2021-2026 Victorian EDPR

Joint submission from Victorian community organisations – summary document

May 2020

Contents

ENERGY CONSUMERS AUSTRALIA

This project was funded by Energy Consumers Australia (www.energyconsumersaustralia.com.au) as part of its grants process for consumer advocacy projects and research projects for the benefit of consumers of electricity and natural gas.

The views expressed in this document do not necessarily reflect the views of Energy Consumers Australia.

1 Summary of recommendations

Victorian community organisations have prepared this joint submission to represent the interest of consumers, and especially vulnerable households, in the upcoming Victorian electricity distributors' revenue period, recognising the importance of distribution spending in maintaining an affordable and sustainable electricity supply.

Brotherhood of St Laurence, Renew, Victorian Council of Social Service, Consumer Action Law Centre, Council on the Ageing (Victoria), St Vincent de Paul Society Victoria, Uniting and Yarra Energy Foundation are signatories to this submission.

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.

Recommendations

1. **Reducing network charges must be prioritised to ensure the affordability of an essential service for all Victorians**

   Affordable electricity remains critical for vulnerable Victorians. There are persistent indications that high energy costs are a major cause of financial stress for many Victorians, and can lead to further debt. Ongoing indicators show that a lack of energy affordability denies vulnerable Victorians sufficient access to an essential service. Furthermore, consumers consulted by all the network businesses expressed a strong desire for lower prices, even when they were supporting network investment in specific areas (e.g. DER enablement). Lowering prices is a consumer priority, and all other new investment must be balanced against that.

2. **Revenue reductions must reflect actual efficiency improvements to ensure affordability over the long term**

   It is important to pursue electricity cost reductions that are underpinned by improved network efficiencies and fundamental costs savings, and that do not simply reflect the current low cost of capital. Currently, the moderate bill savings listed by the distributors are wholly dependent on this external factor. Further revenue reductions are important to secure affordability for consumers.

3. **Continued growth in the Regulatory Asset Base should be avoided, to reverse the ongoing trend of rising electricity prices**

   The Regulatory Asset Base (RAB) is continuing to grow in absolute terms for all distributors – and for most distributors it is also growing in relation to consumer numbers and peak demand. Consumers pay for new assets over their lifetime, so a higher RAB will lock in higher costs over decades. As the asset base has grown over the last decade, assets are used at a lower proportion of their full capacity. This suggests the RAB is increasing beyond consumer requirements - proposed augmentation should be closely scrutinised, to avoid a net increase in the RAB.

4. **The forecasts for consumer numbers, peak demand, and total consumption, appear to be unusually high, raising a risk of overbuilding**

   Forecasting for all parameters will need to be reassessed as the impact of the COVID-19 pandemic becomes clear.

   The current combined forecasts for peak load from the distributors are significantly higher than AEMO's forecast for load at the transmission connection point, despite AEMO forecasts proving to have been conservatively high in the past.

   This may indicate that proposed peak-driven augmentation expenditure exceeds requirements.

5. **Capital expenditure is increasing, despite consistent underspend in previous periods. This suggests that proposed expenditure is likely to be higher than needed**

   Actual capital spending has consistently fallen below proposed and allowed capex revenue allowances over the past 20 years, delivering rewards to distributors through the Capital Expenditure Sharing Scheme (CESS) incentive program.

   Despite the current period's underspend, distributors have proposed increased capex for the next period, raising the concern that this will again exceed actual requirements and create unnecessary costs for consumers.

6. **Expenditure to accommodate solar PV must clearly demonstrate consumer benefits**

   In principle, we support investment to accommodate rooftop solar PV on the distribution network, but in the interests of all consumers, it is important that this reflects the consumer priority for lower network costs.

   It also important to work towards a consistent investment approach across the networks to accommodating DER, albeit an approach that is flexible enough accommodate real differences in the local grid conditions.

   We support a standard approach for valuing exported generation, that reflects the expected changes in the value of DER exports over time and a consideration of the demand for export capacity on the network – including benefits such as the provision of network services and downward pressure on wholesale energy prices.

7. **Past replacement expenditure trends suggest that proposed repex is likely to be higher than required, and should be reduced**

The repex proposed by distributors at the last reset proved to be much higher than the amount required – even while reliability indicators have improved through the current period. Networks were rewarded for this discrepancy through the CESS.

Despite the current period's underspend, some networks are proposing a significant increase in repex for the next period, that is inconsistent with past trends. We are concerned that this is likely to exceed actual requirements, so that consumers may pay the cost of unmerited incentive scheme rewards and financing costs.

8. **Further consultation on Environment Protection Authority (EPA) noise regulations needed**

   Significant expenditure initially proposed by some networks to meet new noise regulations has been withdrawn with a delay to implementation of the new EPA regulations.

   Noise complaints to distribution networks are relatively rare, and it is not clear that this investment is required to meet the regulations, or protect the public or the environment.

   We recommend ongoing consultation between stakeholders to clarify appropriate management for distribution infrastructure.

9. **A standard depreciation schedule should be developed and applied across Victorian distributors**

   Establishing a standard schedule across Victorian distributors would allow a fair, consistent and optimal approach to charging consumers for new investment.

   Where distributors are allowed to set depreciation lifetimes that are shorter than the real average service life, then consumers will pay higher prices through the return of capital.

10. **Operational expenditure productivity has been declining for most networks, which highlights the need for increased operational efficiencies, and the importance of close scrutiny of proposed step changes**

    Opex productivity declined on a long-term trend for most networks between 2006 and 2018 – this makes the case for ongoing productivity improvements.

    Many of the step changes proposed by the networks do not match the criteria for valid step changes, including the requirement that they are a response to ongoing external factors. Step changes increase costs on an ongoing basis, and lower the bar against which efficiency gains are measured – so it is important to test the validity of step change claims.

11. **The NewReg trial has demonstrated gains for consumers – a full assessment of the negotiated AusNet Services proposal will be useful to evaluate the impact of this process and the efficiency of all aspects of the proposal**

    AusNet Services and the Consumer Forum negotiated an initial proposal that achieved significant savings for consumers, when compared to the draft version.

A detailed assessment from the AER of how this was achieved is needed to fully understand the impact of this new approach.

Applying a standard approach to the evaluation of revenue proposals by the regulator will remain an important aspect of the determination process if this approach is more widely adopted in future, especially in terms of preserving consistency and benchmarking efficiency between networks.

12. **Further analysis is needed to support an informed decision on proposed tariff structures**

    The networks have proposed a time-of-use tariff, with a peak charge between 3 and 9 PM, which will be assigned by default, on an opt-out basis, to new solar consumers, new connections, and households with electric vehicles and three-phase connections. We understand that retailers will be required to continue to offer a basic flat tariff through the Victorian Default Offer. We recommend that further analysis is important to underpin a properly informed decision of the impact of these tariffs on Victorian households.

2 The EDPR and Victorian consumers

Distribution costs make up 30-40% of an average Victorian household's electricity bills. Where distributor revenues are allowed to be higher than necessary, this will drive high energy costs over the long term.

In Victoria, electricity bills rose by 104% in real terms between 2008 and 2019,[1] with the distribution component rising steadily to a peak in 2015, driven by investment in programs like smart metering and bushfire prevention upgrades. [2]

Although the growth in electricity prices has recently slowed, there are many indications that high energy costs are still a cause of financial stress for many Victorians.

A 2019 study of calls to a financial helpline found that energy debts remain a strong early indicator of economic hardship, and can lead households into further debt.[3] Energy bills are known to consume a high and growing proportion of the expenditure of low-income households.[4]

---

[1] The St Vincent de Paul Society, 2019, Households in the dark II, accessed 1 March 2020, https://alvissconsulting.com/households-in-the-dark2/

[2] Australian Competition and Consumer Commission, 2018, Restoring electricity affordability and Australia's Competitive Advantage, accessed 1 March 2020, https://www.accc.gov.au/regulated-infrastructure/energy/retail-electricity-pricing-inquiry-2017-2018/final-report

[3] 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

4 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

For many households, high energy costs restrict access to essential services. Many JobSeeker and Youth Allowance recipients are unable to afford to heat or cool their homes.[5] An Alfred Health study found most of their hypothermia patients had been discovered inside, with a lack of adequate home heating likely a significant contributing factor.[6]

Given that the EDPR will establish the rates charged for a significant proportion of household bills over a five-year period, energy affordability and its implications for vulnerable Victorians in particular remain critical.

Key points:

1. The distributors' proposed revenue would be higher than in the current period were it not for the historically low cost of capital.

   Secure affordability over the long term will require cost reductions that do not rely on external factors, but that instead reflect a real decline in the fundamentals of distribution costs, including operational costs and the value of the regulatory asset base (RAB).

3 Revenue trends show a need for further savings, to ensure long term affordability

The attached analysis of revenue trends and proposed revenue shows there is a need for reductions in the proposed revenue in order to deliver affordability.

Key points:

1. The revenues proposed by distributors are level-with or slightly lower-than the current period's revenue, however, any reduction is entirely dependent on the current low cost of capital, without which revenues would actually be increasing. The distributors' revenue includes an allowance for the cost of financing the network, which is calculated by the AER in line with current financial metrics – that are currently at historical lows.

[5] 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

[6] DS Forcey et al, 2019, Cold and lonely; emergency presentations of patients with hypothermia to a large Australian Health Network, accessed 1 March, https://www.ncbi.nlm.nih.gov/pubmed/30963670

2. The total value of the network assets – the RAB – is continuing to grow for all distribution businesses. It is continuing to grow on a per-consumer basis for most businesses, and also growing relative to peak load, which is the historical driver for the RAB. Allowing the RAB to continue to expand will drive higher prices for decades, as consumers pay for the capital expenditure through depreciation over the assets' lives.
3. The increase in the RAB is not caused only by new requirements for investment like bushfire risk reduction programs. Asset utilisation – the loads served by assets relative to their capacity – is continuing to decrease, showing we are investing to expand the network beyond our needs. Network reliability is also continuing to increase, while consumers state a preference for maintaining, rather than improving reliability. These indicators suggest that the RAB is expanding in excess of consumer requirements.

4 Forecasting

The accuracy of forecasts – for consumer numbers, peak energy, and total energy served – is critical in planning infrastructure to meet our needs. The anticipated bill savings for some distributors are also reliant on the expectations for increased consumer growth – where this proves to be an overestimation, bills will increase.

The COVID-19 crisis and resultant economic downturn will necessitate that all forecasts be revisited, and associated augmentation expenditure be reassessed. While there may be uncertainties remaining about the impact of the crisis over the timeframe of the EDPR process, we stress the importance of establishing forecasts that reflect the potential for a substantial economic downturn and slower population and load growth in Victoria.

The analysis below underlines the following concerns regarding the forecasting adopted by networks:

Key points:

1. Some distributors – AusNet Services, Powercor and United Energy – have forecast consumer numbers to increase at a faster rate than recent trends. These assumptions should be verified against independent data. In addition, the impacts of COVID-19 to migration and to the construction industry will require a thorough re-examination of these metrics, as the probable outcomes become clearer.

2. Some distributors – Powercor, United Energy and Citipower – have forecast a significant growth in peak demand, while AEMO has forecast a decline. AEMO forecasts for Victoria can be demonstrated to have been conservative – which raises doubt regarding the distributors' forecast for peak demand, and associated augmentation expenditure.
3. The accuracy of forecasts for total energy will impact tariffs charged to consumers. All distributors except AusNet Services are forecasting an increase in total energy, reversing the current trend of stable or falling loads.

5 Capital expenditure

A top-down analysis of capex trends discovers indications that estimations for capex requirements may exceed requirements.

Key points:

1. Capex productivity has declined for most networks (with Jemena falling the least) between 2006 and 2018.
2. Current rules incentivise distributors to overestimate the amount of capex required for the upcoming period in a number of ways:
    - the revenue allowance includes an allocation for financing forecast capex – this finance allowance is retained, even where the associated capital spending is not made;
    - the Capital Expenditure Sharing Scheme (CESS) rewards capex below the total determined for the period, which further incentivises setting high initial estimates;
    - the current regulatory method means that most of the profit available to the businesses is chiefly through the financial allowance for capital expenditure – which is a further incentive for high capital investment.
3. Between 2001 and 2020, there has been a consistent tendency for the actual capital investment made by networks to be significantly lower than the amounts they have proposed, as well as the AER's allowance.

6 Expenditure to accommodate solar PV

Investment to increase the network's capacity to host PV is a new area of significant augmentation expenditure. The particular solutions deployed will have implications for the energy costs of solar and non-solar consumers, and the shape and function of our future grid.

Key points:
1. Networks have demonstrated that consumers broadly support investment to accommodate solar PV capacity into the grid. However, it is still important to test that proposed investment is efficient. It is also important to ensure that network planning to accommodate DER is consistent with delivering lower costs for consumers, in line with consumers' stated priority.
2. We support a standard approach for valuing exported generation that reflects the expected changes in the value of DER exports over time, and other recognised benefits – such as the provision of network services and downward pressure on wholesale energy prices – where they can be quantified to a reasonable degree of accuracy. This may include a broader consideration of the amount of export capacity that would benefit the network.

7 Replacement expenditure

Key points
1. Proposed repex for most distributors is significantly higher than the allowance for the current period. However, for most distributors, the repex undertaken in the current period will be significantly lower than the allowance in the revenue – with the allowance being lower again, compared to the initial proposal. For the current period, the AER allowed the distributors 80% of their combined claim. This ended up being 60% higher than the amount needed – even while networks continued to deliver ongoing improvements in reliability. This context casts doubt on claims for an increase in repex from some distributors in the upcoming period.

2. We note that networks who were proposing significant replacement expenditure associated with new EPA regulations, have withdrawn this element from their propsals, with the delay in implementation of the new rules.

   Ongoing consultation is required with the EPA regarding the implications of the regulations for distribution infrastructure, to avoid the potential for significant expenditure where there is no real risk to people or environment.

3. Proposed repex for wood poles has jumped significantly for some networks, in response to concerns raised in fire-risk areas. We are concerned that findings for a particular, rural area appear to be being applied across network areas spanning different conditions, environmental exposure and failure risks.

8 Depreciation

The depreciation schedule determines the rate at which distributors recover the cost of capex from consumers through their bills.

Key points

1. Different distributors apply different depreciation schedules to the various asset types – and the asset lifetimes nominated in the depreciation schedules are also different to the asset lifetimes used for repex. Establishing a standard schedule across Victorian distributors would allow a fair, consistent and optimal approach to charging consumers for new investment.

9 Operational expenditure

Opex allowance accounts for the ongoing cost of running the network. Increased opex claims are the driver of the proposed increase in revenue for Jemena, Citipower and Powercor, who anticipate an increase of 20% in network running costs.

Key points

1. Opex productivity declined on a long-term trend for most networks between 2006 and 2018, in contrast to the general obligation for a business in a competitive market. The productivity of the networks has been significantly lower than the average for Australian industries over the long term. This calls into question the efficiency of the base year, and makes the case for establishing a requirement for ongoing productivity improvements by the networks.
2. We are concerned about the high number of proposed opex step changes, and their capacity to increase electricity costs on an ongoing basis, and lower the bar for opex efficiency improvements. We recommend that the validity of these step changes, as ongoing changes to the operational environment, be tested carefully.

10 Consumer engagement and the NewReg trial

All distributors undertook consumer engagement that expanded significantly on the last reset's programs, and the results from this engagement have led to useful interventions on behalf of consumers.

The NewReg trial conducted by AusNet Services demonstrated significant gains for consumers, between the draft and the initial proposal.

However, limitations remain on the extent to which the results of a distributor-run engagement program can be interpreted as a full representation of consumer priorities – a knowledge imbalance remains between distributors and their consumer base in an engagement process.

As such, the results of engagement should inform the regulator's decision, rather than be adopted as deterministic.

We recommend that AusNet Services' proposal, negotiated through the NewReg trial, be subject to the same assessment as the proposals from other networks.

As a pilot, it is useful to gain a detailed understanding of what aspects can be usefully negotiated through this type of process, and what can't. A thorough evaluation of the NewReg will allow a proper evaluation that would highlight the potential contributions and specific limitations of this additional tool in informing revenue determinations in regulated markets.

Applying a standard approach to the evaluation of revenue proposals by the regulator will remain an important aspect of the determination process if this approach is more widely adopted in future, especially in terms of preserving consistency and benchmarking efficiency between networks.

11 Tariff Structures

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 through the Victorian Default Offer.

In their Issues Paper, the AER has said that they will also consider the merits of a 'solar sponge' tariff, as well as a common tariff structure complemented by additional measures to address location specific issues.

While there has been some assessment commissioned by the networks regarding the impact of the proposed time-of-use structure for vulnerable consumers,[7] we recommend that further analysis in the following areas is important to underpin a properly informed decision:

What will be the impact of the proposed tariff for vulnerable consumers?

While understanding the impact of the time-of-use tariff for vulnerable consumers may be less essential given that it will be optional for most households, it is nonetheless an important question to address in the context of ongoing tariff reform.

High-level assessments undertaken by Acil Allen have established that some vulnerable consumers will be better off under the proposed tariff, and some will pay more.

We need to better understand how different types of vulnerable consumers will be impacted – including working and non-working households, consumers with energy-related health conditions and existing hardship consumers and consumers with energy debt.

We also need to better understand the impact of a proposed tariff structure on behaviour in vulnerable households – in this case, peak rates through the late afternoon and evening – to determine whether there may be undesirable consequences, such as an increased incidence of rationing essential heating or cooling.

How would the proposed tariff structure accommodate a high EV uptake scenario?

[7] ACIL Allen, 2019, Vulnerable consumer tariff impact

Preparedness for a high EV uptake scenario is often cited as a driver for tariff reforms.

Analysis should be undertaken to determine how effective this tariff – and the associated assignment arrangements – would be, and how the tariff would interact with other essential measures for managing EVs on the network.

Are the proposed tariffs targeted to reliably deliver network and wholesale savings, and can these savings be quantified or estimated?

If tariffs allow some consumers to reduce their distribution charges by changing their behaviour, it is important to be confident that this will lead to benefits that are shared by all consumers. It is also important to be confident that shared benefits will outweigh the additional network costs borne by consumers unable to respond to the price signal.

12 References

Acil Allen, 2019, *Vulnerable consumer tariff impact,* viewed 1 April 2020 https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/united-energy-determination-2021-26/proposal

ACOSS & Brotherhood of St Laurence 2018, *Energy stressed in Australia*, ACOSS, viewed 1 March 2020, http://library.bsl.org.au/jspui/bitstream/1/10896/4/ACOSS_BSL_Energy_stressed_in_Australia_Oct2018.pdf.

ACOSS, 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.

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

Forcey, D. S., FitzGerald, M. P., Burggraf, M. K., Nagalingam, V., & Ananda-Rajah, M. R. (2020). 'Cold and lonely': emergency presentations of patients with hypothermia to a large Australian health network. Internal Medicine Journal, 50(1), 54–60.

St Vincent de Paul Society 2019, Households in the dark II, accessed 1 March 2020, https://alvissconsulting.com/households-in-the-dark2/

Submission to the Australian Energy Regulator (AER)

Response to proposals from Victorian electricity distribution network service providers for a revenue reset for the financial years 2021-2026 regulatory period

Sponsoring organisations:

Brotherhood of St Laurence
Victorian Council of Social Service
Renew

This submission is also supported by:

Consumer Action Law Centre, Council on the Ageing (Victoria), St Vincent de Paul Society Victoria, Uniting and Yarra Energy Foundation

May 2020

This submission has been prepared by

David Headberry (Headberry Partners P/L)

with input from

Emma Chessell (Brotherhood of St Laurence)

on behalf of the sponsoring organisations.

This project was funded by Energy Consumers Australia (www.energyconsumersaustralia.com.au) as part of its grants process for consumer advocacy projects and research projects for the benefit of consumers of electricity and natural gas.

The views expressed in this document do not necessarily reflect the views of Energy Consumers Australia.

CONTENTS

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 2021 to 2026. In addition, they provided revenue reset proposals for the half-year January 2021 to June 2021, as a result of the Victorian Government decision to do future revenue resets on a financial-year basis rather than continue with the current calendar-year basis.

In order to provide informed comment on these proposals, the Brotherhood of St Laurence (BSL), Victorian Council of Social Service (VCOSS) and Renew – collectively the sponsors – commissioned David Headberry to conduct this analysis.

The sponsors recognise that there is a consistent message from consumers, which is shown clearly in the results from the DBs' customer engagement and in other surveys, that consumers would like to pay less for network services and do not want to pay more for increased reliability. This high-level assessment drives the commentary made throughout this submission.

The sponsors also note that high energy costs (for which the networks contribute 30-40% of electricity bills) have caused considerable financial hardship which can lead households further into debt.

A 2019 study of calls to a financial helpline found that energy debts remain a strong early indicator of economic hardship, and can lead households into further debt.[8] Energy bills are known to consume a high and growing proportion of the expenditure of low-income households.[9]

For many households, high energy costs restrict access to essential services. Many JobSeeker and Youth Allowance recipients are unable to afford to heat or cool their homes.[10] An Alfred Health study found most of their hypothermia patients had been discovered inside, with a lack of adequate home heating likely a significant contributing factor.[11]

These observations provide the very basis for the response provided in this submission.

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

9 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

[10] 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

[11] DS Forcey et al, 2019, Cold and lonely; emergency presentations of patients with hypothermia to a large Australian Health Network, accessed 1 March, https://www.ncbi.nlm.nih.gov/pubmed/30963670

1.1 The structure of the revenue resets

The sponsors are aware that the AER uses an approach described as the "building block" which reflects pricing in the following areas

- Return on capital (regulatory asset base times weighted average cost of capital or RAB*WACC)
- Return of capital (regulatory depreciation)
- Operating expenditure (opex)
- Revenue adjustments (including payment for incentives)
- Allowance for tax payable

The sponsors note that:

- The calculation of the weighted average cost of capital has been previously determined and is not part of this reset review process
- Past capital investments are already included in the Regulatory Asset Base (RAB) and are not subject to review in this regulatory reset process
- Embedded in the RAB for each year of the next regulatory period is new capital expenditure (capex) that is incurred in that year. This means that proposed capex is subject to review in this reset process
- Tax impacts have been previously determined and are not part of this reset review process

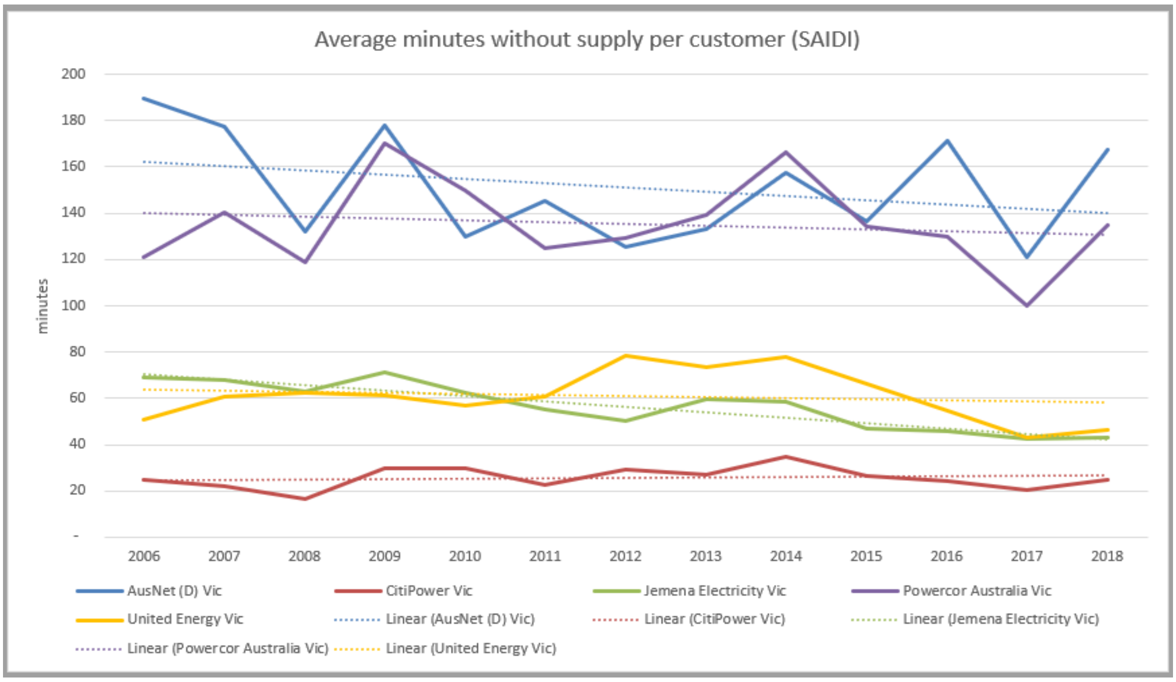
This submission focuses on aspects that are reviewable within the reset process.

1.2 The performance of the networks

The sponsors have analysed the reliability data provided by the AER in its spreadsheet 'Electricity Distribution Networks Performance data report 2006-2018' and identified that reliability of the networks has improved over time.

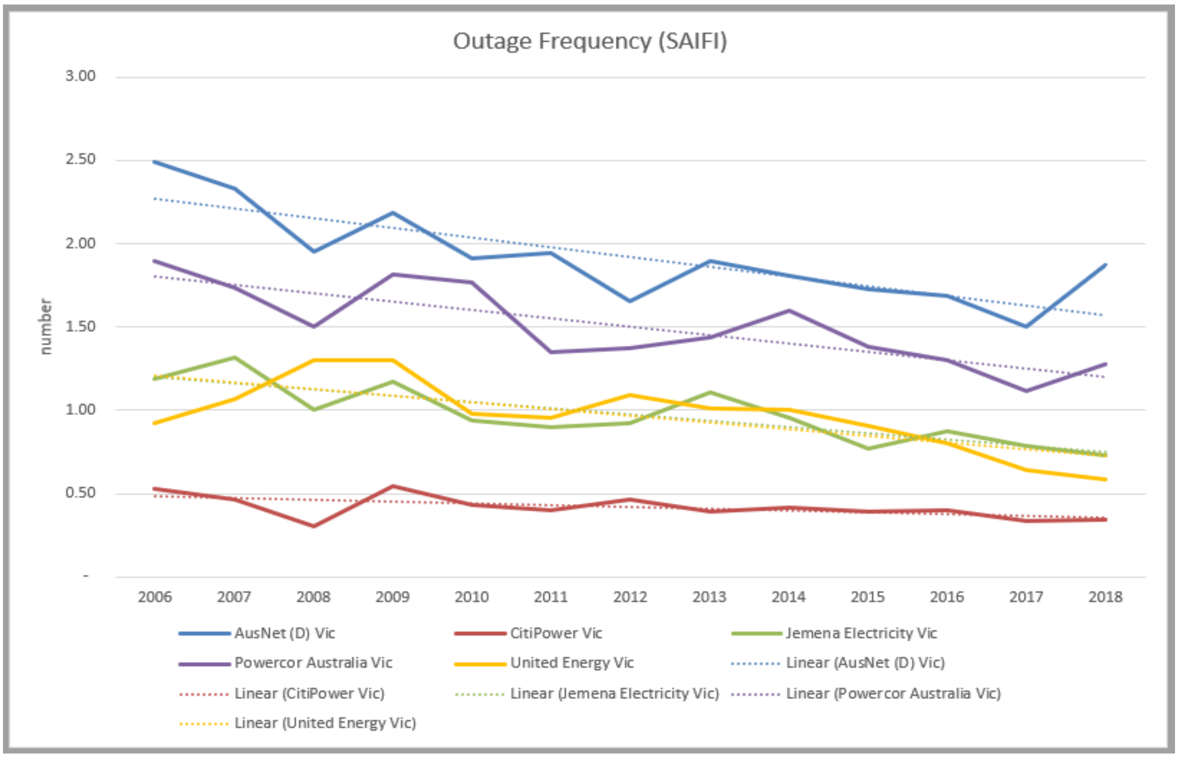
Specifically, system average interruption duration index (SAIDI) and system average interruption frequency index (SAIFI) are both either relatively static (for CitiPower SAIDI) or trending down(for CitiPower (SAIFI) and all other DBs for both SAIDI and SAIFI.) This is shown in the following two charts (figures 1 and 2).

Figure 1 Average minutes without supply per customer (SAIDI)



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

Figure 2 Outage frequency (SAIFI)

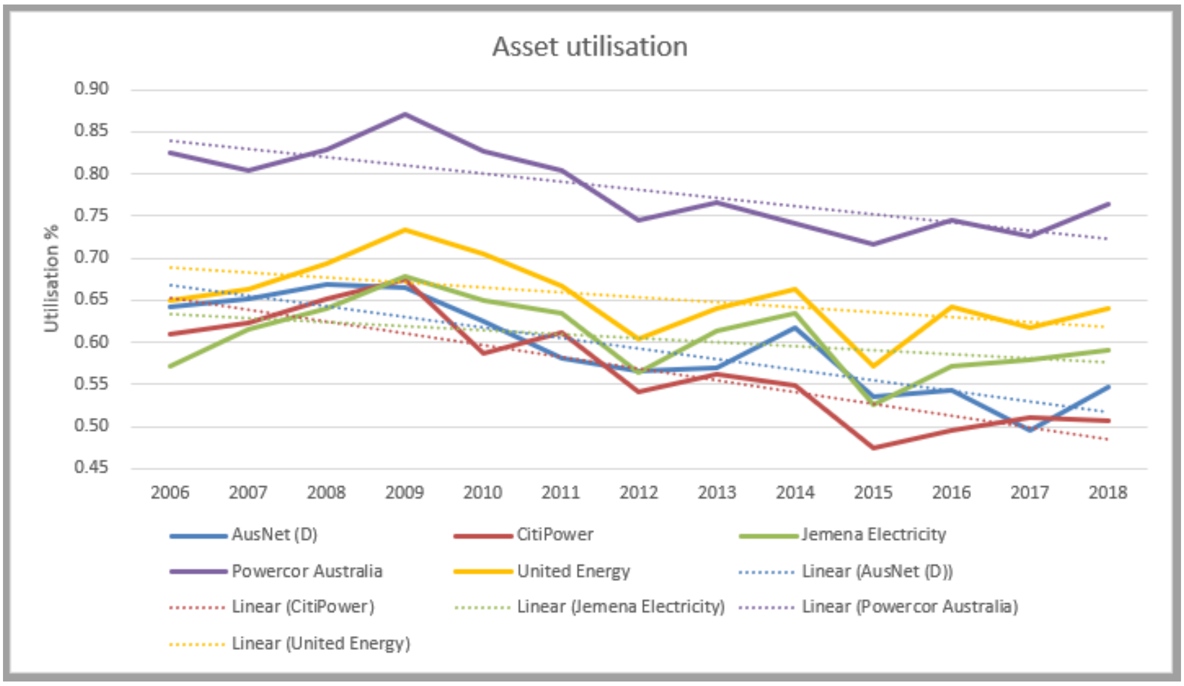


Source: AER Electricity Distribution Networks Performance data report 2006-2018

This demonstrates that all DBs have been committing 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).

At the same time as reliability has been improving, the sponsors note that utilisation of the network assets has continued to fall as shown in the following chart (figure 3).

Figure 3 Asset utilisation



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

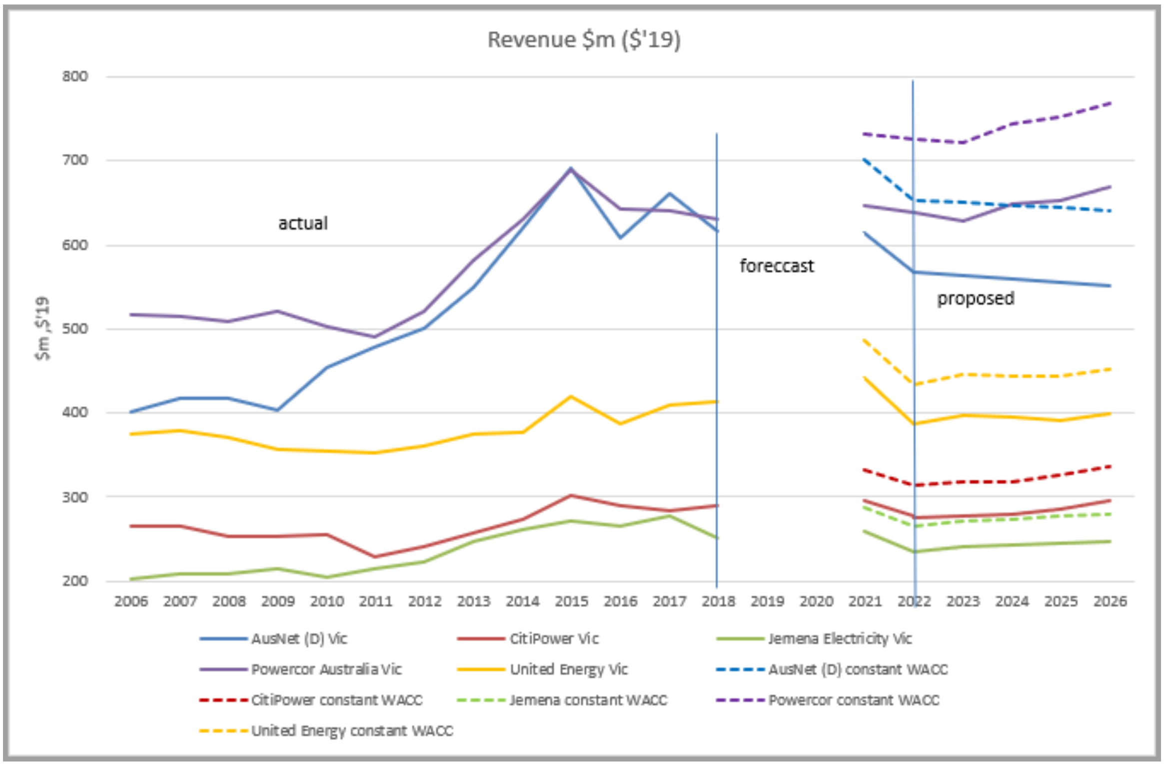
The falling utilisation of the assets provided by the DBs highlights that consumers are increasingly paying more than is necessary for assets needed for the service consumers require.

When combining the improving reliability with falling utilisation, this clearly highlights that the DBs are all increasing investment 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 have provided revenue forecasts for the next period which show either constant revenue (Powercor) or a small decrease (all other DBs) in the revenue they are seeking, as shown in figure 4. What is not made clear by the DBs is that this is driven entirely by the lower cost of capital that will apply in the next period. What is also shown on the chart is what the DB revenue would be if the same cost of capital as used in 2018[12] was applied to the forecast revenue.

Figure 4 Revenue



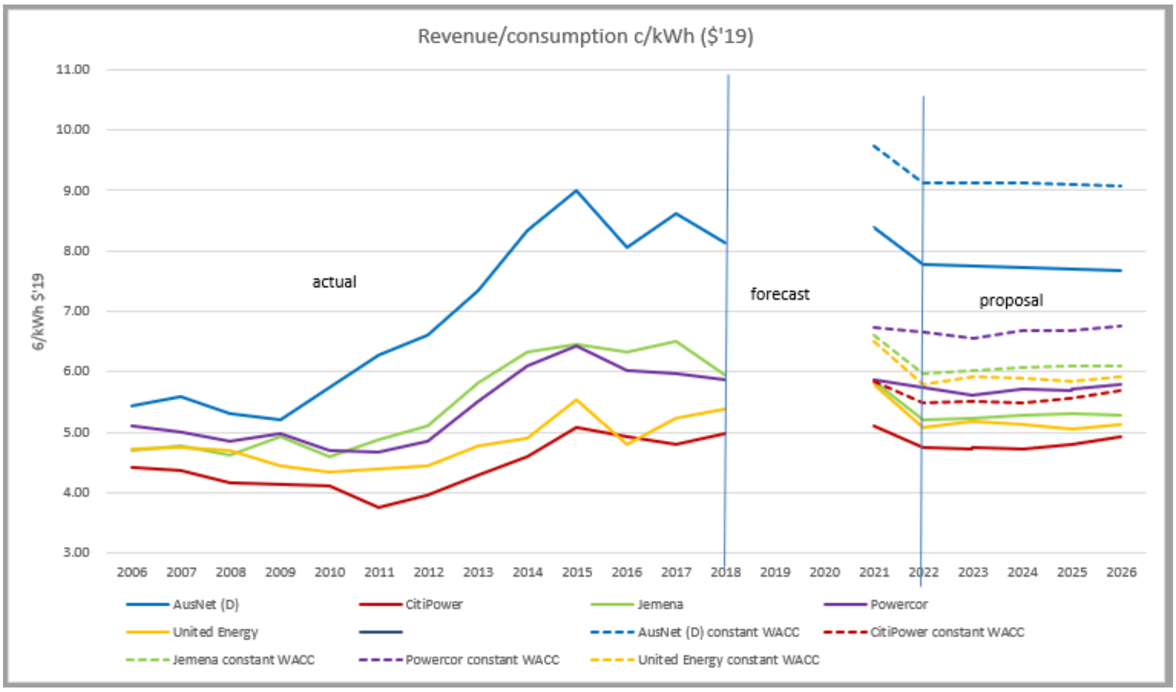
Source: AER Electricity Distribution Networks Performance data report 2006-2018, DB proposals

This analysis is supported by looking at the revenue related to consumption which for small users of electricity is reflective of the tariffs they are charged for DB services. This pricing

[12] In its Electricity Distribution Networks Performance data report- 2016-2018, the AER publishes (on page 12) the return on assets, real pre-tax WACC for the DBs. This constant WACC calculation apples the difference between the WACC used by the DBs in their proposals and the rate allowed for 2018 to each DB's RAB and for this amount to be added to the proposed revenue.

trend and forecast is shown in the following chart (figure 5). Again, on a constant WACC basis all the DBs are exhibiting increased charges for consumers.

Figure 5 Real revenue/consumption c/kWh



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

1.4 Managing the 6-month extension

As noted above, the sponsors generally support the approach the AER proposes for providing a revenue allowance to the DBs to accommodate the 6-month extension period to allow the movement from the calendar year basis for the regulatory period to a financial year basis. However, the sponsors recognise that the National Electricity Rules (clause 6.12.1) clearly state that commencement of any regulatory period and its length are determined prior to the commencement of the control period. In its determination for the current period, the AER determined that commencement of the current period was 1 January 2016 and that it had a duration of 5 years so the current regulatory period must end on 31 December 2020. The clear implication of this, is that the AER must set the allowances for the six-month period based on current assessments and not on assessments made more than 5 years ago.

Since the AER assessments were made for the current period, the DBs have all demonstrated that they did not need the size of the allowances made for opex and capex made in 2015 for the 2016-2020 period. This raises the question as to why the AER considers that the allowances made for the current period but now seen to be demonstrably too high (on the basis that the DBs did not use the allowances given) should be extended into the new regulatory period "stub" of six months. While accepting that the AER will not have produced a final view on what the opex and capex allowances for the regulatory period "stub" might be based on, there is a need to implement an allowance more reflective of actual needs. On this basis, the sponsors consider that the opex and capex allowances for the regulatory "stub" should be based on other approaches, such as

- The average of the actual usage over the 2016-2020 period
- The opex and capex assessed in the AER draft decision for the next regulatory period

Both approaches provide a more equitable allowance based on current fundamentals than carrying forward an allowance that the DBs have demonstrated is too high.

With regard to the tax and depreciation rates, while accepting that these allowances should be based on current fundamentals, the sponsors accept that any error introduced by using the approach proposed by the AER in its Issues Paper rather than a more accurate assessment is likely to be small and therefore the proposed approach is supported.

1.5 Impact of COVID-19

The sponsors note that there are a number of key aspects that represent change, and which will have an impact not only on this reset but also on consumers more widely.

Firstly, the sponsors note that the current COVID-19 virus will have a significant impact. It is noted that the networks, through their organisation, Energy Networks Association, have advised that the networks will "… provide support to customers enduring hardship as a result of the COVID-19 pandemic." This is welcome but the sponsors note that such an approach might result in networks seeking to recover the costs of such support at a later stage. It is essential that the networks be clear on how they might address the recovery of these costs and that the approach has the acceptance of the AER.

The sponsors also note that the COVID-19 pandemic has also resulted in a change to the electricity flows in the distribution networks with less electricity being used by commercial end users and increasing amounts used at the residential level due to increasing "work from home" and unemployed workers remaining at home. This move to increased residential consumption increases the liability faced by residential end users to the supply of electricity, and so increases their exposure to network charges. This increased risk needs to be recognised by the DBs.

A longer-term impact of the COVID-19 pandemic will be on immigration. Respected journalist Laura Tingle in the Financial Review 1 May 2020 comments that:

> "The Prime Minister … mentioned on Friday that Australia is expecting a 30 per cent fall in overseas immigration in the 2019-2020 year, on 2018-2019 figures. In 2020-2021, the forecast is for an 85 per cent fall on 2018-2019 figures. … Migration is a huge, but often unseen, driver of our economy. Its absence will be just one of the significant factors that changes our sense of the economy, time and events for the foreseeable future."

This observation reinforces the view that whilst the impact on permanent immigration in the short term is almost certain to show a reduction, over the longer-term numbers are also uncertain. Even more uncertain will be the medium-term impact on temporary immigration (especially for secondary and tertiary learning) and longer-term immigration noting that. Especially. Victoria has been a destination of preference for much of the temporary and longer-term immigration in recent years. Both of these will change the forecasts of customer numbers and the associated impacts on energy consumption and peak demand.

Recommendations

It's critical that forecasts are revisited, and associated expenditure re-assessed, in line with the potential impact of COVID 19 on the economy.

1.6 Investment to accommodate DER

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 CitiPower, Powercor and United Energy networks (collectively called CPPALUE throughout this submission).

The results from engagement programs across the network show consistent support from customers for investment to accommodate DER, with some differences in detail such as the allocation of costs for this investment

The sponsors support the general case for augmentation to support DER, however, we also consider that that there is a case for further consultation towards a more consistent and optimal approach between the networks.

All networks undertook a business case assessment for DER investment, to build a program around investment where the benefits exceed the costs – however there were significant differences in the approach taken by each.

In the absence of a standard method to value exported solar, businesses adopted different figures, with Jemena and AusNet applying the Victorian FiT from various years, and the CPPALUE commissioning Jacobs to determine a figure. (The Jacobs figure at 4.7c/kWh was more conservative than the FiT, but was based on similar elements, such as an aspect reflecting generation/wholesale costs, and a price for carbon.)

The networks have also proposed different technology pathways for accommodating DER, with the CPPALUE networks proposing to implement dynamic constraints as a first measure, and other networks limiting dynamic constraints to low-density areas like SWER lines (AusNet Services) and to C&I customers only (Jemena).

This means that in undertaking business case assessment, the business-as-usual case against which the value of proposed augmentation is judged is different between the networks. Networks deploying dynamic constraints judge further augmentation in terms of just the constraint that is alleviated, while networks without dynamic constraints value augmentation at the full lifetime's export of any additional systems enabled.

We feel that there is value in conducting a process that will establish a consistent approach to valuing exported energy, to inform the revised proposals for this reset associated, if possible, with the development of the AER's DER Integration Expenditure Guide.

We feel that a more long-term consideration of the value of increasing export capacity is required than the current value of the FiT, or equivalent metrics. Further, we also consider that there is a need to establish a consistent approach to designing the ability to manage the DER and for each business case made for implementing the DER by each DB to include all of the relevant costs, including capex, opex and IT implementation as a standard rather than these costs being allocated to various different cost elements.

It would also be beneficial for a process to consider wider questions relating to the business case assessments undertaken by the DBs, such as:

- What are the relative business case benefits of an approach that implements dynamic constraints as a first measure (such as CPPALUE), and one that accommodates additional installations via augmentation (as AusNet is proposing for areas other than low density rural areas)?

- How much locally generated export is likely to be required/economic, as the network develops? As DER becomes more uniform across the grid, will there be a strong case to augment the network to accommodate peak exports that exceed peak demand? Is there a strong case for augmentation that enables export beyond the zone substation? How much local export capacity is required to enable functions like peer to peer trading, local networks, wholesale arbitrage, transmission congestion), and are the business cases for these programs strong enough to justify the proposed investment in this period?

- Is there a case for adopting a conservative approach to augmentation, given the emergence of new technical solutions to voltage issues on the local grid? Most networks cite current innovation programs, run by themselves or by other networks, testing technologies such as network-scale battery storage, on-load tap changing transformers, Faraday exchangers, reactive power support from customer inverters– etc.

It will also be important to establish a system to monitor and evaluate delivery on proposed DER expenditure, given that DER investment has no implications for reliability, so that the STPIS devised to protect against under-deployment of traditional network infrastructure will not provide the same safeguard for DER-capacity investment.

Recommendations

We recommend a process that will establish a consistent approach to relevant aspects of the DB's proposals for accommodating DER, such as an approach to valuing exported energy over time, and wider questions related to network planning for a high-DER network. It will also be important to establish a system to monitor and evaluate delivery on proposed DER expenditure.

1.7 CPPALUE investment relating to the EPA Amendments

We note that since releasing the draft proposals, CPPALUE has withdrawn the proposed opex step change, and substantial capex related to meeting the new obligations of Environmental Protection (EP) Amendment Act 2018 – relating to zone substation noise mitigation, and a revised bunding program.

This change has been made in response to a deferral of the enactment of the new regulation by 12 months, to July 2021.

The networks have flagged that depending on their assessment of the final regulations, a cost pass through may be required to comply.

We note that consultation with all networks confirmed that the incidence of noise complaints related to zone substations are quite low – and it's not clear that there is a material risk associated with noise emissions from this infrastructure.

Therefore, we recommend that there is ongoing consultation regarding these regulations, to clarify appropriate requirements for distribution infrastructure and to avoid significant investment being prescribed where there is no material associated risk.

2. Consumer Engagement

All DBs undertook engagement programs that were substantially expanded from the consumer consultation completed for previous price resets. The programs run by the distributors were structured differently, with all broadly conforming to the non-prescriptive consultation guidelines issued by the Australian Energy Regulator and Energy Networks Australia.

Jemena convened a People's Panel, as a small citizens' jury that was proportionately representative of their customer base in terms of demographics and market segmentation. The group met regularly while Jemena's revenue proposal was being drafted, and they voted on a set of recommendations to inform the revenue process.

The CPPALUE networks started their engagement in 2017 and executed a coordinated campaign, incorporating a range of methods, in order to engage customers with different levels of experience with energy. Their approach combined quantitative surveys of their customer base, as well as deeper deliberative forums on a range of topics, and close community consultations on specific issues.

The difference in scope and design of the programs run by CPPALUE and Jemena were appropriate to the operational context and size of their relative networks.

AusNet Services participated in a trial of the 'NewReg' early engagement process. They appointed a Customer Forum of five members with relevant expertise to represent the interests of consumers and negotiate the terms of their initial proposal. After the Customer Forum was established, they took over much of the direct engagement with AusNet customers. The Customer Forum was supported by the AER in undertaking their negotiation.

Initial documents framing the terms of the NewReg program suggested that a successfully negotiated proposal may be expedited to some extent through normal EDPR evaluation process, at the AER's discretion.

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 CPPALUE, this has included energy literacy programs for vulnerable customers. AusNet Services cite cost-neutral improvements to customer service communications protocols.

The AusNet Services Customer Forum achieved significant reductions in revenue between the draft proposal issued in 2019 and the 2020 initial proposal, so that the AER, in their Issues Paper, suggested that as an initial position they would (page 30)

> 'focus … assessment on total opex and capex, and conduct less extensive assessment of components of capex and opex forecasts in AusNet Services' proposal, compared to other Victorian DNSPs' proposals.'

Other networks, such as CPPALUE, in their response to the Issues Paper and the Public Forum, suggested that this approach undervalued the consultation program conducted with their customer base. The CPPALUE networks report that they prepared their draft and initial proposal in line with customer responses to their own nominated contestable investment proposals (which were, however, established internally and not made public).

The limitations to which a distributor-led customer engagement process can be taken as a direct reflection of the customer base's priorities are shown by comparing the results between the DB's programs. In many key areas – such as the value of reliability, safety and affordability – the results from the programs included significant differences. The CPPALUE program found no difference, however, between its three networks. This pattern suggests that different research approaches are likely to have an impact on findings.

The results of the distributors customer engagement should inform, rather than determine the EDPR process, along with standard and independent sources of evidence, such as the AER's established models, industry benchmarks, Value of Customer Reliability studies, and evidence compiled by experts and frontline services, such as trends in energy related issues logged via the National Debt Helpline and other indicators of energy hardship trends.[13]

Applying a standard approach to the evaluation of revenue proposals by the regulator will remain an important aspect of the determination process if this approach is more widely adopted in future, especially in terms of preserving consistency and benchmarking efficiency between networks.

Recommendation

With these thoughts in mind, the sponsors do not agree 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.

[13] CALC Energy Assistance Report July 2019 https://consumeraction.org.au/wp-content/uploads/2019/07/190620_Energy-Assistance-Report_FINAL_WEB.pdf

3. Regulatory Asset Base (RAB) and Benchmarking

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. While the current benchmarking approaches by the AER focus on efficient use of capital, and efficient operation and maintenance costs, the sponsors consider there are other benchmarks that the AER should apply to identify whether a DB is operating at the efficient frontier.

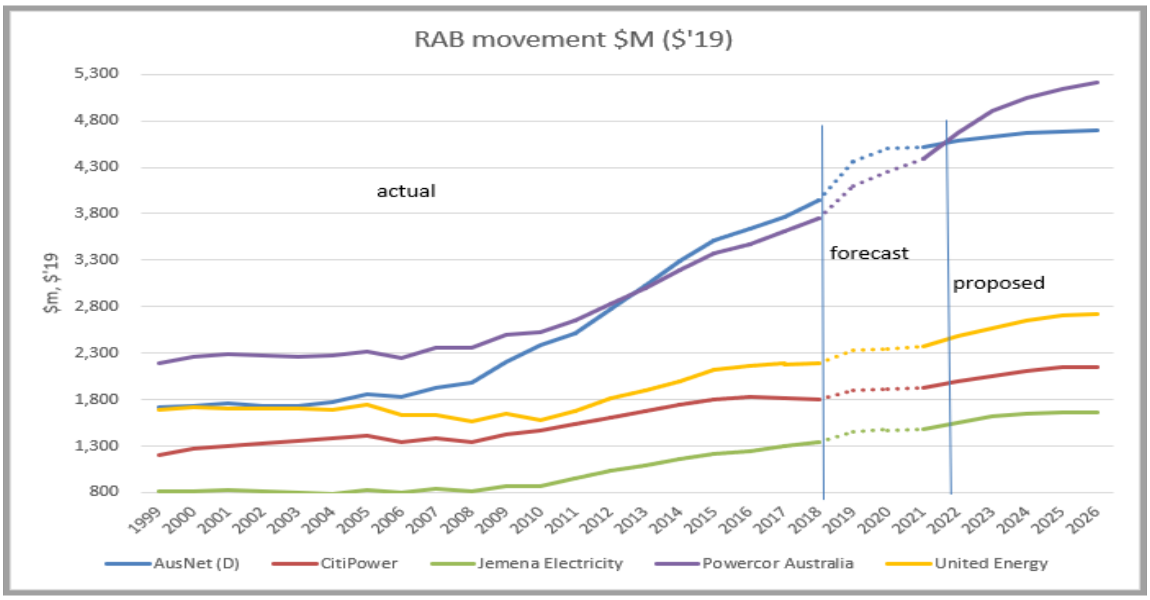
As well as other benchmarks, tracking the change in the RAB is an essential element to identify whether the amounts of capex are delivering value to end users and to see whether the rates of depreciation used are appropriate and consistent across all DBs.

3.1 Regulatory asset base (RAB)

One of the biggest cost elements of the "building block" approach to setting regulatory allowances is the "RAB*WACC calculation". As the cost of capital (WACC) is set independently of the regulatory reset process, it is important to assess whether the RAB is an appropriate figure, reflecting the needs of consumers. The AER has a process which mechanically calculates the RAB on a yearly basis based on the closing RAB from the previous year, deducts the recovery of capital in the current year (depreciation) and asset sales and adds the new capital invested in the current year.

With this in mind, the sponsors have assessed movements in the RABs of the five DBs both in actual real terms and relative to a number of controls. The change in the RABs over the last 20 years for all DBs is shown in figure 6.

Figure 6 Movement of real RAB over time

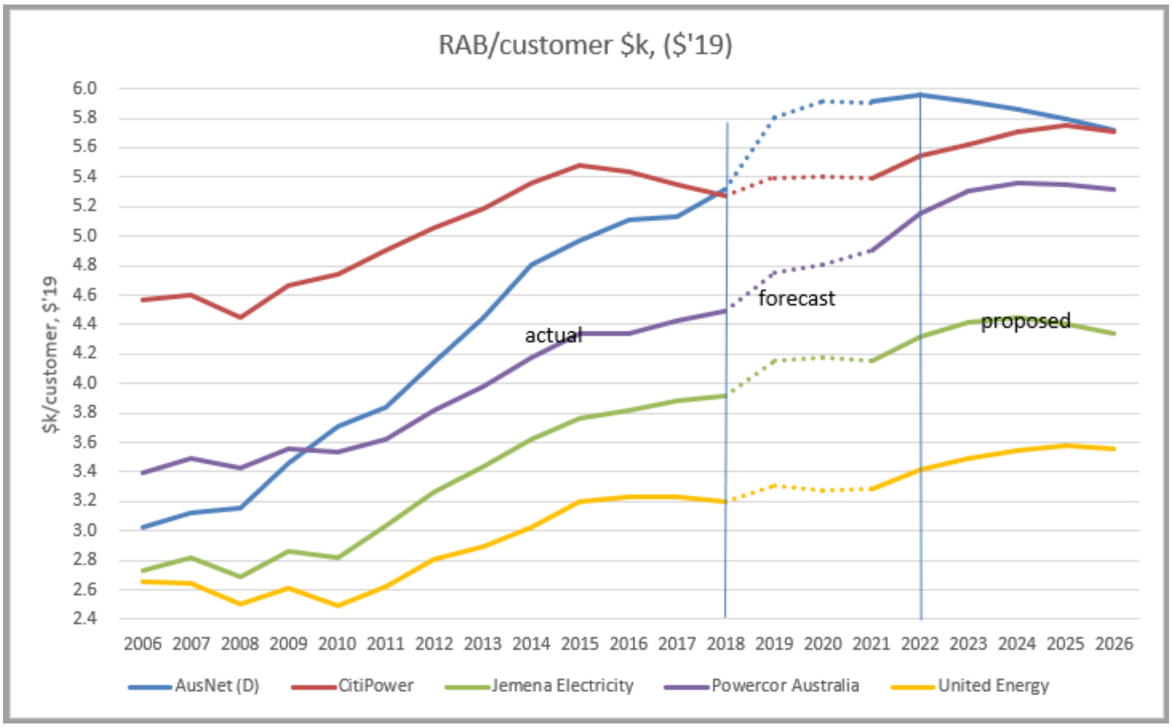


Source: AER Electricity Distribution Networks Performance data report 2006-2018, DB proposals, sponsor analysis

As an overarching assessment, the RAB for each of the five DBs has increased significantly over time, and is forecast to increase further based on the DB proposals. This means that consumers will be faced with providing a return on this amount of money for decades to come. The sponsors recognise that the RAB growth alone is not necessarily an indication of whether the previous capital expenditure was inefficient, as it is expected that as the population grows and demand increases, the RAB would also have to increase. With this in mind, the sponsors have assessed the growth of the RAB in terms of customer numbers (figure 7) and peak demand (figure 8). The purpose of assessing RAB growth in terms of customers and peak demand is to generate an assessment in relative terms in order to eliminate the change in these drivers of RAB growth.

The sponsors point out that the calculations for RAB relative to the next regulatory period are based on the forecasts by the DBs for customer numbers and peak demand. As these values for customer numbers and peak demand are critical to substantiating the increases in capex so it is imperative that these numbers are independently substantiated. If these customer numbers and/or peak demand are overstated, then the RAB will show an even higher relative value, highlighting inefficient investment.

Figure 7 Movement of real RAB/customer over time



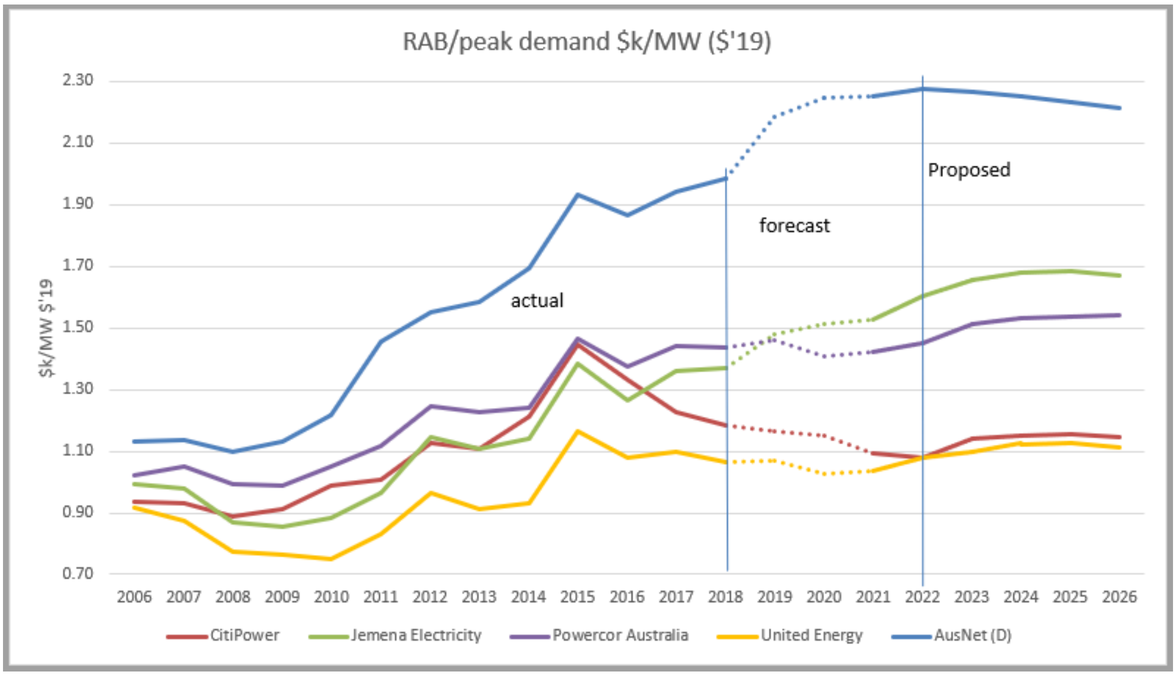
Source: AER Electricity Distribution Networks Performance data report 2006-2018, DB proposals, sponsor analysis

Compared to customer numbers, except for Ausnet, all DBs show quite modest growth in the RAB per customer from 2006 to 2010 (when the DBs were regulated by the regional regulator – Essential Services Commission of Victoria) and all show strong growth in the

RAB/customer from 2010 to 2018, with a modest degree of flattening out of this growth during the next period.[14]

Peak demand is generally seen as a key determinant in the size of the RAB, as peak demand is what the DBs have to manage to ensure that their customers are provided with a reliable supply.

Figure 8 Movement of real RAB/peak demand over time



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

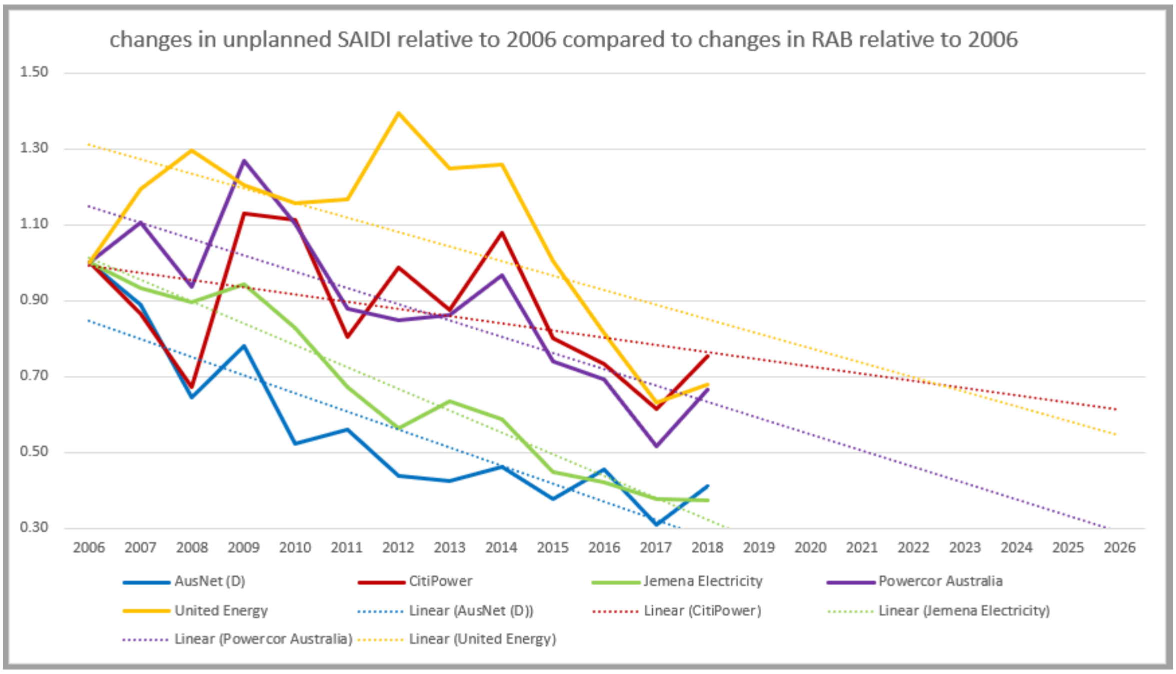
This analysis shows that some DBs have been able to reduce their RABs relative to peak demand in the next period, but all of them show a significant increase in the period 2011 to 2015. All DBs show that RAB/peak demand will either be flat or experience an increase in their proposals. However, if the peak demand forecast by the DBs does not eventuate[15], then this analysis implies that the DBs are continuing to inefficiently invest is assets not needed by consumers.

In section 1 above, improving reliability was identified across all networks while at the same time, there was seen a reduction in utilisation of assets. The sponsors have assessed the changes in the RAB since 2006 relative to changes in both reliability (in terms of SAIDI) and utilisation. Both of these measures are quite telling and are shown in figure 9 (SAIDI) and figure 10 (utilisation).

[14] The sponsors note that the proposed RAB outcomes for the next regulatory period are related to the forecasts made by the DBs in terms of customer numbers and peak demands.

[15] This aspect is addressed in section 4.2 below where the analysis implies that the DBs have overstated expected peak demand growth

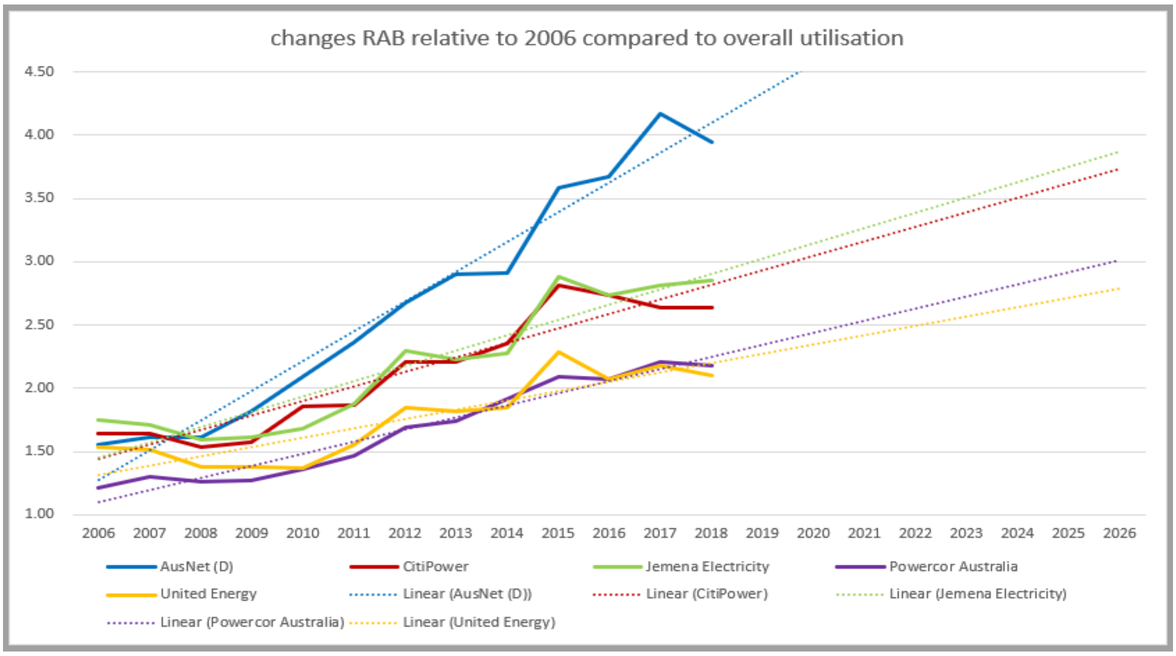
Figure 9 Movement of reliability relative of real RAB over time



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

The chart (figure 9) shows the relative changes in SAIDI compared to the relative change in RAB. This clearly shows that the improvements in reliability have been associated with increasing RAB, which in turn imposes not only increased costs on current consumers, but consumers in the future as well. This identifies a critical aspect, in that the DBs have been able to improve reliability and so earn a Service Performance Target Incentive Scheme (STPIS) bonus through capex paid for by consumers.

Figure 10 Movement of real RAB over time relative to utilisation



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

Figure 10 shows that there is also an association between the fall in utilisation and the growth in the in RAB, suggesting that consumers are funding assets that are not needed by consumers.

When examining all of the charts highlighting the growth in RAB, it is clear that the main cause of this significant growth in RAB for all DBs has been driven by unnecessary investment, whether in the form of augmentation (driven by inaccurate forecasting of growth), replacement of assets for reliability (consumers have expressed acceptance of current levels of reliability and do not want to pay for improved reliability) or for other aspects that have not delivered net benefits to consumers.

The sponsors recognise that past investments are not assessed in the regulatory reset - however analysis of the past RAB movements provides an indication of whether past decisions were appropriate and whether a review of past decisions implying inefficient investment should impact future decisions.

The analysis shows that

- The RABs for all DBs continue to increase in real absolute terms
- The RABs continue to grow at rates greater than the growth in either peak demand and/or customers connected
- The improvement in reliability has not been sought by consumers who have been clearly expressing for many years that they do not want increased reliability at the expense of increased costs.
- The fact that utilisation continues to fall also highlights that the networks are increasing capacity in some areas, but existing assets are being used less and less.

Recommendation

The AER must, as part of its examination of all capex proposals, reflect that capex in past regulatory periods has been too high and has led to an unnecessary increase in the RAB while providing assets that are either underutilised or not required. Therefore, as part of the AER review, it should ensure that the allowed capex is capped at a level that does not result in any further increases in the RAB. The sponsors point out that capping capex is a conventional practice used in competitive industry to ensure that all capex is necessary and does not exceed the firm’s ability to raise the capex.

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[16] by Economic Insights for the AER based on data provided by the networks in their annual Regulatory Information Notices (RINs) data.

3.2.1 Opex productivity

The most commonly used productivity analysis is 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 an 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[17] includes for the opex for years 2006 to 2018. The sponsors note that opex partial factor productivity varies on an annual basis and recognise that the input data[18] 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 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.

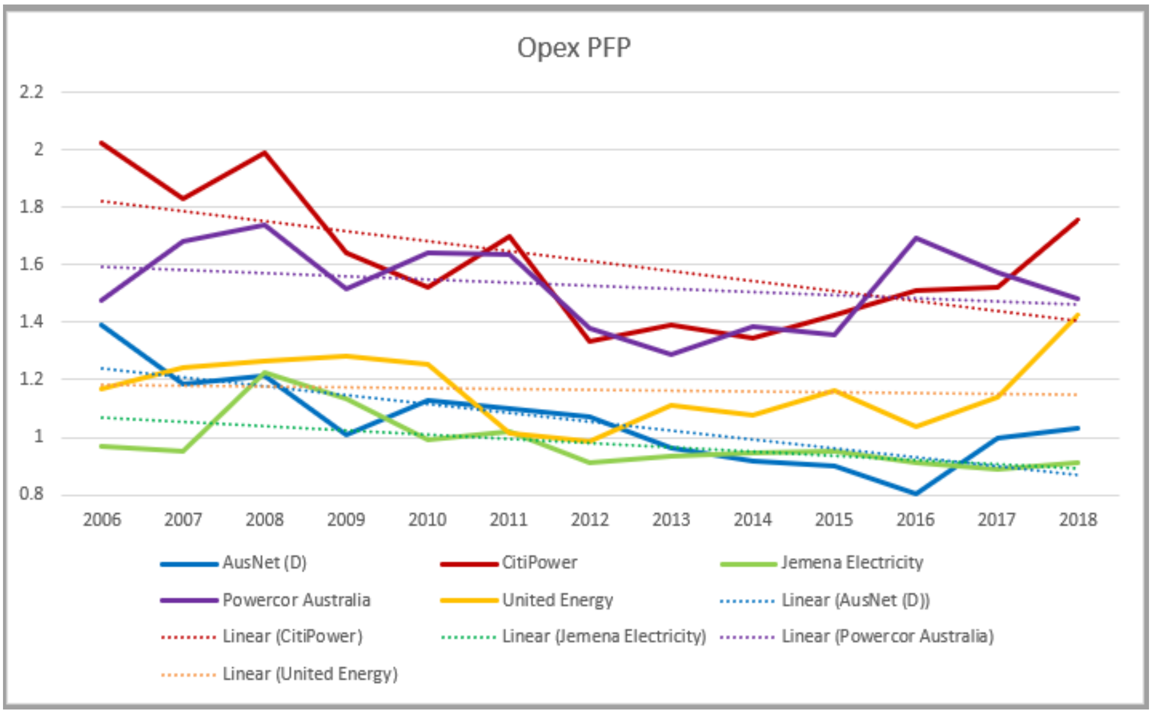
The Economic Insights report provides an examination of the productivity of each of the NEM DBs through a number of different approaches but most of these examine average productivity over the entire 13-year period, whereas the partial factor productivity measure provides a trend over this time period. The sponsors consider that the trend is a better gauge of the impact of incentives to improve productivity and the following chart (figure 11) is drawn from the Economics Insights report.

[16] Economic Insights, which generates these PFP values, notes that there are some. The annual partial factor productivity calculations are subject to adjustment adjusted

[17] Economics Insights “Economic Benchmarking Results for Australian Energy Regulator’s 2019 DNSP Annual Benchmarking Report 16 October 2019

[18] The sponsors note that 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 as inputs the actual opex and overhead and underground subtransmission and distribution lines and transformers and other capital assets

Figure 11 Opex partial factor productivity



Source: AER benchmarking report 2019 and Economic Insights report 2019

What this analysis highlights is that, despite an upturn in opex PFP by some DBs in 2018, the trend for opex PFP of all the DBs has trended down over the past 13 years. In contrast, firms that operate in competitive markets have to continually increase their opex PFP continuously just to stay in business.

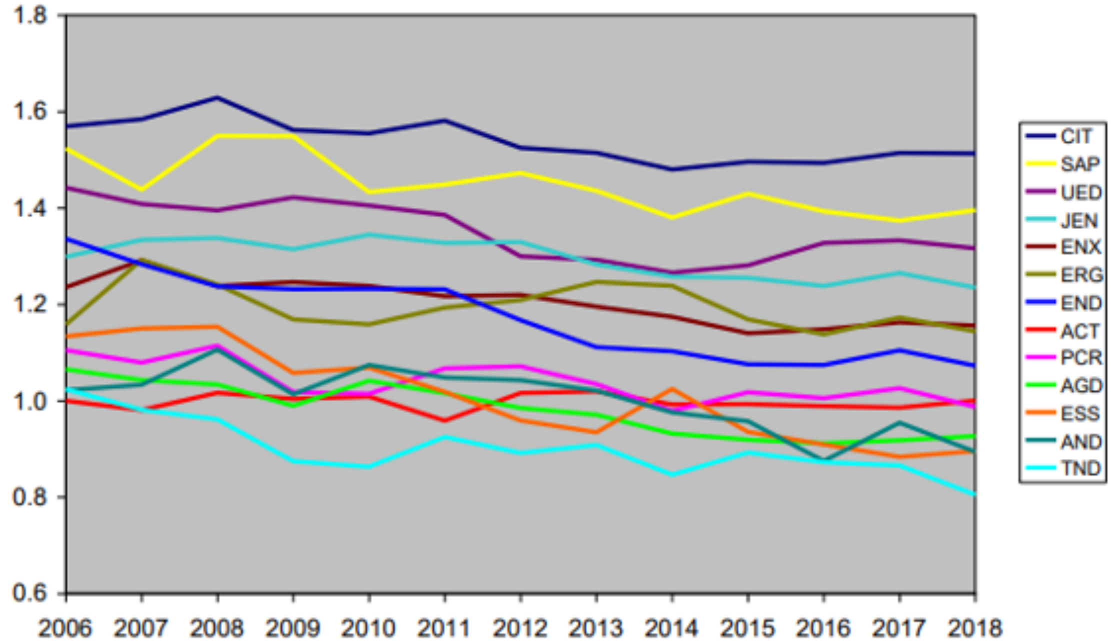
While the Economics Insights productivity series shows the relative productivity performance for all National Energy Market (NEM) distribution networks, it does not show the relative performance between regulated firms and those operating in a competitive market; such a comparison would better show whether the DBs are truly being fully incentivised by the opex incentive scheme.

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

3.2.2 Capital productivity

In the Economics Insight benchmarking report of 16 October 2019, it also provides a chart of the capex partial productivity indexes 2006-2018.

Figure 12 DNSP multilateral capital partial productivity indexes

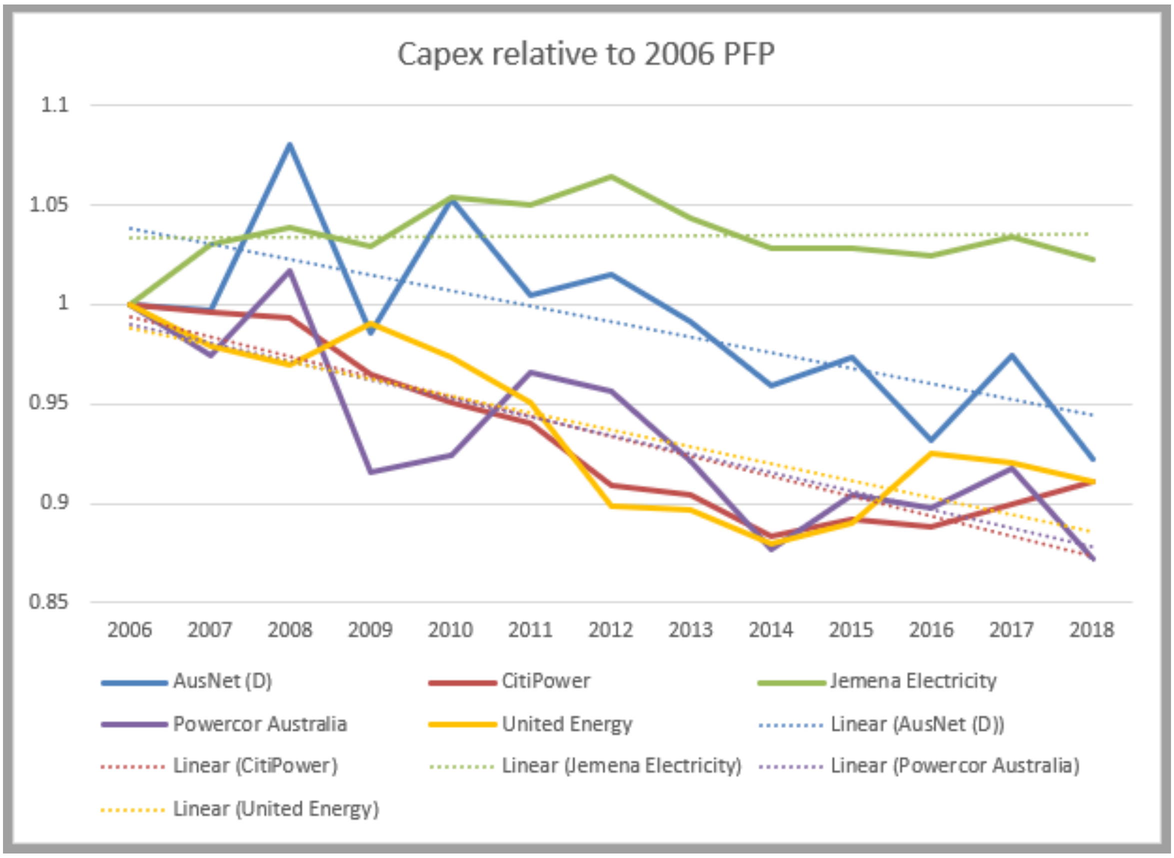


Source: Figure 3.3 Economics Insight benchmarking report of 16 October 2019

It is clear that few, if any, DB has improved its partial factor capex productivity over the period 2006-2018 but unfortunately Economic Insights does not provide the source data for this chart. What is apparent is that CitiPower shows the greatest capex productivity with Jemena and United showing lesser capex productivity with Powercor and AusNet showing similar but rather poor capex productivity, but all of them (with perhaps Jemena demonstrating this the least) show reducing capex productivity over the period 2006-2018.

However, what is available in the Economics Insights report for capex productivity is the capex PFP index referred back to unity for 2006 for each DB so there is some ability to test the relativity between the five Victorian DBs than the above chart, fig 12.

Figure 13 Capex partial productivity factor index for Vic DBs



Source: Economic Insights benchmarking report 2019

This chart reinforces the view derived from Economic Insights' findings that the trends over time show that all DBs (except perhaps Jemena) have quite severely falling capex productivity. This trend reflects the view expressed in section 3.1 above that previous capex has not been efficient.

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 outside of what might be considered to be efficient; the cause of this must be inefficient capex in the past. Inefficient capex imposes unnecessary costs on current and future consumers using the assets.

The benchmarking of opex also leads to the conclusion that opex is greater than is probably needed. The outturn of this assessment is twofold – that the incentive structure has not resulted in the base year opex being efficient and that the AER should have a requirement that future opex should reflect a higher productivity improvement than 0.5% pa.

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. Because of this, the sponsors have examined the forecasts developed by the DBs and attempted to assess these through independent comparisons.

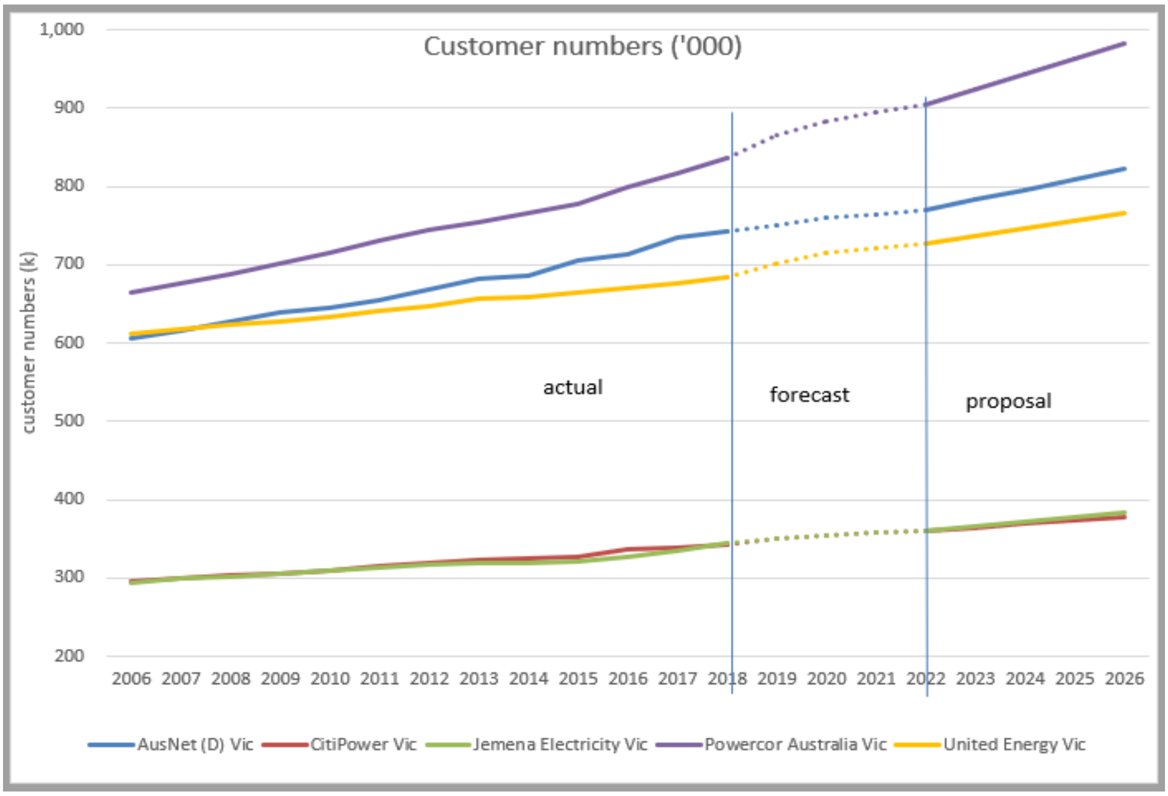
We note that the economic impacts of COVID-19 will require forecasts in all areas to be re-evaluated. While it is likely that there will be remaining uncertainty regarding the medium-term impacts of the crisis, it will be important to establish forecasts that accommodate the potential for a significant economic downturn. The sponsors draw attention to the comments in section 1.5 above.

4.1 Customer numbers

The change in customer numbers has a particular and direct impact on the allowance for capex for new connections and the capex for managing the increase in peak demand - but also indirectly impacting opex which uses customer numbers as a tool to increase the trend growth costs for opex. It also affects the forecasts of energy consumption which also impacts the trend costs for opex.

The DBs have used exogenous data to inform their forecasts of customer numbers, yet there appears to be an assumption that customer numbers will increase at a faster rate than the longer term trend, and this is shown in the following chart (figure 14) which tracks the historical increase in customer numbers.

Figure 14 Network customer numbers



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

Whilst the growth in customer numbers reasonably follows the historical trends for CitiPower and Jemena, the growth forecasts for AusNet, Powercor and United all show a distinct upward trend from 2018 to 2020 and then a faster growth rate during the forecast period and an even faster growth rate included in the proposals.

When the increases forecast in 2015 for the current period are compared to what is expected to result over the current period, there is a substantial difference between the new connections forecast in 2015 and the likely actuals. Across all DBs, an increase in customer numbers of some 440,000 was forecast, yet it is now expected that the actual number will be closer to 270,000 new connections.

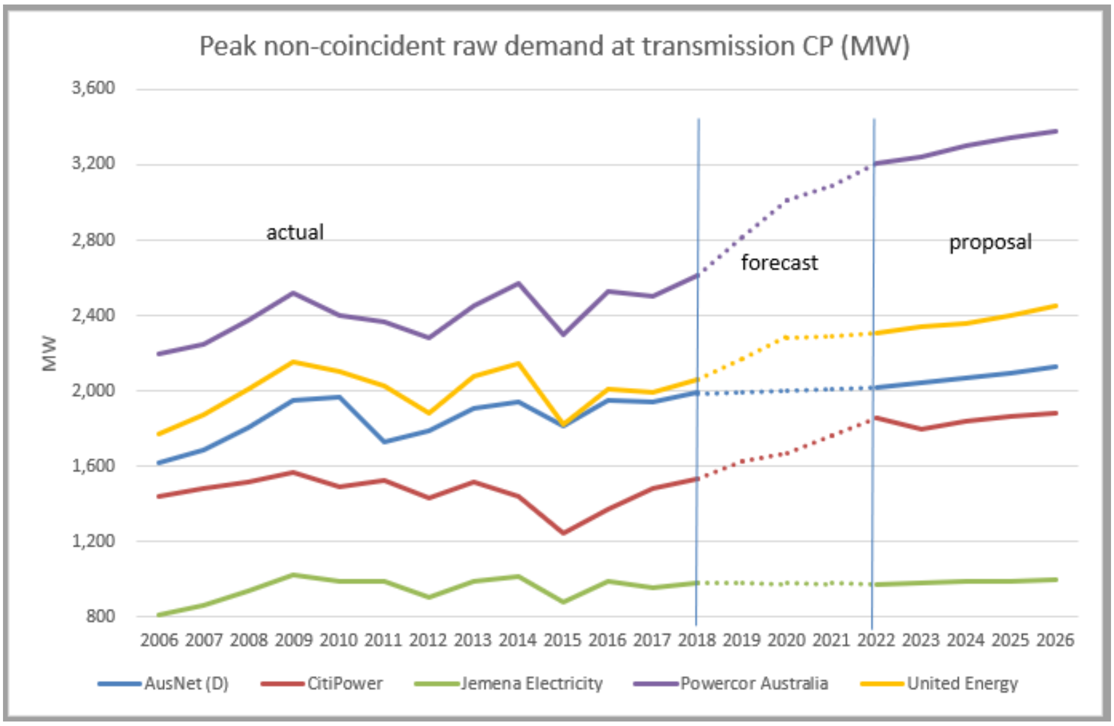
As there is some doubt as to how accurate the forecast customer numbers are and as the issue of customer numbers is critical to the setting of a number of the core expenditure elements, the sponsors consider that the AER needs to carry out an in-depth assessment based on independent data to assess whether the forecasts of customers numbers are inflated.

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 increased capacity of the networks to reflect 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.

Figure 15 Peak non-coincident raw demand

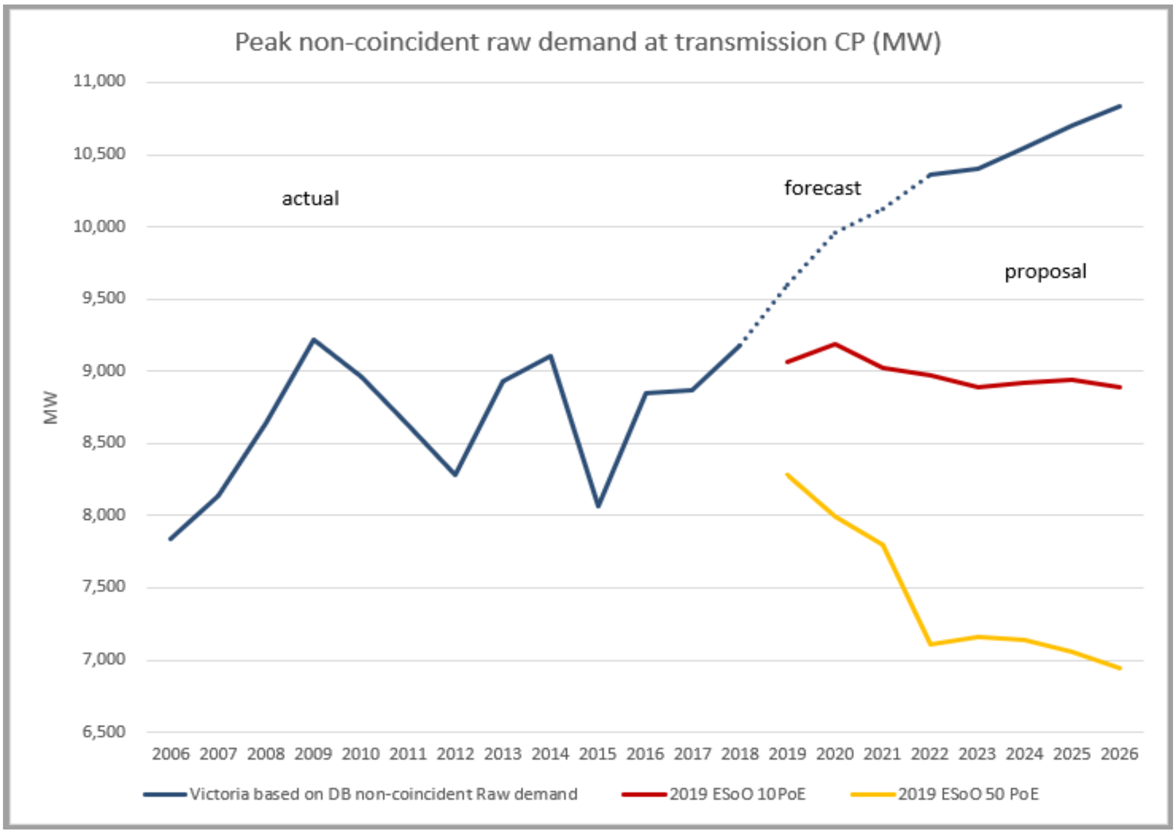


Source: DB RIN data, DB proposals

The chart shows that AusNet is expecting only minimal growth in peak demand and Jemena expects the same. In contrast Powercor, CitiPower and United all indicate a massive increase in peak demand from 2018 to the start of the next regulatory period with further growth thereafter.

In contrast, the following chart (figure 16) shows the AEMO Electricity Statement of Opportunities (ESoO) 2019 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 and 2019 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.

Note 2. What is also important is that there has been considerable criticism of the 2019 ESoO (especially for the Victorian and to a lesser extent the SA forecasts) for its perceived conservatism in its build up. For example, the expected peak demand (10PoE) for 2019/20 in Victoria was expected to be near 10,000 MW yet the actual peak demand was barely above the actual peak demand recorded in 2018/19 year and close to the 50PoE forecast for 2019/20. Historically, the actual peak demand in Victoria has not ever exceeded the 10PoE forecast and on only a couple of occasions exceeded the 50PoE forecast.

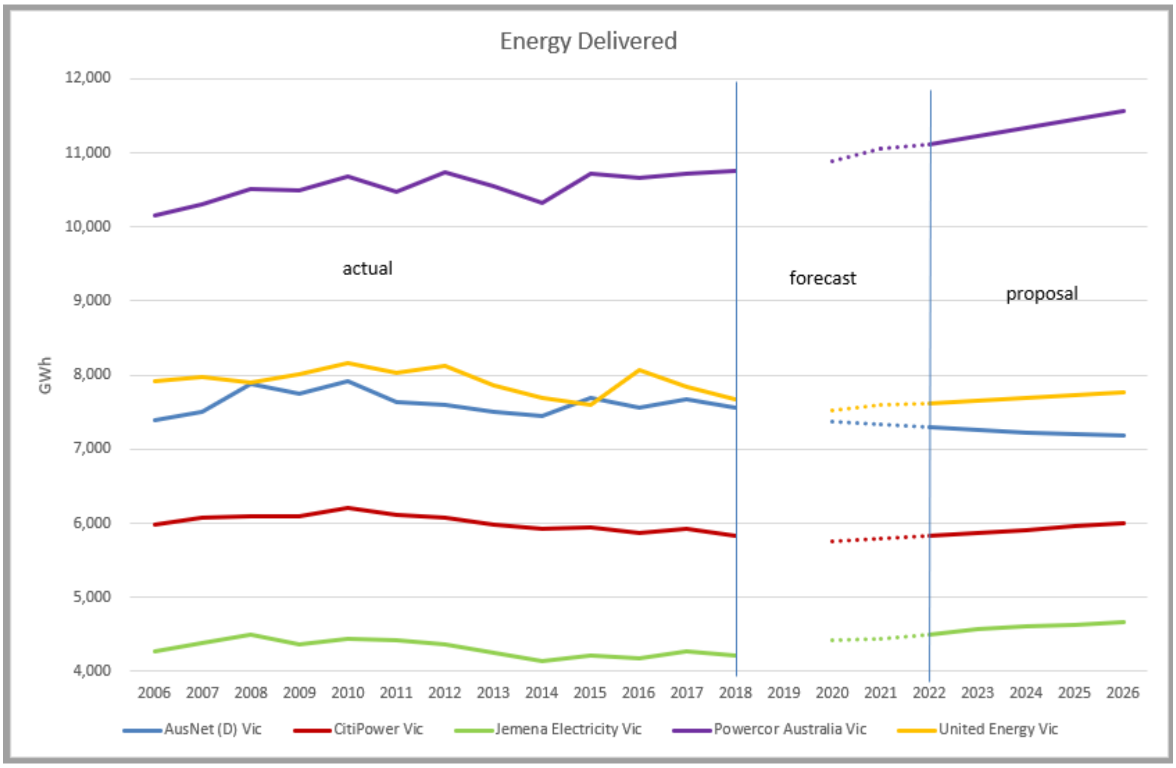
This analysis shows that the DB proposals in aggregate do not reflect the AEMO forecasts for the Victorian regional demand by a significant margin when compared to the 10% PoE central scenario and by a massive differential when compared to the 50% PoE central scenario, even when excluding the concerns about the AEMO 2019 ESoO. This raises a considerable doubt about the accuracy of the DB forecasts for peak demand and therefore the assumptions 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 in 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 sponsors have assessed the forecast energy consumption proposed by the DBs in the following chart (figure 17).

Figure 17 Energy delivered

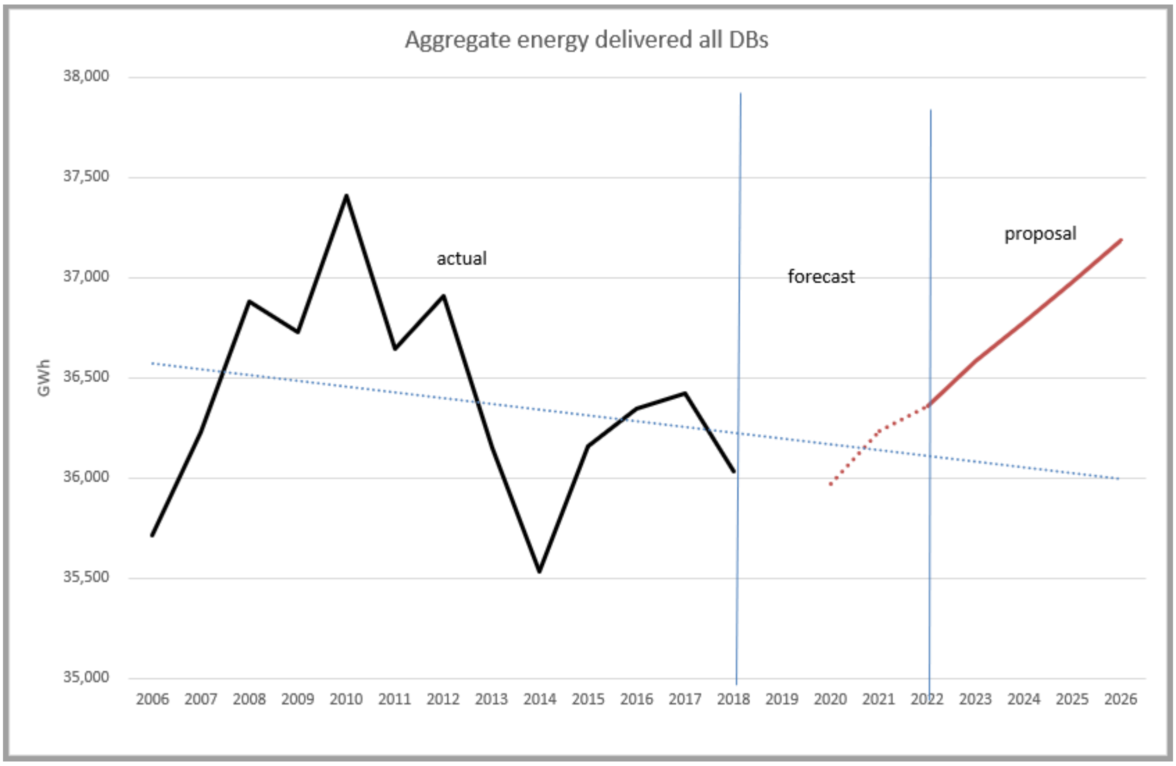


Source: AER Electricity Distribution Networks Performance data report 2006-2018, DB proposals

This shows that all DBs except Ausnet are forecasting increasing amounts of energy to be delivered to their customers. This is seemingly inconsistent with the generally accepted view that energy demand is either static with time or falling since the early part of this decade. In fact, with increasing penetration of distributed energy resources (particularly roof top solar) the fall in energy delivered is to be expected.

In aggregate, the DBs are forecasting a significant increase in energy delivered yet the trendline for the actual amounts of energy delivered supports the view that forecast energy consumption should be falling.

Figure 18 Aggregated energy delivered



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

4.4 Conclusions

The analysis of the forecasts which drive the DB proposals all indicate that the DBs have over-forecast in terms of new connections, peak demand and energy to be delivered. By over-forecasting, the DBs have provided the basis for increasing their proposed revenue requirements and to a degree masking the impacts of this increase in revenue.

5. Depreciation

Depreciation (or return of investment) is a significant element of the building block approach to developing the allowable revenue for the DBs. Inherent in the inclusion of this element in the building block is that over time the DBs should recover the value of the investments made. While the sponsors accept the regulatory approach to inclusion of this principle, we note the observation made by many firms operating in a competitive environment that they seldom if ever recover all of their invested capital, and if they do, it is not through the application of the depreciation approach. As a result, the formalized recovery of capital in the building block approach delivers an outcome which is conservative and therefore is a cost that consumers might not be exposed to if the networks operated in a competitive environment.

The sponsors note that the DBs apply different rates for depreciating the same asset types, and that these rates are also inconsistent with the approach they take to their internal financial reporting. While the sponsors accept that each firm should be allowed to depreciate their assets in relation to their individual financial reporting to suit their investors' needs, the sponsors note that the regulatory requirement is to apply consistency to the development of the efficient costs incurred by a network. The sponsors consider that there is an essential flaw in an approach where the AER allows each of the DBs the ability to set their own different asset lives for the same assets and different again for financial depreciation. The AER is to allow only efficient costs into the building block and this implies that there would be one set of depreciation schedules that delivers the most efficient outcome.

The sponsors also point to the reality that although Victoria is the second smallest region in the NEM in geographical terms, it has five electricity DBs. Again, by a geographical measure, the five DBs combined are smaller than other DBs operating in the NEM and probably smaller than any other two DBs combined in terms of area and asset value. The diversity of setting asset ages and financial depreciation across each region in the NEM is far less varied than is the case in Victoria.

In contrast, the sponsors are very concerned that there is no consistent approach amongst the five Victorian DBs as to how the depreciation approach should be implemented. The sponsors note that each DB seems to have its own unique depreciation schedule that bears little resemblance to other DB depreciation schedules or to the asset ages that each DB uses as the basis for its replacement program.

By comparison with the low level of diversity of distribution asset lives observed in each of the other NEM regions, the significant diversity seen between the Victorian DBs does not appear warranted. The sponsors consider that there needs to be much greater commonality in setting asset ages and in financial depreciation than is currently the case and there should be a common standard for both of these measures implemented.

In appendix 1 is a comparative listing of all asset lives for each of the DBs derived from the category analysis RIN data. What is remarkable about comparing the asset lives advised by each of the DBs is the extreme variation between them for the same assets. For example,

- 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

The asset lives detailed in the category analysis vary significantly from the asset lives detailed by each of the DBs in their economic benchmarking RIN spreadsheet table 3.3.4.

The sponsors are very concerned that each DB has its own schedule for standard asset lives as this provides the first stage of assessing whether an asset should be replaced. The sponsors note that the AER uses these asset lives as the basis for its “repex model” to assess the reasonableness of the replacement capex (repex) proposal. What is very concerning is that there should not significant variation between each of the category analysis standard asset lives between each of the DBs.

The sponsors consider that for regulatory purposes, there needs to be some consistency between all of the DBs and the assessment of asset lives and that this standard life should be used as the basis across all DBs.

The financial depreciation schedules provide a third source of asset lives and the time they are depreciated over sources from the DBs depreciation spreadsheets and proposals. As with the other sources of asset lives, the table below further highlights the variation between each of the DBs and the asset types that are being depreciated and there is no logic inherent in the data.

Table 1 - Standard asset years for financial depreciation

	Standard life (years) for financial depreciation				
Asset class	AusNet	CitiPower	Jemena	Powercor	United
Subtransmission	45	50	45	50	60
Distribution system	50	49	50	51	36
SCADA/Network control	10	13	10	13	10
Non-network IT	5	6	6	6	5
Non-network other	5	10	20	15	8
VBRC		22		26	
Equity raising costs	45	42	47	42	42

Source: DB proposals, depreciation models

The sponsors consider that the financial depreciation schedules should be consistent across all DBs and that they should reasonably reflect the expected asset lives used as the basis for asset replacement.

What is also concerning is that there is little assessment as to when the financial depreciation schedules change and the value of the new rates used. For example, in 2015 Jemena used a standard depreciation life for its subtransmission assets of 53 years, yet has reduced this to 45 years for this reset. Similarly, it has reduced its financial asset life for 'non-network other' from 24 years to 20 years.

While the sponsors accept that each DB should be able to manage its own financial accounts in whatever way it considers appropriate, this should not apply to the regulatory process used to set the allowed revenue. The regulatory process should be consistent across all firms of the same type in how they are regulated, and the assumptions used to calculate their allowed revenues. By giving each DB free rein as to how they financially depreciate their assets exposes consumers to greater risks and inconsistent outcomes.

5.1 Accelerated depreciation

The sponsors note that each of the DBs have proposed accelerated deprecation for some of their assets. In principle, the sponsors see that accelerated depreciation of assets increases costs for consumers, and they have further noticed that networks never increase the age over which assets are depreciated. In a time of very low interest rates and low costs of equity, it is in the interests of the networks to accelerate depreciation as it provides greater cash flow for the networks, at the expense of consumers.

The sponsors note that the AER has previously allowed accelerated depreciation under some limited circumstances where assets have had to be replaced while the replaced asset had some residual value and depreciation was permitted for the change in expected residual life.

The sponsors are very concerned that the DBs are proposing changes which will increase costs to consumers and as a general observation, consider that all such claims should be refused unless it can be clearly shown that the change is demonstrably efficient and reflects current accounting standards.

The sponsors note from the application by AusNet for a transfer of some assets to another class that has a higher turnover rate (i.e. that the depreciation rate of the assets is increased).

The sponsors note an interesting aspect that DBs are tending to buy assets that have a shorter life than other assets that could provide the same service. It is not efficient to have an unnecessarily high turnover rate when longer lived assets are available. In order to obviate unnecessarily high turnover rates of assets, every DB should be required to demonstrate that the selection of assets reflects a balance of longer life against the cost of the asset to ensure that the asset selection is demonstrably delivers the most efficient outcome for consumers.

Four of the DBs have sought approval to accelerate depreciation:

5.1.1 AusNet

The bulk of AusNet's claim for accelerated depreciation relate to a change in asset life for 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 sponsors do not consider that this change should be permitted as it is not clear that the assets to be transferred actually do have the shorter life implied by the proposed new asset class.

AusNet is also proposing to transfer leasing costs from opex to capex. The sponsors accept that if this change is related to new accounting standards then it is probably acceptable.

5.1.2 CitiPower

The first aspect of this accelerated depreciation proposal due to solar enablement is whether these transformers will in fact be replaced to achieve the stated purpose. If they are, the issue then arises that the replaced transformers will still be useful and may be redeployed elsewhere in the network or retained as spares. The sponsors consider that the replaced transformers should not be depreciated to zero as the remaining life is still available for use.

5.1.3 Powercor

Following the comments made for CitiPower, if the transformers are to be replaced then the replaced transformers will still be available for use and should not be fully depreciated.

Similarly, the sponsors note that assets replaced under the REFCL program are still available for use and should the retained for use elsewhere and depreciated as normally.

The sponsors note that accelerated depreciation is proposed for upgrades to control boxes for 5G compatibility. The sponsors consider that this upgrade does not deliver value to consumers and should not be approved – therefore the proposal for accelerated depreciation for the replaced assets should not occur.

5.1.4 United

Following the comments made for CitiPower, if the transformers are to be replaced then the replaced transformers will still be available for use and should not be fully depreciated.

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 be added to the RAB as part of the "roll forward" of the RAB.

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

Firms in a competitive environment have a clear ceiling on their capex which relates to how much they can invest in any one year without seeking additional funds from shareholders[19]. In contrast, regulated firms are incentivised to seek the maximum amount of capex they can from the regulator, even though they may not need all of this. This aspect is discussed in more depth below.

In a competitive environment, once the total amount of capex is determined for the firm by its Board of Directors, the different allocations of capex are determined while maintaining this cap on total capex.

A competitive firm addresses its capex needs on three fundamental bases:

1. The amount of capex used in the previous years to maintain the assets in a state that allows the firm to stay in business. This might involve replacement of some production assets (e.g. repair of plant) and the replacement of tools to allow the staff to continue to maintain the operations (e.g. replacement of office tools such as computers).
2. Discretionary capex which when invested shows a net benefit when assessed in terms of opex reduction or marginal increase in capacity in existing plant. Typically, this discretionary capex must deliver a net benefit over a limited time frame of 2-4 years.
3. Investment of new capital to increase the amount of production. This capex must show a clear net benefit based on the ability to sell the increased production, the time period over which the increased sales are certain, and the price the increased production can be provided at compared to competition.

Once the limit on capex is set by a firm in a competitive industry, it then allocates its capex on the basis of a mix of historical needs and bottom up analysis. In particular, replacement capex is assessed on the basis of historical need with a small allowance for special needs. Discretionary capex has to prove it delivers a benefit in the short term while new investment has to prove a longer-term benefit over the life of the asset. Effectively, competitive industry applies a cap first and then ensures that the actual usage reflects a need for economic efficiency to maintain current levels of reliability and to accommodate

[19] The need for new funds can reduce the dividend paid in a year, so shareholders might cause the share price to fall, implying shareholders consider that the capital retained by the firm has reduced the dividend too far

the need for any growth to maintain or improve the service to customers while increasing profit.

This approach is contrary to the approach taken by the DBs where it appears that all of the capex has been effectively assessed on the basis of bottom up analysis without any cap being applied.

6.1 An overview of capex and its drivers

The AER allows for the amount of capex to be included in its roll-forward model for setting the RAB. There are four impacts from the roll forward approach that create an incentive in forecast capital expenditure.

Firstly, the capex permitted by the AER to be added for the next period allows the DB to receive a return on the new capex added as part of its revenue. Thus, the allowed revenue for each year of the regulatory period includes a return on the allowed capex. If the actual capex in each year is less than that allowed by the AER, the DB receives the return on the capex that is not used, as a bonus. Equally, if the actual capex is more than the allowed capex, then the DB receives a penalty. The sponsors note that over the life of the NEM, over-runs of capex are much less frequent than under-runs.

Secondly, even if a DB does use all of its allowed capex within the period, it can still delay the investment during the period. Because the AER allowance is based on a specific schedule of investment, the allowed revenue includes the return on the investment to match that schedule. If the DB delays the investment to a later time, they can retain the benefit of the unused revenue, increasing their profitability.

Thirdly, at the end of the regulatory period, there is an adjustment of the RAB to reflect only the actual capex incurred, so that consumers only pay over subsequent regulatory periods for assets that were actually added to the network. When assessing the actual capex, if the actual capex is less than the allowed capex, the DB will receive a bonus under the Capital Expenditure Sharing Scheme, effectively adding to any benefit the DB receives from investing less than the amounts of capex that were allowed in each regulatory reset.

Fourthly, there is also a strong driver for a DB not to incur capex in one regulatory period and to request that this same capex be added to the next regulatory period.

It is quite clear that there are a number of strong drivers for the DBs to overstate their real need for capex, to schedule the capex before it is needed, and to undertake capital works that are less than the capex allowance.

Regulatory oversight of capex is usefully augmented by benchmarking. As noted in section 3.3.2 above, the partial factor productivity assessments by Economic Insights for the AER, show that over time, all of the DBs have flat or declining capex productivity. Noting that this data was current to 2018, if the proposals show a significant increase in capex for the coming years, above that level that applied as the basis for the productivity benchmarking, then this would indicate that the capex proposals for all DBs would imply even lower capex productivity.

Table 2 below, provides the data on total capex actual and allowed for the first four regulatory periods and the amount proposed by each DB for regulatory period 5, all in real terms. It shows that all DBs except AusNet and Jemena are proposing 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.

Table 2 - Gross capital expenditure over time

Gross Capex $m ($'19)	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
AusNet	$761	$989	$1,194	$1,776	$2,061	$2,105	$2,220	$2,045	$1,745
CitiPower	$533	$694	$570	$995	$742	$1,067	$1,013	$848	$1,094
Jemena	$255	$332	$393	$567	$754	$902	$925	$751	$748
Powercor	$1,016	$1,320	$1,133	$1,879	$1,533	$2,499	$2,433	$2,189	$2,581
United Energy	$552	$717	$625	$1,064	$1,118	$1,281	$1,135	$1,007	$1,396
Total	**$3,117**	**$4,053**	**$3,915**	**$6,281**	**$6,208**	**$7,853**	**$7,726**	**$6,840**	**$7,565**

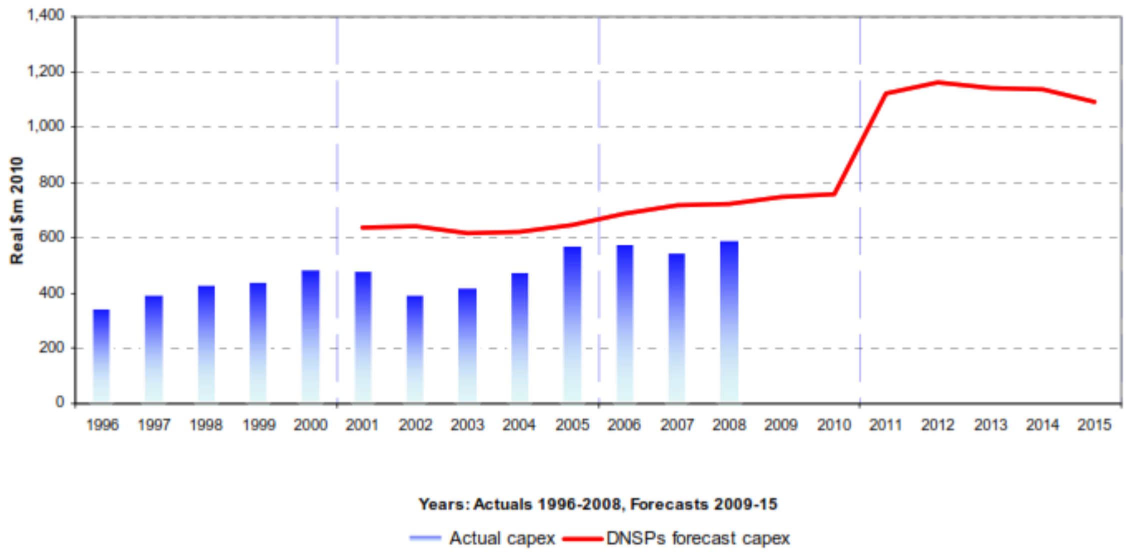
Source: ESCV and AER final decisions, AER Network performance data, DB historic and current proposals

As well as highlighting the impact on the relatively poor capex productivity performance, the table also highlights another worrying trend. In its review of the capex proposals from the DBs in 2010, in its draft decision the AER observed that (page 292):

> "[The] AER's trend analysis suggests that the DNSPs' capital expenditure forecasts tend to systematically overestimate capital expenditure. DNSPs appear to spend significantly less than forecast, and previously allowed, and DNSPs' actual capital expenditure tends to follow a fairly gradually increasing trend.

The AER also provided a chart (figure 19 below) that demonstrated this feature.

Figure 19 Capital expenditure trend analysis



Source: AER internal analysis.

The sponsors have also observed this same trend and in the table above (table 2) replicates this trend in subsequent periods where the DBs all have claimed much more capex than they ultimately invested.

In addition, highlighting that the DBs consistently forecast more capex than they ultimately needed, and also that the DBs tend to consistently underspend the AER allowance, the table also highlights another concerning trend. For the first two regulatory periods the DBs invested much the same amount of capital in real terms. In the third regulatory period (2011-2015) there was a 60% increase in capex which coincided with forecasts for massive increases in demand, which never eventuated. Despite there being no major increase in demand, in regulatory period 4 (2016-2020) the DBs all proposed increases (averaging 25%) above what had been used in regulatory period 3 (2011-2015) and the AER allowed the DBs to have most of this increase. Despite this significant step increase, the DBs actually spent 10% less than they had considered necessary in their applications. For regulatory period 5 (2021-2026), the DBs are requesting more capex than they used in regulatory period 4. There is a clear case that the issue the AER identified in 2009 where the DBs over-forecast their capex requirements and then underspend their allowances has continued for the subsequent periods, especially in the current period where they spent more than 10% less than was allowed. The sponsors consider that the introduction of the CESS has not provided a well-constructed incentive scheme to encourage the DBs to minimise their claims for capex

There is also another strong driver in relation to seeking more capex than might be required. Under the building block approach to setting the allowed revenue, all of the allowed profit is embedded in the rate of return as, in theory, all other elements of the building block are recovered at cost. So there is an incentive on the DBs to invest more in the networks than might be needed to provide the service as this is the mechanism delivers the bulk of their profits.

Each year, the DB is required to reduce the RAB by depreciation of previous capital investments that comprise the RAB. If the amount of actual capex is greater than the amount of depreciation in any year, then the RAB increases, imposing a burden on future electricity consumers. As observed in section 3.1, the RAB, in real terms, for all the DBs has shown a consistent increase (see figure 6), even when observed in relation to customer numbers and peak demand (see figures 7 and 8).

In theory, there should be reached, in relative terms, an equilibrium where new capex equals the amount of depreciation, such that new capex is just sufficient to ensure the continuation of a reliable service. Unfortunately, even after 25 years of regulation, the Victorian DBs have not reached this point and the RAB continues to grow in relative terms.

The purpose of assessing the growth in the RAB in relative terms provides a high-level view as to whether the amounts of capex that have been used in the past and proposed for the future are consistent with reaching a state of equilibrium.

As it is clear that the past investments have resulted in a continued growth in the RAB in relative terms, this implies that historical allowances for capex were higher than necessary to provide the service sought by consumers. As was noted in section 3.1 above, the growth in the RAB has resulted in improved reliability and falling utilisation of the assets provided, both of which support a view that a significant portion of the capital that has been invested (leading to the growth in the RAB) was unnecessary and imposed unnecessary costs on consumers both at the time and for future consumers.

Bottom up analysis is very difficult to argue against as it becomes very subjective, so the real test is the trend analysis (i.e. capex over time) especially for repex and IT capex. Analysis of the five proposals all provide very good reasons for investment using a bottom up basis and such individual arguments are difficult to counter.

The AER has implemented a program where all DBs are required to provide actual costs for all regularly performed activities. This category analysis is a useful tool as it captures the cost of key aspects but it also captures the numbers of each action, so using the latest data for replacement frequency can be manipulated to increase the numbers forecast and so bias the outcome. The sponsors note that the costs gathered by category analysis deliver different costs from each DB compared to others. The sponsors would expect that the AER will ensure that the costs used in its assessment reflect the lowest costs incurred amongst all the DBs.

Augex is effectively driven by peak demand in geographical areas but this raises the question as to what happens at locations where demand is falling. The AER approach tends to base its peak demand on a ratchetted non-coincident peak demand at the key zone substations. By doing this, the AER approach does not highlight where useful assets are no longer required at a location due to falling demand, and could be redeployed to locations where peak demand is increasing.

Connections capex is driven by the increasing number of new connections. As noted in section 4.1 the sponsors are concerned that the growth in customer numbers forecast by each DB could be overstated.

The following sections examine each of the main elements of capex to identify whether the amounts of capex claimed for each of the elements are supportable.

6.2 Replacement capex (repex)

The single largest element of capex claimed for the next regulatory period is that for replacement of existing assets that are required to provide the service but are at significant risk of failing during the next 5-year period causing disruption to consumers when they fail. The impact of the failure rates is measured by the two reliability measures of SAIDI and SAIFI, detailed in section 1.2. As can be seen, SAIDI and SAIFI have shown consistent improvements over the last 13 years, implying that assets are increasingly being replaced well before there is a reasonable risk of failure, leading to an improvement in reliability of supply.

In contrast to the approach used by competitive industry to set repex (where it is effectively set on the basis of historic usage) all the DBs are seeking higher amounts of repex than they have used in the past and this is shown in table 3 below.

Table 3 outlines the changes in the amounts allowed by the regulators (Essential Services Commission of Victoria and AER) in past resets and the actual amounts for the capital investments made by each DB. What is a consistent (although not a universal) feature is that the DBs sought more repex than they eventually used but also that the regulator provided more repex than the DBs actually used. This observation supports the view that as the DBs have strong incentives to overclaim the amounts of capex and actually use less.

Another aspect that can be drawn from the table, is that the average amount of repex over the past four periods is reasonably consistent with what the DBs actually used in the current period, providing support for the observation made above that competitive industry tends to use historical repex as its guide to what is required in the future. This implies that the current actual repex provided by each DB represents a good guide as to what should be allowed for the next period.

Table 3 also shows that the amount of repex sought for the next period is a significant increase from the average repex (in real terms) actually used over the past 4 regulatory periods. The purpose of the long-term view and averaging is to address a concern that AER expressed in its 2015 decision for the current regulatory period. In its preliminary decision, the AER expresses a view that trend modelling has some limitations in that some of the repex is driven by "a lumpy asset age profile". The sponsors agree that this observation has validity, but they also point out that averaging over the longer term (in this case over 20 years) tends to reduce this lumpiness effect.

The AER repex model uses current costs for replacement assets and recent trends in the rate of replacement. While the sponsors agree that use of current costs (which the assessments in this submission adjust for by making all past costs "real") provides a sound basis for forward looking pricing for each element, the sponsors point to a short coming in the use of recent replacement rates. Just as the AER points out that trend analysis has limitations, so too does the use of the most recent rates of replacement. To reduce the impact of "lumpiness" in the asset installations, long term rates of replacement provide a more balanced approach to setting future replacement of assets. In fact, a DB has the ability to influence this recent replacement rate through its practices and so lead to unnecessary replacement and/or generating an overstatement of future replacement.

Table 3 - Replacement capital expenditure over time

Repex $m ($'19)	2001-2005 RQM + 50% ESL actual	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
AusNet	$259	$336	$245	$592	$736	$966	$813	$862	$748	$457	$424	$629
CitiPower	$112	$438	$155	$322	$164	$279	$213	$279	$253	$107	$134	$295
Jemena	$58	$72	$93	$210	$175	$240	$240	$274	$244	$182	$127	$202
Powercor	$323	$466	$278	$598	$475	$774	$653	$720	$653	$387	$366	$601
United	$152	$316	$186	$375	$435	$627	$455	$605	$478	$314	$272	$465
Total	**$904**	**$1,629**	**$958**	**$2,097**	**$1,985**	**$2,886**	**$2,373**	**$2,740**	**$2,377**	**$1,447**	**$1,324**	**$2,193**

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

In aggregate, the DBs sought some $2.9 bn of repex for the current period (2016-2020) yet have incurred for the first 3 years and forecast to use for the remaining 2 years, about half this amount. Based on the DB claims, the AER allowed the DBs about 80% of their combined claim, still some 60% higher than was actually needed. Yet even with the lesser actual repex they provided in 2016-2020, the DBs have been able to continue to improve reliability of supply to consumers.

Across all DBs, the forecast repex for 2021-2026 period is 50% more than the DBs actually spent in the current period. With each DB seeking an increase in repex between 38%

(AusNet) to 176% for CitiPower, the sponsors wonder what benefit consumers will gain from the increases in repex when reliability for all DBs increased over the past 13 years under a much lower actual repex.

The sponsors note that the DBs have compared their repex requirement to the repex that would arise from the AER model. This same approach was used for setting the repex for the current period, yet all of the DBs significantly under-ran the AER allowance which was heavily influenced by the AER repex model. The fact that has been such a significant under-run of the AER repex model, implies that the model is deficient in some way. Because of this, the sponsors do not consider that comparisons based on the AER repex model provide realistic support for exaggerated repex claims.

6.2.1 AusNet

AusNet is proposing a 50% increase in repex compared to its historical actual average. AusNet asserts that the key drivers for the repex program (and presumably the increase in repex proposed are due to:

- deterioration in asset condition associated with increasing asset age, which gives rise to unacceptable reliability and safety risk;
- a reduced opportunity to replace poor condition assets as part of augmentation-related projects;
- asset failure risk, which may cause supply interruptions, increased risk of collateral asset damage, safety risk to public and field personnel, and environmental damage from asset failure;
- technical obsolescence, which increases the cost and risk of retaining assets in service; and
- asset damage caused by third parties. (Part III, page 77/272))

While the sponsors agree that all of these reasons are quite legitimate, it does not explain the 50% increase that is proposed, as all of the same reasons would have equally applied for the current period, including the reduced replacement caused by augmentation projects where AusNet spent less than half the AER allowance.

The sponsors point to the initial proposal for the current period and the actual amounts spent. In 2015, AusNet proposed that it would need $966m for repex yet used half of this; the AER allowed for $748m of repex and still AusNet used 40% less. As the AER used its repex model to support the setting of its allowance for the current period, the fact that AusNet used so much less reinforces the concerns raised in the introduction to section 6.2

6.2.2 CitiPower

CitiPower is proposing a 60% increase from its actual repex for the current period. CitiPower advises that the increase is due to (page 28):

> "…primarily due to increases in our pole replacement program, transformer and switchgear replacements, and the investment required to meet new environmental compliance obligations."

What is concerning is that Citipower have used the observations from Powercor which revised its wood pole replacement program as a result of consumers in one part of the Powercor network expressing concerns that as pole failures led to bushfires in their location, poles need to be replaced more frequently. Citipower provides little reasoning that similar issues apply to their wood poles or that the Powercor program applies to them yet decided that an accelerated replacement needed to be implemented. In contrast, the long-term pole replacement rate used by Citipower has not resulted in increases in loss of reliability or of more bushfires.

The sponsors consider that CitiPower's argument for increasing their wood pole replacement rate lacks credibility and the long term average rate of replacement should be applied, and that same observation applies to line replacement and pole top structures which should also be assessed on the basis of the long term average rates of replacement rather than the most recent four year average.

As noted above, it is relatively easy to provide arguments to spend on new plant and equipment and Citipower does this in the sections on its zone substation transformers, elderly switchgear and switchboards and cable pits. What is important to note, is that while some of this work could well be required, other elements could have their replacement deferred, especially where there is observed a fall in the demand placed on the equipment. The sponsors note that in many parts of the Victorian distribution system, peak demand is falling, placing much less stress on equipment than is currently in use. This lower stress should allow the asset to remain in operation longer than if the equipment was more highly stressed. This aspect has not been considered by Citipower in its assessment for replacement.

6.2.3 Jemena

Jemena makes the observation (page 48) that it had a significant replacement program in the current period leading to a reduction of zone substation replacement activity in the next period. This is demonstrated by Table 3 above, where actual repex in the current period is 40% higher than the long-term average actual repex. The expectation would be that there would be a reduction on repex in the next period to offset the actual increase, yet despite this Jemena is seeking a further increase in repex above the current period repex.

The sponsors consider that the Jemena repex for the next period should be lower than the actual repex in the current period and be closer to the long-term average.

6.2.4 Powercor

Powercor long term average actual repex in the current period is similar to its long-term average actual repex, implying that the both the actual current period repex and the long term actual average are reasonable reflections of what Powercor repex should be for the next period.

Despite this, Powercor is claiming a repex allowance for the next period which is 55% higher than its actual repex for the current period.

The single largest step increase is for pole replacement, which was driven by observations from consumers in one part of the Powercor network where there are concerns expressed that, as pole failures led to bushfires in their location, poles need to be replaced more frequently. Powercor provides support for this assertion by citing backing from politicians, including the Federal Minister for Energy. Powercor then decide to revise its pole management program which results in increased pole replacement. Powercor submitted this new program to ESV which is cited as accepting the new program. The sponsors point out that this new program is one generated by Powercor and not a requirement of ESV.

Powercor does not consider the impact of the REFCL program, and other fire safety measures, and how this might limit the danger posed by poles.

Powercor, in figure 4.6, highlights that its asset caused ground fire starts is declining supporting the view that wood pole asset failure are not leading to increased fire risk. Equally, while it does indicate in figure 4.4 that the number of wood pole failures in 2019 has increased by a total of 8 additional wood pole failures compared to 2015, it does not provide any detail as to what the outcome was from the additional wood pole failures or why they failed other than they were not weather related.

The sponsors note that AusNet (which possibly has a greater issue with bushfires than Powercor) has not seen a need to increase its rate of wood pole replacement and further, the sponsors point to the clear anomaly regarding wood pole life in that Powercor sees that the expected asset age for its wood poles is 39 years (see appendix 1) whereas AusNet considers wood poles should be expected to have a life of 65 years and United 60 years.

The sponsors are not convinced that the faster rates of wood poles is warranted based on the arguments provided by Powercor, despite Powercor assertion that its increased rate of pole replacement will maintain the average age of the wood pole population.

The sponsors do not consider that Powercor has provided sufficient argument to impose a 55% increase in either its current period actual repex or the long term average repex.

6.3.5 United

In its initial proposal for the current period United sought repex of $627m ($’19) but only invested half this amount, which was 15% more than its long term average actual repex. The AER allowed United $478m ($’19) but United only needed 65% of the amount allowed – the sponsors point out that this was achieved under an incentive scheme to minimise capex.

For the next period, United is seeking $465m ($’19) which is 70% more than its long terms average actual repex and 50% more than it used in the current period.

United comments that (page 52)

> "[t]he primary drivers of our forecast increase in replacement investment relative to our historical program are changes to:
> • our pole replacement program
> • environmental compliance obligations."

The pole replacement program is driven primarily by the decision by Powercor to revise its pole management practices but United provides no explanation as to why the Powercor practices would provide a better outcome for consumers in United's area. In fact, the reliability performance of United implies that there is no reason to change its current practices.

The sponsors do not consider that United has provided sufficient argument to impose a 55% increase in its current period actual repex or 70% more than the long term average repex.

6.3 Customer connections

The cost of customer connections 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.

The sponsors understand that the AER has established a policy which determines the amount of customer contribution to each new connection and that the cost of new connections is based on the historic costs revealed in the category analysis RIN provided by each DB.

The sponsors consider that the AER should ensure that the cost per new connection for the five DBs is consistent between each of them and with costs incurred by DBs in other jurisdictions with the most efficient revealed cost from this review being imposed on all of the five Victorian DBs. The sponsors are concerned that some DBs might not be as efficient in the costs for new connections as they might and using the lowest revealed cost from all DBs would assist in driving each DB to the most efficient outcome for consumers.

However, the sponsors note that the customer connection costs are driven primarily by the numbers of new connections forecast. There is an incentive on the DBs to over-forecast the numbers of new connections as any capex not used attracts a benefit as is outlined in section 6.1 above.

In section 4.1 above, the sponsors highlight there is concern about the accuracy of the forecast new customer connection numbers and they express a concern that the forecasts are overstated. Specifically they observe that the forecasts provided by Citipower and

Jemena seem to follow historic trends, whereas the growth forecasts for Ausnet, Powercor and United all show a distinct upward trend from 2018 to 2020 and then a faster growth rate during the forecast period and an even faster growth rate included in the proposals.

Specifically, the sponsors note that the new customer numbers forecast for the current period was significantly overstated. If the forecasts are overstated, then this means that the forecast new connections capex is also overstated.

6.4 Augmentation capex (augex)

Augmentation capex (augex) is driven predominantly by increases in forecast peak demand. As detailed in section 4.2 above, the sponsors note 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 over the next regulatory period (and beyond).

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.

However, the sponsors do note that there are localised parts of each DB where there are forecast increased demands which, following the AEMO forecasts, implies that there are equally parts of the DB networks where demand is forecast to decrease, resulting in lower utilisation and/or an increase in spare capacity. The increases in spare capacity have two significant impacts for consumers

1. That they are paying for capacity and assets that ear either not used or are oversized for the task required
2. There are assets that might be re-used where demand is rising and so reduce the costs faced by consumers where increased demand is occurring.

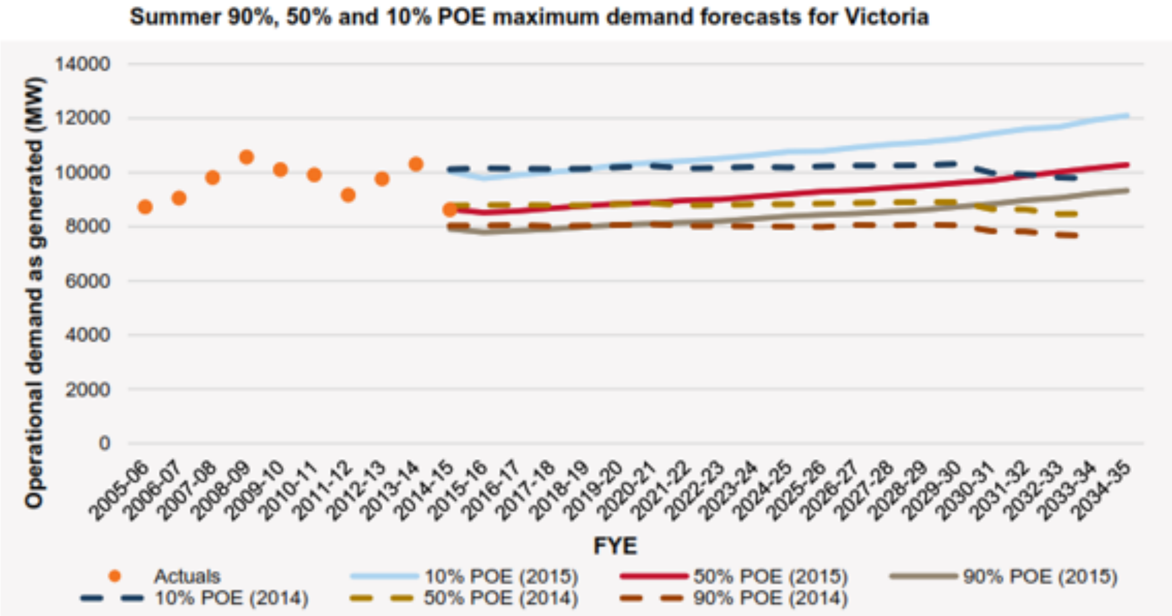
It does not appear that any of the DBs are actively looking to optimize their networks in an endeavour to reduce costs for consumers but are continuing with their practices of increasing capacity with the full knowledge that the costs of providing the increased capacity (and the associated reduction in utilization) is a cost they can pass onto consumers.

The sponsors consider that the AER has a responsibility to consumers to ensure that the DBs are incentivized to increase the utilization of the network assets through a greater attempt to relocate useful assets from the locations where they are effectively redundant.

The sponsors have developed a table (Table 4) which provides a long-term view on augex over the past four regulatory resets. The sponsors recognize that augex tends not to follow a trend (like repex and customer connections capex) but reflects the growth in the peak demand forecast. As a result, augex needs to be assessed with augex incurred in times similar to that where growth is the same as that forecast in the next period.

For the current regulatory period, in 2015 AEMO forecast modest growth in peak demand (this is shown below in figure 20 which is from the AEMO National Electricity Forecasting Report Detailed Summary of Electricity Forecasts figure 51) and that the expected peak demand over the current period (10PoE) would still be less than the highest historic peak that occurred in 2009.

Figure 20 AEMO demand forecasts



Source: Figure 51, AEMO National Electricity Forecasting report 2015

It was on this basis of some modest increase that the AER allowed the DBs $1,116m ($'19) in augex after the DBs initially forecast a need of $1,272m ($'19). What actually occurred over the regulatory period was an actual augex of $613m ($'19), about 55% of the allowance being used. This is shown in Table 4 below.

Table 4 Augmentation capital expenditure (augex) over time

Augex $m ($'19)	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
AusNet	$60	$205	$240	$349	$493	$337	$286	$353	$331	$146	$88
CitiPower	$148	$199	$72	$259	$199	$218	$128	$217	$217	$156	$164
Jemena	$39	$73	$86	$128	$123	$151	$100	$111	$141	$88	$141
Powercor	$117	$295	$166	$296	$233	$388	$259	$333	$294	$113	$274
United Energy	$109	$156	$212	$247	$196	$179	$136	$133	$133	$110	$167
Total	**$473**	**$928**	**$776**	**$1,280**	**$1,245**	**$1,272**	**$909**	**$1,147**	**$1,116**	**$613**	**$835**

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

That the actual augex in the current period was less than the allowed reflects that there was little or no net actual growth in peak demand in the current period. As there is also no likely net growth forecast by AEMO in aggregated peak demand across Victoria, it would be expected that augex for the next period would be similar to the actual augex seen in the current period. In fact, there is forecast a growth of 35% in augex across all DBs.

A standout observation is that although Ausnet is forecasting sufficient growth at two locations in its network where augmentation might be needed (Mernda and Cranbourne), it has agreed with its Customer Forum that only a modest augex is required to manage this growth in the next period. As a result, Ausnet is forecasting less augex for the next period than it incurred in the current period.

In contrast, excluding Ausnet, the other four DBs are forecasting augex of $746m ($’19) which is 60% more than their current period actual of $467m ($’19). This step increase is not warranted on the basis for forecast increases in peak demand.

Each of the DBs has assessed the need for augex on a bottom up basis. As noted above, disputing an assessment of such bottom up cost development is challenging and the sponsors recognise that they have limited ability to address the merits and demerits of these bottom up assessments and expect the AER to examine each of the proposed projects on their merits noting that augex should be constrained within an overall cap.

What the sponsors have noted is that, as well as forecast increases in peak demands leading to the need for augex, each of the DBs is claiming that they need to invest in their networks to allow greater penetration of distributed energy resources (DER), especially rooftop solar. The sponsors agree that the current constraints on DER implementation because of the negative impacts of DER on the networks are unacceptable and that action is required to address the concerns expressed by consumers.

The DBs have provided business cases to support the investment to provide greater DER in their networks but there is a difference in the basis for assessing the value to consumers of the investment, with different views on the extent of constraint that will apply to consumers and the value of electricity that is not exported due to the constraint[20]. It is important that a common basis is developed to assess the benefit of relieving the constraints that the networks will impose in the absence of no change.

However, as discussed in section 1.6 above, the costs proposed to address the enabling of more DER are quite disparate between the DBs, although most networks investment has been presented as “smart grid” aspects, with traditional augmentation aspects.

In their proposals, the CPPALUE networks associate a relatively small amount of smart grid expenditure with their solar program – just $3.5m for the Dynamic Voltage Management System (DVMS) split between Powercor and CitiPower. However, these networks have proposed a separate Digital Networks program, that largely relates to accommodating DER, with many aspects of this program, such as developing an LV model, and network sensors, being included in the solar program for networks like Jemena.

To allow a consistent comparison, the sponsors have included the entire cost of the Digital Networks program in the smart grid and augmentation for the CPPALUE networks in Table – so that these totals are different to those in the proposals.

Table 5 Investment overview (including CPPALUE networks' Digital Networks)

$m ($'21)	Jemena	Powercor	CitiPower	United	AusNet
Opex	3.6	6.2	1.3	4.2	-
Smart grid aspects	13.3	13.6[21] (including 2.5 DVMS[22])	12.15 (including 1.05 DVMS)	19.4	10.23

[20] For example, Jemena and Ausnet use the current Feed in Tariff (FiT) for DER injection benefits yet the CPPALUE networks use an assessment made by Jacobs which is considerably different to the FiT.
[21] Table 7.3 in the CPPALUE Regulatory Proposal documents
[22] Digital Voltage Management System

Augmentation	11.2	65.4 (including 4.7 DN)[23]	37 (including 5.5 DN)	49.2 (including 6.8 DN)	42.85[24]
Total	**28.1[25]**	**85.2**	**50.45**	**72.8**	**53.08**

Source: DB proposals, sponsor analysis

The sponsors consider that the AER needs to assess the DER proposals in total (rather than in separate sections as the DBs have tended to[26]) and to identify a common basis for calculating the benefits from the investment made to enable the DER.

6.4 Other capex

The long-term assessment of "other capex" provides a view that it comprises a considerable portion of the total capex sought by the DBs

The following table 6 summarises the long-term total capex less repex and augex. The long term data for gross customer connection costs is not complete over the four regulatory periods and there are changing approaches to customer contributions over the time but what is available implies that the gross customer connection costs are reasonably static, implying that the growth in other capex consistently has grown over time..

Table 6 Gross capex less augex and repex

Gross Capex less augex and repex $m ($'19)	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-
AusNet	$442	$448	$709	$835	$832	$803	$1,141	$1,443	$1,027
CitiPower	$273	$57	$343	$415	$378	$570	$544	$585	$634
Jemena	$158	$188	$214	$229	$456	$510	$539	$480	$405
Powercor	$576	$559	$689	$985	$825	$1,337	$1,487	$1,690	$1,706
United Energy	$291	$245	$227	$441	$487	$475	$524	$583	$764
Total	$1,740	$1,497	$2,182	$2,905	$2,978	$3,695	$4,234	$4,780	$4,537

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

[23] Table 6.2 in the CPPALUE Regulatory Proposal Documenets – including Solar Enablement and Digital Network devices

[24] Voltage compliance program and Hosting Capacity for DER listed in AusNet Electricity Services Pty Ltd EDPR 2021-26 Part II, p

[25] 2020, Jemena Future Grid Investment Proposal, page 24

[26] The sponsors note that the CPPALUE networks have also costed separately accelerated depreciation for assets replaced to enable DER

The other capex includes a number of categories including SCADA/Network control, non-network general assets – IT, non-network general assets – other, VBRC, REFCL and Land.

The sponsors consider that the AER needs to clearly identify which of the proposed "other" capex needs to be justified through benefits to consumers and to assess whether this investment can be justified

"Other capex" includes information and communications technology (ICT) which is a significant proportion of "other capex". This category has exhibited continuous growth in real terms over the past decade and is forecast to grow further, with consumers at each reset pointing out that they are unconvinced for the ever-increasing amount of ICT capex being claimed by the DBs. The sponsors note that much of the ICT capex can be related back to ostensibly providing a benefit to consumers (e.g. for consumers to be able to access data, the integration of DER, etc); such capex needs to be justified on a net benefit basis, where the cost of the asset has to be justified by the delivery of tangible and usable benefits by consumers. Yet there is no evidence that the provision of the ICT capex being widely used by consumers or that consumers have taken up this "benefit". The sponsors consider that the AER should carry out an ex post review of the stated benefits of past ICT capex to assess whether the ICT enhancements have delivered the benefits claimed when the capex was approved, and an assessment to the extent that consumers have taken up the benefits asserted by the DBs In this regard, the sponsors accept that the capex has been incurred and the AER does not have an ability to remove this capex from the RAB, but the ex post assessment would provide guidance for future claims for similar capex

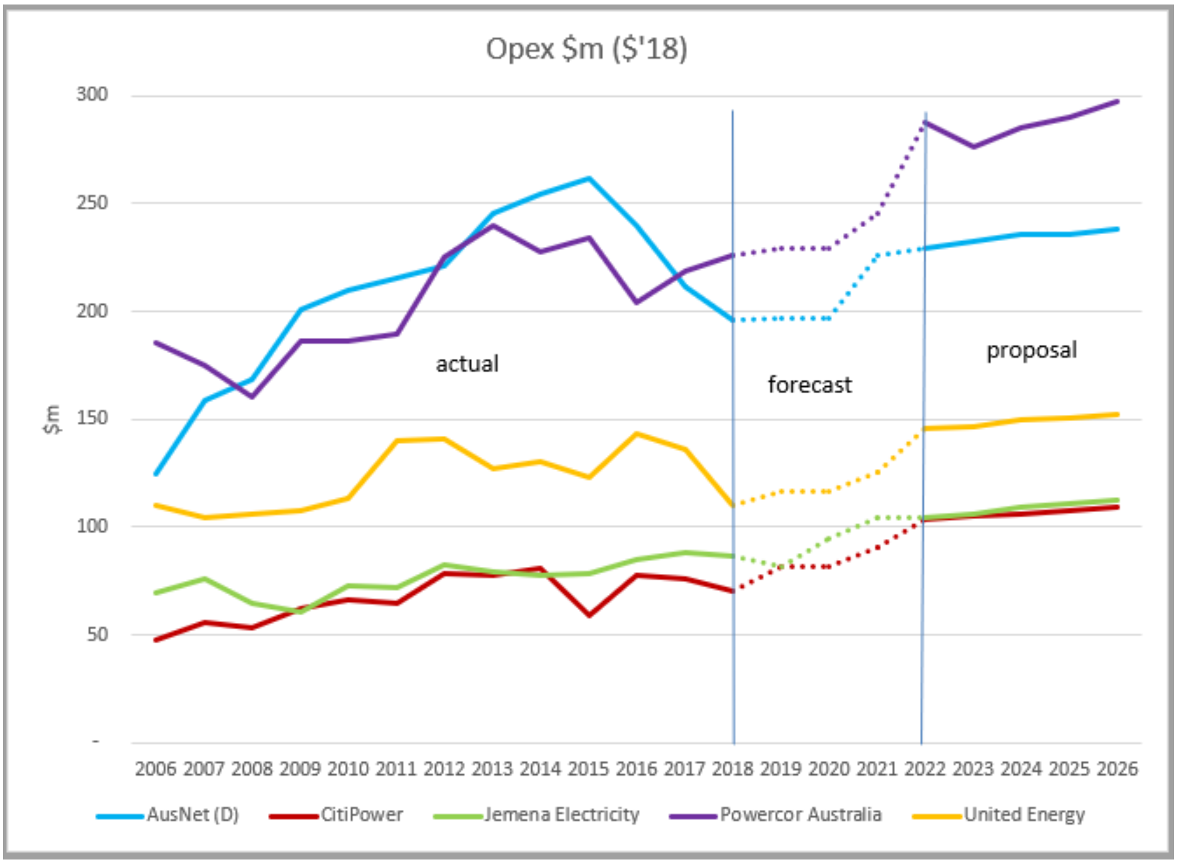
What continues to concern consumers regarding the continued growth of ICT is to what extent does the continued upgrading of ICT provide benefits to consumers, whether much of the upgrading is necessary and whether the existing ICT assets can provide the service that consumers need as distinct to whether the upgrade will merely a more expensive tool to the one already in operation but with little benefit to consumers

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.

The actual opex, forecast opex for the current period and the proposed opex 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 proposals, sponsor analysis

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).

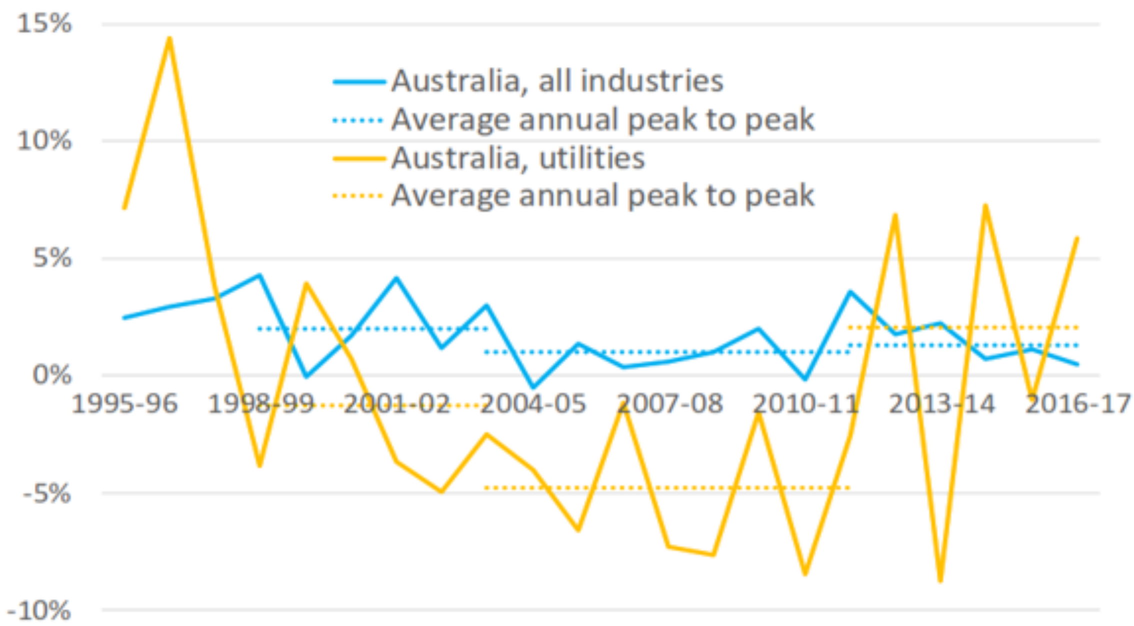
This shows that all of the DBs are forecasting in real terms significant increases in their proposed opex driven primarily by step changes but also, to a lesser extent, growth in prices and output growth coupled with a reduction in opex from productivity growth. All of the DBs have implemented the 0.5% productivity growth in accordance with the AER decision on productivity growth, including AusNet (see workings in AusNet Services workbook 1 – Regulatory determination (2021-2026) – 31 January 2020 page 2.16 opex summary line 22). The sponsors note that AusNet (at the behest of its Customer Forum) had effectively offered to implement a 1% pa opex productivity improvement in its future opex with the additional 0.5% a result of other savings in opex agreed with its Customer Forum .

What is intriguing is that all of the DBs are forecasting an increase in price growth for opex despite the opex being calculated in real terms. The import of this is that all DBs see that inflation is insufficient adjustment for incorporating movements in prices. The sponsors consider that this aspect needs to be investigated further.

7.1 Is the base opex efficient?

The sponsors note that in its final decision "Forecasting productivity growth for electricity distributors" March 2019, the AER provided evidence that across all Australian industries productivity has varied over time and provided a chart of Quality adjusted labour productivity (figure 22). In that final decision it indicates that consistently "all industries" has had a labour productivity of at least 1.0% per annum over the period 2006-2018 yet the trend of labour productivity for the five Victorian DBs has fallen, rather than risen, over the same period shown in the trend.

Figure 22 Quality adjusted labour productivity



Source: Figure 3 AER Forecasting productivity growth of electricity distributors 2019

What is important about the data in this chart is that the performance of Australian utilities has, on average, consistently been less than the "all industries" (which includes the utilities themselves). It is important also to note that in the period since the commencement of the electricity and gas distribution businesses as regulated firms (i.e. the commencement of the NEM), labour productivity has been well below that of "all industries". When this annual underperformance difference is aggregated over the entire period since the commencement of the NEM, it implies that the utilities are grossly more inefficient compared to the "all industries". If the productivity of the "utilities" is so far below that of the "all industries" it could be concluded that the electricity DBs have a lower labour productivity than the "all industries". If this lower productivity has continued for more than a decade, it implies that the current opex is lower than it should have been and has not been significantly incentivised to be closer to the efficient frontier.

As the AER has decided that it will apply a productivity improvement in addition to maintaining its opex incentive scheme, then this opex productivity should be back cast over some years to provide a "catch up" new benchmark opex to be used as the base opex. The sponsors note that in its Final decision paper on forecasting productivity growth[27], the AER observes (page 8)

> "[s]ome distributors currently operate at or near the efficient industry frontier and as such would be considered the most efficient."

The sponsors question this observation as the AER provides no support for such an assertion, although it does provide evidence that some DBs are operating with opex that is demonstrably more efficient than other DBs, but there is no evidence that the DBs overall are operating near the efficient frontier as implied by "all industries".

The AER goes on to state that the new productivity growth factor is not intended to address any catch up of past inefficiency which needs to be adjusted by use of the individual DB forecast base opex but is to enshrine that all industries do exhibit increases in opex efficiency continuously – the sponsors would assert that this increase in productivity is merely to stay in business. The sponsors also note that some of the DBs assert that as they are at the efficient frontier and that to get further efficiency will require capital investment. The sponsors point to the "all industries" productivity which is higher than 1% yet are still able to (in fact they must to stay in business) improve their productivity despite constraint in their capex. The sponsors do not accept that additional capex is warranted to meet the AER requirement of 0.5% productivity improvement.

The sponsors note that the AER has decided to implement a fixed opex productivity requirement on each DB for the future of 0.5% pa which (page 9)

[27] See AER Final Decision "Forecasting productivity growth for electricity distributors" March 2019

> "…reflects the best estimate of the opex productivity growth that an electricity distributor **on the efficiency frontier** should be able to achieve going forward…" (emphasis added)

The operative words are that a DB already at the efficient frontier should be able to generate an opex productivity improvement of this magnitude in the future. This is in contrast to the AER implication of past decisions that DBs were at the efficient frontier already and, by applying a zero productivity improvement, would maintain their position at the efficient frontier – this was despite evidence that "all industries" needed to generate productivity increases of at least 1% per annum just to remain competitive.

The sponsors support the application of a productivity improvement but question the AER decision to impose only a 0.5% productivity growth, considering that at least a 1% productivity growth is a consistent outcome seen more widely across Australia.

The generally falling productivity across all the DBs depicted in figure 11 in section 3 above shows that rather than the general positive productivity growth seen in "all industries", all of the DBs must be considered not to be operating at the efficient frontier.

By not imposing a productivity increase in the previous decisions, the sponsors highlight that this allowed the DBs all to under-run their opex allowances and garner an unearned opex incentive payment through the Efficiency Benefit Sharing Scheme (EBSS).

It would appear that the AER when considering the partial factor productivity assumes that if the outturn opex productivity is in the 75-100% quartile, then the DB is assumed to be at the efficient frontier and therefore the actual base year opex is assumed to be efficient. The sponsors disagree on three counts:

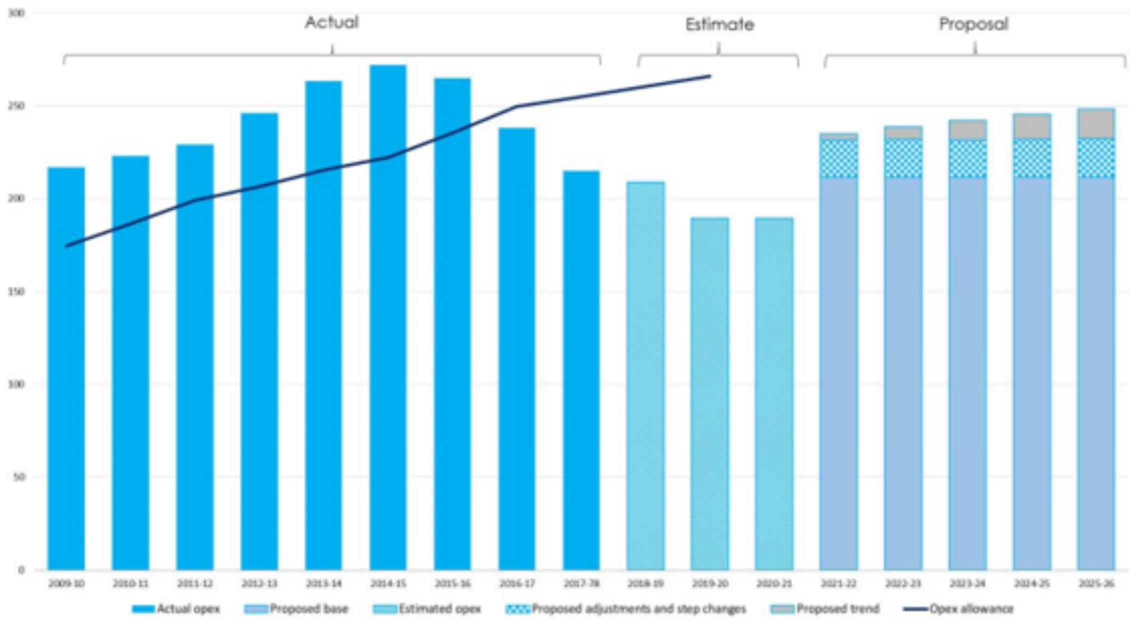
1. The opex is not demonstrably at the efficient frontier as all DBs have exhibited an ability to use less opex than allowed, but at the same time, increasing reliability. This implies that the opex allowance is not efficient
2. Opex productivity for all five DBs has shown a downward trend over the years although (see section 3.2.1 above) in the past two years CitiPower and United have shown a strong increase, AusNet and Jemena are static and Powercor a strong downward trend. In the 13 years from 2006 to 2018, all DBs have demonstrated reduced productivity except United and to a lesser extent Powercor
3. Even under the partial factor productivity measure, some DBs are demonstrably more efficient than the others. Assuming CitiPower was at the efficient frontier with its 2018 opex, then all of the other four DBs could improve their productivity by between 16% (Powercor), 19% (United), 41% (AusNet) and 48% Jemena.

Based on these observations, the sponsors consider that the base year opex for at least AusNet and Jemena need to be adjusted downwards to reflect their observed poor productivity, and that the base year opex for Powercor and United could also be adjusted downward. Not to impose these productivity base year adjustments makes the purpose of opex productivity benchmarking effectively pointless.

7.1.1 AusNet

AusNet has decided that 2018 demonstrates an efficient base year as it exhibited lower opex than in the previous two years. This contradicts the information provided by AusNet in figure 23 below (figure 16 from the AER Issues Paper) which shows that in real terms forecast opex in 2019 would be a lower amount.

Figure 23 AusNet Services opex ($2021m)



Source: Figure 16 AER Issues Paper

AusNet provides a suite of other measures to demonstrate that its base year is efficient but what is concerning about these other measures is that they are averages of performance over 13 years and do not demonstrate that the base year is efficient. The benefit of the partial factor productivity measure is that it tracks performance in each year and so has a close relationship with the selection of the base year.

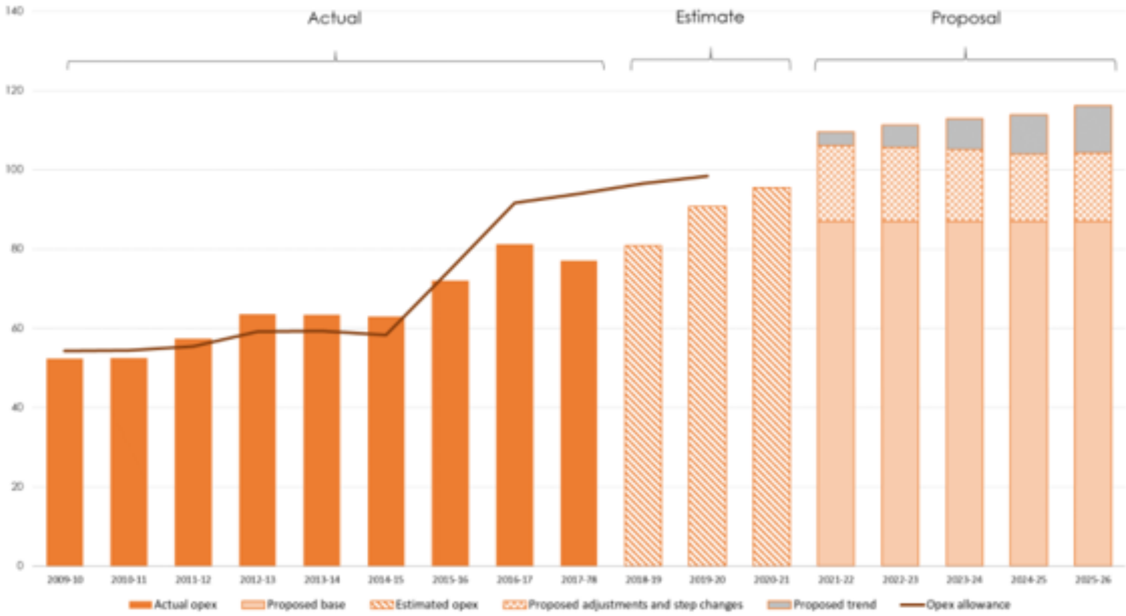
While the opex for 2019 would appear to provide a more appropriate base year performance, it is important to note that despite this apparently improved performance, the 2019 base year is still nowhere near the efficient frontier as measured by partial factor productivity.

The sponsors consider that the base year for opex forecasting should be the 2019 year and that there should be an additional downward adjustment to reflect the low comparative PFP.

7.1.2 CitiPower

CitiPower has elected to use its 2019 opex as the base year for forecasting its future opex needs. Intriguingly, CitiPower uses the long-term average performance of its opex based on the efficiency scores from its Cobb-Douglas stochastic frontier analysis to show it is the second most efficient network in the NEM, even though the PFP analysis shows it is currently the most efficient.

Figure 24 CitiPower opex ($2021m)



Source: Figure 14 AER Issues Paper

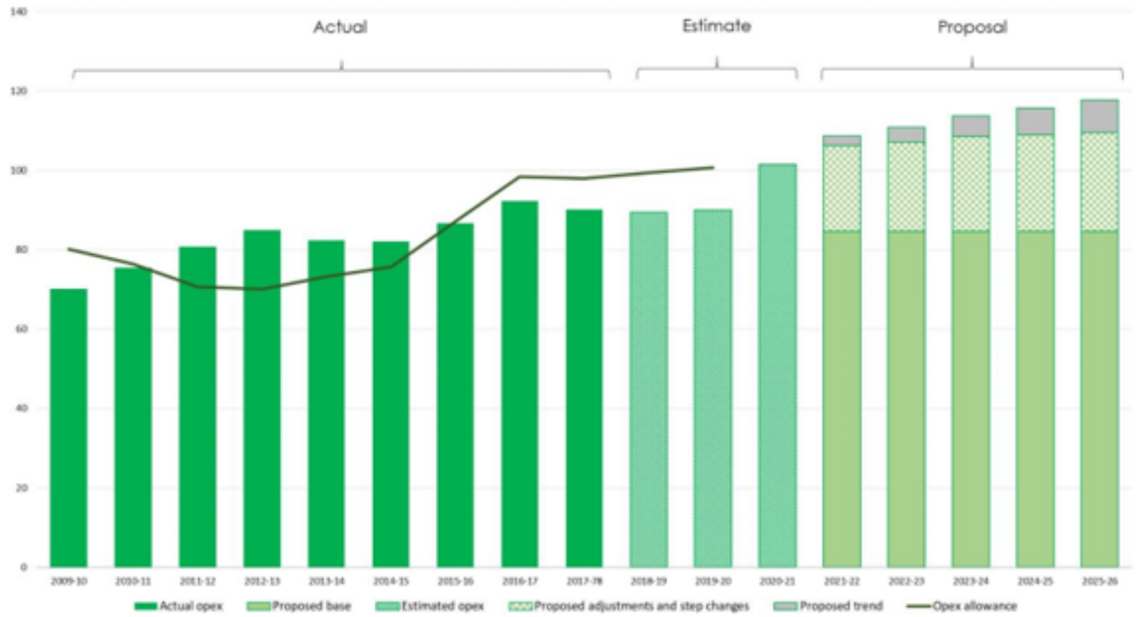
The sponsors note that the actual opex incurred by CitiPower over the current period regularly was significantly below the allowance provided by the AER in the 2015 review implying that there is still greater productivity improvement possible, although CitiPower asserts that as it is at the efficient frontier, it will need investment in technology assets (through the capex program) to be able to meet the new annual productivity requirement.

While the sponsors accept that CitiPower's 2019 opex be used as the base year on the basis that the last full year of opex should reflect the most efficient (assuming the incentive scheme works efficiently), they are concerned that the AER assessment in its Issues Paper, considers that the 2019 opex might be higher than that CitiPower achieved in 2018.

7.1.3 Jemena

Jemena proposes to use 2018 opex as its base year. This is acceptable when considering the actual opex over time as shown by Jemena in figure 17 from the AER Issues paper. What is interesting is that despite the AER considering that 2019 opex will be the same as 2018 opex, Jemena in its figure 6.2 shows a distinctly higher opex in 2019.

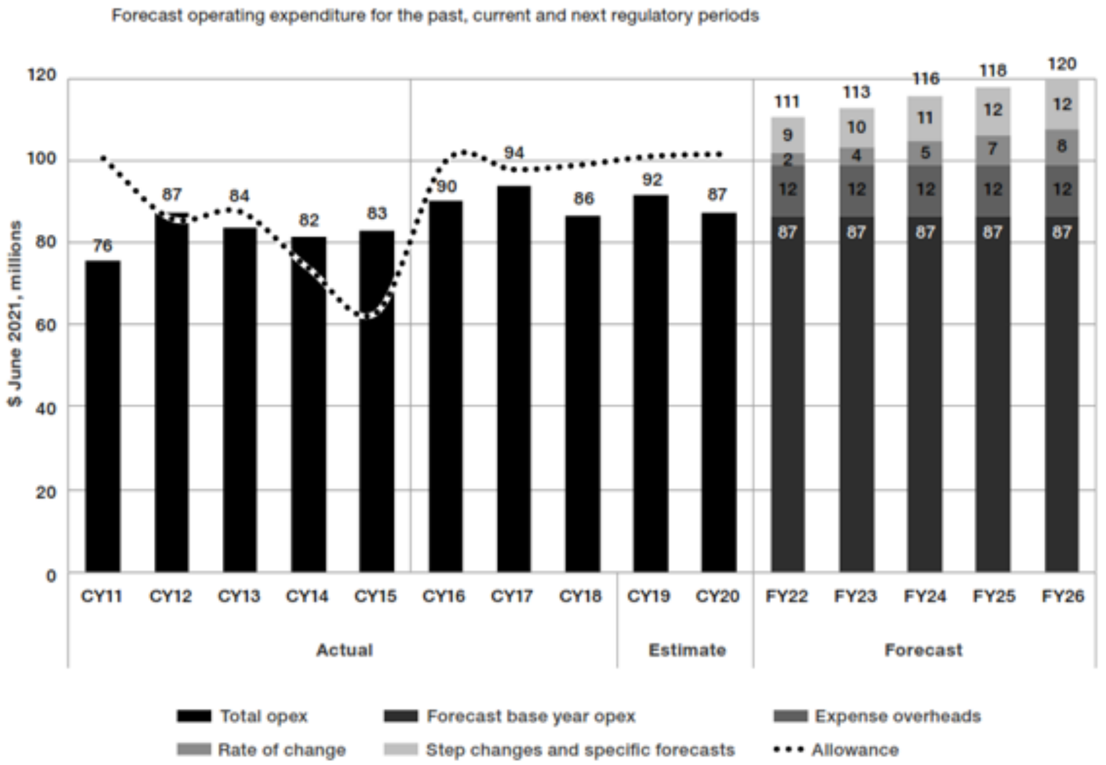
Figure 25 Jemena opex ($2021m)



Source: Figure 17 AER Issues Paper

In contrast, Jemena provides a similar chart but with some stark differences

Figure 26 Jemena opex $2021m (Jemena's forecast)



Source Figure 6.2 Jemena proposal

The sponsors note that Jemena has recently completed its productivity improvement program and that 2019 opex includes for a significant element of the costs of this program. Because of this Jemena has opted to use 2018 as its base year.

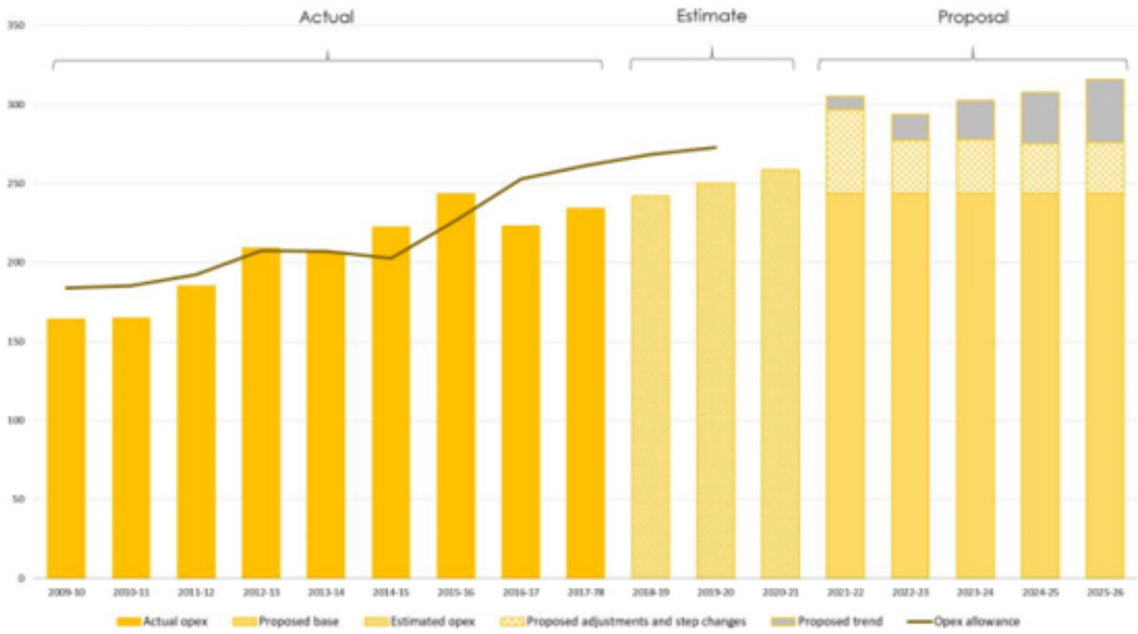
However, despite using 2018 opex for the base year, Jemena opex is still seen as clearly inefficient from the partial factor productivity measure. The sponsors consider that the base year opex needs to be adjusted to reflect the poor productivity that Jemena exhibits.

The sponsors also note that Jemena proposes to increase its base year opex by three adjustments – the greatest of which is the move of overheads for capex being transferred to opex. The sponsors do not support this move as, while it reflects a change in accounting process, it embeds into opex a cost from past activities into future opex. The sponsors consider that such a transfer is inappropriate as those overheads were clearly considered to be, in the past, a capital expense. If this transfer is approved by the AER it should be treated as a "once-off" opex activity and not as a continuing expense which is implied by the embedment of the cost in the base year opex.

7.1.4 Powercor

Powercor has elected to use its 2019 opex as the base year for forecasting its future opex needs. As with CitiPower, Powercor uses the long term average performance of its opex based on the efficiency scores from its Cobb-Douglas stochastic frontier analysis to show it is the most efficient network in the NEM, even though the PFP analysis shows it is currently the less efficient than the most productive (CitiPower).

Figure 27 Powercor opex ($2021m)



Source Figure 13 AER Issues Paper

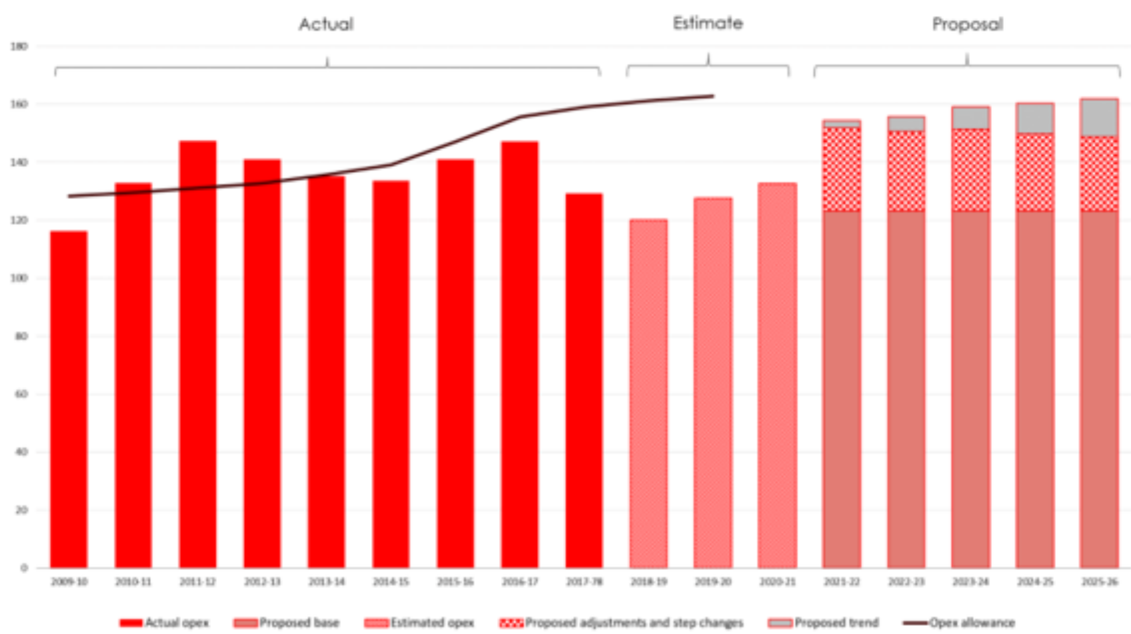
The sponsors note that the actual opex incurred by Powercor over the current period regularly was significantly below the allowance provided by the AER in the 2015 review implying that there is still greater productivity improvement possible, although Powercor asserts that as it is at the efficient frontier, it will need investment in technology assets (through the capex program) to be able to meet the new annual productivity requirement.

While the sponsors accept that Powercor's 2019 opex be used as the base year on the basis that the last full year of opex should reflect the most efficient (assuming the incentive scheme works efficiently), they are concerned that the AER assessment in its Issues Paper, considers that the 2019 opex might be higher than that Powercor achieved in 2018.

7.1.5 United

United has elected to use its 2019 opex as the base year for forecasting its future opex needs. As with CitiPower and Powercor, United uses the long term average performance of its opex based on the efficiency scores from its Cobb-Douglas stochastic frontier analysis to show it is the third most efficient network in the NEM (after CitiPower and Powercor), even though the PFP analysis shows it is currently the less efficient than the most productive (CitiPower).

Figure 28 United Energy opex ($2021m)



Source: Figure 15 AER Issues Paper

The sponsors note that the actual opex incurred by United over the current period regularly was significantly below the allowance provided by the AER in the 2015 review implying that there is still greater productivity improvement possible, although United asserts that as it is at the efficient frontier, it will need investment in technology assets (through the capex program) to be able to meet the new annual productivity requirement.

While the sponsors accept that United's 2019 opex be used as the base year on the basis that the last full year of opex should reflect the most efficient (assuming the incentive scheme works efficiently), they are concerned that the AER assessment in its Issues Paper, considers that the 2019 opex might be higher than that United achieved in 2018.

7.2 Opex growth trends

Following the opex base-step-trend approach to assessing efficient opex, the AER assesses the price, productivity and output growth and applies these to the base opex allowance. What is not included in the analysis is the impact of capital investment, particularly in repex.

7.2.1 Capex impact on opex

All of the DBs are proposing considerably increased repex compared to that they invested during the current period. Overall, there is proposed $2,195m ($'19) of new repex compared to and actual and forecast $1,447m ($'19) repex in the current period. Replacing new assets for old will have an impact on the amount of opex that is required after the new assets are installed.

The trend analysis of opex growth over the current regulatory period (in real terms – see figure 21 above) indicates that during the current period, opex is either flat or falling except for Powercor. This implies that amongst other things, the amounts of repex invested in the current period has contributed an offsetting reduction to the increases in opex incurred as a result of growth and other impacts.

As the amount of repex proposed is nearly twice that actually incurred in the current period, the increased claims for repex should have been offset by a reduction in the growth in opex. In fact, all DBs are seeking a considerable increase in opex through the opex trend growth trends without incorporating the very clear impact of the massive increase in repex compared to the current period.

The sponsors consider that if repex is increased above current actual levels, an explicit offset in the growth trends needs to be incorporated to reflect the increased repex. A further investigation is required to assess whether the increase in other capex will impact the amounts of opex required for the next period.

The sponsors also note that in addition to the amounts of repex, there is considerable other capex that is being invested. Some of this additional capex will impact the amount of opex required and an analysis needs to be undertaken to assess the impact of this other capex (i.e. total capex less augex and repex) on the amounts of opex required. In particular, the sponsors point to the amounts of IT capex that have been invested in the current period and proposed for the next period. The sponsors consider that much of this investment was (for the current period) and will be (for the next period) deemed efficient because it delivered benefits to consumers, and so will impact the amount of opex needed in the allowance. The sponsors consider that the AER needs to assess the downward impact this other capex has on the growth trend allowed for opex.

7.2.2 Price growth

The sponsors note that AusNet and Jemena accept the AER approach to adjusting the base opex for price trends but CitiPower, Powercor and United (CPPALUE) do not, proposing an alternate approach.

The sponsors consider that the AER approach should be used by all DBs. It is not clear that the approach proposed by the three CPPALUE networks delivers a better outcome for consumers and that consistency of approach is preferred.

The sponsors consider the AER should test its approach to assess whether the forecasts of future prices by its consultants providing price growth forecasts are what actually occurred. If there is a consistent deviation from the forecasts provided when previous assessments are tested against actual outcomes, then the AER should review whether an adjustment should be made to more closely reflect the actual outturn values for future prices.

7.2.3 Output growth

The sponsors note that the three CPPALUE networks have proposed an alternative to the weights and methodology used in the past by the AER to set the output growth. The sponsors consider that a consistent approach to setting the output growth measure is essential. If there is to be a change to the approach in assessing output growth, then the DBs proposing the change need to demonstrate that the revised approach is demonstrably more efficient and that the change should be applied to all DB's forecasts.

The sponsors also consider that there needs to be consistency between the output growth application to the base opex and the application of outputs in the assessment of productivity. To have different approaches to both of these applications does not lead to internal consistency between benchmarking and forecasting allowances.

7.2.4 Productivity growth

The sponsors note that all of the DBs propose to accept the AER decision on productivity growth.

However, the sponsors also note that AusNet had offered to its Customer Forum to implement a 1% productivity growth for its opex

> "We have agreed with the Customer Forum to double the ongoing cost savings sought by the AER to over 1% per annum. This represents a substantial outperformance of the AER's productivity setting of 0.5% per annum in the 2021-26 regulatory period."

The sponsors note that this "over 1%" is comprised of the AER 0.5% productivity growth coupled to other reductions in the opex that they would have otherwise sought an increase for and this was agreed with the Customer Forum.

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.

The step changes can be tabulated as follows

Table 7 Opex step changes

Step change $m	AusNet	CitiPower	Jemena	Powercor	United	Driver
REFCL program	6.0		1.3	13.3*		Gov't
5 minute and global settlement	3.6	1.9		4.9	3.9	Reg
Cyber security	4.7	14.4	2.9	14.5	45.9	?
IT cloud	2.6	2.3		5.9	4.7	Net benefit
EPA amendment Act 2018 **		6.1	4.2	9.6	11.8	Gov't
ESV levy		1.5		4.0	2.5	Gov't

Financial year RIN		1.8	1.4	1.8	1.8	Reg
Yarra trams pole relocation		14.4				?
Solar enablement, DER in future grid		1.3	3.8	6.2	4.2	Net benefit
Insurance			28.8	5.0	2.2	?
HBRA zone Reclassification **				21.5		?
Replacing EDO fuses				11.2		Net benefit
Demand management					8.6	Net benefit

Source: DB proposals

*Now reduced to $8.4m through a revision released by CPPALUE

**Now withdrawn (reduced to $0) under the CPPALUE revision

The sponsors consider that step changes need to be assessed on a number of bases, viz:

1. Is the step change an implicit increase in ongoing opex? If not, then the change is not an opex step change
2. Are the step changes imposed on the DBs by government or the regulator? If so, then there is a basis for the step change
3. Has the obligation already been included in the base opex? If so, the obligation is not current and is not a step change
4. If not imposed by government or the regulator, is there a net benefit to consumers? If not, then the step change should be rejected. If there is a net benefit for consumers has this been demonstrated?
5. Are the costs (and benefits if a net benefit is required) provided by the DB reasonable?
6. Is there consistency in price between the DBs? If not, the costs might not be reasonable

The sponsors have examined each of the step changes advised by the DBs under these criteria

7.3.1 REFCL program

The REFCL program has been required by government and has already been implemented. The question that needs to be asked is where are the additional costs considering that the base opex already includes for opex associated with much of the REFCL program?

The REFCL program mostly impacts AusNet and Powercor yet Powercor is seeking more than twice the amount in this step change than AusNet. This differential needs to be investigated in more depth as well as the base cost provided by both.

7.3.2 5 minute and global settlement

This program has been made a requirement of the National Electricity Rules by the AEMC and although recently delayed will come into operation during the regulatory period. The costs are driven predominantly by customer numbers and the amounts of data that needs to be collected and stored. In the discussions during the rule change process, it was considered by AEMC that the costs for distribution networks would be quite small.

Of concern is the difference in costs advised by the five DBs with Jemena not considering there are any related costs and CitiPower considering the costs are relatively small compared to the costs sought by the other DBs.

7.3.3 Cyber security

It is asserted that the AER has considered the costs associated with increased cyber security were granted to SA Power Networks in its recent regulatory reset. However, the decision for this requirement was made in 2017 and since then the DBs have had this obligation and so the costs should be already included in the base opex.

Of concern is the large difference in the costs proposed by each of the DBs, with AusNet and Jemena considering the costs to comply with the requirement to be quite modest, and CitiPower and Powercor seeking 3 to 5 times what AusNet and Jemena require. United’s cost is a massive 15 times what Jemena’s cost is. There is no consistency in the costing and if the AER considers that the base opex excludes the costs, then we feel it is important to determine why the DBs’ costs are so different and the most efficient allowance applied to all.

7.3.4 IT cloud

This requirement is not derived from government or the Regulator and must be assessed on the basis of the net benefit to consumers. The variation between the four DBs proposing this enhancement implies that there is doubt about the benefits. For example, AusNet considers that the cost would be $2.6m over 5 years, but as it has similar customer numbers to Powercor, then the cost advised by Powercor, there is unlikely to be a net benefit for Powercor customers. The same approach applied to United results in a similar outcome.

Overall, the sponsors doubt whether there will be a net benefit.

7.3.5 ESV levy

While the ESV does impose a levy and the networks are obliged to pay it, the fact that AusNet and Jemena do not seek an increase implies that the change is not a step change. The fact that the step change costs are so different between the three CPPALUE networks raises concerns about the calculation and how much of the levy is already embedded in the base opex.

7.3.6 Financial RIN

The sponsors note that AusNet does not consider this to be a step change, but the other four DBs all have sought costs. As AusNet considers there are no costs associated with the conversion (or has accepted not to claim the cost as part of its agreement with the Customer Forum), this raises the question as to the cost the other DBs are seeking.

The sponsors consider that the DBs all have an ongoing obligation already to provide RIN data and note that once the format conversion to financial year is complete, the costs for providing the RIN data on a financial basis will be the same as on a calendar year basis. This means that the move to a financial year basis is a project and not an on-going cost. On this basis, the DBs should, at most, only seek a single project payment for the conversion and no ongoing costs.

However, the sponsors consider that a financially competent firm would monitor its costs properly and, on this basis, the sponsors do not consider this to be a step change.

7.3.7 Yarra Trams pole movement

The sponsors do not see this as an opex step change but capital works. Once the project is complete, there will be no further costs in the on-going opex allowance, and this work would not require ongoing opex.

If the AER considers that Citipower should be allowed to recover the costs for this project, the sponsors consider that the costs for this should be a charge on Yarra Trams which is the beneficiary of the project.

7.3.8 Solar enhancement, DER future grid

This work is effectively a project for each of the DBs and once implemented there are no on-going opex costs. While assets might be changed to accommodate the new flows of electricity, the number and type of assets remains unchanged and do not require additional opex.

As this project is being undertaken to provide consumers with a better outcome, the costs of the project need to be offset against the benefit consumers might get and should only proceed if there is a net benefit to consumers. Further, a project of this nature results in benefits to some consumers so a further issue that needs to be resolved is why should consumers that do not get a benefit have to pay for works that deliver a benefit to only some.

7.3.9 Insurance

There are two concerning features related to this claim:

Firstly, why only three of the DBs see that the change in the insurance industry risk management see that this has resulted in increased costs for them. The reasons provided relate to bushfires in other parts of the world and so the premium increases would be universal to all DBs, yet this is not the case.

Secondly, why the costs for Jemena are so much higher than the costs seen by Powercor and United. The AER is required to allow only efficient costs into the revenue stream so if a DB institutes a cost which is higher than the costs seen by other DBs then the higher cost is not efficient and should not be allowed.

More investigation by the AER is required to identify if the claim for additional insurance costs for these three DBs is warranted and then if they are, what the costs should be.

7.3.10 EDO fuses

This work is not an opex step change but a specific project and therefore, if demonstrated to provide a net benefit to consumers, should be justified under the capex budget. Once the project implemented, the opex should not increase by the change in fuses.

7.3.11 Demand management

This project proposes a deferral of capital investment at the expense of increased opex for a non-network solution. In principle, this is a legitimate opex step change provided that the costs are not already embedded in the opex base.

The costs and benefits claimed by United need to be assessed to ensure that they are appropriate and do deliver a net benefit to consumers.

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.

The sponsors note that three of the incentive schemes are closely related in that increasing both opex and capex can result in benefits to the STPIS, and that increases in capex can lead to a reduction in opex. While the sponsors are aware that the AER attempted in the development of these three schemes to make them complementary, the sponsors are not convinced that this is the case.

With this in mind, the sponsors make the following comments:

8.1 Opex incentive

In the discussion above on opex, the sponsors have intimated that they are not convinced that the EBSS is achieving the stated goal of getting opex to the efficient frontier. Whether this is a flaw in the design of the EBSS or because the EBSS is not sufficiently highly powered to drive opex closer to the efficient frontier, or whether the AER is not using the benefits of the productivity analysis to its maximum extent is not clear, yet the outturn is that opex is becoming less productive and further from the efficient frontier.

What is also not clear is the extent to which capex is assisting the DBs garner a benefit under the EBSS, where consumers fund capex which leads to the bonus delivered by the EBSS. While some capex can lead to needed increases in opex, there are elements where the capex can lead to an opex reduction. While increases in opex are automatically delivered by the "trend" adjustment from growth of the network, there is no similar automatic driver to reduce opex from other capex, which most commonly results in the DBs commenting that they have included for opex reductions capex (particularly repex) but there is no transparency that opex has been actually been reduced as a result of the proposed increase in capex.

The sponsors consider that the AER needs to review the EBSS to improve its ability to drive opex to the efficient frontier

8.2 Capex incentive

The CESS has not been in operation as long as the EBSS but it has already been identified as not being well constructed. The major flaw with the CESS is that the setting of the capex in any reset is independent of the outturn performance of the DB in relation to its capex utilisation in the previous period. This leads to a number of issues.

Firstly, the DBs are incentivised to argue for the capex they consider that the AER will tolerate for the reset rather than what is seen as essential for the period. Under the EBSS, the forecast opex is clearly linked to the actual performance in previous years providing a clear starting point for the opex in the next period. There is no clear interrelation between past performance in capex with the future allowance.

Secondly, capex can be delayed within the current period from the forecast capex program, generating a benefit to the DB as the DB can retain the return on the capex for the year(s) the investment is delayed.

Thirdly, capex from one period can be deferred into the next, allowing a bonus to be paid for the current period with no penalty to the DB. As the bonus is paid on the total under-run for the current period, regardless of when the capex was programmed, just a one-year delay in implementing the capex program at the end of a period could result in a bonus based on the entire period under-run.

With these concerns in mind, the sponsors consider that the CESS needs to be refined so that any benefit is

- only paid on the actual under-run on each specific capex program rather than cumulative across the period,
- the bonus needs to be discounted for any benefit that is generated by a delayed scheduling of a capex project
- the bonus is discounted for a capex project that is not completed in the period and is added to the next regulatory period

However, the overriding issue is that the CESS needs to be used as the basis for setting the capex allowance for the next regulatory period, in a similar manner to that used for the

EBSS. This would require the CESS program to continue to operate across regulatory periods rather than terminate at the completion of the regulatory period.

8.3 Service performance

The STPIS is the longest running of the incentive schemes and was initially developed to drive increased reliability in the networks. Over the years the STPIS has delivered benefits to the DBs in terms of bonuses and to consumers in terms of increased reliability

However, as noted earlier, consumers would prefer to pay less than see improved reliability. The continued improvement in reliability in the networks has seen net bonuses paid under the STPIS which adds to the costs seen in future regulatory periods, so there is a clear link between improved reliability and increased costs for consumers.

The STPIS measures are directly influenced by the amounts of opex and capex that the DBs utilise. While the EBSS tends to limit the opex allowance (and therefore indirectly the STPIS outcomes), capex for the next period is not constrained in any way by the CESS outcomes in the current period, effectively allowing the DBs to enhance the ability to gain a STPIS bonus through their capex program.

The STPIS targets are set each regulatory period based on performance in the current period. Effectively, this means there is a significant time period between when the reliability measure was achieved and when the measure is used to generate the reliability targets in the next period. This allows the impacts of the opex and capex programs to generate the improved reliability in the next period, enhancing the likelihood that a STPIS bonus will be generated.

To overcome this shortcoming, the sponsors consider that the STPIS targets should be refined on an annual basis (just like the EBSS operates) so that the targets are set on a continuing basis. This can be readily achieved so that the STPIS targets in any one years are based on the average of the previous 3- or 4-year actual outcomes on a rolling basis.

As with the CESS, the sponsors consider that constraining the STPIS to a single regulatory period is generating a bias in the DBs gaining a benefit under the STPIS at expense of consumers.

8.4 Demand management incentive scheme

The sponsors accept that the DMIS can provide some value to consumers and support its retention. However, the sponsors consider that there needs to be close control over what projects are permitted under the DMIS so that the same projects are not carried out by multiple DBs and that the learnings from each DB are shared with all DBs.

8.5 Customer service incentive scheme

The sponsors recognise that the current service incentive scheme (telephone answering times) is inadequate and that an improved service incentive arrangement would be an advantage.

However, the sponsors consider that in any improved scheme, there are some key elements that must apply. These are the service

- must have real value to customers
- is capable of being measured
- must have sufficient power that it will deliver the desired outcome

The sponsors are not convinced that the customer service incentive scheme proposed by Ausnet (and picked up to some extent by the other DBs) is necessarily fit for purpose and consider that more investigation is carried out on the proposed changes.

9. Pricing

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

In their Issues Paper, the AER has said that they will also consider the merits of a Solar Sponge tariff, as well as a common tariff structure complemented by additional measures to address location specific issues.

The sponsors note that the impact of the tariffs will have to be included in retail tariffs provided by the retailers. This raises the question as to whether retailers will pass these network tariffs through to consumers and if they will actually do this. The sponsors therefore are concerned that even though network tariffs are changes, to what extent will retailers implement them and then pass the benefits through to consumers.

In the absence of clarity on how retailers will act, the sponsors consider the AER has a role to address this vexed issue.

While there has been some assessment commissioned by the networks regarding the impact of the proposed time-of-use structure for vulnerable customers,[28] we recommend that further analysis in the following areas is important to underpin a properly informed decision.

What will be the impact of the proposed tariff for vulnerable consumers?

We note that understanding the impact of the time-of-use tariff for vulnerable customers is less essential given that it will be optional for most customers – however, in the context of ongoing tariff reform, this is an important question to address.

High-level assessments undertaken by ACIL Allen has established that some vulnerable customers will be better off under the proposed tariff, and some will pay more.

We need to better understand how different types of vulnerable customers will be impacted – including working and non-working households, customers with energy-related health conditions and existing hardship customers and customers with energy debt.

We also need to better understand the impact of a proposed tariff structure on behaviour in vulnerable households – in this case, peak rates through the late afternoon and evening – to determine whether there may be undesirable consequences, such as an increased incidence of rationing essential heating or cooling.

Are the proposed tariffs targeted so as to reliably deliver network and wholesale savings, and can these savings be quantified or estimated?

If tariffs allow some customers to reduce their distribution charges by changing their behaviour, it's important to be confident that this will lead to benefits that are shared by all customers. It is also important to be confident that shared benefits will outweigh the additional network costs borne by customers unable to respond to the price signal.

[28] ACIL Allen, 2019, Vulnerable customer tariff impact

10. Pass through events

The sponsors note that the AER has approved certain aspects of the regulatory bargain to permit the DBs to assess the costs of changes and to include them in the approved revenue should the change occur during the regulatory period.

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 pas 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 addition to these already accepted pass through events, the DBs have nominated additional pass through events or sought changes to the definitions of already accepted pass through events.

Table 8 Proposed new pass through events

New pass through event	AusNet	CitiPower	Jemena	Powercor	United
Insurance coverage event	X	X		X	X
Electric vehicle uptake event	X	X		X	X
Major cyber event		X		X	X
Act of aggression event		X		X	X

Underlying the proposals for new pass through events or to modify the existing allowed pass through events is a desire to pass the risk of these events to consumers, yet some of the issues raised by the DBs fall into their ability to manage the risk through good business practices. The sponsors do not accept that, as a matter of principle, the DBs should be able to require consumers to carry the risk for events that can be managed or better managed by the DBs. It needs to be remembered that all firms operating in competition carry the risks for all of these events, including those already accepted within the rules and by the AER as reasons for transferring risks to consumers.

The DBs have included in their weighted average cost of capital (WACC) an allowance for accepting risks through the development of the cost of equity element of the WACC. The cost of equity is based on the inclusion of the market risk premium which is derived from the returns an investor would get from investing in the ASX as a whole. Therefore, implicitly, the approach used by the AER to set the WACC includes for the DBs to carry the risks in these pass-through events.

The sponsors agree that the cost of equity calculation reduces the market risk premium through the application of the equity beta, but as the equity beta is derived from the actual performance of listed firms supplying network services, the cost of equity does include for the DBs to carry some risks. Consumers accept that they should pay for another party to manage a risk that consumers cannot manage and the DBs are paid for this service through the equity risk premium they receive. The sponsors therefore do not consider that the networks should be able to get both an equity risk premium as well as pass risks onto consumers.

However, the sponsors do accept that in the past, the rules and the AER accept that some risks are not included in the risk premium and have allowed pass through events. As the AER has previously developed clear definitions for these pass-through events, the sponsors consider that changes to these definitions are not warranted and the existing definitions should be maintained. The sponsors do not consider that issues have changed since the last reset where the AER determined the appropriate definitions for each of the pass-through events and so a change in definitions is not warranted

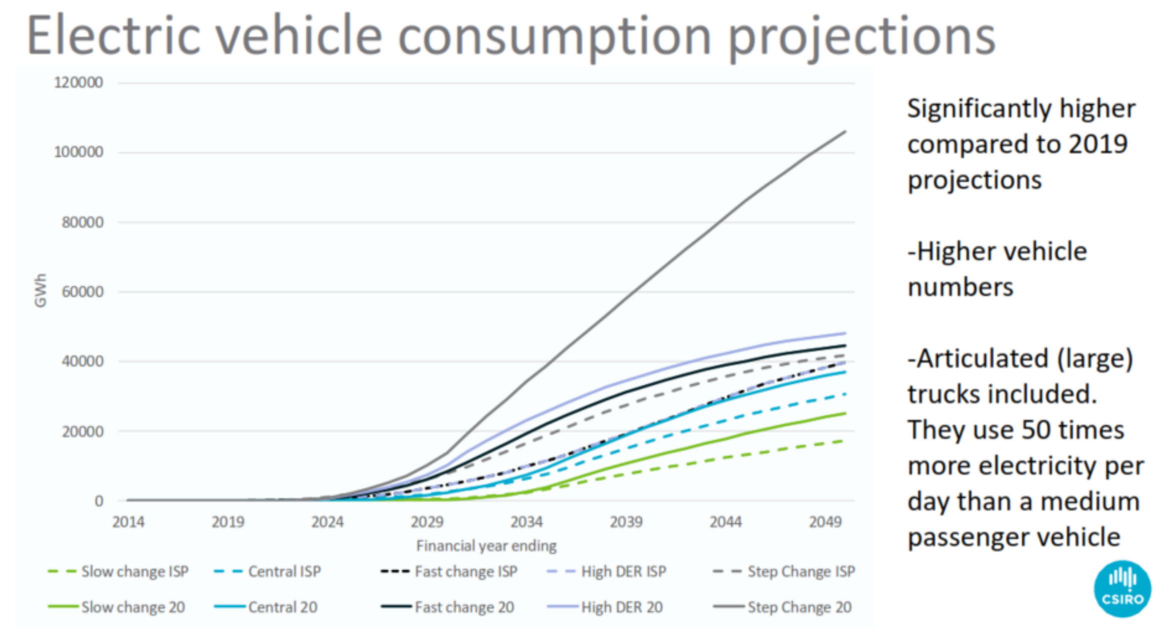
With regard to the new pass through events proposed by the DBs, the sponsors comment as follows:

Insurance coverage event. The existing pass through events include an insurance cap event but the DBs seek to extend the definition to further minimise their risk in the event that their insurance is inadequate. The DBs are expected to be competent in risk assessment and to ensure that their insurance cover is sufficient but also at a level that a prudent firm would purchase its insurance, noting that there is tension between the cost of the insurance and the cost of that insurance, and the DB is best placed to assess the efficiency between cost and coverage.

In previous resets, the AER has examined the tension between costs and coverage and reached a position where some of the risks can be passed to consumers in the interests of setting an efficient cost. The sponsors do not consider that insurance matters have changed so significantly since the last reset, that a change in definition or an extension of the pass-through event is warranted

Electric vehicle uptake. At its most fundamental, the issue of electric vehicle uptake is one of a risk that demand might increase in the networks and the timing of any increase. Already the DBs have sought increases in capex and opex to manage the expected increases in demand, so seeking to have the ability to pass through further costs because of an increase in demand, potentially caused by new government policies unrelated to the electricity industry is incongruous.

Any introduction of policies leading to an increase in EVs is not going to cause an instantaneous increase in demand, and any increase will occur over a considerable period of time. The CSIRO has provided the AEMO Forecasting Reference Group the following chart forecasting expected national growth in electricity consumption from EVs and which clearly shows that there is no need for the DBs to require a pass through for EV uptake and that the DBs will have more than adequate time to respond to any increase in demand caused from EV uptake.



A further consideration is that the impact of EVs is unknown – for example, it's not certain that charging will occur at peak times, so that associated consumption could potentially increase utilisation of the network rather than drive augmentation.

The sponsors consider that a claim for a pass-through event due to concerns of increased consumption, whether driven by government policy (e.g. the take up of EVs) or any other driver, is totally unwarranted, inappropriate and unnecessary.

In particular, the sponsors point to the forecast growth in demand from EVs which highlights that over the course of the next regulatory period, the impact of EV driven increased consumption is negligible and does not warrant and pass through event.

A major cyber event. All commercial and government enterprises are exposed to the risk of cyber-attack and firms are expected, being competent, to take appropriate actions to prevent such actions impacting their operations.

Further, the sponsors are aware that in addition to their regulated activities, all DBs have some involvement in unregulated activities where there is no ability for the firm to pass such costs onto consumers.

The sponsors consider that passing the risk to consumers of a major cyber-attack reduces the DBs' drive to avoid the outcome of such an attack. The sponsors point out that the major impact of a cyber-attack will be felt predominantly by consumers through their losses of supply and ask why there is a need for a pass through of further costs to be added to the costs consumers are already bearing as a result of the cyber-attack. It would appear that the DBs are seeking recovery only of their costs if there is an event without considering the impacts on consumers more widely.

The sponsors do not consider that the DBs should be effectively indemnified by consumers if they have not implemented appropriate protections.

If a DB is concerned that such an event might occur, then the DB should develop a business case demonstrating the net benefit of implementing an enhanced program for preventing such events impacting their network.

Act of aggression event. The sponsors do not consider that this should be included as a pass-through event. The sponsors note that the AER has already provided a view that a "war event" should not be allowed (see draft decision on the Essential Energy claim) and the claim for an act of aggression is much wider than the claim by Essential Energy and therefore increases the risk to both consumers and the DBs.

The sponsors point out that in the event there is an act of aggression, it will impact more people and firms than just the DB. Other firms and individuals that will also be impacted by an act of aggression do not have the protection sought by the DBs. The sponsors are of the view that an act of aggression is different to an act of terrorism which the AER has accepted as a pass-through event. In the case of an act of terrorism, the act of terrorism is more likely to be focused on the network as this would cause significant impact to consumers. In contrast, an act of aggression is not focused on the networks specifically and therefore it falls into the category of more widespread activity, which impacts all firms and individuals, all of whom do not have the ability to pass through the costs to another party. Intuitively, the risk of an act of aggression is included in the market risk premium used in the development of the cost of capital.

The sponsors consider that the impacts of an act of aggression are included in the risk premium that all firms operating in Victoria and Australia face and the DBs should not be granted special immunity that is not enjoyed by others who face this widespread risk.

11. Public lighting

The sponsors note the public lighting is a consideration that has wide public value in terms of providing a safe environment for all. It is also important that public lighting reflects the most efficient approach in its provision.

The sponsors have identified that there are proposals from the DBs where suggestions are made that over time, all public lighting should be converted to high efficiency lights (especially using light emitting diode lighting) away from the less efficient lights generally used for this purpose.

In principle, the sponsors support the transition to more efficient lighting but note that the more efficient lighting is often more expensive to supply and install then the existing approaches.

As consumers have made it clear that they do not support increased costs for the supply of their electricity supplies, it is clear that a transition to more efficient lighting should only be undertaken if there is a clear case that the costs of making such a change are less than the benefits from lower electricity usage.

With this in mind, the sponsors consider that the AER needs to establish a guideline which provides a consistent approach that the DBs should apply when assessing whether or not to change public lighting to more efficient lighting. Such a guideline would have to include an unequivocal approach as to how the cost of electricity will be calculated to identify the benefits of the savings generated by the change to more efficient lighting.

Appendix 1 Response to AER Issues Paper

The AER has published an Issues Paper to provide some guidance to stakeholders as to the issues the AER on which the AER has asked specific questions seeking stakeholder feedback with regard to the five DBs proposals. Four of these issues are listed and the sponsor responses are detailed below:

AER issues:

1. Due to the AusNet involvement in the NewReg approach to customer engagement, the extent to which AusNet's proposal opex and capex are amenable to assessment at the total level with less detailed assessment at the level of capex and opex components, compared to other Victorian DNSPs' proposals
2. Whether the proposals for expenditure and tariff reform support a transition to integrating distributed energy resources (DER)
3. Expenditure elements of:
    - Opex increases from the base
    - CitiPower, Powercor and United increased rate of pole replacement
    - The different approach to addressing the EPA Act
    - Allocating metering costs to standard control services
    - The trade-off between increased capital cost vs more efficient lighting
4. Accommodating the additional six-month period caused by moving the regulatory periods from a calendar basis to a financial year basis.

Each of these elements is addressed in more detail in the body of this submission but as a high-level observation, the sponsors comment:

Assessing the NewReg Trial

- The sponsors do not support the approach to applying a lesser level of investigation into the AusNet opex and capex because of the NewReg process for two reasons
    - The clear implication inherent in this approach is that the customer engagement undertaken by the other DBs is considered to be of a lesser standard than that of the AusNet CE. The sponsors are not convinced that this is the case and the AER and AusNet have not provided any evidence that the NewReg approach is superior to other forms of CE.
    - The sponsors recognise that the NewReg approach is very much a trial as an alternative approach to getting consumer input embedded into the reset proposal as an alternative approach to more conventional consumer engagement. Because of this, the sponsors consider that the process has to be assessed as to whether the goals of the process were achieved and to what extent. This implies that the AER

should assess whether the approach has delivered a better outcome for consumers than might otherwise have occurred.

Whether expenditure and tariff reform support a transition to integrating DER

DER integration expenditure is addressed in section 1.6. In summary, we support the general case for augmentation to support DER, however, we also feel that that there is a case for further consultation towards a more consistent and optimal approach between the networks.

We feel that there is value in conducting a process that will establish a consistent approach to valuing exported energy, to inform the revised proposals for this reset.

It would also be beneficial for a process to consider wider questions relating to the business case assessments undertaken by the DBs, as listed in section 1.6.

It will also be important to establish a system to monitor and evaluate delivery on proposed DER expenditure, given that DER investment has no implications for reliability, so that the STPIS devised to protect against under-deployment of traditional network infrastructure will not provide the same safeguard for DER-capacity investment.

Time-of-use tariffs

The networks have proposed a time-of-use tariff, with higher residential charges between three and nine PM. The tariff will be assigned to some customers (new solar customers, new connections, electric vehicles and three-phase customers), 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.

In their Issues Paper, the AER has said that they will also consider the merits of a Solar Sponge tariff, as well as a common tariff structure complemented by additional measures to address location specific issues.

While there has been some assessment commissioned by the networks regarding the impact of the proposed time-of-use structure for vulnerable customers,[29] we recommend that further analysis in terms of the **impact of the proposed tariff for vulnerable consumers, and the likely effect of the tariffs on distribution and wholesale costs.**

Expenditure elements

[29] ACIL Allen, 2019, Vulnerable customer tariff impact

Increases in opex and capex above the level necessary to maintain the current levels of reliability of supply should only be allowed if they clearly demonstrate a quantifiable net benefit to consumers in the short to medium term.

Accommodating the 6-month period

The sponsors consider that AER approach to incorporating the additional 6-month period is generally supported but reference is made to the comments included in section 1.4 above in relation to opex and capex allowances.

Appendix 2 Table of average asset lives for each DB

The following table gathers together the average asset ages expected by each of the DBs – this data is drawn from the of the DB RIN data on category analysis

Table 9 – Average asset lives by DB

Asset age profile (mean)		**AusNet**	**Citi Power**	**Jemena**	**Powercor**	**United**
Poles by: highest operating voltage; material type; staking (if wood)	Staking of a wooden pole	65	36	11	39	20
	< = 1 kV; Wood	55	36	41	39	60
	> 1 kV & < = 11 kV; Wood	55	36	45	39	60
	> 11 kV & < = 22 kV; Wood	55	36	38	39	60
	> 22 kV & < = 66 kV; Wood	55	36	38	39	60
	< = 1 kV; Concrete	100	36	28	39	70
	> 1 kV & < = 11 kV; Concrete	100	36	30	39	70
	> 11 kV & < = 22 kV; Concrete	100	36	27	39	70
	> 22 kV & < = 66 kV; Concrete	100	36	20	39	70
	< = 1 kV; Steel	35	36	30	39	40
	> 1 kV & < = 11 kV; Steel	35	36	-	39	40
	> 11 kV & < = 22 kV; Steel	35	36	-	39	40
	> 22 kV & < = 66 kV; Steel	35	36	-	39	40
	Other	35	36	32	39	-
Overhead conductors by: highest operating voltage; number of phases (at hv)	< = 1 kV	55	60	29	41	53
	> 1 kV & < = 11 kV	60	60	32	41	52
	> 11 kV & < = 22 kV ; SWER	46	-	-	41	60
	> 11 kV & < = 22 kV ; Single-Phase	56	-	29	41	60
	> 11 kV & < = 22 kV ; Multiple-Phase	56	60	24	41	48
	> 22 kV & < = 66 kV	61	60	40	41	60
	Other	-	60	-	41	-
Underground cables by: highest operating voltage	< = 1 kV	50	70	11	70	70
	> 1 kV & < = 11 kV	50	70	26	70	55
	> 11 kV & < = 22 kV	50	70	14	70	55
	> 33 kV & < = 66 kV	50	70	31	70	40
	Other	-	70	-	70	-
Service lines by: connection voltage;	< = 11 kV ; Residential ; Simple Type	40	-	34	-	40

customer type; connection complexity	< = 11 kV ; Commercial & Industrial ; Simple Type	40	-	32	-	40
	< = 11 kV ; Residential ; Complex Type	-	-	-	-	40
	< = 11 kV ; Commercial & Industrial ; Complex Type	-	-	-	-	40
	Other	-	65	-	55	-
Transformers by: mounting type; highest operating voltage ; ampere rating; number of phases (at lv)	Pole Mounted ; < = 22kV ; < = 60 kVA ; Single Phase	58	-	25	45	50
	Pole Mounted ; < = 22kV ; > 60 kVA and < = 600 kVA ; Single Phase	58	-	11	45	50
	Pole Mounted ; < = 22kV ; > 600 kVA ; Single Phase	58	-	-	-	-
	Pole Mounted ; < = 22kV ; < = 60 kVA ; Multiple Phase	58	45	25	45	50
	Pole Mounted ; < = 22kV ; > 60 kVA and < = 600 kVA ; Multiple Phase	58	49	23	45	50
	Pole Mounted ; < = 22kV ; > 600 kVA ; Multiple Phase	58	-	21	55	50
	Kiosk Mounted ; < = 22kV ; < = 60 kVA ; Single Phase	58	-	15	55	50
	Kiosk Mounted ; < = 22kV ; > 60 kVA and < = 600 kVA ; Single Phase	-	-	-	-	50
	Kiosk Mounted ; < = 22kV ; < = 60 kVA ; Multiple Phase	58	55	43	55	50
	Kiosk Mounted ; < = 22kV ; > 60 kVA and < = 600 kVA ; Multiple Phase	58	55	12	55	50
	Kiosk Mounted ; < = 22kV ; > 600 kVA ; Multiple Phase	58	55	11	55	50
	Ground Outdoor / Indoor Chamber Mounted; < 22 kV ; < = 60 kVA ; Single Phase	-	-	-	45	-
	Ground Outdoor / Indoor Chamber Mounted; < 22 kV ; > 60 kVA and < = 600 kVA ; Single Phase	-	-	-	45	-
	Ground Outdoor / Indoor Chamber Mounted; < 22 kV ; < = 60 kVA ; Multiple Phase	50	55	-	45	-
	Ground Outdoor / Indoor Chamber Mounted; < 22 kV ; > 60 kVA and < = 600 kVA ; Multiple Phase	50	55	29	45	50
	Ground Outdoor / Indoor Chamber Mounted; < 22 kV ; > 600 kVA ; Multiple Phase	50	55	25	55	50
	Ground Outdoor / Indoor Chamber Mounted; > = 22 kV & < = 33 kV ; < = 15 MVA	50	55	23	-	51
	Ground Outdoor / Indoor Chamber Mounted; > 33 kV & < = 66 kV ; < = 15 MVA	50	55	55	51	-

	Ground Outdoor / Indoor Chamber Mounted; > 33 kV & < = 66 kV ; > 15 MVA and < = 40 MVA	50	55	61	51	55
	Ground Outdoor / Indoor Chamber Mounted; > 33 kV & < = 66 kV ; > 40 MVA	50	55	-	51	-
	Ground Outdoor / Indoor Chamber Mounted; > 66 kV & < = 132 kV ; < = 100 MVA	50	-	-	-	-
	Other	-	49	-	50	-
Switchgear by: highest operating voltage ; switch function	< = 11 kV ; Fuse	50	-	21	-	30
	< = 11 kV ; Switch	47	55	24	50	35
	< = 11 kV ; Circuit Breaker	45	41	52	45	45
	> 11 kV & < = 22 kV ; Switch	47	55	21	50	34
	> 11 kV & < = 22 kV ; Circuit Breaker	45	55	27	52	45
	> 22 kV & < = 33 kV ; Switch	47	-	-	-	-
	> 22 kV & < = 33 kV ; Circuit Breaker	45	-	-	-	-
	> 33 kV & < = 66 kV ; Switch	47	55	14	55	45
	> 33 kV & < = 66 kV ; Circuit Breaker	45	39	48	47	45
	> 66 kV & < = 132 kV ; Switch	47	-	-	-	-
	> 66 kV & < = 132 kV ; Circuit Breaker	45	-	-	-	-
	Other	-	49	-	47	34
Public lighting by: asset type ; lighting obligation	Luminaires ; Major Road	35	20	17	20	20
	Luminaires ; Minor Road	35	20	17	20	20
	Brackets ; Major Road	35	-	29	-	20
	Brackets ; Minor Road	35	-	36	-	20
	Lamps ; Major Road	-	30	4	30	-
	Lamps ; Minor Road	-	30	3	30	-
	Poles / Columns ; Major Road	35	50	22	50	50
	Poles / Columns ; Minor Road	35	50	22	50	50
	Other	-	-	-	-	-
Scada, network control and protection systems by: function	Field Devices	20	20	26	20	25
	Local Network Wiring Assets	-	-	-	-	25
	Communications Network Assets	20	15	12	15	33
	Master Station Assets	-	5	-	5	-
	Communications Site Infrastructure	-	15	-	15	-
	Communications Linear Assets	-	25	22	25	-
	Other	-	-	-	-	-

Other by: dnsp defined	Buildings		-	-	50
	Civil		-	-	45
	Capacitor Banks - Large	30	-	-	45
	Fences		-	-	45
	CTs and VTs	45	-	-	50
	NER's	30	-	-	45
	OTHER - EARTHING	60	-	-	
	OTHER - REGULATORS	50	-	-	
	OTHER - SUPPLY TRANSFORMERS (LINES)	58	-	-	
	OTHER - STATION SUPPLIES TRANSFORMERS	50	-	-	
	OTHER - SURGE DIVERTERS	45	-		
	OTHER< = 11 kV ; REACTOR ;	62			
	OTHER> 11 kV & < = 22 kV ; REACTOR ;	62			
	OTHER> 22 kV & < = 66 kV ; REACTOR ;	62			
	OTHER - CROSS ARMS	45			