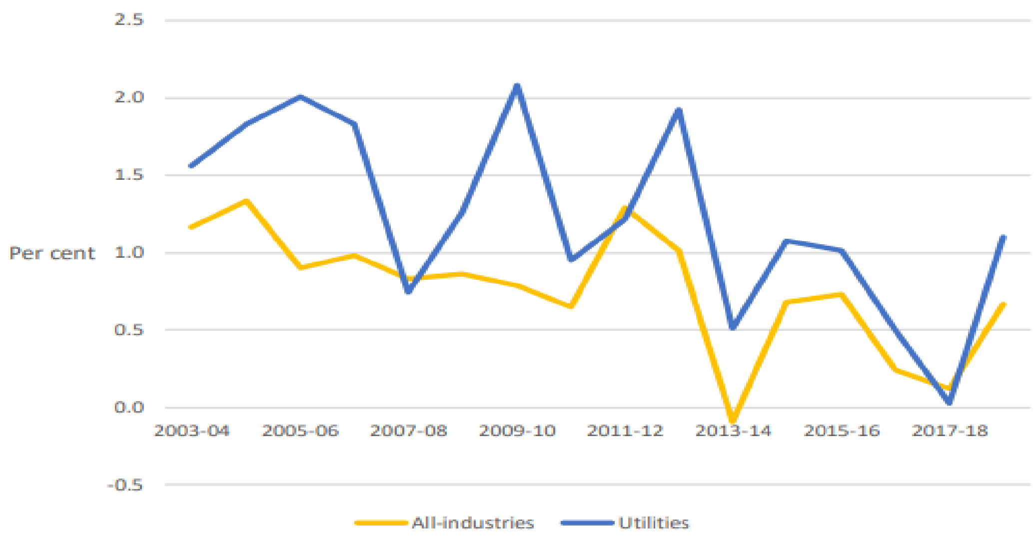

Figure 21: Real WPI growth, Australia (percent) (Source: AER)

BIS Oxford Economics suggested that a significant reason why both it and Deloitte had over forecast WPI growth for the Australian utilities industry was because all-industries WPI growth had been lower than expected. As seen in Figure 6.3, Australian all industries WPI growth slowed significantly from around 2014. Utilities industry WPI growth slowed from around the same time.

We remain concerned by the historical gap between fuel industries labour price escalator and the utilities real wage growth projections with concern that this trend could continue into the future where many energy customers, large and small, will be adversely affected by COVID-19 impacts.

<u>Productivity</u>

CCP17 expect that the annual productivity improvement of at least 0.5% will be factored into all operating cost projections, recognising that AusNet Services expect to deliver a higher level of annual productivity improvement.

6 Forecasts

We noted the following in our presentation to the public forum in April.[34] These notes and questions were based on comments in the AER's Issues Paper, and our own initial thoughts:

1. All Victorian distributors are forecasting growth in customer numbers, the circuit length of their networks and in maximum demand in 2021-26.
2. Distributors are forecasting lower growth in energy throughput, with AusNet Services forecasting a decline in energy throughput over the forthcoming regulatory period.
3. In general, the forecasted peak demand increase may be overstated. Any impact of the expanded uptake of time-of-use for customers installing rooftop solar may counteract peak demand growth. Conversely, the use of reverse-cycle air conditioners, especially in new subdivisions, may also impact demand growth. We intend taking a closer look at demand forecasts, especially in the context of new housing growth and the uptake of new technologies such as electric vehicles. It is recognised that the emerging economic challenges will have an effect on forecasts, and we expect in the revised proposal utilities will revise forecasts and the impact on connections, large connections, solar enablement and demand-driven augmentation.
4. There are some deviations between AEMO demand forecasts and those of the utilities. AusNet highlights some reservations with recent changes to AEMO forecasting methodology (proposal s7.6.3), but the conclusions agree regarding their growth augex projects.
5. Forecasts of energy usage, peak demands and connections (new connections, and existing connections disconnecting) will need to be revisited in light of the impacts of COVID-19 on the economy. AEMO forecasts are also likely to be revised in light of COVID-19.

The key issues that we distilled for discussion here were:

- Deviations between the utilities' forecasts and AEMO forecasts; and
- Impacts of COVID-19 on the forecasts.

These two key issues are inter-connected, because AEMO forecasts are also being revised in light of COVID-19.

Our thoughts regarding uptake of solar PV are discussed separately in section 9, *Enabling Distributed Resources*.

6.1 Deviations between utility forecasts and AEMO forecasts

The AER's Public Forum process gave us the opportunity to submit questions to other stakeholders. We asked all the Victorian Distribution Businesses:

> *How material is the disparity between the business's load forecast and AEMO forecasts, and what are the reasons for and implications of the disparity?*

The responses we received were as follows:

AusNet Services:

The difference between the AEMO demand forecast and our own forecasts was not found to be significant.

[34] See slide 43

AEMO and our own growth rates in demand were found to be very similar, which provides confidence in the assumptions around economic conditions and other growth factors that were used. To be precise, the annual growth forecast by AEMO for our terminal stations between 2019 and 2026 was 1.31% compared to our forecast growth of 1.34% (for demand at a probability of exceedance of 10%).

CitiPower / Powercor / United Energy:

Our forecasts differ to AEMO’s due to methodological differences. A detailed assessment of the differences in our forecasts to AEMO's is provided in attachments CP ATT022, PAL ATT022 and UE ATT022.

While we compare our demand forecasts with AEMO's to identify discrepancies, we have found our forecasting approach is more reliable as it takes account of localised network and economic conditions. As the recent maximum demand record shows, some areas of our network are experiencing strong demand growth. We forecast specific demand drivers at each terminal station level to ensure that growth corridors are appropriately captured in the modelling, unlike AEMO that forecast demand based on observed trends in the data at a terminal station level reconciled to state-wide forecasts.

An implication of using AEMO’s forecasts instead of our methodology would be not capturing growth areas accurately and potentially threatening security of supply in that area.

For the 2016-2020 revised regulatory proposal, CIE, Oakley Greenwood and GHD also reviewed AEMO's forecasting approaches and found them to be lacking in several aspects. Key areas of concern with AEMO’s approach include:

- AEMO’s connection point forecasts fail to incorporate key drivers of demand at the connection point level and therefore do not allow the responsiveness of demand to key drivers to differ spatially.
- AEMO’s reconciliation process under-utilises information at the connection point level and results in a simple apportionment of state-wide forecast growth across connection points
- AEMO’s forecasts are insufficiently weather normalised and therefore result in unrealistically low starting point for the forecasts, leading to lower demand across the forecast period
- AEMO’s forecasts are not accurate and unbiased.

Jemena:

Each year JEN undertakes a comparison of the AEMO transmission connection point forecasts against the forecasts developed by our independent consultant.

AEMO’s 2019 summer POE10 connection point forecasts for Victorian predict demand growth at terminal stations BTS, SMTS, TSTS, KTS and WMTS, and declining demand at terminal stations BLTS and TTS.

This outcome is consistent with our forecasts.

6.2 Impacts of COVID-19 on the forecasts

The businesses’ proposals were submitted in January 2020, while the impacts of COVID-19 only started to be felt in Australia in March 2020. This is discussed in more detail in Section 15 of this advice – “Implications of the pandemic – planning and delivery”.

The AER’s Issues Paper in April 2020 already anticipated: “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",[35] and "These forecasts may need to be revisited in light of the impacts of COVID-19 on the economy."[36]

CP-PC-UE provided a response to the AER's Issues Paper, which included:

> *"The forecasts that underlie our proposals were sourced mid-2019. Our forecasts are sensitive to the macroeconomic environment.*
>
> *For example, in May 2019 the Victorian Government forecast gross state product (GSP) to grow at 3.0% in 2020 and thereafter 2.75% per annum. Following the bushfires of early 2020 and COVID 19 it is expected GSP will decline in the short term (the department of treasury and finance has predicted an unprecedented 14% decline in GSP in the June quarter, relative to previous forecasts) then rebound strongly".*[37]

Section 15 of this advice includes some initial indications of some of the effects of COVID-19 that have already been observed. These include the following:

- There has been some reduction in aggregate electricity demand in Australia as a result of COVID-19. While clearly observable, the initial level of reduction was not substantial.
- AEMO expects that reductions in demand may continue to increase incrementally over time at current levels of restrictions. Victoria, South Australia and Tasmania may also begin to exhibit changes in demand. However, as some states and territories take steps to ease restrictions, this could impact these changes.

On 5 May 2020, AEMO reported: Some potential COVID-19 demand impacts have now been recognised in Victoria where average demand reduction during morning peaks reached 8% (approx. 400 MW) for the first time over a working week in the state. The midday trough fell 5% (approx. 200 MW) from pre COVID-19 levels on weekdays and 3% on weekends (approx. 100 MW) and rooftop solar variability makes it uncertain if the demand reductions are from COVID-19".[38]

Section 15 of this advice contains a large number of likely impacts of COVID-19 on electricity distribution businesses and concludes by proposing five key COVID-19 responses.

Following a national cabinet meeting on 1 May 2020, the Prime Minister told reporters that Australia's migration intake is expected to fall 85 per cent due to coronavirus. With international border closures expected to be in place for at least another three to four months, the federal government expects net migration to fall to just 36,000 in 2020-21 – the lowest number in more than 40 years.[39]

On 20 May 2020, the Sydney Morning Herald published forecasts from the Housing Industry Association (HIA):[40]

> *The Australian Treasury has provided guidance that net overseas migration in the next financial year is expected to drop to about 85 per cent below the level recorded in the 2019 financial year.*

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[35] Issues paper | Victorian distribution determinations 2021–26, page 3
[36] Issues paper | Victorian distribution determinations 2021–26, page 15
[37] Response to AER's issues paper | Regulatory proposal 2021–2026, page 5
[38] https://www.aemo.com.au/news/latest-covid19-demand-impact-summary
[39] See for example https://www.sbs.com.au/news/australia-s-migration-intake-to-fall-85-per-cent-due-to-coronavirus-scott-morrison-says
[40] https://www.smh.com.au/business/the-economy/housing-construction-poised-to-fall-off-a-cliff-20200520-p54uu4.html

This could see Australia's population growth rate drop to about 0.5 per cent per annum, according to the HIA.

"If Australia's population growth rate drops to around 0.5 per cent, the implied demand for new home building will drop to around 70,000 homes per annum. This level of demand could be satisfied simply by completing the dwellings that are already under construction," it said.

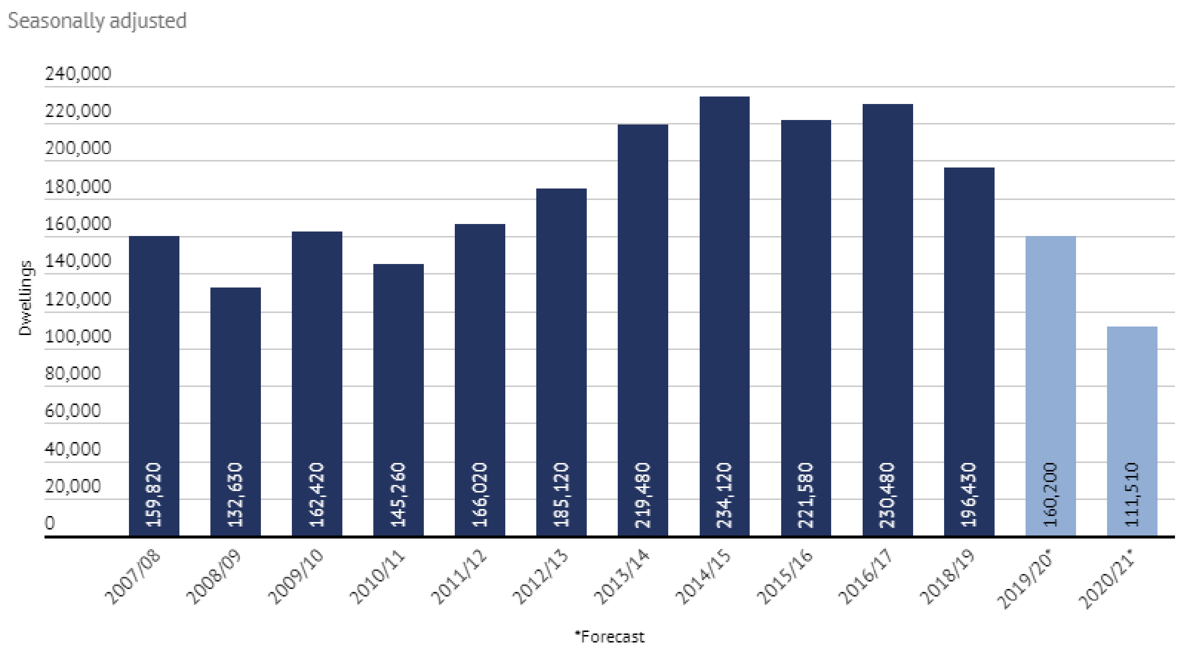

Figure 22: New residential construction and HOA forecasts, Victoria (Source: Housing Industry Australia)

This would affect the number of new connections, as well as the electricity usage.

6.3 Summary

Clearly there are some discrepancies between business views and AEMO forecasts, with CP-PC-UE going as far as to say that AEMO's forecasts are not accurate and unbiased.

Importantly, AEMO's forecasts and the businesses' forecasts are to be revisited when there is more clarity regarding the effects of COVID-19. We expect to see revised forecasts taking into account the points mentioned in this section of our advice, and other relevant matters, and we will then reassess those revised forecasts at a later date.

7 Capital Expenditure

7.1 Introduction

Electricity customers and the community assess the prudency of the capital investment by distributors in terms of reliability, safety, quality of the service interactions, respect for the environment and the ability to connect as needed. Efficiency is presented to consumers through a fair and affordable price for the service. Therefore, much of the consumer and stakeholder engagement leading to these proposals centred on five key issues:

- Does the reliability of the network meet accepted community standards?
- Is the electricity network perceived as being safe?
- Are customers' expectations regarding the adoption of new customer technologies being met?
- Are service interactions informative, timely and efficient?
- Is the cost of accessing this service seen as fair and reasonable by all sectors of the community?

From a network point of view, capital investment is a complex and many-faceted consideration. In these proposals, we see trends that are not dissimilar to those seen in recent regulatory decisions in the other states, being:

- Replacement of ageing assets is the predominant area for expenditure, with costs increasing beyond that of previous regulatory periods, driven primarily by a concern of increasing safety risk
- Developing the technical and analytical capability to accommodate the rapid increase in Distributed Energy Resources connected to the network
- Meeting strong subdivision growth in the fast-developing fringe areas of Melbourne, as well as the demands of urban infill development in what were previously inner-city industrial areas
- Falling levels of investment in demand-related augmentation against a fairly stable forecast of low peak demand growth, with energy consumption even falling in some cases as a result of PV growth.
- Increasing compliance costs flowing from changing regulatory obligations

Underpinning these needs, around 15% of capital investment is required to maintain and augment information and communication (ICT) systems and infrastructure to support business operations, facilitate better and more efficient decision making and lifting levels of customer services.

It is important to recognise the significant investment Victorian electricity customers have made in the Restricted Earth Fault Current Limiter (REFCL) programme in response to the Government's response to the 2009 bushfires. Notwithstanding the significant benefits this investment has delivered in terms of fire safety, we cannot ignore the cost – including ongoing costs – related to these assets. Therefore, we look to see where distributors have maximised the 'collateral' from these considerable investments, capitalising on the new fire risk profile and inherent asset renewal when planning other investments.

Similarly, we look to the DNSPs maximising the application and return from the significant investment by consumers in Advanced Metering Infrastructure.

<u>The case for restraint</u>

As we emerge into a post-COVID19 environment, we recognise the significant economic challenges that will be faced by many parts of our community. The long-term benefit of electricity consumers lies not in the provision of the best levels of customer service, or the most elegant response to future network needs, but for the spirit of the proposals to have affordability and balance as the uppermost priority. Over the next few years, it is reasonable to expect that affordability by many sectors of the community will be a priority, and that many assumptions that underpin forecasts of growth drivers may be highly variable.

In the short term, that means finding the compromise with the business case with strong NPVs and question, 'can all customers afford this change?'

Over the longer term, we also consider the impact on the Regulated Asset Base (RAB). Growth in the RAB has the potential to result in significantly increased prices for customers in the future when returns on asset increase from the current low levels. Therefore, despite capital investment having only a moderate impact on prices in the regulatory period, we place an extra level of scrutiny to consider what may be facing customers over the longer term.

Much of the consumer engagement – which was almost exclusively undertaken before COVID-19 was evident, the case for capital investment is presented as 'only a few dollars per customer per year'. We acknowledge this data is generally factual or based on the best available data, but in some cases the way it is presented trivialises the magnitude and nature of the investment. It is important to present the costs of capital programmes as a total and also as the cost to customers over the life of the investment, including the returns to the distributor, and in the context of all other investments, price changes and risks of exogenous variables that may support or destroy the value from the investment.

Therefore, we consider affordability as the highest priority in forming our opinions regarding capital investment, challenging some expenditure as not being prudent even if it shows a strong positive business case. With affordability such a significant issue in customers' minds now and in the future, there is an imperative to view capital funds as a finite resource.

Key Points

CCP17 supports the majority of the planned capital investment by the five distributors.

There are a few 'red flags' overall that require more detailed consideration and analysis, including considering taking these issues back to consumers to confirm their position now that more detailed information is available. These key areas of concern are:

a) The value of the Regulated Asset Base (particularly per customer) has been increasing steeply over recent regulatory periods. RAB per customer growth tends to stabilise or fall in the next regulatory period in the case of Jemena and AusNet Services, which is to be commended, yet continues to grow markedly for the CPU distributors.

   There is a strong case for approaching capital as a finite resource, asking at every point "what impact will this expenditure have in affordability for all customers over the longer term?"

b) Asset Replacement is the major driver of capex in Victoria. The Victorian distributors plan to spend more on asset replacement than in the 2016-20 period. Specifically, we see the significant change in pole replacement strategy for the CPU group as the single largest issue of capital investment to be scrutinised across the proposals, noting the significant departures from the AER repex models. Detailed analysis and close scrutiny of the repex proposals of Powercor, CitiPower and United Energy, particularly poles, is a high priority.

c) Network augmentation focuses on accommodating significant growth in Distributed Energy Resources. While acknowledging the strong consumer support for networks to support environmental change, we see several risks and perhaps even a level of misinterpretation of customer sentiment inherent in the investment cases. This may result in the DNSPs overstating their capital requirements. In essence, it is prudent for the level of investment to meet DER growth could be reduced slightly, prioritised and staged in this upcoming period with less focus on physical network augmentation.

This matter is discussed at some length separately in this advice.

d) Distributors have regularly underspent their allowance, suggesting there are continually emerging opportunities for improving the efficient delivery of asset replacement needs. This pattern of under-expenditure, then asking for increased repex the following period, needs to be scrutinised closely by the AER, as does the CESS framework, as it is difficult for consumers to support.

e) Capital investment on non-network assets, in particular ICT, has accelerated over recent regulatory periods, and continues as historically high levels. The recent work by the AER to separate ICT into recurrent and non-recurrent expenditure is useful, however the expected cycles of investment are not apparent. Consumers remain concerned at the way ICT investment continues to become a larger proportion of the overall capital investment.

We wish to highlight the number of areas in AusNet Services' proposal that have been redacted as being commercial in confidence. This limits our ability to meaningfully comment on the approach to the analysis and prudency of the options selected.

Across the proposals, we are generally comfortable with the way the utilities have engaged with consumers regarding reliability, safety and emerging connection requirements. The conversations, while high-level in almost all cases, align with the approach taken by the utilities.

We expect that the DNSPs will review key growth factors such as the number of new connections, energy forecasts and peak demand growth in their revised proposals to consider the changed global economic environment.

7.2 Common trends in consumer engagement

CPU, Jemena and AusNet Services undertook extensive consumer engagement using various techniques. As a result of this engagement, several themes emerged as common attitudes to the investment in the networks. We summarise our observations of these common themes as follows:

- Maintaining energy affordability remains a top priority, with a large number of consumers still viewing electricity as being poor value for money.
- Supply reliability is important, but consumers are generally happy with the quality of supply and do not see justification for further investment to improve reliability, except in areas experiencing significantly worse supply performance. Small business and commercial customers see some value in improved reliability and supply quality.
- Providing a safe environment for customers and workers is seen as critical. The response in South-west Victoria to asset safety following the St Patrick's Day fires understandably presented a very strong view regarding the poor or failing quality of asset safety, whereas more generally across the state the view is that safety is adequate, but it is very important 'not to drop the ball.'
- Customers expect distributors to 'keep up with the times' regarding technological advances that support customers' adoption of new technologies and constantly improve services and information.
- Engagement related to Distributed Energy Resources growth has been framed very strongly as the right of consumers to export excess energy from rooftop solar. Consumers clearly indicated their disapproval of distributors restricting the number of systems to be connected or limiting the amount of excess energy that a consumer with PV may wish to feed into the network.

7.3 Analysis

CCP17 recognises the immense level of detail, thought and analysis that goes into the preparation of a distributor's capital investment proposal. We have a particular insight into this process, having been invited into the businesses as part of their engagement and sharing of their deliberations.

Once the proposals are submitted, with five utilities sharing a similar heritage, the opportunity exists to make some level of comparisons between the drivers and nature of their capex proposals. This comparative analysis is not easily available to the customers on the consultative panels for each distributor, and generally not presented as part of the engagement for various initiatives. It presents an opportunity to compare some analysis and ask questions to better understand the reasons for the different approaches by the five distributors.

Our first level of analysis is to consider the level of capital investment normalised to the number of customers and the value of the Regulatory Asset Base, as shown in Figure 24 and Figure 24.

Some questions for clarification arise, such as:

1. What mechanisms lead to both the most extensive rural distributor and that with the highest customer density to spend more per customer that the other distributors?
2. What influences the above-average growth in the RAB by some distributors?

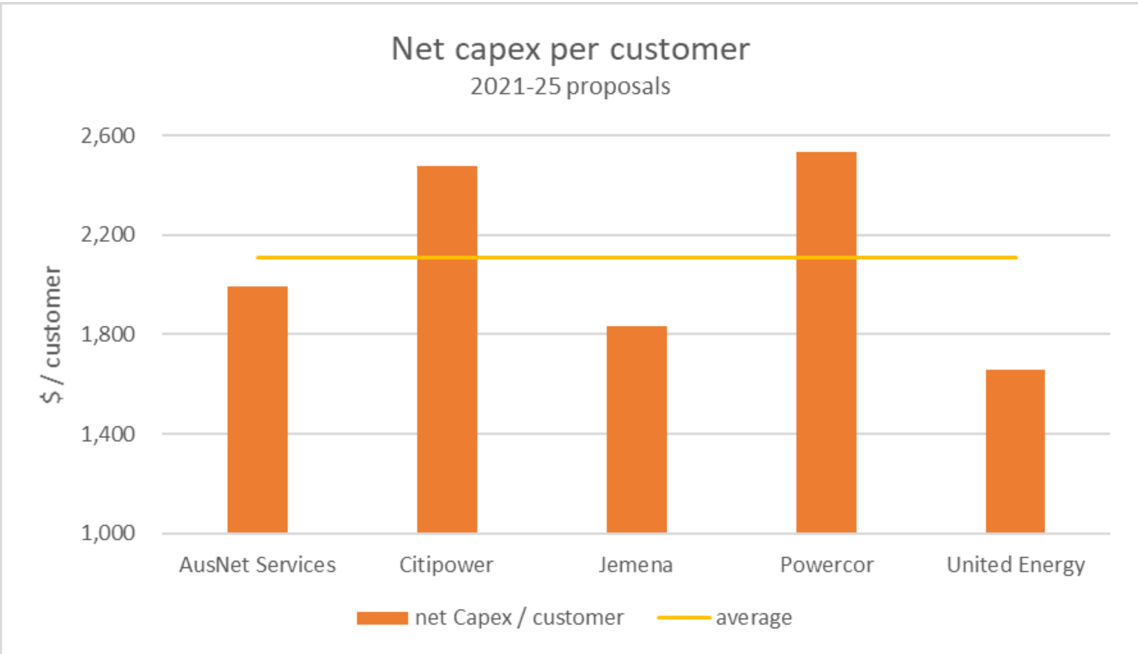

Figure 23: Normalised Capital proposals (per customer) (Source: RINs, CCP analysis)

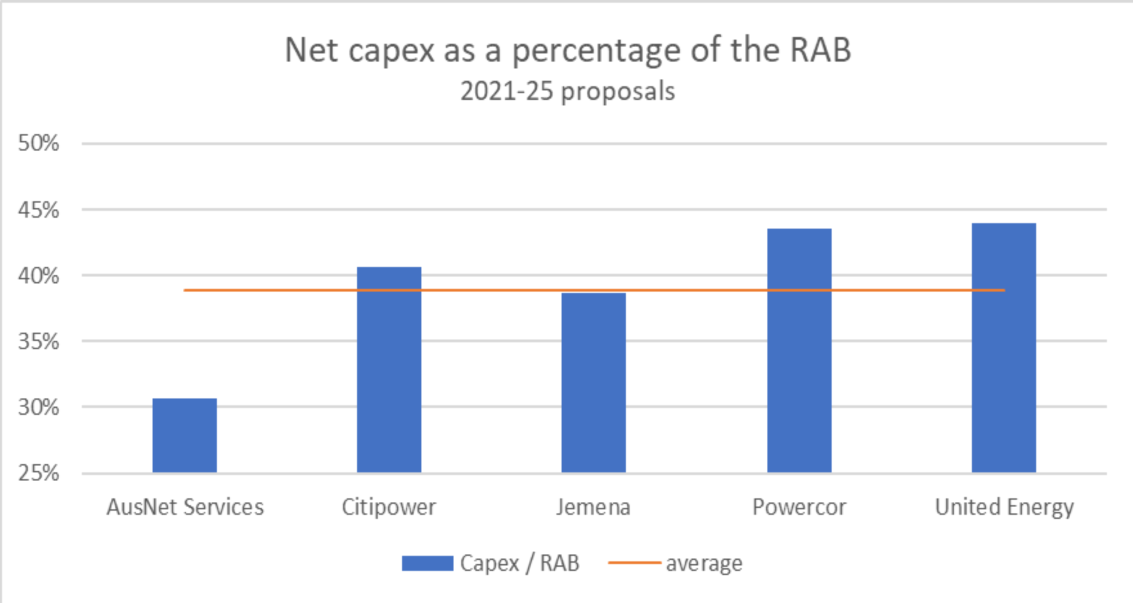

Figure 24: Normalised Capital proposals (percentage of RAB) (Source: RINs, CCP analysis)

<u>Trends in under-expenditure</u>

Every utility is proposing a significant capital efficiency carryover. Underspending an allowance then asking for an increased capital allowance in a subsequent period draws consumer interest, where we ask the question "if it is so important, why not get on with it now?", and "have the deferred works been postponed due to true efficiencies, or just delayed with minimal impact, questioning the priority in the first place?"

Figure 25 tells us that, on average, in the 2016-20 regulatory period the distributors only invested eighty-five cents in every dollar of their capital investment allowance. In CitiPower's case, less than three-quarters of their allowance was utilised.

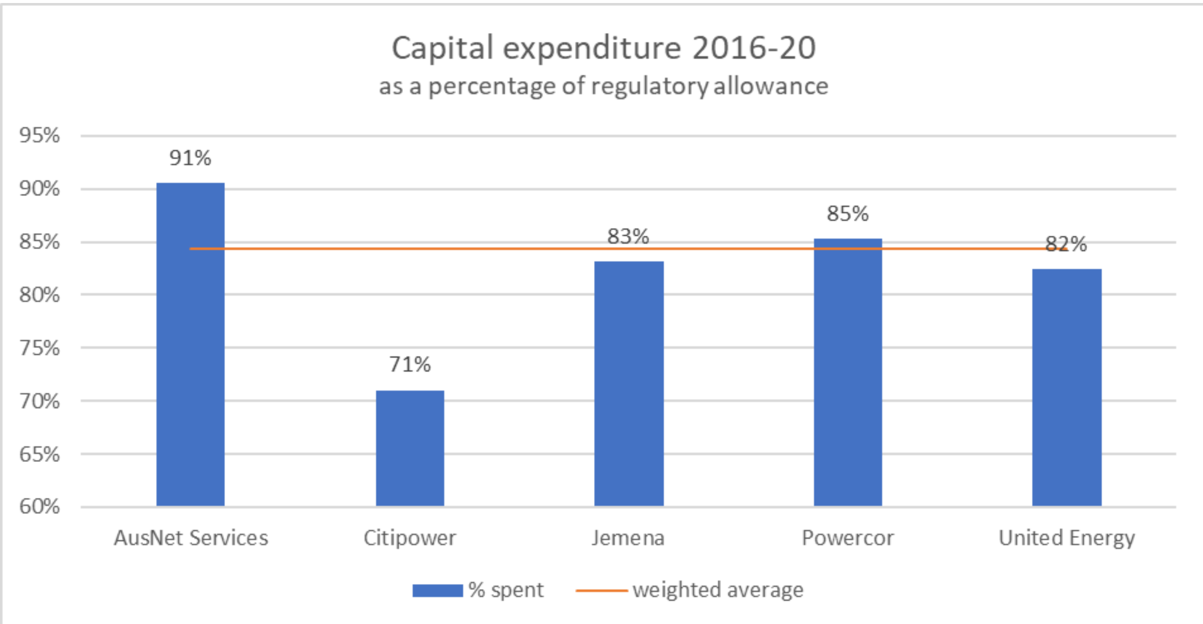

Figure 25: Capital under-spend as a percentage of regulatory allowance (Source: RIN CESS data)[41]

It is also useful to consider is the AER's treatment of the distributor's capital investment proposals for the 2016-20 period. In their final decisions, the AER elected to reduce the distributors capital proposals by between 5.6% and 12.8% (noting no adjustment for Jemena).

In many ways, this is a testament to the efficiency incentive regime under the CESS, and we recognise that much of the under-expenditure is due to the distributors being able to defer or cancel planned investment though innovation and more efficient solutions. We commend Jemena who produced their explanatory document *Attachment 05-02, Capital expenditure for the 2016-20 regulatory period*, which goes some way to explain in the public arena how the under-expenditure eventuated. AusNet Services also provided a level of explanation in section 9.3 of their proposal.

There has not been an observable decline in network reliability or an inability for customers to connect new loads as a result of the reduction in investment. We acknowledge the general approach to by the community to the asset safety in respect to bushfire risk has shifted, resulting in the significant investment in the REFCL systems. Other works to reduce fire risk have been a feature of distribution network investment programmes for many years.

The net impact is that customers are wary of the distributors' capital investment proposals, particularly those that propose significant increases in the level of investment from previous years.

We highlight the multiple incentives for distributors to benefit from the overestimation of required future network capacity, including:

- the allowance for financing the approved capital,
- receiving the capital allowance whether the capex is invested or not,
- retaining the unspent majority of the funds under the Capital Expenditure Sharing Scheme, regardless of any demonstrated efficiency on the part of the distributor; and
- the significant dependence of network profit on the rate of return.

While acknowledging the detailed and extensive bottom-up development undertaken by the companies to establish the proposals, from a top-down view it is not unreasonable for consumers to conclude that synergies across safety and augmentation programmes exist. Along with the trend in under-expenditure, reductions in the proposed capital expenditure may be possible without a negative effect on safety, reliability, service or sustainability.

7.4 Common issues

Service wire replacement programme

Most Victorian distributors raised with consumers at various workshops the issue of the increased risks associated with PVC twisted service lines. In particular, the 'dog bone' wire suspension system is seen as having an age-related common mode of failure. While firm data regarding the increasing rate of failure of these devices was not clearly explained, without exception, customers supported the continuation of this safety programme.

Figure 26 shows CCP analysis of the proposed expenditure on the replacement of low voltage service wires.

[41] Using CESS RIN model data, NPV to Dec 2019

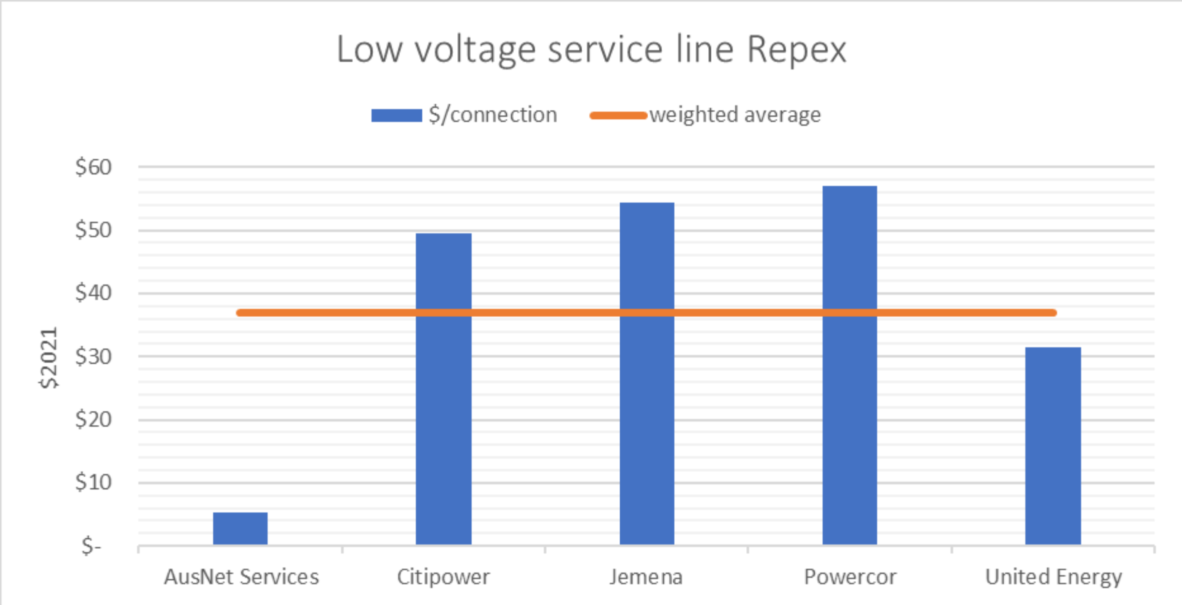

Figure 26: Service line replacement repex by total customer base (Source: RINs and Proposals)

The large range of expenditure is clear. Given the technical common standards that have applied in many aspects of network design some years ago, we raise this range for further investigation. We acknowledge the comment by AusNet Services in their proposal:

> *"Our forecast expenditure for service lines is significantly below the amount suggested by the AER's model. This is because our model assumes that (as a prudent and efficient business) we replace a significant proportion of service lines when we replace other assets, such as poles or cross-arms. That is, our forecasts for service lines reflect a residual amount of expenditure that results from subtracting the estimate of the service lines that can be replaced during other work from the estimate of the total number service lines to be replaced in the same period."*[42]

We commend AusNet Services for this approach and note that, unlike CPU, they did not raise the safety of service lines, particularly 'dog-bone' terminators, to any extent their engagement. We also note that CitiPower is using AMI facilities to identify inherent faults in service lines that are not immediately obvious.

We assume the unit costs across the DNSPs to replace a service line are not largely dissimilar. We are curious, however, as to what leads to such a large discrepancy in the perceived need to address this issue across the five DNSPs. We ask:

- Could AusNet's approach be extrapolated to the other distributors?
- Perhaps AusNet has addressed this risk in earlier regulatory periods and does not have such a level of safety risk?
- Is the rate of replacement justified by the level of physical service line failures?
- Should the high rate of pole replacements as proposed by CPU eventuate, are there synergies, particularly in the CitiPower and UE areas, between pole replacement and service line repex?

CitiPower and Powercor, as promised to the community in their engagement and in response to feedback, have commenced work replacing the service wires in this current regulatory period, as shown in Figure 27.

[42] AusNet Services proposal part 3, p86

We commend CitiPower and Powercor for this action. CitiPower has proposed $1M in accelerated depreciation related to the replacement of PVC service cables.

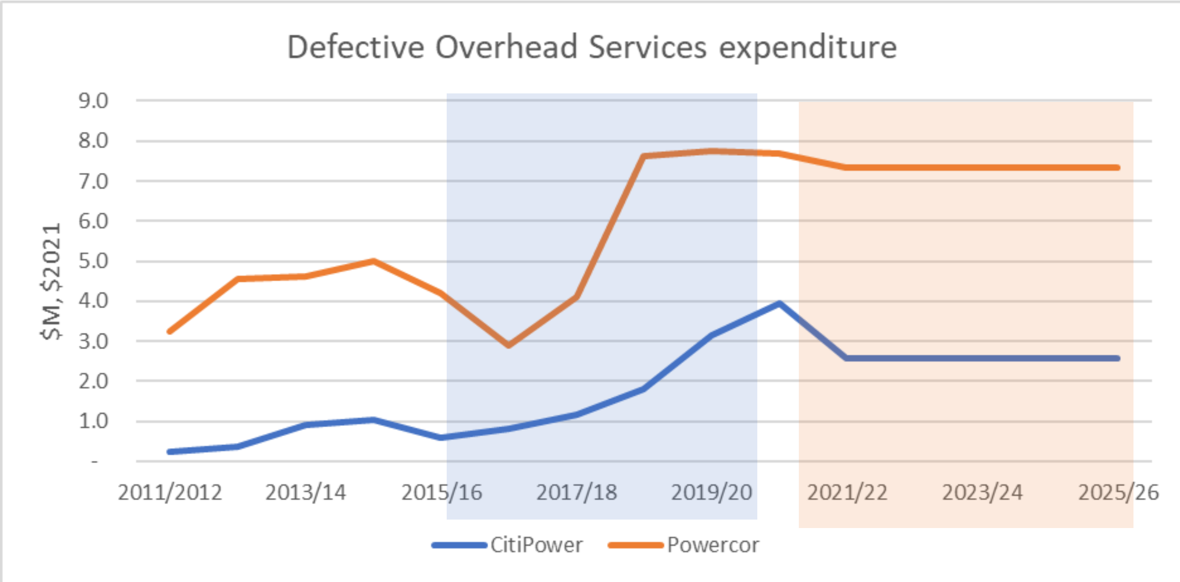

Figure 27: Defective service wire replacement capex, Powercor & CitiPower (Source: models 04-06)

<u>Circuit breakers, protection and control systems</u>

Some DNSPs have proposed a significant share of their repex expenditure be targeted at the replacement of switchgear, protection and control systems.

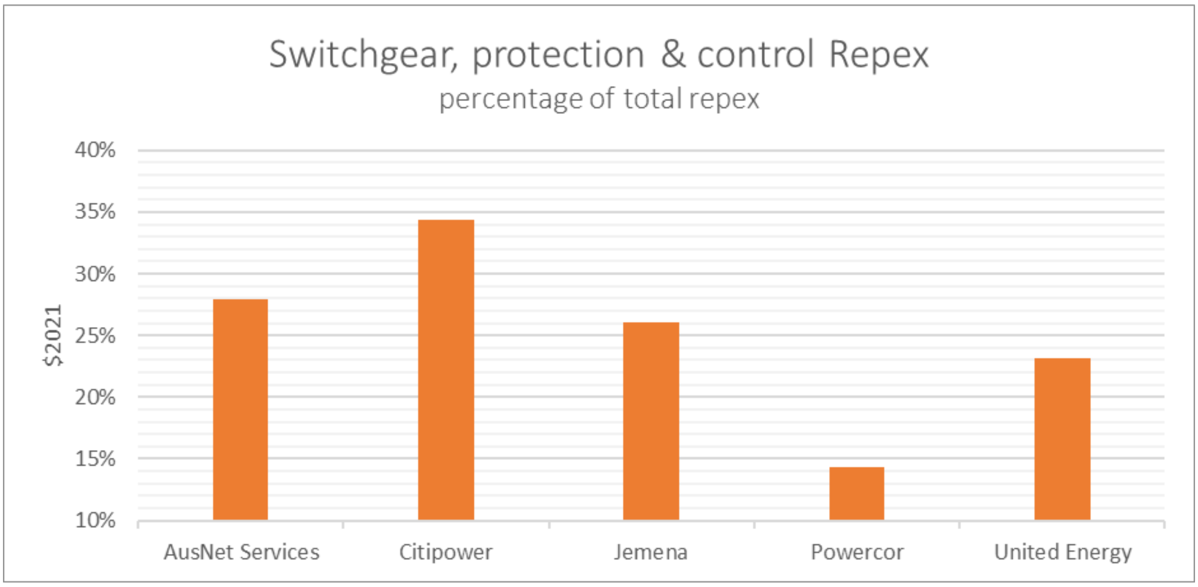

Figure 28: Asset replacement planned investment as a ratio total planned repex (Source: RINs, CCP)[43]

Figure 28 shows the share of switchgear, protection and control system repex planned by each DNSP.

This approach is consistent across most distributors in the NEM. In Queensland and New South Wales, a lot of substation switchgear, transformers and protection equipment was replaced some years ago as a result of significant changes to network security standards and rapid demand growth.

[43] Data - RIN1 tab 2.2 'repex' (all substation-related categories)

Victorian DNSPs were not exposed to such needs to change, and therefore an appreciable amount of substation equipment that is reaching the end of its safe service remains service in Victoria. We note the parallel conversation raised by some distributors regarding the accelerated depreciation, or reclassification of asset life, for electronic substation equipment.

Jemena arranged field tours to observe the aged condition of some substation equipment as part of the Jemena People's Panel engagement. While the visit to substations was a first for many attendees, Jemena built a strong case based on the age and failure risk of this equipment, as well as the consequence of failure being a risk to public safety. From this visit, the People's Panel clearly supported the replacement of substation circuit breakers, protection and control systems as a priority for Jemena.

Given the common ancestry of the equipment across Victoria, we assume similar situations exist across the state. Therefore, we support the replacement of compound-insulated switchgear by all distributors based on the risk of injury and extended power interruptions as a result of age-related catastrophic failure.

Even considering the increase in wood pole repex increasing the level of total repex, we are comfortable with this profile as being reflective of the way these categories were raised and discussed as priorities in the consumer engagement. This support is of course subject to the AER determining the expenditure is efficient.

7.5 AusNet Services

<u>Comment on the proposal documents</u>

AusNet Services has elected to redact significant parts of its analysis and models from the public versions of many documents; in contrast with the greater level of commercial and modelling information that is provided to consumers by the other DNSPs. While we respect AusNet's right to consider its commercial-in-confidence position, the reduced amount of information provided to consumers has a detrimental impact on CCP17s's ability to provide commentary and advice on investment trends and options analysis, given our advice is a public document.

Safety as an expenditure category does not form part of the AER's formal capex build up, but it is a feature this and previous proposals by AusNet. In this proposal, some major activities have been reclassified from safety into other capital categories. While we recognise the value of reporting safety-related capex, these changes make the assessment of expenditure trends just a little more difficult. The proposal also appears to use dollar values that vary between the AusNet classifications, the AER classification and what appears to be with or without overheads allocated.

We expect that this situation can be considered in the production of the revised regulatory proposal.

<u>Investment trends</u>

The capital investment proposed by AusNet Services of $1,478M (net) over the 2021-26 period is approximately 18% lower than the expected net capex to be invested in the current regulatory period, leading to a falling value of the RAB per customer and lowering the future cost burden on customers. The proposed accelerated depreciation of assets assists this trend, although it raises other concerns regarding bringing forward costs to customers and a direct impact on prices.

Of the five Victorian DNSPs, AusNet expects to spend the largest proportion of their current regulatory allowance in the current period, with an under-spend of around 9% compared with the Victorian DNSP average of 15%.

AusNet Services discusses the variance between the regulatory allowance and the forecast expenditure for 2016-20 in section 9.3 of their proposal. We appreciate this information.

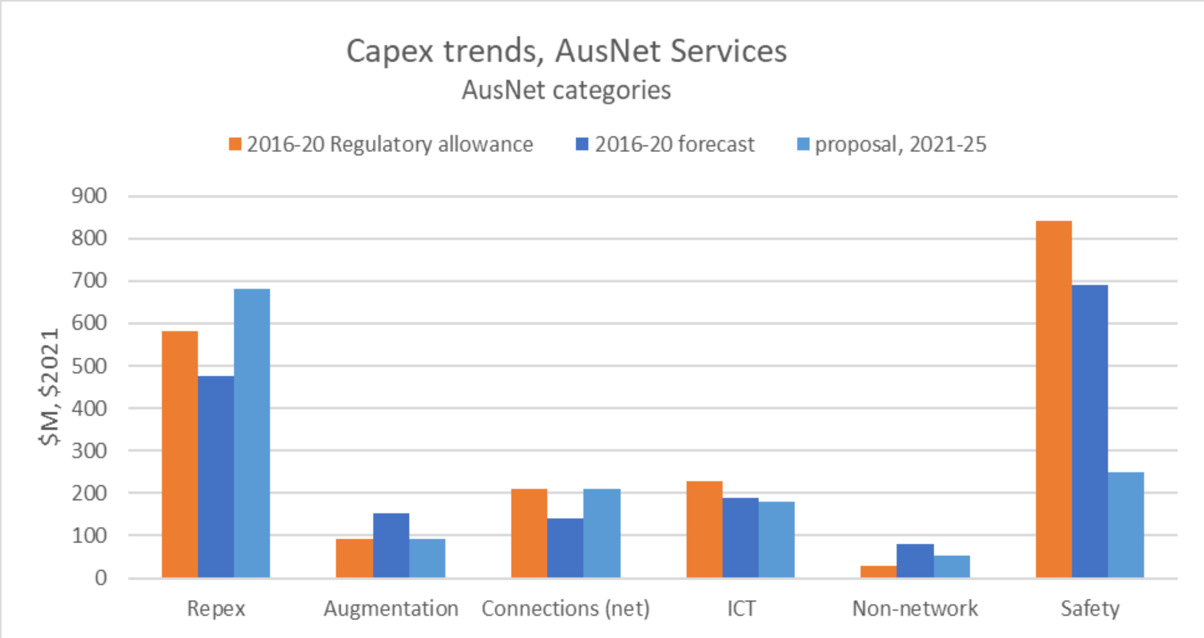

Figure 29: Capital investment trend, AusNet Services (source: AusNet proposal part 3, CCP analysis)

Figure 29 shows the capital investment trend for AusNet Services based on CCP analysis of data in the proposal. A significant influence on the reduction in the capital expenditure is due to the reduction in the safety component, which at $250M in the coming regulatory period is down 64% from the forecast investment in the current period.

However, outside the safety-related expenditure, AusNet Services is forecasting an 18% increase of $182M in the non-safety related aspects capital investment, predominantly asset replacement, with a planned investment of $681M, a 43% increase on the expenditure forecast for this current period (using AusNet Services capex categorisation).

On first observation, customers may draw the conclusion that AusNet is severely reducing its investment in safety. AusNet explains the changes to this expenditure in section 9.9 of their proposal, noting the completion of the mandated REFCL programme planned for 2023. AusNet also comments on the investment related $74M Victorian Government funded Powerline Replacement Fund not being captured in this data. AusNet has also reclassified conductor and cross-arm replacement as Repex rather than safety.

We note these changes, despite them being a little confusing, and commend AusNet Services for the continuing improvement in public safety performance including marked reductions in incidents with fire potential and fire starts.

Our analysis of the repex priorities shown in Figure 30 provides a level of assurance to customers, as the priorities for repex align well with the issues raised in stakeholder engagement. Even though AusNet has not noted the impact of the ESV's report into pole management practices for Powercor, the pole priority aligns with our expectation that this category is the primary focus for AusNet.

The investment targeted at switchgear, SCADA and control systems is consistent with priorities we have seen in in most other Victorian DNSPs.

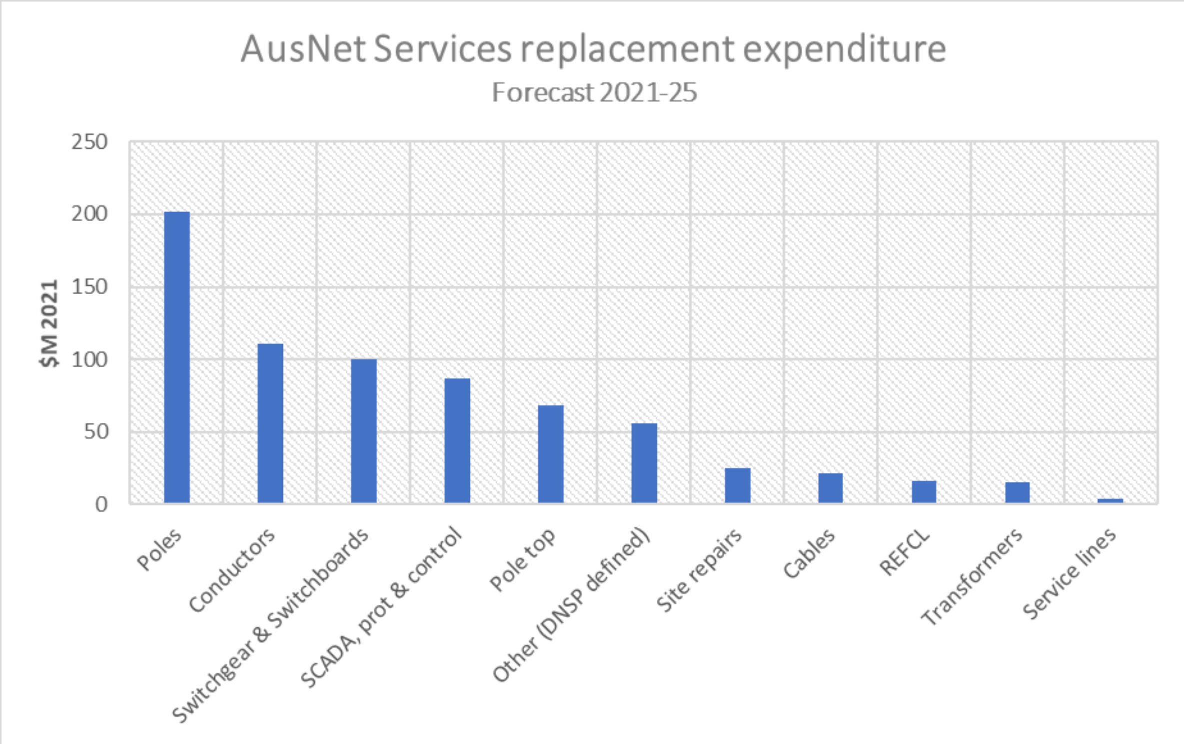

Figure 30: Category analysis, replacement expenditure, AusNet Services (source: AusNet RIN Workbook 1)

The AusNet Services Customer Forum

The Customer Forum negotiated directly with AusNet Services on capital investment matters totalling 7% of the planned expenditure.

Regarding system augmentation, the Forum agreed with AusNet that the Clyde North substation transformer installation should proceed, with the planned work at Doreen being deferred. Replacement capital expenditure was not formally part of the scope of the Forum, however they chose to include it because of the large number of customers that are impacted by asset performance. After their discussions with AusNet Services, the portfolio of major repex projects was reduced from nine to seven, reducing the cost by 27% to $78.3M.

CCP17 was kept well-informed of the Forum's negotiations with AusNet regarding these matters and were invited to participate in the workshops related to the proposals. We support the position on augmentation and asset replacement reached between AusNet Services and the Customer Forum.

We have comments regarding the growth of rooftop solar PV, and therefore take a different position to that of the forum regarding investment to meet DER growth, noting that DER investment was not part of the Customer Forum's scope with the AER. We discuss this issue extensively in the Distributed Energy Resources section of this advice.

Specific comments related to the capex proposal

Safety related capital

A significant part of this programme next period is the final tranche of the REFCL programme, plus the remarkable ongoing compliance costs. We view this work as, for a customer's point of view, inevitable.

We recognise AusNet's obligation to underground SWER lines in codified areas and the relationship to the Powerline Replacement Fund. We support the intention to reduce the volume of work to balance affordability with the commitment to meeting the community's expectations around bushfire risk.

Augmentation, the Low Voltage Network and synergy

With a level of augmentation expenditure of $92M (being $216M in the AER categorisation), AusNet is proposing a significant reduction in their planned demand-related category expenditure. AusNet may revisit its augex forecasts in its revised proposal on the basis of changes to new VCR information.

The majority of the expenditure is related to the low voltage network and the growth of DER, including:

- Customer supply compliance programme $6M
- LV network capacity, identifying overloads $11.4M
- Hosting capacity for DER, addressing emerging constraints $20.9M
- Voltage compliance programme to address steady state voltages $20.6M

There is opportunity for a significant level of synergy across these projects, including work planning, investigations, engineering analytics, procurement, field resource allocation and common modes of rectification of problems that are found (i.e. fixing one problem can address many). Also related in the area of ICT investment is workforce collaboration($8.6M), network performance information management ($13.8M) and DER enablement ($11.4M).

In the DER section of this advice where we encourage investment to address the existing issues with the LV network and invest in innovative modelling and voltage control, but defer any significant investment in low voltage network augmentation. This suggests that the project 'Hosting capacity for DER' ($20.9M) should be considered closely, but we agree that the other projects in this portfolio are important to pursue.

We expect that a top-down assessment of these projects, considering the many overlaps in analysis and response, would yield a significant efficiency opportunity that would reduce the overall cost of meeting the renewed challenges of planning, operating and optimising the low voltage network.

We note the 5% efficiency adjustment applied to the augmentation programme, valued at $4.5M. However, we expect that the synergies and efficiencies in taking a holistic view of the low voltage network challenges would yield greater benefits.

Eliminating network operational deficiencies

This small expenditure of $1.4M is intended to rectify operational deficiencies that are identified when work is undertaken on the network. We cannot support this particular investment, for the following two reasons:

1. We expect that rectifying operational difficulties will lead to efficiency improvements and productivity opportunities for AusNet itself, through fewer customer interactions, efficient use of field resources though avoided out-of-hours work and the like. Therefore, it should be considered 'business as usual'.
2. We question the materiality of the investment and the benefit to all consumers, especially when the efficiency benefits to AusNet are considered.

ICT – Customer Information / Relationship Management (CIM / CRM) System

The Customer Forum has highlighted the importance of the relationship between the customer and the DNSP whenever an interaction, such as a complaint, connection query or service requirement is required. It is recognised by consumers that these in interactions with DNSPs are generally not of a high quality. Therefore, we are supportive of investment related to customer interactions. This is not inconsistent with our support for CPU's development of their customer interaction portal, as well as supporting actions that underpin the proposed Customer Service Incentive Scheme.

The business case notes that this project, valued at $7.2M to the electricity business, is a shared expense with the AusNet's gas business. The programme brief is highly redacted, limiting our ability to comment.

We have three points to note regarding this project:

1. AusNet has proposed the introduction of a CRM in the past two regulatory proposals, suggesting in the 2016-20 proposal that "a *CRM will equip AusNet Services with a single view of integrated customer and asset information, enabling visibility of crucial customer requirements and optimisation of maintenance and delivery of asset works."*

   The value of this investment is not publicly available, being redacted from AusNet's public documents.

   This project appears not to have proceeded, with AusNet noting that despite the CRM being approved by the AER in the 2016-20 proposal, AusNet "*elected to not proceed with this investment as we required more clarity on our role in managing customer interactions and shifting requirements for this solution could mean wasted investment*" [44] We question "have customers already paid for an AusNet Services CRM?"

2. We have reservations that AusNet may have understated the costs and overstated the benefits of a CRM, for the following reasons:

   - AusNet will already have ICT systems to manage customer data for the purposes of network and non-network billing, outage management, customer correspondence, sensitive and life-support customers, complaints and queries, contact centre interactions, correspondence and service order management. These systems support many of the functions proposed for the CIM. It is unclear how a new CIM will integrate, enhance or replace these systems. Is it a case of 'using existing systems well, before buying a new one?' This needs to be explored.
   - Retiring legacy customer-facing systems is likely to reduce the net costs of a new CRM.
   - For the vast majority of energy-related issues, customers will contact their electricity retailer. AusNet's survey of customer profiles in 2018 [45] noted fewer than 50% of customers are aware of AusNet as their electricity distributor.
   - Customer data to populate a CIS is highly dependent on the retailer as the first point of contact and the supplier of key customer data such as name, contact details, tariffs, billing, payment arrangements and the like. DNSPs are highly dependent on retailers for much of this information, and the quality, timeliness and completeness of customer data through the AEMO MSATS system is often questionable. We ask: "Can the distributor be confident of the quality and timeliness of the customer data, particularly regarding new connections, in order to establish and maintain an effective and efficient customer relationship?"

3. Many of the benefits of a CIM would lie in efficiencies within the DNSP's operation, in which case we question the customer carrying the full cost of implementation. A single CRM may be a useful tool in integrating many customer-facing functions for significant benefit to AusNet, especially should a Customer Service Incentive Scheme be established within the life of the CRM. With efficiency benefits to AusNet, we ask 'could customers pay once, maybe twice, for the system that delivers efficiencies to AusNet?'

[44] AusNet Services Program Brief Customer Information Services (Technology Program), Jan 2020, p5
[45] Quantum Research – *AusNet Services Customer Profiles*, May 2018

CCP17 does not suggest that an elegant Customer Information System would not benefit the efficiency and quality of customer interactions with AusNet. Our main concerns are that there are many factors that could, in AusNet's words, "*mean wasted investment*", or that customers will pay for a system that will not only deliver efficiencies to AusNet but also potential CSIS benefits, risking 'double counting.' We expect that these matters will be considered prior to the approval to proceed with such an investment.

7.6 CitiPower

At approximately $790M, CitiPower is proposing to invest slightly less than the allowance for the current period, but significantly more than that forecast to be spent. As a result, the value of the RAB per customer is expected to rise by close to 5%.

CitiPower forecasts to under-spend this period's capital allowance by close to $120M or 28%, resulting in a capital efficiency payment to CitiPower of almost $60M.

CitiPower's customer engagement programme was run alongside, and integrated with, the quite extensive engagement for its sister companies Powercor and United Energy. Please refer to our comments regarding the Powercor engagement for much of the approach and findings from that work.

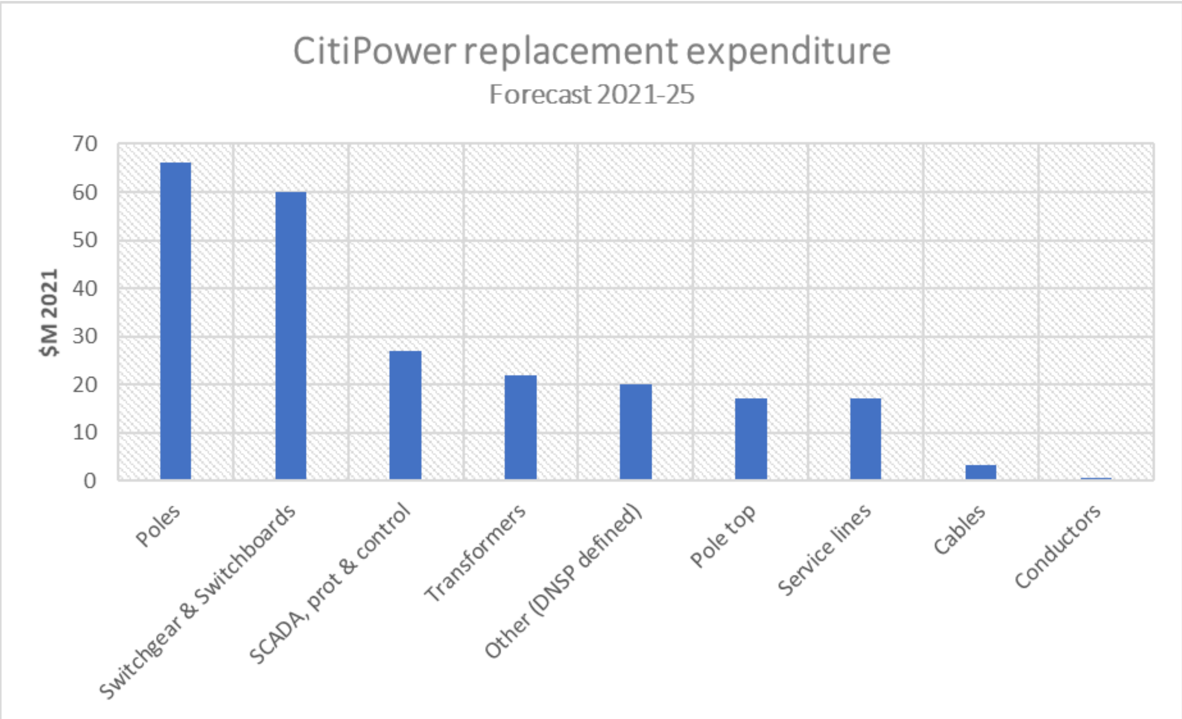

Figure 31: Category analysis, replacement expenditure, CitiPower (source: CitiPower RIN Workbook 1)

Figure 31 shows the asset replacement priorities for CitiPower. We are not supportive of the approach taken in the proposal to the replacement of wood poles, as discussed below. The focus on switchgear, protection and control systems is clear. In general, we are supportive of this prioritisation, on the basis that the AER analysis shows the investment is efficient.

<u>Repex – Poles</u>

CitiPower is intending to replicate the changes in the pole management and serviceability assessment practices being introduced in the Powercor area. This results in a significant increase in the proposed pole replacement expenditure to $59M, as noted in Figure 32. We acknowledge that the expenditure this year (2019/20 and 2020/21) may ultimately be higher than that presently forecast.

CCP17 has examined the proposed change and the impact of the ESV study into Powercor's pole management practices from the consumer's point of view extensively in the Powercor section below.

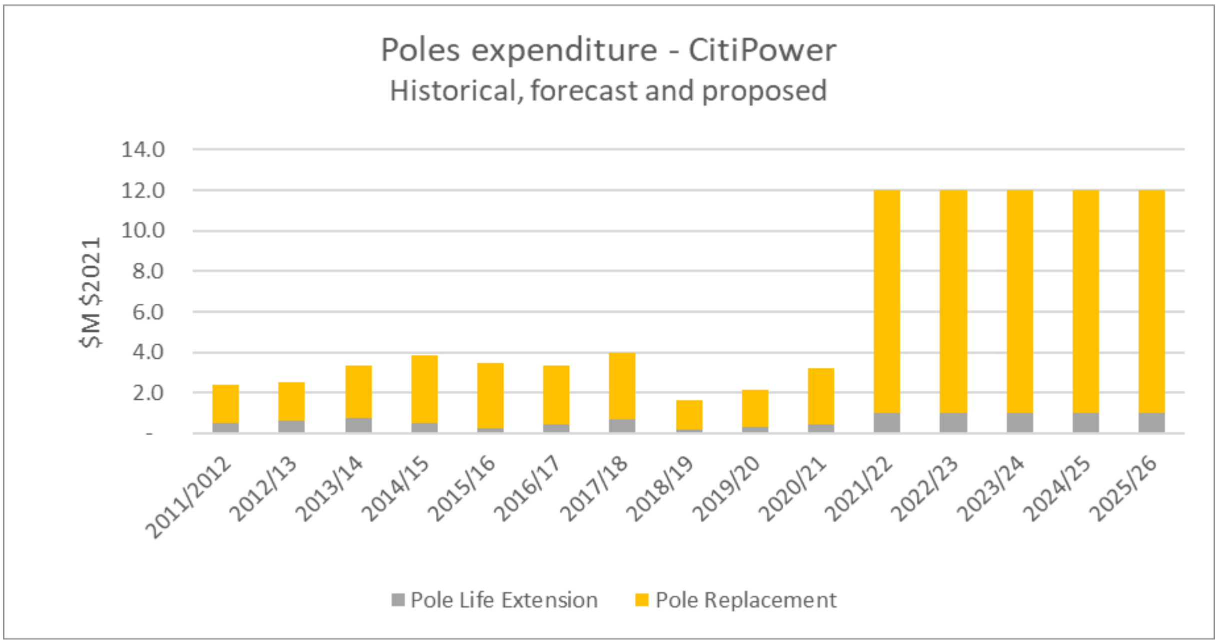

Figure 32: CitiPower pole repex expenditure (Source: CitiPower model 04.06 – Lines replacement)

The situation in the CitiPower region is different, and it Is not valid to directly extrapolate the risks and historical events in the Powercor area as a justification for the significant increase in pole replacement rates in the urban area. With pole failures being a fundamental output measure of pole management, CitiPower states, in relation to its population of approximately 35,000 wood poles:[46]

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

We recognise the changes to the risk-based modelling approach taken by Powercor and largely extrapolated to CitiPower and United Energy. Our understanding is that the approach relies on serviceability as a proxy for the probability of failure and location of the asset as a proxy for the consequence of failure. Key to our concerns about the proposal is that a 'pole failure' manifests itself very differently in an urban area.

We reject the proposal to extend the changed pole sustainability approach to CitiPower, for the following reasons:

1. The ESV's investigation and report were based on the safety performance that relate primarily to Powercor's Bushfire Mitigation Plan, following observed failures in the plan that are alleged to have resulted in major destruction of property by fire.
2. The ESV report makes no reference to the findings being relevant to any other distributor other than Powercor.
3. CitiPower has a high predominance of wood poles (approximately 63%) that are LV only, and present quite different failure modes and public risks due to the urban landscape and effect of service wires attached to the poles. We expect that the consequence of pole failure manifests itself

[46] CitiPower regulatory proposal, p 31

differently in an urban context. In the experience of many urban distributors, failure due to contact from trees in storms, contact with vehicles and crossarm, conductor or insulator failure leading to a 'wire down' present the large proportion of electrical hazards in urban areas.

4. CitiPower notes a low rate of unassisted pole failures under their existing maintenance regime, suggesting that the increased rate of unserviceable poles does not reflect an underlying risk that the asset more likely to fail in service.

We commend CitiPower in seeking to improve their asset management practices, however we challenge the need to adopt the revised pole serviceability as a criterion for the probability of asset failure and consequently unacceptable public risk in the CitiPower region; an action that will increase costs for CitiPower customers for what we propose would be very little noticeable benefit.

Improved rapid crew response, active vegetation management, enhanced low voltage network fault protection and effective public safety information campaigns are likely to be more effective in reducing public risk related to pole failures in populated urban areas before a widespread change to pole serviceability assessment should considered, especially given the low pole failure rates that currently result from existing practices.

From a consumer point of view, it is difficult to see the justification to adopt a much more aggressive sustainability assessment criterion that results in a significant increase in capital requirements, addition to further RAB growth and costs to consumers for many years to come.

<u>Specific comments related to the capex proposal</u>

Repex – zone substation switchgear and CBD cable pits

CitiPower proposes three significant projects to replace 1970's- era compound-insulated, bulk oil 11KV circuit breakers. Jemena also raises the requirement to replace aged switchgear, network protection and supervisory control facilities. While this issue did not feature to any extent in their engagement, we agree with CitiPower's assessment that the failure risk and mode of failure of these circuit breakers presents an unacceptable safety and supply security risk to consumers.

As discussed earlier in this advice, our observation is that similar renewal has already taken place in Brisbane and Sydney inner urban areas, driven by the significant change in urban and CBD supply reliability standards that took place around fifteen years ago. Melbourne did not see such a change in standards, and hence has a large proportion of ageing substation plant that has reached its service age.

Aged CBD cable pit structures are recognised by utilities as being a risk to workers and the public. SAPN, in their proposal engagement, took their committee on a tour of these sites, and received strong support for their replacement. We expect that similar risks exist in the CitiPower area. CitiPower raised the issue of the ageing pit structures in its engagement, and received support for a prioritised, staged approach to replacing and refurbishing CBD cable pits.

Subject to the AER determining the efficiency of the replacement proposals, we are supportive of these initiatives in a phased, prioritised manner.

Augmentation

CitiPower's proposal for solar enablement and Digital Networks is discussed elsewhere in this proposal. Otherwise, we have no specific comments on CitiPower's proposed investment to meet the challenges of large-scale urban infill projects.

ICT – Intelligent Engineering

CitiPower, along with Powercor propose investment of $4.4M[47] each to support 'Intelligent Engineering'.

The project is identified as reducing safety risks through an enhanced Dial Before You Dig (DBYD) facility and generally provide better asset information. Once again, in the analysis of options within the project scope, CitiPower has embraced the most expensive option.

We commend CitiPower for the commitment to provide the highest quality service for its customers. We have no doubt this project will lead to more accurate and timely service. However, in the spirit of restraint in expenditure and looking for every opportunity to keep costs down for customers in both the short and long term, we ask whether this is essentially a 'business as usual' activity? Keeping GIS records accurate, updating the quality of the data, providing more effective and efficient interfaces are activities that benefit both customers and the distributor alike. We assume that the investment will allow CitiPower to streamline its internal business operation as well, with better records leading to less design rework and fewer emergency callouts. The business model notes:

- Savings from fewer damaged assets
- Savings from fewer inspections
- Savings from internal data accuracy and design
- Time saved from fewer delayed projects
- More efficient recording of DBYD applications

It is reasonable to expect that both customers and CitiPower itself will benefit greatly from the enhanced data and systems, which raises the question "Should customers pay for something that will allow the company to enhance their own operational efficiency? Is this a cost CitiPower may consider absorbing?"

ICT – non-recurrent expenditure, SAP upgrade

We note the number of utilities that are planning upgrades to SAP S/4 HANA, and expect that the AER will explore not only the economies of scale that should be available from the parallel upgrade implementation, but also consider the capability and possible customer impact of these companies undertaking upgrades at the same time.

7.7 Jemena Electricity Networks

Jemena's planned capital expenditure is $781M (gross, including overheads), being slightly below the planned expenditure in the current period. This is despite the inclusion of the $43M Coolaroo REFCL project. Jemena presented their programme as being part of a gradual decline in total expenditure, being assisted by the change in the allocation of corporate overheads to operating expenses.

Jemena underspent its regulatory allowance by $124M, or 17%, in the current regulatory period. We commend Jemena's production of their Attachment 05-02, which goes some way to explain the reasons for the under-expenditure.

We also note Jemena has obtained ISO 55001 and ISO 27001 accreditation for their asset management system and Information Technology security, respectively. We view this as indicating that customers can reasonably assume a robust, transparent approach to asset management governance within the organisation through independent audit.

[47] From CitiPower Business Case CP BUS 7.07

Within Jemena's capital programme is an allowance to meet demand growth in both greenfield and infill developments, including significant projects to increase the capacity of sub-transmission and distribution assets. We cannot recall Jemena presenting a multi-faceted approach to their People's Panel regarding future networks that considered the role of demand management or improved asset utilisation to defer some of this augmentation capital investment.

As we have noted elsewhere in this advice, a strategy that encompasses the distributor's vision of microgrids, energy storage, innovative tariff signalling and direct load control to meet the broader objectives of affordability and sustainability would be useful. Customers would view initiatives such as network capacity augmentation and DER control systems more favourably if there was a clear and well-communicated overall vision of Jemena's efficient, capable future network.

Overall, we are reasonably comfortable with Jemena's capital proposal, noting that we consider the investment to meet DER growth separately in this advice.

<u>Issues from the Stakeholder workshops</u>

Jemena's customer engagement, through its People's Panel, highlighted affordability on several occasions. Consistent with other engagement, the key themes of maintaining reliability, keeping safety and environmental risks as low as practicable, addressing customers connection needs and allowing reasonable connection of solar PV were expressed. Condition monitoring of assets and delaying replacement until absolutely necessary was also a key outcome of the engagement.

When the issue of reliability was discussed, around two thirds of customers saw no reason to change, with the remaining group expecting a continuation of the gradual decrease in the duration and frequency of power interruptions. [48] Customers were not alerted to the fact that Jemena was likely to significantly underspend their capital allowance in the current period.

The specific issues their engagement related to capital investment were:

- Moderate demand growth from new residential development in the corridors north of Melbourne
- The impact of growing solar PV required a response to the feed-in of excess energy
- Urban infill, including some large infrastructure projects, drove connections costs
- Ageing assets present increasing risks to supply reliability, fire starts and cybersecurity
- New regulatory obligations were driving new costs.

We observed that customers were generally accepting of these cost drivers, seeing them as reasonable areas to address within the overarching objectives of keeping price rises in check and not over-investing in reliability or new assets before they are needed.

[48] Jemena People's Panel, CCP17 notes, 9 August 2018

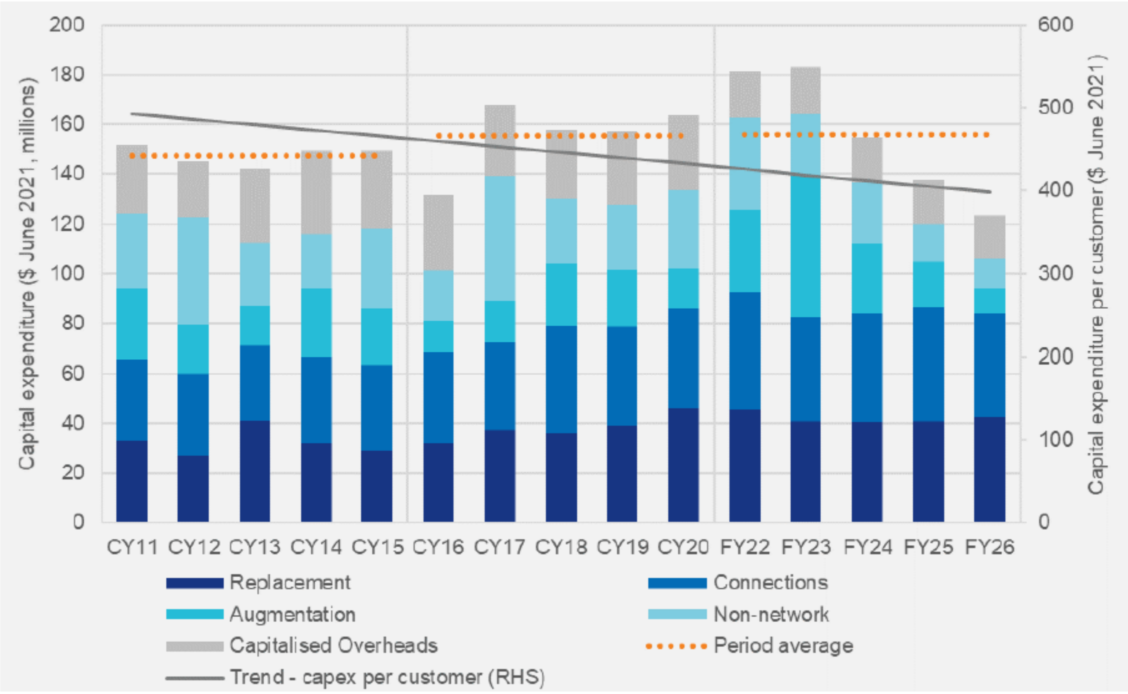

Figure 33: Capital expenditure, Jemena (Source: Proposal attachment 05-01, Capital Expenditure)

The components that contribute to a relatively stable total capital investment are important to note, as:

- Underlying asset replacement (excluding customer-funded asset relocations) capital is increasing by around 5%.
- Planned augmentation costs spike in the middle of the period when the expenditure on the Coolaroo REFCL plant is expected. As noted earlier, there is some doubt whether this project will proceed.
- Demand related augmentation is moderating, replaced by investment to meet DER growth.
- Non-network capex is reducing, as is the allocation of corporate overheads to capital works ($62M to operating expenses).

Several of Jemena's repex categories show a marked slowdown in the current regulatory period, with higher levels of investment planned in the following period. Replacement of pole top structures, overhead conductor, service lines and switchgear tend to demonstrate this pattern; however, we note the marked increase in expenditure on transformers. While it is much more comforting to see stable repex investment over the long term for these high-volume assets, we assume that Jemena has prioritised expenditure to meet the requirement of some high -cost, low frequency investments.

<u>Asset Replacement (Repex)</u>

We acknowledge the moderate increase in planned asset replacement expenditure, excluding the net effect of the customer-initiated asset relocations which are largely customer funded. Despite this increase, we remain generally supportive of the Jemena's proposal.

Figure 34 highlights Jemena's priority to address the replacement of substation control and protection equipment and substation switchgear in the next regulatory period. Service lines also feature, which is a consistent approach seen in the other Victorian distributors. We note the high rate of service line replacement, which is discussed earlier in this advice.

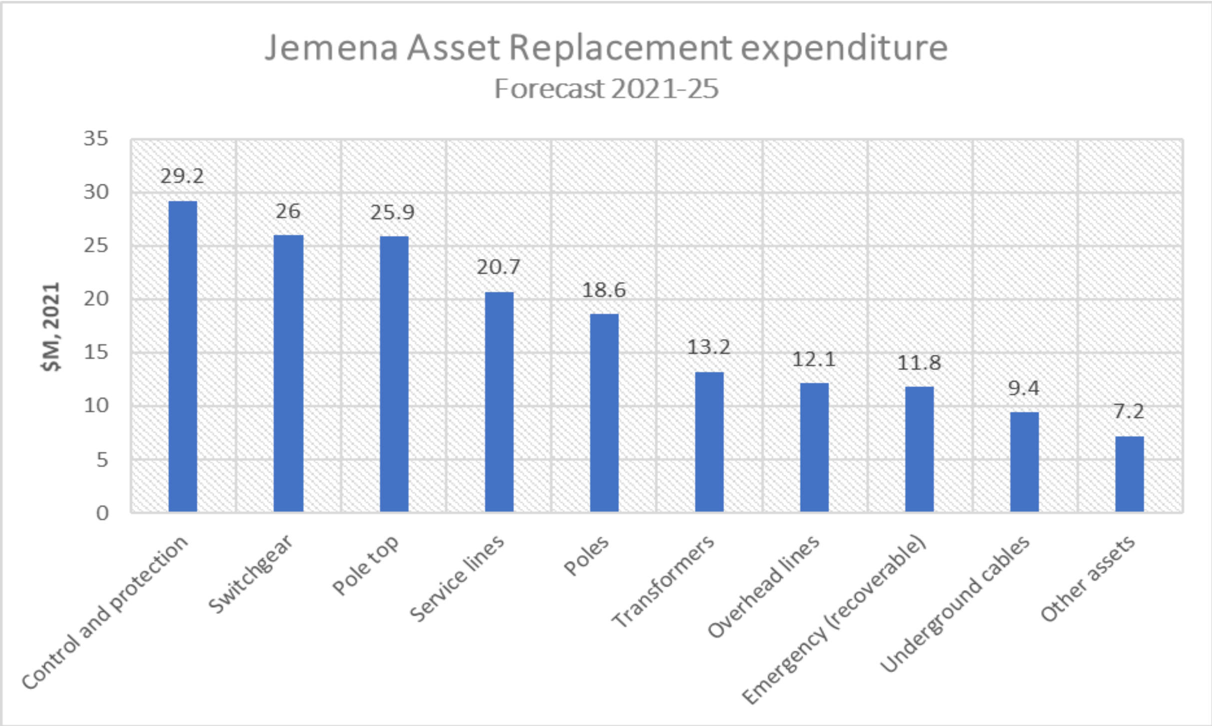

Figure 34: Proposed asset replacement expenditure, Jemena (Source: Jemena proposal att 05-01, CCP)

Figure 34 also shows the approach to substation equipment is part of an escalating programme over the last two periods.

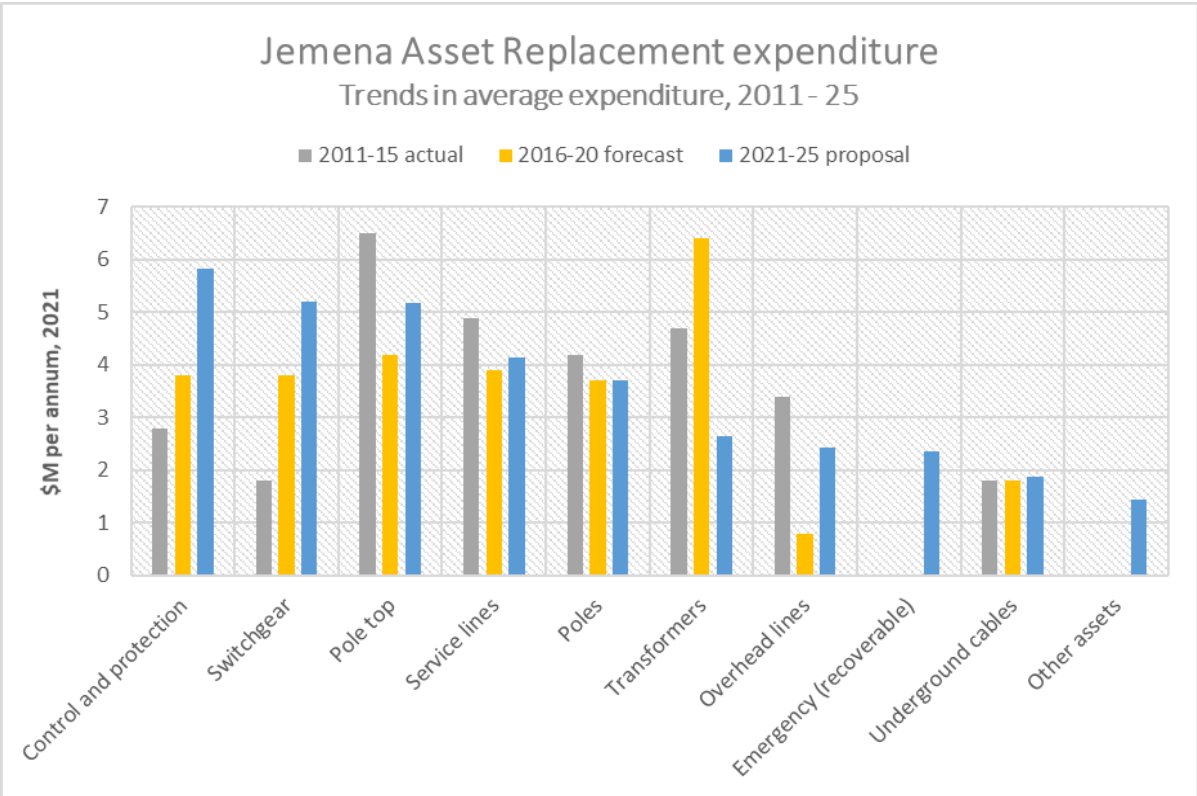

Figure 35: Asset replacement expenditure trend, Jemena (Source: Jemena proposal attachment 05:01, CCP)

CCP17 does not raise many concerns with Jemena's repex proposal. We support much of the proposal on the proviso that the AER is satisfied with the efficiency of the components of the programme.

We make this observation based on the following criteria:

- The modelled Repex compares favourably with the AER's threshold forecast.
- The programme does not include any notable departure from past asset replacement strategies or abnormal events, such as the conductor clearance concerns seen in Queensland.
- The failure rates by asset class generally remain consistent with 2018 levels, and reliability is maintained or slightly improved. This approach is consistent with the consumer preferences expressed in Jemena's consumer engagement.
- The case for increasing expenditure on protection and control systems and substation switchgear was discussed at length in the consumer forums, including a field trip by many members of the People's Panel to inspect old and new plant. In addition, the need to renew compound-insulated switchgear and first-generation protection systems is well understood across the wider industry.
- Underground cable replacement, particularly addressing the public risk of cast iron terminations, is stable and reasonably explained. Other utilities have undertaken similar programmes in recent times for similar reasons.

<u>Other specific comments related to the capex proposal</u>

Repex – poles and pole-top structures

The planned pole replacement rates appear stable. We note - and support - that neither Jemena nor AusNet Services has adopted the revised pole sustainability assessment criteria that have come from the ESV's report into Powercor's pole management strategy and are proposed to be adopted by CitiPower and United Energy.

In response to CCP17's question on the AER Issues Paper, Jemena noted:

> *"The Electricity Safety (Bushfire Mitigation) Regulations 2013 contain a number of specific actions which must be undertaken … as well the requirement to develop a Bushfire Mitigation Plan which must be accepted by Energy Safe Victoria.*
>
> *JEN's Bushfire Mitigation Plan contains a number of programs … ensuring we have appropriate controls in place to manage bushfire ignition risks"*

We support Jemena's position, on the basis that the current pole management strategy appears to be resulting in acceptable pole failure rates and public safety. We also observe a falling trend of pole and crossarm fires,[49] questioning the justification of $8.6M risk-based pole top fire mitigation programme.

Repex – overhead lines & conductors

Replacement of overhead conductors has become a pressing issue after a period of inaction. Data from Jemena also shows a pattern of low investment in the current period, with a significant increase proposed in the next. Again, as these are expected to be long-term, stable replacement programmes, we question the volatility, low period of investment through 2016-20 and subsequent step up in the planned expenditure.

That being said, we respect the initiative to remove all LV mains located in high bushfire risk areas, noting the programme has considerable work ahead to complete.

[49] Jemena proposal attachment 05-01, *Forecast Capital Expenditure*, Figure 4-8

Augmentation

Jemena notes a significant underspend of $93M or 36% in their augmentation expenditure for the current period, due to lower-than expected demand growth allowing the cancelling or delay in capacity upgrades for distribution substations, as well as the deferral of the establishment of the Craigieburn zone substation.

The shutdown of large industrial sites in Melbourne's north is well-publicised.

The proposal asks for demand-driven investment of $88M, almost the same amount forecast to be actually invested in that category in the current period. Given the expectation of stable growth in customer numbers, on average low annual demand (acknowledging the continued development in the northern suburban fringe growth corridor and the Yarraville and North Essendon areas) and no significant step change in customer energy demand mix anticipated, this appears to be a reasonable position.

Jemena has no significant plans to consider the development of microgrids, expanded demand management capability or community energy storage initiatives. This could be encouraged, particularly in the infill opportunities such as Moonee Valley, as an alternative to traditional network development. This may assist in the deferral of the BTS – NS sub-transmission upgrade.

Jemena explained the Preston voltage conversion programme at one of the customer engagement sessions. Despite the significant cost, the logic of removing legacy assets was generally accepted. Given that the programme is well progressed and reviewed in 2019, including two RIT-D tests, the continuation of the programme in the 2021-25 period is accepted.

The non-demand driven augmentation projects include $43M for the proposed REFCL installation at Coolaroo. We encourage Jemena to resolve the issues around the proposed REFCL with the government as soon as possible, so that its need to proceed and likely cost can be clarified.

7.8 Powercor

Powercor intends to invest approximately $2,100M in capital works over 2021-26, and increase of approximately 4% on the forecast for the current period, after the reduction in the expenditure to meet changes to the EP Act is considered. [50]

The investment in REFCL Ground Fault Neutralisers has contributed significantly to the expenditure in both the current and next regulatory periods, as shown in Figure 36.

Outside the REFCL investment, we note the key drivers of Powercor's capital investment are:

a) A significant increase in the number of poles planned to be replaced following a reconsideration of the asset management strategy prompted by an ESV technical report, leading to a considerable step up in wood pole replacement expenditure to $233.8M.

b) New zone substations to meet growing residential demand in Western Melbourne and Geelong, as well as sub-transmission line projects.

c) A marked increase in expenditure to augment the low voltage system, driven predominantly by the expected rapid growth of rooftop PV.

Connections and non-network asset growth are stable or falling.

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[50] CPU letter to the AER, *Amendments to step changes and capital programs,* 15 May 2020

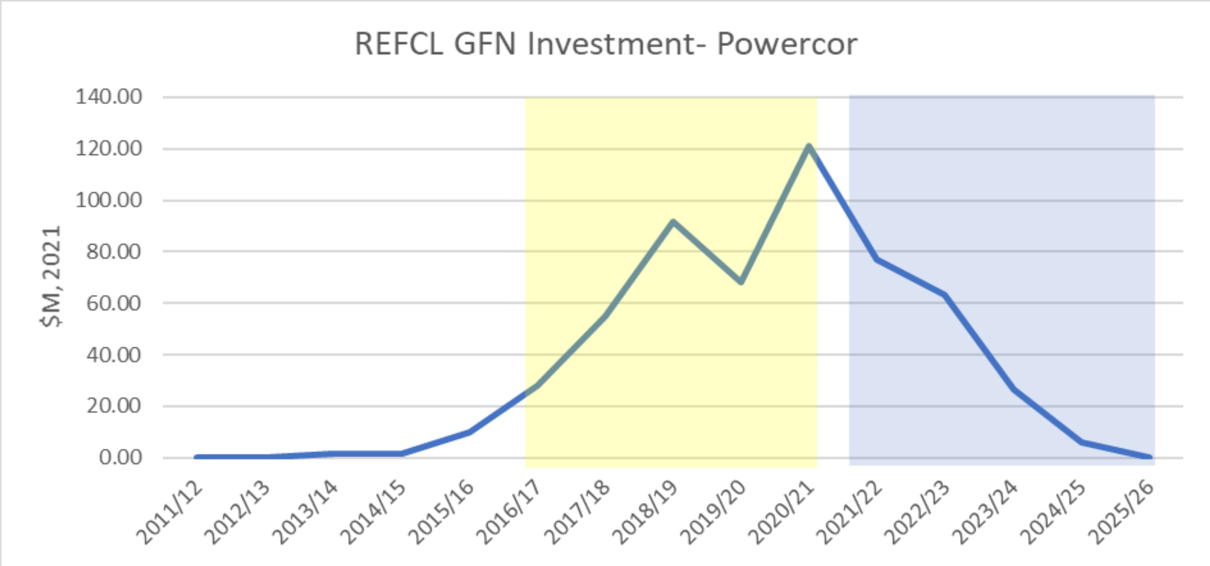

Figure 36: REFCL investment, Powercor (Source: Powercor model 06.09 Bushfire Safety)

We have addressed investment in Future Network initiatives and Distributed Energy Resources elsewhere in this document.

<u>Issues from the Stakeholder workshops</u>

Throughout the extensive engagement process, we observed in general a degree of high satisfaction by Powercor's customers in terms of the quality of service interactions and customer focus in existing customer-facing tools and capability, in particular connections and claims. Powercor also demonstrated a strong empathy with the communities it services.

Powercor put some proposals related to capital investment to customers during their extensive engagement and workshops leading to the proposals, based in the findings from Stage 1 of their engagement. Woolcott Research [51] noted that:

> *"Most participants stated that they had no concerns about the safety of the network - two-thirds of Powercor residents and businesses"*
>
> *and*
>
> *"improving areas of poor reliability to the average level of reliability was favoured by the vast majority of forum participants with much smaller numbers who wanted to either maintain the status quo or increase compensation payments. "*

This led Powercor to adopt a Steady State scenario, with the priority to reduce costs while maintaining network performance and security of supply. Increasing consumer interest in renewable energy prompted Powercor to adopt a strong position on energy feed-in from rooftop solar PV. An overview of the customer engagement is available on the Powercor website.

Powercor notes that around two-thirds of their customers perceived their electricity bills as too high.[52]

Throughout this advice, we have highlighted the importance of balance in the proposals, seeking clear evidence where the distributor notes the value of an investment, but then 'steps back' to respect of the

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[51] Woolcott Research – *Phase 3 Integrated Summary Report,* October 2018
[52] Powercor proposal, p19 – outcomes of Phase 1 research

importance of keeping electricity bills low in both the sort and long term. Powercor, along with the other DNSPs, has quite rightly acknowledged that a full upgrade of their low voltage network to accept full energy feed-in from rooftop solar as being unaffordable. Otherwise, in many business cases, Powercor has opted to accept the most expensive capital option for some initiatives. Granted, the outcomes of the investment will no doubt deliver improved serves for customers and operational efficiencies for the company. We ask: 'Can all customers afford the best solution?' given the significant economic challenges that lie ahead.

We highlight the approach towards digital network, regional capacity upgrades, customer portal development and wood pole management as being areas where it has been very difficult for consumers to see where Powercor has reduced the scope or considered compromises in their plans in response to customers' feedback about electricity prices.

The St Patrick's Day fires, wood poles and the ESV response

CCP17 makes no comment or implication regarding the failure causes or legal action that has taken place in relation to these events. We do wish to point out, however, that the issue of poles and overhead line maintenance is undoubtedly a critical issue to Powercor and its customers, especially those in high bushfire risk areas.

In March 2019, specific engagement sessions held in Warrnambool; a major centre close to regional areas severely affected by fires in March 2018, known as 'the St Patricks Day fires'. One well-attended roundtable specifically discussed Powercor's pole management practices.

Woolcott, in summarising the meeting, notes:

> *"Firsthand experience at the Warrnambool forum meant that residents in this area felt that more needs to be done by Powercor to address the depth of community concern about network-related bushfires, to ensure faulty network assets do not start them.*
>
> *There was a greater strength of feeling there, with participants wanting to see undergrounding by 2025 and the maximum number of pole replacements (4000+). Even then, they weren't sure if this would be 'enough' to alleviate the risk of bushfires."*

More than 40,000 hectares across 219 farms were destroyed in the fires close to Terang and Camperdown. Emotions were high regarding Powercor's alleged involvement in the fires, with a class action against Powercor's maintenance contractor seeking an estimated $119M in damages. [53]

In their proposal, Powercor notes "*we are responding to concerns raised by communities about the long-term sustainability of our pole replacement volumes*". This is no doubt the case, and the litigation and negative findings against Powercor's pole and powerline management outcomes by ESV also contributed to the significant change to their pole repex proposal. The strong customer sentiment noted in the workshops is clearly reflecting what has been an unacceptable safety position, one that devastated the local community and was well-reported across Victoria in the media.

Against this background, we are not at all surprised to see Powercor highlighting customer support for key consumer issues[54] including the review of the sustainability factor for wood poles, undergrounding of infrastructure in bushfire areas and increasing pole inspections, especially in the South West region.

[53] *Powercor agrees to pay 2018 St Patrick's Day fire victims after revelations of sub-par pole maintenance* – ABC News, 6 Dec 2019

[54] Powercor Regulatory proposal, p15

We appreciate the sentiment:

> *"We need confidence in the infrastructure. People need to feel safe."*

Energy Safe Victoria elected to prosecute Powercor for 'numerous powerline clearance breaches' in various areas across their service territory, three of which resulted in fires. Regarding the St Patrick's Day fires, ESV found the fire was caused by a power pole that snapped in high winds due to 'decay and termite infestation', and laid charges against Powercor over the network failures that caused two of the four fires on that day. The matter was heard in the Warrnambool Magistrates Court.

ESV determined 'Powercor's inspection regime failed to identify that the pole was compromised'[55]

Powercor advise that the significant change in their pole inspection and replacement regime is as a result of work with the ESV to address community concerns about the long-term sustainability of poles. In its technical report of December 2019, ESV[56] notes that despite Powercor's current asset management principles and objective being adequate, the serviceability criteria that were applied were not identifying enough unserviceable poles, leading to the conclusion:

> *"The wood pole management system in place in March 2018, at the time of The Sisters fire at Garvoc, would not deliver sustainable safety outcomes for the future"*

and

> *"Powercor's current wood pole intervention methodology (is) inconsistent with good practice and unlikely to support sustainable safety outcomes (p 13)"*

When considering the execution of the policy, ESV found several improvement opportunities, including inspection practices, performance analysis and modelling. Included in its thirteen recommendations, ESV refers to Powercor developing a new wood pole management plan (recommendation 1) and the development of a Serviceability Index (SI) – based assessment methodology (recommendation 7). ESV acknowledges that the changes to Powercor's serviceability assessment improvement initiatives are likely to result in a higher number of poles being classified as unserviceable.

We note ESV's acceptance of Powercor's revised policy for pole testing, and the new policy will be included in the Bushfire Mitigation Plan. [57]

Clearly, the terrible events of 2018 dictated action by Powercor and ESV, driven by a community greatly concerned about perceived shortcomings in Powercor's past wood pole management practices. ESV is clearly supporting improvements to Powercor's wood pole management strategy to deliver 'sustainable safety outcomes for the community'. On the other hand, Powercor noted that historically "*over the long term, our pole asset management practices have resulted in relatively low wood pole failure rates, historically around four poles per 100,000*", despite the information provided in Figure 4.4 of the proposal that shows a steadily increasing pole failure rate since 2015.

From a consumer perspective, we fully support Powercor revising its pole and powerline maintenance strategies and improving the 'on the ground' safety assessment of poles. The situation that led to the recent actions by the ESV and damage to public property attributed to power line maintenance failures must be rectified. In doing so, the following questions must be considered:

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[55] Energy Safe Victoria News – 'ESV prosecutes Powercor over St Patrick's Day fires' – October 2019
[56] Energy Safe Victoria ' *Powercor Wood Pole Management, Detailed Technical Report'* – December 2019
[57] ESV letter to Powercor, 27 April 2020

- To what measure has Powercor done ‘just enough’ to respond to the ESV requirements? Can the revised Serviceability Index (SI), upon which the pole replacement rates are driven, be demonstrated to be prudent, efficient and consistent with peers, and no more?
- Is there evidence that previous allowances have been invested prudently, in light of significant CESS benefits? The ability to claim significant capital efficiency benefits ($77M) when the safety regulator (ESV) finds ‘*that pole intervention methodology is inconsistent with good practice and unlikely to support sustainable safety outcomes*’ [58] does not sit well at all with consumers.

  At the least, we suggest that Powercor should consider reinvesting some or all of the CESS benefit towards their pole and powerline safety programme, with customers not perceiving that they may be ‘paying twice’.
- Figure 37 suggests that the revised practice of accelerated pole replacement does not commence in a significant way until the 2021/22 financial year, i.e. next regulatory period. We suggest that in the community’s eyes, there is an implied imperative to ‘get onto this, straight away’, especially in light of the projected capital underspend (and associated efficiency benefit) that is likely in the current period.

  Also notable from the figure is the steady decline in pole replacement expenditure in the early part of the current regulatory period.

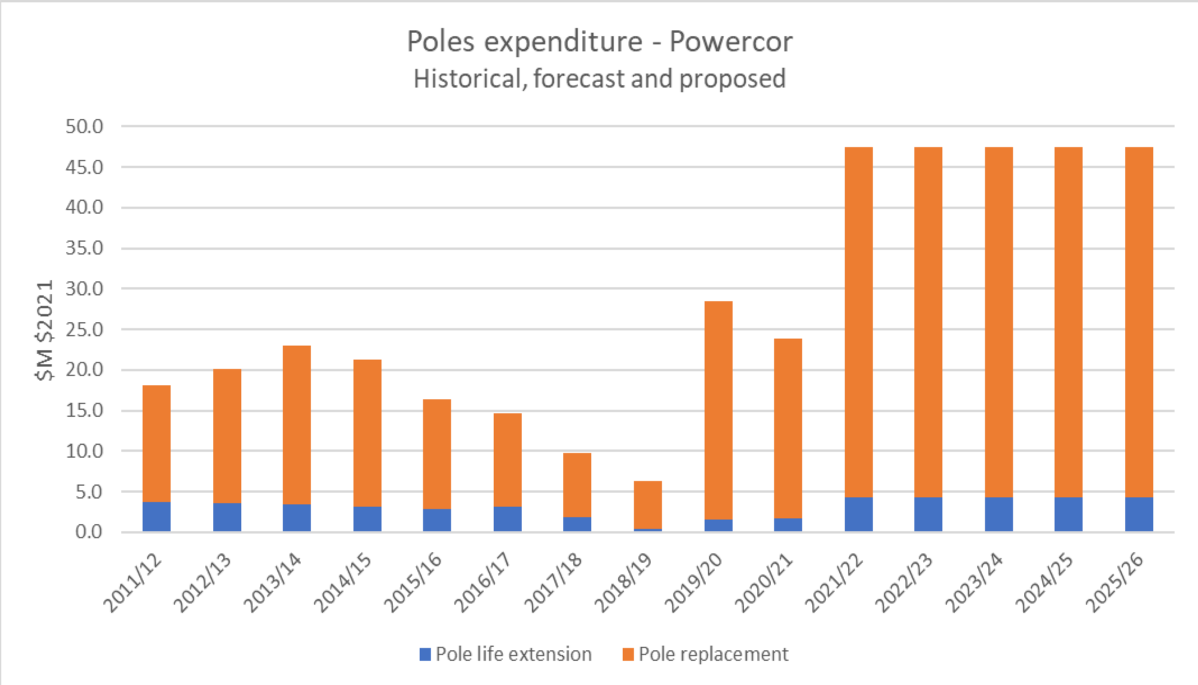

Figure 37: Powercor pole repex expenditure (Source: Powercor model 04.06 - Lines replacement)

<u>Specific comments related to the capex proposal</u>

Mitigating REFCL impacts

Powercor outlined to the community workshops the impact of REFCL systems have on the normal operation of automatic circuit reclosers, resulting in reduced reliability for many customers. Media reports highlight the impact of reduced reliability on the township of Apollo Bay. We see this as an unfortunate bi-

58

product of the installation of the REFCL systems; and consequently, support the proposed $13M expenditure to address this issue.

Augmentation - Upgrading Regional Supply

Powercor is proposing to invest $8.7M as targeted upgrades to four local supply networks in regional areas, recognising the value of three-phase upgrades to dairy farms.

The limitations of single wire earth return (SWER) lines in supply modern dairy farms are a well-known issue. For many years, initiatives have been proposed to share the often-prohibitive cost to upgrade these rural lines to three-phase construction. Replacing SWER in codified (high fire risk) areas is already a supported and well-understood programme. However, this particular investment proposed by Powercor does not relate to a high bushfire risk area.

We have no doubt that the upgrade of regional SWER lines will benefit those connected to the line. By definition, SWER was a low-cost rural electrification option with known limitations. The issue is many regional areas and industries have evolved to the point that the SWER supply limitations are becoming significant.

Powercor has demonstrated the support of many customers, industries and local stakeholders who will directly or indirectly benefit from the upgrade. We are not aware of the matter being presented to consumers outside the regional areas that were flagged to benefit from the upgrade to assess their willingness to contribute to the cost.

A similar matter was encountered over twenty years ago, when the outcome was a tri-partite funding agreement between the United Dairy Farmers Federation, the Victorian State Government and the electricity distributor, reflecting the three primary beneficiaries of the investment.

Ultimately, while we appreciate the community-based approach that underpins this initiative to upgrade regional supply in this or any other regional areas supplied by SWER systems, we cannot support the proposal as it is presented, because:

- All beneficiaries – customers, the state government and the distributor – should make reasonable contributions to the cost of the upgrade. It should not be borne by electricity consumers alone.
- The investment can create a precedent that can translate to SWER retirements in many other areas in the state. Powercor's proposed assessment criteria could easily apply to many other parts of the network, so clarity as to 'why here' is needed.
- If this initiative is to proceed, we strongly recommend a broader consumer engagement programme to demonstrate widespread customer support for a SWER upgrade policy and shared funding arrangements, particularly considering our overarching affordability imperative.
- Powercor could recognise its commitment to regional development by perhaps making its own significant contribution to the upgrades without recovering the cost through the asset base, perhaps in the form of a community sponsorship.

Augmentation and ICT – Solar Enablement & Digital network

These issues are discussed in detail in the following sections of this advice.

1. Opex – Fuse replacement programme

The proposed opex step for EDO fuse replacement ($11M) is more appropriately considered a capital investment as part of the wider bushfire risk mitigation programme.

2. Information and Communication Technology

The $11M investment proposal for the digital network programme is discussed in the section 'Future Networks.'

In recent years, utilities have planned the replacement of their SAP systems to S4. This has been the subject of detailed analysis in other determinations, in particular that for SA Power Networks, and the AER's position will be revealed in that determination.

Several utilities are planning upgrades to SAP S/4 HANA, and we expect that the AER will explore not only the economies of scale that should be available from the parallel upgrade implementation, but also consider the capability and possible customer impact of these companies undertaking upgrades at the same time.

ICT – Intelligent Engineering

Powercor, along with CitiPower propose investment of $4.4M each to support 'Intelligent Engineering'. We are unable to support this investment, on the basis that it also delivers significant efficiency opportunity to the company itself, and therefore should be self-funded.

Please refer to the CitiPower comments for a more expansive discussion of this part of the proposal.

Non-network investment

Powercor has a significant property programme of $114M, upgrading and redeveloping depots. We do not recall these issues being widely consulted on in any part of the engagement. Therefore, we will rely on the AER's assessment of these proposed investments.

Consistent with our wider comments on the need to restrain RAB growth to maintain downward pressure on prices, and accepting the increase in expenditure on pole replacements, REFCL and augmentation, we suggest that Powercor take the view that capital is not unlimited, and prudency suggests that as many of these projects as possible could be deferred to later regulatory periods.

7.9 United Energy

United Energy is planning to invest net capital of $1,137M in the next regulatory period, after allowing for the adjustment to the costs to comply with the changes to the Environmental Protection legislation. This is the largest increase (28%) on the forecast spend in the current period for all five distributors, noting that United Energy is expecting to under-spend the current period allowance by close to $166M, or 17%, with an associated CESS carryover of $72.4M

Figure 38 shows this trend, noting the change in the forecast related to the new approach to the EP legislation is not included in this data.

Asset replacement is by far the largest programme at $505M.

The planned capital expenditure is driven primarily by:

- A significant increase in non-network capex for ICT, future networks, and property upgrades
- A large increase also in network augmentation across several categories
- An increase in asset replacement capital, largely in the pole replacement programme and transformers and switchgear

This pattern of investment does not sit well with consumers. Admittedly, there are irregular, 'lumpy' investments in property and future networks that could be argued are infrequent and it is coincidental that these have become necessary in the same regulatory period. We have highlighted previously that customers expect utilities to behave like large industry in recognising that capital constraint is a real thing, and despite many projects having attractive economic returns, 'it all can't be funded at once.'

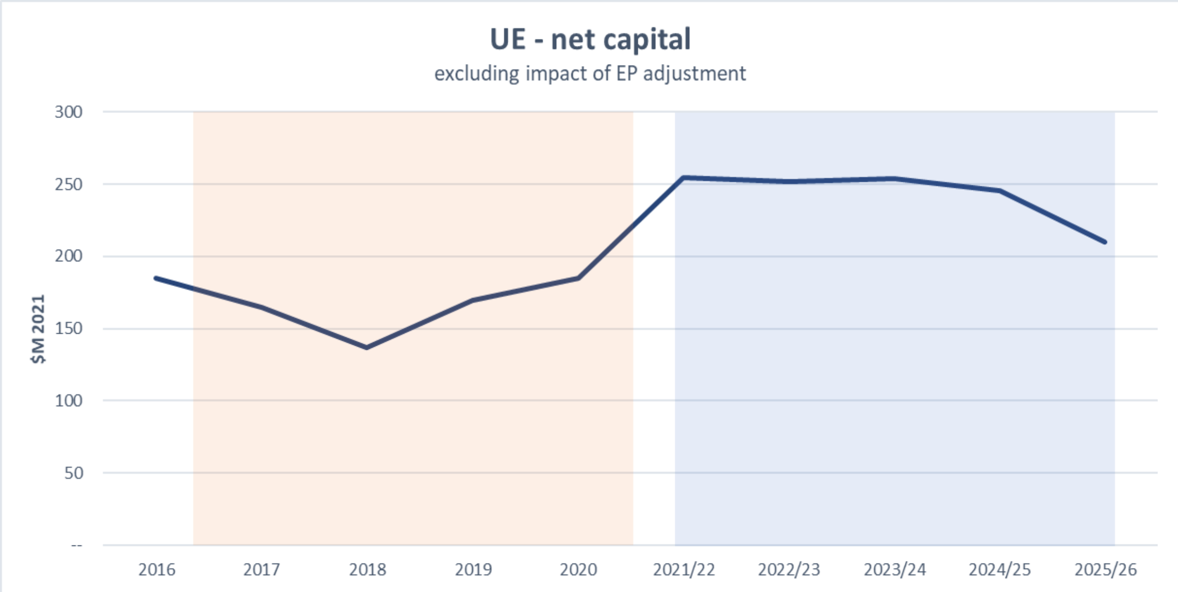

Figure 38: United Energy capital expenditure trend (Source: UE Model 10.05 consolidated Capex)

<u>Issues from the Stakeholder workshops</u>

United Energy followed a similar engagement programme to that of its sister companies Powercor and CitiPower and in general, the key messages from consumers were also aligned:[59]

- Over two-thirds of residents had no concerns about the safety of the network
- There is a preference to underground power lines
- The service wire safety programme (dog bones) should proceed on a prioritised basis
- 86% are satisfied with the reliability of their power supply
- Affordability remained the key issue, with nearly tw0-thirds regarding their bills as too expensive.

United Energy is well regarded in its innovation and research programmes, including the battery energy storage trial, dynamic voltage management system, Summer Saver and various other demand response initiatives. United Energy considered the growth in electric vehicles will be a noticeable impact on their network, forecasting an eight-fold increase in EV numbers to around 55,000 by 2026.

<u>Asset Replacement (Repex)</u>

UE plans to invest $505M in asset replacement. Notably, this is around $100M more than the amount discussed in the draft plan in early 2019. The pole replacement is the primary component in this large repex program. However, transformer and switchgear replacement programmes are also significant.

[59] Woolcott Research, *United Energy Phase 3 Integrated Summary Report*, October 2018

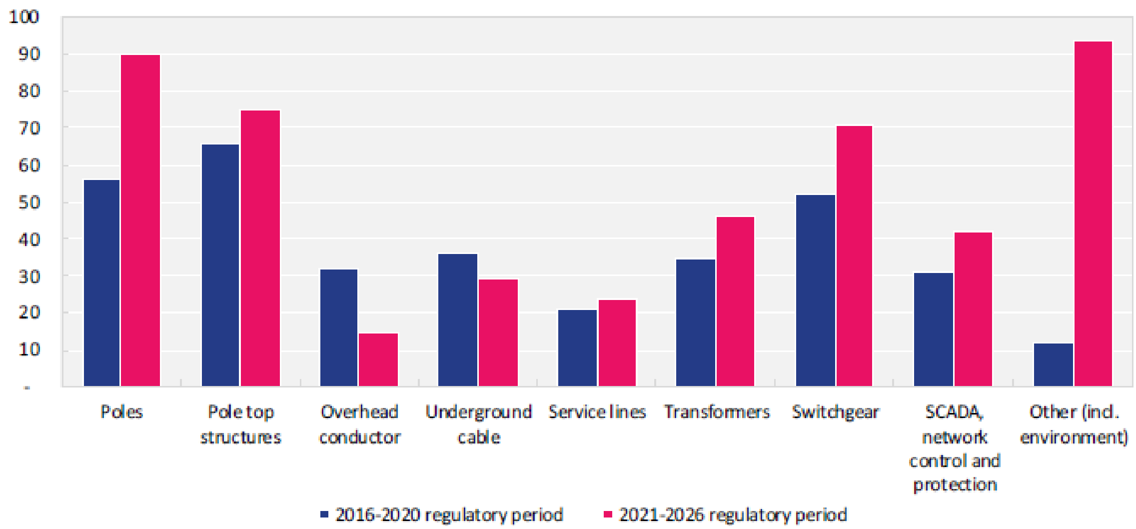

Figure 39: Historical and forecast replacement investment, United Energy (Source: UE proposal fig 4.2)

United Energy proposes to adopt much of the changed wood pole asset management strategy established by Powercor following the 2019 review into pole management practices after the St Patrick's Day fires. In our response the proposal by CitiPower to adopt this methodology, we outlined the reasons why this is not appropriate. The same reasons apply here. United Energy notes in its proposal:

> *"… we are now the fourth best performing distributor network in terms of unplanned minutes off supply in the National Electricity Market (**NEM**), surpassed only by two predominantly underground central business district based networks and within four minutes of the third placed urban distributor."*

> *"To ensure our commitment to safety, we have key measures … Since 2013, we have more than halved the number of public incidents across our network and have held the number of fire starts constant."*

> *"Our existing asset management approach for poles reflects a condition-based replacement program. To date, this approach has resulted in our network having amongst the lowest wood pole failure rates in Australia."*

This data indicates that United Energy has a pole safety record to be proud of. We see no justification to apply the increased safety index criteria in the United Energy region, nor have we observed instances where customers of UE have supported a significantly increased programme of pole replacements.

United Energy proposes to carry out work on a limited number of concrete poles that are not connected to the common multiple-earth neutral (CMEN) system. We are aware of the requirements of this programme, and it has our full support.

Specific comments related to the capex proposal

Augmentation

We discuss the solar enablement and network devices part of the augmentation proposals elsewhere in this advice. Otherwise, we have no specific comment on United Energy's demand-related augmentation programme.

United Energy held deliberative forums with customers to explore the options to meet demand growth in the Doncaster area. We were not able to observe this forum, nor have any notes been made available.

Non-recurrent ICT expenditure

Digital networks and customer enablement are discussed in the Future Networks section of this advice.

We note the number of utilities that are planning upgrades to SAP S/4 HANA, and expect that the AER will explore not only the economies of scale that should be available from the parallel upgrade implementation, but also consider the capability and possible customer impact of these companies undertaking upgrades at the same time.

ICT – Intelligent Engineering

United Energy, along with CitiPower and Powercor propose investment to support 'Intelligent Engineering'. We are unable to support this investment, on the basis that it also delivers significant efficiency opportunity to the company itself, and therefore should be self-funded.

Please refer to the CitiPower proposal for more detail.

8 Future Networks

8.1 Introduction

In the consumer engagement leading to the regulatory proposals, discussion on Future Networks featured prominently, with the companies running multiple workshops, forums and focus groups to explore their customers' expectation of the response to their future energy needs. By far, the discussion focused on the growing role of rooftop solar PV. Technologies such as energy storage and electric vehicles were considered briefly but in any material way in so far as how the technologies influenced the proposals.

Customer access to meter data and enhanced service interactions were also another common themes.

The predominant aspect of the five DNSPs' Future network programmes is developing hosting capacity in the network to facilitate the increased levels of feed-in energy from growing customer investment in rooftop PV. This significant area is discussed extensively in Section 09 of this advice.

Across the engagement, it was clear that customers also expect distributors to continue to develop contemporary customer services capabilities such as online applications and the provision of timely and personalised information, especially regarding network outages. As we have noted across this advice, we encourage the DNSPs to re-engage with their customers to ensure the priorities, assumptions and sentiments that related to future networks investment remain valid in this post-COVID19 environment.

Just what defines Future Network investment can be a difficult question. In the engagement, the customers and distributors have landed on future network investment being "*investment to continually evolve and adapt network infrastructure and services so as to enable emerging technologies*."

The true costs and benefits of investing in a future network capability are often difficult to see, as many initiatives form part of other investments, such as solar enablement or demand response. Often, the objectives of developing future network capability come 'built in' as part of the business-as-usual process of renewing and upgrading systems and skills. The costs to invest in future network capability appear in multiple budget line items, such as augmentation, ICT, non-network expenditure and operating expenses. Unfortunately, the benefits of such investments can be even less transparent and tangible.

The advice by large customers in the United Energy engagement in October 2018 reflects the customer regarding future network by noting:

> *"(The) preferred energy future was a steady and progressive integration of renewable energy with a measured reduction in tariffs by 2025 and improved power quality (fewer power fluctuations)."*[60]

Maximising the value of the AMI assets

Key to our advice is the recognition that Victorian electricity customers have already made a significant investment in Advanced Metering Infrastructure. We also expect that within the next regulatory period it will be necessary to consider the replacement and upgrade of many of these assets. Against that background, we see it as critical that the DNSPs demonstrate that they have made the absolute best use of this asset. AMI provides detailed and timely data on the state of the network, as well as robust communication infrastructure, which provides a foundation for a 'Future Network'.

[60] Woolcott Research, *United Energy Phase 3 Integrated Summary Report*, October 2018

The case study noted by CitiPower regarding the detection of neutral integrity issues,[61] United Energy's Dynamic Voltage Management System (DVMS) and AusNet Services' Distribution Energy Network Optimisation Platform (DENOP) are examples of benefits already realised by the clever use of emerging technologies. We fully support these innovative applications that capitalise on the AMI capability.

Many of the Future Network proposals included installing more metering or controls. We can support this investment only after it can be shown that extrapolation or intelligent modelling using the current amount of detailed data is clearly not feasible. We ask: "*Have the distributors extracted as much benefit as possible from the AMI systems, including through modelling and state estimation, before investing in further data gathering equipment?*"

8.2 Consumer sentiment

Without exception, customers expressed a clear expectation that the networks will efficiently invest to meet the demands of a changing mix of household technologies, including electric vehicles and energy generation and storage.

For consumers, investment in smarter networks is matter for both 'heart' and 'head'. To a large extent it is an emotional decision, reflecting the expectation that networks will reflect the technological and service-related advances seen in so many other parts of daily life. Support for change is not based on detailed analysis and unequivocal cost / benefit calculations, rather a trust that tangible returns to consumers will result - not just promises of future benefit based on possible scenarios - often at the same, or lesser, cost.

In assessing the value of the future network proposals to consumers, we refer to the research undertaken by AusNet Services . From that research, the priorities can be paraphrased as being:

a) Deliver on the basics – maintain a safe, capable, reliable network

b) Keep customers informed

c) Maintain an affordability focus

d) Safety is non-negotiable

All the proposals in this category note a positive return on investment. In considering the return, we ask:

e) Are the benefits based on robust, reliable and practical assumptions?

f) The Pareto approach – can most of the benefits be delivered in a simpler, cheaper way?

g) Does the mechanism exist where these benefits, particularly bill savings, are confidently delivered to customers in an equitable, timely and transparent way?

Some of our detailed analysis does not, in our opinion, stand up to public scrutiny as having taken an adequate account of risks, explored the sensitivities to key assumptions or widely considered alternative options and approaches. Uppermost in our concerns are the growth forecasts and use patterns for electric vehicles, the nature and pace of tariff reform in Victoria and the appropriateness of the distributor as a primary source of meter and consumption data to customers.

Regarding customer service interactions, we note the advances already made by some distributors, including Powercor. Further development of portals will clearly yield benefits to customers and the distributors alike.

When it comes to data provision to assist customers making better energy decisions, throughout the engagement a common theme for better and more accessible and timely data was evident. Given the clear

[61] Powercor CitiPower business case BUS 7.08. p8

message regarding energy affordability, we are not at all surprised that customers will approach any informed source, including DNSPs, as a potential source of assistance in minimising bills. We are not convinced that this support is a strong reason to base expenditure plans to expand the way meter data is made available to customers. In order to claim strong customer support, we require the engagement to put the distributors' proposals in context with the other tools that already exist on the market.

In the wider context however it still seems a very sensible step that distributors embrace new technologies to improve their asset management capability, provide better data to consumers (in particular outage data, complaints and customer services), address falling network utilisation and operate the network more efficiently. As rooftop solar PV and other new customer technologies proliferate, utilities should make reasonable investments to not only capitalise on the vast pool of AMI data to optimise network operation but to also provide a greater basis in fact to make more informed decisions regarding emerging network risks, investments and opportunities.

We support prudent investment that addresses these important matters for electricity consumers.

8.3 A future networks operating model document would be helpful

CCP17 is a strong supporter of any initiative to improve the falling load factors and network utilisation seen in modern networks. The challenge to use existing assets as productively as possible, managing peak demand and facilitating the local consumption of solar PV is an admirable objective.

There are programs that refer to demand response capability. For example, United Energy refers to optimising load control devices in several areas within their proposal, including $8.6M for 'demand management solutions'. We recognise that UE is well progressed in demand response, so this suggests there is the risk of overlap of the programs and may present an opportunity to consolidate the spending for a more efficient outcome. However, we cannot see a where the networks can demonstrate where technical, social, and commercial initiatives fit into a broader, integrated and multi-faceted vision for a more efficient and better-utilised network.

We see a lot of value in the DNSPs each publishing a 'future operating model' document into the public arena. This would allow future network investment to be discussed more widely, to encompass the many aspects of efficient and customer-focused energy use in a vision document, which would consider matters such as:

a) How networks are planned to evolve in the medium term to meet the power supply needs to remote and regional communities, considering microgrids, local energy autonomy, 'thin connections' and a high proportion of renewable energy

b) The role of energy storage, both in the grid and at customer's premises

c) The application of active and passive demand response by customers

d) A position on changing energy mix, including gas

e) A strategic view of the distributors' role in the many aspects of demand response

f) The role of advanced tariffs in meeting peak demand, encourage best use of DER and hemp mitigate any peak demand risks from electric vehicles.

g) How actions at the sub-transmission and distribution network level integrate with the broader transmission system operating requirements and emerging new planning criteria.

Having a clearer vision of a future operating model would put many of these future networks proposals discussed below in some context. Seeing how these initiatives fit into the 'big picture' that integrates with asset planning, tariff design and market development would be especially useful, and provide a platform to carry out appropriate engagement, sensitivity analysis, testing and modelling.

8.4 CitiPower, Powercor Australia and United Energy

CitiPower, Powercor and United Energy have all taken a similar approach to Future Networks. From their proposal overview documents, the capital costs are shown below. Digital network costs include a separate network investment for additional devices at contestable metered sites and distribution transformers.

The proposed investment in solar enablement, the major component of the CPU future network proposals, is discussed separately in this advice.

Program	Intent		Powercor	CitiPower	United Energy
Solar Enablement	to allow approximately 95% if customers to connect rooftop solar PV with export capability		$61M	$31M	$41M
Digital Network	intended to enhance affordability and customer choice	ICT	$11M	$11M	$19M
		Network	$4.7M	$5.5M	$6.5M
Customer Enablement	to meet a demand for real-time meter data		$8M	$3M	$13M

Digital Network

Powercor, CitiPower and United Energy plan to invest in new technological capability to increase the distributors' monitoring of the network and analysis of data to deliver more informed decisions regarding the operation and development of the LV networks. The basket of activities under this section of the proposal includes IoT platforms, real-time grid analytics, an enhanced LV system model and additional metering and power quality devices to be installed across the networks.

The three businesses have described the need of the investment as being "*to improve the ways we combine and generate real-time, actionable insights from our data through analytics and implement more sophisticated monitoring and management capabilities so that we can run the LV network dynamically*." It includes extending the coverage of Advanced Metering Infrastructure (AMI) network devices to contestable metering customers (large customers) and unmetered supply in a targeted rollout.

CPU have taken a long-term view of costs and benefits to 2040 for future network investments - over four regulatory periods - with two options examined. Based on their consultant's (Jacobs)[62] analysis, each suggests an attractive rate of return for consumers. The benefits are noted as:

a) Reduction of network losses (theft)

b) Support for cost-reflective pricing

c) Electric vehicle charging optimisation

d) Customer load monitoring and optimisation, with a reduction in peak demand growth

e) Additional potential benefits in the LV system

The engagement was extensive gained customer support for the overarching capability of being able to make better decisions regarding new energy technologies and efficient network development. The

[62] Jacobs, *Cost Benefit Analysis for Digital Network Implementation, VPN and UE* – 9 Dec 2019

headline benefit claim is $71M through to 2040 through 'making better network decisions and improve network safety for customers by closely monitoring power usage.'[63]

What was not so clear in the engagement is the individual initiatives that sit under the future network banner, and whether each item was critical to fulfilling customers' expectations. In particular, the detail that supports the estimated net benefit calculations have not been challenged in customer forums to our knowledge.

Option 1 or option 2?

The consultant's advice (Jacobs) considers two options for Powercor and CitiPower in digital networks:

Option 1:

> Investment in the Digital Network Infrastructure, including Foundations, Platforms, Comms, Integration, Security and Application Platforms. Digital Network will provide monitoring and control and will provide benefits through integrating the existing customer AMI into the Digital Network Framework.

Option 2:

> Increasing the current coverage of network devices to improve efficiency, accuracy, effectiveness and coverage of the Digital Network. Install AMI at contestable metering sites, installing Smart PE Cells at unmetered sites and installing CT measuring devices at critical distribution transformers.

The businesses favour option 2 of their consultant's report, being "*in addition to investing in new technology that provides greater network monitoring and control capabilities, increase the current coverage of network devices to improve LV visibility*", consistent with the consultants' findings that option 2 has the highest NPV over the long term.

The benefits from option 2 are largely the same areas as option 1, only expected to be greater in quantum over the longer term. Neither the proposal nor the business case provides clarity as to the actual cost differential between the options, instead focusing on highlighting a higher IRR, then proceeding to model option 2 costs. We are concerned that there appears to be little rigour behind the sensitivity analysis, and limited customer engagement related to the two options. As noted in the introduction, there are a lot of questions that could be asked about the benefit realisation of each initiative against our measures of practicality, elegance, and benefits realisation.

The consultant's report informs the proposal [64]. However, many questions remain, including:

a) Reduction in non-technical losses

AMI in Victoria already means unauthorised usage (theft) is very low, around 0.03%. The proposal is to better detect unauthorised usage and reduce unauthorised use by 25% - 50% and under-recorded energy use at unmetered sites by 90%.

- How does the reduction in network non-technical losses result in savings for all consumers? What is the role of the retailers in passing on cost savings from unbilled technical network losses?
- The case assumes that energy use at unmetered sites is under-recorded by 10%, and that the programme will reduce this by 90%. Where is the evidence that supports this estimate?
- Can under-recording risk of unmetered sites be addressed by sample testing or other statistical means rather than install meters and become 'metered' sites? Often, unmetered sites are just that

[63] Powercor Regulatory proposal, p12

[64] Powercor attachment 009 - *Jacobs Cost Benefit Analysis for Digital network Implementation* - 9 December 2019

due to the impracticality of installing metering because of physical limitations, the ability to easily estimate the usage or due to the risk of vandalism. Has this been considered? Have the owners of the non-metered sites agreed to the change?

- Is there a risk that metering a previously unmetered site could show that the site is in fact overcharged, thereby reducing the benefit of the business case?
- If undercharging is NBN sites is a widespread issue, what action has been taken to remove their unmetered status, in which case it becomes a new connection with appropriate cost recovery from the customer directly? Or, at least, can the level of unmetered consumption be renegotiated?

b) Cost reflective pricing

This case centres on deferred network augmentation facilitated by the extension of the 'Summer Saver' programme, requiring smart metering being extended to large customer sites and several distribution transformers.

- Are there viable alternatives to the proposal to install distributor metering in parallel with revenue metering at contestable customer sites? Does it really make sense to put network monitoring and metering in parallel with existing contestable metering, the data from which is available each day through normal market processes?
- Will 'Summer Saver' be attractive to larger customers, who may already be working with retailers or aggregators on demand response programmes?
- Is there a risk that a broader demand response programme is implemented over the life of the benefit calculation of this investment (2040)?

c) Electric vehicles charging optimisation

The proposal considers the direct control and coordination of EV charging, and the deferred capital expenditure resulting from optimised EV charging. Table 10 of the Jacob's review assumes that the distributor will implement charging control to 52% of EVs in the region.

- What are the sensitivities to the assumed growth and network costs associated with electric vehicles?
- Is more monitoring and control needed now, or will the approach taken in many other jurisdictions of EV charging-appropriate tariffs and customer choice be sufficient initially?
- What customer research has been done to suggest implementing charging control will be acceptable? Will customers accept the rollout of devices such as IoT for network reasons?

d) Customer load monitoring and optimisation

Under this part of the proposal, VPN and UE would use the Digital Networks Framework to identify which customers were typically higher users during peak. They would approach those customers and offer an opt-in program with the aim of implementing some form of control and/or optimisation over the main appliances to reduce peak demand. The benefits of $149M are unclear as to whether it is deferred network augmentation or customer savings.

On the surface, we applaud any initiative that addresses the falling load factor and declining utilisation of the network. We strongly encourage all distributors to embark on a coordinated, robust, well-researched and integrated (technical, commercial and social) approach to improving network utilisation though an advanced demand response capability.

This particular initiative as presented however appears to be piecemeal and inefficient. Once again, however, we have queries and doubts, including:

- Would not the existing AMI provide guidance as to users with high demand peaks?
- What is the role of demand pricing to encourage customers to change energy use?
- What would be the value proposition to customers, and is it attractive?
- Is the proposed infrastructure efficiently expandable to a larger cohort of customers?
- Regarding using water heating to self-consume solar PV, is this a role for a distributor, and can the impacts be reliably modelled from a sample, without requiring digital network framework to identify the benefits?

Summary – Digital Network

Consequently, we have concerns regarding the validity of many of the assumptions that underpin the suggested benefits, let alone the comparison between option 2 over option 1.

The comparison with other distributors in the business cases, while useful, tends to overlook the fact that all Victorian consumers have already paid $2.24B to introduce advanced metering at almost every customer supply point, putting Victorian distributors at a significant advantage on other jurisdictions. We question whether the distributors cannot draw reasonable advantage regarding energy theft, customer energy profile modelling and EV charging analysis from the existing systems.

Notwithstanding all these questions, we acknowledge that a level of investment is needed to establish a data gathering and analytics capability to further explore these benefits. Therefore, we encourage the AER to consider the proposals for investment in the core data management and core analytics capability inherent in the more basic levels of investment in Digital Network, but we do not support the vast majority of this proposal, on the basis that:

a) other simpler, less costly alternatives exist to achieve similar outcomes
b) The many expectations of customer acceptance of these initiatives are untested
c) The benefits to customers are not clear, are over a long time (to 2040), are not assured, and are subject to exogenous factors that may or may not change as required to support the proposals.

<u>Customer Enablement</u>

The three CPU distributors propose to integrate and enhance their customer-facing information systems to enhance customer experience during 2021–2026 by:

- improving and consolidating the existing customer-facing easy access tools into a unified access point, with one username and password and the same interface
- improving the effectiveness of SMS notifications during outages and introducing notifications on the efficiency of customers' rooftop solar output and exports
- extending tools to HV customers and embedded generators
- providing customers access to more frequent usage data to better inform their energy choices.

Against the ‘do nothing’ option where the customer applications appear as largely separate applications, CPU have considered two options – to unify and enhance the existing tools, and further to include near-real time access to AMI data. Both options are presented to have significant positive benefit.

CCP17 is supportive of the development of seamless, modern web and mobile based tools to assist with customer-facing operations such as supply and connection applications, outage notifications and streetlight reporting. We recognise the advances that CPU have made in improving customer interactions and acknowledge customer support for the development of these facilities to continue. Therefore, we are provisionally supportive of 'option 1' of the CPU proposal, at a cost of $9.5M for Powercor and CitiPower,[65] and $12.3M for United Energy,[66] on the basis that the AER determine the cost to be efficient.

We are less enthusiastic about the extension of the proposal to 'option 2' – that is, to provide more frequent usage data on to customer to better inform energy choices. We acknowledge that customers of CitiPower and United Energy were keen for options to make it easier for them to make informed choices, but we question "is the distributor best placed to provide that assistance?".

We are unaware whether the distributors explored this interest by customers further, by demonstrating the form and extent of the data that would be made available to customers under this project, compared with the various forms of data already available. We also point out that:

- customers can already access their usage data, updated every hour, on the existing portal.
- while usage data is useful, customers are seeking the data to manage bills. Raw usage data needs to be converted to billing data through retail tariffs, which are subject to fixed charges, varying rates and specific conditions. Retailer portals and Energy made Easy are much more powerful and relevant for customers' bills.
- Retailers are just as likely to develop information portals that will be more useful to customers than the raw consumption data from the distributor.

Therefore, despite the low incremental cost, we do not support CPU's development of the real-time data access facility though their enhanced portals.

8.5 Jemena

Jemena held three future network forums in 2017 and 2018. The workshops introduced the 'megatrends' in electricity, with much of the discussion related to pricing and pricing structures. Regarding network investment, customers supported 'modernising the low voltage grid to accommodate more DER'.

Consequently, under the banner of their Future Grid programme, Jemena anchors its investment on the ability to accommodate higher penetration of DER, particularly rooftop solar PV, with a large part of the future grid proposal directly aligned with enabling greater PV hosting capacity.

Program	Intent	ICT Capital	Network Capital	Opex
Enable DER	Implementation of new LV network model	$5.9M		$0.8M
	Dynamic DER control for the control and management of DER	$6.4 M	$2.7M	$1.0M
	Augmentation of LV network assets		$9.4M	$1.8M
Optimise Asset Investment	Utilise the network in a more informed manner	$2.8M	$2.2M	

As part of its 'Enable DER' programme, there is the intention to develop an LV network model. We support this initiative as it is consistent with the plans of other distributors, as well as providing a platform to

[65] Powercor / CitiPower business case BUS 7.02 – Customer Enablement
[66] United Energy business case BUS 7.02 – Customer Enablement

operate the LV system more effectively and approve both load and DER connections in a timely and more customer-focused way. The benefits of such a capability have been well-documented by several distributors, and it is our assumption that similar benefits will be delivered for Jemena customers through this investment.

We question the nature of the $0.8M operating cost step associated with the LV model. The gathering of LV data to populate the model, preparing work packages for ICT and the payment to customers to update inverter settings could be reasonably seen as a 'one-off' task, and hence considered as capital investment.[67]

Regarding 'Optimise Asset Investment', we note the key features include improved condition monitoring for end-of-life assets and implementing dynamic ratings for asset operation. The proposed cost of $5M is expected to deliver benefits predominantly in the future reduction in asset replacement costs. The use of dynamic plant ratings is also an area of focus for CCP17, with its implication of better asset utilisation and deferred augmentation costs.

Given the opportunities to optimise what is a significant asset replacement programme, we are comfortable with this proposal to increase the capability to make more informed network investments. The level of support from consumers observed in the engagement sessions strengthens this position, given the proposal's alignment with the specific feedback that customers want Jemena to 'ensure network equipment is not upgraded too early'. We also note that better condition monitoring and plant rating capability has delivered tangible benefits in reduced capital expenditure in other distribution companies.

8.6 AusNet Services

AusNet has elected to mark much of the cost benefit analysis and functional detail of these programmes as being commercial in confidence, and therefore making it difficult for stakeholders to make an informed assessment of the merits of the investment.

In its proposal, AusNet Services has not nominated investment that is specifically labelled as 'Future Network'. Instead, there are projects embedded in the augmentation and ICT capital proposals, as well as some new operating allowances, that will assist AusNet Services to "*continually evolve and adapt network infrastructure and services so as to enable emerging technologies"*.

Program	Intent	Category	Value
Hosting capacity for DER	address emerging constraints associated with the increasing penetration of DER	Network augmentation	$20.96M
Voltage compliance programme	compliance issues driven by the growth of DER connections to the network	Network augmentation	$20.6M
Distribution Network Optimisation (DENOP) & other IT	dynamic network control technology develop a HV/LV model	ICT investment	$8.98
DER enablement	more accurately forecast DER uptake and better understand the impact of DER on the network and existing connected customers	ICT investment	$11.4M

[67] Jemena proposal attachment 05-04, *Future Grid Investment proposal,* pg A3

Program	Intent	Category	Value
Future distribution network management	ensure appropriate systems and capabilities are in place to manage new the growth in distributed generation, residential batteries and Electric Vehicles.	ICT investment	$34.7M
Customer Information system	to provide appropriate advice to assist customers, including those who are connected with DER	ICT investment	$7.2M
Innovation expenditure	trialling new technologies or research and development	Operating	$7.5M

AusNet is well advanced in many areas of exploring future network topology. The Mooroolbark Mini Grid, Grid Energy Storage System and Residential Battery Storage trials are examples of innovation investments that explore future grid requirements.

<u>DER enablement</u>

Many of the components of AusNet Services' future network initiatives relate to meeting the challenges of the growth of rooftop PV. Hosting capacity, voltage compliance and network optimisation and DER enablement are discussed in the following section of this advice.

<u>Future Distribution Network Management technology programme</u>

AusNet Services notes the objectives of this programme as:

- Ensuring the continued safe operation of network management assets (maintain current services)
- Periodic refresh of network management assets to ensure a supported, risk mitigated, technology solution
- Meet customers' increasing expectations and evolving needs for improved network performance, service delivery, integrated information, and smart control.
- Implement core technology platforms capable of supporting, orchestrating, managing, and controlling the forecasted growth in DER, residential batteries, and Electric Vehicles.

Benefits include improved DER connectivity and reduced network management costs through predictive and proactive outage management capabilities.

We acknowledge that AusNet held deep dive workshops in ICT investment, for which this programme is a component; however, we have no record of any detailed consumer engagement regarding this project. Feedback from the Customer Forum noted the need to provide clarity on the ICT proposal and to be explicit on the benefits. Given the amount of redacted information on the public version of the proposal, we have taken no position regarding the consumer benefit of this proposal.

Broadly, however, the justification of these investments depends largely on the capability and elegance of the existing legacy systems and quality of the current data. On the assumption that this project is designed to make a quantum leap in AusNet Services' network management capability through an advance distribution management system (ADMS), the investment is supported in principle.

<u>Customer Information System</u>

This matter is discussed in the previous section of this advice (capex).

Innovation Expenditure

This part of the proposal has been subject to significant engagement through workshops and interaction with the Customer Forum.

Our position supporting this proposal remains unchanged; that is, we support effective, targeted innovation by network businesses, where this can deliver meaningful benefits to customers. AusNet Services' approach to project guidance and governance is commended. We encourage AusNet Services to respond to the AER's comments regarding clarity for the projects and objectives.

From the information supplied in the workshops and the proposal itself, we expect that AusNet can prepare business cases for each individual project, with a heavy weighting placed on the tangible benefits to customers.

9 Enabling Distributed Resources

9.1 Overview

Given the similarities in the engagement, influences and approach taken by the five distributors in response to the PV growth in Victoria, CCP17 has framed this part of our advice as being common to all the proposals. We acknowledge that some specific differences in approach exist across the companies and have attempted to identify these departures where they exist.

Driven by the Victorian Solar Homes programme, customers are likely to invest in large amounts of rooftop solar PV over the next few years. The five Victorian DNSPs are gearing up to meet this increase in distributed generation. Indeed, facilitating the export of excess energy from rooftop solar PV is the centrepiece of all five proposals in respect to Future Networks. Overall, we estimate a remarkable $209M in capital and $3.5M annually in operating costs is proposed to be invested in new technologies and network capacity by the five distributors over the next five years related to the challenge to meet this expected growth.

We are aware of the adage expressed by some distributors and the AER that Victoria is *'on the same DER growth trajectory as Qld and SA, only 6 or 7 years behind*'. Our own analysis supports this position. Figure 40 shows an overall penetration of small embedded generators in Victoria in early 2020 as approximately 16%; similar to that in NSW today and a level seen in Queensland and South Australia around 2013.

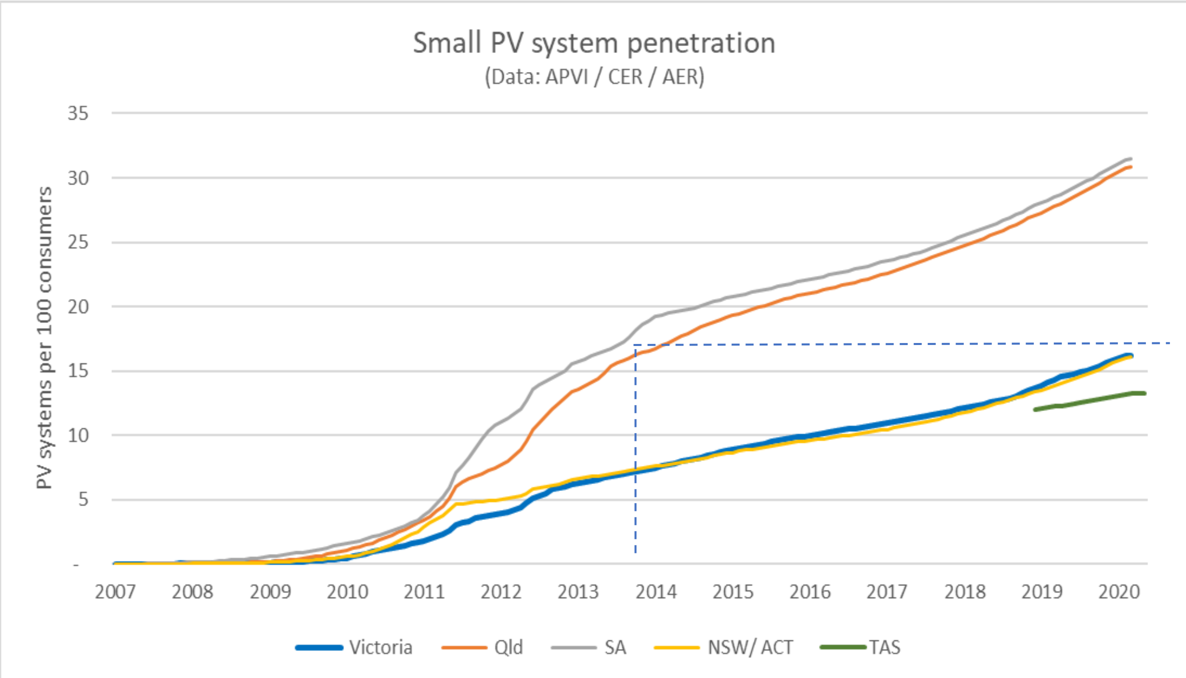

Figure 40: PV distribution network penetration by state (source: APVI / CER / AER data, CCP analysis)

As a rough benchmark, we note the recent SAPN decision considered an investment of approximately $93 per customer to meet DER growth in the next five years. This compares with around $71 per customer averaged across the five Victorian DNSPs. While the lower level of investment is commendable, the Victorian DNSPs should be looking at a lower relative level of investment due to three key issues:

a) The Victorian distributors are in a strong position to capitalise on AMI to facilitate a more staged, incremental and progressive approach to DER growth. The investment in AMI provides a much higher level of visibility of the low voltage network, providing a powerful platform to efficiently identify and respond to localised issues on the low voltage network such as phase balancing and transformer tap adjustments. AMI also provides the basis for the relatively low-cost development of low voltage network models and advanced network voltage control systems such as UE's DVMS.

b) The level of PV penetration in Victoria is still low on average when compared to South Australia and Queensland. It is generally accepted that Victoria 'is lagging the other states in PV penetration by 5 to 7 years', and the statewide level of PV penetration is not expected to reach that of SA or Qld until the next regulatory period.

c) There is a 'late mover' advantage, where a greater proportion of PV installations in Victoria will have a inverters set to, or at least capable of, contemporary volt-watt and volt-var settings that will significantly reduce the impact of high penetrations of PV on the network.

<u>How much export?</u>

A consistent theme in the investment cases is that customers should be able to export as much energy as they wish, within reasonable bounds of network augmentation. Powercor, CitiPower and United Energy note 'to remove 95% of solar constraints from 5kW export capable connections' as the deliverable. AusNet is targeting permitting 70% of solar constraints, and we interpret the Jemena plan to permit the continuation of the performance of the solar PV systems already in their network.

This approach was the focus of many workshops and unsurprisingly received strong customer support. While we certainly do not deny that such response was evident in the engagement, the way the case was presented and how the response has been interpreted in underpinning the distributors' expansive investment plans may have led to the distributors overstating these customers' expectations.

<u>What is the export worth?</u>

The assumed value of rooftop solar exports used in the capex modelling is, in the case of at least one DNSP, over the life of the network asset. We do not consider this an appropriate assumption, given the life of the customer's PV system is generally little more than 10-15 years. Similarly, the value of energy feed-in is generally set at the current retail feed-in benefit of 10-12 cents. This does not consider that over the life of the investment there might be zero or negative pool prices in Victoria, as there are now in Queensland and SA.

AEMO expects the frequency of these events will increase significantly in the next 5-10 years. is driving plans to control rooftop solar like a large distributed generator.

<u>Step by step approach</u>

The businesses have remarkably similar components of the proposed investment to DER growth:

a) *Optimise the existing network* - address known limitations through low-cost actions such as phase balancing, network tap adjustment, implementing contemporary inverter settings and some minor network augmentation. This is often integrated with other Power Quality (PQ) improvement works. This area includes the application of advanced voltage management systems such as the UE Dynamic Voltage Management System (DVMS), exploring every opportunity to reduce the network voltage wherever possible.

b) *Establish better visibility and modelling of the LV distribution system* by extending data-gathering and modelling capabilities to include the low voltage network to better understand feed-in impacts, improve voltage estimating and support optimal connection requirements. Analytics improves forecasting to make more informed, fact-based and timely decisions regarding the efficient operation of the network and to inform dynamic export limits.

c) Explore and apply 'non-asset' approaches such as advanced tariffs and innovative connection agreements to encourage maximum self-consumption at times of high levels of generation.

d) *Establish control and communication systems* for the network and customer equipment to implement dynamic export limits and other near-real-time functions such as demand response. CPU's proposed Distributed Energy Resources Management System (DERMS) is one example.

e) Finally, undertake more expansive (and generally expensive) physical network augmentation to address outlying capacity and voltage limitations. Similar work is undertaken to address demand changes for other reasons, such as localised infill development (augex).

In this advice, we strongly support the DNSPs investing in the first three types of investment – optimising the existing network, establishing better tools to bring innovation to the management the low voltage network and new DER connections, and refining 'non-asset' approaches.

<u>Control and augmentation could be largely deferred</u>

We have concerns regarding the prudency and value of other components in the Victorian context at this stage. Recent media reports[68] support other engagement that shows consumers with rooftop solar have clearly expressed a reluctance to allow 'control', related to plans by AEMO will impact in the specifications and level of control that AEMO may require on DER equipment. It is prudent to defer much of the investment in systems that dynamically control customer PV output, until there has been a lot more customer engagement on the subject and the inverter control can be shown as being consistent with a broader DER strategy.

In addition, the advantages of addressing known network shortcomings, along with intelligent network control, will reap significant benefits. We agree with the findings from the recent Renew[69] report regarding DER integration that notes:

> *"Many of these issues (with DER integration) manifest due to reasons other than DER exports – some have many causes, others have other causes but are exacerbated by DER exports, and some are not caused by DER at all, but are made visible by DER uptake."*

Therefore, we do not support any more than the absolute minimum investment in augmentation of the physical network, to be done only when all other actions are in place. Much of it can be deferred significantly as result of the positive impacts of the network optimisation, intelligent voltage management and control. The actual energy export by customers is highly unlikely to eventuate to the level that may have been indicated in the engagement.

<u>Customer engagement – key issue</u>

The DNSPs have, in their planning to meet the rooftop PV growth, assumed relatively high levels of concurrent energy feed-in, based on the strong customer support expressed in the engagement for 'unconstrained' solar feed-in capability.

The issue of constraint and restriction regarding new solar connections and the feed excess energy from rooftop solar was the focus of most workshops related to Future Networks and received strong customer support. While we certainly do not deny that such response was evident in the engagement, the way the case was presented and how the response has been interpreted in underpinning the distributors' investment plans may have led to the distributors overstating their customers' expectations.

We base this position on several thoughts:

- Our observations were that the customer forums and workshops focused on "*the level of comfort with the idea … of utilities limiting or controlling solar exports to enable more solar connections*

[68] *Concerns over plans to switch off household solar* – ABC News, 20 May 2020
[69] Renew – *Enabling Distributed Energy in Electricity Networks* – May 2020

and exports overall",[70] without the context of the overall technical and commercial practicalities and opportunities of rooftop PV in the household customer environment; noting widespread research showing that a customer's primary reasons for investing in rooftop PV are to reduce their own electricity costs and to provide a level of energy independence. We would be much more supportive of the proposal had the engagement included consideration of 'how can solar be integrated without the need for expensive system upgrades?'

- An undercurrent of distrust towards large utilities being aligned with customers' interests still exists, and that this lower level of trust and understanding of the role of distributors contributed to a generic response that customers do not wish to be limited, or dictated to, by utilities; especially where matters of return of personal investment or the contribution to a low-carbon environment are concerned.

We view the businesses' counterfactual or base cases of 'do nothing' as being somewhat unrealistic. We propose that any reasonable utility (supported by any reasonable regulator) would at least take some steps to address such a situation within existing regulatory allowances. Therefore, the magnitude of the benefit from the proposed investment may be overstated both in both the way they were presented to consumers and in the proposals themselves.

<u>Priority to optimise the network first</u>

The application of the Distribution Voltage Management System and the widespread use of more contemporary inverter settings are likely to go a long way to meeting customers' expectations. We also suggest that voltage reduction is available in many parts of the network as a first step to alleviate network congestion from solar feed-in, and that this opportunity has been largely overlooked in the proposals. We support the recent findings by renew where:

> *"In a material number of circumstances, offload tap reconfiguration is likely to be the lowest cost solution to enable greater penetration local distribution networks. Optimal voltage adjustments appear to be sufficient in areas with low to moderate DER injections and provide the right starting point for other remediation measures once they become necessary."*

Our own experience and analysis of the DNSPs proposals come to the same conclusion, as discussed later in this section.

We see the PV growth forecast as high-risk, but not unreasonable, assumptions. Our analysis suggests that, at the time of preparing this Advice, industry capability exists to develop rooftop solar PV consistent with the distributors' forecasts, albeit requiring a very high level of installation activity over several years.

The proposals do not consider in any detail the impact of batteries or other forms of customer-funded energy storage or demand response capability, nor the role of electric vehicles or progressive tariffs, in assessing the impact of increased levels of DER. The Powercor, CitiPower and United Energy (CPU) proposals list enhanced demand response and progressive tariffs as a benefit of their Future Network investment, but the impact of these initiatives on the DER proposals are not discussed in any detail.

<u>Conclusion</u>

There is clearly a level of support by energy consumers to invest a small amount of money in their bills to allow more solar power from a growing number of rooftop systems to be exported to the network. The cornerstone of the distributors' investment proposals is to take actions to avoid the risk of the occurrence of high voltage that leads to the inverter's disconnection, as numbers of systems increase.

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[70] For example, refer *JWS Solar Research for AusNet Services*, research report, Sept 2019, p5

We endorse the approach where the DNSPs work to optimise the network first, with some investment in terms of implementing smarter systems that provide the ability to monitor, model and operate the networks in a way conducive to higher penetrations of PV as necessary steps to meeting future challenges. Investments that streamline DER connection arrangements, foster innovative optimisation of energy feed in and support grid initiatives such as demand response and frequency response are useful, forward looking and clearly in customers' interest.

Notwithstanding that support, overall, the proposed levels of network investment are likely be overestimated, with the result being excessive costs to consumers to be paid over the long period of the network assets' lives.

It may be more in consumer's interests if the distributors take a conservative view of DER growth and network impacts, balancing their current stance of highly proactive planning with a more staged or 'wait and see' reactive approach, tempering their investment proposals for 2021-25. We acknowledge that the distributors have favoured a 'remove constraints when economically justified' approach, however we suggest that the consideration of 'constraint' and 'economically justified' could be reconsidered in the current environment of uncertainty and importance of electricity costs to many sectors of the community.

We support Investment in technology that provides a platform for new DER growth, such as models of the low voltage networks and intelligent network voltage control, however our expectation is that investment advanced DER control systems and all but essential network augmentation should be reconsidered.

If the current assumptions prove correct, the worst outcome would be that some 'late comers' to install DER may be curtailed for a short period of time, or encouraged to increase self-consumption – a situation that can be measured and rectified (if considered economic to do so) in the next regulatory period.

If growth in PV does not meet these aggressive targets, or if customers with PV demonstrate a greater propensity to self-consume their energy for best personal economic benefit rather than maximise export, then we have avoided excessive network investment that would need to be paid for over many years.

In our opinion, this is certainly a risk that consumers are prepared to take.

9.2 Commentary

<u>A different approach to Rooftop PV is being taken in Victoria</u>

In the past year or so, the language in the world of Distributed Energy Resources (DER), particularly around rooftop solar PV, has shifted. Previously viewed as a large collection of stand-alone customer-owned investments each targeted at reducing individual household energy bills, networks, the market operator and governments are now viewing DER more as an aggregated resource akin to a 'large footprint, customer-owned, virtual solar power station'.

From this viewpoint, the aggregated generation from these rooftop systems is considered as a resource that needs to be facilitated, encouraged, and ultimately controlled and dispatched, not unlike other large renewable power sources supplying all consumers in the electricity network.

This thinking fosters the approach that customers should be allowed 'unconstrained' access to the network to export as much energy as they wish.

While the physics of DER clearly remain constant, justifying network investment on the basis of customers with rooftop solar PV contributing to the wider pool of energy generation is a central theme of the five distributors' proposals. While we recognise this contemporary approach as valid, we lament the fact that it in many ways overshadows or even overlooks the customer view of PV, understating the fundamental reasons why customers invest in all forms of DER – both active and passive - to the point that some assumptions that underpin the distributors' investment cases may be exaggerated.

The DNSPs point to "*prioritising projects to ensure our customers will have the ability to export excess energy where the cost of us carrying out works is economically efficient*". [71] Admittedly, addressing energy export capacity and managing network voltage performance (the prime focus in South Australia, Queensland and New South Wales) are two sides of the same coin. In the engagement and analysis leading to the Victorian investment proposals however, the strong focus on enabling high levels of energy export from rooftop PV – as opposed to encouraging customers to optimise their PV investment though best energy use patterns and passive and active demand response - has not been seen to that extent in other jurisdictions.

A large part of the engagement with customers and stakeholders was to test options related to removing constraints to energy export, and 'unlocking' the full potential of DER to contribute to the benefit of all energy consumers. This approach has been taken to address two issues:

- To support the objective of the Victorian Solar Homes programme to further renewable energy as a community benefit; and
- Off the back of a broadly generic response from consumers, networks should enable the feed-in of renewable energy from homes and businesses with solar PV.

The distributors refer generally to 'building future hosting capacity' and 'unlocking future opportunities' as well as 'assisting the customer maximise the benefit of their systems'. To illustrate, the stated objective by Powercor is "*consistent with feedback, we will enable all our customers to connect to solar, and enable 5kVA solar systems to be available for export for most of our customers …*"[72]

This investment planning strategy for DER support in Victoria is to be commended in the way it is trying to 'get ahead of the game' regarding DER development and supporting the Victorian government's renewable energy objectives. Such an approach also has the potential to be more efficient in terms of network design, technology investment and resource management.

This more contemporary approach is also reflected in initiatives by the Australian Energy Market Commission (AEMC) and the Australian Energy Market Operator (AEMO).

Generally, the distributors have estimated the required investment for the next five years based on the investment option to remove solar constraints when economically justified. Behavioral incentives, such as tariff signals, have been largely discounted. The funding proposals hinge on two key concepts:

- how quickly will solar uptake proceed,
- what is meant by 'economic justification to remove solar export constraints?'

<u>Key assumptions</u>

In the proposals, forecasting of DER growth, and hence investment requirements, is based on several fundamental assumptions, each having significant influence on the investment outcome and ultimately the costs and benefit for consumers. These assumptions are:

1. That the growth in the number (penetration) of rooftop PV systems, driven by the objectives of the Victorian Solar Homes Programme (Solar Victoria), will continue at a high rate, even higher than currently the case, for the next five years at least.
2. That consumers who invest in solar PV not only wish to *but will actually use energy in* a way that regularly results in high levels of coincident peak energy feed-in, perhaps at almost the full rating of the standard inverter offering of 5 kilowatts capacity, for much if not most of the time.

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[71] Quoted example is from the AusNet proposal Pt 3, p109
[72] Powercor proposal, p74

3. That reduced network congestion (periods of curtailment of peak energy feed-in) as a result of the proposed expenditure will continue to deliver economic benefits for all customers, including the majority without DER, for the life of the investment.
4. That consumers will continue to accept the 'everyone benefits, everyone pays' approach to connections of small (rooftop) PV systems.
5. Lowering network voltage generally and addressing the (statistically infrequent) occurrences of minimum voltage at consumer premises is not a cost-effective option to explore, in the short to medium term at least.

Each distributor has applied an economic test to consider the net benefits of removing export constraints, such as a reduction in wholesale generation fuel costs.

Risks in the assumptions

Based on our own observations and analysis, the solar industry can meet the installation rate expected in the Solar Homes initiative. However, there is a real chance that, in the emerging challenging economic climate, the sustained record rate of customer investment in DER may slow. In the way it focused on 'curtailment', consumer engagement may have led consumers possibly overstating their preference for high levels of coincident peak energy feed-in.

The distributors have used different ways of valuing the feed-in energy in their business cases. We acknowledge that several consultants and market bodies are currently considering how that energy is valued to the customer and the community. We have no comment on the current methodology but note that expert advice is that the value is very likely to change over the life of the investment.

We agree with the position of the Brotherhood of St Lawrence, in conjunction with Renew and VCOSS, who note: [73]

> *"At the time of current solar constraints, it is likely that the generation and carbon-related values of displaced grid power are much lower than average, given that constraint occurs when loads are low and solar generation is high.*
>
> *Given that a dynamic feed-in tariffs is likely to be introduced … this approach may return a higher economic value for implementing solutions such as dynamic constraints, rather than investment in augmentation to enable export to the High Voltage network at times of low load."*

There is also a risk that market reform may not proceed as expected. AEMO in 2019 stated: [74]

> *"economic conditions are challenging, leading to a slowdown in investment and hence slower transformation of the electricity industry. Consumers and governments concentrate more on protecting standards of living than on structural reform to the energy sector"*

Energy Networks Australia (ENA) has sponsored the development of their OpEN project to allow the benefits of DER to be captured. A framework to facilitate DER participation on the wholesale market is an important component to deliver the benefits central to the proposal to 'unlock' solar capability. In its 2020 Position Paper, ENA notes:

[73] BSL, Renew, VCOSS – *Presentation to the AER Public Forum for the Victorian EDPR,* April 2020
[74] AEMO *Forecasting and planning scenarios, inputs and assumptions* (2019)

> *"Under the central DER deployment scenario, the costs outweigh the benefits for all four OpEN frameworks, leaving consumers to face material costs in developing a distribution market, without any concomitant benefits. If, as a result of the COVID-19 pandemic, Australia follows the slow change scenario, the risks of consumers incurring negative net benefits from the development of a distribution market are high "*

A significant level of analysis and research has gone into the distributors' proposals, and we acknowledge that this work has been undertaken prior to the COVID-19 pandemic. The distributors' proposals largely require that 'all the ducks are in a row' for a large part of the proposed investments to be considered prudent. However, at the same time, due particularly to COVID-19, many factors are still unknown.

The proposals are largely silent on the development and impact of 'behind the meter' energy storage and the likelihood that consumers, particularly those with solar PV, can change their energy use patterns.

<u>Risks to changes in the economic environment and customer perceptions regarding energy</u>

The state of the economy is a major factor in projecting adoption of small-scale technologies.[75] In terms of direct financial costs and returns, there is risk of significant change in customer perceptions of the key economic drivers which influence the outlook for rooftop solar and battery storage adoption and the value of feed-in energy. These include:

a) The continuation and quantum of any available subsidies and low interest loans

b) The practicality and installed cost of rooftop solar and battery storage systems and any additional components such as advanced metering

c) Current and perceived future levels of retail electricity prices

d) The structure of retail electricity tariffs or other incentives available to that residence or business,

e) The level of feed in tariffs (FiTs) which are paid for exports of rooftop solar electricity

f) Wholesale (generation) prices which may influence the future level of FiTs

g) The incentives and ability for the customer to influence the shape of their load curve, optimising self-consumption for greatest personal economic benefit.

Our experience has been that other than the Federal government SRET scheme, state-based incentive schemes tend to have lives of less than five years.

There are also environmental factors that have a large influence on solar PV and DER take-up that could be subject to change over the period of the proposed investment, Including:

h) The sense of 'energy independence' in challenging times, ultimately 'going off grid'.

i) The benefit of energy self-sufficiency in challenging environments, such as high bushfire risk.

j) The emergence of a viable peer-to-peer energy market to be embraced by consumers.

k) Solar / battery packaging in new homes.

It is our view that the proposals have not adequately explored the influence of these factors on the nature, configuration and likely growth rate of new PV and DER, particularly to their influence on the propensity of consumers to support greater level of energy feed-in.

[75] *Projections for small scale embedded energy technologies*, CSIRO, June 2019

PV focus

The proposals focus almost exclusively on rooftop solar PV. Admittedly, this is 'the main game in town' given the rate of uptake by residential customers, fueled by the attractive incentives being offered under the Victorian Solar Homes programme. However, the emergence of DER encompasses so many other technologies. Apart from some specific (and commendable) demand response programmes predominantly by United Energy and AusNet Services, and the aggregate impact of DER on the energy forecasts, the proposals do not discuss the wide range of DER in any substantial way.

The predominance of gas as a heating fuel and instantaneous water heating in Victoria has meant that passive DER in the form of storage electric water heaters is not a major consideration. However, as the world changes to embrace energy storage, a possible transition from gas to electricity as a heating fuel and the increasing penetration of air conditioning in the residential sector, it is necessary to consider the wider range of DER, both passive and active, in the broader context of 'building future hosting capacity' and 'unlocking future opportunities'.

9.3 DER expansion in Victoria

Note: In this discussion, average DER penetration rates (percent, or number per hundred homes) are quoted to provide guidance and comparison of the DER impacts across network areas. While this is a useful and not inaccurate approach, CCP17 acknowledges that DER uptake is not evenly distributed throughout networks, and as voltage constraints are highly localised and can vary in nature across different network types, it is possible for constraints to arise in local segments the networks.

Commencing in 2012, significant rises in the retail price of energy, a heightened awareness of sustainability and falling solar PV system prices drove high levels of investment in rooftop PV by consumers across most of Australia. Federal capital subsidies underpinned the reduction in system costs. In Queensland, South Australia and to some extent New South Wales, this initial growth in PV numbers was supercharged by very generous feed-in tariffs until around 2014.

The rooftop solar industry in Victoria established momentum, and investment beyond the 'early adopters' become prevalent.

Since mid-2016, as the price of solar PV continued to fall to the stage where the cost of energy from rooftop PV is competitive with that of grid energy, PV development in all states experienced an upturn in growth, as shown in Figure 41.

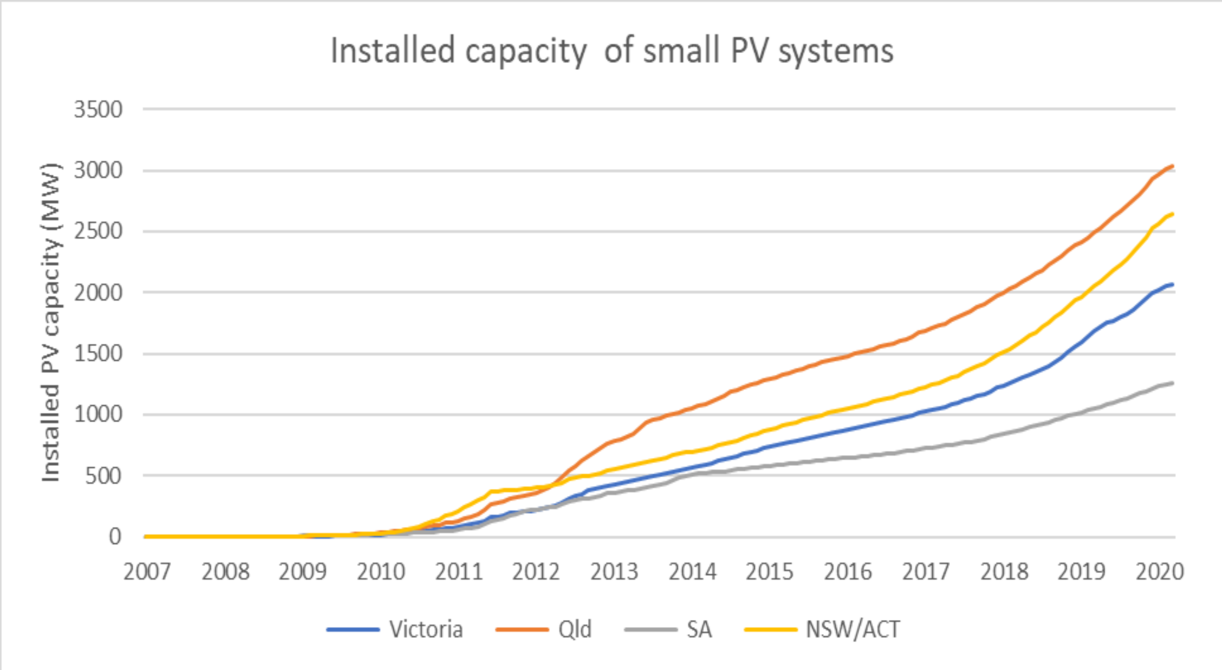

Figure 41: PV capacity growth (source: CCP analysis of APVI / CER data)

The rate of installation continues to increase. It is useful to note that an increasing proportion of the recent PV growth in other states has been in the 10 – 100kW system size, indicating the commercial attractiveness of rooftop PV to the business sector, where the majority of energy is consumed in the daytime.

Coincident with – and, as it is generally accepted, as a result of - the early stages of the Victorian Solar Homes programme in 2018, the Victorian solar industry endured a volatile rollercoaster ride of highly subsidised installation activity, seen in Figure 42.

The criticism of the early impact of the Victorian Solar Homes Programme in its governance and effect on the installer industry is well documented. *"The industry is apoplectic. It welcomes the rebate, and particularly its focus on lower income housing, but it says the design of scheme is effectively strangling the market, and this is beginning to show in data on solar installations and small scheme certificates."* [76]

Even when overlooking the ups and downs of the scheme, the rapid and steady uptake of rooftop solar in Victoria since mid-2016 is quite clear. Notably, growth rates in some other states are also increasing even without the influence of a powerful state subsidy scheme. We acknowledge that an increasing proportion of this interstate growth is due to commercial (10-200kW) PV installations.

[76] "*Victoria solar rebate "disaster*" – Renew Economy.com.au, Sophie Vorrath & Giles Parkinson, 1 August 2019

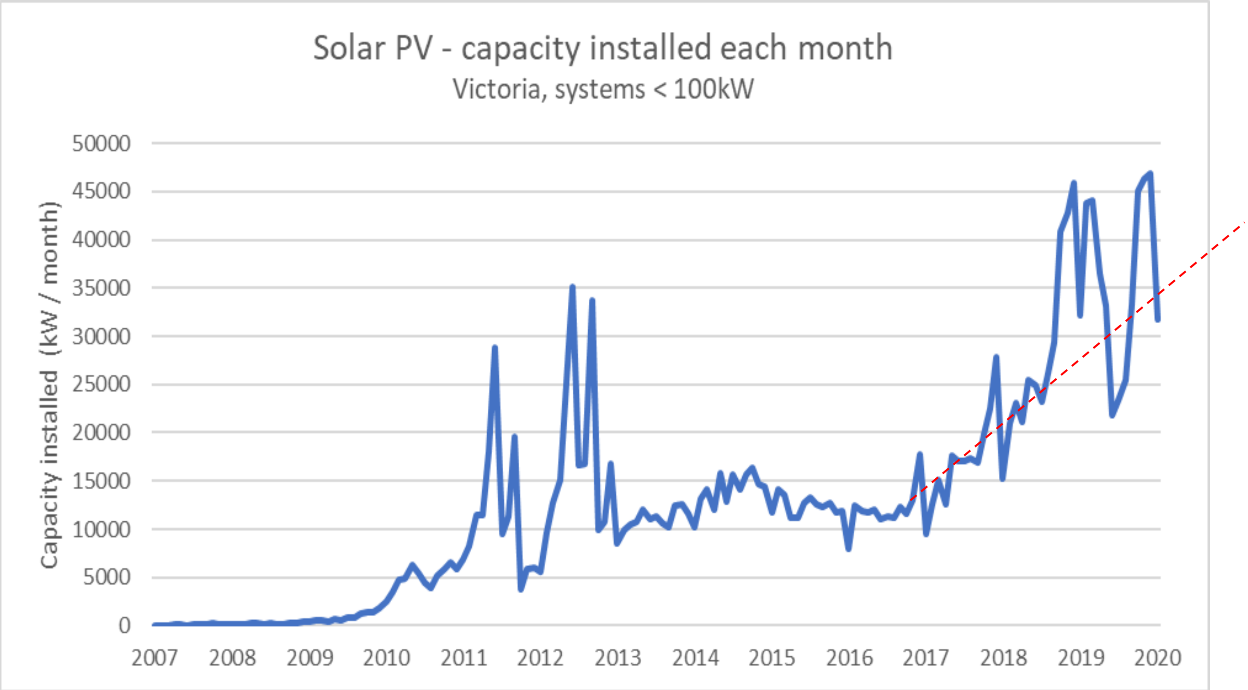

Figure 42: Solar PV growth in Victoria (Source: APVI / CER data)

Data from the Clean Energy Regulator[77] indicates that in the past 3 years, PV systems have been installed in Victoria at a rate of 57,000 per annum, increasing to 73,000 systems per annum as the government scheme stabilised (Figure 44). Our reading of the supporting material from most of the proposals indicates no concerns with the industry's ability to meet this growth rate, noting that these reports were compiled before the emergence of the current negative global trend.

[77] ibid

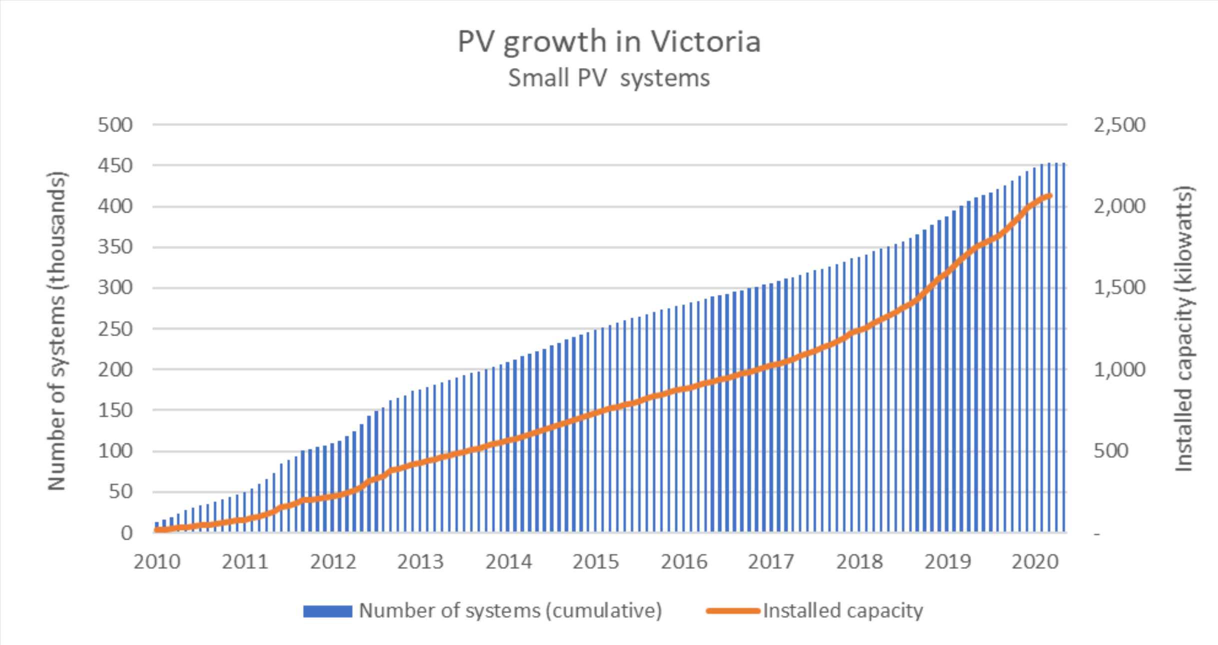

Figure 43: PV installations in Victoria (source: APVI / CER, CCP analysis)

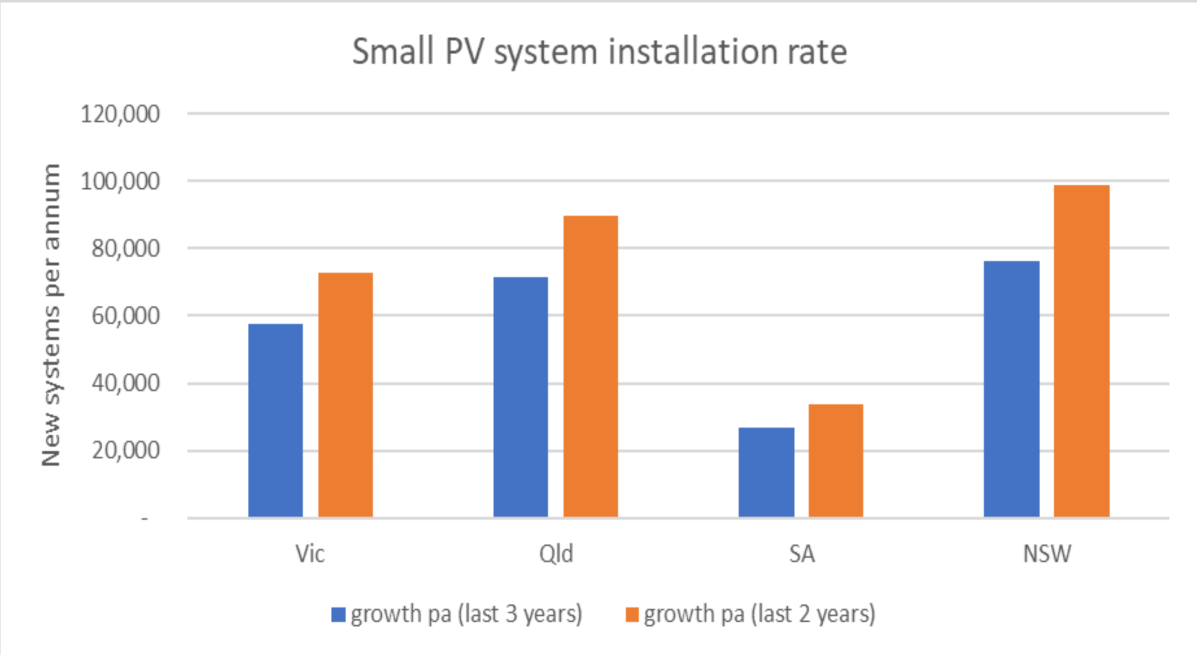

Figure 44: Annual rate of PV installations in recent years (source: CER data, CCP analysis)

By March 2020, there were approximately 455,000 small (sub-100kW capacity) PV installations in Victoria, with a combined rated output of 2,083 megawatts (Figure 43) [78]. The average system capacity is 4.5 kilowatts, although in the past years the average capacity of new systems is closer to 7 kilowatts, reflecting both the adoption of 5 kilowatts as a 'standard residential offering' by suppliers and the greater proportion of larger (30 – 100kW) three-phase systems on small commercial buildings as the case for these systems strengthens. [79]

[78] From Clean Energy Regulator SGU (Solar panel) RET creation data to March 2020
[79] ibid

The Victorian Solar Homes Programme

The Victorian Government Solar Homes Programme is by far the predominant influence on the growth forecasts inherent in the distributors' proposals. The Solar Victoria website notes the objective of the programme, announced in August 2018, is "*over 10-years … (to) enable the installation of solar panels, solar hot water systems or batteries on 770,000 homes across the State, resulting in over one million Victorian homes powered by renewable energy*" [80]

The Department of Environment, Water, Land and Planning (DELWP) has established Solar Victoria, the body responsible for the delivery of the Solar Homes Program. The programme provides a rebate of up to $1,888 (originally $2,225) for solar panel (PV) system installation for homeowners and rental properties. Householders can also apply for an interest-free loan for an amount equivalent to their rebate amount, to be repaid over four years. In addition, the programme offers rebates on solar hot water systems and energy storage (batteries) in particular postcodes.

CCP17 Is not aware of the level of coordination between the distributors and DEWLP to optimise the offered incentives to avoid areas of network congestion. We do note however that the incentives to install battery storage equipment does have a 'preferred postcodes' requirement which we presume is to encourage storage in areas most likely to deliver benefit or lower cost to implement.

We also acknowledge that the Solar Homes Programme is essentially targeted at residential installations.

To assist in our analysis of the impact of the Solar Homes programme in relation to the distributors' proposals, we have considered the steps needed to achieve the programme objective, as noted in Table 8.

Data from the Clean Energy Regulator indicates 401,000 small (<100kW) solar PV systems were installed in Victoria by March 2019. This compares reasonably with the information provided by the distributors when considering timing changes in reporting. By the end of 2019, the CER data indicates 443,000 systems installed. This equates to an existing PV penetration statewide of 16%.

Our approximations are shown in Table 8.

Solar Homes programme target	1,000,000 homes by 2028
Current number of residential systems (at end 2019)	Say 400,000
New systems to meet target	600,000
Annualised build rate for the next 8 years	75,000
New systems in the 5 years period 2021-26	375,000
PV penetration (statewide average) in 5 years' time	28%
PV penetration at programme end 2028	36%

Table 8: Victorian Solar Homes Programme - forecast assumptions (CCP analysis)

This will equate to an average PV penetration rate by 2030 of 36%, or 36 homes in one hundred should the programme reach its goal, noting South Australia and Queensland are currently recording an average penetration of around 32%.

Analysis by several consultants providing data to inform the distributors' proposals tend to support the attractiveness of the scheme to consumers and suggest that the programme is deliverable. Our own

[80] https://www.solar.vic.gov.au/what-we-do

analysis suggests that the required PV installation rate is not unlike the current progress but will need to be sustained for the next 8 years. To do so would be challenging, but not impossible, on the assumption that the global economic downturn does not negatively impact the industry and supply chains.

We also note that the Victorian Government programme includes subsidies for battery systems and solar hot water. Our brief perusal of the monthly reports from Solar Victoria suggests around 5 - 7% of the subsidies paid relate to battery storage systems. Rebates for new solar hot water systems appear to be an order of magnitude lower again. The distributor's proposals are largely silent on the customers' response to the take-up of energy storage.

9.4 Analysis – growth in the number of PV systems

The analysis challenges

Critically analysing forecast PV and DER growth in the proposals is not straightforward.

Some utilities, along with AEMO, consider growth in terms of aggregate installed inverter capacity, in megawatts. The Victorian Solar Homes programme, being customer-oriented, considers number of systems. In order to address the value of curtailed energy, the utilities focus on energy (kilowatt-hours) generated by typical PV systems.

To consider these factors, consumers require additional information to understand the assumptions taken by distributors in forming the forecasts. For instance, "what is the assumed average inverter capacity?" "What is the range of capacities that are considered in this analysis – all small (<100kW inverters, or just typical residential systems?)." "What is the expected efficiency of a PV system, and what is that efficiency around the time of the risk of curtailment?"

The distributors have the advantage of using observed performance from the AMI systems of customers with solar PV, which is useful. As forecasts are generated and compared however, being explicit as to the relationship between the number of systems, aggregate capacity and energy feed-in would be useful to assist consumers to better understand the plans.

Could the growth be overstated?

As noted earlier, the five utilities have largely based their forecasts of residential PV growth on the stated objectives of the Victorian Solar Homes programme. To illustrate this acceptance of the programme as the basis for growth forecasts, we note a comment by a consultant providing advice to two distributors:[81]

> *"… Rather, it has been assumed that given the magnitude of the incentive customers receive for installing a solar PV system under the Government's policy announcements, the underlying economics of installing solar systems under the Government's current policies is not in question.*
>
> *In a practical sense, this means that we have implicitly assumed that the Victorian Government's solar packages will be fully utilised by Victorian residential customers over their 10-year durations, and that these packages will represent the total amount of solar PV that is taken up by residential customers in Victoria"*

We are not critical of this assumption, given the environment at the time it was prepared. The subsidies, both in the Federal SRET scheme and the Victorian programme, are likely to remain attractive and there is a reasonable expectation that the solar homes programme would be fully subscribed.

[81] Oakley Greenwood *Profiling Uptake of Solar PV*, prepared for CitiPower and Powercor, 8 March 2019

In parallel with the Victorian homes programme, Victoria, as in other states, is seeing an increasing interest in commercial (10-200kW) PV systems[82] being connected to distribution networks. As businesses recognise significant savings in electricity bills that can arise from local rooftop generation that is self-consumed under a typical commercial load factor, interest in larger systems is growing.

It is our assumption though, that these systems are typically connected to more robust networks, subject to more elegant connection agreements and, in many cases, accepting of export limitation as most of the generated energy is consumed on-premises anyway. While not explicitly discussed in the proposals, we assume that they reflect the growth in commercial systems in the numbers, including the impact on energy forecasts.

Our own analysis tends to support the forecasts in the distributors' proposals; that is, assuming sustained installation rates supported by the Victorian Solar Homes programme and ideal market conditions, the overall rooftop PV penetration rate could by 2026 quite realistically reach the order of 28%, similar to the level of penetration seen in PV-leading states such as South Australia and Queensland today.

This position comes with three caveats.

1. There is an assumption that consumers (and both Federal and State governments, as providers of significant subsidies) will continue to invest in rooftop PV (and to a much lesser extent, energy storage) for at least the next five years. With the major economic upheaval seen in the last few months, it would be prudent to question whether customers and governments will continue to support investment in all forms of DER.

   Green Energy Markets, at the AEMO forecasting reference group meeting of April 2020, noted:

   > *"The COVID-19 pandemic in 2020 has had a significant impact on the renewable generation sector. While it is too early to fully understand the economic impacts of the pandemic, the predictions for large- and small- scale renewable generation deployment indicate a significant downturn of 25 per cent to 50 per cent."*

2. In the emerging global commercial environment, the supply chain of imported inverters and panels and the viability of the installer industry could also be severely disrupted, again challenging the ability for the industry to ramp up and sustain the expectations of the Solar Homes Programme.
3. The forecasts tend to ignore any risk of 'Consumer Saturation', instead assuming there will be an inexhaustible supply of customers to take up the offer and install large (5KW) systems. While the offer under the Victorian scheme is certainly attractive, it is important to consider the possibility that most willing customers may have taken up the offer before reaching its target, especially should the incentive payment continue to shrink. We have not seen any analysis by the distributors considering this possibility, other than perhaps the lower forecast penetration rate planned by CitiPower.

We agree with the position taken by Energy Networks Australia, who recently noted:[83]

> *"The 2020 COVID-19 pandemic has had a significant short-term impact on renewable electricity uptake, but the medium to long-term impact on the deployment of DER is yet to be determined. As the benefits of implementing a distribution market is dependent on very high levels of DER, it is suggested adopting an incremental approach during this period of economic uncertainty"*

[82] APVI Postcode data - https://pv-map.apvi.org.au/postcode

[83] Energy Networks Australia *Open Energy Networks Project Position paper*, March 2020

In summary, we acknowledge that the forecast growth in PV penetration by all the distributors is not unrealistic and could eventuate. There are significant risks in those assumptions however that suggest they could easily be overestimated. We urge a high level of caution and sensitivity analysis in those forecasts.

Comparative analysis

Figure 46 summarises the proposed change in PV penetration by each of the distributors. The targets for the Victorian Solar Homes Programme are included.

From their proposals, Powercor expect to install 156,000 more systems totaling 750MW (4.8KW average system peak rating), CitiPower 61,000 (3.8kW average) and United Energy 88,000 (4.2kW average). Data regarding the average installation capacity (rated) for the other utilities is not evident.

For reference, the data sources for the following figures above are noted in Table 9.

	Source (penetration)	Source (number of systems)
Powercor	PAL BUS 6.02 p8	CPU presentation, issues day, p33
CitiPower	CP BUS 6.02 p8	CPU presentation, issues day, p21
United Energy	UE AGX BUS06 p8	CPU presentation, issues day, p43
AusNet Services	Proposal Pt 4 p14	Proposal Pt 4 s6.5
Jemena Electricity	Proposal p15	Estimate
Victorian Solar Homes target	Programme datasheet, interpolated	

Total DER proposal $M, 2021	AusNet Services	CitiPower	Jemena	Powercor	United Energy
Opex	3.8	1.15	3.6	5.57	3.82
Capex	51.82	31	24	60	42

Table 9: PV growth data sources and assumptions

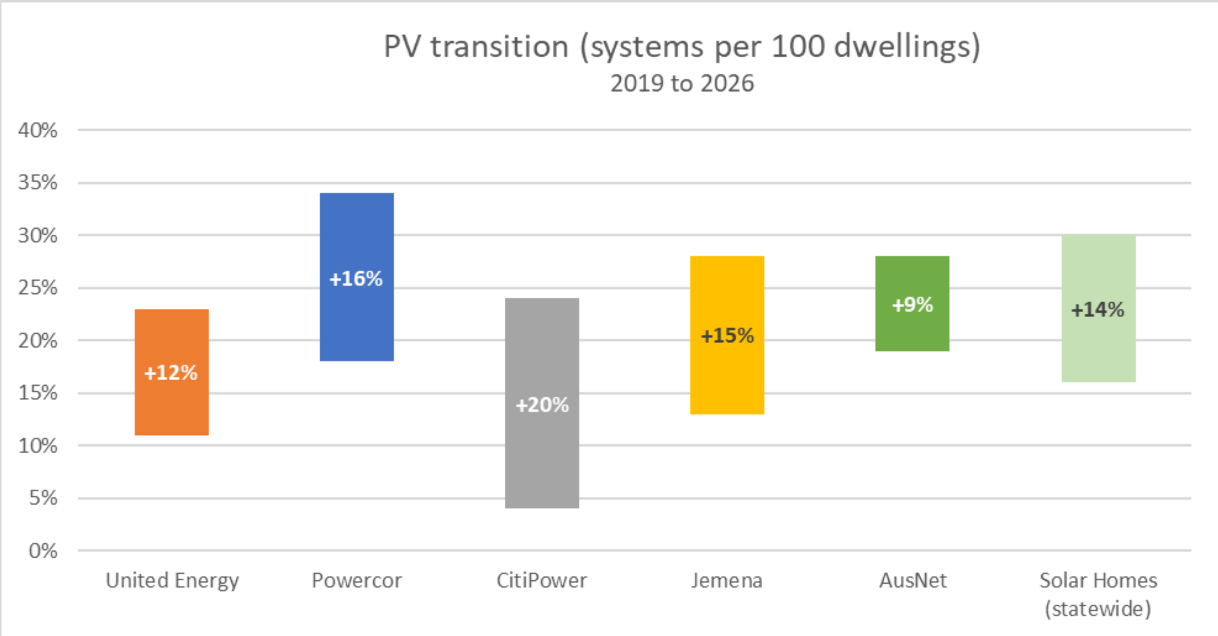

Figure 45(a): Forecast change in PV system numbers (Source: proposals)

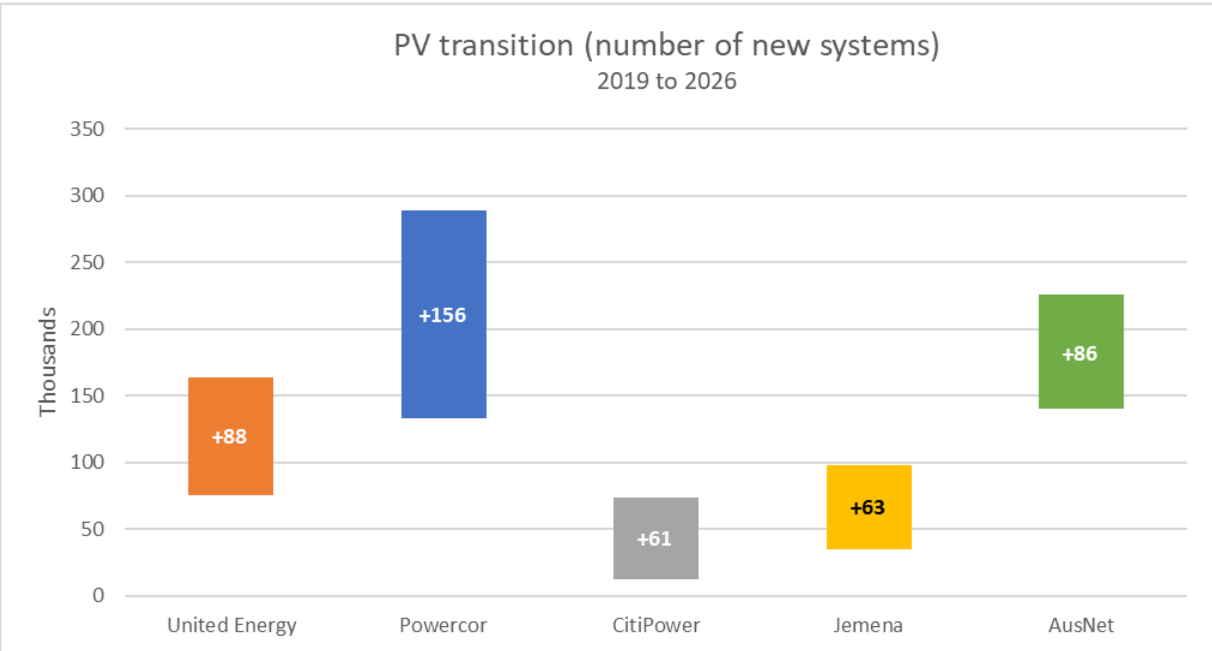

Figure 46(b): Forecast change in PV system numbers (Source: proposals)

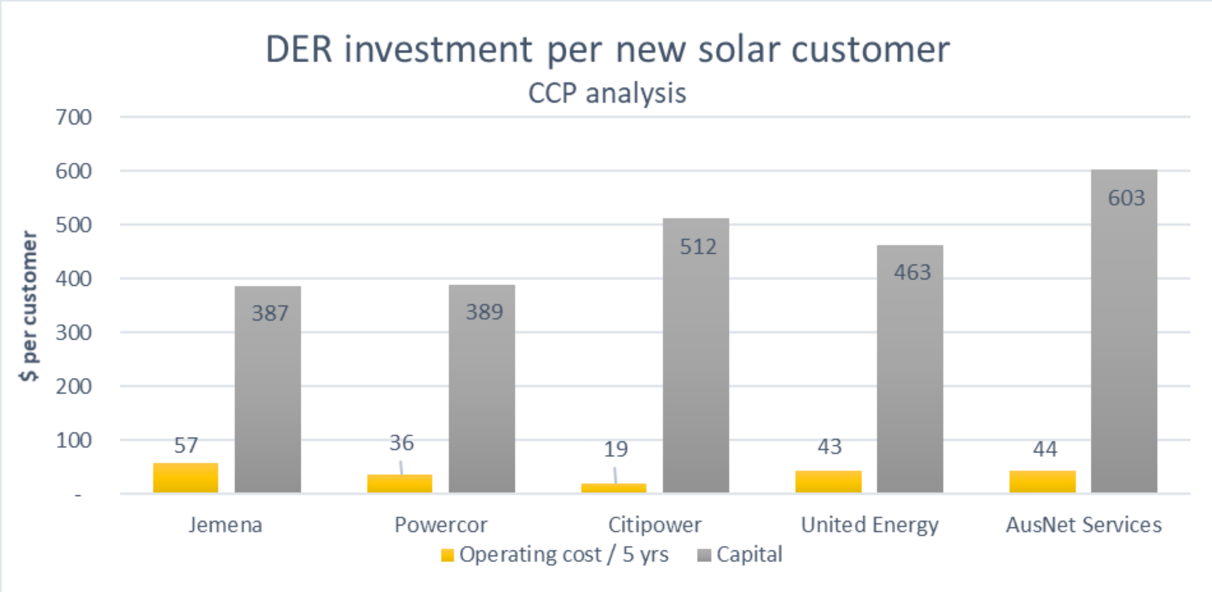

Figure 47: DER investment per new solar customer (Source: CCP17 analysis)

CCP17 has considered the cost of addressing DER growth on a per customer basis for new solar installations, shown in Figure 47.

Perusal of the information presented in Figure 46 raises some matters for consideration.

1. ***The total number of new systems proposed exceeds the number required under the Solar Homes Programme.***

In our earlier analysis, we etimated that approximately 600,000 new PV systems in the next 8 years are required to meet the programme targets by 2028; suggesting around 375 to 400 thousand new systems are to be subsidised in the next regulatory period 2021-26. Totalling the proposals indicates an expected increase of almost 450 thousand new systems.

Therefore, we must assume that the increase in PV system numbers includes systems additional to the Victorian Subsidy scheme, including larger systems for commercial customers. This is a reasonable assumption. However, as larger systems tend to have high levels of self-consumption and anecdotally are amenable to feed-in peak energy limitations, then need to be considered differently in the assessment of 'curtailment' in the rest of the solar enablement business case.

2. ***Powercor is forecasting a remarkably high average penetration level of 34% by 2026.***

This is a high proportion of PV, especially as this is an average level and experience shows localised levels can be much higher. Powercor, too, has a large number of both long 22KV lines and of single-wire earth return (SWER) lines. Experience from other distributors, in particular Ergon Energy and Essential Energy, suggests this situation carries significant operational challenges and voltage risks to customer equipment at the best of times. We ask: "Is this the most appropriate approach to the installation of DER for these customers?'

We suggest that it would be in both the utility's and customer's interests to encourage the use of energy storage, proper system specification, microgrid arrangements and changing customer installations to encourage maximum self-consumption. Stand-alone or largely self-sufficient systems may be a viable alternative with the additional benefits of safely interrupting network supply in periods of bushfire risk.

Again, this does not challenge forecast of the number of systems but suggests that the 'unlocking capacity' approach to justify expenditure may not be appropriate in this instance.

3. Powercor and AusNet Services are similar utilities yet forecasting different levels of PV penetration.

Given the similarities between the two utilities in terms of geography, network topology and customer profile, we suggest further investigation into why these two utilities are forecasting differing levels of solar PV take-up – 34% for Powercor and 28% for AusNet Services.

4. ***CitiPower is forecasting a significant take-up of new solar systems relative to the number of dwellings, much higher than that of other utilities with predominantly urban footprints and greater proportions of detached dwellings.***

Given the larger proportion of smaller urban dwellings and multi-occupancy buildings, we again suggest further scrutiny of this forecast. We do acknowledge the forecast for smaller systems (3.6KW average) in the CitiPower proposal.

We expect that the distributors will as a matter of course seek to revise their forecasts of PV growth later this year as part of their revised proposal. We expect that this revision would include not only a review of the progress and future of the Victorian Solar Homes programme, but engagement with consumers and the solar PV industry regarding their expectations. It would also be advantageous for distributors to review the installation rate and nature of larger commercial-scale PV systems, as well as consider the number and impact of energy storage systems subsidised under the Victorian scheme.

The cost per new solar customer raises the opportunity for more detailed consideration. We do not recall these costs, expressed as being applied to all customers, both solar and non-solar, as being part of consumer engagement to any degree. These costs are, per new solar customer:

a) An additional operating cost of between $4 and $10 per year, or

b) Investment by the utilities in new systems and assets of between $390 and $600.

9.5 Consumer support for the proposals

Note: in this section, we have attempted to draw out common themes and approaches that we have observed in the consumer engagement by the five distribution companies. In doing so, some generalisations are inevitable. We acknowledge that different companies have taken different approaches to their engagement, and the issues raised here may apply in differing degrees to each utility.

We acknowledge the significant effort that the distributors have undertaken in preparing their 'integrating DER' proposals. Many hours have been expended on scenario planning, deep-dives and consumer preference research related to DER. Much of this engagement was undertaken with the assistance of well-respected and capable engagement specialists who have produced useful and complete summaries of the engagement.

For all the distributors, the requirements of excess solar generation feed-in was a significant part of the "Future Network' engagement programme.

Summary

The information presented in this section highlights the strong support that was demonstrated by consumers for increasing the solar PV feed in. Customers were divided on the issue of paying to remove constraints until presented with information showing the small annual cost of doing so.

Despite this demonstrated support, we still interpret the message from consumers as mixed. The issue of lower bills (best realised by maximising self-consumption) and energy independence remain a clear priority for customers with solar PV, with the value of feed-in further down the list. Also, the way the information was presented to consumers, focusing on feed-in energy restrictions without the context of best economic outcomes for customers with PV or the possibility of the value of feed-in energy changing as more large solar farms come on line, may not have allowed consumers, most who do not have solar panels, to formulate a fully informed response. In addition, presenting the financial commitment as an annual charge per customer also has the effect of reducing the understanding the magnitude of the economic commitment over the full life of the asset. It is also more appropriate to amortise the customer investment over the life of the rooftop solar – say, 10 years – than the 40-plus year life of the network investment.

Adding to the uncertainty is customers' guarded response to 'who pays' to connect solar; a response that, in our opinion, has been largely glossed over by the distributors in favour of connections being funded through DUoS.

The engagement demonstrated powerful support for energy feed-in in isolation. In general terms, consumers – especially residential customers – clearly see value in energy feed-in as both an opportunity to earn return on their investment, through feed-in payments and eventually 2-sided market participation, and as a contribution to the lower-carbon energy landscape.

On the basis of the information provided in the engagement, the 'middle ground' approach generally taken by the distributors – removing blanket energy export restrictions where economically reasonable, while recognising that network accommodation of unrestricted operation of DER systems is too costly – is appropriate. We use the term 'disciplined investment'.

The detail and nature of this middle ground, in terms of average feed-in capability, the mechanism of the control capability and the attitude of consumers to the as-yet undefined requirements of dynamic control remain largely unexplored, and needs to be the focus of ongoing consumer engagement by utilities before significant investment is made.

<u>Observations of the engagement on DER</u>

1. ***Customers strongly indicated their support for energy exports from rooftop solar to be largely unconstrained. However, when the issue of paying to remove these constraints is raised, the messages are mixed***

Without exception, there is widespread support by consumers for increasing levels of generation and use of renewable energy, and agreement that distributors should undertake commercially disciplined investment to develop their 'DER capability' and 'Solar Enablement'.

While perhaps using different terminology, the consumer feedback to the five distributors reflected some common themes, including:

a) Broad community support for sustainability and a lower carbon environment exists. Despite this, there was a mixed response from the community regarding who should pay for the network investments that facilitate greater revels of renewable energy.

b) All customers who wish to invest in new technologies, such as rooftop solar PV, energy storage or electric vehicles should not be prevented to do so, even if some limitations are applied.

c) Consumers listed 'to save money', 'sustainability' and 'to be more self-sufficient' as the top 3 reasons for them to invest in new energy technology. The ability to 'sell electricity back into the grid' was also noted, however generally less than one in three consumers surveyed responded that feed-in was the prime reason to invest in DER. [84]

[84] CPU *Customer Insights Report*, 22 Nov 17, p18 (n > 1160)

d) The expectation that distributors need to 'make it easier to export solar' was stronger in residential customer cohorts that small business. Larger customers viewed solar exports as largely inconsequential to the business advantage of installing rooftop solar PV and other DER. [85]

e) Frustration exists regarding the connection approval process and cost for solar PV connections.[86]

Key to this attitude is the term 'disciplined investment', particularly as affordability remains an overarching priority for most energy consumers. In the engagement, consumers highly value affordability and many see electricity prices as too expensive.

AusNet Services' research shown in Figure 48 shows customers divided on the issue of paying for infrastructure to be upgraded to accommodate more solar exports, with most customers undecided.

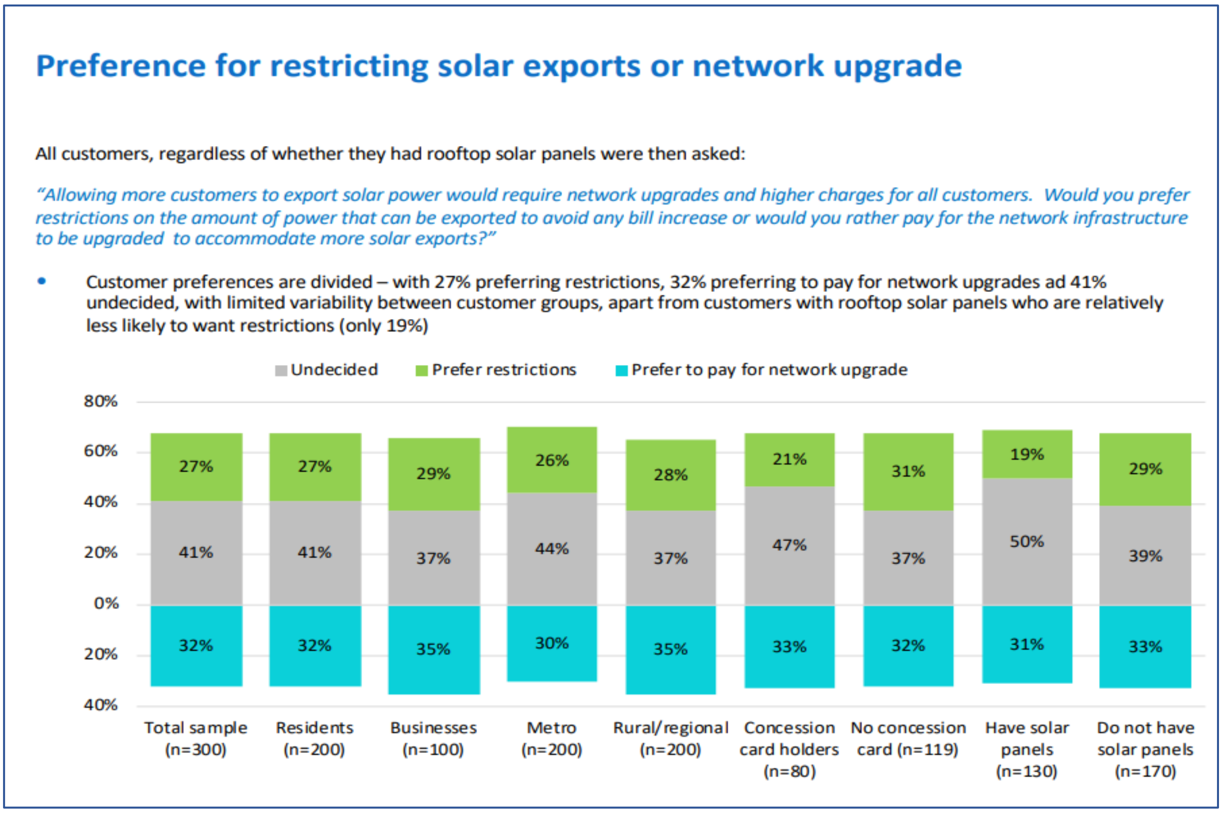

Figure 48: Investment preference (Source: AusNet Services Customer Forum, October 2019) [87]

The same research then nominated a dollar amount to facilitate more solar export. Figure 49, presented customers with the cost of $1 per annum, or nine cents per month, to reduce the times a customer's solar PV may be limited. The response is strong support for the proposal. Our own analysis supports the $1 pa amount as a reasonable estimate of AusNet Services' additional operating cost.

Similar conversations, with similar results, were observed in customer forums with other distributors.

We have seen this 'low cost per annum' approach in several determinations, which we refer to as 'it's only a cup of coffee' approach. While we do not contradict the approach taken or the response observed, we ask whether the same response would be obtained if the question was framed differently, such as:

[85] *Powercor Phase 3 Integrated Summary Report* – Woolcott Research, Oct 2018, p7
[86] *CPU – Community Opinion leader Forum report* – Woolcott Research, June 2018
[87] https://www.ausnetservices.com.au/-/media/Files/AusNet/About-Us/charges-and-revenue/Who-Should-Pay-Survey.ashx?la=en

"Do you support AusNet Services' plan to spend over $52M over the next five years to increase solar export? Do you think that money could be better spent elsewhere?"

Or perhaps,

"Every consumer will contribute to a total of $600 to accommodate each new solar connection. In the next 5 years, we expect that amount to total $52M, the cost which will be borne by all customers."

There is no intent to criticise AusNet Services in this example, acknowledging that the engagement was undertaken professionally and fairly. As this approach was evident in the engagement we observed by all distributors, our intention is to demonstrate that the way the question is framed may have a significant influence on the response.

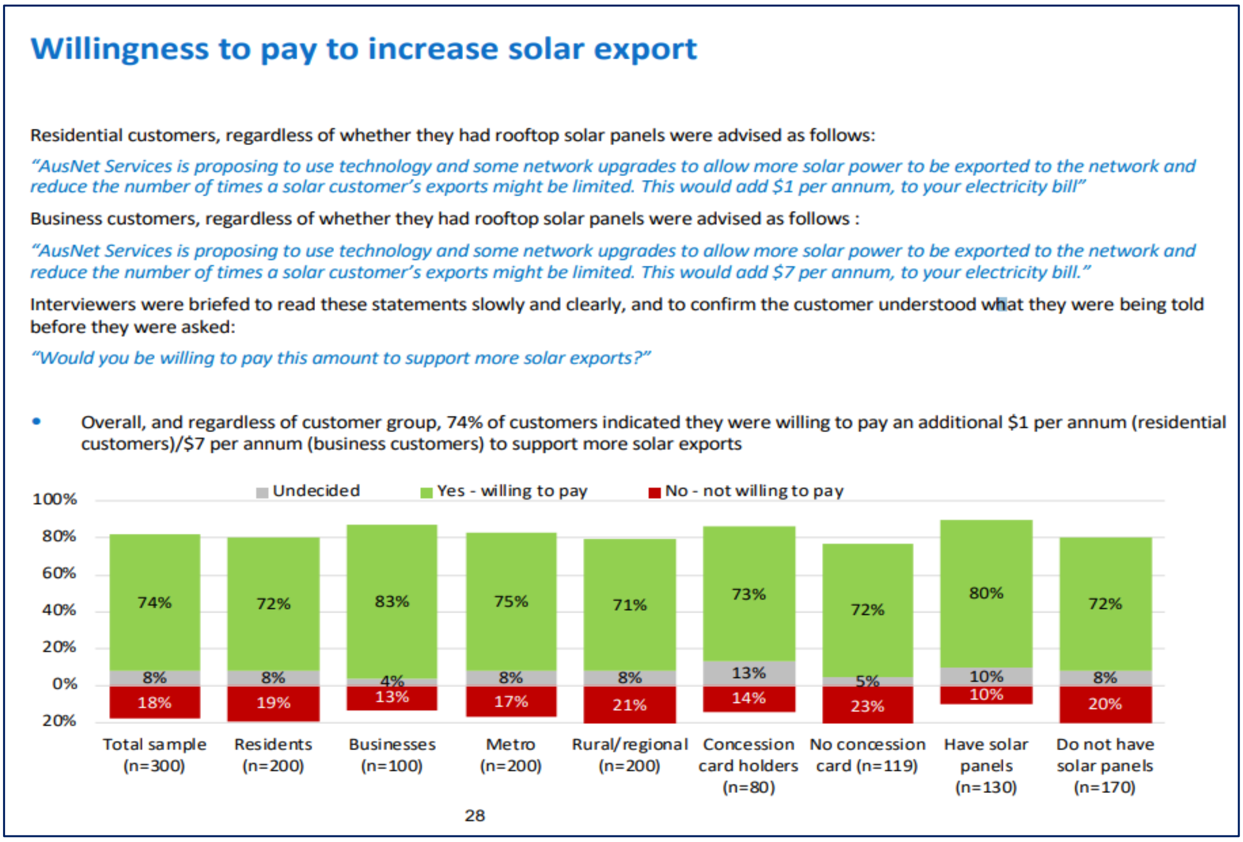

Figure 49: Willingness to pay research, AusNet Services (Oct 2019)

2. ***While feed-in is important to customers, cheaper bills remain the highest priority***

Figure 50 shows the results of research by Woolcott on behalf of Powercor in October 2018. This information is not unlike research we have seen from other utilities where solar export capability is clearly seen as valuable by consumers (56% as 'high' or 'extremely' important), but matters such as reliability, safety and cost are viewed as higher priority.

The engagement on 'unlocking constraints' did not, in our opinion, give adequate weight to the broader customer intentions for investing in DER, being reduced energy costs (especially through self-consumption) and a level of 'energy independence'.

Options presented in one workshop offered only three options for differing feed-in levels at different low additional costs to each customer. For balance, we expected to see options presented in the context where customers are encouraged to change usage patterns to increase energy self-consumption, or invest in storage, or consider investment in smaller PV systems.

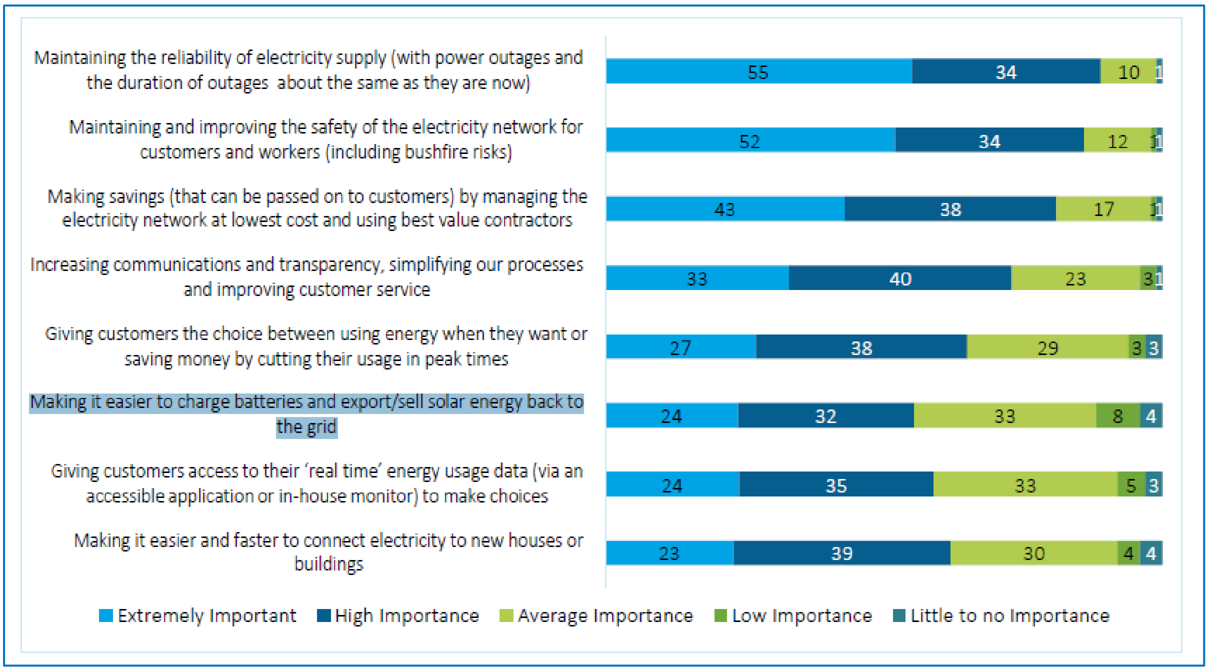

Figure 50: Importance of benefits for Powercor to focus on (source: Woolcott Research, 2018)

Research by the AusNet Services customer forum found a similar level of priority placed on solar PV investments my customers, as shown in Figure 51. It is our view that the strong desire to save money on cheaper bills implies a preference to maximise self-consumption or to store energy in passive and active systems.

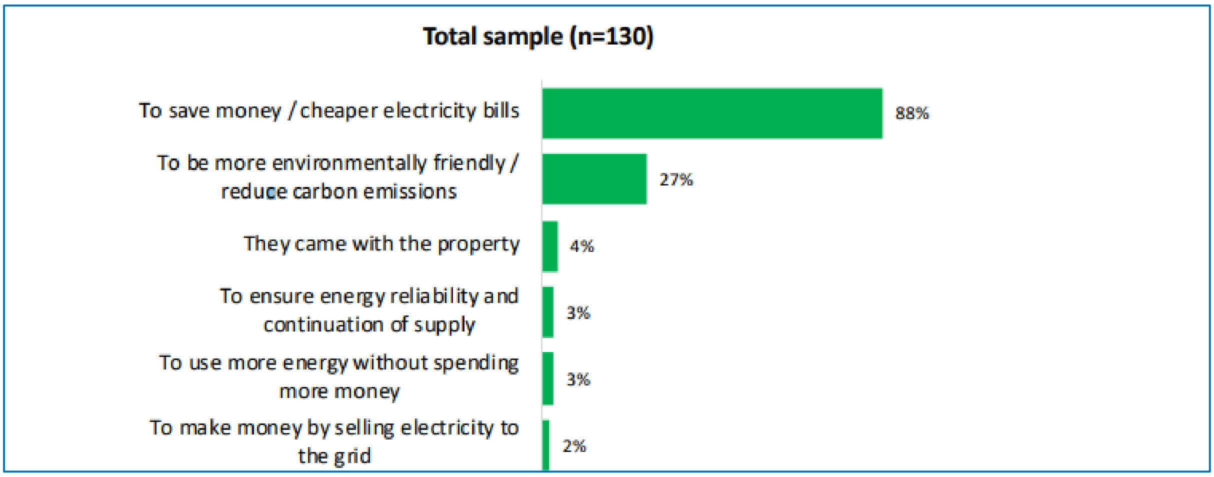

Figure 51: Customers' key motivations to have rooftop solar

(Source: Customer Attitudes Research for AusNet Services Customer Forum, October 2019) [88]

3. *Difficult issues, such as 'who should pay' were discussed, but rarely progressed in detail*

To their credit, most of the distributors broached the issue of how costs for network investment to increase solar export should be considered. Options explored generally included increased connection charges, a

[88] https://www.ausnetservices.com.au/-/media/Files/AusNet/About-Us/charges-and-revenue/Who-Should-Pay-Survey.ashx?la=en

‘quasi-export charge’ in the form of a reduction in any feed-in tariff and an ‘everybody pays, because everybody benefits’ approach.

One utility notes a 65% preference by customers and stakeholders that the cost is paid for by those wishing to connect and export solar. This was a view reinforced by advocates representing financially vulnerable customers.

In this case, the utility elected to largely disregard the preference of most consumers, with the following justification:

a) Solar is now ‘mainstream’. We question this statement given that, even after (if?) the objectives of the Victorian Solar Homes programme are delivered, only around 1-in-3 homes will have solar PV or other DER facility on the premise.
b) The benefits of feed-in solar PV energy will indirectly benefit all consumers through mechanisms such as reduced wholesale energy cost
c) The ‘price impact is relatively small’, especially in the context of falling network prices
d) There is uncertainty whether changes to charging mechanisms will be permitted under tariff rules or licenses.

It is uncomfortable to see the dismissing of a matter that is clearly of importance to consumers, yet other feedback is largely unquestioned and forms critical parts of the substance of the proposals.

AusNet Services research is equally unclear. In its early research, customers respond:

> *“Customers evaluate program options on a number of factors including cost to household, the amount of export enabled and potential for reducing voltage impacts. In considering these trade-offs, customers claim they are prepared to share the cost for this, with government and the energy sector.”*[89]

<u>Constraint – an opportunity or a threat?</u>

The term ‘constraint’ featured heavily in the engagement, with the removal of the constraint almost unquestioned as ‘given’ and expressed as the forecast net benefits to all electricity users. All utilities used ‘constrained PV’ as the base case of their options analysis, generally defined as:

> *“After the threshold is reached, PV generation systems are assigned a ‘zero export’ constraint to prevent network issues”*

While it was no doubt unintentional, the language used in many of the DER workshops implied quite a negative environment should investment in DER not be made or - dare we say it - constrained in any way.

For example, it was stated by network representatives that:

> *“No action ... will lead to unmitigated tripping, significant constraints“*
>
> *“When the local solar penetration creates a voltage constraint, require new solar to be set to 'no exports'*
>
> *“first in first served approach' was considered 'un-Australian' “*

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[89] JWS Research, *Community Perceptions Toward Solar and Innovation Propositions,* AusNet Services, Sept 2019

"30% of new PV systems will be constrained annually"

Our notes taken from attendees at some engagement included:

> *"If removing the constraints … leads to millions of dollars of benefit, are customers guaranteed to get that benefit? Who takes the risk?"*
>
> *"I feel that we are being 'massaged'"*

In addition, the data presented to consumers and included in some proposals seems, on the surface, difficult to accept. For instance, Powercor states in its proposal and in the engagement material:

> *"the red line indicates the time which solar is forecast to be constrained in 2025 if we undertake no action; this will result in the average customer at 47% of our zone substations experiencing constraints more than 20% of the time, and almost 15% experiencing constraints over 40% of the time"*

We interpret that situation as almost half (i.e. 140,000) customers with solar PV will have their inverter trip off for a total of one day in every five. Even if this interruption may be only for a few minutes per day, we suggest that such a situation would be untenable for both Powercor and its customers. Realistically, no utility will stand by, allowing such a situation and take 'no action'. From a customer point of view, this was not a realistic counterfactual.

Customer feedback warrants close consideration. In their engagement, AusNet Services notes:

> *"'Control' is a key issue for our customers. Specifically, through customer engagement we have found that there is strong concern regarding any possibility that limits will be placed on customers' solar exports. For example, research found that 80% of customers would be dissatisfied if restrictions to export DER were in place.*

This sentiment expressed also relates to similar schemes, such as the application of remote control for air-conditioning as a demand response.

> *Similarly, research found a strong preference for voluntary rather than automated demand response programs, again emphasising the desire of our customers to retain control."* [90]

This sentiment is echoed in similar terms in the engagement by other companies.

The underlying message from customers can be interpreted in two ways. Some utilities have in their proposals interpreted this sentiment as a strong desire to export energy. However, the context is important. Less than two in ten customers have solar PV and are likely to a good concept of the practicality and real commercial benefits of energy export. Also, earlier questions in the engagement considered matters such as electricity as value for money, where around two-thirds of consumers expressed dissatisfaction with the price of electricity.

Energy independence and empowerment are also recognised as strong drivers of DER investment by consumers. Recent surveys note the continued low level of trust in the electricity industry. [91] Therefore, the strong support for not placing limits on solar PV exports is likely more to do with the emotion of not

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[90] AusNet Services proposal, s9.4

[91] "*Utility companies have a significant consumer distrust problem*", Roy Morgan research, May 2020

wanting to be 'controlled' by the electricity industry, rather than a deep commitment to the value of exported energy from rooftop solar systems.

Finally, from our observation of several workshops, the term 'constraint' was not well defined. Important concepts, such as "*what is curtailment – a few hours on a few days per year, or for all time?*" and "*what can I do as an owner of DER to minimise the risk of curtailment?*" were generally not well explained. Discussion and clarity as to the benefits, changes in energy use behaviour and costs in terms of the actual people who will be investing (or considering investing) were not, as a rule, featured.

Curiously, the outcomes preferred by the consumers in the engagement for all distributors (other than AusNet) featured the word 'smart'.

In summary, we have no doubt that there is strong support from consumers that excess energy generated from rooftop solar should be made available to other consumers through feed-in. We also acknowledge that many consumers recognise the wider commercial and environmental benefits of feed-in energy. However, that engagement drew out a view from many participants that 'constraint, in terms of being told what they can't do from a big electricity company, is not good'.

The engagement we observed did not to the same extent assist consumers with 'big picture' - discussion of the value of export in relation to self-consumption, the opportunity to change household energy use patterns, the likely future of feed-in tariffs and other variables that would influence a consumer's commercial and socio-economic attitudes to DER.

Therefore, a more balanced approach to 'constraint', developed from a pool of customers where the term constraint is defined in the context of the cost / benefit of a PV system to the customer, including mitigation options and future trends, would have been more appropriate.

9.6 What is a reasonable level of energy feed-in?

Central to the distributors' proposals is the calculation of the value of energy curtailed. The amount of energy curtailed is calculated as the estimated amount of energy (kilowatt hours) that would be fed into the grid had the export limit not been applied, multiplied by the value of that energy.

<u>The value of feed-in energy</u>

In the proposals, the energy is valued at varying amounts. Significant work is being done across the industry to understand better the value of energy from DER to the wider community. As a result, there is a high chance that the value of exported energy will change over the life of the proposed investment.

For the benefit calculations, Jemena adopts the Essential Services Commission (ESC)'s feed-in tariff of $0.10/kWh. Powercor indicates it has adopted $0.47c/kWh based on consultant's advice. AusNet services advises they have applied the 2019 single rate Feed-in Tariff of 12 cents/ kWh, being is between the shoulder rate (11.6 cents/ kWh) that applies from 7am – 3pm on weekdays and the peak rate (14.6 cents/kWh) that applies from 3-9pm on weekdays.

We see these numbers as unrealistic over any reasonable period of time. Feed-in rates are set from time to time, but more generally they will become subject to pressures to reflect retail or pool pricing, which has to consider the fact that over the life of PV system - and certainly over the life of the network assets - might be zero or negative as has been the case in other states.

Also, in the case of at least one DNSP, the assumed value of rooftop solar exports used in the capex modelling is over the life of the network asset. We do not consider this an appropriate assumption, given that the life of the customer's PV system is generally little more than 10-15 years.

In the engagement, the value of exported energy was often referred to fairly generically, but to our knowledge these price risks, not the period over which the benefits were calculated, we discussed in any detail in the engagement.

The AusNet Services Customer Forum report and other engagement activity claims that there will be a reduced wholesale cost of electricity for all consumers from increased penetration of renewables. It is unspecified whether this refers to residential solar as opposed to commercial scale solar farms. This is a contentious claim, with varied positions taken by industry experts. We support the Forum's qualified view saying that wholesale price reductions do not automatically mean retail price reductions.

We are not satisfied about the extent customers were adequately informed in the issue of the value of exported energy and are relying on the assumptions in making their responses.

<u>How much energy is likely to be curtailed?</u>

This key term is the amount of energy that is likely to be exported should the inverter not be tripped due to adverse network conditions or the mandatory application of an export limit from the network operator.

An inverter will cease or restrict output when network voltage conditions exceed the maximum limit (or minimum limit for that case, but such occurrences are rare). This is not a desirable action. In some cases, an export limit can be prescribed in the connection approval. This is often seen in larger commercial PV systems embedded in the distribution grid.

The cornerstone of the distributors' investment proposals is to take actions to avoid the risk that the occurrence of high voltage leads to the inverter's disconnection. Central to the analysis is the diversified level of peak net export (kilowatts, like peak demand, in reverse) that drives voltage rise. Just as peak demand can create low voltage conditions, peak net export can lead to high voltage conditions.

Powercor notes that the average peak feed-in observed through their metering is just over 3 kilowatts. This level 'rings true' with observations in other states, given the standard new residential PV installation. In their engagement with consumers however, and in the evidence presented as part of the proposals, the distributors consider new embedded generation installations as being up to 5 kilowatts capacity.

CCP17 does not have the information nor the resources to consider the detail of the curtailment risk calculations – determining the likelihood, extent and duration of network conditions that will trip the inverter. However, we can offer some observations regarding peak net export and the consequence of adverse network conditions.

1. *The expectation of 5 kilowatts of peak net export for 95% of customers (70% in the case of AusNet Services) , especially diversified over a local network area, is excessive.*

It is expected that that most customers will be seeking to self-consume some energy at least. We have not observed any evidence that customers with solar PV will change behaviour to meet this level of export, being close to the full rated output of a typical residential PV system, especially considering the diversity of individual household energy usage patterns that is likely to exist in a local group of residential connections.

There are many factors that influence a customer's view of value of peak-energy export, including:

a) Current and perceived future levels of retail electricity prices

b) The structure of retail electricity tariffs or other incentives available to that residence or business,

c) The level of feed in tariffs (FiTs) which are paid for exports of rooftop solar electricity

d) Tariffs and other incentives that influence the shape of their load curve, optimising self-consumption for greatest personal economic benefit.

e) The sense of 'energy independence' in challenging times, to 'going off grid'

f) The emergence of a viable peer-to-peer energy market

g) We find it most unlikely that the base 'do nothing' is a reasonable counterfactual case. The networks have presented scenarios as the base case that would not be accepted by consumers.

Powercor, for instance, notes:

> *"if we undertake no action to accommodate it. By 2025 the average customer on 47% of our zone substations are expected to experience constraints more than 20% of the time. Almost 15% are expected to experience constraints over 40% of the time"*

Similarly, in their proposal, AusNet advises:

> *"If we do not take appropriate action to reduce network constraints, we forecast that by 2025 nearly 30% of our customers (around 235,500 customers) will be experiencing voltage issues by the end of the 2022-26 regulatory period. For $20.9 million of capex, we can improve the experience of 97% of these customers and reduce constrained exports by 70%."*

We agree that 'no action' leads to a situation that is untenable. We suggest that any reasonable utility (supported by any reasonable regulator) would at least take some steps to address such a situation within existing regulatory allowances, even if not to almost alleviate the likelihood of curtailment to the extent outlined in the proposals.

This was highlighted in customer feedback:

> *"… some felt that there were not enough future-focused outcomes compared to 'business as usual' outcomes. …also, there was no statement of leadership in the value propositions or any indication of what roles the distributor would play in driving or facilitating change."*[92]

2. *Choice modelling focused on high level commercial outcomes based on the 'value of DER'*

After presenting the unacceptable situation that arises from the somewhat unrealistic 'do nothing' option, most utilities then offered the customers in the engagement a form of choice in the form of "for this price, everyone can export all spare energy. For less, you may be curtailed by this much". Instinctively, the results tended to support the middle option of 'very little constraint and be smart about it' (our phrasing). This is not surprising, given the benefits were quoted in the millions, and the cost was 'about a cup of coffee'.

What was missing in our opinion in the choice selection was informing customers just what 'curtailed by this much' actually meant:

- Is it the most likely situation? (statistically, some self- consumption is expected)
- which scenario presents the best commercial outcome for the owner of the PV system? (on the basis that maximising self-consumed energy generally represents the best outcome for owners of PV)
- what other actions customers can take to reduce the amount of feed-in?
- which scenario is in the best interests of non-solar customers?

In our Advice regarding the proposals, we are supportive of innovative approaches such as the application of a Dynamic Voltage Management System, which will go some way to addressing the high levels of curtailed energy noted in the base case.

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[92] Woolcott Research, *Phase 3 Integrated Summary for CitiPower*, October 2018. P17

Other considerations include:

3. Some customers may be quite agreeable to the imposition of a system export limit, opting to modify their energy use patterns.
4. Better modelling and analytical tools for networks - investments supported in this advice - will help with ‘fast turnaround’ connection approvals, reducing the delays and blanket limitations that typify existing restricted connection approvals. This will support new PV connections in places where the energy is consumed locally, and the risk of voltage rise is reduced.
5. The implications of energy storage and other local innovations need to be considered. Storing energy, or running pool pumps or other appliances are simple approaches to reducing the likelihood of 100% energy fed in. Battery storage is subsidised under the Victorian Solar Home programme.

9.7 Other matters for consideration

Seeking a demonstrated efficiency advantage as a ‘second mover’

We expect the Victorian distributors to have a distinct advantage in determining the most efficient investment needed to support PV and DER growth. Learning from the experiences in those jurisdictions, as well as the significant advantage of AMI in Victoria providing a large data set, and the predominance of more contemporary inverter standards, all present the opportunity for more accurate planning, timely responses, and robust risk management.

We have a high expectation that the Victorian networks will be able to accommodate the growing levels of DER more efficiently than other states. This ‘second mover’ advantage is driven by:

a) AMI providing greater granularity and timely visibility across the whole network of areas of network congestion, allowing the response to be targeted in scope and timing, almost ‘Just-in-time’, based on actual local network conditions.
b) The opportunity for advanced network voltage management provides a scope for more efficient operation of the medium and low-voltage networks, reducing the need for widespread physical network upgrades.
c) A higher proportion of inverters being set to comply with contemporary performance settings, such as volt-var output control and staged voltage trip thresholds.
d) Batteries being offered as part of the Solar Homes subsidy package in many areas, providing options to diversify energy-feed-in patterns and assist in reducing peak demand.
e) All new customers being assigned to network tariffs that encourage daytime consumption and load shifting. Under the current Tariff Structure Statement, all new connections, including new residential developments that are likely to incorporate a large proportion of solar PV growth, are assigned to a network tariff that is expected to have a similar impact as the SAPN ‘Solar Sponge’.[93]

Voltage reduction opportunity

United Energy has highlighted the operation of its Dynamic Voltage Management System (DVMS) as an effective tool for the contingency reduction of customer peak demand through the reduction in network voltage. UE also notes that DVMS is an effective tool in managing voltage variations from rising levels of solar generation. To meet both these objectives, UE reports the opportunity exists to efficiently reduce grid voltage with only a small number of non-compliances that require network augmentation to resolve.

[93] United Energy *Tariff Structure Statement Explanatory Document*, p27

CCP17 commends the application of DVMS and support its proposed use in other utilities, being in the interests of all electricity consumers. Given the reported advantages of the system, we question whether the distributors have considered, implemented and assessed the viable non-asset solutions such as DVMS and contemporary inverter settings to address the impacts arising from solar PV penetration before opting for significant investments in physical network augmentation.

Similarly, we seek clarity on the commercial operation of DVMS as a Demand Response (Reserve) market offering while funding to address limitations of the system remains part of customer-funded capex.

United Energy has highlighted the operation of its DVMS as an effective tool for the contingency reduction of customer peak demand through the reduction in network voltage. This valuable development represents an initial investment of $5.76M in part funded through an ARENA grant [94] and has been presented in several public technical forums in the past two years.

UE offers the DVMS system to AEMO as part of large-scale demand response capability. The system also uses AMI data to dynamically adjust zone substation voltages downward to significantly improve voltage compliance at varying levels of network demand, including light load and high generation.

We commend this valuable initiative by UE and support its proposed use in other utilities, noting the planned investment by Powercor ($2.45M) and CitiPower ($1M).

However, it is difficult to reconcile the claimed effectiveness of the DVMS to efficiently reduce the number of instances of high grid voltage and still be able offer demand reduction (voltage reduction) as part of AEMO Demand Response requirements. In their proposals, networks require significant amounts of investment in physical network augmentation to address voltage rise above regulatory limits because of solar PV feed-in.

To support the case for network augmentation as being necessary to increase the amount of installed PV generation in the network, the utilities have provided extensive evidence of the existence of excursions above maximum allowed voltage, both presently and as modelled as the level of PV generation increases. Figure 52, used in the CitiPower, UE and Powercor business cases, is a typical example and reflects similar justifications made in the proposals from the other distributors.

In the options analysis presented in both engagement sessions and in the proposals, consumers have not been presented with the option to effectively implement DVMS to reduce grid voltage in times of high PV generation; a period when low supply voltage to premises is unlikely. The graphic in Figure 52 below seems to show that minimum measured voltage of around 242V; well above the permissible minimum voltage at the consumers' terminals of 216V. This matter is not discussed in any detail in the proposals.

Similarly, the report from United Energy,[95] having implemented DVMS, notes that across their entire network on a typical mild day with DVMS in service:[96]

a) V99% voltage is being regulated at all times within the 253V limit

b) V1% voltage is being regulated at all sites within the 216V limit

c) 0.005% of customers are at times operating below the minimum 216V and 0.31% of customers above 253V

d) V1% is 231V, V99% is 251V, a spread of 20V and a *demand response margin* down to 216V of 15V.

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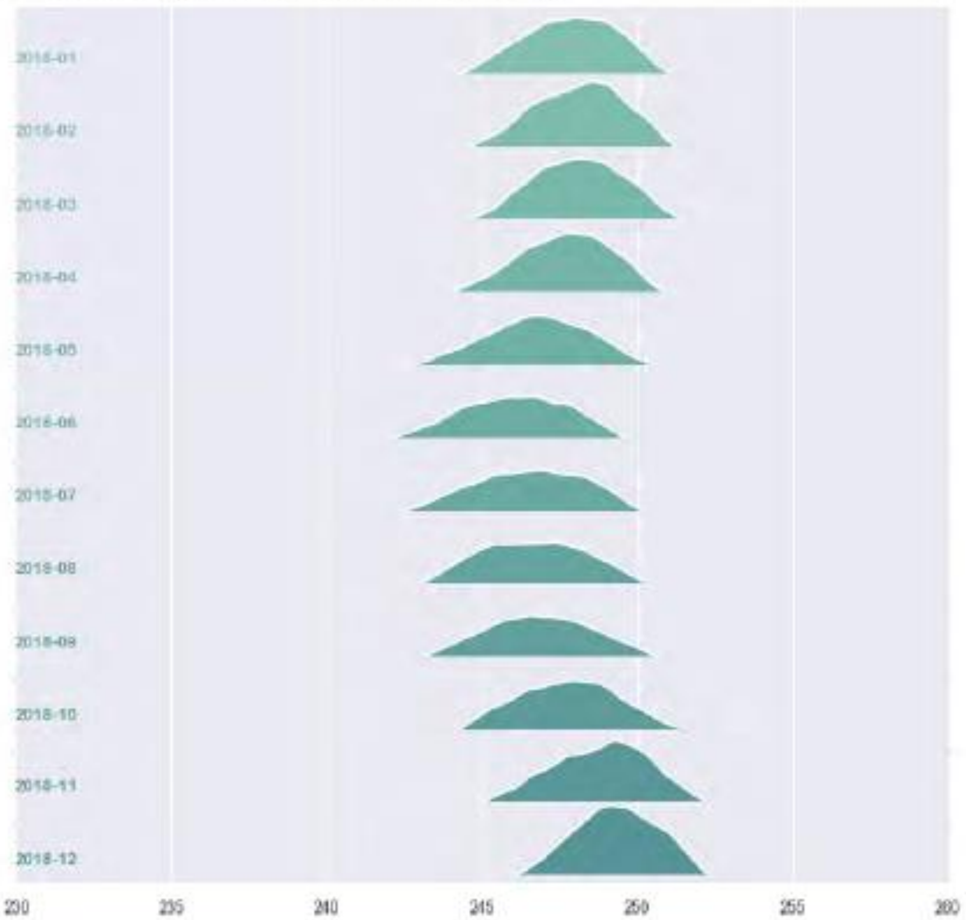
[94] https://arena.gov.au/blog/united-energy/

[95] From *United Energy Demand Response Project Performance Report- Milestone 6,* 17 Dec 19, p8

[96] Reference Australia Standard AS61000.3.100 for network power quality limits

Figure 12 Actual voltage readings on a single transformer



Source: United Energy

Figure 52: Voltage readings on a distribution transformer (source: United Energy proposal)[97]

UE then summarises (p21):

- "Implementation of the DVMS in Summer 2018/19 arrested the increase in (voltage) complaints"
- "Since the tuning of the DVMS in early 2019, we now have the lowest complaint volumes in 2 years, despite a doubling of solar PV connections"
- "The outcome has allowed us to maintain our 10kW per phase export limit for basic residential solar PV systems. "

Similar information is contained in the AusNet Services proposal, as shown in Figure 10, noting that at no time does the voltage appear to fall below 226 volts, against a regulated allowable minimum of 216V.

CCP17 acknowledges the complexity, breadth of variables and the highly locational factors that impact voltage management and the rectification requirements faced by utilities, and recognises that the UE report does note that residual non-compliances with overvoltage and undervoltage areas do exist, requiring investment on local remedial solutions.

[97] United Energy proposal, Business Case UE 6.06, p29

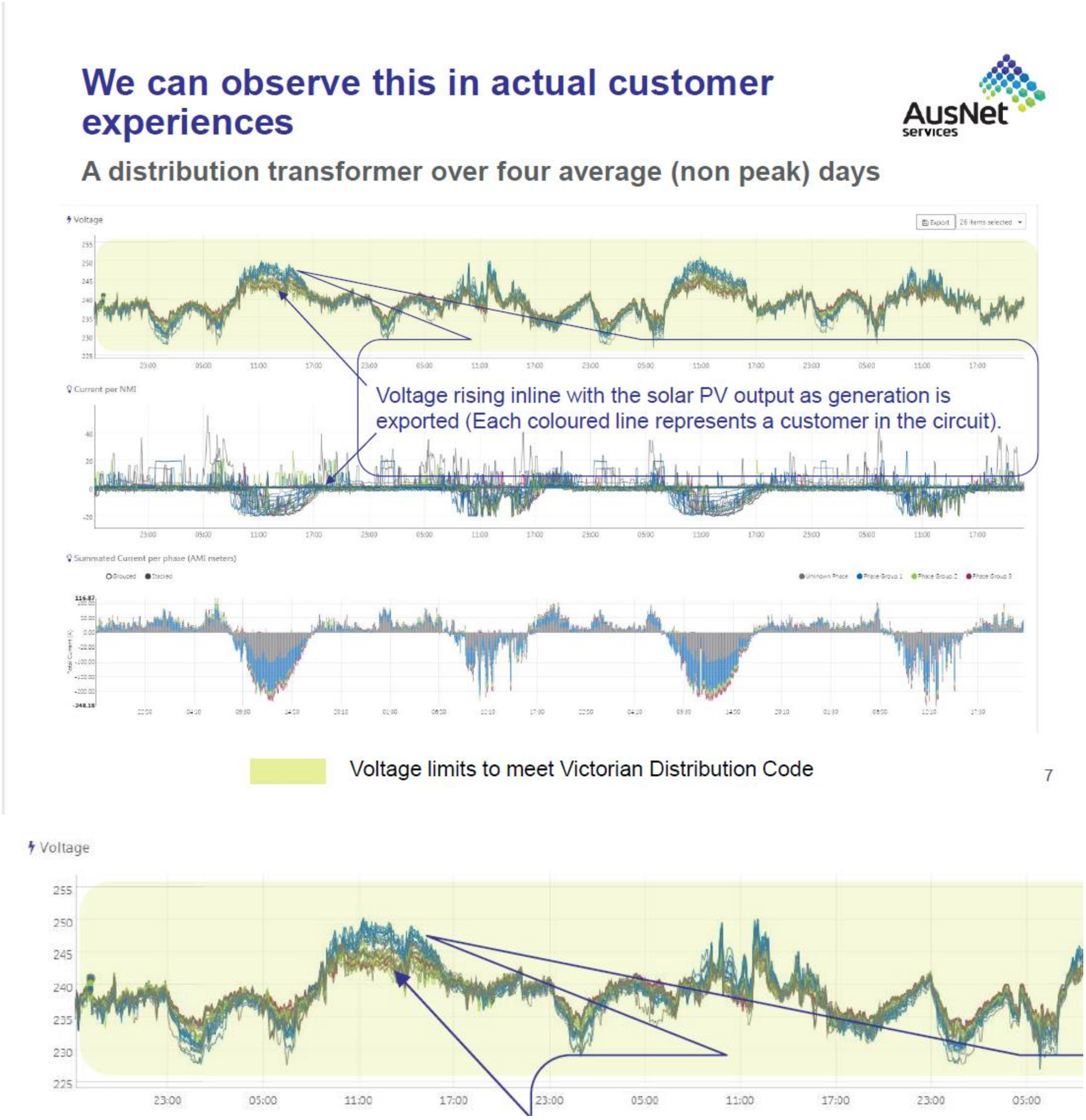


Figure 53: Typical voltage readings, AusNet Services (source: AusNet Deep Dive into DER, May 2019)

We also acknowledge that in some cases technical limitations such as tap restrictions on substation transformers are being reached; however, the general application of voltage reduction should be considered in places where it can be reasonably be enacted. The data provided by UE shows that the DVMS can effectively manage network voltage at times of high and low demand, and that the lower level of investment required by UE to meet the requirements of increasing solar PV is in part assisted by this innovative approach to voltage management.

We are highly supportive of the other distributors adopting DVMS and note Powercor and CitiPower's plan to adopt the system. Our recommendation is that the AER encourage and support the development of DVMS by other utilities an effective approach to managing voltage rise and enhancing PV feed-in capability.

In so doing, important questions remain regarding the role of DVMS in the overall proposals by the utilities.

a) While DVMS (or similar facility) is mentioned as a component of the proposals to address DER growth, its impact and influence in reducing the reliance on 'asset-upgrades' is not discussed. Along with only minimal discussion on the impact of the recent (2018-19) implementation of contemporary inverter settings, we can assume that the distributors are taking a 'belts and braces' approach and may benefit from a more 'one step at a time' plan at lower cost in this period and perhaps overall.

b) The fact that DVMS as a Demand Response tool suggests to consumers that there could be a tension, overlap or conflict regarding network investment to address voltage variations due to solar PV and to be able to offer a commercial (albeit important) facility to the wider network.

c) The distributors appear not to have discussed the impact of DVMS on related network augmentation activities such as LV augmentation for demand growth or power quality improvement. There is an opportunity that these other activities may be in some ways reduced or benefit from the more stable voltage management offered by DVMS, at a lower overall cost.

We encourage the AER to consider these opportunities in the light of perhaps reducing, smoothing or staging the proposed expenditure by the distributors. We also request clarity of the AER's position regarding SCS expenditure for voltage management and the distributor's market roles as Reliability Emergency Reserve Trader and Demand Response provider through DVMS.

9.8 Suggested further engagement

The engagement to date regarding DER has provided a powerful insight into consumer thinking and values related to DER and solar enablement. However, there remain some significant gaps or broad assumptions that could be investigated either in the lead up to the final regulatory proposal or in the early stages of the next regulatory period.

1. ***Go back to consumers and validate the option analysis and level of support for the planned investments, now that better data regarding cost is available***

In the engagement, customers noted support for the investment in DER capacity and cost-sharing principles when provided with indicative or guideline costs. At the time, costs to augment the network to permit various levels of feed-in were largely indicative and generic. Now that the proposals provide costs are much more concrete and visible, it would be particularly useful to discuss the actual expenditure proposed. This would help define consumer attitudes to feed-in limitations, costs per customer, level of 'cross subsidy' proposed and test the benefit stream against likely real-world experience.

2. ***Most utilities are considering a facility to dynamically limit DER and inverter operation. Consumer acceptance of control mechanisms remains unclear and not well-informed.***

In the engagement, customers expressed a level of concern about the amount of interaction and control that will become a prerequisite in new DER connections. Recent media reports highlight the concerns and distrust that exist in segments of the community.[98]

Distributors have all expressed the intent to establish dynamic export limits and facilities for the distributors or third parties to control customer installations in some way. On face value, we recognise such facilities as eventually being necessary. It is especially important to note that over 80% of consumers who have installed DER have the primary intention to reduce household electricity bills. [99] Against this background, AusNet's engagement importantly notes the need for further consumer engagement to refine

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[98] ABC News, "C*oncerns over plan to switch off household solar panels",* 7:30 report, 20 May 2020

[99] *Energy Networks Australia Open Energy Networks Project* position paper, 2020, p23

the nature, communication, and implementation of these control mechanisms and not to assume that they will be accepted by consumers.[100]

'Control' is a key issue for our customers. Specifically, through customer engagement we have found that there is strong concern regarding any possibility that limits will be placed on customers' solar exports. For example, research found that 80% of customers would be dissatisfied if restrictions to export DER were in place. Similarly, research found a strong preference for voluntary rather than automated demand response programs, again emphasising the desire of our customers to retain control.

AusNet Proposal, part 4 (p48)

Customer expectations need to be carefully managed, as some noted that there may be confusion, loss of trust and also customer backlash if not clearly communicated, articulated and understood by customers. Many customers would just expect to be able to install solar and export with no constraints and have a fear of a 'big brother' approach being implemented.

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3. ***As the analysis proceeds, other important issues central to the further development of DER policy and investment priorities come into sharper focus. It will be useful to take these issues back to consumers in more detail for informed engagement.***

These matters include:

- Is it clear – or, at least, a consistent and accepted approach – to understand what the benefits to all consumers are, including non-solar customers? There have been studies, including work by the AEMC, in this area.
- How critical is the 5kVA export capability that forms part of the distributor's technical analysis? Could it be 3 kVA or a different value, influenced by tariff conditions and/or the imperative to self-consume? Is the planning by some utilities for 95% of customers to export 5kW realistic?
- Are we sure that the 'all customers pay' approach has the support of all customers? We note the analysis by CPU on the charging options, although we question the conclusion reached that the costs be spread over all customers, despite the customer preference that 'connectors pay'. (PAL BUS 6.02 p19)
- Have the benefits of 'non-asset' investments, such as load balancing and active network voltage control, been fully explored before the next level of investment by networks is required?
- Have existing initiatives such as contemporary inverter technical settings and the impacts of current tariff strategies to encourage consumer behaviours such daytime energy consumption been given time to take effect and their impact assessed and understood?

It may be valid to consider the proposed expenditure of the Victorian Distributors in the light of expenditure undertaken by Energex, Ergon and SAPN to embrace increasing levels of DER in the current regulatory period.

[100] *AusNet Services Deep Dive Workshop Four Summary Report* - Seed Advisory, June 2019

10 Tariff Structure Statements (TSS)

This section of our advice discusses the Tariff Structure Statements (TSS) that each of the Victorian Distribution Businesses is proposing as part of its regulatory proposal. The Tariff Structure Statements set out the structures of the tariffs that the businesses are proposing to put in place to levy network use of system charges on users of their network in the upcoming 2021-26 regulatory period. Network use of system charges comprise:

- Distribution use of system charges,
- Transmission use of system charges, and
- Jurisdictional scheme charges.

Alongside the Tariff Structure Statements (TSS), the businesses have set out the indicative prices that they propose to charge in each year of the regulatory period.

This section of our advice considers in turn:

- The stakeholder engagement activities in which the businesses engaged in the process of formulating their TSS proposals,
- Relevant requirements of the National Electricity Rules (NER) in regard to TSS,
- The Victorian context in the regulatory requirements for TSS,
- The actual TSS proposals of the businesses,
- The issues raised in the AER's issues paper and in the AER's public forum in regard to the TSS,
- The need for a holistic approach, where network tariffs are considered in the context of the distributors' proposals on expenditure, connection policies and demand management initiatives,
- Cost reflectivity in network tariffs,
- Network tariff choice,
- Effects of network tariff reform on vulnerable customers,
- Customer well-being considerations,
- The option to remain on a single-rate network tariff,
- The target audience for network tariffs,
- Consideration of a solar sponge network tariff in Victoria, and
- Uniformity in and simplicity of network tariffs across Victoria.

10.1 Stakeholder engagement activities

<u>Status as at our March 2019 progress report on the businesses' consumer engagement activities</u>

In our March 2019 progress report on the businesses' consumer engagement activities, we noted that the Victorian DBs had agreed to work together on issues of common interest. Victorian network tariffs were one such area, where the businesses had established a joint program to progress network tariff reform in Victoria. We commended the businesses for implementing this initiative.

Two joint forums and a consultation paper in September 2018 covered the businesses' approaches to tariffs for residential customers, and small businesses with annual usage below 40 MWh.

The first joint forum was held on 1 November 2017. Customers and stakeholders established the shared objectives for network pricing reform. The second joint forum in April 2018 considered the design of pricing structures, and who the pricing structure should be directed toward.

As the initial joint forum was conducted prior to formation of CCP17, there was not a CCP representative in attendance. CCP17 was present at the second forum, and continued tariff reform discussions with the businesses in conjunction with members of CCP sub-panel 21 – Tariff Reform.

We noted at that stage that the benefits of the Victorian DNSPs' joint approach for consumers were clear – a common approach to tariff structures for the jurisdiction as a whole, particularly in localities where distribution zone boundaries artificially divide communities; and an efficient engagement process for consumers and their representatives.

We also noted that at that time there was not yet an agreed common approach to network tariff structure design and implementation for the Victorian DNSPs.

A third joint Tariff Reform Forum, targeted at consideration of residential customers' tariffs, had been scheduled for 20 March 2019.

<u>Relevant TSS-related consumer engagement activities since our March 2019 progress report</u>

The CCP sub-panel 21 – Tariff Reform did not proceed beyond June 2019. It served as a means to bring consumer advocates together to discuss tariff reform but did not publish any findings or advice to the AER.

Rather it was left to the sub-panel assigned to each regulatory determination process to consider TSS alongside other elements of each regulatory proposal.

CCP17 attended the third joint Tariff Reform Forum on 20 March 2019.

The businesses each also undertook business specific-consumer engagement alongside the joint DB consumer engagement activities on the TSS.

Each of the businesses has provided an Explanatory document containing reasons for its TSS which sets out in more detail the business' TSS related consumer engagement activities and how the business responded to stakeholder engagement feedback.[101] These are backed by various supporting documents that set out proceedings at and responses resulting from the various forums that were held.[102]

The businesses have also provided presentation slides from ACIL Allen that were presented to the third joint Tariff Reform Forum on 20 March 2019. These slides presented findings from research involving an online survey of approximately 2000 Victorians. Data was then matched at individual level to electricity usage data, to calculate two annual network 'bills': based on a standard flat rate tariff and a revenue neutral TOU tariff provided by the DBs for

- 293 customers with past payment difficulty *and* perceived difficulty funding an unexpected $500 expense; and
- 738 customers with perceived difficulty meeting unexpected expense *regardless* of past history.

Our notes from that forum state that the research analysis assumed that the ratio of peak to off-peak price in the revenue neutral TOU tariff that was modelled was 2.5:1.

The ACIL Allen analysis showed that vulnerable customers collectively would receive lower bills if everyone were on a ToU tariff, with the average vulnerable customers' bill impact being an $11.93 decrease. This

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[101] See CP APP05, PAL APP05 and UE APP05 sections 4.2, 5.2 and 6.2 in respect of households, small businesses and large businesses respectively; JEN Att 08-02 sections 3.2, 4.2 and 5.2; AusNet – TSS Explanatory Statement sections 3.2 and 4.2.

[102] These are documents authored by Woolcott Research and Engagement, and Seed Advisory.

indicates that vulnerable customers generally use relatively less electricity during peak periods. However, a diversity of consumption profiles occurs within vulnerable customers as it does for non-vulnerable customers. The analysis showed that while on average vulnerable customers would receive lower bills, there would still be around 27% of vulnerable customers who would be negatively impacted by more than $10 per annum. Across the population of Victorian vulnerable customers, this would be a significant number of households.

10.2 Relevant requirements of the National Electricity Rules (NER) in regard to TSS

As with other aspects of regulatory proposals, the TSS must comply with the National Electricity Objective to be in the long-term interests of consumers.

The NER also set out requirements for network tariffs in the Distribution Pricing Rules (Part I) of Chapter 6: Economic Regulation of Distribution Service. Among the requirements in the NER, clause 6.18.5 sets out the network pricing objective that the tariffs that a network charges in respect of its provision of direct control services to a retail customer should reflect the network's efficient costs of providing those services to the retail customer.

Other requirements set out in the pricing principles in clause 6.18.5 of the NER include that:

- Each tariff must be based on the long run marginal cost of providing the service to which it relates to the retail customers assigned to that tariff.
- The network must consider the impact on retail customers of changes in tariffs from the previous regulatory year.
- The structure of each tariff must be reasonably capable of being understood by retail customers that are assigned to that tariff.

Network businesses are further restricted by clause 6.1.4 of the NER which prohibits a distribution network from charging distribution use of system charges for the export of electricity generated by a user into the distribution network.

The requirements in the NER still leave considerable freedom in the hands of the network businesses as to how they structure network tariffs.

In assessing the TSS, the AER must consider whether they comply with the NER.

10.3 The Victorian context in the regulatory requirements for TSS

Victoria's Advanced Metering Infrastructure (AMI Tariffs) Order was made on 18 June 2013 under section 46D of the Electricity Industry Act 2000. It has had various amendments since. These include amendments that regulate in regard to Victorian electricity retail and distribution tariffs until 31 December 2020, thus limiting the tariff structures that can be offered, and limiting which tariff structures can be implemented as mandatory tariffs or tariffs which a customer can opt-out as against opt-in.

These provisions currently expire on 31 December 2020, which is before the forthcoming 2021-26 regulatory period. We expect that more information will be available later in this regulatory process regarding what will follow from the current Order to apply from January 2021 and propose to respond accordingly in later advice to the AER.

10.4 The actual TSS proposals of the businesses

The businesses' TSS proposals can be summarised as follows:

Residential customers

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

Business customers

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

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.

10.5 Issues raised in the AER's issues paper and in the AER's public forum in regard to the TSS

Section 2.5.2 of the AER's Issues Paper covers the role of tariff reform in supporting the transition of the energy system.

The AER stated:

> *"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.*

In regard to tariffs and demand management, the AER stated:

> *"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.

In regard to the role of retailers, the AER noted:

"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.

The AER concluded:

"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.

10.6 A holistic approach

We support the view of the AER that the tariff proposals need to be considered in the context of their proposals on expenditure, connection policies and demand management initiatives, and whether the overall package of the distributors' proposals provides a sensible and coherent strategy to address the energy system transition. It is important to consider the interactions both ways between pricing and other areas such as capex, uptake of electric vehicles, demand response, demand growth, and the impact of solar generation uptake.

10.7 Cost reflectivity in network tariffs

There is much talk of the need for tariffs to be 'cost-reflective', but it is not always obvious what cost reflectivity actually entails. A tariff that is not flat may or may not have a more cost reflective structure than a flat tariff. If it is badly designed, a complex non-flat tariff may actually be counter-cost reflective. It should not be assumed that every possible complex tariff is more cost reflective than a flat tariff. There remains an onus on any proponent of a complex tariff to demonstrate that it really is more cost reflective than a flat tariff.

Tariff reform should seek to promote additional investment in the network by distributors only when consumers value that increased demand more than the cost of delivering the additional network capacity necessary to meet that demand.

Nowadays, consumers make more decisions than whether to consumer more or less electricity. They may also choose whether to generate their own electricity, to generate surplus electricity to export, and/or to invest in battery or other storage. Tariff reform must take those more complex consumer decisions into account as well.

This is consistent with the views of the AER as stated in its final determination of Energy Queensland's TSS for 2020-25:

"*While we and the Queensland distributors consider network tariff reform is important, our reasons for supporting network tariff reform and the majority of the Queensland distributors' revised TSS* *proposals reflects our own views on what we consider to be the key rationale for network tariff reform in Queensland. This is somewhat different to the Queensland distributors' reasons for their proposals which, among other matters, was framed in terms of unwinding what the Queensland distributors considers to be cross-subsidies between different consumers.*

Our reasons are framed more in terms of creating the right incentives on retailers and consumers for more efficient and innovative retail products and more efficient and informed end user choices in when and how they utilise the grid. In turn, we expect this to lead to more efficient utilisation of the network and network investment in the long-term interests of all consumers.[103]

It is important that network tariff reform is forward looking, focused on increasing efficiency of future use of the grid and of future investments.

10.8 Network tariff choice

In its final determination of Energy Queensland's TSS for 2020-25, the AER supported giving retailers a choice of cost reflective tariff structures. The AER accepted the businesses' proposed transitional demand tariffs as the default tariffs for small customers, while allowing an option of an opt-in time of use tariff for residential and small business customers as an alternative. The AER stated that providing a choice of cost reflective tariff structures will support the objective of incentivising the retail market to discover innovative ways of managing the risks created by reform.[104]

We support the use of optional tariffs that provide stronger price signals.

We see the AER's acceptance of the demand tariff as the default tariff, with an alternative opt-in of a time of use tariff in Queensland, as being analogous to the Victorian businesses' proposal of a default time of use tariff, with an alternative opt-in of a demand tariff.

We prefer the Victorian approach to the Queensland approach, because customers find time of use tariffs easier to understand than a demand tariff. The AER has acknowledged that stakeholders have opposed demand tariffs on that basis that it is too difficult for customers to understand and respond to such tariffs and have raised serious concerns about the economic efficiency properties of demand charges given that they are based on the individual customer's maximum demand, which may not necessarily coincide with the timing of localised critical network congestion.[105]

The AER has stated: "we consider that demand tariffs can be designed to be as cost reflective as time of use tariffs."[106]

10.9 Effects of network reform on vulnerable customers

We are concerned regarding the effects of tariff reform on vulnerable customers. Research conducted by ACIL Allen that was discussed above showed that, while on average vulnerable customers would receive lower bills, there would still be around 27% of vulnerable customers who would be negatively impacted by more than $10 per annum. Across the population of Victorian vulnerable customers, this would be a significant number of households.

The ACIL Allen analysis covered a limited number of customers and was also restricted to a single flat rate against TOU tariff comparison. We suggest that further work is needed to consider the effects on

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[103] Attachment 18: Tariff structure statement | Final decision – Ergon Energy and Energex 2020–25, page 18-18
[104] Attachment 18: Tariff structure statement | Final decision – Ergon Energy and Energex 2020–25, June 2020
[105] Attachment 18: Tariff structure statement | Final decision – Ergon Energy and Energex 2020–25, June 2020, page 18-20
[106] Attachment 18: Tariff structure statement | Final decision – Ergon Energy and Energex 2020–25, June 2020, page 18-20

vulnerable customers, using a larger sample, and using tariffs that reflect what actually might be implemented. Specifically, the ratio of peak to off-peak rates should match the businesses' proposals, and some sensitivity analysis should be conducted around that ratio.

We also note that seasonality affects budgeting even if tariffs do not vary seasonally. The results published by ACIL Allen only included annual impacts and have not considered bill variability due to seasonality which is significant in Victoria. Even if customers will pay a lower bill in total on an annual basis, in future their bills might vary more significantly than previously in different seasons. Those who have difficulty budgeting may be adversely affected if an individual monthly or quarterly bill is higher, even if their total bill annually is lower.

10.10 Customer well-being

Customer well-being was discussed in two Etrog Consulting submissions to the AER's consideration of the TSS to apply in Queensland from 2020 to 2025.[107]

Often, in comparing the effects of tariff reform on consumers, network businesses define whether a customer is "better or worse off" solely in relation to the size of the electricity bill, without regard to levels of household stress that may be adversely affected by more complex tariffs. Customer wellbeing is important and needs to be assessed as part of network businesses' impact analyses of new proposed tariff structures. There is a growing body of research that has found that complex tariffs could risk customers' wellbeing by causing discomfort and anxiety.

We welcome the AER considering customer well-being in its consideration of network TSS in order to satisfy the customer impact principle in the Rules.

10.11 The option to remain on a single-rate network tariff

We understand that the AER may have some concerns with the businesses' proposal that the retailer can choose to opt-out of tariff reform and face a single-rate ("anytime") tariff. For example, the AER has said:

> "*We consider that distributors should no longer offer customers who are on a cost reflective tariff the ability to opt-out to anytime energy network tariffs. The risks of allowing continued access to anytime tariffs – inefficient use of, or investment in, the network – outweigh the benefits of customers understanding these simple tariff structures*.[108]

On the other hand, allowing the option to continue to face a single rate tariff is consistent with the Victorian context, where to date the Tariffs Order has allowed customers to remain on single rate tariffs.

Further, in other jurisdictions, interval metering capable of supporting more complex tariffs is being rolled out over a period of time, so a requirement for customers with interval metering to be put on a more complex tariff is introduced gently over a period of time, as the metering is rolled out. Often the interval meter is installed because of solar PV installation, when the customer is engaged in considering their energy usage, and that can be a good time to get their attention to introduce them to anew supply tariff.

In contrast, Victoria already has full roll-out of interval metering, so a requirement for all customers to be put on complex tariffs with no opt-out would cause much more rapid take-up of complex tariffs (i.e. all, immediately), at a time when customers are not engaged and are not expecting change, as against the more gradual uptake in other jurisdictions when customers are engaged. This is another reason to allow opt-out as a special case in Victoria even if that is not approved in other jurisdictions.

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[107] See Etrog Consulting: Report on TSS 31 May 2019, and Report on AER draft determination 2020-25 and EQ revised TSS 15 January 2020

[108] Attachment 18 – Tariff structure statement | Draft decision - Energex 2020–25, page 18-92

We also note that customer support for the businesses' proposed transitioning of customers to a new time-of-use pricing structure was on the basis of the opt-out option being available. See for example:

> "*Our proposed strawman was that life support customers and medical cooling concession customers would not be re-assigned to a ToU tariff structure, and all other households could 'opt-out' from the new tariff structure for five years. About 79% of participants were ok with or supported the transition strategy*.[109]

Further, with COVID-19, it is difficult for retailers and other stakeholders to undertake the necessary consumer education and other measures to ensure that customers understand the consequences for them of moving from a single-rate tariff to a more complex tariff. The AER's recent final decisions in regard to the TSS to apply in Queensland from 2020 to 2025 amended the businesses' proposed TSS to allow customers to temporarily opt-out to legacy consumption tariffs to mitigate the potential impacts of the COVID-19 pandemic on the Queensland distributors, retailers and end-customers. This was required in order to satisfy the customer impact principle in the Rules.

We support the opt-out to flat tariffs, particularly for vulnerable customers who may be worse off on a TOU tariff. It is important that the level of the flat rate is not set artificially high in comparison to the TOU rate, to encourage vulnerable customers not to opt-out. The flat rate tariff must offer a reasonable safety net for these customers. The more complex tariff should not be set at a significant discount to the flat tariff as that would detract from the effectiveness of the flat rate tariff as a safety net tariff.

We propose to revisit this issue when there is more clarity as to the future of the Victorian Tariffs Order beyond 31 December 2020.

10.12 The target audience for network tariffs

We understand that the AER considers that the target audience for cost reflective network tariffs is primarily retailers, not end-use customers. However, among the pricing principles set out in the NER:

- The network must consider the impact on retail customers of changes in tariffs from the previous regulatory year.
- The structure of each tariff must be reasonably capable of being understood by retail customers that are assigned to that tariff.

These pricing principles are aimed at impacts on customers rather than retailers, and capability of understanding by customers and not just retailers. Thus the AER does need to consider the network tariffs from a customer perspective rather than just a retailer perspective.

10.13 Consideration of a solar sponge network tariff in Victoria

We support that the AER should 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). This should be looked at as part of a holistic approach to the uptake of DER and expenditure on DER enablement. We have raised this opportunity of a broader approach to network utilisation in our discussion on DER in section 8, Future Networks.

One of the problems with having a peak pricing period that coincides with when solar generation is occurring is that it gives consumers mixed messages. On the one hand, the consumer receives a relatively low feed-in tariff for export (unless they are on a grandfathered premium feed-in tariff), so have financial incentive to use more energy while the sun is shining on their panels rather than export that energy. On

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[109] CP APP05, page 25

the other hand, if they use more energy instantaneously than they are generating, they are penalised by having to buy the amount they require above their self-generation at a higher rate than if they had used the energy at a different time of day. This is almost impossible for the consumer to manage. Should they shift discretionary loads to peak period to soak up their excess solar generation? Or should they shift their load to off-peak when they are not generating, to take advantage of off-peak rates?

The perversity can be illustrated through an example of two dwellings, one on top of the other (say two apartments). The upper apartment has access to the roof space and installs an oversized solar PV system. Their incentive is to use energy when the sun shines, even if the supply is peak rate, since they are driven to minimise their export. The lower apartment does not have access to solar PV and their incentive is to use electricity off-peak when the sun isn't shining (say at night). It is clearly not economically efficient for two loads on the same block of land to get such different pricing signals.

An advantage for customers with solar PV of having a solar sponge tariff is that it coincides the cheapest time to use electricity with when the customer might have surplus PV generation. Our perverse example would not arise: both residences now have the incentive to use electricity at the same time – when there is surplus solar PV which coincides with when rates are lowest.

An alternative is to reform the feed-in tariffs to recognise the value of solar export at peak times, but we know that is outside the scope of the regulatory determinations.

10.14 Consideration of change in fuel mix in end-use loads

Some years ago, there was a federal government policy initiative to shift energy use for water heating away from electricity to gas (or to solar with electric boost), to reduce greenhouse gas emissions. Nowadays, there are initiatives in some jurisdictions to encourage shifting of load away from gas to electricity that is sustainable and generated from non-fossil fuel sources, again in the name of reducing greenhouse gas emissions.

There is widespread uptake of gas in Victoria. Shifts between end-use fuels, particularly for heating, will significantly shift load shapes. Energy tariffs will be a key factor taken into account by end-users when they make fuel choices. The interaction of tariffs with energy fuel choices deserves more consideration.

10.15 Uniformity in and simplicity of network tariffs across Victoria

As noted above, the businesses' proposals for default tariffs are as follows:

- ***Residential customers***: 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.
- ***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.

For ***residential customers***, we see the 3pm-9pm window as allowing for customers to some extent to engage in demand response, to shift load away from that window. As stated for example by CitiPower:

> Our new ToU tariff with off-peak rates before 3pm and peak rates after 3pm provides incentives to reduce midday solar exports, for instance by installing west-facing solar panels or to use batteries to charge from their solar panels and discharge when electricity is needed. Therefore our proposed new ToU tariff serves the dual purpose of providing incentives to reduce network demand and to reduce midday solar exports.[110]

[110] CP APP05, pages 36-37

This is presented by some of the business as explaining why there is no need for a solar sponge period when network charges are very low.[111]

While understanding the sentiment, we note that:

- Many residential customers will have loads between 3pm and 9pm that are difficult to shift, because they relate to family needs at that time, such as cooking evening meals.
- If tariffs are flat, customers get most benefit from installing solar panels that are north facing, as that will maximise the amount of solar generation.
- Many solar panels are already installed north-facing and are unlikely to be moved.
- Customers considering installing west-facing panels will need considerable convincing that this is cost-beneficial for them. Their starting point is that the total generation will be lower. In the winter, west-facing panels will generate little electricity, and the bulk of the 3pm to 9pm peak period will come after panels have switched off for the day. Customers will need confidence that time-of-use tariffs with higher prices in the afternoon are going to be in place for the longer term, and that the price differential will be sufficient to warrant the changed direction.
- Most customers will not install battery storage in the short to medium term, and nor will it be cost-effective for them to do so. Complex tariffs are efficient at the moment if they are well-designed because battery storage is not ubiquitous, and therefore the costs of production and distribution of electricity vary during the day to match customer demands. If / when battery storage is so cheap and efficient that it becomes ubiquitous, the need to produce and distribute electricity to match instantaneous customer demands will no longer exist. Rather it will allow electricity to be produced when it is cheapest, to be distributed when networks are not congested, and then to be stored cheaply and efficiently, close to where it is ultimately used. This will likely lead to pricing becoming flatter again, as the time of usage will not materially affect the production or distribution costs.

We also note the businesses' comments that residential peaks can and do occur on any day of the week, including public holidays,[112] and that some peaks also occur in winter months.[113]

In regard to ***small business customers (<40 MWh pa)***, the proposed peak period of 9am to 9pm is very wide, and this is acknowledged in the proposed TSS. It arises largely as a result of the businesses seeking to have a consistent pricing structure across the Victorian distributors. For example, CitiPower states:

> While there appear to be few peaks between 10 am to 2 pm across all networks, this is not the case for CitiPower who cover the Melbourne CBD. We have taken this into account when creating a single peak period for Victorian small business customers.[114]

In ***summary***, we support the AER's intent 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. On the other hand, we also see that there is merit in setting a common structure between distributors for simplicity to progress network tariff reform, as long as this does not create perverse effects that would be mitigated if the tariffs were separately designed for each distribution area.

We also note that in some remote areas, ***large business customers (>40 MWh pa)*** such as primary producers, water companies and irrigators have been reported to be investing heavily in renewable generation, possibly with a view to going off-grid or creating local microgrids. Their investment decisions

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[111] See for example CP APP05, page 37
[112] See for example CP APP05, page 37
[113] See for example CP APP05, page 35
[114] CP APP05, page 56

will be driven by tariff levels and tariff structures. Their large loads can make large differences to energy and demand forecasts and to economic efficiency in sharing network costs between users.

11 Alternative Control Services

The AER's framework and approach paper incorporated some changes to ACS arrangements, including the reclassification of some service trucks to standard control services, introduction of new services and the reclassification of previously negotiated services.

11.1 Metering Services

Metering services accounts for approximately five to ten percent of the Victorian DNSPs' revenue.

CCP17 recognises the value in the responsibility for revenue metering being vested in the DNSPs. There has been significant debate about the value of metering contestability across the NEM. The arrangements in Victoria have been proven to be pragmatic and efficient, which is why we support the role of metering as it is in this state.

While it is disappointing that the metering reform in Victoria did not act as a catalyst for changes to tariffs, the relationship between the revenue metering function and the gathering of network performance data and insight into the energy demand patterns deep into the low voltage network have proven beneficial. Many of the investments planned by the DNSPS will benefit from the information and amenity provided by the AMI system.

Therefore, we are supportive of the trend for metering expenses to be reallocated to standard control services wherever appropriate where the functions support the improvement of network operations and broader customer service improvements. It is important that the net benefit to the DNSP does not change through any reallocation of costs.

We commend all DNSPs' actions in reducing metering charges and the abolishment of move-in move-out fees.

<u>Changes to communication arrangements</u>

Regarding the transition to 4G communications, we join the AusNet customer forum in asking whether the works are definitely required in the timeframes noted in the proposals, given the vagary around the closure of the 3G network.

We are supportive of the investment in transitioning to 4G communications, provided the DNSP has considered:

- Clear advice from their Telco that the shutdown of 2G / 3G will occur before 2026
- Switching to another carrier who maintains 3G is not technically and commercially feasible

11.2 Public Lighting

The ESC Public Lighting Code regulates the provision of public lighting and minimum standards in Victoria.

Each utility held conversations with stakeholders, predominantly councils, the Victorian Government and VicRoads, specifically regarding lighting. There is widespread support of a phase-out of inefficient lights and a change in practice where all failed lights are replaced by the efficient LED alternatives. Even residential and small business forums noted string support for the change to energy-efficient public lighting.

Consistent with other jurisdictions, most distributors are introducing new public lighting categories to assist with the roll-out of energy efficient lighting.

In the engagement, we noted consistent concerns from the stakeholders regarding the accuracy of pricing, the completeness of the database that drives charging of councils, and disagreements about the number of failed lights and their repair under the Memoranda of Understanding.

Each utility gave undertakings to continue to engage with stakeholders to minimise the impact of any revenue increases or alleged problems with lamp replacement activities.

The practical issues for customers changing to energy efficient lights also remains a point of active conversation. Stakeholders are keen to see an accelerated rate of change to LED and more energy efficient lighting; however, the complications of bracket replacement and early retirement of existing luminaries is proving problematic. The impact the Minimata convention may have on replacement rates is still largely unknown.

It is a pity that the transition to energy-efficient public lighting – so well supported by stakeholders – requires individual lighting fees to increase. For instance, AusNet notes an increase on average of 11%. Each DNSP has strategies to balance these increased costs with the stakeholder requests.

It is useful to note the overall falling public lighting costs. We ask the AER to consider the pricing of LED lighting to encourage and support these stakeholder and community benefits.

12 Transitional six-month period

We recognise that the Victorian Government has indicated their plans to move Victorian distribution business regulatory periods to a financial year basis after historically having a calendar year basis. This means that there will be a six-month transitional period between the current regulatory period ending 31st December 2020 and the commencement of the next regulatory period from 1 July 2021

In the issues paper, the AER recommended "*a simple trended-forward methodology for establishing most building blocks and applying the 2018 Rate of Return 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 Rate of Return Instrument."

The EBSS and STPIS incentive schemes will continue to apply, but the CESS will not apply due to the large and less regular nature of capital expenditure.

CCP17 recognises that the regulatory treatment and the practical implementation of the six-month transitional period need to be as simple as possible and continue to give good outcomes for consumers. We consider that the approach outlined by the AER is sensible and support the simple trended forward methodology and the other measures outlined by the AER in the Issues Paper.

We also accept that ex-post adjustments may be required should unforeseen circumstances arise. We expect that there is a high probability that some aspects of the 2021-26 decisions will need to be "re-opened" particularly due to the COVID-19 induced uncertainties.

13 How should the AER regard NewReg Trial and Customer Forum negotiation?

One of the questions that the AER needs to consider as part of the assessment of Regulatory Proposals from the five Victorian network businesses is the level of scrutiny that it applies to the aspects of the AusNet Services regulatory proposal that have been negotiated with the Customer Forum, which was set up through the NewReg process.

In answering this question, the AER needs to have regard to:

1. Acting consistently with the objectives of the NewReg trial, to which the AER is one of three partners.
2. Ensuring procedural fairness in the assessment of the regulatory proposals from the other four Victorian DNSPs.
3. Maintaining consistency in its regulatory processes.
4. Awareness of precedent creation.
5. Acting within the National electricity rules (and by inference national gas rules.)

<u>Acting consistently with the objectives of the NewReg trial</u>

One of the early documents that was instrumental in setting the course for the NewReg trial that was undertaken by AusNet Service was the approach paper released in March 2018: Towards Consumer-Centric Energy Network Regulation.[115]

This paper says that

"The overall vision for the project is that energy consumers' priorities and stated preferences should drive, and be seen to drive, energy network businesses proposals and regulatory outcomes. We believe there are significant opportunities to better incorporate consumer preferences in revenue determination processes, and to improve consumer trust and confidence in network regulation. Further, there is scope to improve the efficiency and effectiveness of the regulatory process.

The project is proposing a new dialogue and a better process to align interests so that revenue proposals and AER determinations reflect the interests of consumers …

A process that puts consumers at the centre of the regulatory process will benefit network businesses and the regulator.

Upfront agreement that the network business revenue proposal reflects consumer interests provides greater certainty than lengthy and detailed regulatory processes about what the long-term interests of consumers are."

The paper also says *that "The core outcome is the extent to which the Consumer Forum agrees to the network's revenue proposal. The extent of that agreement (or disagreement) needs to be formally reported to the AER (and all other stakeholders) together with the basis for reaching that agreement."*

[115] https://www.aer.gov.au/system/files/NewReg%20Approach%20Paper%20-%20Towards%20Consumer-Centric%20Energy%20Network%20Regulation%20-%20March%202018.pdf

AusNet Services website says

"Elements of AusNet Services' Regulatory Proposal for the 2021-26 regulatory period are being negotiated with the Customer Forum."[116]

Details of the establishment and purpose of the AusNet Services Customer Forum are provided in section 3 above. The Customer Forum's role was to represent AusNet Services' customer base and negotiate aspects of the Regulatory Proposal on their behalf. Members of the Customer Forum were well qualified for the role, bringing to the task a broad range of experience including consumer advocacy, market research, finance and communications.

In early discussions between AusNet Services, the AER and the Customer Forum a defined scope of interest for the Customer Forum was agreed.

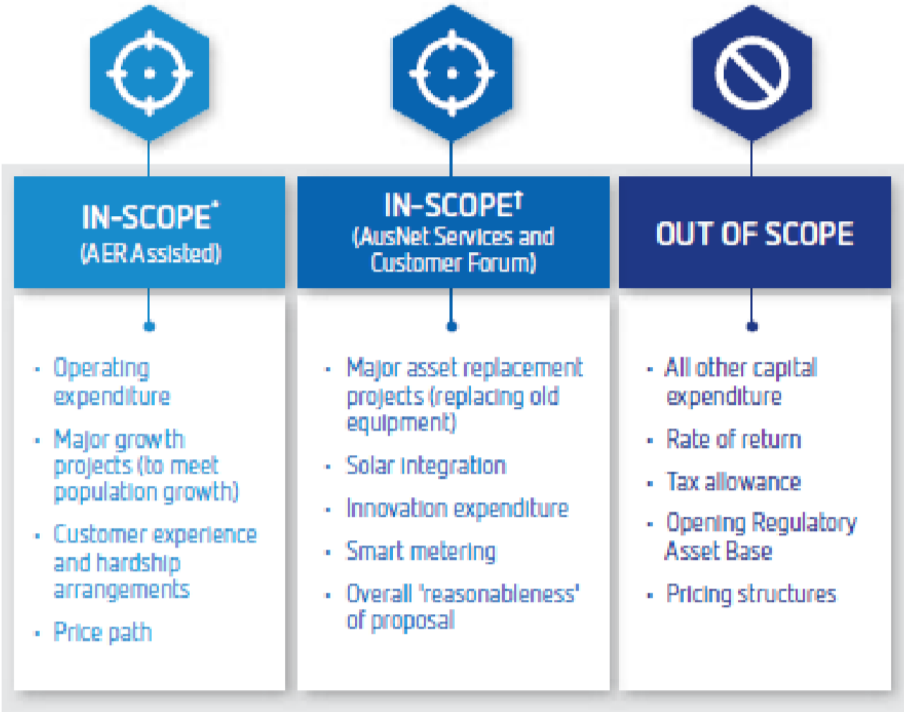

Figure 54: Scope of Customer Forum negotiations (Source: AusNet Services)

Note: *AER assisting Customer Forum by providing information and independent advice.
†Not in scope of the AER's assistance to the Customer Forum.

It is also important to recognise that the NewReg trial is 'methodology agnostic,' while the Customer Forum model trialled is most likely (it will be evaluated separately) a sound model for enhanced consumer influence in a regulatory process, it is not the only methodology that can achieve this goal. The NewReg trial is understood to be about the outcome, less about the model applied. CCP17 is clear that there are many approaches for effective consumer engagement and influence and that NewReg was not about suggesting or implying a preferred methodology.

From these statements relating to the AusNet Services NewReg trial we suggest that key objectives include:

[116] https://www.ausnetservices.com.au/en/Misc-Pages/Links/About-Us/Charges-and-revenues/Electricity-distribution-network/Customer-Forum

- an active process of negotiation between the business, AusNet Services and the group representing consumer perspective, the Customer Forum;
- a clear documentation of agreement between these two parties, as part of the submitted AusNet Services Regulatory Proposal for aspects that were deemed to be “in scope” for negotiation;
- a negotiation process that involved the AER as agreed;
- and open and transparent process, both to demonstrate good outcomes for consumers and also to encourage negotiation approaches leading to agreement between consumer interests and network businesses in future regulatory proposals.

Ensuring procedural fairness in assessment of the other four Victorian DNSPs

All five Victorian DNSPs need to be treated fairly in assessing the regulatory proposals in particular with good practice in consumer engagement recognised and reasonable regulatory proposal elements with strong, demonstrated consumer support accepted by the Regulator.

CCP17 observes in section 3 - Consumer and Stakeholder engagement, that all five businesses have undertaken sound and innovative consumer engagement activities so it would be inappropriate for AusNet Services to gain relative benefit as a result of NewReg where other businesses had also engaged effectively but using a different methodology.

Maintaining consistency in its regulatory processes

Consistency is a central tennet of effective regulatory practice, and we suggest a strength of the AER. AusNet Services’ Regulatory Proposal must be submitted to the same models and analysis as other Regulatory Proposals. In other words, application of the PTRM, Repex and other established regulatory practice cannot be waived away on the strength of a great NewReg outcome.

Awareness of precedent creation

Precedent creation includes both providing signals for the manner in which preferred consumer engagement processes are treated in future regulatory proposals and guarding against unwittingly creating incentives that could diminish from high-quality consumer engagement.

In assessing the AusNet Services regulatory proposal the AER needs to identify the sort of process elements and outcomes that they would expect to see in future regulatory proposals from other network businesses and where possible to provide incentives to encourage processes that produce sound consumer outcomes.

AER acting within the Rules

While the AER, and probably other parties, may want the Regulator to provide tangible benefits to AusNet Services as a result of its negotiation with the Customer Forum, the options are limited under current rules, which we argue have not been designed to reward robust and effective consumer engagement. We are aware for example that the UK regulator, Ofgem is now able to fast track regulatory proposals that it regards have been strongly influenced by consumer input. The AER does not currently have this option.

Perhaps an outcome from the NewReg trial will be a rule change that will give the AER more options to provide incentives for high-quality consumer engagement and negotiated outcomes. However, for this regulatory process, all five regulatory proposals need to be rules compliant.

NewReg Outcomes

A central question in considering the consumer engagement from the NewReg trial, for the AER, is whether the consumer engagement process has led to an outcome that the AER might consider in total without detailed analysis of each element at a lower level, while maintaining integrity of the regulatory process?

CCP17 suggests that this might be possible, based on assessment of the extent to which these criteria are met, and other considerations:

a) the engagement undertaken by the network business was at least at the "collaborate" level of the IAP to spectrum: which has the promise to the public of "we will look to you for advice and innovation in designing and conducting the research process and incorporate your advice and recommendations to the maximum extent possible,"

b) there is documented agreement,

c) the negotiating party or parties had adequate information to engage in negotiation and provided a diversity of consumer perspective,

d) the negotiation process, including inputs, has been transparent with information utilised readily accessible to the public,

e) the components of documented agreement are within the Rules,

f) the proposal is intuitively reasonable (meets the 'pub test'). The overall outcome compares well with historical allowances and compares well with peers.

Since the NewReg trial is tied to the Victorian distribution network regulatory process for 2021-26 and the host of the NewReg trial was AusNet Services through the Customer Forum, we first consider these criteria against the available evidence of outcomes through the Customer Forum negotiation.

The Customer Forum final report '*AusNet Services 2021-2025 Electricity Distribution Price Review Customer Forum Final Engagement Report 31 January 2020'* provides the following comments in the Executive Summary about outcomes from the direct negotiation between the Customer Forum and AusNet Services:

"The Customer Forum has negotiated elements of AusNet Services' 2022-2026 Electricity Distribution Price Review (EDPR) which will deliver significant benefits to customers. The outcomes recognise key concerns of AusNet Services customers, and include:

- an overall average cost reduction of at least $110 per customer per annum ($2021), representing a fall of around 12% from currently anticipated prices at the end of 2020,
- cost increases limited to inflation only after the initial fall; and for the first time in many years, a reduction in the Regulated Asset Base (RAB) per customer, which lays the foundation for lower costs for customers in the future.

Additionally, AusNet Services has agreed to the following:

- a range of new customer service initiatives commencing from 2019, including the introduction of a new Customer Service Incentive Scheme (CSIS) which exposes AusNet Services to a greater revenue risk if it fails to achieve a range of customer service targets,
- AusNet Services will be held to account for the customer service improvements it has agreed to through the publication of an annual Customer Interaction and Monitoring Report,
- customers will save an estimated $500,000 ($2021) over the EDPR period as a result of AusNet Services agreeing to self-fund Guaranteed Service Level (GSL) payments for missed appointments and connections not completed by the agreed date. AusNet Services is the first distributor to agree to self-fund GSL payments,
- a $43 million ($2021) DER augmentation program will address voltage impacts on customers arising from increasing solar exports and minimise the number of customers whose export of solar energy is constrained; all customers should benefit through the downward pressure this enablement places on wholesale electricity prices,

- opex cost absorption of $21 million ($2021) resulting in AusNet Services achieving a productivity saving greater than the AER mandated 0.5%, and
- The Customer Forum's negotiations with AusNet Services will contribute to cost savings for customers of at least $490 million ($2021) over 2022-2026.

(Note that this is an edited version of the executive summary; other outcomes were also reported by the Customer Forum)

Objectives of the NewReg trial were both about improved (price) outcomes for customers and culture change within the business. While the full evaluation of the NewReg trial is yet to be completed, and CCP17 has no intent to compromise that review, we observe for the purposes of regulatory consideration, that both of these intended outcomes have been achieved, recognising that it is too early to categorically claim that lasting culture change has occurred.

In the opex section of this submission we identify the effectiveness of opex cost reductions that have been achieved through the current regulatory process and the extract from the Customer Forum report above identifies significant cost savings for AusNet Services customers in the next regulatory period.

In considering the extent of post lodgement analysis that the AER gives to negotiated AusNet Services regulatory proposal elements, we recognise Guidance Note 9[117], in which the AER 'says' to the Customer Forum:

> *"The AER must still undertake its formal assessment of matters that have been negotiated between AusNet and the Customer Forum as normal, in accordance with the NER.*
>
> *If the New Reg process works as intended in assessing AusNet's proposal, the AER will be able to have regard to the extent of the Customer Forum's agreement with AusNet on certain matters in the proposal, and the extent to which that agreement is based on sound evidence of consumer perspectives and preferences.2 The AER can then take into account the matters that have been agreed and, conversely, those that have not been agreed, in its consideration of AusNet's proposal."*

We also observe that the "in scope – AER assisted" elements that were negotiated by the Customer Forum were subjected to more consumer perspective scrutiny than any other Australian regulatory proposal of which we are aware. We are drawing a distinction between the "In scope – AER assisted" and "In scope – AusNet Services and Customer Forum" elements). Appendix B from the AusNet Services Customer Forum Final Engagement Report shows that the Customer Forum met on over 70 occasions and was involved in about 30 negotiation specific meetings, received something of the order of 150 presentations and 10 AER guidance notes. This is substantial scrutiny and negotiation from a highly skilled and highly competent Customer Forum membership. CCP17 considers that the negotiated elements of the AusNet Services Regulatory Proposal were subject to more detailed external scrutiny than has probably ever occurred before for an Australian energy network proposal.

In applying our suggested six criteria to the Customer Forum – AusNet Services negotiation for the "In scope – AER assisted" elements we reached the following observations:

1. The engagement undertaken by the network business was at least at the "collaborate" level of the IAP to spectrum: which has the promise to the public of "we will look to you for advice and

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[117] https://www.aer.gov.au/system/files/Energy%20Safe%20Victoria%20-%20Letter%20to%20Powercor%20regarding%20Policy%20for%20Annual%20Capacity%20Testing%20-%2027%20April%202020.pdf

innovation in designing and conducting the research process and incorporate your advice and recommendations to the maximum extent possible,"

- Following a comprehensive negotiation process, it is apparent that the advice and recommendations provided by the Customer Forum have been applied to the regulatory proposal "to the maximum extent possible" in line with the IAP2 spectrum, "collaborate" level.
- This criterion has been met.

2. There is documented agreement
   - Agreement has been documented both by the Customer Forum in their final report and AusNet Services have identified aspects of negotiated agreement in their regulatory proposal.
   - This criterion has been met
3. The negotiating party or parties had adequate information to engage in negotiation and provided a diversity of consumer perspective
   - The comprehensive nature of briefings, including guidance papers from the AER and other reports prepared for the Customer Forum demonstrate that they had considerable information at their disposal, for negotiation.
   - This criterion has been met
4. The negotiation process including inputs has been transparent with information utilised readily accessible to the public.
   - AusNet Services and the AER have posted documentation about the NewReg trial and the Customer Forum negotiations on their respective websites.
   - This criterion has been met
5. The components of documented agreement are within the rules
   - To the best of our knowledge or components of the negotiated agreements are within the rules.
   - This criterion has been met.
6. The proposal is intuitively reasonable
   - This is an intuitive 'test' of overall reasonableness of a proposal. For example, with reducing costs to customers, efficient expenditure and the business having a clear sense of its direction and relationships with customers as well as comparing favourably with past performance of the business and with peers.
   - This criterion has been met.

Consequently the CCP17 view is that where negotiated agreement between the Customer Forum and AusNet Services is presented in the Regulatory Proposal for the "In scope" aspects that were "AER assisted", then the AER can reasonably accept the negotiated outcome, with the understanding that it meets the rules and where relevant, fits within the parameters of the various AER regulatory models that are uniformly applied to all regulatory proposals.

The second question germane to the Victorian network distribution regulatory process is about implications for the other for distribution businesses.

CCP17 is of the view that where the six criteria that we suggest have been applied, then those consumer-driven elements of regulatory proposals should be treated in the same manner as we propose for the relevant negotiated outcomes with the Customer Forum.

For example, this would mean that the AER would not reduce analysis for proposals from businesses other than AusNet Services (In scope – AER assisted) for the 2021-26 Victorian distribution resets, including (but not limited to) the following which had high levels of effective consumer engagement:

a. Powercor’s proposals for pole replacement that have been driven by active input from the Warrnambool community;

b. The Jemena Peoples’ Panel proposals that have been included in the JEN regulatory proposal;

c. “In scope – AusNet Services and Customer Forum”

The AER will need to carefully consider consumer input on the issues raised above and other issues where solid consumer engagement has been demonstrated. We have stated elsewhere that CCP17 has been impressed with the range of engagement activities that the Victorian DNSPs have undertaken. We do not think that any of the engagement activities undertaken outside of NewReg were undertaken with the expectation that they would result in reduced AER scrutiny at the time when the engagement was undertaken. We also do not consider that all aspects of our six-point test have been met by these or other engagement activities.

<u>Future implications</u>

We anticipate that the regulatory proposal assessment approaches to the NewReg trial will be an important aspect of the review of NewReg.

It is also our opinion that for future network regulatory processes the Framework and Approach document could very usefully include discussion about consumer engagement approaches that could lead to some form of more expedited treatment by the AER, under the Rules. This could include a framework specification under which AER guidance notes could be developed for intensive consumer engagement processes that are intended to be undertaken by network business and that have reasonable lead time. Both the AER and the network business could also indicate the type of support that could be offered to consumers and consumer groups for more intensive consumer engagement processes.

14 Implications of the pandemic – planning and delivery

14.1 Responding to COVID-19

COVID-19 requires a holistic approach and we recognise that many of the responses to the pandemic need to be "NEM wide", while there are some responses that have more immediate application to the Victorian electricity distribution resets. In this section we consider both NEM wide and Victorian electricity distribution reset responses as they are inter-twined for CCP17 considerations.

On page 1 of the Issues Paper, Victorian electricity distribution determination, 2021-26, the AER observes "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."

The Introduction describes the different approach that was undertaken in conducting the Public Forum due to COVID-19. The AER concludes the Introduction section with the following "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 business's submissions. This may also impact on timing of some elements of the process going forward."

We agree that the impacts of COVID-19 have been and will be significant and cannot be reasonably predicted, therefore all stakeholders involved with this reset will wrestle with uncertainty where previously there was at least a reasonable degree of predictability, even if it didn't seem to be the case, at the time.

The next section provides a brief background to key responses to COVID-19 to date and the following section provides some thoughts from CCP17 about some of the areas of impact and processes to deal with the largely unknown impacts of COVID-19 pertinent to this reset.

<u>What has happened?</u>

The COVID-19 pandemic was not a factor for consideration when the five Victorian DNSPs lodged their Regulatory Proposals in January 2020. For Australia, responses to the global pandemic started during mid-March and rapidly escalated by the end of March, by which time all Australian residents were being told to self-isolate, working from home where they could and businesses that could not operate with social distancing requirements ceased operation. The Commonwealth Government instituted a JobKeeper payment to enable people with no work, but likely work with their employer post COVID-19, to be retained by employers and still have income while maintaining isolation.

Two of the substantial impacts of the March COVID-19 measures have been:

- a significant number of businesses pausing their operations for an unknown period of time; and
- a substantial increase in the number of people unemployed or underemployed and spending more time at home.

<u>Electricity network business responses</u>

Quite early in the COVID-19 isolation phase, on 2nd April, Energy Networks Australia (ENA) released a statement on behalf of energy networks across Australia that recognised the arrival of COVID-19 and committed network businesses to some responses.

ENA CEO Andrew Dillon said, "*Networks understand these are extraordinarily tough times for small business and energy bill relief will really help*".

His explanation of assistance to be provided by networks included:

> *"For small businesses that are mothballed, electricity and gas network charges will not be applied from the start of April to the end of June 2020, if their consumption is less than a quarter what it was in 2019.*
>
> *Networks know it is in everyone's interest to support small businesses through what is an extremely challenging period … Networks will be deferring or rebating electricity and gas network charges for impacted customers.*

This assists impacted customers and helps energy retailers, who administer energy hardship programs."

The ENA has further explained that "*the residential part of the network relief package aims to support energy retailers so that they can better assist residential customers who experience energy bill hardship as a result of COVID-19, networks will work with individual retailers to determine how retailers systems can best deliver assistance to affected customers… Networks are working with retailers to develop transparent and easily administered criteria for the application of the relief package."*

In early April on the 9th, the AER released a formal "Statement of Expectation" to give guidance to both energy businesses and consumers about reasonable responses to a sudden influx in rates of people experiencing financial hardship, both for households and small businesses. The AER's Statement of Expectations required energy businesses *"to ensure the continued safe and reliable supply of energy to homes and businesses, and to support both residential and small business customers experiencing financial stress*."

The statement included 10 principles intended to both protect customers at risk and to maintain reliability of supply for energy markets, these principles being:

- Offer all residential and small business customers who indicate they may be in financial stress, including small businesses eligible for the JobKeeper Payment, a payment plan or hardship arrangement, regardless of whether the customer meets the 'usual' criteria for that assistance.
- Do not disconnect any residential or small business customers who may be in financial stress (including small businesses eligible for the JobKeeper Payment), without their agreement, before 31 July 2020 and potentially beyond.
- Do not disconnect any large business customer, including businesses eligible for the JobKeeper Payment, without their agreement, before 31 July 2020, and potentially beyond, if that customer is on-selling energy to residential or small business customers (for example, in residential parks or retirement villages).
- Defer referrals of customers to debt collection agencies for recovery actions, or credit default listing until at least 31 July 2020.
- Be prepared to modify existing payment plans if a customer's changed circumstances make this necessary.
- Waive disconnection, reconnection and/or contract break fees for small businesses that have ceased operation, along with daily supply charges to retailers, during any period of disconnection until at least 31 July 2020.
- Prioritise the safety of customers who require life support equipment and continue to meet responsibilities to new life support customers.
- Prioritise clear, up-to-date communications with customers about the issues addressed in this Statement, including by keeping website, social media and call centre waiting and hold messages

up to date, so customers can readily access updates when they need them and relieve some pressure on affected call centres.

- Prioritise clear communications with customers about the availability of retailer and other supports, including the availability of payment plans, energy efficiency advice and fault repair.
- Minimise the frequency and duration of planned outages for critical works and provide as much notice as possible to assist households and businesses to manage during any outage.

Some of these principles reflect particular responses required in the current COVID-19 pandemic, while others reinforce existing requirements under energy laws.

The AER also said "We recognise that our expectations in this Statement may add to the risks and costs facing energy businesses. We are particularly concerned about the continued viability of energy businesses and we are proactively working with all stakeholders on options to appropriately balance these risks and costs across the sector and to ensure energy businesses get the assistance they may need in the coming months."

On the same day, 9 April 2020, the Australian Energy Market Operator (AEMO) submitted an urgent rule change proposal to the Australian Energy Market Commission (AEMC) proposing to delay the commencement of the Five Minute Settlement (5MS) and Global Settlement and Market Reconciliation (GS) rule changes by 12 months.

AEMO suggests that "a delay to 5MS and GS would free up both human and financial resources which would be under strain during this period, ensuring the ongoing supply of energy and appropriate customer support."

Subsequently the AER submitted an urgent rule change[118] to back-up their Statement of Expectations to allow electricity retailers to defer payments to networks. The AER proposal states that:

"While the Government has taken steps to increase income support, it is clear many electricity customers are facing difficulties in paying their electricity bills. More than 20,000 electricity customers have registered for payment plans since early March 2020 and over a thousand customers per week are seeking assistance from retailers."

The intent of the rule change is summarised as "Notwithstanding any agreement for payment deferrals for customers in financial stress, the National Electricity Rules (NER) currently require retailers to make full payment of network charges as they fall due. The purpose of this rule change proposal is to alleviate cash flow pressure on electricity retailers. In particular, we are concerned that the COVID-19 pandemic could potentially undermine the operation of retail electricity markets leading to multiple retailer failures."

In summary the rule change proposal is stated by the AER as: "We propose network charges for customers on a COVID-19 customer arrangement be deferred by up to 6 calendar months."

The AER explains that some of the aspects of the rule change include:

"Network charge deferrals include distribution and transmission components. Distribution networks would in turn withhold a reasonable amount from transmission networks to account for transmission charge deferrals. At the end of that period, network charges in respect of eligible customers must be paid by retailers regardless of whether the customer has paid the retailer."

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[118] https://www.aer.gov.au/communication/aer-proposes-new-rule-to-support-electricity-retailers-during-covid-19

We are also aware that signatories to the Energy Charter are also actively collaborating on industrywide responses to energy affordability issues related to economic slowdown and social isolation impacts of COVID-19.

CCP17 members commend energy network businesses including the five Victorian DNSPs and the AER for very rapid, public responses to the angst and uncertainty for many households and businesses that relate to the uncertainty arising from the sudden arrival of COVID-19. We recognise that the (regulator) expectations and responses summarised above are the right thing to do but we are also aware that the full impact on DNSPs, in this instance, will be unknown for several months, if not years.

Initial observations of COVID-19 impact

A little over a month after the initial isolation response to the virus, AEMO released some early modelling to explore initial aggregate impact on electricity demand from the COVID-19 responses on 28th March[119]. The result was summarised in Figure 55 below and shows that while there has been some reduction in aggregate demand in Australia as a result of COVID-19 the initial impact, while clearly observable, the level of reduction has not been substantial.

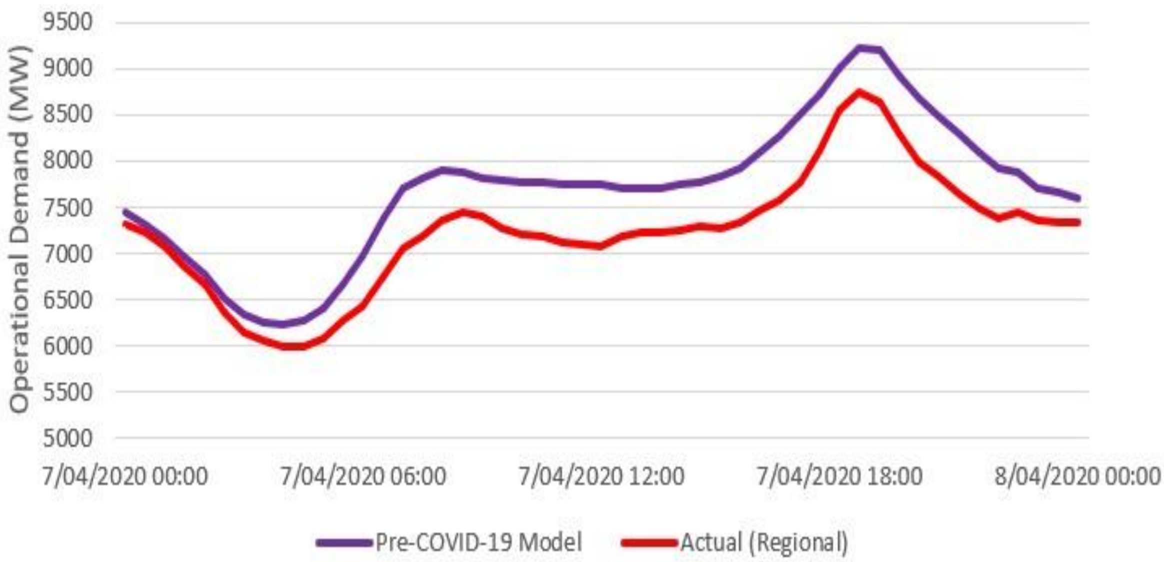

Figure 55: Operational electricity demand, Victoria (Source: AEMO)

The AEMO summary states "Australia, overall, has seen only moderate reductions in demand over the past few weeks, with the impacts increasing incrementally over time. Much greater reductions have taken place internationally, particularly in countries like Spain, France, and Italy where tighter COVID-19 restrictions and full-lockdowns have been implemented. Demand reductions in the order of 20 to 30% have been observed in those countries.

AEMO expects that reductions in demand may continue to increase incrementally over time at current levels of restrictions. We anticipate that Victoria, South Australia, and Tasmania may also begin to exhibit changes in demand. However, as some states and territories take steps to ease restrictions this could impact these changes.

[119] https://aemo.com.au/news/demand-impact-australia-covid19, (COVID-19 demand impact in Australia, 28/04/2020)

In addition, we expect that as cooler weather prevails, we might see an increase in load volatility, reflective of a greater proportion of residential (weather sensitive) load on the grid."

On 5th May, AEMO reported that "Some potential COVID-19 demand impacts have now been recognised in Victoria where average demand reduction during morning peaks reached 8% (approx. 400 MW) for the first time over a working week in the state. The midday trough fell 5% (approx. 200 MW) from pre-COVID-19 levels on weekdays and 3% on weekends (approx. 100 MW) and rooftop solar variability makes it uncertain if the demand reductions are from COVID-19".[120]

<u>Victoria actual operational demand against pre-COVID-19 control model</u>

Figure 56 shows that for Victoria, reductions on the morning peak were beginning to be observed over (what was probably) the first full week of COIVD-19 isolation, with the magnitude and timing of the morning peak shifting to later in the day. A potential reduction in the midday trough was also observed.

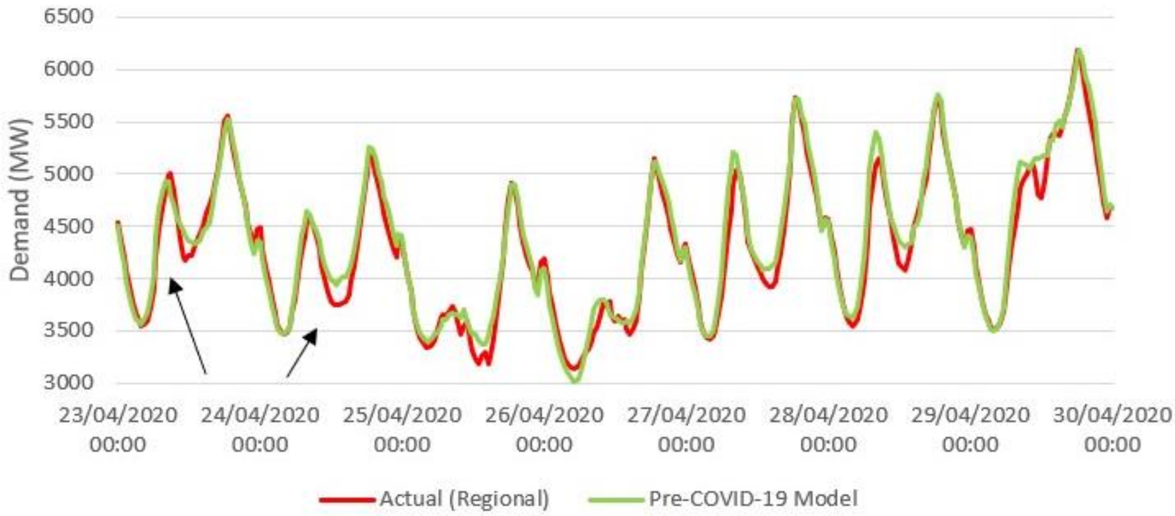

Figure 56: Operational electricity demand, comparison (Source: AEMO)

The AER recognises the "unprecedented" nature in their rule change proposal, stating:

> *"We are mindful that the COVID-19 pandemic has created an unprecedented situation where retailers could be financially pressed between customers who are unable to pay their electricity bills, and the retailers' own obligations to pay wholesale and network energy charges."*
>
> *The AEMC echoes the severity of the situation saying in their considerations of the 5 Minute Settlement timing rule change with the following:*
>
> *"The COVID-19 pandemic has caused a severe economic downturn impacting consumers ability to pay their energy bills*
>
> *The potential reduction in revenue may cause financial stress for retailers and financial contagion in the energy sector, potentially impacting the effective operation of the wholesale exchange."*

[120] https://www.aemo.com.au/news/latest-covid19-demand-impact-summary

14.2 What can be done?

<u>Should COVID-19 change the reset process or considerations?</u>

This discussion is a preamble to the question of how, if at all, the processes for consideration of the Victorian electricity distribution reset for 2021-26 should be adjusted to consider all impacts of COVID-19.

CCP17 suggests that we are now at the stage of COVID-19 responses when we are able to identify a significant number of the “known unknowns” and so be able to identify many of the potential impacts and hence some reasonably well developed thinking about how the Regulator responds to these, at least by the time that the draft decision and final decisions are released.

It is quite easy to identify a long list of likely through to possible impacts of COVID-19 on the Victorian DNSPs. The Victorian DNSPs will be impacted operationally in much the same way as other network businesses are affected, however the timing of the reset process arguably means that at least some COVID-19 responses will need to be considered for the Victorian DNSPs before the impacts are considered for network businesses at different stages in the regulatory cycle.

Likely impacts of COVID-19 on electricity distribution businesses include:

- delayed payments from retailers, as per the AER statement of expectations,
- reduced revenue due to a higher number of customers unable to pay their bills and some sharing of these increased under recoveries with retailers,
- changed cash flow,
- some movement of load from business to households with potential changes in load shape,
- greater uncertainty in demand forecasting,
- greater difficulty in engaging with “end use” customers,
- changing methodologies for consumer and stakeholder engagement,
- cancellation or deferment of significant new connection projects or government subsidy programs related to energy,
- delayed implementation in regulatory requirements e.g. five-minute settlement,
- potential supply chain delays particularly for major capital expenditure requiring equipment or expertise from overseas,
- deferred or reduced license fees to be paid by network businesses,
- a greater need for more frequent review of all key aspects of business operation,
- changing circumstances for opex step changes including those related to opex cost trend factors, and
- changed global economic circumstances with implications for network business rate of return and depreciation rates.

We also note that some of these impacts will be time-limited, others may play out over months or years or even the entire regulatory period.

General Responses

The following are CCP17 views about options for dealing with COVID-19 uncertainty with particular reference to the Victorian DNSP resets, recognising that many of the responses will need to be “NEM wide”.

Consumer Engagement

While consumer engagement processes will be impacted as social isolation and public gathering conditions apply, this is no reason for consumer engagement activity to be reduced. Engagement methodologies will need to be adjusted to approaches that do not require groups of people in the same location. Neither should effective consultative approaches be readily discarded because “there’s no time to do them”.

The reality is that the network businesses that have well-established relationships with consumers, consumer advocacy groups and other relevant stakeholders, will be best placed to utilise these relationships to maintain engagement and consumer perspective on their decision-making. COVID-19 restrictions will make it more difficult to make new contacts and to establish new relationships, but this is not impossible either.

Consumer engagement should be an ongoing priority for network businesses and the AER should expect to see evidence of consumer support for key network business decisions. Indeed, it is a CCP17 opinion that times of heightened uncertainty mean that the best responses are those where there is a greater level of shared understanding of the challenges and shared decision-making. This means more frequent interaction between consumers, consumer interest groups and stakeholders. More consumer engagement should be expected in response to the COVID-19 crisis, not less. We recognise that there are resourcing issues for consumer advocacy groups that could hinder optimal levels of engagement.

Statement of Expectations

The AER’s initial Statement of Expectations was timely, responsive and appropriate. We suggest that this approach be applied throughout the COVID-19 period with (semi) regular updates of further expectations, from the AER, and developed through nimble engagement with consumer groups and other relevant stakeholders.

The “Statement of Expectations” approach can reduce uncertainty but is most effective in an environment of cooperation. We have seen good evidence of heightened cooperation with the process for this reset.

Embrace mistakes

Some responses to the challenges thrown by COVID-19, made in good faith and on reasonable evidence, will, in hindsight prove to be the wrong decisions. It is critically important that a culture of “no blame” is applied in such circumstances. The crucial process for these unprecedented times is that learning is constantly created and shared, particularly including learning from mistakes.

Getting on the Front Foot

CCP17 expects that the AER will carry out sensitivity analysis on the components within the revenue determination building blocks and form a plan to respond to these variations should they arise. This is preferable to scrambling to develop a response after major problems have occurred.
Plan for Incentive Schemes

It is also important that there is a plan on how to manage efficiency payments, in particular CESS and EBSS, in a volatile environment.

<u>Responses more specific to Victorian resets 2021-26</u>

The following suggestions relate more directly to aspects of the Victorian resets for the period 2021-26.

Timing for Victorian Resets

With arguably more uncertainty than usual as a consequence of COVID-19, there is the temptation to look to delay regulatory processes (and others) in the hope / expectation of better information being available to make better decisions.

We are not inclined to see merit in any extensions to the original timelines for this process since there is always the risk that there is better information 'around the corner', and consequently the hope for greater certainty for decision-making.

We suggest that at any time there is always the likelihood of better information in the near future and that there is merit in the certainty of staying with the initial and known timeframes. This way all parties know what to expect and established decision-making practices are applied. Circumstance will change, but we suggest it is better to be nimble and responsive to changes as they occur rather than to delay established processes in the hope of greater certainty.

This approach means that the AER would continue to 'run' the various models (PTRM, repex etc) as for a standard reset and that RINS and other network information would be provided by the network businesses as for standard reset timings.

Regular Updates

In order to attempt to keep key stakeholders in touch with the rapidly changing circumstances that envelop this reset, we suggest that the AER with the businesses should consider providing updates and briefings for stakeholders. These could occur in the period between the lodgement of responses to the regulatory proposals and stakeholder responses to the Draft Decision and Revised Revenue Proposals. This is a period of 7-8 months, during which some of the impacts of the initial COVID-19 isolation will become more evident and allow for some nimbleness of approach to be taken to the anticipated changing circumstances. The updates and briefings would deal with substantive issues where circumstances changed, including demand, forecasts, major shifts in capex projects etc.

The updates could be in the form of a videoconference (using a platform such as Zoom, Webex, Skype, or Microsoft Teams) briefing of between 60 minutes and 90 minutes in duration with limited moderated questions for clarification, not debate of content.

This would provide one straightforward mechanism for keeping stakeholders in touch and enabling the relevant AER teams and the five network businesses to be keeping each other informed. This also responds to an anticipated higher rate of change over coming months than has occurred over similar times in previous resets.

These updates and briefings would be additional to the anticipated October 2020 pre-determination conference in response to the draft decision – a forum whose process remains uncertain but we are optimistic that this could well be a face-to-face forum. In-person participation is the format we strongly recommend if at all possible.

Alternatively, additional public forums could be scheduled in addition to the predetermination conference.

Greater Flexibility

In the Issues paper, the AER has committed to a "greater degree of flexibility in our approach to requesting and receiving information" for this reset. We support this approach and observe that the impacts of COVID-19 uncertainty have been and should continue to be an attitude of flexibility, even forgiveness, when things do not go as planned or anticipated.

Decision Review

We suggest that in this instance the AER should signal that it will be reviewing the final decision in response to COVID-19 impacts, and perhaps suggest a notional timeframe, maybe 18 to 24 months after the final decision is made.

Summary

In summary we are proposing 4 key COVID-19 responses:

1. Engagement needs to continue, but differently;
2. Regular updates in the interest of ‘no surprises’;
3. Be flexible and note that the standard processes may not work as well due to exogenous factors;
4. Consider re-openings triggers and process.

Appendices

Appendix 1 – Jemena People's Panel Recommendations

<u>RECOMMENDATIONS TO IMPLEMENT</u>

Jemena should…

1. Improve the information available to customers and the ease of access to smart meter data. This should be through: a. Improving Jemena's portal b. Adding additional services such as apps for smart phones.
2. Increase investment into energy literacy and awareness in the community by $330,000 per annum.
3. Investigate how customers could be provided with personal usage and bill information for different pricing structures.
4. Enable increased feed-in of solar (and other renewables) into the grid, by improving the performance of the grid through new technologies.
5. Improve their channels of customer service by increasing their services to include mobile apps and using simpler processes.
6. Invest in smart technology across the grid to ensure network equipment is not upgraded too early.
7. Maintain the number of outages as they are today – on average each customer experiences four outages every four years.
8. Maintain the length of outages as they are today – on average 51 minutes per outage.
9. Send SMS messages to all customers for unplanned outages. The message should include an estimation of how long it will take to fix the outage.
10. Provide email or letter notifications about all planned outages. This should include accurate details of how long the outage will be and suggestions for how to manage the time without electricity.
11. Work with retailers to create an opt-out process for notifications, so all customers can receive notifications via their mobile unless they choose not to.
12. Note that the Panel believes that the Monthly Maximum demand pricing structure is the best for customers, so long as customers can opt out
13. Note the Panel's recommendation that Jemena continue to explore using rebates to encourage customers to respond during times of need (for example hot days)

<u>RECOMMENDATIONS FOR JEMENA TO ADVOCATE</u>

14. Increased docking stations for Electric Vehicles across Jemena's network.
15. Jemena will advocate for an impartial and technically accurate source of information for people who are considering installing solar. The information would include:
16. What capacity can people legally have installed
17. What are the tariffs available for solar customers, and how they impact bills?
18. What are the returns with the current feed-in tariffs?
19. How do you best manage appliance use during the day to maximise energy generated from the panels?
20. New technologies that make the grid less carbon intensive such as renewable energy storage, efficient technologies and new housing development that enable efficient technologies.

21. 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.
22. Support for vulnerable customers who may get left behind because they cannot take part in new technologies.
23. Government-supported energy literacy programs and educating customers about retailer deals.
24. A bipartisan plan that responds to the energy crisis.
25. Provide bills in other languages.
26. Provide education resources about different supply and usage charges, and how charges are broken down.
27. Investigate pre-paid or bundled plans to eliminate bill shock or difficulty planning.
28. Simplify pricing rates to ease competition and consumer choice.
29. Encourage retailers to keep providing paper bills for customers who want it.

Appendix 2 – Acronyms and abbreviations

Acronym/Abbreviation	Meaning
$ nominal	These are nominal dollars of the day
real $2019-20	These are dollar terms as at 30 June 2020 2020-25
Regulatory control period	the period commencing 1 July 2021 and ending 30 Jun 2026
ACCC	Australian Competition and Consumer Commission
ACS	Alternative Control Service
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ARR	Annual Revenue Requirement
ATO	Australian Tax Office
Augex	Augmentation expenditure
CALD	Culturally and Linguistically Diverse
CAM	Cost allocation method
capex	Capital expenditure
CBD	Central business district
CCP	Consumer Challenge Panel
CESS	Capital efficiency sharing scheme
CIM / CRM	Customer Information / Relationship Management
CMEN	Common Multiple-Earth Neutral
CPI	Consumer Price Index
CPU (or CP-PC-UE)	CitiPower, Powercor and United Energy
Current regulatory period	1 January 2016 to 31 December 2020
DENOP	Distribution Energy Network Optimisation Platform
DER	Distributed energy resources
DB / DNSP	Distribution Network Service Provider
DM / DR	Demand Management / Demand Response
DMIA	Demand Management Incentive Allowance
DMIAM	Demand Management Innovation Allowance Mechanism
DMIS	Demand Management Incentive Scheme
DUOS	Distribution Use of System
DVMS	Dynamic Voltage Management System
EBSS	Efficiency benefits sharing scheme
ECA	Energy Consumers Australia

EDPR	Electricity Distribution Price Review
ESV	Energy Safe Victoria
EV	Electric Vehicle
Extension period	1 January to 30 June 2021
F&A	Framework and Approach
GSL	Guaranteed service level
GWh	gigawatt hours
HV	High voltage
ICT	Information and Communication Technologies
JEN	Jemena Electricity Networks
LED	Light emitting diode
LRMC	Long Run Marginal Cost
LV	Low voltage
MW	megawatt
NEL	National Electricity Law
NEO	National Electricity Objective
NER	National Electricity Rules (or Rules)
Next regulatory period	the period commencing 1 July 2021 and ending 30 Jun 2026
NMI	National Metering Identifier
Opex	Operating and Maintenance Expenditure
POC	Power of Choice POE
PTRM	Post-tax revenue model
PV	Photovoltaic (Solar PV)
RAB	Regulatory Asset Base
RBA	Reserve Bank of Australia
Regulatory Proposal	regulatory proposal submitted under clause 6.8 of the NER
Repex	Replacement capital expenditure
Revised Regulatory Proposal	revised proposal submitted under clause 6.10.3 of the NER
RFM	Roll Forward Model
RIN	Regulatory Information Notice
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAPN	South Australia Power Networks
SCS	Standard Control Service
SRET	Small-scale Renewable Energy Target

STPIS	Service target Performance Incentive Scheme
TSS	Tariff Structure Statement
TUOS	Transmission Use of System
WACC	Weighted Average Cost of Capital (also known as Rate of Return)