2021-2026 Victorian EDPR

Joint submission from Victorian Community Organisations

January 2021

Contents

ENERGY CONSUMERS AUSTRALIA

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1 Summary of recommendations

Victorian community organisations (VCO) have prepared this joint submission to represent the interest of Victorian households and vulnerable consumers, in the current Electricity Distribution Price Reset (EDPR), recognising the importance of distribution spending in maintaining an affordable and sustainable electricity supply.

Brotherhood of St Laurence, Renew and Victorian Council of Social Service are signatories to this submission.

This follows a submission to the initial proposals from a larger group of organisations, who were unavailable to participate in this submission round due the process' schedule through the holiday period.

Our recommendations are informed by research undertaken through an Energy Consumers Australia (ECA)-funded project. Analysis was undertaken by Headberry Partners – the detailed analysis informing this submission is included as the second part of this document.

We'd like to thank the Australian Energy Regulator (AER) for consulting directly with our project on particular issues – and to thank Jemena and the CitiPower/Powercor/United Energy (CPPALUE) networks for being proactive in consulting with us directly during the preparation of their revised proposals.

Recommendations

1. **Many of the AER's draft findings directly address the concerns of community organisations, and should be retained for the final determination.**

   The AER's determination responded to concerns raised by Victorian Community Organisations and other stakeholders, and we support the majority of the decisions made by the AER.

2. **Energy affordability remains critical for Victorian consumers. Following the pandemic, achieving this priority will support those households and businesses facing increased hardship.**

   A 2020 analysis of calls to a Victorian debt helpline shows that energy bills remain a major source of household debt.[1] The networks' Energy Relief Package, and supports like JobKeeper worked well to shield Victorians from the immediate disruptions of the COVID-19 pandemic. However support agencies have identified

[1] Consumer Action Law Centre, 2020, *Bills Here Bills There The Lived Experience of Victorian Energy Reform*, accessed 8 December 2020, https://consumeraction.org.au/bills-here-bills-there-report-on-the-lived-experience-of-victorian-energy-reform/

that many households anticipate future hardship as the temporary support measures are progressively lifted.[2]

Some households and businesses are hit particularly hard. Delivering affordable energy is an important way to support vulnerable households and recovery for the state as a whole.

3. **Fundamental cost reductions are needed to secure affordability, rather than a fall in revenue that depends on the current low cost of capital.**

   The AER's Draft Determination has identified appropriate reductions in the distributors' claims – however the Draft Determination's nominated revenue is still higher than that of the last period after the impact of the current Weighted Cost of Capital (WACC) is accounted for. Meaningful revenue reductions are needed to secure affordability for consumers over the next period and into the future.

4. **The COVID-19 Pandemic will influence connections, peak demand and economic forecasts, and will increase uncertainty. Accommodating an appropriately conservative forecast will support Victorians through the recovery.**

   The VCO support the AER's approach to apply up-to-date AEMO forecasts to demand growth.

   The recovery of the Victorian population will depend on international as well as local factors – conservative planning will allow distributors to respond efficiently to any long term trends to emerge from the pandemic.

5. **The results of customer engagement should inform rather than determine regulatory decisions.**

   The AER acknowledged the feedback from stakeholders that customer engagement should not displace detailed analysis as part of the regulatory process.

   There are many positives in the framework the AER has articulated to evaluate engagement – we also agree that the weight attributed to the outcome of engagement should include a consideration of the consultation's context.

6. **Operational expenditure (opex) efficiency has been declining over the long term for most networks. We support AER's decision to require improvements.**

   Opex productivity declined on a long-term trend for most networks between 2006 and 2018. Analysis supports the adjustments applied to Jemena's base year, and suggests improvements are also appropriate for AusNet Services.

[2] Australian Council of Social Service, 2020, *COVID shines light on failure of energy system for people experiencing disadvantage,* accessed 8 December 2020, https://www.acoss.org.au/media_release/covid-shines-light-on-failure-of-energy-system-for-people-experiencing-disadvantage/

7. **The reduced capital expenditure (capex) allowances of the Draft Determinations address stakeholder concerns about a continually-growing RAB. The revised proposals for capex increases are likely to exceed requirements.**

   The AER has determined that initial capex proposals exceed current requirements. Their decision acknowledges concerns raised by many about the implications of ongoing growth in the RAB – although RAB-per-customer still increases in most cases.

   Distributors' revised applications for capex increases, including AusNet Services and Jemena's rejection of almost the entirety of the AER's decision, reverse this progress.

8. **Replacement expenditure (repex) allowances are significantly higher than the historical average, despite improving reliability measures.**

   Reliability indicators have continued to improve for most networks through 2019, despite general customer preference for affordability. Trend analysis did not find evidence to support the approval of repex that was 25% above the historical average.

9. **The Draft Determination's challenge to the CPPALUE networks' proposed pole repex program, through comparison to historical outcomes, is appropriate.**

   We support the development of a refined pole repex model that manages bushfire risks, and also aligns with historical outcomes, and properly accounts for differences in the hazard and risk profile of different operating environments (especially urban/rural.)

10. **Trend analysis finds that augmentation expenditure (augex) proposed for the upcoming period is higher than actual spending in the current period, while AEMO's forecast for static state-wide demand growth suggests that an increase would exceed requirements**

    While demand growth will not be static in all areas, AEMO's forecast for continuing stable state-wide maximums suggests the next periods' augex should be similar to current levels.

    Stable demand at the state level suggests there may be opportunities to optimise the network to accommodate local growth.

11. **DER integration has been introduced as a new class of augex. Customers will benefit from a consistent approach from the distributors.**

    The AER's Value of DER study will benefit customers by establishing a consistent and meaningful way to value export.

    Customers will also benefit from a detailed understanding of other aspects of the programs, including the proposed technology pathway to alleviate given constraints, and detailed assessment to confirm that the DER proposals of AusNet

Services and Jemena are proportional to their specific demands, despite overall capex trends.

We support the distributors' initiatives to build the smart-grid capability needed to manage and control DER on the network.

12. **Customers benefit where the Customer Service Incentive Scheme (CSIS) is based on quantifiable and consistent metrics calibrated to reward improvement.**

    Targets and rewards should be calibrated to support ongoing improvement, and avoid delivering bonus revenue for maintaining the status quo.

13. **Where there are inconsistencies between depreciation and repex schedules, and in the schedules of different distributors after the impact of asset class aggregation is considered, customers will benefit from establishing standard values.**

    The AER has suggested that apparent inconsistencies in depreciation and repex schedules are likely to be due to asset class aggregation. Where material differences remain, customers will benefit from optimal and standard values being established across the state.

14. **The Environmental Protection Amendment Act (EPAA) should not be designated for potential pass through before stakeholders have established that the Regulations are considered and fit-for-purpose for distribution infrastructure.**

    Stakeholders shared concerns about the original proposed expenditure by the CPPALUE networks to meet EPAA changes – these provisions in the initial proposals were withdrawn, and the question of suitability was not resolved.

    Distributors should be proactive in engaging and including stakeholders to determine that Regulations are designed to manage distribution infrastructure appropriately. Without this process, we don't support a pass through for this legislation.

15. **The AER's suggestion to extend opt-out Time-of-Use (TOU) tariff assignment to legacy TOU customers is a sensible measure to reduce complexity.**

    We support this addition to the opt-out assignment policy.

16. **We are concerned about the potential implications of the ongoing trend towards higher fixed charges for residential tariffs.**

    Increasing the fixed proportion of tariffs will benefit those with high loads. While some types of vulnerable customers may have high loads, others have lower-than-average loads.[3]

[3] ACOSS & Brotherhood of St Laurence 2018, *Energy stressed in Australia*, ACOSS, viewed 2 September 2019, http://library.bsl.org.au/jspui/bitstream/1/10896/4/ACOSS_BSL_Energy_stressed_in_Australia_Oct2018.pdf

We are concerned that the shift towards higher fixed charges is continuing without the level of understanding of the relationship between consumption patterns and economic wellbeing that is necessary to satisfactorily understand the impacts.

17. **We support a grid-scale battery tariff that would allow this technology to be fully evaluated against alternative technologies, and that would enable its deployment on the distribution network.**

    Option 2 and 4 proposed by the AER have the potential to be pragmatic solutions that would allow grid-scale batteries to be introduced to the distribution network in an appropriate cost-reflective manner.

    We support the establishment of a consistent approach between networks.

2 The AER's draft determination responds to stakeholder concerns

The AER's determination acknowledged many of the concerns raised by VCO and other stakeholders. In particular:

- The AER has confirmed they are scoping a broad review of incentive schemes.
- The AER has acknowledged the risks of a continually-increasing Regulatory Asset Base (RAB), and has considered this in their assessment of proposed capex.
- The AER interrogated the large number of proposed operational expenditure (opex) step changes proposed by distributors, and has rejected those deemed unqualified.
- The determination questioned the high forecasts in some proposals for connections growth and peak demand. The AER highlighted that forecasts need to be updated to properly accommodate the impacts of COVID-19.
- The AER acknowledged the feedback from many stakeholders that customer engagement should inform rather than determine revenue decisions.
- The AER commissioned a Value of Distributed Energy Resources (DER) report, to establish a standard approach to valuing increased export capacity.

Key points:

1. The VCO acknowledge the many aspects of the AER's determination that reflect stakeholder concerns, and support their inclusion in the final determination.

3 The EDPR and Victorian consumers

Energy affordability remains crucial for Victorian households and given the potential for the COVID-19 pandemic to increase the number of Victorians facing energy stress, it is important that distributor revenues are no higher than necessary.

Energy debts are a strong early indicator of economic hardship and a driver for further household debt.[4] Energy bills consume a high and growing proportion of the expenditure of low-income households.[5] For many households, high energy costs restrict access to necessities.[6]

The pandemic's implications for the circumstances of existing and newly-vulnerable households has been masked through 2020 by the effectiveness of government support programs, including JobKeeper.[7] The impact of COVID-19 is uneven and varied, so that some Victorians are facing more significant set-backs than average economic indicators may reflect. BSL's study of COVID-19's impact on participants of the longitudinal 'Life Chances Study' finds that those with insecure work and fewer resources have been disproportionately impacted.[8]

Key points:

1. Delivering affordable energy will be an important way to support households and businesses particularly impacted by the pandemic, as well as the recovery of the economy at large.
2. Consumer priorities should not be assumed to be unchanged since consultation, especially for non-core services, given the scope of the pandemic's impact.

[4] Consumer Action Law Centre, 2019, Energy Assistance Report, accessed 1 March 2020 https://consumeraction.org.au/wp-content/uploads/2019/07/190620_Energy-Assistance-Report_FINAL_WEB.pdf

5 Australian Council of Social Service & Brotherhood of St Laurence 2018, Energy stressed in Australia, ACOSS, viewed 2 September 2019, http://library.bsl.org.au/jspui/bitstream/1/10896/4/ACOSS_BSL_Energy_stressed_in_Australia_Oct2018.pdf

[6] Australian Council of Social Service, 2019, 'I regularly don't eat at all': Trying to get by on Newstart, accessed 1 March 2020, https://www.acoss.org.au/wp-content/uploads/2019/07/190729-Survey-of-people-on-Newstart-and-Youth- Allowance.pdf

[7] ACOSS, 2020

[8] Harrison, Ursula et al, 2020, *Setbacks at 30: Life Chances and COVID-19,* Brotherhood of St Laurence, accessed 29 December 2020 http://library.bsl.org.au/jspui/bitstream/1/12354/1/BSL_COVID-19_Insights_Setbacks_at_30_LifeChances_Dec2020.pdf

4 The COVID-19 pandemic – forecasting and other impacts

Forecasting connection numbers and peak demand

The potential to overestimate growth factors risks inflated costs for consumers, through unnecessary connection allowances, premature proposed augmentation, incentive program benefits, and fewer customers to cover costs.

The VCO's submission to the initial proposals noted that the connections forecasts from AusNet, Powercor and United Energy assumed an escalation in customer growth, and an aggregated peak demand forecast that was significantly higher than Australian Energy Market Operator's (AEMO) 2019 Electricity Statement of Opportunities (ESoO). This increase was applied despite that AEMO demand growth forecasts have proven to be conservatively high in the past.

The AER rejected distributor demand forecasts exceeding AEMO's Transmission Connection Point (TCP) Forecast (November 2019, confirmed against AEMO's August 2020 ESoO to account for COVID-19 impacts). COVID has been generally assumed to act as a temporary shock followed by a recovery rather than an enduring lag.[9]

Analysis from Headberry Partners (attached) shows that some distributors' customer forecasts are much higher than the Victorian budget figures (see Figure 14). The aggregate peak demand forecast by distributors is also significantly higher than that in AEMO's Victorian ESoO – despite the fact that AEMO's forecasts can be shown to be conservatively high (see Figure 16). (The analysis points out that AEMO's 10% PoE has never eventuated in the NEM, and the 50% PoE has rarely been exceeded.)

The AER flags that it will update their applied forecasts if there are significantly divergent official forecasts released at the time of the final determination.

We support the AER's approach, especially in rejecting forecasts that exceed estimates from AEMO. We also note the following considerations as relevant to the final forecasts adopted:

- Some distributors have argued for a more optimistic revision of forecasts, given some positivity in recent economic figures, and Victoria's effective control of community transmission of the COVID-19 virus.[10]

[9] AER, 2020, *Powercor Distribution Determination 2021 to 2026 Attachment 5 Capital Expenditure,* accessed 1 December 2020, https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/powercor-determination-2021-26
[10] AusNet Services, 2020, *Revised Regulatory Proposal EDPR 2022-26,* accessed 19 December 2020, https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/AusNet-services-determination-2021-26/proposal

However, the uncertainty created by the pandemic is an argument for conservatism. Where distributors are able to accommodate possible growth through the deployment of available measures - such as new demand management capabilities supported by the period's future grid projects – this will support the state's recovery from the pandemic.

- Long term post-COVID trends are not yet clear. Observed patterns, such as urban to rural migration may shift growth on the network.[11] Conservative estimates will help accommodate changed trajectories that endure post the pandemic.

- Lower birth-rates, and lower overseas migration will both impact Victoria's growth in connection numbers.

  Births contribute to households upsizing and new construction in the suburbs. COVID-19 accelerated a declining trend for birth-rates in Victoria.[12]

  Overseas migration, especially student migration, was the key driver for growth in Victoria before the pandemic. Its recovery will depend on global economic conditions as well as local management of COVID-19 and our economy.

  The university sector's recovery is expected to take years. A recent estimate considered 'optimistic' in a Melbourne University study anticipated recovered rates by the end of the upcoming period. [13]

- Forecasts with a long-term outlook anticipate an enduring lag after the rate of growth recovers. This is seen in the federal Centre for Population's recent Annual Population Statement, as well as their federal and state forecasts.[14]

- Population growth has been steadily falling in Melbourne's growth corridors for a number of years, including areas of planned augex, such as Whittlesea

[11] Minister for Population, Cities and Urban Infrastructure, December 2020, *First annual population statement released today*, accessed 29 December, https://minister.infrastructure.gov.au/tudge/media-release/first-annual-population-statement-released-today
[12] Minister for Population, Cities and Urban Infrastructure, December 2020, New *Projections for Australia's Future Fertility Rate*, Federal Government's Centre for Population, accessed 29 December 2020, https://minister.infrastructure.gov.au/tudge/media-release/new-projections-australias-10-year-fertility-rate
[13] Ian Marshman and Frank Larkins, 2020, *Modelling individual Australian universities resilience in managing overseas student revenue losses from the COVID-19 pandemic,* accessed 1 December 2020, https://melbourne-cshe.unimelb.edu.au/lh-martin-institute/insights/modelling-individual-australian-universities-resilience-in-managing-overseas-student-revenue-losses-from-the-covid-19-pandemic
[14] Australian Government Centre for Population, 2020, *Annual Population Report,* accessed 1 December 2020, https://population.gov.au/publications/publications-population-statement.html

Shire, which includes Doreen.[15] The context of declining growth pre-pandemic increases the possibility of a shock from COVID-19 to endure.

- The Victorian Government's Big Housing Build program has the potential to increase connections by a known quantity. It's important that the additional 12,000 dwellings are not accounted for more than once, between the distributors.

  Consultation should be undertaken with the Victorian Government to establish the distribution of these dwellings. Where locations are undecided, dwellings should be allocated systematically, e.g. in proportion to existing customer numbers.

Key points:

1. VCO support the AER's adjustments to customer number and peak demand forecasts, as well as the proviso that numbers be adjusted as information becomes available. Most long-term forecasts predict an enduring lag in population numbers in Victoria rather than a V-shaped recovery.
2. The Pandemic has increased the uncertainty of forecasts, however adopting a conservative approach will support Victoria's recovery and the wellbeing of Victorians particularly hard-hit. Drawing on non-network solutions to accommodate growth, will also allow an optimal response to long-term shifts resulting from the Pandemic.

5 Customer engagement

The AER acknowledged input from the VCO and other stakeholders that customer engagement undertaken by distributors should inform rather than determine regulatory outcomes, and that distributors' representations of consumer priorities determined through engagement should not displace regulatory scrutiny.

AER Framework for considering consumer engagement

The engagement presented to inform the EDPR process has been evaluated by the AER according to the framework outlined in Table 7 of the Draft Determination. These guidelines specify the AER's weighting of the outcome of each consultation process. We support the AER's position that this structure is not a 'fixed view'. It is important that critical evaluation is applied to all distributor-led customer engagement processes, and the weight given to engagement outcomes may need to change in different contexts.

[15] Australian Government Centre for Population, 2020, Whittlesea Population Growth Dashboard, accessed 1 December 2019

Much of the Table 7 framework is appropriate, and in line with existing industry guidance such as the 2016 Guideline from Energy Networks Australia (ENA).[16]

We note that the table does not include the common requirement[17] to account for diversity within the customer base, and understanding the priorities of customer sectors. We think this is an important consideration – especially for low income and vulnerable customers, for whom access to an essential service may sometimes be in the balance against other customers' willingness-to-pay for non-core services.

We note that the CPPALUE engagement program was the most successful of the Victorian EDPR processes in testing the priorities of different sectors within their base. While Jemena accounted for diversity in the proportional makeup of the People's Panel, their approach did not allow distinction between the groups' priorities. Understanding diversity was a particular weakness of AusNet Services' program. It's possible that the CPPALUE program's focus on customer segmentation may have contributed to the fact that their customers were less directly 'involved' in decision making. Where different groups are surveyed separately, a third party is required to synthesise results, which might interrupt direct involvement.

The different advantages and disadvantages of the various approaches taken to customer engagement reflects the fact that there are limits to which engagement can accurately reflect customer priorities. Barriers such as the imbalance in knowledge between the parties can be ameliorated, but not resolved.

Relevant considerations of the context of engagement

We support the AER's provision that considerations beyond those listed in Table 7 are relevant. We support the evaluation of engagement in the context that the process was conducted.

This is particularly relevant where engagement is undertaken on topics that are unfamiliar to the participants. While customers may choose to engage on areas that are new to them, it's valid to consider the extent to which customers are likely to have properly understood the full relevant context of the decisions presented. Although the engagement may include education or backgrounding - by the distributor or an independent third party - the further the topic of engagement is from participants' knowledge and experience, the more susceptible the engagement will be to intentional or unintentional influence.

[16] Energy Networks Australia, 2016, *Customer Engagement Handbook,* Accessed 1 December, https://www.energynetworks.com.au/assets/uploads/customer_engagement_handbook_engagement_draft_april_2016.pdf

[17] ENA, 2016

In some instances, customer engagement has been organised by distributors to challenge aspects of the Draft Decision by demonstrating customer support for their original claim.

We question whether customer engagement of this kind – that focuses on specific questions with direct significant revenue consequences - are likely to be as free from influence – intended or otherwise – as general engagement on customer priorities.

Additionally, where engagement focuses on questions of efficiency – an area where by definition business and customer interests are directly opposed – we also question whether the outcome of engagement should be considered with equal weight as engagement on customers' preferences and priorities.

Evaluation of New Reg outcomes

We note that AusNet Services cite the AER's approval of their customer engagement process as a key reason for the AER's general acceptance of their proposal.[18] While there were positive aspects of AusNet Services' New Reg customer engagement process, there were also comparative weaknesses.

Each of the different approaches adopted by the distributors were associated with pros and cons – sometimes these reflect inherent limitations on business-led engagement, due to barriers such as knowledge imbalance between the parties.

Examples of weaknesses in the AusNet Services New Reg process include a consultation process that did not effectively survey different sectors of their base - large energy user representatives have reported a lack of engagement through the process[19], and there was no specific engagement with vulnerable consumers.

The Customer Forum's customer engagement process has been criticised as ad-hoc and reactive – for example, surveying beneficiaries regarding proposed augex projects rather than the wider customer base.

We do not agree that AusNet Services' New Reg engagement process should have contributed to any decision to apply a less detailed assessment from the AER than otherwise.

[18] AusNet Services, 2020, *EDPR 2022-26 Revised Regulatory Proposal*, accessed 1 December 2020, https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/ausnet-services-determination-2021-26/proposal

[19] Major Energy Users Association, 2020, Presentation to AER Public Forum, accessed 1 December, https://www.aer.gov.au/system/files/EUAA%20-Presentation%20%20-%20Predetermination%20conference%20-%20Victorian%20Electricity%20Distributor%20Determination%202021-26%20-%2015%20October%202020_3.pdf

Key points:

1. The AER acknowledge stakeholder input that community engagement is an important part of the distributors' planning process that should inform rather than determine revenue allocation.
2. The AER framework for evaluating engagement is reasonable. It omits some important factors that are included in most industry guidance, such as understanding priorities of customer sectors.
3. The New Reg process – like the process undertaken by all distributors – was associated with relative strengths and weaknesses. We do not agree that it warrants a less-detailed scrutiny of the distributors' offering.
4. It is appropriate for the AER to also consider aspects of engagement context that are not articulated in the guidelines – such as the prior familiarity of customers with topics of engagement, the extent to which business and customer interests are opposed, and the amount of revenue directly at stake.

6 Opex

Opex overview

The AER's draft decision adjusted AusNet Services proposed opex by 3.7%, largely to accommodate COVID-19 impacts. Jemena's was reduced by 13.3%, United Energy and Powercor by about 12%, and CitiPower by 17%.

AusNet Services has returned revised opex 1.4% higher than the Draft Decision, challenging decisions on step changes and trend, and introducing new step change proposals. The CPPALUE networks have challenged step change decisions. Jemena has challenged the application of the base year efficiency adjustment, as well as aspects of the trend inputs.

Opex trend analysis

Analysis by Headberry Partners highlights the consistent tendency for distributors to under-spend their allowance most years. It's argued that were the opex base year approaching efficiency, the allowance would be regularly exceeded.

The analysis highlights the productivity decline over time for all distributors except United Energy. The average annual decline in opex productivity over the last 14 years of available data exceeds the AER's requirement for an opex improvement, with trends ranging between -1% and -2.7% decline per year, versus the AER's nominated 0.5% improvement.

A bottom-up 'sanity check' has been proposed as a potential step in evaluating efficiency.

Opex base year

The base year for CPPALUE networks was updated for real 2019 figures, which reduced the allowance for these networks. Jemena's base year was determined to be inefficient, and a reduction by 15% was recommended, to be achieved over the course of the period.

Jemena opex base year efficiency

We support the AER's decision to apply an efficiency adjustment to Jemena's base-year opex.

We note that Jemena already achieved almost half of the applied efficiency adjustment before it was imposed, by applying the gains from their 2019 transformation program in their initial update.

In the VCO's submission to the initial proposals we noted that Jemena's benchmarked opex productivity was low not just compared to other networks, but had also declined over the long term (See **Error! Reference source not found.**). This decline over time – unlike the low benchmarking result against other distributors – is not resolved by addressing objections raised by Jemena in their revised proposal, such as the treatment of capitalisation.[20] (We also note that Jemena ranks behind the other urban Victorian networks in capex productivity according to the October 2019 Economics Insight benchmarking report, in a trend that is also declining.[21])

This demonstrates the case for the AER's decision to apply a glide path towards a 15% efficiency improvement on the base year over the course of the period.

AusNet Services opex base year efficiency

The VCO's submission to the initial proposals also raised the potential that AusNet Services' opex base year was inefficient.

Attached analysis from Headberry Partners puts forward several points of evidence to support this case: AusNet's opex is consistently and significantly lower than Powercor's

[20] Jemena, 2020, *2021-2026 EDPR Revised proposal Attachment 5, Operating Expenditure,* accessed 1 December 2020, https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/jemena-determination-2021-26

[21] Economic Insights, 2020, *Economic Benchmarking Results for the Australian Energy Regulator's 2019 DNSP Annual Benchmarking Report*, accessed 1 December 2020, https://www.aer.gov.au/system/files/D19-190817%20Economic%20Insights%20AER%20DNSP%20Benchmarking%20Report%20-%20October%202019.PDF

(Victoria's other rural network), on a range of measures, and AusNet's productivity has declined most steeply over time.

The analysis also notes the increase in repex over time and in the current period, and the expectation that an increase in repex should be expected to reduce the opex requirement.

Opex step changes

The AER's Draft Determination addressed the concerns many stakeholders raised about the legitimacy of proposed step changes from all distributors.

Many of the step change decisions were accepted by distributors, with a number still in negotiation via the revised proposals.

The CPPALUE networks objected to the AER citing materiality as grounds for challenging step changes. We support the arguments included in Headberry Partners' analysis in defence of the validity of materiality as a criterion – small increases in operating costs should be expected to be offset by equivalent reductions which are unlikely to be nominated as negative step changes.

The analysis has suggested materiality as a relevant reason to challenge the proposed AEMO fees and ESV levy, which we support.

AusNet Services innovation fund

We support the innovation projects proposed by AusNet Services and acknowledge the importance of building capacity in the areas nominated. In this case, we are not opposed to granting the funds nominated, given that the total funding for the seven projects is not excessive, and AusNet has agreed to claim only money spent, without applying CESS.

However, allowing regulated businesses to charge customers for innovation projects is not best practice. It is preferable that innovation projects to benefit consumers be selected through a competitive process, and that funds be administered by an independent external party. Proper oversite will also ensure that knowledge from publicly-funded projects is properly shared by distribution businesses.

Although we do not oppose AusNet Services innovation proposal for this EDPR, we recommend that a better independent framework to ensure accountability is established for future resets.

AusNet Services bushfire insurance

AusNet Services has made a revision in their revised proposal to allow for increased insurance costs from those anticipated a year ago, despite taking measures to reduce ongoing insurance cost by carrying more risk (increasing the deductable and reducing coverage).

We support the attached report's appeal for an analysis of the insurance proposals from each distributor, to consider the balance of risk and coverage implied by each – and to ensure that AusNet Services' new step claim for $10.5 million in insurance costs, and the other networks' pass-through request, will not lead to double-counting with any of the other elements of the insurance proposals.

Given that the driver of these costs is climate change, increases can be expected to continue in future periods, which highlights the importance of ongoing consultation on how to best manage this issue, beyond the EDPR process itself.

Opex growth trends

We support the AER's decisions on opex growth trends, and the application of a consistent approach for the Victorian networks.

Key points:

1. Opex productivity is declining over time. Distributors underspend their opex allowance in most years, and are awarded through incentive schemes. If opex were at an efficient level, the allowance would be expected to be exceeded more often.
2. Declining opex productivity over time suggest that both AusNet Services and Jemena's base year is not competitively efficient, and an efficiency adjustment is appropriate for both networks.
3. We support the AER's decisions on opex growth trends, and we advocate for the application of a consistent approach for the Victorian networks.
4. We support the AER's scrutiny of opex step changes, and the decisions imposed in the Draft Determination.

7 Capital expenditure

Overview

The Draft Determination reduced AusNet Services and Jemena's proposed capex by 4.4% and 4% respectively, as an adjustment to address the changed context post COVID-19. The Draft deemed CPPALUE proposed capex not capable of acceptance, and put forward capex determinations that were 26-27% lower than their proposals.

AusNet Services' and Jemena's revised capex proposals are close to their initial claims. AusNet Services' revised proposal includes a claim for a 13.7% increase on connections, and a 4.1% increase on augex. Jemena's challenges the decision on repex and augex, and increased non-network and DER claims.

The CPPALUE networks have challenged aspects of the Draft Determinations, with revised repex proposals, and a higher claim for connections capex than the initial proposal. Their augex claim is slightly increased from the Draft Determination.

Capex analysis

The attached analysis from Headberry Partners indicates that the networks' revised capex proposals are likely to exceed requirements.

The analysis highlights the following trends, which together indicate that the capex claims are too high:

- Distributors are proposing to increase capex in the next period compared to the actual spend in this period, despite declining productivity,
- SAIDI and SAIFI continue to improve in 2019, accompanied by increasing capex productivity decline for most networks (Figure 11).
- A diminishing return for improved reliability is evident for the increasing investment in the RAB. At the same time, the fall in asset-utilisation is accelerating (Figures 9 and 10).
- The value of the RAB relative to peak-demand was higher in 2019 than forecasted (see Figure 8), supporting the argument that near and mid-term demand forecasts are likely to be overstated.
- The Draft Determination capex allowance is similar to the capex actuals of the last period (except in the case of AusNet Services, whose capex has decreased after recent periods' elevation). Given static state peak demand forecasts, increases on the Determination allowance are likely to exceed requirements.
- Current period capex spending has fallen short of the initial proposals in the 2015 EDPR, and also the AER's allowance.

Repex

Analysis from Headberry Partners shows that the Draft Determination's repex is 25% higher than the historical average, and 15% higher than the actual repex expenditure of the current period. In the context of steadily-improving reliability and the customer priority for affordability, exceeding historical averages may indicate an excess.

CPPALUE Poles Repex

CPPALUE made a significant increase in the proposed repex for wood poles across their three networks in response to an ESV review in 2019.

Powercor proposed to increase pole repex by 243% on the current period, with United Energy and CitiPower also proposing significant increases.

The AER challenged the proposed repex by budgeting for the replacement rate from the most recent period where Powercor exceeded failure rate targets, 2010-15, as well as a 'backlog' from the intervening years.

CPPALUE has rejected the AER's decision, on the grounds that the asset management practices behind the 2010-15 rate are no longer approved by the ESV and meet compliance obligations of the Electrical Safety Act.[22]

Stakeholders also challenged CPPALUE for failing to distinguish between the failure rate, and the consequences of pole failure in an urban environment and the rural networks. This shortcoming is particularly apparent given that concerns over bushfire risk have driven this process.

We accept that CPPALUE are adjusting their processes to meet new risk-management requirements. We also feel that calibration of these processes against historical results – given the large number of assumptions that feed into the new models, and the sensitivity of the model to estimation of the failure rate – is a reasonable challenge from the regulator.

We support the application of a refined model, consistent with historical results, and detailed enough to properly consider different hazards and risks applying to urban settings.

We note that CPPALUE accepted the AER's decision that it is appropriate to reinvest CESS benefit towards pole safety, and we commend this commitment pending the wider revision of the incentive framework currently being scoped by the AER.

AusNet and Jemena Repex

Analysis from Headberry Partners argues that the AER's general acceptance of the proposed repex from these two networks relies on a comparison to expenditure in the current period, without a full consideration of the extent to which the current period has increased from the historical trend.

The analysis also questions the approval of a higher repex allowance for AusNet Services than Powercor, given the similarities in the asset base of these networks.

[22] Powercor, 2020, *Revised Proposal 2021 – 2026* , accessed 1 December 2020, https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/powercor-determination-2021-26

The CESS award granted to these networks as a result of underspending the repex allocation for the last period is a reason for careful consideration of these networks' revised submission for increased repex from the Draft Decision, despite the approval of a large percentage of their initial claim.

Augex

Headberry Partners' analysis draws attention to the potential for optimising network assets rather than augmenting the network to address local peak demand increases, in the context of static state-wide peak demand and falling utilisation.

AEMO forecasts do not anticipate Victorian peak demand to exceed the current period. This indicates that augex requirements for the upcoming period should be analogous to the actual requirement of the current period, given that non-coincident demand to 2019 did not exceed that of 2014.

Initial augex proposals were similar to the initial claims for the current period, despite the significant underspend of this period in an analogous static demand environment. This trend analysis supports reduction to proposed augex beyond the decision in the Draft Determination.

Key points:

1. An analysis of capex trends discovers a range of indicators that the capex claims in the revised proposals exceed the requirements of the networks.
2. Repex proposals are higher than for the last period, and significantly higher than historical levels.
3. In the context of AEMO forecasts for minimal Victorian peak demand growth, trend analysis suggests that forecast augex requirements should be commensurate with the current period.

8 DER expenditure

The AER undertook a detailed assessment of the DER expenditure for CPPALUE. Less extensive assessment was undertaken for Jemena and AusNet Services, given that overall capex was deemed capable of acceptance for these networks, although the AER flagged potential issues with the assumptions underlying both claims.

CPPALUE DER expenditure

The AER reduced the allowance for expenditure on DER integration for the CPPALUE networks due to deviations in the assumptions of their business case assessment from accepted standards (such as the NPV period). In general terms, CPPALUE's physical network augmentation spending allowance was reduced, while the budget for developing smart grid capabilities was allowed.

VCO supports this approach in line with our position that we share and recognise broad support for investment to accommodate DER, but also understand the importance that it demonstrate benefits.

CPPALUE made a strong case for smart-grid programs such as dynamic voltage management, and that many of the functions of the proposed platform, such as dynamic operating envelopes will be necessary as the grid develops whatever the ultimate level of DER uptake will be.

These functionalities will allow network constraints to be safely managed while significantly reducing the need to restrict customers from installing PV and connecting to the network. Consumers hope that establishing and operating these systems will inform a more detailed and specific understanding of where augex is required to enable DER integration, and where this provides a net benefit to customers.

AusNet Services and Jemena DER expenditure

The AER accepted the DER proposals from AusNet and Jemena in the context of accepting capex overall, despite 'concerns about the underlying assumptions and forecasts of AusNet Services' DER integration capex'[23] and elements 'not demonstrated against capex criteria' for Jemena.[24]

The Value of DER adopted by AusNet Services differed from the approach recommended in the AER-commissioned Value of DER Study.[25] The AER also queried Jemena's assumption that interventions would be required where penetration reached 30% - despite other networks demonstrating that higher penetrations can be achieved than the point at which issues first emerge.

Compared to the businesses for whom export constraints are a present issue, Jemena's forecast expenditure needs have been estimated with reference to less network data, and rely more heavily on assumptions. In this context, it is worth considering that the forecast penetration for Jemena by the end of the period is close to the current penetration of AusNet Services and Powercor, where issues have until now been largely managed through manual tap changes and other opex measures.

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[23] Ausnet Services, 2020

[24] Jemena, 2020, *2021-2026 EDPR Revised proposal Attachment 4, Capital Expenditure,* accessed 1 December 2020, https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/jemena-determination-2021-26

[25] CSIRO and Cutler Merz, 2020, *Value of Distributed Energy Resources Report*

Value of DER

The Value of DER study undertaken by the AER addresses the concerns raised by the VCO and other stakeholders around the business case evaluation methodology employed by the distributors, including the assumption that the value of exported energy would remain unchanged over time, and the benefits of pursuing a consistent approach between networks.

We would like to make the following points about relevant considerations in adopting or applying these recommendations:

- Many submissions to the Value of DER study argued that there were differences in the value of enabling kW of PV to be installed by consumers on the distribution network, rather than having equivalent kW installed in large generators. No difference was recognised by the Value of DER study.

  Equity between early and late adopters is one reason stakeholders see value in allowing consumers to access PV.

  The value of providing access to install and connect PV provides different values to customers than alleviating export constraints during periods of excess generation.

- The study does not include a recognition of the carbon cost alleviated, although it accommodates the possibility for this to be considered in line with state government policy.

  We support the inclusion of the cost of carbon, in line with strongly-demonstrated customer preference for transition to a low-carbon network.

Consistent DER integration planning

The Value of DER study is an important contribution to a framework that will maintain consistency between Victorian networks as they undergo transition (with respect to the constraints of existing infrastructure).

There are other aspects of the DER implementation planning where aiming for a consistent approach will deliver best value for consumers, and enable consistent customer interaction with DER across the state.

Important examples are: proposed technology pathways in response to particular constraint contexts, deployment policies for dynamic operating envelopes, agreed constraint levels (relevant to the network context) to trigger remediation, etc.

An exploration of the networks' planning policies for these aspects would allow a closer understanding of a proportional investment proposal for DER integration that is appropriate to a distributors' current situation.

Some decisions will also have implications for DER-customer interactions and decision-making. For example, consultation with AusNet Services and the CPPALUE networks early in 2020 suggested that at that time they had different strategies for deploying dynamic constraints. This may have implications for customers as to the appropriate response – increasing or decreasing loads - when there is a local voltage constraint active.

This year's determination introduced this new class of expenditure to the Victorian process. It is a useful opportunity to compare the detail of this planning between the networks.

Upgrades should be implemented within a comprehensive plan for a future network

Consumer advocates would like to see more evidence that DER augmentation proposals are implemented within the context of a comprehensive plan for a future network, so that we can be confident that that its benefits have been properly valued, and that the network is developed without redundancies.

We are concerned that augmentation to accommodate an expanded voltage range or reverse flows in constrained areas of the network lead to constraints developing elsewhere, potentially upstream as PV penetration increases on multiple branches across the low voltage network.

Where this is possible, it is a relevant consideration for business case assessments for proposed augex. Where business case assessments neglect to consider the possibility for constraints to occur elsewhere on the network, then it is likely that the benefits of proposed augex will be overstated.

This issue was not considered explicitly as part of the Value of DER study, however it is relevant to preparing a representative business case. It's also important to take this into account to properly evaluate the relative value of all potential technical solutions. Distribution grid-scale storage, for example, may be more expensive upfront than a transformer upgrade, but may provide better support for the greater network.

The importance of establishing a better understanding of the likely development of the network's transition is another argument in support of the AER's determination regarding the DER capex proposals of the CPPALUE networks. It is likely to be equally relevant to the other networks.

Evaluation of DER spending

The outcomes of DER spending are not currently addressed by existing incentive mechanisms, so this may create an unbalanced incentive for distributors to underspend allocated DER funds.

We are also concerned that any scheme developed to incentivise or oversee DER spending should not incentivise inefficient excessive augmentation for DER enablement. Some distributors have proposed that they measure the outcome in terms of the amount of constrained exports enabled. The consumer outcomes-focused approach is positive, however the value of exports should also be considered with respect to the development of the network as a whole, as discussed above.

AusNet Services' indication that they will return unspent funds is also a positive step. It is also important that the augmentation undertaken is confirmed to return a net benefit.

Key points:

1. We support the approach of the AER's Draft Determination for the CPPALUE networks' DER integration proposal – we also suggest that the critiques made for the other networks are equally valid.
2. Given that this is a new class of expenditure, we believe that customers would benefit from a consistent approach across the state (relative to local network conditions.) The Value of DER report will support a uniform approach, however other aspects of network planning are also relevant.
3. We welcome measures from the networks to provide accountability for DER integration spending. A uniform approach should be developed, that demonstrates value for customers.

9 Incentive Schemes

Customer Service Incentive Scheme

The proposed Customer Service Incentive Schemes (CSIS) is an example of the way different customer consultation processes can lead to different outcomes.

Jemena has retained the STPIS phone answering metric, in response to the advice of the Peoples' Panel that a CSIS is not warranted.

The CPPALUE networks introduced a CSIS in their revised proposal, in response to AusNet Services' program.

CPPALUE surveyed customers to inform the design of the scheme. This resulted in a proposal that would reward improvement on planned SAIFI and SAIDI metrics, SMS notification for outages, and a smaller amount for the call-answering metric.

These metrics are reasonable and are a likely reflection of customer priorities. Metrics that are easily measurable will provide a more accurate indication of improvement than sample data collected through a survey (this is especially true given the uneven distribution of reliability events across the network). The scheme will allow benchmarking over time and between networks that will assist in setting appropriate targets to underpin ongoing improvement.

The metrics identified through CPPALUE's engagement program are similar to those nominated by AusNet Services' customers. AusNet Services' proposed scheme measures customer satisfaction with planned and unplanned outages, new connections and complaints, through a survey.

(Unplanned outages are already included in the STPIS, so that surveying customers on their experiences in this area may double up on incentives here, in a context where stakeholders have already raised the concern that reliability may be over-incentivised.)

Given this similarity, there is an opportunity to standardise these schemes.

Although the new CSIS has been designed intentionally as a principles-based scheme, to allow flexible response to changes in priorities – the similarities in the design of the CPPALUE and AusNet Services schemes show that currently, the services valued by customers are similar, and relate to basic core distribution business offerings. Given this result, we suggest that it is worth considering whether the scheme's capacity for flexibility outweighs the benefits that might be gained from applying uniform benchmarks.

We are also concerned that the targets and rewards be set at appropriate levels to incentivise improvements, not generate additional revenue for the status quo. Our approval of the scheme is dependent on the AER's scrutiny and satisfaction with the target set.

Key points

1. Where CSIS schemes are applied, customers will benefit from those that adopt directly measurable metrics, rather than using survey results, and those that set an appropriately-high bar for reward. We recommend that customers would benefit from negotiating a uniform CSIS between networks to allow benchmarking between networks and over time.

Incentive scheme operation and review

The attached analysis by Headberry Partners includes commentary on the function of the EBSS, CESS and STPIS, and identifies indications that these schemes may not be working to achieve value and efficiency for consumers: by incentivising a service level in excess of customers' needs or priorities; by rewarding savings against revenue allowances that don't represent real productivity gains; or through other inconsistencies.

We welcome the incentive scheme review currently being scoped by the AER, and submit that the issues raised in the attached analysis be considered for review.

Key points

1. We welcome the incentive scheme review currently being scoped by the AER, and submit that the issues raised in the attached analysis be considered for review.

10 Depreciation

Consistency of asset life

VCO's submission to the initial proposals noted the disparity in asset lives between the distributors' schedules, and noted that consumers would benefit where common rates were established.

The AER addressed this concern in their Draft Determinations, and suggested that much of this apparent difference is due to aggregation of asset classes. Headberry Partners has raised specific examples where they believe differences to persist.

Where asset lives do differ between networks and between the depreciation and repex schedules, we believe that customers will benefit from a review to optimise and standardise these schedules.

Accelerated depreciation – AusNet Services

Headberry Partners' analysis has highlighted some specific concerns associated with the accelerated depreciation claims included in AusNet Services' proposals, and raises concerns about the implication of this decision for the depreciation schedule for the other assets included in this class (See Section 5.1).

Key points

1. Where there are differences in the schedule for a given asset class, between distributors or between repex and depreciation schedules, customers will benefit from establishing a consistent approach.
2. The acceptance of AusNet Services' proposed accelerated depreciation of assets within a class raises questions regarding the implications for the altered accuracy of the schedule applied to other assets.

11 Pass through events

Environment Protection Authority Pass Through Events

A number of distributors have flagged that the enactment of the new Environmental Protection Amendment Act 2018 may trigger the need for cost pass-throughs.

The CPPALUE networks' inclusion of a large amount of repex and other spending increases in their initial proposal (withdrawn before the draft determination) gives an indication of the volume of additional revenue that might be sought in relation to these amendments.

Many stakeholders questioned whether there were any real-world drivers for the proposed compliance measures, such as a large amount of noise-related repex. Consultation with distributors confirmed that noise-related complaint volumes were very low. The EPA confirmed, during consultation in early 2019, that distribution infrastructure had not been considered through the drafting stages. Many similar infrastructure installations were listed in the Regulations as exclusions.

Our initial submission stressed the importance of proactive engagement on this issue, to ensure that any final regulations were specifically drafted to be appropriate to manage any real environmental risks relating to distribution infrastructure, and to avoid unnecessary expenditure.

The extension of the Act's enactment provided an opportunity for these issues to be resolved, and for further engagement to ensure that the regulations were considered and appropriate for distribution infrastructure.

Without the resolution of consumer doubts relating to the need for this investment and the extent to which the regulations are fit-for-purpose, it is not appropriate that this spending be approved as an appropriate pass-through.

Key points	
1	We do not support the inclusion of EPA regulation compliance as a pass through, given the lack of consideration of distribution infrastructure in the regulations' drafting process, and the lack of consultation undertaken with the EPA to resolve these concerns after the CPPALUE networks' initial EPA-related expenditure was redacted.

12 Tariff Structures

Time of Use Tariffs

The networks have proposed a time-of-use tariff for distribution pricing, with higher residential charges between three and nine PM for affected households. The tariff will be assigned to some consumers (new solar consumers, new connections, electric vehicle owners, and three-phase consumers), on an opt-out basis for most networks. We understand that retailers will be required to continue to offer a basic flat tariff through the Victorian Default Offer.

Assignment for legacy TOU customers

The AER recommended that legacy TOU customers be assigned to the new tariffs on an opt-out basis. Distributors have confirmed that the majority of customers on existing TOU customers will be better off under the new rates.

VCO support this proposal, which will simplify the range of available offers.

Fixed tariff component

Jemena and United Energy have proposed significant increases in the fixed component of their tariffs.

Distributors have justified this shift on the grounds that fixed tariffs more closely reflect the sunk costs that make up the majority of distributors' costs, and that this satisfies the NER requirement for cost reflectivity.

Jemena and United Energy currently have a lower proportion of their tariffs charged through fixed rates than other NEM distributors.

Consumers benefit from achieving reasonable consistency in tariff structures between the Victorian networks. VCO accepts consistency as a principle for bringing the tariffs into closer alignment.

However, we are concerned about the potential customer impacts of the ongoing trend of increasing fixed charges, and it has not been demonstrated to us that they have been fully considered.

Higher fixed charges may benefit the type of vulnerable customer that typically has a larger-than-average load – due to factors like inefficient appliances and housing, non-discretionary loads like air-conditioning needs, large families, or a lack of control over their lived environment (like renters.) This type of vulnerable customer is often represented amongst identified hardship customers.

However, many low income households, who are burdened by high and growing costs-of-living, generally have lower-than-average loads. These customers are disadvantaged by increasing fixed charges.

Further, higher fixed charges reduce the capacity of consumers to act to reduce their electricity costs by changing their behaviour when they are unable to afford their bills.

We are particularly concerned that these decisions are being made without a strong understanding of the relationships between electricity consumption patterns (especially total annual volumes) and income/vulnerability to energy stress, and the relative numbers of different types of vulnerable customers – low versus high consumers – are in our community. A quantitative understanding of this correlation is needed to make an informed decision about customer impact. Additionally, more clarity about the business reasons for setting the fixed charge at the proposed level would aid our assessment of how well the networks have balanced cost-reflectivity with customer impact.

Network-scale battery tariff

The determination flags that they are seeking input on the proposals from some distributors for grid-scale battery tariffs, while also noting that upcoming rule changes proposed by AEMO may supersede decisions made in relation to these proposals.

The AER proposes four potential approaches:

1. Accept the Victorian distributors' proposed treatment of grid-scale batteries.
2. Require AusNet Services and Jemena to offer similar network tariff exemptions to those proposed by CitiPower, Powercor, and United Energy.
3. Require all Victorian distributors to exempt grid-scale batteries from the residual component of network tariffs.
4. Require all distributors to exempt grid-scale batteries from network tariffs if the battery is registered as a scheduled load.'

VCO welcome the distributors proposals to formalise arrangements for grid-scale batteries. We are keen to see the development of a framework that will enable the full lifecycle costs and benefits of batteries to be fairly evaluated against other potential solutions to given grid constraints.

Fully cost-reflective tariffs are appropriate for grid-scale batteries. Battery operators should cover any cost that they directly incur– such as augmentation required to enable export at times of high grid voltage if required, or a modest cost to administer their establishment on the network. However, they should not be required to cover general sunk or ongoing operation costs in line with any consumption/export charges that relate to consumers – they should instead be considered network infrastructure. Distribution charges must be consistent with the treatment of other technologies available to resolve grid constraints, such as transformer upgrades, to allow meaningful business-case options analysis.

In line with this principle, Option 2 (depending on the nature of the contracts established, of which little detail is provided) and Option 4 appear to be practical approaches to accommodating early grid-scale batteries on the network.

Option 2 may provide advantages where it is possible to use API platforms to define dynamic envelopes rather than scheduled operation – so that operators are able to seek value from other markets, within boundaries that also support the distribution network.

We support a consistent approach between networks.

Key points

1. We support the assignment of the new TOU tariff to legacy TOU customers with consistent optionality to the other classes (in this case opt-out).
2. We are concerned about the ongoing trend towards higher fixed charges, without a quantitative understanding of the relationship between consumption patterns (especially volume) and vulnerable consumers of all kinds (including but not limited to hardship customers).
3. We support the introduction of a framework that supports grid-scale batteries to be deployed, and for their costs and benefits to be fully and fairly evaluated against other available solutions to network constraints. The AER's proposed Option 2 and Option 4 have the potential to provide this, for early installations.

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Headberry Partners P/L
Energy, Management and Procurement Services
ABN 75 011 240 472

[redacted]

Report to the Sponsoring Organisations

Brotherhood of St Laurence
Victorian Council of Social Service
Renew

This analysis of the AER Draft Determination and the Victorian Electricity Distributors' revised proposals has been prepared by Headberry Partners P/L at the request of the Sponsoring Organisations

January 2021

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1. Introduction and overall assessment

In January 2020, the five electricity distribution networks (AusNet Services, CitiPower, Jemena electricity network, Powercor and United Energy – collectively the DBs) submitted revenue reset proposals to the Australian Energy Regulator (AER) for implementation in financial years 2022 to 2026. In September 2020, the AER released its draft decisions for all five DBs and in early December the AER released the revised proposals from the DBs. This submission addresses both the AER draft decision and the revised proposals

In their response to the initial proposals, the sponsors commented that there is a consistent message from consumers, shown clearly in the results from the DBs' customer engagement and in other surveys, that as consumers considered electricity prices already too high they would prefer to pay less for network services and want to pay more for increased reliability. Further, they noted that high energy costs had contributed to significant financial hardship which can lead households further into debt.

This high-level assessment drives the commentary made throughout this submission which addresses the AER draft decisions on each of the DB initial proposals and on the revised proposals provided by the DBs subsequent to the AER draft decision.

1.1 The structure of this report

The AER uses an approach described as the "building block" to determine the allowances that each DB will be granted for the provision of the services that they sell to consumers. It is also noted that the AER revenue allowance derived from the "building block" approach provides a revenue allowance that the DBs are free to spend in any way they consider necessary to deliver the services they provide. This means that, in principle, what has been included by the AER in its draft decision does not necessarily provide "approval" of a specific expenditure and this submission is based on this premise.

This response focuses on aspects that are reviewable within the reset process. Specifically, this submission does not address the setting of the cost of capital, inflation or tax allowances.

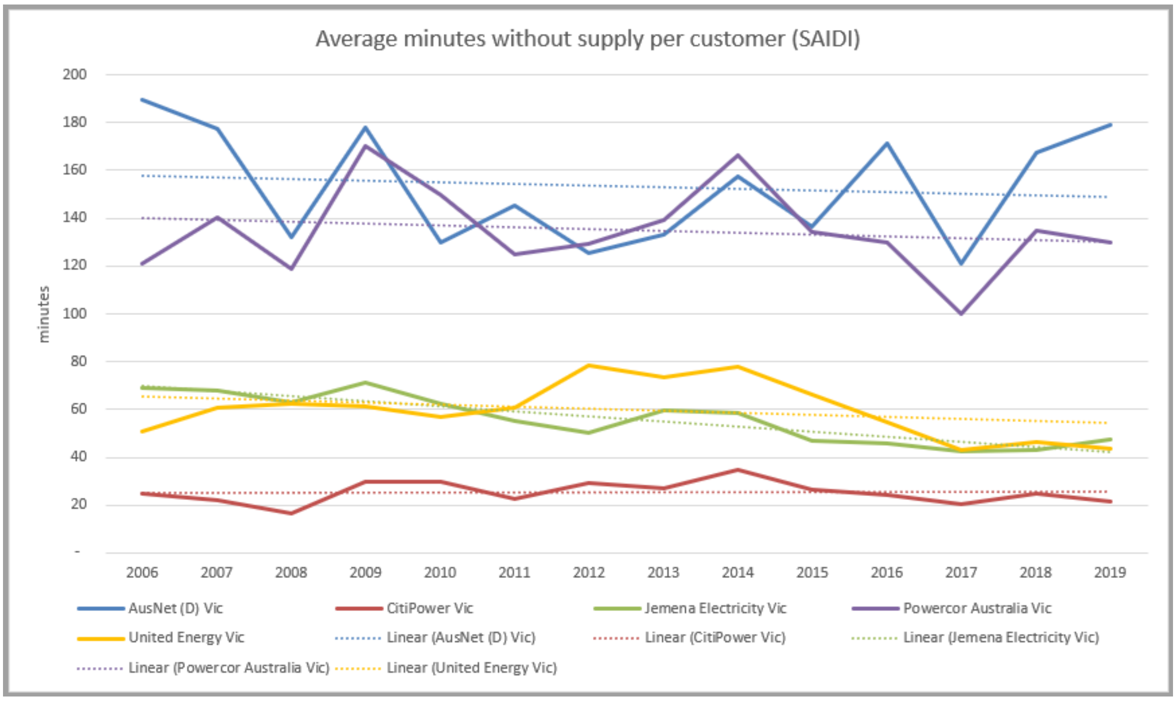
Where in this submission, there is reference to "the DBs" this refers to all five of the Victorian distribution network service providers but a reference to "CPPALUE" refers only to CitiPower, Powercor and United Energy which share many common approaches to their initial and revised submissions.

1.2 The performance of the networks

In its response to the Initial proposals, the sponsors reviewed the key aspects of reliability of the services provided and the utilisation of the assets. Since then, the performance measures have been updated to reflect the inclusion of 2019 data; this new data was released by the AER in September 2020.

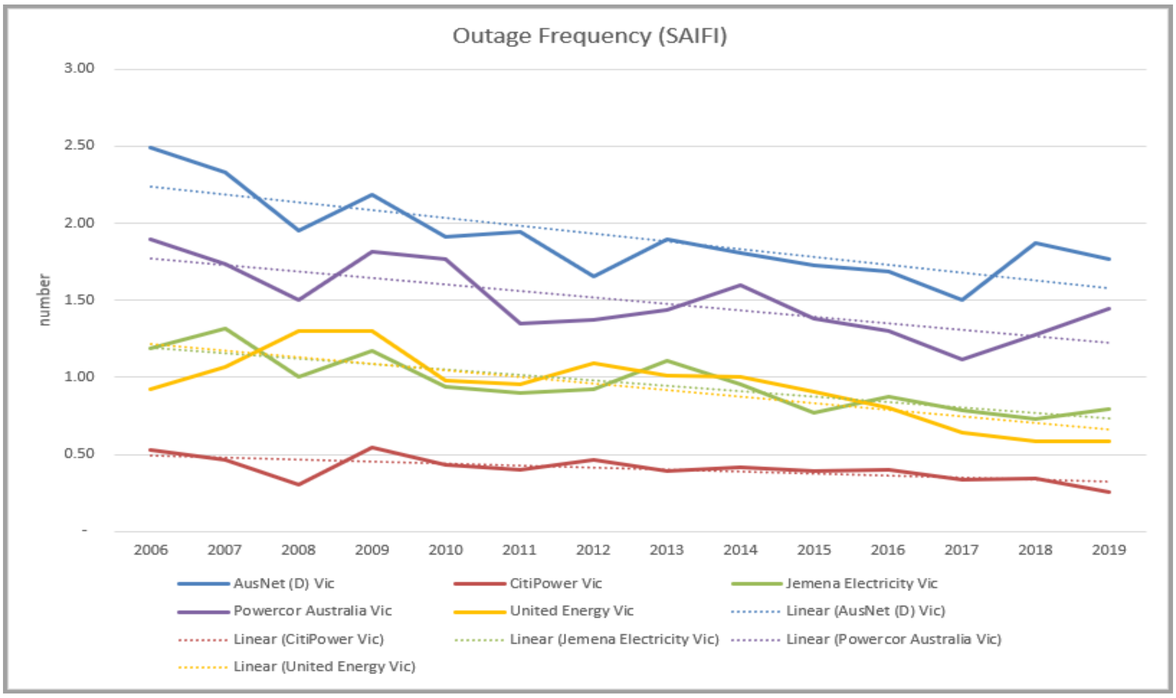
The updated data, specifically system average interruption duration index (SAIDI) and system average interruption frequency index (SAIFI) continue to show the same longer-term trends identified in the response to the initial proposals, and that both measures are either relatively static or trending down (ie show an improvement). The updated data is shown in the following two charts (figures 1 and 2) along with the historical performance from the commencement of the performance reporting.

Figure 1 - Average minutes without supply per customer (SAIDI)



Source: AER Electricity Distribution Networks Performance data report 2006-2019

Figure 2 – Outage frequency (SAIFI)

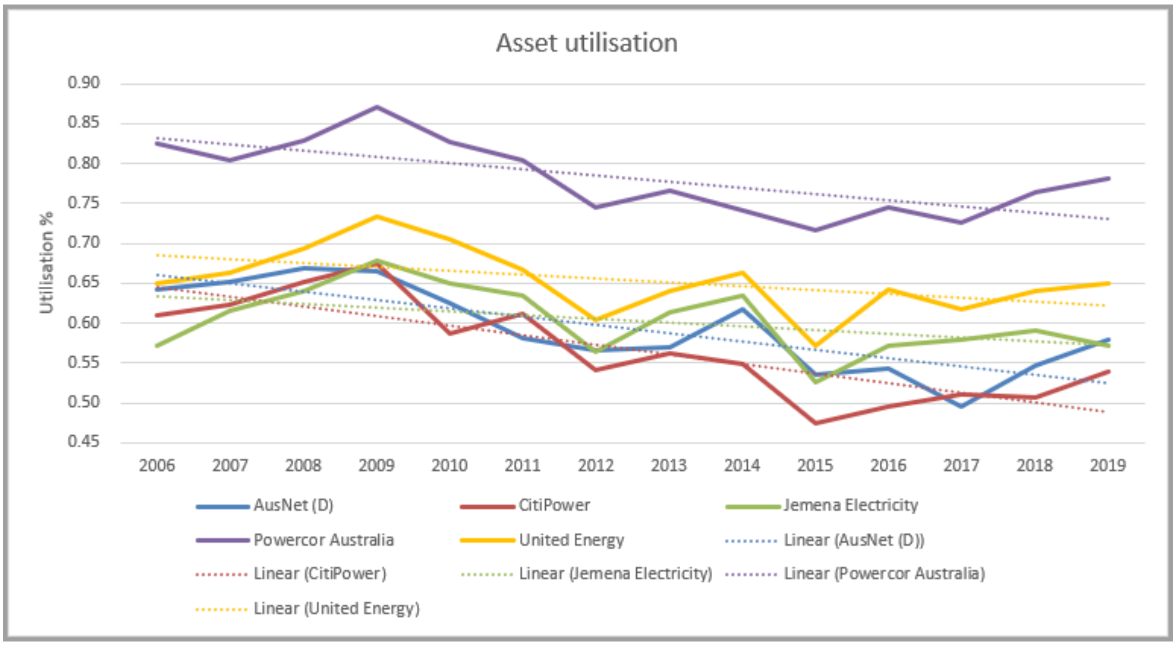


Source: AER Electricity Distribution Networks Performance data report 2006-2019

The updated data does not change the overall view that all DBs have continued to commit funds to increase reliability of supply for their customers, yet customers have been stating since before 2016 they would prefer lower costs to improved reliability. Not only have the DBs been devoting funds (particularly capital) to improving reliability, they have been gaining incentive payments for exceeding forecast reliability levels through their service target performance incentive scheme (STPIS).

The updated data for the other key metric (utilisation of assets) shows that utilisation has risen in 2019 (except for Jemena) although the overall trend for all continues to decline as shown in the following chart (figure 3).

Figure 3 – Asset utilisation



Source: AER Electricity Distribution Networks Performance data report 2006-2019

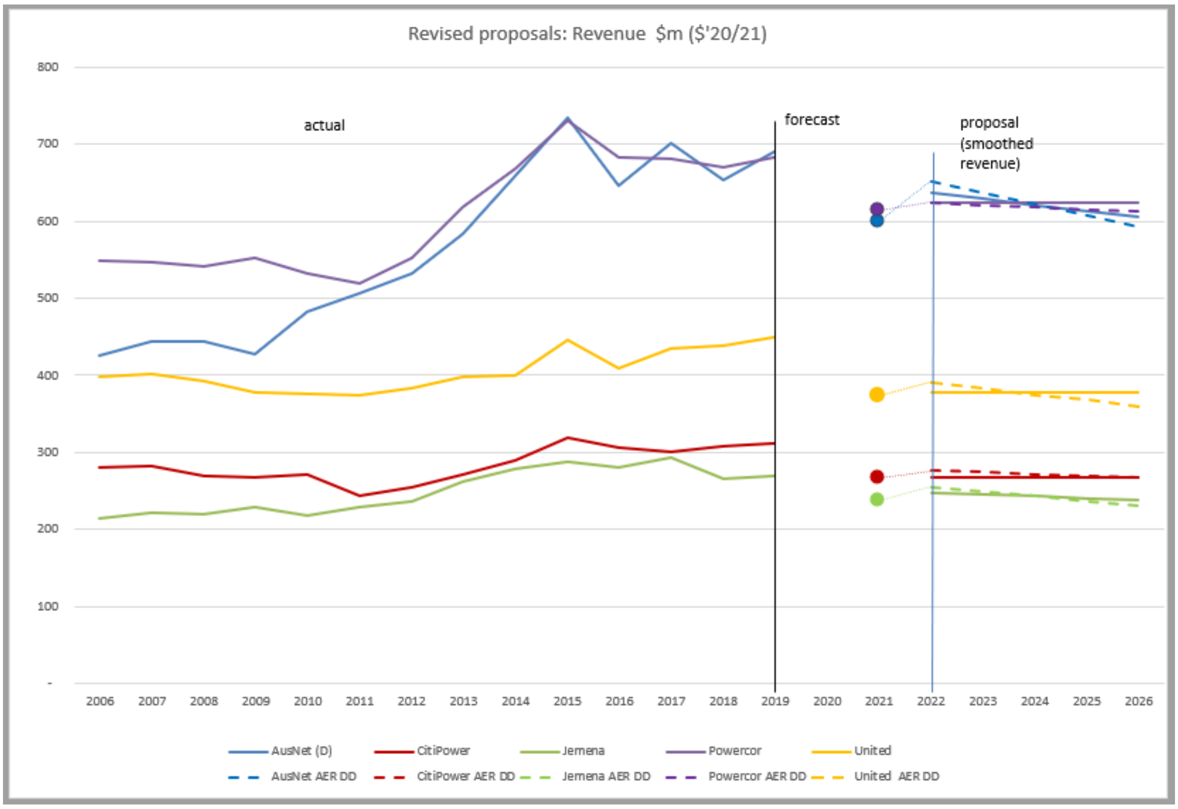
The falling utilisation of the assets provided by the DBs highlights that consumers are increasingly paying more than is necessary for assets needed for the service consumers require. What is concerning is about this falling utilisation is that consumers are being required to pay for assets that do not deliver an efficient service. If the networks were optimised to the service required, then the costs that consumer face would be considerably lower. This issue is discussed further in later sections, but what is important to note is that there are increasingly sections of the networks that are considerably over-sized for the service required and the DBs need to be encouraged to relocate assets where these are not required rather than acquire new assets and leave the old ones in place.

When combining the improving reliability with falling utilisation, this clearly highlights that the DBs are all continuing to invest to provide assets and services that are not required by consumers. This observation has a critical impact on the amounts of capex and opex that are necessary for the next regulatory period.

1.3 The revenue claims

All of the DBs provided initial proposals where revenue forecasts for the next period showing either constant revenue or a small increase in the revenue they are seeking. Since that time, the AER has released its draft decisions and the DBs have provided revised proposals. The following figure 4 shows the draft decision and the revised proposals and that the smoothed revenues in the revised proposals reasonably reflect the AER draft decisions.

Figure 4 – Revenue



Source: AER Electricity Distribution Networks Performance data report 2006-2019, DB proposals, AER DD smoothed values
Note: the dots reflect the annualised allowance provided by the AER for the "mini-period 1 Jan 21 to 30 Jun 21

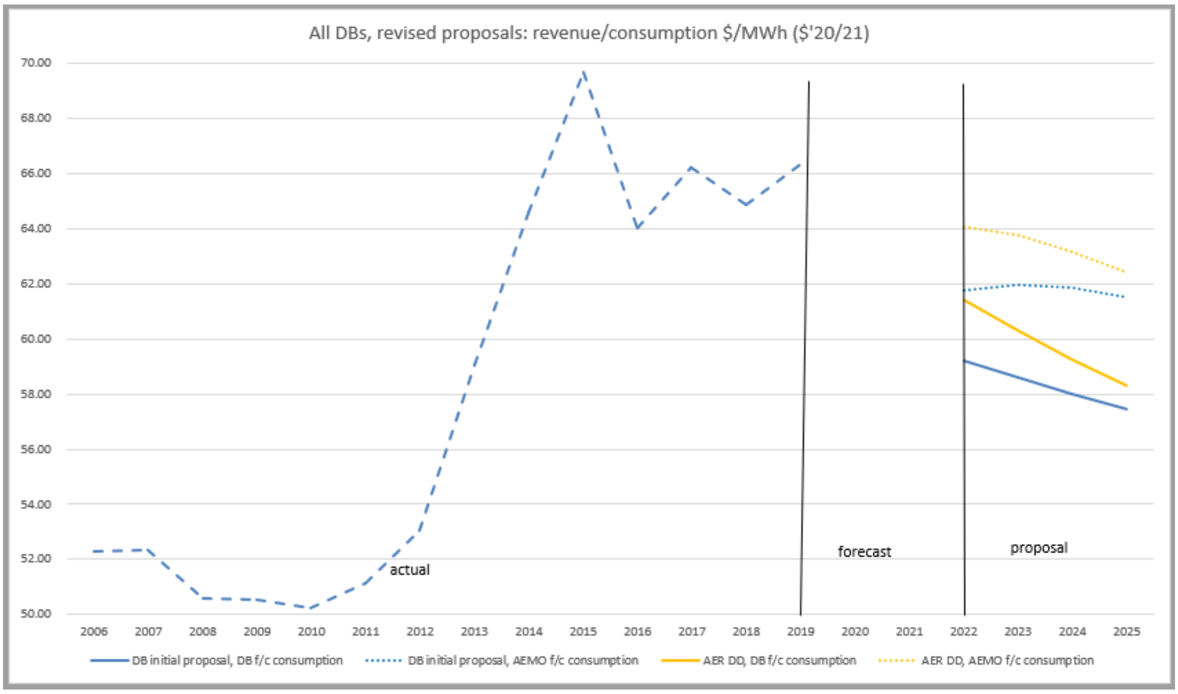
The AER draft decisions for each DB show a reduction in the allowable revenues from the amounts initially claimed by the DBs. This is to be expected because the AER has made some reductions in elements of the proposals from each DB. However, in its submission to the initial proposals the sponsors had identified that all of the of the reductions in the revenue claimed by the DBs was entirely attributable to the reduction in the weighted average cost of capital (WACC) and that on a constant WACC basis, all of the DBs increased their claimed revenues significantly. Analysis shows that the reductions included in the AER draft decision allowances are still less than the impact of the reduction in WACC, which effectively highlights that the AER draft decision still allows a real increase in revenues from elements other than the cost of capital.

It is expected that the revenue allowances might increase as the network grows and more customers are being provided with a service, this effect can be moderated. As consumers pay for the service based on their usage of the assets, the following chart (figure 5) normalises the increase in revenues with the amount of energy used. This measure is appropriate as it most closely reflects the tariffs that most consumers use and how they measure their use of electricity.

However, as more fully investigated in section 4 below, the sum of the expected consumption data forecast by the DBs is significantly higher than the expected Victorian consumption (excluding direct connected load) forecast by AEMO for Victoria. Because AEMO-published data of consumption is generated on a region basis (although it is expected that the AER will be provided with more detailed breakdown by AEMO) figure 5 is generated on an aggregated state-wide basis, but it still provides a very important assessment.

The chart not only reflects the impact of the AER draft decision compared to the initial proposals, but also the impacts of the difference that the AEMO forecast of consumption has on notional tariffs. So, while the AER draft decision does have a positive outcome for consumers (as do the revised proposals), much of the value of this work is lost in tariffs terms by an over-estimation of future consumption by the DBs.

Figure 5 - Real revenue/consumption $/MWh ($'20/21)



Source: AER Electricity Distribution Networks Performance data report 2006-2019, AER DD, DB revised proposals, sponsor calculation

What this analysis shows is that despite the DBs all implying that they are reducing costs to provide their services, fundamental costs are increasing, and the only reduction that is occurring is the impact of exogeneous factors, specifically the falling cost of money; much of the benefit of lower cost capital is being lost in tariff terms, through unrealistic forecasts of consumption.

It is also important to note that as network charges increase, this incentivizes end users to further limit their usage and/or seek other means to source the energy they use, reducing the usage on the networks and leading to effectively higher tariffs for other consumers without the ability to better manage their electricity usage.

1.4 Managing the 6-month extension

The sponsors tended to accept the AER approach to the 6-month extension period with regard to addressing the cost of capital. The sponsors did not agree with the AER that the opex and capex allowances for the "mini-period" should be based on the allowances in the current period, especially as the DBs all used less opex and capex in the current period than the AER allowed in 2015 and are forecast to do so in the next period.

On 8 October 2020, the AER wrote to the DBs providing advice as to the allowed revenue for the 6-month period 1 January 2021 to 30 June 2021. While earlier documents provided detail on the way the AER would calculate the cost of capital allowance, there was no detail as to what the allowances were used for opex, capex, depreciation and tax.

It is noted that the AER has issued a draft decision on opex and capex allowances which are less than the amounts claimed by the DBs in their initial proposals which, in turn, were less than the allowances for the 2016-20 period. It is also clear that opex and capex allowances forecast to be needed now are demonstrably less than the needs forecast in 2015. There is concern that the AER has used capex and opex allowance for the "mini period" based on the amounts allowed in the current period.

The AER has not provided a clear explanation as to what values that have assigned to these elements of the allowed revenue but as shown on figure 4 above, the allowances would appear to be reasonably consistent with the draft decision for the period 21/22-25/26.

1.5 Impact of COVID-19

In their earlier submission the sponsors noted that there are a number of key aspects (especially the impact of the COVID pandemic) that represent change and which will have an impact not only on this reset but also on consumers more widely in terms of electricity usage and demand and forecast customer numbers.

In section 4 below, the impacts on these elements are more fully addressed and the latest information has been used to generate data on forecast peak demands, consumption and customer numbers. While it is accepted that these forecasts are still being impacted by new information about the impacts of the pandemic, it is clear that the forecasts (in terms of customer numbers, peak demand and consumption) by the DBs are significantly overstated, and that more up-to-date data is needed to ensure that the allowed revenues are not overstated.

1.6 Investment to accommodate DER

In their submission to the Initial Proposals, the sponsors noted that investment to accommodate Distributed Energy Resources (DER) capacity is a significant new area of augmentation expenditure in all the proposals, with IT spend and opex also included in DER programs (as well as accelerated depreciation proposed by CPPALUE).

The sponsors noted that while there was support for investment to allow increasing amounts of DER embedded in the networks they had observed there were significant differences proposed in the approach to incorporating DER but that all DBs had undertaken business case assessments to support the approach each took but using different inputs to develop their decisions.

Because addressing the needs of DER covers so many elements that make up the allowed revenue, the sponsors provided a view that there should be an all-encompassing analysis including all elements involved with providing for the DER needs so there could be a clear understanding of what the total cost to consumers would be for addressing the DER needs and for this to be compared to the value of the benefits the increased investment from all sources will deliver. This has not been done and each element (augex, ICT capex and opex) has been assessed in isolation so that there is no clear understanding as to whether the AER allowance for accommodating DER is efficient or not. While the AER draft decisions have basically accepted the capex proposals for AusNet and Jemena, they did not do so for CPPALUE. Implicit in the capex proposals were amounts to manage DER so the DER approach by AusNet and Jemena was basically accepted but not that by CPPALUE. This means that there is no clarity on what approach to DER will be accepted

In the draft decisions, AER references the outcome of the Value of Distributed Energy Resources (VaDER) report so that it can provide a common basis for assessing the benefits of the way each DB addresses the issue, and this is understandable. However, incorporation by the AER in its Final Decisions of the results of this study and of the cost benefit of the programs to test efficiency does not allow consumers to provide their input to that analysis.

This is a significant flaw in the AER draft decision.

It is recommended that rather than include a fixed revenue allowance for addressing DER in the Final Decisions, the AER should include in the Final Decisions a contingent amount that is to be refined when the cost benefit analyses can be prepared on a consistent basis and where all of the costs can be collated to compare to the assessed benefits and so determine the efficacy (or otherwise) of the proposed approaches.

2. Consumer Engagement

In its response to the initial proposals and the AER Issues Paper, the sponsors provided a view on each of the various Consumer Engagement approaches used by each of the DBs or groups of DBs, noting that

- AusNet used the NewReg process initiated by the AER, Energy Consumers Australia (ECA) and the Energy Networks Association (ENA),
- Jemena used a "Peoples Panel" approach and
- CitiPower, Powercor and United Energy (CPPALUE) used a range of engagement methods appropriate to the diversity of customers each of the DBs have.

The sponsors noted that all programs demonstrated benefits to customers, especially in terms of new or changed programs or processes developed in direct response to customer feedback. For Jemena and CPPCUE, this included energy literacy programs for vulnerable customers. The sponsors recommended that the AER should not conduct less extensive assessments of components of capex and opex in AusNet's proposal, and recommend the AER should subject all proposals with equal scrutiny.

Despite this recommendation, the AER has implied that they had greater confidence in the NewReg approach used by AusNet and as a result were prepared to accept the outcomes of the NewReg approach with less rigour than they appear to have applied to the proposals by the other four DBs. This is exemplified by the observation from AusNet in its revised proposal that

> "The AER found that our Initial Proposal was "*strongly and directly influenced by its consumers*" ; and "*clearly influenced by its commitment to consumer affordability*". Based on this and an assessment of our Initial Proposal against the requirements of the NER, the AER has largely accepted our proposed operating and capital expenditures. It found that were it not for the unforeseen changes in economic conditions due to COVID-19, it would likely have accepted our operating expenditure proposal."

This view is concerning as it is clear from statements from organisations representing larger consumers in AusNet's region[1] that they were dissatisfied with the extent of engagement by the Customer Forum with larger commercial and industrial energy users. This observation is supported by a review of the numbers of commercial (especially larger commercial) enterprises that the Customer Forum had contact with as it developed its recommendations and pursued its negotiations with AusNet in the final details in the AusNet proposal. The numbers of these C&I consumers were miniscule when seen in comparison with the much larger cohort of residential consumers contacted, despite the

[1] Such as by Major Energy Users and Energy Users Association of Australia

reality that C&I users use as much electricity as do residential consumers in AusNet's network.

In contrast, the AER assessments of the consumer engagement with the other four DBs is less supportive of the outcomes of that engagement as it was integrated into the initial proposals from the DBs.

This criticism of the NewReg process and the extent to which the AER has assumed the reasonableness of the AusNet initial proposal is not intended to deny that the Customer Forum did good work (in fact the outcomes indicate that it did achieve some positive outcomes for consumers) but to support a view that good consumer engagement should encompass all consumers and not focus on a certain sector to the detriment of others. While supportive of the development of the AER draft decision Table 7, it is clear that consumer engagement by the AusNet customer forum did not meet the requirements of "breadth and depth". Implicit in the Table 7 is a basic assumption that "consumers" is a homogeneous concept yet the reality is that there are many different cohorts of consumers in any network and for the Customer Forum to focus its attentions so greatly on one cohort to the exclusion of others implies that the outworkings of the Customer Forum and the AER reliance on these in its draft decision, leave much to be desired.

Further, because of this greater focus on one element of the consumer spectrum, the outcomes of the consumer engagement need to be assessed by the AER with equal rigour for all DBs, including AusNet rather than what it has done in essentially accepting the AusNet initial proposal did not require as much investigation as the AER applied to the other DBs.

Subsequent to the release of the AER draft decision, all DBs carried out further consumer engagement in an endeavour to gain input to their revised proposals. What is concerning about this further engagement is the extent to which this consumer engagement was successful and useful, noting that the time frames for this engagement were limited and therefore more likely to be influenced by the advice provided by the DBs on the limited numbers of issues that might be addressed.

With this in mind, there is little confidence that this late stage consumer engagement can be classified as being as reliable as that carried out earlier and therefore less weight should be attributed to it

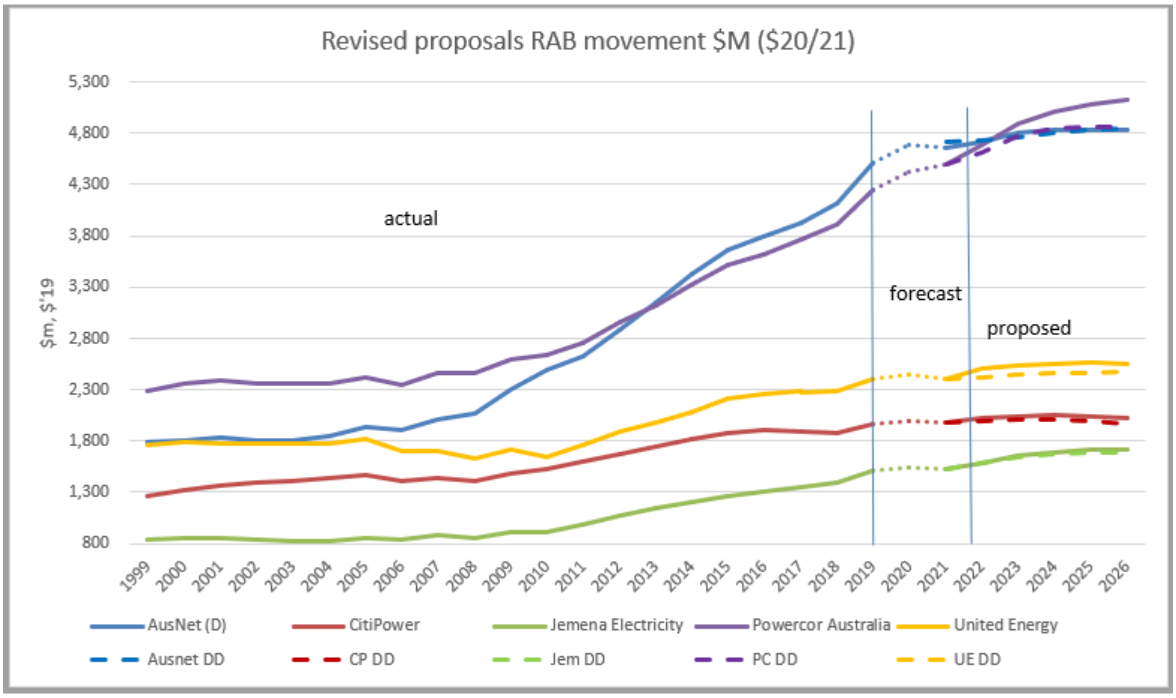
3. Regulatory Asset Base (RAB) and Benchmarking

3.1 Regulatory asset base (RAB)

The response to the initial proposals by the sponsors observed that benchmarking is a critical element of the regulatory bargain which the regulator uses as a means to reflect the benefits of competition on a firm that does not operate in a competitive environment, in order to drive the regulated firm to the point of greatest efficiency and hence the lowest costs for the firm's customers.

The AER draft decision effectively reinforces this observation and the AER does raise the issue of the ever-growing RABs for each of the DBs. With this in mind, the following chart (Figure 6) shows that despite the concern expressed, there is continuing growth in the RABs of all DBs.

Figure 6 Movement of real RAB over time

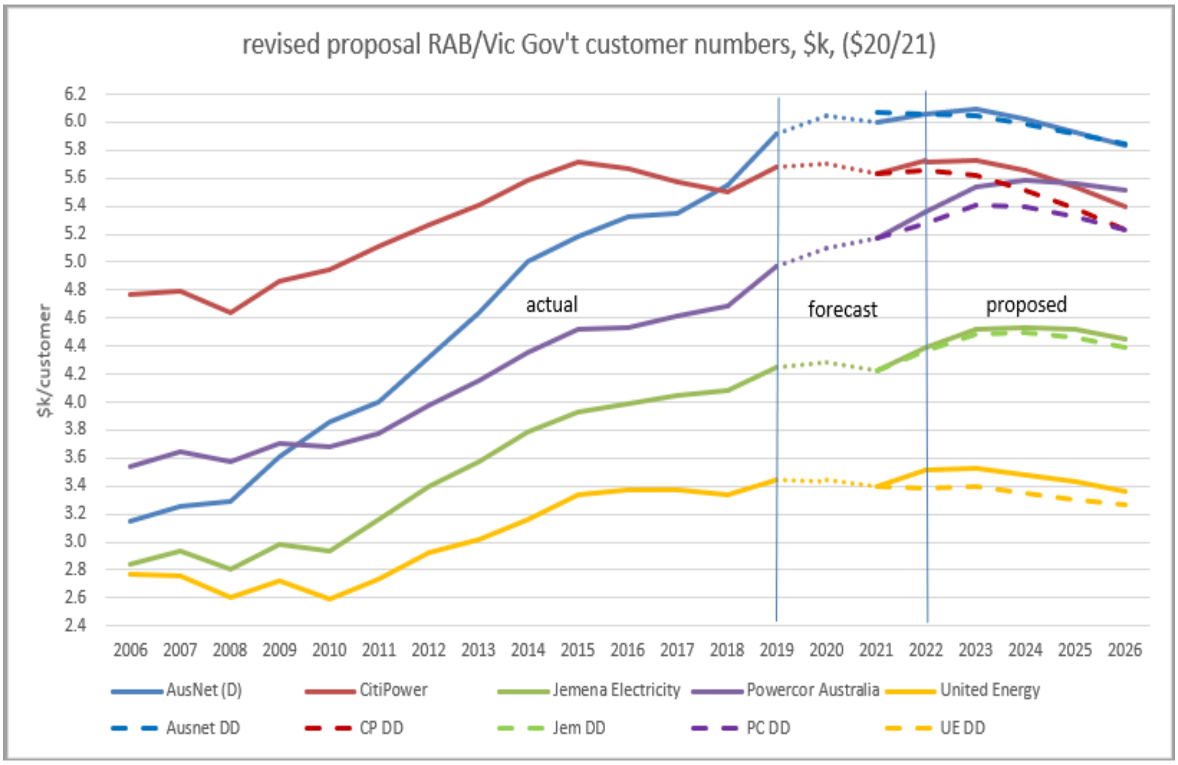


Source: AER Electricity Distribution Networks Performance data report 2006-2019, DB revised proposals, AER DD

While it might be expected that the RABs will grow over time reflecting increasing numbers of customers in each network, increasing amounts of energy efficiency tend to depress the growth in peak demand which tends to drive the size of the network. As shown in section 4 below, while there is growth in customer numbers, the growth in peak demand as forecast by AEMO is negative as is growth in consumption over the next period. In contrast, all of the DBs are forecasting increases in both of these two critical measures as well as in consumption.

The following chart (figure 7) shows the growth in RAB (from both the draft decision and the revised proposals) relative to customer numbers based on the Victorian government forecast population growth figures included in its 2020/21 budget released in December 2020.

Figure 7 Movement of real RAB/customer over time



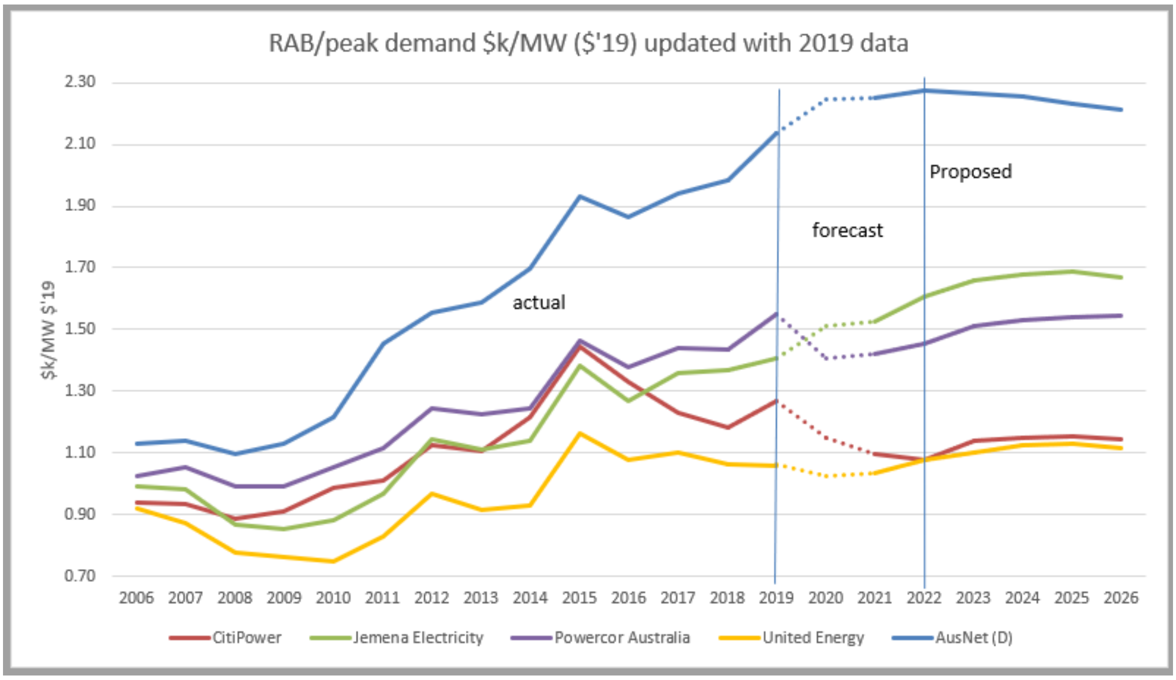
Source: AER Electricity Distribution Networks Performance data report 2006-2018, DB proposals, AER DD, revised proposals

This chart shows that while most DBs are "topping out" in terms of RAB/customer, AusNet, CitiPower and United show an actual reduction from 2019 levels in this important measure whereas Powercor and Jemena show a continuation in growth in the measure. This is concerning. It is pointed out that the measure does not seek to benchmark each DB against the others, but against itself over the long term and, at a fundamental level, RAB per customer should have shown a long-term reduction reflecting the outcomes of energy efficiency and cost pressures, returning to be closer to the values of earlier years.

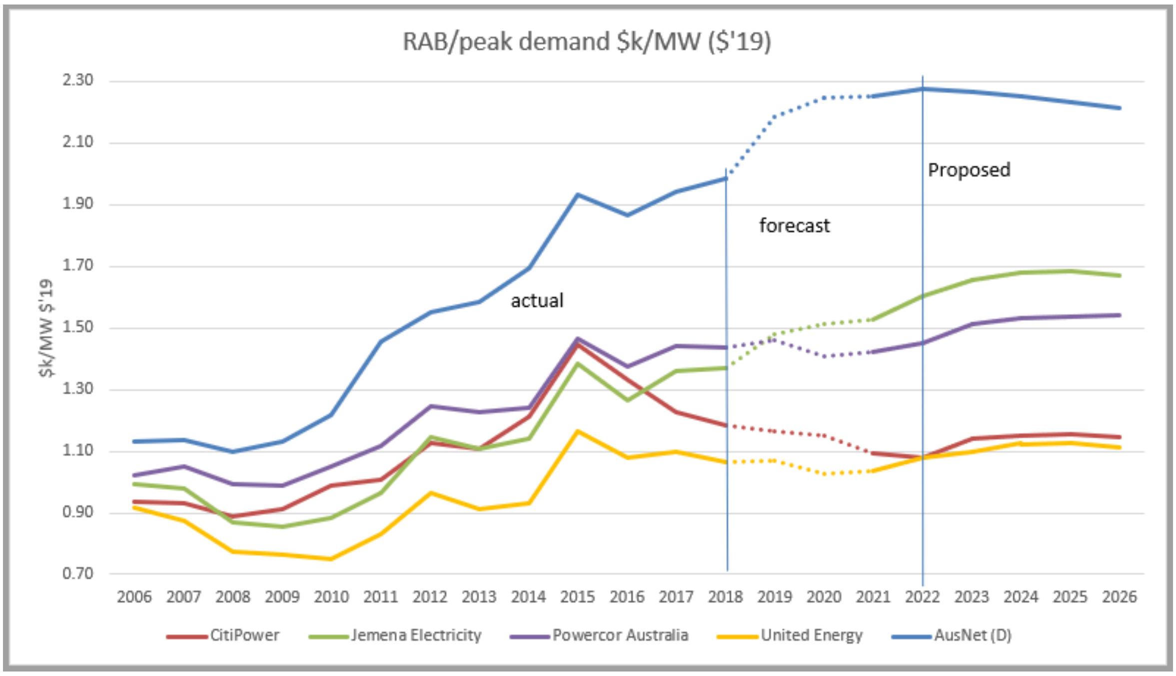
However, RAB is probably more related to peak demand and possibly consumption and the sponsors provided a view in their response to the initial proposals that the DBs had significantly overstated forecast peak demand and consumption compared to the AEMO forecasts. This is explained more fully in section 4 below but, at a high level, there is significant concern at the difference between AEMO forecasts for peak demand and the aggregation of all the DB forecasts for peak demand.

The following two charts (figure 8) update the movement in real RAB provided in the initial proposals relative to the peak demand provided by the DBs. The lower chart was provided by the sponsors to the initial proposals and the upper chart adjusts the same chart to include the actual 2019 data. What is concerning is that the actual 2019 data shows higher values of RAB/peak demand than was forecast by each of the DBs.

Figure 8 Movement of real RAB/peak demand over time



Source: AER Electricity Distribution Networks Performance data report 2006-2019, DB proposals,



Source: AER Electricity Distribution Networks Performance data report 2006-2018, DB proposals,

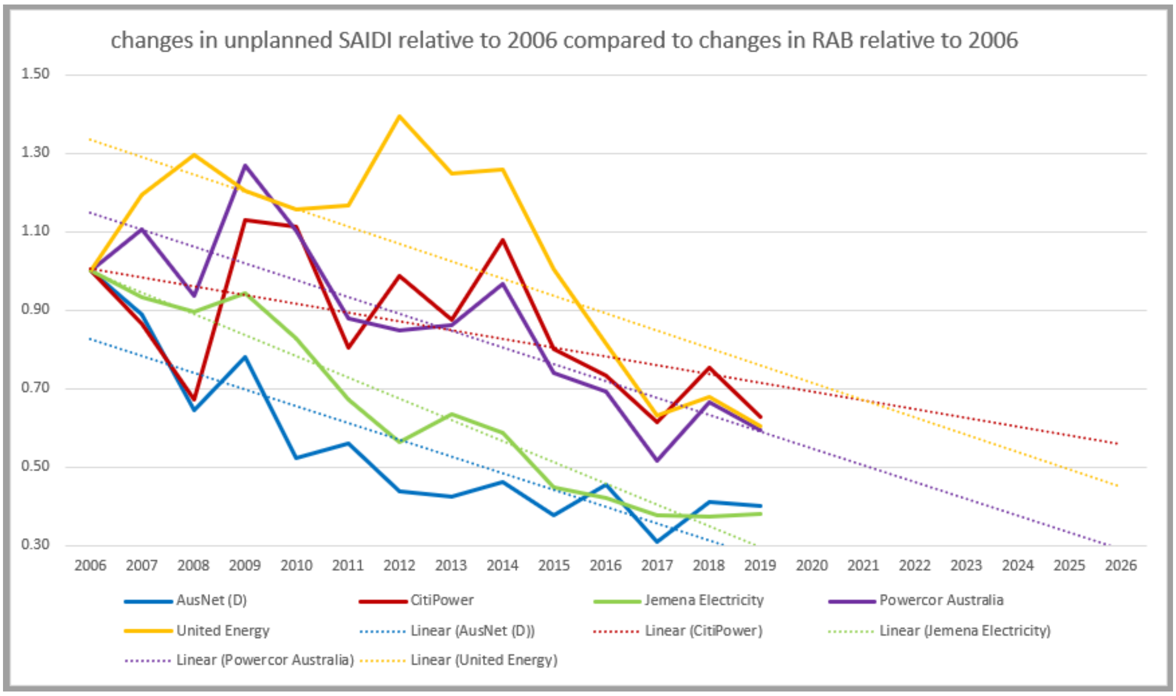
This comparative analysis highlights two key aspects – that the DB forecasts of peak demand tend to be higher than actually occurs and that the key measure of RAB/peak demand remains an issue of concern when assessing new capex.

In section 1 above, reliability improvement was identified across all networks while at the same time, there was seen a reduction in utilisation of assets. In their response to the initial proposals, the sponsors assessed the changes in the RAB since 2006 relative to changes in reliability (in terms of SAIDI) and utilisation.

When these charts are updated with 2019 data, the trends for both show a continuation of the trends identified by the sponsors – that while:

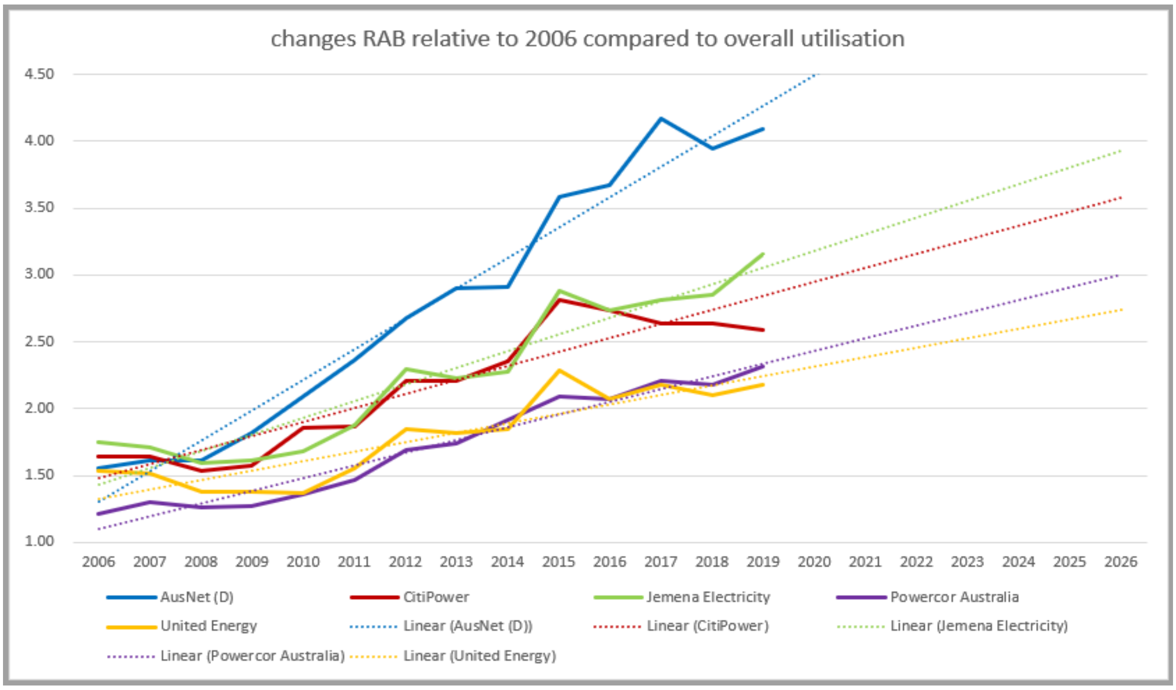
- reliability has slightly improved over time, the cost to consumers in terms of RAB growth has been excessive (figure 9) reinforcing the view that DBs have continued to improve reliability and so earn a Service Performance Target Incentive Scheme (STPIS) bonus through capex paid for by consumers.
- utilisation has declined over time, the impact of the RAB growth has been even greater causing consumers to pay more for assets that are used less (figure 10).

Figure 9 Movement of reliability relative of real RAB over time



Source: AER Electricity Distribution Networks Performance data report 2006-2019, DB proposals, sponsor analysis

Figure 10 Movement of real RAB over time relative to utilisation



Source: AER Electricity Distribution Networks Performance data report 2006-2019, DB proposals, sponsor analysis

In its response to the initial proposals, the sponsors observed that this continued growth in RAB in real and relative terms was imposing significant costs on current and future consumers and that the AER needed to ensure that this growth in the RAB through large amounts of capex needed to be addressed.

It is noted that the AER would have appeared to have addressed this concern about the growth of the RAB in its assessments of capex. This is pleasing but equally, it is observed that the DBs in their revised proposals have not considered that the growth in RAB needs to be addressed to the same extent that the AER, as:

- AusNet, considers that despite "largely accepting" the AER reduction of $90m decision this capex is too low and that $79 m of this reduction needs to be replaced
- CitiPower considers that the AER erred in its capex assessment in reducing capex by $232 m and while agreeing to some the reduction, $66 m more than the AER assessment was needed
- Jemena seeks an additional $24 m (back to its initial proposal)
- Powercor considers that the AER erred in its capex assessment by reducing capex by $582 m and while accepting about half of the reduction, $263 m more than the AER assessment was needed
- United considers that the AER erred in its capex assessment by reducing capex by $291 m and while accepting much of the reduction, $110 m more than the AER assessment was needed

It is clear that any capex more than the AER draft decision will exacerbate the reality that the RABs have grown too large and that steps are needed to ensure that the RABs start to return to the levels seen in the first decade of the NEM.

3.2 Network productivity

The other critical benchmarking that the AER has implemented as part of its "Better Regulation" program is the benchmarking of operating expenses (opex) and capital investment (capex). Both of these measures are addressed through partial factor productivity measures and calculated annually[2] by Economic Insights for the AER based on data provided by the networks in their annual Regulatory Information Notices (RINs) data.

The productivity measures developed by the AER (with the assistance of their consultant Economics Insights) are examined on a number of bases, with significant attention given to the averages of productivity over time and various techniques are employed to assess these. While it is accepted that long term averages do have a role to play in the assessment of productivity, it is considered that trends in productivity changes are just, if not more, important.

The following assessments look more at the trends and from these draw quite important conclusions. This approach was used by the sponsors in their response to the initial proposals and those assessments are re-examined using updated data.

3.2.1 Capital productivity

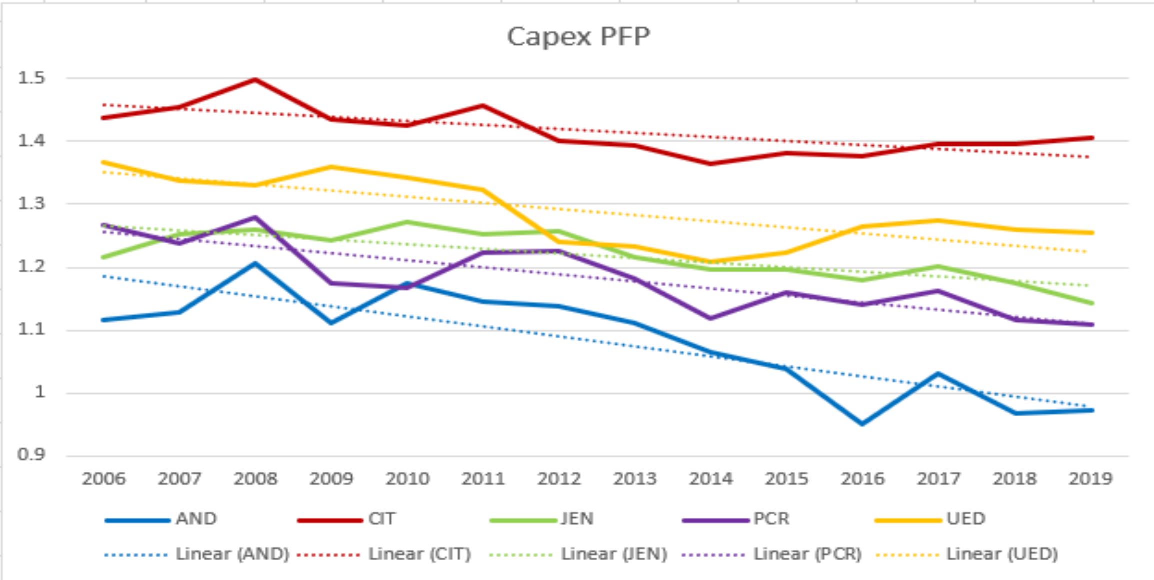
In its latest benchmarking report (2020 DNSP Annual Bench Marking Report released 13 October 2020) Economic Insights provides the capital partial factor productivity (PFP) data for each of the DBs in the NEM including that five Victorian DBs.

The following chart (figure 11) provides the capital productivity of the five Victorian DBs and what it shows, is reflective of the assessment of the data in section 3.1 about RAB growth. The capital productivity of the five DBs is falling, albeit at different rates, in counterpoint to the continuing growth of the RAB – this is despite the introduction of the capital incentive scheme

[2] Economic Insights, which generates these PFP values, notes that there are some changes to the weightings and these result in changes to previous values.

While the 2019 data shows that capital productivity improved in 2019 for CitiPower, its long-term trend continues to be downward. All other DBs exhibited a continuing downward trend in their 2019 data.

Figure 11 Capital Partial Factor Productivity



Source: AER benchmarking report 2020 and Economic Insights report 2020

While it is accepted that each of the DBs is a little different in its physical arrangements and its customer mix and therefore strong comparisons between the DBs might be considered weaker than might be expected, the clear outturn of this chart is that the capital performance of all DBs is worsening over time when comparing each to its own earlier performance.

3.2.2 Opex productivity

The most commonly used productivity analysis is that of the operating expense. The AER has implemented an incentive scheme that provides networks with a bonus if they reduce their opex. The presence of an incentive scheme leads to an AER assumption that the DBs are all driving their opex to the efficient frontier. Based on this assumption, the AER accepts the opex from the most recent full year is "efficient" and can be used as the basis for opex in the next regulatory period, after adjustment for growth in the network.

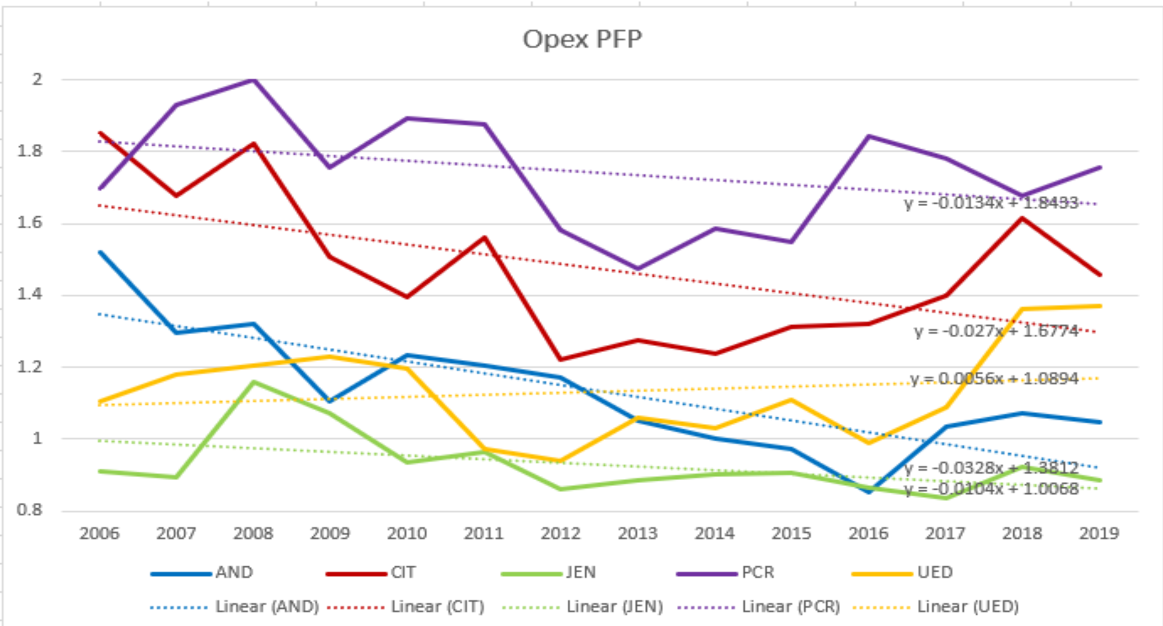
The most recent assessment of productivity measures[3] includes for the opex for years 2006 to 2019. It is recognised that opex partial factor productivity will vary on an annual basis

[3] Economics Insights "Economic Benchmarking Results for Australian Energy Regulator's 2020 DNSP Annual Benchmarking Report 16 October 2020

and that the input data[4] used in the generation of the opex productivity causes this annual movement, as well as the actual opex used by each DB. This means that it is most clearly the long-term trend that is critical in assessing the opex productivity rather than any specific year value which may be impacted by unique aspects in that year or averages over time. Despite this annual variation, the AER continues to view the most recent actual annual opex as the starting point for assessing the future opex allowance.

The Economic Insights report provides an examination of the productivity of each of the NEM DBs through a number of different approaches but most of these examine average productivity over the entire 14-year period (or over a shorter period), whereas the partial factor productivity measure provides a trend over this time period. This trend in opex PFP is a better gauge of the impact of incentives to improve productivity and the following chart (figure 12 complete with data to analyse the slope of the trend line) is drawn from the Economics Insights 2020 report.

Figure 12 Opex partial factor productivity



Source: AER benchmarking report 2020 and Economic Insights report 2020

What this analysis highlights is that, despite a recent upturn in opex PFP seen for some DBs in the 2015 to 2017 period, the longer-term trend for opex PFP of all the DBs but United, has been downward over the past 14 years.

That opex partial factor productivity generally shows a long-term downward trend implies that the opex incentive scheme is not achieving what true competition to the network firms

[4] The productivity data uses as outputs the minutes off supply, amount of energy transferred, customer numbers, peak demand, and circuit length which can all move in different proportions each year and uses as inputs the actual opex and overhead and underground subtransmission and distribution lines and transformers and other capital assets which also vary on an annual basis.

would deliver to consumers. This then questions whether the use of the latest year actual opex is an appropriate starting point to set the opex for the next regulatory period. This issue is addressed in more detail in section 7 below but it is noted that recently, the AER has introduced a requirement for increasing opex efficiency by imposing a set opex productivity adjustment of 0.5% pa improvement into the opex forecast. But of concern is that the downward slopes of the long-term trends lines are between -1% and -2.7% (except for United which has a slight upward long term trend) so the imposed 0.5% productivity improvement requirement will not address the reality that most DBs are becoming less efficient in their opex.

3.3 Conclusions

Assessing the growth in the RAB and the benchmarking of capex productivity shows that previous capex has been inefficient and is causing the RAB to grow beyond of what might be considered to be efficient.

This assessment of the RAB growth reinforces (in real and relative terms) that consumers are paying more for the same outcome that they received in the earlier years of the NEM and that action is needed to address this. It is necessary that the DBs and the AER recognise that continuing growth in the RAB is of great concern and that the trends indicate that the AER approaches to address this so far have not been sufficient.

The benchmarking of opex also leads to the conclusion that opex is greater than is probably needed. While the imposition of productivity expectation will move to minimise the downward trend, the productivity improvement requirement will not offset the long-term downward trend seen for most of the DBs.

4. Forecasting – customer numbers, peak energy demands, and total energy to be distributed

Forecasts of customer numbers, peak demand and total energy transferred have a major influence on both the quantum of opex and capex but also the cost to each consumer through the tariffs structured and the allocation of these costs to each customer.

It is pointed put that the impact of the COVID-19 pandemic has been seen to be very wide and deep across the whole of the nation, but particularly so in Victoria due to the "second wave"[5] which severely exacerbated the effects seen nationally. As a result, a detailed review of the impacts is required, especially of customer number increases forecast by the DBs, forecast peak demands and total consumption.

What is also important, is that new forecasts will exhibit considerable uncertainty (especially in the short to medium terms) due to impacts that are yet to be fully understood and the emergence, availability and timing of a reliable vaccine. While there has already been exhibited some rebound in economic terms across the nation (but to a much lesser extent in Victoria), it is unknown the extent of the impact of the reduction and elimination of the JobKeeper and JobSeeker subsidies will have over 2021 and into 2022.

The charts used by the sponsors for the response to the initial proposals have been updated to include 2019 data which generally is lower than that forecast by the DBs. Further, the data has also been updated to reflect data from later sources such as the Victorian government budget forecasts for population growth and the data inherent in the AEMO 2020 Electricity Statement of opportunities.

4.1 Customer numbers

Assessment of customer numbers has a significant influence on a number aspects of the assessment of proposals from the DBs, including on the numbers of new connection costs, assessment of peak demands (and hence augmentation capex), developing growth elements on opex, and assistance in identifying the X factor in the CPI-X annual revenue adjustment.

While the AER addresses the issue of customer growth in the AusNet draft decision in relation to the development of the annual X adjustment factor, it does less so in the draft decisions for the other DBs.

The AER has accepted the forecasts of new connections provided by AusNet, CitiPower and Jemena and then applied a "COVID-19 discount" to the forecasts. For Powercor and United,

[5] There also might be a "third wave" based on recent NSW outbreaks which are already flowing to other states, particularly Victoria

the AER was more aggressive in its assessment by not only reducing forecast numbers but also then applying the "COVID-19" discount.

The AER approach to its assessment has some flaws in that it uses averages of historical data for the numbers of new connections. While such an approach has merit in terms of the cost of these new connections (adjusted for inflation), short term averages can exhibit significant variation in both directions. Longer term historical data in terms of numbers is more likely to provide a better guide to the numbers of new connections than data based only on the period since a new connections policy change was introduced[6].

It is concerning that the AER has not assessed the raw data on new connections in its own right, rather than by assessing the impacts of customer number growth on different elements affected by such change.

While the AER has based its new customer growth assessment on a number of bases (assessment of pre COVID-19 to post COVID-19 growth coupled to HIA forecasts made in April) a more robust approach to estimating new connection growth is needed.

The Commonwealth government has released its budget for 2020/21 as has the Victorian government released its budget for 2020/21. Included in both sets of budget papers is a forecast of Victorian population growth.

The Victorian budget assumes that the population growth will be as table 2.1 in the Budget papers and these forecasts are replicated in the Australian Government Centre for Population publication "Population Statement" released in December 2020.[7]

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[6] The proportion of the allocation of costs would be influenced by the change in connections policy but not the raw numbers of new connections

[7] Available at https://population.gov.au/publications/publications-population-statement.html

Table 2.1: Victorian economic forecasts [(a)] (per cent)

	2018-19 actual	2019-20 forecast	2020-21 forecast	2021-22 forecast	2022-23 projection	2023-24 projection
Real gross state product	3.0	–0.25	–4.00	7.75	3.25	3.00
Employment	3.4	1.2 [(b)]	–3.25	3.50	2.25	2.00
Unemployment rate [(c)]	4.6	5.4 [(b)]	7.75	7.00	6.25	5.75
Consumer price index [(d)]	1.7	1.7 [(b)]	0.75	1.50	1.75	2.00
Wage price index [(e)]	2.7	2.4 [(b)]	1.00	1.75	2.00	2.25
Population [(f)]	2.1	1.60	0.20	0.40	1.10	1.70

Sources: Australian Bureau of Statistics; Department of Treasury and Finance

Notes:

(a) Percentage change in year average terms compared with the previous year, except for the unemployment rate (see note (c)) and population (see note (f)). Forecasts are rounded to the nearest 0.25 percentage points, except for population (see note (f)).
The key assumptions underlying the economic forecasts include interest rates that follow movements in market expectations; an Australian dollar trade-weighted index of 61.7; and oil prices that follow the path suggested by oil futures.

(b) Actuals.

(c) Year average.

(d) Melbourne consumer price index.

(e) Wage price index, Victoria (based on total hourly rates of pay, excluding bonuses).

(f) Percentage change over the year to 30 June. Forecasts are rounded to the nearest 0.1 percentage point.

While the data provides an assessment to 2024, it expected towards the end of the next period the COVID-19 impact will have been well managed so the last two years of the regulatory period would probably see a reversion to the longer-term population growth forecast by the government of 1.7 to 1.8% (eg see budget papers for 2016/17).

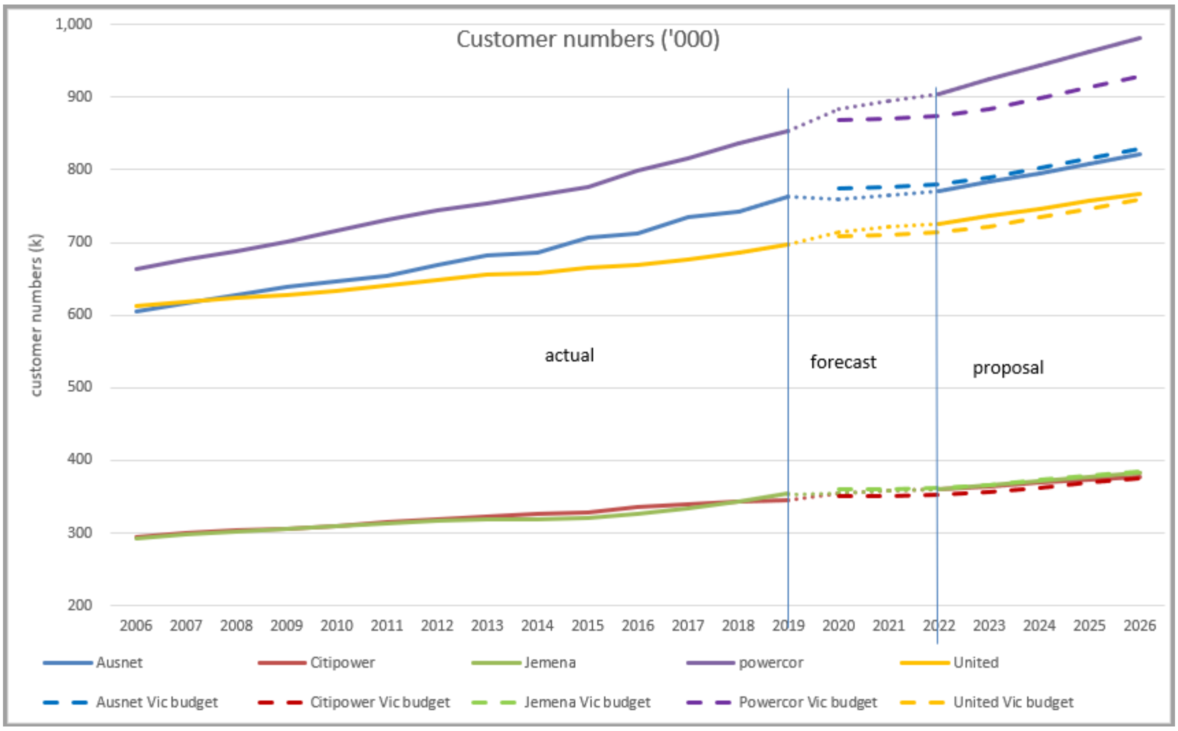
The forecast population growth reflects an expectation that probably overstates the growth in new connections due to the slower take up of new businesses after the COVID-19 pandemic and declining fertility and immigration. With this in mind, the government forecast population growth is more likely to err on the high side.

It is recognised that Victorian government population forecasts would primarily impact residential new connections (as HIA forecasts do) so there needs to be a separate assessment related to new commercial and industrial connections and these will be more related to government stimulus and overall growth in the economy. The Victorian economy has taken a significant "hit" as a result of the COVID-19 impacts and therefore there is significant negative growth forecast in gross state product. While the Victorian government has announced significant investment activities, the Federal government is less prepared to continue their stimulus (especially the JobKeeper and JobSeeker payments) so this will tend to reduce the value of the Victorian Government stimulus activities. The budget forecast implies that overall Victorian economic growth over the next regulatory period will be half what might have otherwise been expected – this will have a significant impact on new connections for business.

The AER has not committed to any customer numbers in its draft decision but uses a "COVID-19" adjustment to HIA forecasts which were made before April 2020. As Victoria exhibited a significant second wave in the pandemic, there is considerable concern that the HIA plus AER adjustment is still a valid forecast. As the AER has stated that it will provide an update with its Final Decisions, this means that stakeholders will not be able to comment on what the AER finally settles on in terms of customer numbers but there is concern that the AER will have a preference to use a forecast from an entity which might be self-serving, such as a HIA forecast seeking to embellish housing starts after the pandemic slow down.

Based on the Victorian government forecast growth in population (backed up by the Federal government forecasts) made subsequent to the COVID-19 second wave (and potential third wave), it is clear that the forecasts by the DBs in their initial proposals (and possibly in the AER draft decision) on future customers numbers will be high. This is shown in the following chart (figure 14) which shows the customer numbers included in the initial proposals along with adjusted forecasts based on the Victorian government November 2020 budget population forecasts.

Figure 14 Network customer numbers



Source: AER Electricity Distribution Networks Performance data report 2006-2019, DB proposals, Vic gov't budget papers

Whilst the adjusted growth in customer numbers reasonably follows the historical trends for AusNet, CitiPower and Jemena, the adjusted growth forecasts for Powercor and United still show a distinct upward trend from levels in the 2018 to 2020 period, but a reduced increase in numbers over the next regulatory period.

As there is some doubt as to how accurate the forecast customer numbers are and as the issue of customer numbers is critical to the setting of a number of the core expenditure elements, the AER needs to carry out an in-depth assessment based on independent data to assess the most likely scenario for customer growth.

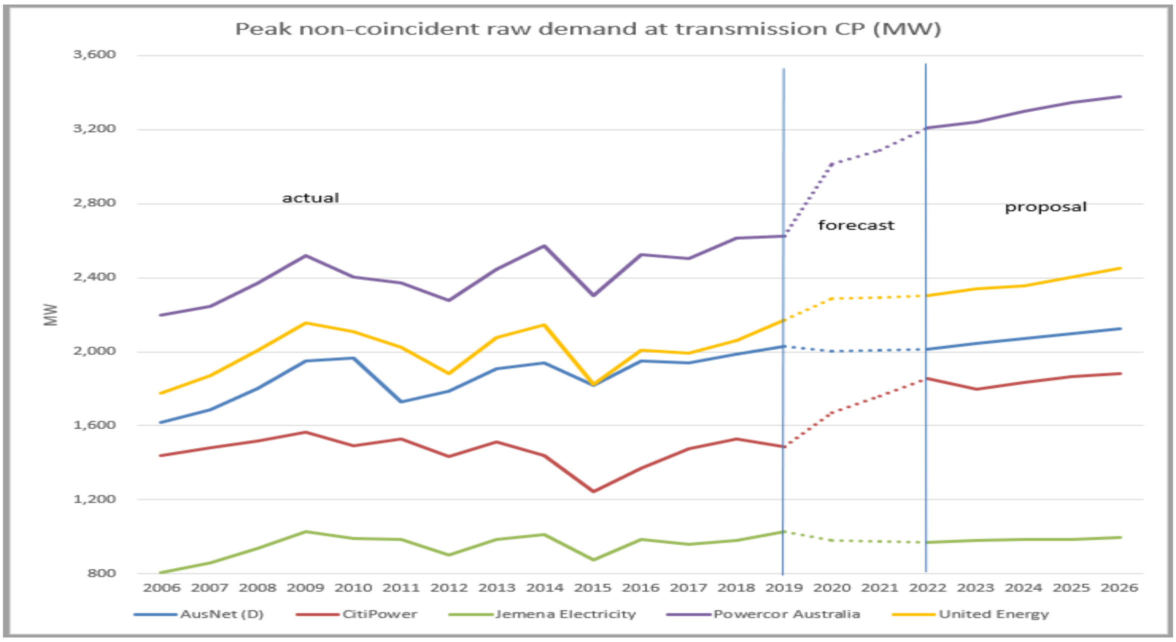
In the context of COVID-19, this assessment will become critical.

4.2 Peak demand

Peak demand is historically the driver of new augex and the increased capacity of the networks to manage the growth in demand. The following chart (figure 15) tracks the growth in non-coincident peak demand at the transmission connection points in each network showing actuals to 2019 and the DB forecasts. This chart was provided by the sponsors in their response to the initial proposals but has been updated with 2019 data.

To contrast the DB forecasts, the sponsors noted that the AEMO 2019 ESoO showed effectively a reduction in peak demand in Victoria raising real concerns about the DB forecasts of the peak demand increases which they use to justify the increases in some capex.

Figure 15 Peak non-coincident raw demand

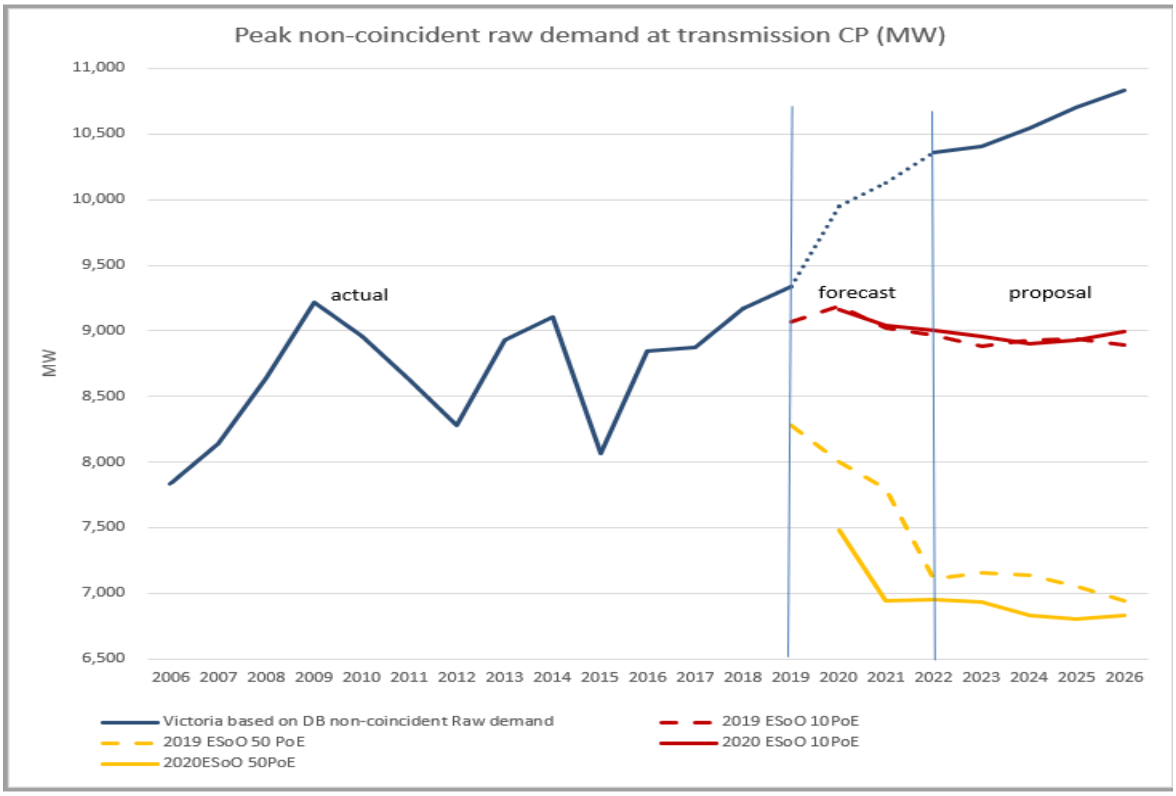


Source: DB RIN data, DB proposals

This updated chart shows that peak demands in 2019 barely changing over those seen in the previous two years.

In contrast, the following chart (figure 16) shows the AEMO Electricity Statements of Opportunities (ESoO) 2019 and 2020 view of the regional demand for Victoria (at 10% PoE and 50% PoE) over the next regulatory period, and beyond, combined with the aggregate of the 5 DBs non-coincident raw demand.

Figure 16 Aggregated peak demand



Source: DB RIN data, DB proposals, 2018, 2019 and 2020 ESoO central scenario

Note 1. As the AEMO forecasts also include for the direct connected demand such as Portland smelter and BlueScope Westernport which do not flow through the distribution networks, the AEMO forecast traces have been reduced by 700 MW to reflect the absence of this demand in the distribution networks.

The DBs consider the AEMO forecasts do not reflect the realities the DBs face and that AEMO has underestimated the peak demand. In this regard, it is pointed out that over the life of the NEM, AEMO has forecast peak demands for Victoria (10% PoE) that have never eventuated and that, in only a few cases, has AEMO 50% PoE for Victoria been exceeded. As AEMO forecasts of 10% PoE have never been exceeded in Victoria it implies that AEMO forecasts for Victoria might also be overstated.

The AER has expressed a view that the AEMO forecasts of peak demand are more reliable than those prepared by the DBs and their consultants, and this assessment is supported. However, it is pointed out that the AEMO 2020 ESoO was developed early during the Victorian COVID second wave and therefore may also be overstated, especially in the early years.

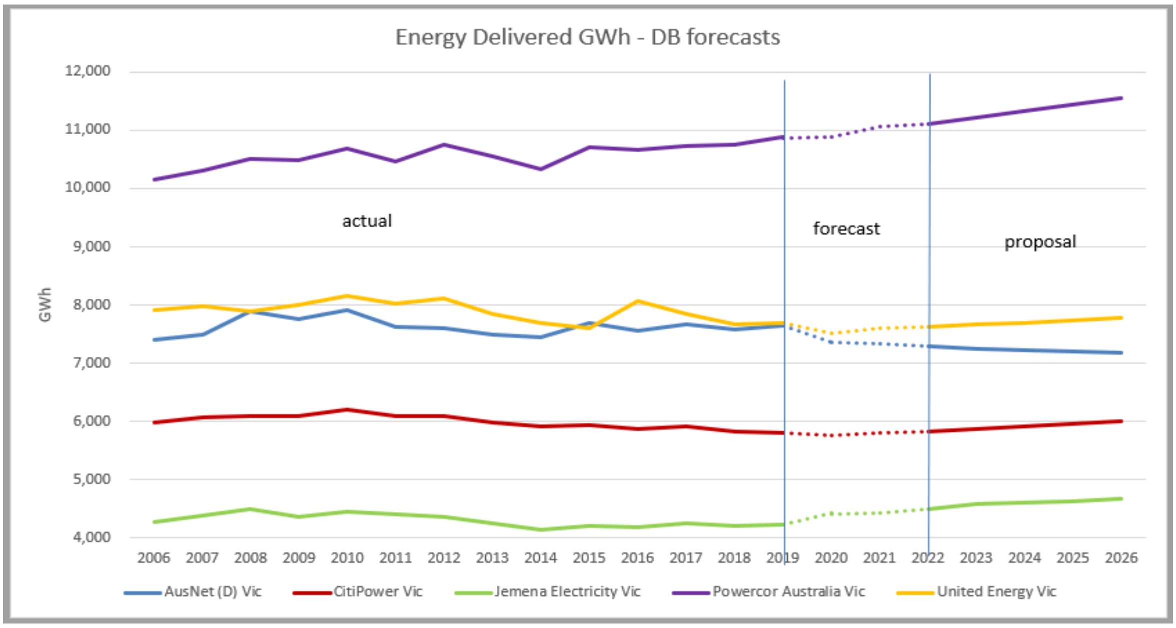
This analysis shows that the DB proposals in aggregate do not reflect the AEMO forecasts for the Victorian regional demand by a significant margin when compared to the 10% PoE central scenario and by a massive differential when compared to the 50% PoE central scenario, even when excluding the concerns stakeholders had expressed generally about the AEMO 2019 ESoO and particularly about the Victorian forecasts. This raises considerable doubt about the accuracy of the DB forecasts for peak demand and therefore the assumptions they have made about the capex for growth.

4.3 Energy consumed

While the amounts of energy consumed do not directly impact the amount of revenue that the AER will allow the DBs, they do have an impact on the assessment **by consumers** of the significance of the proposals, given their implications for tariffs recognising that the higher the forecasts for energy consumed, the lower the apparent tariffs being generated, leading to an assumption that increases in revenue might be more acceptable.

With this in mind, the forecast energy consumption proposed by the DBs is shown in the following chart (figure 17).

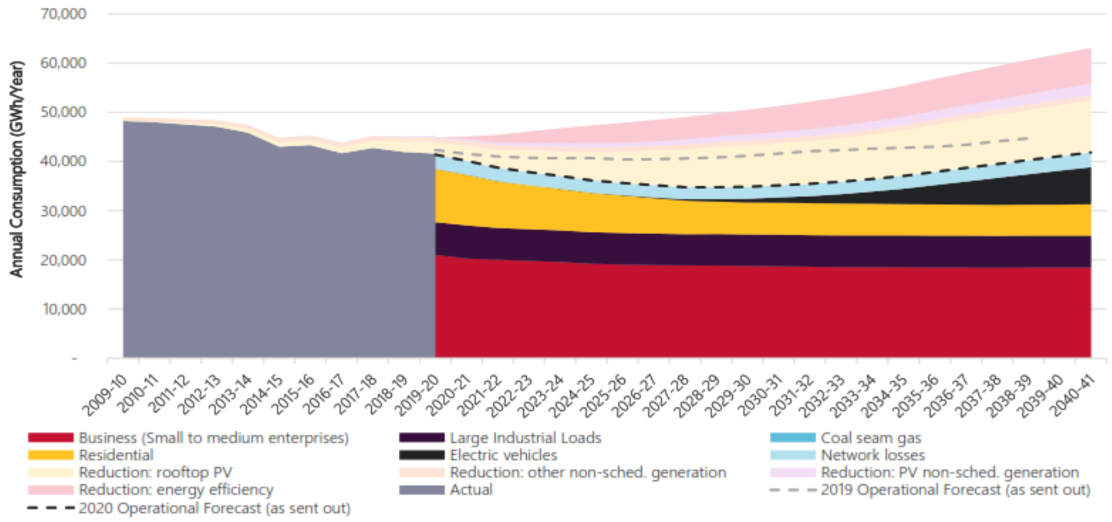
Figure 17 Energy delivered



Source: AER Electricity Distribution Networks Performance data report 2006-2019, DB proposals

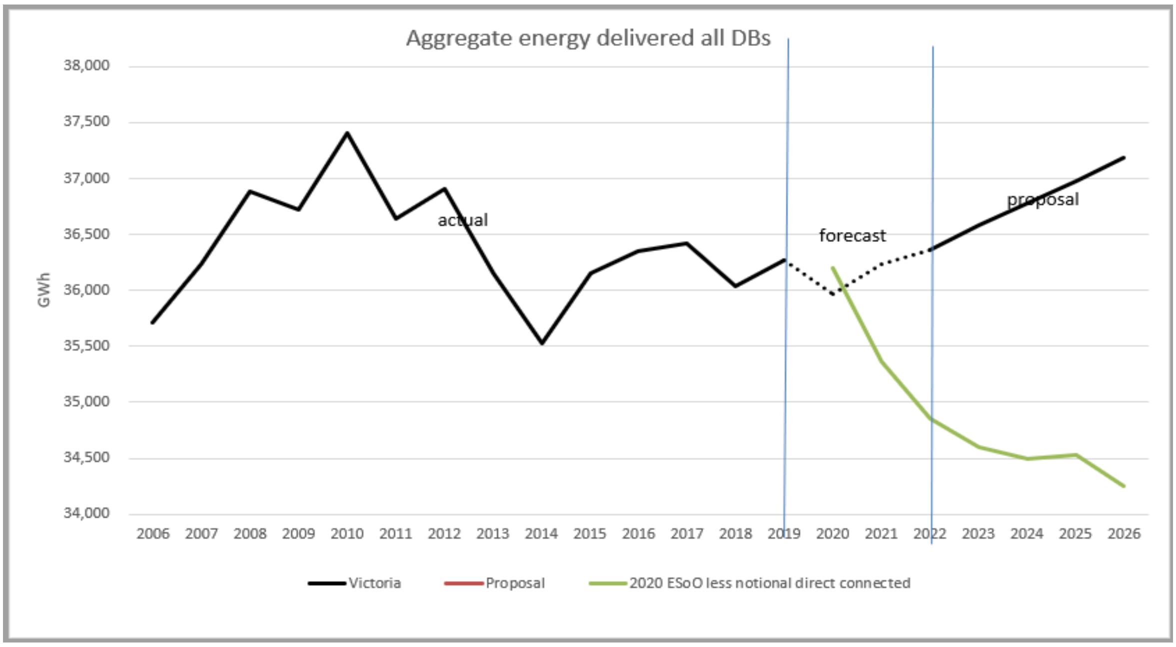
This shows that all DBs except AusNet are forecasting increasing amounts of energy to be delivered to their customers despite the reality that consumption has been essentially flat for the past 4-5 years. This is seemingly inconsistent with the generally accepted view that since the early part of this decade energy demand is either static with time or falling. This declining consumption is shown as figure 57 in in AEMO's 2020 ESoO.

Figure 57 Victoria operational consumption in MWh, actual and forecast, 2009-10 to 2039-40



In aggregate, the DBs are forecasting a significant increase in energy delivered yet the trendline for the actual amounts of energy delivered and the AEMO forecast supports the view that forecast energy consumption is falling. Figure 18 shows the aggregate of the DB forecasts along with AEMO's forecasts for the same period based on the AEMO 2020 ESoO forecast energy consumption across Victoria.

Figure 18 Aggregated energy delivered



Source: AER Electricity Distribution Networks Performance data report 2006-2019, DB proposals, 2020 ESoO

The AEMO data has been discounted for the expected consumption by the transmission direct connected end users (Alcoa Portland and BlueScope Steel Westernport).

The chart highlights that the DBs' views on consumption are at odds with both AEMO and the historic trends.

4.4 Conclusions

This analysis indicates that lower levels of capex than the AER draft decision provides, are needed to reverse the past trend to increase capex at each reset and so lead to an ever increasing RAB which has imposed unnecessary costs onto current and future consumers. The revised proposals by the DBs to seek higher capex than the AER draft decision is concerning and would not appear to be warranted but on the drivers for investment.

5. Depreciation

In its draft decision the AER effectively discounted the sponsors' view that there needs to be greater consistency across the depreciation schedules used by the different DBs. The AER comments (for example in attachment 4 to the CitiPower draft decision page 4-16) but repeated in the other decisions:

> "We encourage consistency in asset lives for similar assets. However, differences can appear to emerge when assets are aggregated into asset classes."

While the comment is correct in some limited respects, there are considerable parts of every Victorian DB asset base where the assets are quite common and should have a common rate of depreciation. In its response to the initial proposals the sponsors gave clear examples where large parts of the DB asset bases have common assets and which are described in the same way yet are depreciated in quite different and significant ways. Specifically, the sponsors gave examples of:

- the asset life for a concrete power pole advised by AusNet is 100 years, United a life of 70 years but CitiPower, Jemena and Powercor consider its life is 36-39 years whereas Jemena considers a concrete pole has a life of 37 years, much the same life as their wood poles
- Overhead cables in AusNet, CitiPower and United area have a life of ~60 years but in Powercor and Jemena area have a life of ~40 years
- Underground cables in AusNet have a shorter life than overhead cables but the reverse applies in CitiPower

These differences are quite significant and the assets are quite clearly identified. For the AER to assert that:

> "…differences can appear to emerge when assets are aggregated into asset classes"

is dissembling as the bulk of the assets the DBs have is overhead lines on poles and substations. There is no reason why the bulk of the DB assets could not be brought to a common depreciation schedule. The sponsors pointed out that even with the aggregated subgroups there were significant variation and this is related back to the variances in depreciation for each specific category.

The AER further comments:

> "The depreciation schedules have evolved over time. In certain aspects they are a carryover from the previous jurisdictional arrangements in Victoria."

is again a little dissembling. The bulk of the assets were inherited from the State Electricity Commission of Victoria (SECV) which had a common depreciation schedule. What occurred subsequent to the dissolution of the SECV and the creation of the five DBs was that the DBs themselves decided on their own depreciation rates and over time they have further changed these.

To exemplify its decision not to adjust the depreciation schedule rates, the AER draws on one relatively small asset class where its assertion has some validity but then fails to recognise that this example does not address the much larger elements of the asset base where there is significant commonality between the DBs.

The AER concludes that:

> "We consider the depreciation schedules across the Victorian distributors are comparable to each other and to the repex assessment when these differences are recognised."

This assertion is not really supported by the DB depreciation schedules, nor of the DB expected lives of the assets they provide. That the repex assessment might look at the useful or engineering lives of the assets and address the differences is not the issue for depreciation but an issue of cost impact as these different depreciation rates between DBs have a significant impact on the costs current consumers incur, the values of the RABs for each DB and the costs future consumers will have to carry.

It is recommended that the AER reconsider its decision not to address these anomalies.

5.1 Accelerated depreciation

In their submission to the initial proposals, the sponsors noted that each of the DBs proposed accelerated deprecation for some of their assets and that the AER had previously allowed accelerated depreciation under some limited circumstances.

The sponsors expressed concern that the changes would increase costs.

Four of the DBs sought approval to accelerate depreciation and the AER made different decision regarding each.

5.1.1 AusNet

AusNet proposed that it should exclude some SCADA/Network control assets which have to date been treated as subtransmission and distribution assets and depreciated over the life of the longer-lived assets that constitute this class. The AER has effectively agreed to this occurring so that these assets will be depreciated to match their engineering lives. This change is concerning when this acceptance by the AER is seen in context with its views expressed in response to the sponsors concerns, that the asset classes are so broad that it is acceptable to allow different DBs to have different depreciation schedules and differences appear when assets are aggregated.

If AusNet's aggregated depreciation schedules reflect the actual mix of the assets that are included for each classification if some assets are removed (as proposed by AusNet) then this means the depreciation life of the asset class (after removing the faster depreciating assets) should be increased, so that the average depreciation is the same before and after the change.

AusNet is also proposing to transfer leasing costs from opex to capex. If this change is related to new accounting standards then it is probably acceptable.

5.1.2 CitiPower

The sponsors provided a view that the transformers to be replaced due to solar enablement can be redeployed and so should not be immediately depreciated. It is noted that this observation has been implemented by the AER in its draft decision and that CitiPower appears to have accepted this.

5.1.3 Powercor

The sponsors provided a view that much of the accelerated depreciation proposed by Powercor should not be allowed. It is noted that the AER draft decision does exclude much of this accelerated depreciation and that Powercor appears to have accepted this decision.

5.1.4 United

The sponsors provided a view that the transformers to be replaced due to solar enablement can be redeployed and so should not be immediately depreciated. It is noted that this observation has been implemented by the AER in its draft decision and that United appears to have accepted this.

6. Proposed capital expenditure (capex)

An integral part of a regulatory reset is the regulator's allowance for new investment to be added to the Regulatory Asset Base (RAB). Under the electricity market rules, the AER is required to permit the DBs a certain amount of capex to be allowed and for this to be added to the RAB as part of the "roll forward" of the RAB. At the end of the regulatory period, the RAB is adjusted for actual investments and under some very specific circumstances for the actual capex to be reduced.

The capex allowance development is much more subjective than the development of the opex allowance where the process is more clearly defined and based on exogenous issues and historical performance.

However, it is noted that the AER has looked to implement trend analysis to develop their view on the allowance for capex (especially repex and ICT) and has developed a suite of tools to help ensure that the use of trends reflects an efficient allowance. With the capex allowance being more subjective than opex development, this allows the DBs greater scope for "gaming" of the allowance and while this was always an issue in the past, the implementation of the Capital Expenditure Saving Scheme (CESS) has increased the attraction for DBs to seek greater capex allowances than they might need and/or for them to claim a need capex in one regulatory period but later decide to defer the capex into later regulatory periods.

It is also important to note that the capex allowance is a forecast and that circumstances might change over the course of the regulatory period. To accommodate these, there are a number of tools available to the DBs to get changes to the allowance if needed, including pass through events, contingent capex and the ability to later incorporate efficient additional capex into the RAB.

While the greater use of trend analysis is supported in the development of capex allowances, there has been a tendency by the AER to use more recent data over which to assess the trends. While the CESS might seem to assist in driving actual capex reductions since it was first introduced, it is important that longer term trends (preferably over 3 or 4 regulatory periods) are used to provide guidance as these are more likely to reflect future needs as it has long been recognised that there have been periods where greater and lesser capex was needed for managing swings of previous expansions (such as to manage step changes in demand) and replacements (the "bow wave" effect) and increased capex was warranted for reasonable short times. To adjust for this variation in some regulatory periods, a longer time frame for assessing trends is important. These longer time frames provide not only a cross DB assessment but a longitudinal analysis addressing the concerns that each DB does have some unique features.

6.1 Capex productivity

In its response to the Initial Proposals from the DBs, the sponsors noted that the productivity for capital investment showed a distinct downward slope for all DBs in the period 2006 to 2018. Since then, the AER consultants for assessing productivity (Economics Insights) have updated their benchmarking report, released in 16 October 2020. This shows the continuing decline in capex productivity for all DBs except for a very small increase to CitiPower. This is shown in figure 11 in section 3.2.1 above.

It is clear that none of the DBs have improved their capex productivity over the period 2006-2019 and the most recent data (for 2019) does not change this view. This reinforces the view detailed in section 3.2.1 above that consistently the DBs have been allowed to increase their capex but the benefit to the consumers that have funded this increase has been less than expected. This data reinforces the concern expressed that the growth in the RAB relative to a range of controls shows that the amounts of capex allowed in the past have been more than was needed to deliver the services required by consumers.

This productivity data coupled to the RAB growth clearly shows the need for the AER to severely limit new capex until capital productivity returns to that experienced in earlier regulatory periods.

6.2 An overview of allowed capex

The AER allows for the amount of capex to be included in its roll-forward model for setting the RAB.

In the response to the initial proposals, the sponsors noted concern that the DBs are incentivised to overstate their capex needs. By gaining an allowance greater than what they need, the DBs have access to a benefit through the CESS and by delaying the investment but have no risk exposure if they don't use the full capex allowance. It is not clear that these concerns have been fully addressed in the AER draft decision, although the AER has reduced the capex allowances from the amounts claimed by the DBs.

Table 2 below, provides the data on total capex, both actual and allowed for the first four regulatory periods, the amount proposed by each DB for the next regulatory period and the AER allowances in the draft decision, all in real terms. The table shows that:

- All DBs (except AusNet and Jemena) proposed to significantly increase their capex above current actual levels implying that the three CPPALUE networks (CitiPower, Powercor and United) will demonstrate even lower capex productivity than they show now, Jemena would continue with its flat capex productivity and AusNet might marginally improve its current poor capex performance.

- In the current regulatory period,
    - the initial claims by the DBs were all significantly overstated when compared to their actual capex
    - the AER allowance was significantly higher than was actually needed, implying that the AER was induced to grant more capex than was actually needed.

It is clear that capex needs should be significantly less than the amounts sought by the DBs.

Table 2 - Gross capital expenditure over time

Gross Capex $m ($'20/21)	2001-2005 actual	2006-2010 allowed	2006-2010 actual	2011-2015 allowed	2011-2015 Actual	Initial proposal 2016–20	AER allowed 2016-20	2016-2020 Actual	initial proposal 2021-2026	AER draft decision 2020	Revised proposals 2021-2026
AusNet	$793	$1,031	$1,245	$1,851	$2,148	$2,194	$2,313	$2,131	$1,818	$1,682	$1,762
CitiPower	$556	$724	$594	$1,037	$773	$1,111	$1,056	$883	$1,094	$826	$888
Jemena	$266	$346	$410	$591	$785	$939	$963	$782	$780	$745	$769
Powercor	$1,059	$1,376	$1,181	$1,958	$1,597	$2,604	$2,535	$2,281	$2,690	$2,081	$2,181
United	$575	$747	$651	$1,108	$1,165	$1,335	$1,182	$1,049	$1,370	$1,034	$1,121
Total	$3,248	$4,224	$4,080	$6,545	$6,468	$8,183	$8,050	$7,128	$7,882	$6,368	$6,721

Source: ESCV and AER final decisions, AER Network performance data, DB historic and current proposals, AER DD, revised proposals

While not explicitly detailed, it is pointed out that the table is based on gross capex which includes the amounts of capital new customers are required to contribute. Capital contributions constitute some 23% of the total capex budget. Of the remaining capex budget (ie the net capex) repex comprises some 35%, augex 20%, net connections some 14% and capitalised overheads some 13%. While only net customer connection capex gets added to the RAB, it is important that gross costs should still monitored as they are a cost to new customers and should be controlled.

This table has been updated to a common base year from that provided in the earlier submission and expanded with the AER draft decision and revised proposals to enable long term comparisons to be made. Developing this table has been quite challenging as the AER detailed breakdown of the capex does not follow the process used by the DBs in the development of their capex claims. In particular, the AER has separated out distributed energy resource (DER) capex from augmentation capex in some cases but not others.[8]

[8] It is noted that the sponsors concluded in their response to the Initial Proposals that DER augmentations should be assessed in their entirety as these augmentations can be assessed against the value that they deliver to consumers. That the AER has separated the DER augmentation elements out into specific categories makes it more difficult for consumers to identify if these augmentations are efficient.

Despite this, the table highlights that the AER draft decision, while leading to an overall reduction in capex for all DBs still includes for only modest decreases from that actually incurred in the current period except for AusNet[9]. What is concerning is that despite the much lower capex in the current period, this still resulted in increases in the RAB in both actual and relative terms as shown in figures 6 and 7 above.

While it is accepted that in its draft decisions the AER has addressed the issue of capex in a reasonable manner, it is still considered that the AER draft decision allowances are still too high, especially when considering that

- There is no growth expected in the state-wide peak demand which is the primary driver of augmentation capex and consumption is forecast to continue to fall
- The performance of the networks (especially in terms of operational performance) has consistently improved over time, implying that the amounts of capex provided are delivering this outcome when consumer view improved service performance as secondary to the costs they incur
- There is still growth in the RAB in relative terms and a continuing underutilisation of the assets included in the RAB

The AER notes in its draft decision that it generally accepts the capex forecasts or AusNet and Jemena subject to some relatively minor adjustments but expresses concerns regarding the CPPCUE DBs where the AER has determined that significant reductions need to be made to meet the AER assessments of prudency and efficiency. It is considered that the AER has been overly optimistic with its views of the AusNet and Jemena claims and that there are sound reasons for the AER to look more closely at the revised capex claims which effectively reject the AER modest reductions.

There is specific concern at the assumption by the AER that the AusNet NewReg process leads to the AER taking a more light-handed approach to AusNet capex. For example, the AER, while noting that the Customer Forum had limited scope for "negotiating" outcomes with AusNet (AER DD page 5-14),

> "…the Customer Forum agreed upon certain aspects of capex that, under our typical assessment approach, may not necessarily have been included in our alternative capex forecast, we are satisfied that some of this is offset by capex AusNet Services has not included in its forecast due to the focus on affordability during the negotiations."

The clear implication of this is that the AER has not addressed the AusNet capex claim with as much rigour as it did for the other DBs where a much more rigorous approach was used

[9] It is noted that over half the total decrease in total capex allowance for all DBs compared to the actually incurred total capex comes from the AusNet allowance which in turn reflects the significant reduction in capex proposed by AusNet.

(particularly for CPPALUE), including by an independent expert technical consultant. There is significant concern that the close involvement the AER had with the NewReg project has led to the AER making potentially unfounded assumptions about the AusNet capex claims that it did not with the other DBs. This observation reflects the submission to the Initial Proposals by the sponsors that the AusNet claims should receive the same amount of attention as for the other DBs.

In the following sections, there are reasons provided where it is considered the AER assessments for individual capex elements are overstated.

6.2 Replacement capex (repex)

Replacement capex (repex) is targeted to maintain the quality of the service provided by the DBs in that it ensures that the reliability of supply does not fall below acceptable levels. Consumers have expressed a view that the current levels of reliability are generally acceptable and they do not want to pay more for improved reliability. As shown in section 1.2 above, under the long term historical repex, the DBs have been slowly improving the reliability of supply, measured in terms of SAIDI and SAIFI, which has slowly improved over time as shown by the trend lines. As reliability of supply is so closely aligned with replacement of those assets which are no longer reliable, it is important to measure the need for repex contiguous with the outturn performance over the long term.

It is also recognised that of all capex, distribution repex can be closely assessed in terms of long-term trends. It is on the basis of these long-term trends, matched to outturn reliability performance that is the basis for this analysis has been carried out.

What is concerning is the AER has focused mainly on the amounts of repex used in the current period and basing its draft decision on the repex used in this time frame when the actual performance is measured over a longer time frame.

Table 3 below was provided by the sponsors in their response to the Initial Proposals and outlines the changes in the amounts allowed by the regulators (Office of the Regulator General, Essential Services Commission of Victoria and AER) in past resets and the claimed and actual amounts for the capital investments made by each DB. A feature that the table reveals is that in most periods the DBs have used less repex than they forecast and allowed by the regulator. The table has been extended to include the AER draft decision and the revised proposals from the DBs.

Table 3 - Replacement capital expenditure over time

Repex $m ($'20/21)	2001-2005 RQM + 50% ESL	2006-2010 RQM + 50% ESL	2006-2010 RQM +50% ESL actual	2011-2015 RQM + 50% ESL	2011-2015 Actual	Initial proposal 2016–20	AER Preliminary Decision 2016-20	Revised proposal 2016-20	AER allowed 2016-20	2016-2020 Actual	average actual for 2001 to 2020	initial proposal 2021-2026	AER draft decision 2020	Revised proposals 2021-2026
AusNet	$270	$351	$256	$617	$767	$1,006	$847	$898	$780	$476	$442	$703	$675	$652
CitiPower	$116	$457	$161	$335	$171	$290	$222	$290	$264	$111	$140	$261	$125	$145
Jemena	$61	$75	$97	$219	$182	$250	$250	$286	$255	$190	$132	$211	$208	$211
Powercor	$336	$486	$290	$623	$495	$806	$680	$751	$680	$403	$381	$678	$426	$530
United	$158	$329	$194	$391	$453	$653	$474	$630	$498	$328	$283	$420	$304	$344
Total	$942	$1,697	$998	$2,185	$2,069	$3,007	$2,473	$2,855	$2,476	$1,508	$1,379	$2,337	**$1,738**	**$1,882**

Source: ESCV FD for reset 2006-2010, AER reset documents, AER network performance data DB historical and current proposals, AER DD, revised proposals

Specifically, the table includes the average repex used over the past 4 regulatory periods (2001 – 2020) as this reflects the same time frame against which reliability performance of the DBs has been measured; in this regard it should be noted that there is a time lag between incurring the repex and the outturn reliability measures. In total, the long-term average repex is 10% below the actual repex in the current period. Again, in total, the AER draft decision provides a 15% increase in repex above the current period usage, essentially a 25% increase in allowed repex for the next period above the long-term average repex actually used by the DBs to provide a consistent improvement in reliability.

The AER has assumed that the actual repex (especially if incentivised by the CESS) is a strong indicator of reasonable repex and while this is supported to some extent, the over-reliance by the AER on the current period actual spend does not incorporate the longer term trends and future impacts on reliability of supply.

Further, current unit costs do not necessarily equate to those that will apply in the future as it is widely recognised that there are parts of the networks that have higher costs due to local difficulties and others where the costs are lower due to ease of access and type of asset. This reinforces the view that longer term averages both in terms of numbers and unit costs are more appropriate than those of a single regulatory period.

In aggregate, the AER draft decision to provide a 15% increase in repex above current period actual and a 25% increase above long term actual is not warranted in terms of maintaining the current and considered acceptable reliability performance. That the DBs have rejected the AER draft decision and sought increases in repex is concerning and these claimed increases need to be rejected by the AER.

The following sections address specific DBs.

6.2.1 AusNet and Jemena

It is noted that the AER has assessed the repex sought by AusNet and Jemena without reference to independent technical advice and has effectively accepted the repex proposals by each albeit with some modest adjustments.

It is considered that the AER has erred in its draft decision when it is seen that the long term repex provided by the DBs is well below the repex in the current period. That the AER has then increased the repex for the next period above the rate used in the current period is not consistent with the AER acknowledgment that it is important to reduce the RABs from their current excessively high levels.

Of particular concern is the AER observation that the AusNet repex proposal is reasonable (subject to some minor adjustments) as it is

> "…in line with its current spend (forecast being 4 per cent above current regulatory control period spend)." (AER DD on AusNet capex page 5-22)

This observation is at odds with the data provided by AusNet and the actual proposed increase is much greater than the current repex spend shown in figure 9-17 in AusNet initial proposal part 111 page 76/272. In fact, the repex increase is much greater than 4% and so needs to be assessed more closely.

As Powercor is a comparator to AusNet in many ways, it is appropriate to compare the repex sought by both. In this regard, it is concerning that the AER considers that AusNet should be allowed much more repex than it does for Powercor. This observation is even more important when it is considered that Powercor repex underwent assessment by the independent consultant whereas AusNet's repex did not. This indicates that a more thorough examination of AusNet's repex might have resulted in an outcome comparable to that of the AER's draft decision on Powercor.

It is noted that the two DBs (AusNet and Jemena) have both provided revised proposals to reinstate the levels of repex that they sought in their initial proposals, effectively ignoring the AER draft decision. It is also pertinent to point out that both DBs had sought and been granted significant increases in their repex for the current period on the basis that this was required to maintain reliability. Subsequently both of them used significantly less repex while at the same time improving reliability and by doing so earned a considerable CESS bonus as well as a STPIS benefit.

It is very concerning that the AER has not only allowed significant increases in repex for both DBs from long term averages, but that both DBs did not accept the AER draft decision despite the AER effective acceptance of their proposals.

6.2.2 CitiPower, Powercor and United (CPPALUE)

The AER has taken a much more intrusive approach to assessing repex for the CPPALUE DBs and has reduced the allowed repex by significant amounts; in this task the AER was assisted by an independent consultant, EMCa. This approach by the AER is strongly supported.

Generally, the AER has reduced the repex allowances in total to near the current period actual even though this is still above the long-term average by some 5%. On balance, the AER draft decision for repex for the three DBs is supported, even though it is higher than the long-term average repex.

The predominant increase in repex proposed by the three DBs is related to the pole replacement program, along with service line repex and switchgear repex and the AER has identified this in its draft decision. The AER approach to assessment for each of these elements is supported.

Despite the AER draft decision, in their revised proposals the three DBs have all disagreed with what the AER assessed, especially in relation to poles and to a lesser extent switchgear. Equally, it is recognised that all three in their revised proposals have reduced the amount of repex they stated was needed in their Initial Proposals.

All three DBs provided a comprehensive explanation of their wood pole replacement programs and the reasons behind the need for greater investment in wood pole replacement than exhibited in the past. All make reference to a desire by government and Energy Safe Victoria (ESV) for the DBs to increase their rate of wood pole replacements as this would increase reliability of supply and reduce the risk of other damage. This is understandable as neither the government nor ESV have to pay for the replacement of serviceable poles – consumers pay, and consumers have expressed considerable concern about the costs of the services provided by the DBs. What is also important to note is that ESV has not issued a requirement on pole replacement as such, but expressed support for a program initiated by Powercor for pole assessment and replacement. CitiPower and United have effectively “piggy-backed” on the program developed by Powercor and expressed a view that ESV now requires the implementation of the Powercor pole replacement program. As distinct from ESV and Victorian government support for increasing pole replacement, the AER has to determine the amount of funds it considers is needed for the efficient operation of the networks.

There is a subtle difference in view that this requires. What is also not recognised is that even though the AER might determine the efficient financing for wood pole replacement, the DBs are free to spend more on this (or any other activity) if they so desire – the AER is not mandating a rate of replacement, it is merely providing an efficient allowance for the activity. If the DB exceeds the amount of the total allowed capex, then the AER has the ability to carry out an ex post assessment of capex prudency and decide whether the capex over-run can be included in the RAB. On the other hand, the DBs have the considerable incentive to over-claim their capex needs both in terms of quantum and timing of the expenditure.

With this in mind, it is considered that if the DBs consider that the AER allowance is too low and that reliability of supply will be adversely impacted, they can use more capex as a tool to offset the penalty/bonus that comes from the reliability incentive scheme (STPIS – see section 8 below).

The AER has the requirement to only include in the regulatory allowance funds that are efficient. The three DBs have not demonstrated that their revised repex is efficient, but have provided a view that **in their opinion** a faster replacement of poles will benefit consumers. While there might be a benefit, such a benefit will be an increase in reliability which is something consumers have stated they do not want if it increases costs.

It is noted that the DBs did discuss the draft decision on poles with their consumer advisory groups and as a result have reduced their forecast pole replacement programs from those in the initial proposals.

What is concerning is that the historic approach to pole replacement has delivered the needed reliability (United's historic program was stated to be "world class" by United in its revised proposal) yet the three DBs persist in providing a view that historic performance is not adequate. Until the DBs can clearly show that the AER draft decision will deliver less reliability then to assertions of the DBs in regard to wood pole replacement cannot be seen to be more persuasive than the arguments of the AER for its view based on historic replacement rates.

The arguments provided above in relation to wood pole replacement are the same as those supporting the AER draft decision in relation to the service lines and switchgear where the revised proposals seek more than the AER draft decision.

It is also noted that the DBs have sought an increase in repex for switchgear and service lines. The same commentary applies to these elements of the repex claim as for the wood pole replacement.

6.3 Customer connections

The net cost of customer connections to be included in the RAB is driven by three elements – the forecast numbers of new connections (and their type), the cost of each connection and the policy on how much each customer must contribute to the provision of the new connection. Of these, probably, the forecast for new connections is the most critical and in section 4.1 above, it is highlighted there is concern about the accuracy of the forecast new customer connection numbers by the AER draft decision and the DBs in their revised proposals and a concern expressed that these forecasts are overstated.

Table 3 below provides a longitudinal review of gross new connections capex. Gross capex is considered to be the key aspect for assessment, even though a considerable portion of the gross capex will be recovered directly from the new customers.

Table 3 – Gross capex for new customer connections

Gross customer connections $m ($'20/21)	2001-2005 actual	2006-2010 allowed	2006-2010 actual	2011-2015 allowed	2011-2015 Actual	Initial proposal 2016–20	AER allowed 2016-20	2016-2020 Actual	initial proposal 2021-2026	AER draft decision 2020	Revised proposals 2021-2026
AusNet	$366	$389		$465	$375	$410	$449	$513	$552	$514	$530
CitiPower	$159	$207		$286	$317	$370	$368	$405	$427	$377	$391
Jemena	$107	$119		$171	$168	$254	$192	$201	$227	$198	$199
Powercor	$412	$389		$718	$740	$864	$807	$985	$865	$738	$651
United Energy	$193	$158		$299	$256	$278	$353	$331	$370	$294	$286
Total	$1,236	$1,262		$1,939	$1,856	$2,176	$2,170	$2,434	$2,557	$2,121	$2,057

Source: ESCV FD for reset 2006-2010, AER reset documents, AER network performance data DB historical and current proposals, AER DD, revised proposals

Based on the longitudinal assessment, and subject to a review of new customer numbers, the AER draft decisions and the revised proposals are likely to reasonable.

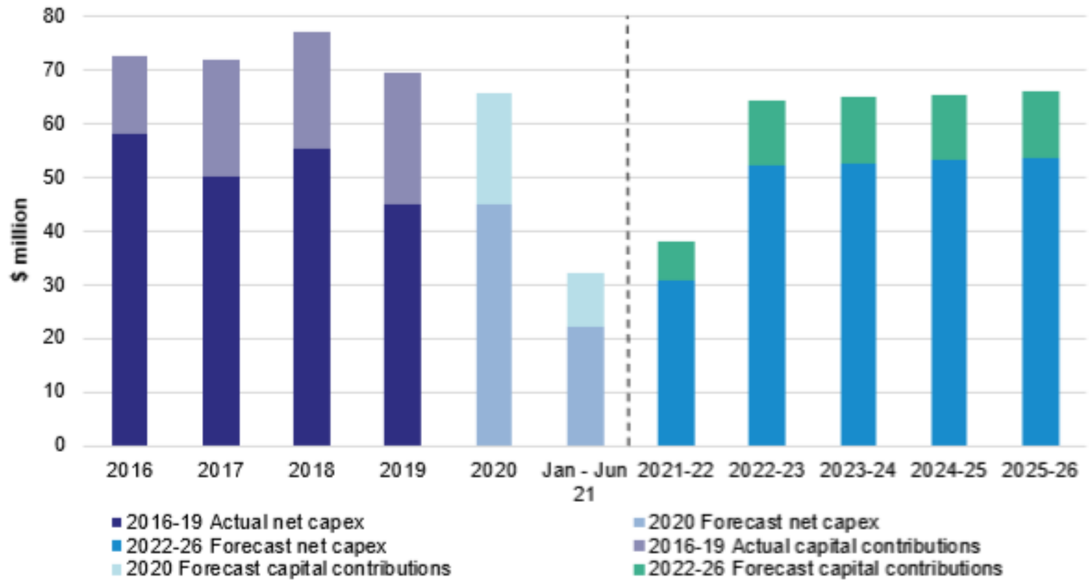
What is intriguing though, is the quite significant variation between the DBs in the percentage of customer contributions as a proportion of the gross new connections capex, leading to varying net capex outcomes. Analysis of the data indicates that the percentage of customer contributions as a proportion of gross new connection costs varies between 50% and 80% depending on the DB at what point the assessment is made (ie initial proposal, draft decision and revised proposal). While from a RAB viewpoint the greater the percentage, the less added to the RAB but, to balance this, the greater the contribution each new customer contributes. This issue needs to be investigated further to ensure there is some rationale behind the forecasts of customer contributions as distortion in this value provide a significant distortion to overall capex.

For example, AusNet provides the following chart[10] for their gross customer connections and the proportion which will be recovered from new customers.

[10] This chart seems to be at odds with AusNet's table 3-5 with the table 3-5 showing higher values for both gross connections capex and customer contributions

larger

Figure 3-1: Actual/Forecast connections capex 2016 - 2026 ($m, 2021)^



Source: AusNet Services

^ Excluding gifted assets and large embedded generation.

This chart implies that customer connections in the current period are a larger percentage of the gross connections capex than is forecast in the next period but there is no explanation as to why this is the case and why the RAB should be higher as a result. There needs to be an explanation as to how the customer contributions are calculated by all the DBs to assess whether there is consistency in approach.

Also, in AusNet's revised proposal is a significant increase in the gross connections capex for large embedded generation. Connection costs for embedded generation should be a cost to the new generator and not included in the RAB and AusNet comments this is the case (AusNet revised proposal, page 51/210):

> "… large embedded generation connections (>5MW) … [do] not impact on forecast 2022-26 net connections capex, since its expenditure forecast is matched with equal and offsetting capital contributions."

However, the introduction of such large generation can impose both a need for deep connection assets to be provided and create disturbances for the consumers that pay for the assets to supply electricity to them. It is concerning that such large generation is seeking to be embedded in the distribution network and should preferably connect to the transmission network.

The concern expressed above in relation to the percentages of consumer contribution recovery and large embedded generation indicates that there is a need for greater clarity in presentation with some disaggregation of gross connection capex into a limited number of sectors and to allocate the amounts of customer contributions to each sector. The lack of such limited disaggregation makes is challenging for stakeholders to be able to provide more useful input to what is a significant element of the overall capex. While it is noted that there are detailed worksheets providing this data, converting this into useful but limited aggregated data is time consuming and potentially subject to error rendering the limited aggregation by a stakeholder potentially misleading.

6.4 Augmentation capex (augex)

Augmentation capex (augex) is driven predominantly by increases in forecast peak demand. As detailed in section 4.2 above it is noted that the non-coincident peak demand in aggregate across Victoria summated from the DB forecast peak demands is greater than the 10% Probability of Exceedance (10PoE) peak demand forecast by AEMO across Victoria in its most recent ESoO (ie 2020 ESoO) over the next regulatory period (and beyond). This is shown in figure 16. What is important to note is the consistency between the 2019 and 2020 ESoO forecasts for peak demand and that AEMO expects peaks demands to fall (albeit marginally) over the next period.

Figure 15 also shows that AEMO does not expect the forecast 10%PoE Victorian demand to exceed the current peak demand experienced in Victoria and while there is consistency between the AEMO 2019 and 2020 peak demand forecasts the 2020 ESoO 50%PoE shows a distinct fall from that forecast in the 2019 ESoO 50%PoE.

What is also telling is that the non-coincident peak demand in the Victorian networks experienced in 2009 has not been exceeded until 2019.

In contrast to the AEMO forecasts, the DBs see significant growth in peak demand but the AER expresses a view (for example in the Powercor draft decision page 5-79) that it is

> "… not satisfied that Powercor's demand forecasts reasonably reflect a realistic expectation of demand over the forecast regulatory control period … [and that] AEMO … forecasts are more reasonable, based on currently available information."

This view expressed by the AER view is supported.

The conclusion drawn from this forecast peak demand analysis is that there is little need for any increase in capacity in the DB networks and so little or no augex should be required for the next regulatory period. Equally, it is accepted that there will be localised areas in each DB region where peak demand is increasing beyond the capacity of the local network and that some local network augmentation will be needed.

What is concerning is that not only is the state-wide peak demand not increasing but asset utilisation continues to fall as shown in figure 3 above while RABs continue to rise. What is absent from both the AER draft decision and the revised proposals is any recognition of the need to optimise the networks so that utilisation can increase and so avoid the need for augex by the relocation of existing assets.

In 2015 there was an expectation expressed by AEMO that there would be a modest increase in peak demands in Victoria. On this basis, the AER allowed quite significant increase in augex for the current period and this is shown in Table 4 below. Yet despite the expectation of an increase in non-coincident peak demand in 2015, the networks did not exceed the peak reached in 2014 in the current period although the non-coincident peak demand in 2019 did match the 2014 actual non-coincident peak demand; this is shown in figure 15 above.

The import of this analysis is that the amounts of augex used in the current period (which reflects a very modest increase in non-coincident peak demand) should be an appropriate measure for augex when there is no or at most a very modest expectation of a peak demand increase.

Table 4 below provides the aggregated historical augex as well as the AER draft decision and the augex in the revised proposals from the DBs.

Table 4 Augmentation capital expenditure (augex) over time

Augex $m ($'20/21)	2001-2005 reinf + 50% ESL actual	2006-2010 reinf + 50% ESL allowed	2006-2010 reinf + 50% ESL actual	2011-15 allowed reinf + 50% ESL	2011-2015 actual	Initial proposal 2016–20	AER Preliminary Decision	Revised proposal 2016-20	AER allowed 2016-20	2016-2020 Actual	initial proposal 2021-2026	AER draft decision 2020	Revised proposals 2021-2026
AusNet	$62	$214	$250	$364	$514	$351	$298	$367	$345	$152	$216	$216	$220
CitiPower	$155	$208	$75	$270	$208	$227	$133	$226	$226	$163	$192	$148	$150
Jemena	$41	$76	$90	$134	$128	$157	$104	$116	$147	$92	$146	$137	$131
Powercor	$122	$307	$173	$309	$242	$404	$270	$347	$306	$118	$510	$340	$345
United	$114	$163	$220	$257	$204	$187	$142	$139	$139	$114	$201	$128	$136
Total	$493	$967	$808	$1,333	$1,297	$1,326	$947	$1,195	$1,163	$639	$1,239	**$969**	**$989**

Source: ESCV FD for reset 2006-2010, AER reset documents, AER network performance data, DB historic and current proposals, AER DD, revised proposals

What is telling from this table is that the AER draft decision for the current period allowed 50% more augex than was actually used by the DBs and the AER final decision for the current period allowed 80% more than was actually used. The AER allowance in the draft decision for the current period was the forecast closest to the actual augex spend with the DB initial and revised proposals and the AER final decision all well off the mark.

In their initial proposals for the next period, the DBs have sought about the same amount of augex as they did in their initial proposals for the current period which was about double what they actually needed. The AER draft decision for the next period allows the DBs a 50% premium on the actual for the current period, and about the same as the draft decision for the current period. The DB revised proposals for the next period reasonably match the AER draft decision for the next period.

Based on trend analysis, and an expectation of peak demand moving much as it did in the current period, it is clear that the AER draft decision provides much more augex than is needed for the next period. On the basis of trends, it is expected that the actual augex for the current period should have been what the AER draft decision allows.

This review does not support the AER draft decision for augex and recommends that in the final decision, augex should be reduced for AusNet, Jemena, Powercor and United, recognising that CitiPower augex reasonably reflects its current period augex.

6.4 Other capex

"Other capex" includes allowances for capex for DER, IT and communications, property other non-network capex and overhead capitalisation. This is presented in table 6 below.

Table 6 Assessment of "other capex"

Other capex $'20/21	excluding overhead capitalisation			overhead capitalisation		
	Iniitial proposal	Draft decision	Revised proposal	Iniitial proposal	Draft decision	Revised proposal
Ausnet	225	225	205	147	145	146
CitiPower	164	130	137	110	90	109
Jemena	126	126	136	91	89	90
Powercor	473	421	433	265	218	285
United	331	254	286	120	91	108
Total	1319	1156	1197	733	633	738

Source: DB current proposals, AER DD, DB revised proposals

The largest of the allowances is for overhead capitalisation. Each DB has its own approach to capitalisation of overheads and the AER assessed each DB approach. Its assessment was that overhead capitalisation was overstated and made adjustments reducing the allowance. In their revised proposals all DBs effectively restated their initial proposed allowance for this category. This submission does not have sufficient data or understanding of the issues involved to provide detailed input and relies on the AER to more fully investigate this aspect.

With regard to the "other capex less capitalised overheads" the AER made a number of adjustments that are supported. In their revised proposals the DBs (other than AusNet) have sought small increases from the AER draft decision but the arguments provided to sustain these increases are not supported.

The major change between the draft decision and revised proposal in "other capex less capitalised overheads" relates to United's approach to managing its Burwood and Keysborough properties. A fundamental question arises in that if the current arrangements have provided adequate support for United's activities and as there has been and will continue to be marginal growth is assets, why consumers should fund a major investment when the existing assets provide the b]needed support. What is absent from the United revised proposal is a business case which shows that the proposed change will deliver benefits to consumers. In the absence of a benefit to consumers, the investment is not supported.

The other issue that needs to be addressed more fully is the management of the increase in DER seen in the distribution networks. In its response to the initial proposals, the sponsors observed that the changes to the networks to manage DER need to be assessed on a total basis including augmentation capex, ICT capex, opex and value of exports rather than looking at each element independently. Overall, a business case is required to demonstrate the value of allowing increased exports to the cost of providing this capacity. Unfortunately, the AER has decided not to take this approach and has addressed the inputs for managing DER separately and the DBs have followed suit in their revised proposals.

The report Value of Distributed Energy Resources: Methodology Study[11] (VaDER) provides a clear approach for assessing the benefits of DER and how this interfaces with the distribution networks. This report specifically considers that any approach by the DBs to manage DER growth must be based on a business case including all costs (opex and capex) as well as incorporating a specific approach to assessing the value of increased exports. This has not been addressed by the AER in draft decision

The issue of DER has been addressed in section 1.6 above and a recommendation made that rather than include a fixed revenue allowance for addressing DER, the AER should include in the Final Decisions a contingent amount to be refined when the VaDER report outcomes can be applied and all costs and benefits combined into one assessment and so ensure the most efficient outcome for consumers is achieved.

[11] Available at https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/assessing-distributed-energy-resources-integration-expenditure/update

7. Proposed Operating Expenditure (opex)

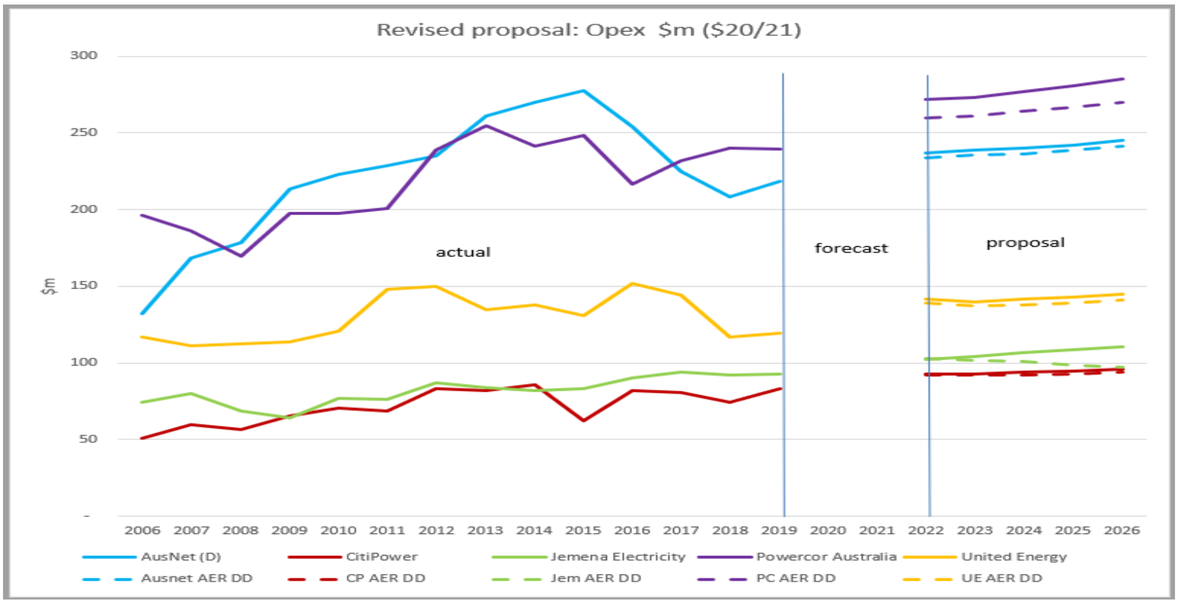
Under the AER approach there are three elements to setting the future opex – the base setting (assumed to be the most recent revealed opex which has been assumed to be driven by the EBSS to get to the efficient level), the changes in the obligations the DB has (i.e. step changes caused by government or regulator obligations) and the trend aspects (which combines the impacts of output growth, inflation and productivity growth). All five DBs have used the base-step-trend approach to setting their opex in their revised proposals although they have not necessarily accepted all of the AER draft decisions on opex development.

It is important to note that the AER sets considerable store on trend analysis to develop their view on the allowance for opex and has developed a suite of tools to ensure that the outcome reflects an efficient allowance. As the DBs tend to accept that this is an acceptable approach to development of their opex allowance, it then becomes an issue as to what inputs are used to generate the trend and thus the final allowance.

It is also important to note that the opex allowance is a forecast and that circumstances might change over the course of the regulatory period. To accommodate these, there are a number of tools available to the DBs to get changes to the allowance if needed, including pass through events and the ability to incorporate efficient costs into the future. With this in mind, it is important that only aspects that are known should be built into the opex allowance.

The actual opex, the opex allowed in the AER draft decision and the proposed opex in the revised proposals for the next period is shown on the following chart (figure 21).

Figure 21 Movement in opex over time



Source: AER Electricity Distribution Networks Performance data report 2006-2018, DB revised proposals, AER DD

The base year has been set by each DB as 2018 actual opex (AusNet and Jemena) and as 2019 actual opex (CitiPower, Powercor and United) and these base years have been accepted by the AER as being efficient.

The AER has been a consistent user of the base-step-trend approach to setting the opex for many years and has looked to refine that process over time. This means that essentially historic data drives the AER assessment of opex and that little effort over the years has gone into assessing whether the outturn values are supported by a bottom up assessment of the opex proposed. While benchmarking is considered to be a powerful tool to use in assessing the relative rankings of different DBs, longitudinal studies are also important as a benchmarking tool, yet the AER seems not to use this as widely as it could be.

It is also considered that there needs to be a check as to whether the benchmarking tools are providing the most efficient outcome and a bottom up assessment can be helpful as an occasional "sanity" check of the benchmarking approach. In this regard, it is noted that a longitudinal assessment of allowed opex compared to actual opex shows that consistently (with a few exceptions) the Victorian DBs have been able to implement lower opex than was allowed by the regulators who used the base-step-trend approach to setting future opex. Despite this regular ability to under-spend allowed opex (and so achieve a bonus under the opex efficiency schemes in place) the DBs have also demonstrated a reduction in opex productivity. As the bulk of the opex allowance is based on the revealed opex and opex productivity has fallen over time for four of the five Victorian DBs (see figure 12), there is concern that the setting of the base opex allowance might not be as efficient as the AER assumes.

7.1 Base year opex

The setting of the base year is critical to the AER approach to setting an efficient allowance for opex. The base year is assumed to be efficient because it is being driven by the opex incentive scheme (EBSS) but despite this incentive, the DBs have demonstrated a continuing fall in opex productivity as calculated by the AER consultants Economic Insights (EI). The most recent updating of the opex partial factor productivity data provided by EI is included in section 3.2.2 (and the associated figure 12) which shows a continual long-term trend of a loss in productivity for all DBs but United. Following a long-term trend provides the ability to benchmark each DB against itself as well as against its peers. That the EI data shows that all DBs except United have long term downward trends implies that the base years are probably not efficient.

Despite this the AER has accepted that the base year proposed by each of the DBs is considered to be efficient except for Jemena which is considered to need an efficiency improvement of 15%. It is pointed out that AusNet long term productivity has fallen well below its level of earlier years and despite this the AER has assessed AusNet's current opex as efficient. It is noted that the 2020 report from EI shows that for 2019, AusNet opex productivity(as measured by the opex PFP) again fell after showing a distinct step improvement in 2017.

What is concerning about the AER analysis of AusNet base year opex is that its closest Victorian comparator (Powercor which has to manage similar environmental factors to AusNet) consistently shows a productivity well in excess of that of AusNet against all of the measures used by the AER in trying to demonstrate that AusNet base year is efficient. The differences between Powercor and AusNet for each measure are significant:

- On average opex efficiency scores over 2006-2018 AusNet is at 70% of Powercor's performance
- On opex MPFP 2006-18, AusNet is at 60% of Powercor's performance
- On opex/customer vs customer density AusNet is 75% of Powercor's performance
- On opex/circuit length vs customer density AusNet is 85% of Powercor's performance

On this basis, AusNet's performance cannot be judged to be efficient.

In its response to the initial proposals, the sponsor's provided a view that the base year opex for both AusNet and Jemena were not efficient. The AER draft decision to require Jemena to implement opex efficiency improvements is supported but it is considered that AusNet should also be subject to a similar requirement based on its own longitudinal loss of productivity and the comparison to Powercor opex performance.

It is noted that AusNet, CitiPower, Powercor and United have accepted the AER draft decision in relation to the base year opex but Jemena does not.

It is pointed out that the "efficient" base year opex being used reflects a relatively low level of repex that was implemented during the current period (compared to the current period allowance and the proposed repex for the next period)[12] so it would be expected that for all DBs the increased amount of repex proposed for the next period will lead to a lesser amount of opex and there should be a downward adjustment of the opex allowance to offset the increase in repex expected to be implemented.

It is noted that the DBs provided advice from consultants NERA and Frontier Economics with regard to input price weights, utilities WPI, weighted average output growth rates and drivers for MPFP modelling. The approach used by the AER to address these concerns is supported.

[12] See table 3 in section 6.2 above

7.2 Opex growth trends

Following the opex base-step-trend approach to assessing efficient opex, the AER assesses the growth in prices, productivity and outputs and applies these to the base opex allowance. These are each addressed below.

7.2.1 Price growth

Typically, the AER uses a price growth measure based on the average of its selection of an independent data source and that of the DB's selection. This is sensible. In its draft decision, the AER has used only one source of data which it considers better reflects the impacts of the COVID-19 pandemic than the data source nominated by the DBs. It is pointed out that the AER should use even later data which incorporates the Victorian government latest budget which was released in December 2020. In their revised proposals, the DBs have all suggested that a second source of independent data be used, and this is supported providing the data is current.

The AER has assessed (as have the DBs) that price movements of materials is most likely to match movements in CPI and this approach is supported.

It is also noted that the AER has assessed different weightings for the labour/materials balance. It is considered that the weighting across all DBs should be the same and the weightings proposed by the AER would appear to be more reflective of actual expenditure patterns than those proposed by the DBs and so the AER draft decision is supported.

7.2.3 Output growth

The approach used by the AER for developing an output growth provision and the decision to get updated information for application in the final decision is supported. The AER decision regarding the NERA and Frontier reports is also supported.

It is noted that the DBs have proposed variants to the AER draft decision on output growth. It is considered that it is important that there be consistency across all DBs in the development of the output growth provision so while specific inputs might change as updated information is provided, the overall structure and controls need to be the same for all DBs.

7.2.4 Productivity growth

It is noted that all of the DBs propose to accept the AER decision on productivity growth.

While accepting the AER draft decision, it is pointed out that the sponsors in their response to the initial proposals considered that the productivity growth allowance of 0.5% pa set by the AER is too low and should be greater.

In this regard, it is noted that AusNet decided after discussions with its Customer Forum that it would increase opex productivity by 1.0% pa comprising the mandated 0.5% pa coupled to opex adjustments to include the other 0.5% pa. While this approach is accepted, it would be better if the allowance was made more explicit and obvious for future analysis.

7.3 Step changes

All DBs propose that there step changes included in their opex proposals and the sponsors note that all of these add costs and there are no step changes seen by the DBs that would reduce the opex, although AusNet observes that there are some step changes that they will not include even though there are costs associated with them.

In its response to the initial proposals, the sponsors provided a table of the step changes sought by the DBs. Table 7 below is an update of the sponsor's table and reflects the AER draft decisions.

Table 7 Opex step changes

Step change $m	AusNet	CitiPower	Jemena	Powercor	United	Driver
REFCL program	5.8		1.3	2.6		Gov't
5 minute and global settlement	3.5	1.8		4.5	3.7	Reg
Cyber security	0	13.4	2.9	13.4	32.4	?
IT cloud	0	2.2		5.5	4.5	Net benefit
EPA amendment Act 2018		0	0	0	0	Gov't
ESV levy		0		0	0	Gov't
Financial year RIN		0	0	0	0	Reg
Yarra trams pole relocation		0				?
Solar enablement, DER in future grid		0	0	0	0	Net benefit
Insurance			28.2	0	0	?
HBRA zone Reclassification				0		?
Replacing EDO fuses				0		Net benefit
Demand management					0	Net benefit

GSL	46	0.06	0.9	13	3.3	
Innovation	1.2					
Debt raising	11.3	4.8	4	11.2	5.9	

Source: DB proposals, AER draft decisions
Note: Where an allowance is marked zero, this reflects where the AER has rejected the claim for a step change. Blank areas are where the DB did not make a claim for a step change

The AER decisions are broadly supported as they reflect many of the points made by the sponsors in their response to the initial proposals.

As a general observation, the AER has rejected a number of step changes on the basis that they are immaterial and can be absorbed in the base opex. This is a legitimate approach and is supported as the allowed opex does not comprise a number of discrete elements but is a broad assessment. On this basis it can be expected that small step changes will be offset by reductions in other areas. Over time, this balancing of "pluses and minuses" will become part of the base opex in the future. It might be asserted that the DB is disadvantaged by this approach as it has the potential to reduce the reward it receives under the EBSS. This view by the DBs is not a legitimate concern as the EBSS is designed to provide an incentive for the DB to implement changes where it can to reduce opex and that reductions arising from exogenous sources should not be the basis for a windfall bonus. That DBs have in the main been able to reduce their opex below the AER allowance attests to the need for this approach to be implemented.

However, the DBs have not necessarily accepted the AER draft decision in relation to the step changes. The following comments refer to the points made by the DBs.

7.3.1 REFCL program

Powercor does not accept the AER draft decision on the REFCL program and seeks an additional $1.1 m in total. This increase needs to be assessed by the AER as there is insufficient detail to provide an informed observation.

7.3.2 Cyber security

The AER has allowed the DBs that requested a step change to implement cyber security to have amounts to implement this but not to the security level that the DBs requested[13]. It is noted that this issue is further complicated in that all of the DBs provide unregulated services and that the cyber security concerns will apply equally to the regulated activities. Care must be taken so that any allowance provided to the regulated entity does not benefit the DB unregulated activities.

In their response to the initial proposals the sponsors had expressed a view that this should not be a step change. It is considered that managing cyber risks is a normal part of business

[13] The DBs sought security level MIL 3 but the AER has decided security level MIL 2 is sufficient

operations and should not be treated as a cost unique to networks. The return on equity provides a premium for networks for taking on non-diversifiable risk. As all firms operating in the market face this risk then it is not considered to be a step change.

CPPALUE DBs all offer a reduction in the cyber security allowance subsequent to release of the draft decision.

7.3.3 IT cloud

The CPPALUE DBs have been granted this step change but AusNet was denied it and Jemena did not seek it.

In its response to the initial proposals the sponsors expressed a view that there had to be a net benefit to consumers if these projects were to be funded. The AER assessment is that there is a net consumer benefit from implementing this approach.

AusNet has provided more information to support its case for this step change. If there is a net benefit for consumers, as asserted by AusNet, then the program should be allowed.

7.3.4 ESV levy and AEMO fees

In addition to the ESV levy, AEMO has indicated that it might impose a levy on the DBs to recover some of its costs and the DBs other than Jemena have sought for these charges to be recoverable as a step change.

AusNet seeks to have the ESV levy recovered through a separate mechanism (B factor) and AEMO fees through an L factor.

CPPALUE DBs seek to have both recovered through an L factor adjustment.

It is considered that these charges are quite modest in comparison to the total opex and that some ESV levy is already included in the base opex. The AER draft decision on this is supported as it is considered that these charges should be absorbed by the DBs (as noted above) and not be reimbursed through these proposed new mechanisms.

7.3.5 Solar enhancement

The AER rejected this step change by a number of the DBs on the basis that the costs proposed were higher than efficient and that there are lower cost options to accommodate the increasing amounts of distributed energy resources (DER). When assessing the lower unit costs, the overall cost was considered to be immaterial and the remaining costs were insufficiently justified.

CPPALUE DBs do not accept the AER draft decision on solar enablement and seek $1.0m, $4.8m and $3.9m respectively. These amounts are less than in the initial proposals by a total of $2m. The DBs have not provided a convincing argument to counter the AER draft decision, relying only on assertions that the AER is wrong in that the AER has:

- not assessed correctly, the opex/capex trade off and the opex assisting in deferring capex
- no regulatory right to reject "immaterial" step changes, especially when the costs are material
- not demonstrated that the output growth allowance includes the growth of DER
- demonstrated that the costs used by the AER are appropriate

It is considered that while some of these assertions might have some validity, neither have CPPALUE demonstrated that the costs they consider are correct are demonstrably so.

In particular, CPPALUE have not demonstrated that there is a net benefit for consumers of the work proposed.

7.3.6 Insurance

AusNet seeks an additional $10.5 m in opex to reflect the growth in insurance costs. This issue is addressed in more detail section 10 below under the pass-through events. It would seem that the additional insurance is above the pass-through proposal that has acceptance. There is concern that this additional amount in the opex has been double counted.

Jemena, Powercor and United also have sought a new bushfire insurance coverage event as a pass through and it is not clear why they should both get this pass-through ability but also a large increase in opex for insurance to reflect the insurance changes. There is concern there is a double counting of the costs.

What is required is a careful analysis of the approach taken by each DB with regard to the premium, insurance deductible and insurance cap in relation to bushfire insurance to ensure that each DB has the most efficient mix of costs and exposures.

Further, there is no clarity as to whether the insurance step change is just for bushfire insurance or included general insurance as well. In principle, there is support for developing the most efficient bushfire insurance program for each DB with consumers sharing in the increased costs and risks.

However, this acceptance specifically includes any costs and risk changes related to general insurance which has not been impacted by the increased bushfire risk and costs seen more widely.

8. Incentive schemes

There are currently four incentive schemes in operation with electricity DBs:

- the incentive to minimise opex (Efficiency Benefit Sharing Scheme - EBSS)
- the incentive to minimise actual capex (Capital Efficiency Sharing Scheme - CESS)
- the incentive to improve reliability (the Service Target Performance Incentive Scheme – STPIS)
- the demand management incentive scheme (DMIS)

To this suite of incentive schemes is proposed to be added an expanded Customer Service Incentive Scheme, following on from AusNet's Customer Forum concept.

In its response to the initial proposals, the sponsors noted that three of the incentive schemes (EBSS, CESS and STPIS) are closely related in that increasing both opex and capex allowances can result in benefits to the DB from the STPIS, and that increases in capex can lead to a reduction in opex. As a result, they expressed concern that the way the schemes do interact does not make them truly complementary with the approach the AER applies to setting opex and especially capex.

8.1 Opex incentive

The EBSS is supposed to provide an incentive to drive the DB to the efficient frontier of opex yet the AER has had to mandate a fixed productivity increase of 0.5% pa as the DBs have fallen behind the general Australian working productivity. If the EBSS was achieving its goal, the DBs would have matched (or even exceeded) the economy wide productivity increases. This leads to the conclusion that the EBSS is not sufficient to drive opex to the efficient frontier.

One of the drivers of increased productivity is the replacement of old equipment (which requires greater attendance) with new and therefore reduce attendance. In addition, the replacement should require less attendance over its life due to technology improvements.

This means that there should be some correlation between the amounts of repex provided by each DB and the productivity improvements in opex. Yet the assessment of repex by the AER is made quite independently of the assessment of opex.

For example, in the current 2016/20 period, the amount of repex allowed was a significant increase from the previous (2011/15) period actual (see table 3 above) yet the opex allowance for the current 2016/20 period was based on the 4th year actual opex of previous 2011/15 period. The actual opex for the current 2016/20 period reflects that the DBs used about half the amount of repex that was allowed. Despite the lower amounts of repex actually provided, opex in the 2016/20 period also fell below the opex allowances provided. If the EBSS had driven the DBs to the efficient frontier, then it would be expected that current opex would have exceeded the allowance for the current 2016/20 period because of the lower actual repex but this did not occur. The conclusion from this is that the opex is not efficient.

The EBSS is a rolling forward scheme crossing regulatory periods, and this is supported. However, both the CESS and STPIS, with which the EBSS is intended to be balanced, do not, with the CESS being assessed within its regulatory period and the STPIS for the next period based on targets derived on achievements made in the first 4 years of the current period and the last year of the previous period. This lagging effect weakens the relationship between the three performance measures.

This high-level analysis implies that the EBSS is not achieving its goal in driving opex to efficient levels. Further, the approach to assessing repex independently to the setting of opex and out of date targets from the STPIS weakens the power of the EBSS.

8.2 Capex incentive

In the current period, actual gross capex will be some 13% below the allowance for gross capex provided by the AER for the current period (see table 2 above). As a result, all DBs will get a bonus under the CESS.

Despite this very large capex under-run in the current period, the AER proposes to allow the DBs only 10% less capex for the next period than their actual in the current period. The DBs revised proposals in aggregate seek only a 5% reduction with both CitiPower and United seeking an increase, despite not spending their capex allowance in the current period.

Unfortunately, the CESS operates within a regulatory period and not across periods like the EBSS does. This provides the DBs with the ability to “game” the CESS. In particular, this “gaming” has a number of outcomes that must be addressed

1. There is no transparency as to which capital projects planned for the current period have been carried forward to the next period, despite them being included in part of the current period capex allowance. It is imperative that the AER ensure that the current year benefit from the CESS exclude any projects that have been carried forward into the next period
2. It is reported that a number of capex projects could not be implemented due to the COVID-19 pandemic. If these projects could not be completed the performance of the DBs was not impacted and therefore the projects were not needed, this raises two important aspects

    - Why were they included in capex allowance in the first place?
    - Should the CESS be paid on projects that could not be implemented and are demonstrated not to be needed
3. As noted above, actual repex was about half the allowance but the impact of this under-run on opex was a reduction. By assessing the CESS within a regulatory period rather than across periods (as the EBSS is) the ability to use the CESS to be balanced with opex incentives, is significantly weakened
4. The STPIS targets for the next period are set on the average performance seen over the first 4 years of the current period and the last year of the previous period. This means that actual capex has had a significantly reduced impact on the outturn performance of the network, so the effect of any under-run in capex (and hence bonus under the CESS) will not be seen in the STPIS until well into the current period, indicating that the STPIS and the CESS have little relationship, despite the AER asserting that all three incentives are designed to be balanced due to the lagging effect of the measures

Overall, the CESS needs to be made to operate across regulatory periods as is the EBSS and the setting of capex ex ante needs to have a much closer connection to the performance of the EBSS and CESS.

8.3 Service performance

In its response to the initial proposals the sponsors noted that the current version of the STPIS (version 2.0) has some shortcomings, particularly that

- There was a continual reliability improvement which, because consumers were paying the DBs a bonus, they are effectively paying for improved reliability.
- There is an unwillingness to pay for increased reliability
- The STPIS targets for the next period are based on performance that was achieved well into the past and a rolling average target based on the previous 3-4 years is a better incentive for performance and provides a better outcome for consumers.

The AER draft decision states that the current STPIS (version 2.0) is to be applied to the next regulatory period without change, meaning that the current detriments observed will continue. This is disappointing.

The AER also observes that the unwillingness to pay for increased reliability is addressed within the Value of Customer Reliability (VCR). While the provision of the VCR does provide guidance as to the willingness of consumers to pay it is pointed out that consumers have been quite clear that they do not want to pay at all for improved reliability so the application of the VCR should refer more to the price consumers are prepared to pay for maintaining or avoiding reductions in reliability rather than them paying to further increase reliability.

The AER also commented that it does not consider that there is a relationship between reliability of supply and the development of the opex and capex allowances as any proposal by the DBs to improve reliability has to demonstrate a clear relationship between the cost of the improvement and the change in reliability to be achieved. This is not the point.

The commentary by the sponsors was that the amount of capex and opex do have a relationship with the reliability achieved and if the opex and capex allowance is higher than needed to maintain reliability then there will be improved reliability. Effectively, if reliability is improving over time, then it is because the AER has provided more capex and opex than were needed. This is what is being observed – that reliability is improving implying that the opex and capex allowances are higher than necessary.

With this in mind, the allowances for opex and capex should include recognition of the trend of reliability performance.

8.4 Customer service incentive scheme

In their response to the initial proposals, the sponsors expressed support for the CSIS process, noting that the telephone answering measure alone really did not meet customer needs.

It is noted that Jemena does not consider that a separate CSIS is needed based on advice from its consumer engagement process, but that the other four DBs have proposed its implementation in different guises. The following table outlines the elements that are proposed by each of the DBs.

Table 8 Proposed customer service measures

	Telephone answering	SMS notification	Planned outages	Satisfaction levels			
				Planned outages	Unplanned outages	New connections	Complaints
AusNet				X	X	X	X
Citipower	X	X					
Jemena	X						
Powercor	X	X	X				
United	X	X	X				

Source: DB revised proposals

Whilst supportive of the proposed changes there is concern that the target measures are too easily achievable, that the value ascribed to each of the measures is too large compared to the value customers attribute to the measure and that the overall reward (as a percentage of revenue) is too large compared the value customers attribute to the benefit delivered. In particular, there is concern that the value ascribed to improve SAIDI and SAIFI for planned outages are too great.

The AER is requested to examine in detail the proposed targets and values given to each measure and that the value that the DB might get from the CSIS remains commensurate with the value that consumers will get, noting that consumers have widely expressed a view that increased reliability is not required and that cost reductions are the highest priority.

9. Pricing

As a general observation, to maximise its effectiveness, a Time of Use (ToU) tariff needs to reflect the times when the network is most used. In pure economic theory, a ToU tariff will reduce the peak demands and so limit the need for network augmentation. It is also noted that the AusNet approach to setting a critical peak demand tariff has a similar effect.

What a ToU tariff does not necessarily do is reflect consumer behaviour. For example, on a hot day when the ToU peak tariff applies, will consumers turn off their airconditioners to reduce their network charges – probably not! This means that a ToU tariff is unlikely to deliver the benefit expected and may lead to some consumers seeing a distinct increase in costs which they cannot manage.

The change in tariffs to more ToU does provide an incentive to those that can either change their usage pattern and/or afford the capital cost of implementing the necessary hardware to make better use of ToU tariffs. This reality is a disadvantage which penalises less well-off end users and provides benefits to those better able to manage their energy consumption.

The question as to either have “opt in” or “opt out” when forcing change is vexed. The DBs have generally decided to force change so that all new customers (including those that add solar and where occupancy changes) will be automatically put on a ToU tariffs with the ability to “opt out” on request. This is acceptable providing that the DB makes it very clear to the customer that they will automatically be put on a ToU tariff, what the cost/benefit might be to be on this tariff and that the customer can opt out if they so desire.

It is noted that the AER supports the introduction of a driver to move consumers off flat tariffs to ToU tariffs by discounting the residential ToU tariff relative to the flat tariff over time such that increasing numbers of residential consumers will be better off under ToU compared to a flat tariff, encouraging the transition. While generally supportive of such a move, it is important to recognise that there will be some disadvantaged consumers that will not have the funds to help them move usage away from the critical times and/or the time availability to achieve this. With this in mind, it is suggested that such customers must be treated so they are not further disadvantaged by this tariff reform.

It has also been noted that tariffs are trending to include larger fixed charges and demand charges and lower usage pricing, reducing the incentives to better manage demand. Particularly, higher fixed charges remove incentives to minimise consumption overall. While there is support for pricing to reflect demand and move usage away from peak demand times, it is important to note that minimising consumption overall does have potential significant side effects, leading to more and more consumers looking to alternative sources of electricity, increasing the costs for those remaining on the network.

There is considerable discussion about the costs that small generation (distributed energy resources – DER) and whether the generators should pay for the assets needed for the export or whether consumers more generally should carry the costs. While it is accepted that this issue is currently being considered as a result of proposed rule changes, in the customer connections capex (see section 6.3 above) there is reference to AusNet and the connections cost for large embedded generation. This raises an important issue for the pricing of services. This will create issues for consumers because large embedded generators are not charged for the use of the distribution assets or transmission assets they use or the deep connection costs incurred by the introduction of large embedded generation and these costs are carried by consumers.

The AER needs to ensure that consumers are not charged any cost in relation to large generators seeking to be embedded in the distribution network and that these generators pay DBs for the use of the assets they cause to be provided.

10. Pass through events

The Rules allow pass through events related to

- a regulatory change event
- a service standard event
- a tax change event
- a retailer insolvency event

In addition to these the AER has also allowed additional pass through events, including

- an insurance cap event
- an insurer credit risk event
- a natural disaster event
- a terrorism event

However, within these categories the AER has stipulated certain requirements before these pass throughs events are accepted.

In the initial proposals, there were additional pass through events added and of these the AER has accepted only one. The AER rejected proposals for major cyber, act of aggression and EV events.

A number of DBs proposed there be added to the accepted pass through events, an insurance coverage event and the AER has accepted the premise behind this proposal. As written, this proposed change provides a degree of balance between the costs of bushfire insurance, the deductable and the cap provided by the insurance. Where such risks are unknown such as the likely extent of damage, the timing of the incident and the frequency the insured incident occurs, there is some benefit to consumers that they accept some of the risk and receive a benefit in a reduction in or elimination of a higher premium.

This approach is accepted in principle but subject to a careful examination by the AER of the balance, noting that to a large extent it incorporates the already allowed Insurance Cap event pass through.

However, there is potential that a "bushfire insurance event" could be extended to cover all insurance events. The concept of a bushfire insurance event is supported in principle, but there is no support for a pass-through event which includes more general insurance. This issue is more fully discussed in section 7.3.6 above and below.

Table 9 below shows the new pass through events sought in the revised proposals .

Table 9 Proposed new pass through events

New pass through event	AusNet	CitiPower	Jemena	Powercor	United
Insurance premium event	X			X	X
Pole management event		X		X	X
Major cyber event	X				
Environment protection event	X	X	X	X	X

Source: DB revised proposals

The following comments address the new pass through events proposed by the DBs as follows:

Insurance Premium event. A number of DBs have provided more information regarding the rejected Insurance Premium Event pass through. From the changes proposed to the Insurance Coverage event (noting that it is primarily aimed at the bushfire risk insurance), it would appear that the requested additional pass through event for Insurance Premium event are addressed in the Insurance Coverage event to the extent that the DB is covered providing it can demonstrate that in balancing the different competing elements of the insurance (price, deductible and cap) it has demonstrably and properly reached the most efficient outcome.

With this in mind, the proposed Insurance Premium event is not supported if it goes beyond just bushfire insurance. The approach for establishing the bases for general insurance issues are a well-known process and there is adequate competition available to the DBs for this class of insurance. There is concern that providing pas through event protection to the DBs for general insurance has the potential for the DBs to under-insure (generating a reduction in opex) and then pass through the costs of any un-insurance or under-insurance to consumers. The discipline of being liable for establishing the correct amount of insurance must lie with the DB and so the proposal should continue to be rejected by the AER.

In summary, a bushfire insurance event process is supported if the DB demonstrates ate the rest that it has balanced the cost, deductible and cap to be efficient such that the unexpected costs beyond the insurance are recoverable via a pass-through event.

General insurance is not to be covered under the pass-through process.

Pole management event. This pass through event has its genesis in the decision of the AER to (rightly) reject the excessive repex costs sought for pole replacement which was generated as a result of Powercor proposing a major pole replacement program and gaining Energy Safe Victoria (ESV) to support the program, which it did.

What has now occurred, is that the DBs are now asserting that the pole management program they espoused is a direction from ESV.

It is recognised that if ESV made a determinative requirement to implement a pole management program then this would trigger a pass through even based on the other pass through provisions. But this has not occurred, and the pole management program remains a “like to” proposal from the CPPALUE DBs.

If it becomes imperative, the CPPALUE DBs have the ability to implement their pole replacement program and seek agreement of the capex involved from the AER at the end of the regulatory period, just as other urgent but unplanned capex is managed.

This pass-through proposal is not supported.

A major cyber event. The AER rejected the major cyber event proposals from other DBs and even though AusNet has provided its reasoning behind why it considers this should be a pass through event the arguments provided add little to those provided by the other DBs and which the AER rightly decided were insufficient to justify the transfer of costs to consumers.

In the response to the initial proposals, the sponsors observed that passing the risk to consumers of a major cyber-attack reduces the DBs’ drive to avoid the outcome of such an attack and did not consider that the DBs should be effectively indemnified by consumers if they have not implemented appropriate protections.

The decision made by the AER to reject this pass-through event is appropriate and should be applied to AusNet’s proposal.

Environmental protection event. The proposed pass through is based on a concern that the Environmental Protection Authority (EPA) will institute changes that impose costs on the DBs. If the EPA makes a requirement of the changes it makes and imposes these on the DBs then this would be covered under the current suite of pass through allowances.

As with the pole replacement program, if the capex and opex required to comply with an EPA direction is assessed by the AER at the end of the regulatory period to be prudent or a regulatory requirement, then the DBs will be allowed to incorporate the costs into the RAB and the future opex allowance. This means that the risk to the DBs is small.

There does not seem to appear to be a need to have a special pass through event to be implemented for this potential change.