AusNet Electricity Services Pty Ltd

Electricity Distribution Price Review 2022-26

Revised Regulatory Proposal

3 December 2020

PUBLIC

About AusNet Services

AusNet Services is a major energy network business that owns and operates key regulated electricity transmission and electricity and gas distribution assets located in Victoria, Australia. These assets include:

- A 6,574 kilometre electricity transmission network that services all electricity consumers across Victoria;
- An electricity distribution network delivering electricity to approximately 680,000 customer connection points in an area of more than 80,000 square kilometres of eastern Victoria; and
- A gas distribution network delivering gas to approximately 572,000 customer supply points in an area of more than 60,000 square kilometres in central and western Victoria.

AusNet Services' purpose is 'to provide our customers with superior network and energy solutions.'

For more information visit: www.ausnetservices.com.au

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Executive summary

Introduction

AusNet Services owns and operates one of the five electricity distribution networks in Victoria. We serve around 765,000 customers located across the east of Victoria, from the edge of Melbourne to the border of New South Wales.

On 31 January 2020, we submitted our regulatory proposal (Initial Proposal) to the Australian Energy Regulator (AER) setting out our revenue requirements for the 2022-26 regulatory period.[1]

Our proposal reflected agreements with our Customer Forum, which was established to represent the perspectives of our customers, on key aspects of our expenditure plans and service offerings. We were the first Australian utility to adopt this approach, which was a trial of the 'New Reg' process jointly developed by the AER, Energy Consumers Australia (ECA) and Energy Networks Australia (ENA).[2] The Customer Forum was supported by the AER when agreeing its positions with AusNet Services.

On 30 September 2020, the AER published its Draft Decision on our Initial Proposal endorsing key elements agreed with the Customer Forum.[3]

This document, together with its accompanying supporting material, constitutes our response to the AER's Draft Decision and is our Revised Proposal for our electricity distribution network for the 2022-26 regulatory period.

Our Revised Proposal responds to the issues raised in the AER's Draft Decision and updates our Initial Proposal to incorporate more recent information, including the expected impact of COVID-19.

This *Executive summary* provides an overview of our Revised Proposal including required revenues and the price impact, changes that have occurred in our operating environment since we submitted our Initial Proposal and how we have responded to stakeholder feedback in developing this Revised Proposal.

This Revised Proposal covers the services set out in Appendix A – Service Classification and applies the Cost Allocation Methodology set out in Appendix B.

The dollars presented below are stated in real $2021 terms unless noted otherwise.

Revenue requirement and price impact

We are proposing revenues of $3,331.8 million (nominal, smoothed) for the 2022-26 regulatory period. This is $98.9 million (2.9%) lower than the revenue we sought in our Initial Proposal and $72.5 million (2.2%) higher than the revenues proposed by the AER in its Draft Decision. This is shown below.

As set out in more detail in the *Key features of our Revenue Proposal* section below, we have only departed from the Draft Decision when invited by the AER, to provide more information to address the AER's concerns and, in very few cases, to reflect new exogenous information.

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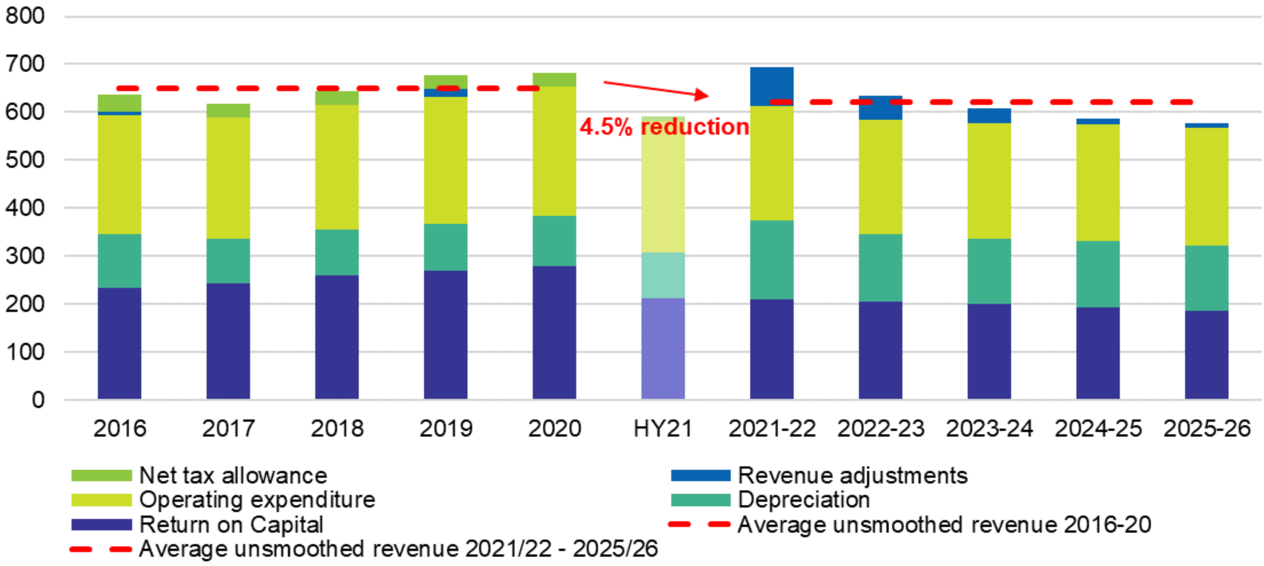
1 This document is available at: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/ausnet-services-determination-2021-26/proposal (accessed 19 August 2020).

2 AER, *New Reg*, available at: https://www.aer.gov.au/networks-pipelines/new-reg (accessed 19 August 2020).

3 This document is available at: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/ausnet-services-determination-2021-26/draft-decision (accessed 18 November 2020).

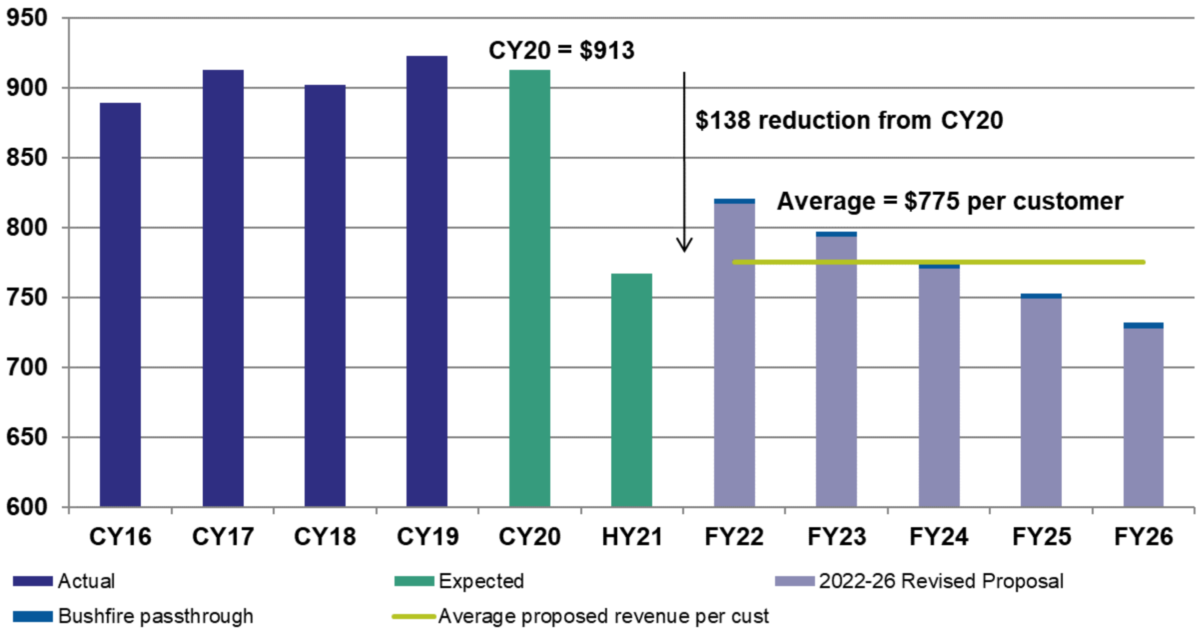
Unsmoothed revenue requirement ($m, real 2021)



After accounting for our expenditure forecasts, lower interest rates and AER decisions that lower the cost of capital, the above figure shows that our average revenue requirement will be 4.5% lower in real terms over the 2022-26 regulatory period.

To indicate the impact on customer bills, we set out the average annual revenue per customer below. We consider this is the best way to explain the customer impact of our proposed distribution charges, which account for approximately 32% of electricity bills. The figure also shows the bill impact of the 2019-20 bushfire cost pass through application, which was approved by the AER on 19 November 2020.

Revised Proposal revenue per customer per annum ($ real 2021)



A combination of the reduction in our annual revenue requirement and customer growth results in an average annual reduction in revenue per customer of $138 (or 15%) over the 2022-26 regulatory period, compared to 2020. This comparison includes the impact of the approved bushfire cost pass through application.

The bill impact on specific customers will depend on various factors including their energy consumption, demand and the applicable network tariff. For this reason, we also present indicative bill impacts for customers on particular tariffs. The table below shows the total forecast revenue for each tariff divided by the expected number of customers on these tariffs and is consistent with the data underpinning the indicative rates included in the Tariff Structure Statement.

Bill impacts of Revised Proposal (nominal)

Tariff class	Tariff	2020	FY22-26 average	$ change	% change
Residential	Single rate	508	496	-$12	-2.4%
	Two rate	696	580	-$116	-16.6%
	Two rate solar	500	440	-$60	-12.0%
Small Industrial & Commercial (40-160MWh)	Single rate	943	928	-$15	-1.5%
	Two rate	1,470	1,208	-$262	-17.8%
	Two rate plus demand	7,078	6,959	-$119	-1.7%
Industrial & Commercial (>160MWh)	Critical peak demand (160-400 MWh)	23,807	23,518	-$289	-1.2%
	Critical peak demand (750-2,000 MWh)	73,463	72,984	-$480	-0.7%
	Critical peak demand (High voltage)	259,051	255,300	-$3,751	-1.5%

Source: AusNet Services

Changes in our operating environment since our Initial Proposal

2020 has been a highly unusual year for several reasons. The COVID-19 pandemic, its economic and financial market impacts and extreme weather events continue to have deep and wide-ranging impacts across all parts of society. These events also create challenges for us in operating and maintaining our distribution network while endeavouring to meet the evolving needs and expectations of our customers.

When we submitted our Initial Proposal in January 2020, COVID-19 had not yet been declared a pandemic and the summer 2019-20 bushfires were not yet extinguished (our Initial Proposal did not include the cost impacts of these bushfires). As such, there has been more change than anticipated between the submission of our Initial Proposal and this Revised Proposal. The AER has also acknowledged that, due to the economic uncertainties and its review of estimating expected inflation, there is potential for a larger-than-normal change between its Draft and Final Decisions.

The impacts of specific changes and areas of uncertainty are explained below.

COVID-19

The impact of COVID-19 on us and our customers has been significant and will continue. We took the following steps to assist our customers during this time:

- We voluntarily offered network pricing relief which involved waiving or deferring network charges for residential and small business customers who were in energy hardship because of the economic impacts of COVID-19. We also offered payment deferrals to commercial and industrial customers.
- We minimised disruptions to support our customers who were at home during the day due to government restrictions, by:
  - Deferring non-critical work; and
  - Reducing the length of required outages to under 5 hours where possible, but not if this would increase outage frequency during the period of COVID-19 restrictions.

We are yet to experience any material reduction in demand for our network services due to the impacts of COVID-19. For example, between March and November 2020 we have observed the following:

- Consumption between 1 April and 23 October 2020 has reduced by just 1% compared to the same period in 2019. Residential consumption grew by 10%, while small business consumption fell by 12% and large business consumption by 11%.
- Demand has increased compared to the same period in 2019. We have not yet experienced a summer where the impacts of ongoing working from home (either due to continuing restrictions or changes in working habits) on peak demand can be observed.
- Growth in load connections has remained steady, with no current signs of a slowdown in either lagging (connection numbers) or leading (estate applications) indicators.
- The number of DER connections has exhibited strong growth, up 25% in the period April to August 2020 compared to the same period last year, despite restrictions.

As explained in Chapter 1, the adjustment the AER made to the Draft Decision to account for the economic impacts of COVID-19 is reasonable and is supported by our internal forecasts, which account for recent key economic data. If the AER is minded to change this adjustment in its Final Decision we would like an opportunity to provide feedback on its intended approach.

Extreme weather events

Summer 2019-20 bushfires

The 2019-20 ‘Black Summer’ bushfires across Eastern Australia caused widespread devastation across regional areas and heavily impacted our network. A total of 1,000 km of powerlines were affected, leaving 7,000 customers off supply because of the damage. The fires caused direct damage to assets, and indirect damage from burning trees falling across power lines. We did not have access to some of the affected network to restore customer supply until many weeks after initial damage due to ongoing fires or an inability to otherwise obtain safe access for fields crews.

The importance of maintaining supply to communities and customers during the crisis, where safe to do so, was also crucial. In recognition of the hardship being experienced by the community, we offered a range of concessions and other support arrangements to our customers.

On 27 May 2020 we submitted a natural disaster cost pass through application to recoup the expenditure associated with the bushfire response and remediation works. The AER published its decision on 19 November 2020 to allow the recovery of $13.7 million of opex and $6.9 million of capex (net amounts incurred in 2020 and the half year period), amounting to $13.9 million of revenue to be recovered over all five years of the 2022-26 regulatory period. The impact of this on distribution prices is shown in the figure above.

The substantial remediation works undertaken in bushfire-affected parts of our network have reduced the need for asset replacement and vegetation management in the 2022-26 regulatory period because assets were damaged and replaced following the bushfires, and less vegetation management is required as trees on the affected line easements were destroyed or removed in the clean-up. A total of $1.0 million of expenditure has been removed from our Revised Proposal to reflect this.

August 2020 storms

Four consecutive days of severe storms in August 2020 impacted 140,000 (around 19%) of our customers. This was the largest storm event to hit our network since 2003 and resulted in extensive damage requiring over 260 construction jobs to restore supply.

We deployed an emergency response to this event and restored supply to most customers within days. We have not sought to pass through the material costs associated with these remediation works.

The AER's Inflation Review

The AER is currently undertaking a review of the methodology used to set expected inflation in revenue determinations. A Draft Position was released in September 2020 which, if adopted, significantly improves the accuracy of the estimate. The AER's Final Decision is expected in December 2020. This Revised Proposal provides indicative estimates of the revenue impact of the AER's Draft Decision (see section 2.5). Under current economic conditions its application would increase approved revenues, therefore, the AER has asked for stakeholder feedback on the appropriateness of a staged transition to its new approach.

We do not consider a transition is appropriate or consistent with the National Electricity Rules (NER). The NER emphasise that the best estimates should be used when available.

Nonetheless, we are conscious of potential price impacts on customers. Therefore, we have accepted the AER's Draft Decision to reduce our accelerated depreciation and have not sought additional revenue for various other increased costs. This ensures that the full and immediate implementation of the more accurate inflation forecast will not compromise the price outcomes agreed with the Customer Forum.

We also note that continued low interest rates underpin the reductions in revenue forecast. We were already in a low inflationary and low return environment when we submitted our Initial Proposal and economic conditions have significantly worsened over the course of 2020. The cost of equity set in the Final Determination is expected to be impacted by the Reserve Bank of Australia's $100 billion government bond buyback program which will artificially suppress yields of Government bonds – a critical input into the cost of equity.

The combination of a low return environment and an unrealistically high expected inflation parameter creates financeability pressures under the regulatory regime, which is currently delivering the unusual or unsustainable outcomes listed below.

- **The benchmark entity is incurring cash losses**. The AER's Draft Decision results in negative cash returns for equity investors in the benchmark entity totalling $135 million over the 2022-26 regulatory period.[4]
- **Expected nominal return on equity of close to 2% (i.e. below the current cost of debt)**, if equity investors in the benchmark entity adopt inflation expectations indicated by market data (i.e. their inflation expectations when investing in network equity securities match their expectations when investing in other financial securities); and

[4] Appendix 7A – Frontier Economics, The impact of artificially supressed government bond yields, 23 November 2020.

- **Regulatory allowance is inconsistent with observed market data**. The Draft Decision sets regulatory allowances on the basis that the real risk-free rate is -1.44%, when the observed real risk-free rate is around 90 basis points higher.

The full and immediate implementation of the more accurate inflation forecast will reduce the impact of, but not eliminate, these outcomes.

Even if the AER immediately applies its new inflation approach in full, developments in financial markets over the next few months could further stress financeability for Victorian distributors. We anticipate that the AER will wish to deal with these pressures during the 2022 Rate of Return Review.

Key features of our Revised Proposal

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

We have reflected the majority of the AER's Draft Decision in our Revised Proposal, including:

- **Capital expenditure** (capex). Capex for replacement, augmentation (including for Distributed Energy Resources (DER)), safety (other than expenditure relating to our Rapid Earth Fault Current Limiter (REFCL) program) and non-network activities subject to updated labour cost escalators. At the AER's request, we have also removed the cost of asset replacements (totaling $0.4 million) that were undertaken as part of the 2019-20 bushfire remediation works.
- **Operating expenditure** (opex). The opex base year, opex output growth and productivity trend parameters, the 5-minute settlement step change and the cyber security step change reallocation to Transmission. This has included reducing our REFCL opex step change by $1.5 million to reflect expected Energy Safe Victoria (ESV) exemptions and removing $0.5 million of avoided vegetation management opex because of the 2019-20 bushfire remediation.
- **Accelerated depreciation.** The Draft Decision accepted our proposal to accelerate the depreciation of Intelligent Network Devices (IED) protection relays and Remote Terminal Units (RTUs) acquired between 1997 and 2016. However, the AER reduced the amount of our accelerated depreciation by $43.4 million, as a result of calculating the depreciation on a more granular basis. $30.9 million of this will be recovered over the 2026-31 regulatory period. We have applied the AER's revised amount for accelerated depreciation, as this change helps mitigate the potential price impacts of applying the improved inflation forecasting methodology.
- **Metering revenues.** We have adopted the adjustments made to metering revenues in the Draft Decision with one exception being we have reallocated some metering costs to distribution customers in line with our Initial Proposal.
- **Incentive schemes.** The Revised Proposal reflects the AER's Draft Decision on the incentive schemes that have been applied in the 2016-20 regulatory period and will be applied in the 2022-26 regulatory period, subject to the following data updates:
    - A more recent 2020 and January to June 2021 capex forecast;
    - Service Target Performance Incentive Scheme (STPIS) incentive rates and Demand Management Innovation Allowance Mechanism (DMIAM) to reflect Revised Proposal revenues; and

  - Customer Satisfaction Incentive Scheme (CSIS) targets and deadbands have been updated to reflect more recent customer satisfaction survey results.

There are several areas where the AER has invited us to provide updated information or we have provided new information to address issues raised by the AER. These include:

- **REFCL regulatory requirements**. The AER requested updates to our REFCL capex forecast given the scope for us to implement an alternative solution at three zone substations. This has resulted in a $27 million reduction to our augmentation program, which is required to maintain acceptable levels of capacitance as the network grows. We have also included revised costs for the REFCL Tranche 3 project at Kalkallo zone substation. Although our costs for Tranche 3 have increased relative to the Draft Decision, our Revised Proposal is a more cost effective solution compared to building a new Zone Substation (Kalkallo North), which was the solution we previously proposed to the AER.
- **Labour cost escalators**. As invited to by the AER, we have incorporated updated labour cost escalators from BIS Oxford in our Revised Proposal. These account for the expected economic impacts of COVID-19 and will allow the AER to apply its standard approach of averaging labour cost escalators of its consultant forecasts with those submitted by the network business.
- **Distributed Energy Resources (DER)**. Our Revised Proposal adopts the AER's Draft Decision in relation to DER capex. In response to the Draft Decision, we have provided sensitivity analysis of different uptake rates and explained why we have not applied the outcomes of the Value of DER study which was very recently published by the AER.[5] Our view is that no further changes to our DER capex is warranted, particularly as our further engagement with the Customer Forum has confirmed its support for our proposal.
- **Information and Communication Technology (ICT) cloud opex step change**. The AER rejected the ICT cloud step change as it considered there was insufficient evidence to establish the required capex/opex trade off. We have now provided this evidence and have, therefore, resubmitted the step change. The Customer Forum has reiterated its support for the functionality underpinning this step change, which formed part of our agreement on the Initial Proposal.[6]
- **Guaranteed Service Levels (GSL)**. The AER accepted our proposal, subject to a minor adjustment, but recognised that this amount would need to be updated to take account of expected changes to the scheme. The Essential Services Commission (ESC) has now provided details of its proposed changes to the scheme, which will lead to increased GSL payments. We have incorporated the expected impact of these changes including appropriate transitional arrangements in our Revised Proposal.

In certain circumstances, new cost imposts, external information or stakeholder consultation has resulted in revisions to our Initial Proposal and, therefore, a proposed modification the AER's Draft Decision. This variance has arisen in relation to:

- **Bushfire liability insurance premium step change**. Despite taking significant steps to minimise the recent increases in insurance premiums (including raising our deductible from $10 million to $25 million), we still expect costs to increase by a minimum of $10 million over the next regulatory period.
- **Connections capex**. While we have adopted the AER's adjustment in 2021-22 to account for the economic impacts of COVID-19, we have updated our forecasts to reflect the:

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5 CSIRO and Cutler Merz, *Value of Distributed Energy Resources: Methodology Study, Final Report*, October 2020, < https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/assessing-distributed-energy-resources-integration-expenditure/update>.

6 See Appendix 3A.

  - Material decline in the real rate of return. This will reduce the level of contributions (comprising cash contributions and gifted assets) that new connecting customers will make towards the cost of their connections[7]. The impact of this update has increased net connections capex (including overheads) by $52 million (27%) relative to the Draft Decision.
  - Application of a higher marginal cost of reinforcement in REFCL areas. This means that customers connecting in higher bushfire risk areas pay a cost commensurate with the network cost of that connection.

- **Recovery of market institutions fees and levies**. These costs relate to the activities of the ESV and the Australian Energy Market Operator (AEMO), which are recovered through annual charges. As these costs are outside our control, it is appropriate for the actual costs to be recovered from customers through the annual pricing process, rather than exposing customers to the risk that the actual costs incurred are lower than the AER's forecast. By the same token, we should not be exposed to the risk that the ESV's and AEMO's actual costs are higher than forecast.
- **Metering cost reallocation**. The AER's Draft Decision accepted the principle that our metering activities support the distribution business and, therefore, justify a rebalancing of our cost recovery from metering charges to network charges. However, the AER did not accept all of our cost re-allocation and proposed a different allocation between metering and network charges. In this Revised Proposal, we provide additional evidence to support a change from the Draft Decision.
- **Large embedded generator connection charges**. To reduce the cross-subsidy paid by our customers to large embedded generator connections and to maintain competitive neutrality between generators connecting to the transmission and distribution networks, we have amended our connection policy to allow us to charge economic tax costs to large connecting generators.

While the following expenditure requirements have arisen since our Initial Proposal, we have not added these costs based on stakeholder feedback:

- **Additional ICT capex totalling $18 million**. These costs arise in relation to the expected cost of delivering 5-minute settlement; a digital solution to support safe and compliant REFCL operations; and enhanced communications for planned outages to achieve compliance with new Electricity Distribution Code (EDC) requirements; and
- **Additional augmentation at the Doreen zone substation totalling around $10 million**. This augmentation is required in light of the updated demand forecasts following the 2019-20 summer. This requirement arises despite including a negative adjustment to demand to account for the impact of COVID-19 on business demand and not accounting for the potential future increase in working from home.

Instead we will bear risk (rather than our customers) by seeking to deliver the above works – some of which are required to meet regulatory requirements – within the total allowance provided by the AER by seeking lower cost alternatives across the portfolio.

A detailed summary of the components of the AER's Draft Decision and our Revised Proposal is provided in the relevant chapters of this document. We have also updated our Tariff Structure Statement to address matters raised in the AER's Draft Decision, which is submitted alongside this Revised Proposal.

The key changes to our Tariff Structure Statement include:

- Discounting our cost reflective tariffs to encourage uptake;

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[7] This arises because under the Incremental Cost less Incremental Revenue (IC - IR) test, the stream of future revenues is discounted at a much lower rate, increasing its value relative to the Incremental Cost.

- Enabling small customers with solar to opt onto a flat tariff;
- Reassigning over 200,000 residential customers to our new time of use tariff to increase the take up of cost reflective tariffs; and
- Refining the peak period window of our medium business tariffs to better align with times of network peaks from 1 July 2023. This will allow customers to prepare for this change.

The Revised Proposal reflects stakeholder and customer feedback

Our Revised Proposal reflects the priorities and objectives we identified through our broad-based and deep engagement with our customers in developing our Initial Proposal. This engagement has continued following the submission of our Initial Proposal and the subsequent publication of the AER's Draft Decision.

'New Reg' and the Customer Forum

While the AER's Draft Decision is broadly consistent with the agreement we reached with the Customer Forum, the Revised Proposal seeks to align additional aspects, such as the ICT Cloud opex step change, which funds the delivery of functionality deemed critical by the Customer Forum.

In developing this Revised Proposal, we re-engaged the Customer Forum to give its views on our intended responses to the AER's Draft Decision. This includes the reasonableness of our approach and whether it reflects stakeholder feedback provided during engagement sessions held following publication of the Draft Decision.

The approach to engaging with stakeholders and the Customer Forum in developing our Revised Proposal is set out below.

The Customer Forum provided high level support for our amendments and its memo is attached at Appendix 3A.

Stakeholder engagement approach

In developing our Revised Proposal, we have undertaken the following engagement:

- **6 October 2020** – Briefed our Customer Consultative Committee (CCC) on the AER's Draft Decision and sought initial feedback on the Draft Decision.
- **27 October 2020** – Held a stakeholder forum with a wide range of consumer advocates, our Customer Forum, our CCC and the AER's Consumer Challenge Panel (CCP) to seek feedback across a broad range of issues we were considering in our Revised Proposal.
- **29 October 2020** – Met with our Customer Forum for a detailed discussion on our initial response positions.
- **6 November 2020** – Sought feedback from our CCC on our response. The Customer Forum and the CCP were in attendance.

How stakeholder feedback has been incorporated into our Revised Proposal

We have taken stakeholder feedback into account in the ways described below.

Presentation of price impacts

Stakeholders have expressed confusion about the different ways in which the price impacts are presented by businesses and the AER. We have presented the price impacts of this Revised Proposal in terms of revenue per customer and by tariff, based on the indicative rates submitted in the Revised Tariff Structure Statement. We recognise there are many different ways in which price impacts can be expressed and have endeavoured to be clear about the assumptions underpinning our analysis.

Impacts of COVID-19

There was broad recognition of the high level of uncertainty surrounding the expected economic impacts of the COVID-19 pandemic. We presented internal scenario analysis on customer growth to stakeholders, which included a scenario based on assumptions underpinning the Federal Budget. Stakeholders encouraged us to more weight on some of these assumptions, such as the decline in the fertility rate. We have incorporated this into our analysis presented in this proposal. We have also provided analysis on why other aspects of the Federal budget modelling is not supported by the connections activity we have seen on our network during 2020.

Capital expenditure

The Customer Forum did not support re-visiting our demand-driven augmentation program at this stage of the review process, due to the scrutiny they (supported by the AER) gave to this part of the Initial Proposal prior to submission. This Revised Proposal does not include additional costs for projects that have become economically justified during the 2022-26 regulatory period due to updated demand forecasts.

We heard mixed views from stakeholders on our DER integration capex proposal. Some stakeholders expressed concern over the use of the feed-in tariff in our economic justification and considered the 45 year time horizon over which we measure benefits of this capex was too long. Other stakeholders considered that late updates to our proposal were not warranted, given it appropriately balanced the economic considerations with the need to meet the expectations of our customers connecting DER systems.

While we have not made changes to our proposed DER integration capex (which was accepted in the Draft Decision) we have set out sensitivity analysis on various assumptions underpinning our case, including forecast uptake which the AER noted was below the Victorian Government's forecast. We note that the Victorian Government has recently announced additional incentives for solar uptake by small businesses. The impact of this has not been factored into either our proposal or our sensitivity analysis.

We also heard positive feedback on our proposed reduction in REFCL augmentation capex as we have adopted lower-cost solutions.

Operating expenditure

We informed stakeholders of the steps we have taken to manage the increase in our bushfire liability insurance premiums, including raising the deductible from $10 million to $25 million, which would be borne by customers under cost pass through arrangements if an event did occur. We heard stakeholder support for keeping ongoing costs low, with the trade-off being that costs would be higher when an event occurred.

We also discussed our ICT Cloud opex step change with the Customer Forum, who continued to support this in line with the original agreement in our Initial Proposal (see section 4.6.3.4). The Customer Forum considers that the functionality funded by this step change is required to improve the experience of our customers. We have, therefore, provided the evidence sought by the AER in relation to this step change.

Regarding the allocation of expenditure from metering into the distribution network where the expenditure benefits customers of the distribution business, we heard feedback that allocating these costs into the distribution business would benefit low use customers, as the amount they would pay would depend on levels consumption, rather than being part of a fixed fee. We also heard that this was not a material issue for customers given there is no net price impact, and the levels of expenditure we are considering re-allocating are relatively low in the context of the proposal as a whole.

In this Revised Proposal we have sought to re-allocate some expenditure from the metering into the distribution business, informed by the feedback we received around the price impact of low use customers.

Structure of this document

This Revised Proposal comprises 14 chapters with the remainder of this document structured as follows:

- Chapter 1 explains our revised demand and energy forecasts, including how this proposal accounts for the economic impacts of COVID-19;
- Chapter 2 summarises the building block components, total revenue and X-factors for our Revised Proposal;
- Chapter 3 outlines our revised proposal for capex, including augmentation, replacement expenditure and capital contributions for connections;
- Chapter 4 outlines our proposed opex, including our step changes and how we have updated our labor forecasts to better capture current Victorian economic conditions;
- Chapter 5 provides information on how we have determined and the reasonableness of our opening Regulatory Asset Base (RAB);
- Chapter 6 outlines our approach to depreciation;
- Chapter 7 provides information on our proposed return on capital and gamma;
- Chapter 8 provides information on our proposed corporate tax allowance;
- Chapter 9 outlines our approach to various incentive schemes, including the new Customer Satisfaction Incentive Scheme;
- Chapter 10 outlines the cost pass throughs we intend to take forward;
- Chapter 11 provides information on our connections policy;
- Chapter 12 provides information on the control mechanism for Standard Control Services (SCS);
- Chapter 13 explains our approach to metering and the charges/fees we intend to apply; and
- Chapter 14 outlines the proposed charges we intend to apply for Alternative Control Services (ACS).

Next steps

Following the submission of our Revised Proposal the key next steps are:

- Submissions on our Revised Regulatory Proposal are due to the AER by 8 January 2021;
- The AER publishes its Final Decision on our Revised Regulatory Proposal by 30 April 2021; and
- The next regulatory period for electricity distribution in Victoria commences on 1 July 2021.

1 Demand and energy forecasts

1.1 Key points

- Recognising the impact of COVID-19, we have accepted the adjustment to our customer number forecast applied in the AER's Draft Decision, which applied the Housing Industry Association's (HIA) April 2020 dwelling starts forecasts. An adjustment of this magnitude is supported by our analysis and is reasonable.
- The AER considered that our energy consumption forecast accounted for the historical trends of energy consumption and was a reasonable indicator of a prudent and efficient forecast. We have accepted the position taken in the AER's Draft Decision.
- We have updated our demand forecasts to capture more up-to-date information, including our expectations of how COVID-19 will impact our network. These forecasts are presented in this chapter. Importantly, and as discussed in Chapter 3, we have not increased our augmentation capex in response to an increase in forecast demand.

1.2 Chapter structure

The remainder of this chapter is structured as follows:

- Section 1.3 outlines our updated customer number forecasts;
- Section 1.4 outlines our updated energy consumption forecasts;
- Section 1.5 outlines our updated maximum demand forecasts; and
- Section 1.6 outlines the supporting documents for this chapter.

In the event of inconsistency between this chapter and our Initial Proposal, the information contained in this chapter prevails.

1.3 Customer number forecasts

1.3.1 Our Initial Proposal

In our Initial Proposal, we forecast a steady customer growth of approximately 1.7% per annum over the 2022-26 regulatory period, led primarily by the residential and industrial sectors, which are expected to grow more rapidly than the commercial segment.[8] The forecast in our Initial Proposal is reproduced below.

Table 1-1: Initial customer numbers forecast

	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26
Customer numbers	756,598	769,586	782,596	795,734	809,066	822,443
Annual growth	N/A	12,988	13,010	13,137	13,333	13,377

Source: AusNet Services

We explained that our forecast growth in customer numbers is driven by the significant population and development projections in various growth corridors, including key urban local government

8 Our Initial Proposal explains in detail our customer forecasting methodology and the relationship trends between our different customer types.

areas such as Whittlesea and Casey (which are located on the northern and south-eastern fringes of our metropolitan Melbourne network) and the Shire of Baw Baw.

1.3.2 Draft Decision

The AER considered that:

> … *had COVID-19 not occurred, AusNet Services' connections forecast was likely to be reasonable*.[9]

However, to take into account the impacts of COVID-19, it adjusted our connections forecast for the year 2021–22 based on the HIA's construction forecasts.[10] For the years after 2021–22, the AER accepted the forecasts included in the Initial Proposal.[11]

1.3.3 Addressing the AER's Draft Decision

We consider the AER's proposed adjustment to our connections forecast is reasonable, albeit moderately conservative. We have, therefore, reduced our 2021-22 connections forecast in line with the AER's Draft Decision. We have not updated our forecasts for the remaining years, given our initial forecasts were accepted in the Draft Decision.

The AER's adjustment is supported by our own analysis, which was shaped by discussions with our stakeholders. Our analysis suggested that following a significant reduction in 2022 connections, which is sustained for a short while, a gradual recovery follows before returning to expected growth. This is known as a U-shaped recovery.

The expected shape of the recovery in customer numbers was settled after testing a range of options with our stakeholders on 27 October 2020 and the Customer Forum on 30 October 2020. In these discussions, we tested the following scenarios:

- A V-shaped recovery built from a foreshadowed 'unprecedented' level of investment in the upcoming State Budget, together with low interest rates and recent high savings rates. This scenario is supported by high volumes of connections following the Global Financial Crisis (GFC).
- A U-shape which assumes growth returns to normal in 2022-23 as economic stimulus packages take effect and a potential COVID-19 vaccine is approved and distributed (a middle ground scenario).
- A downside scenario based on the negative net overseas migration assumptions in the 2020-21 Federal Budget (the 'Federal Budget' scenario).[12]

Following discussions with the stakeholders – on issues such as COVID-19's potential impact on fertility rates, its scope to impact metropolitan and regional areas differently, Victorian building permits and established dwelling activities – we refined our U-shaped proposal to better reflect customers' views. Our refinements included pushing back the timing of when we might start to see the effect of COVID-19 on our customer connections and modifying our proposal to capture a potential decline in fertility rates across the population. The result of these changes was a customer number forecast that was broadly aligned with the forecast proposed by the AER.

Our updated final scenarios are outlined below.

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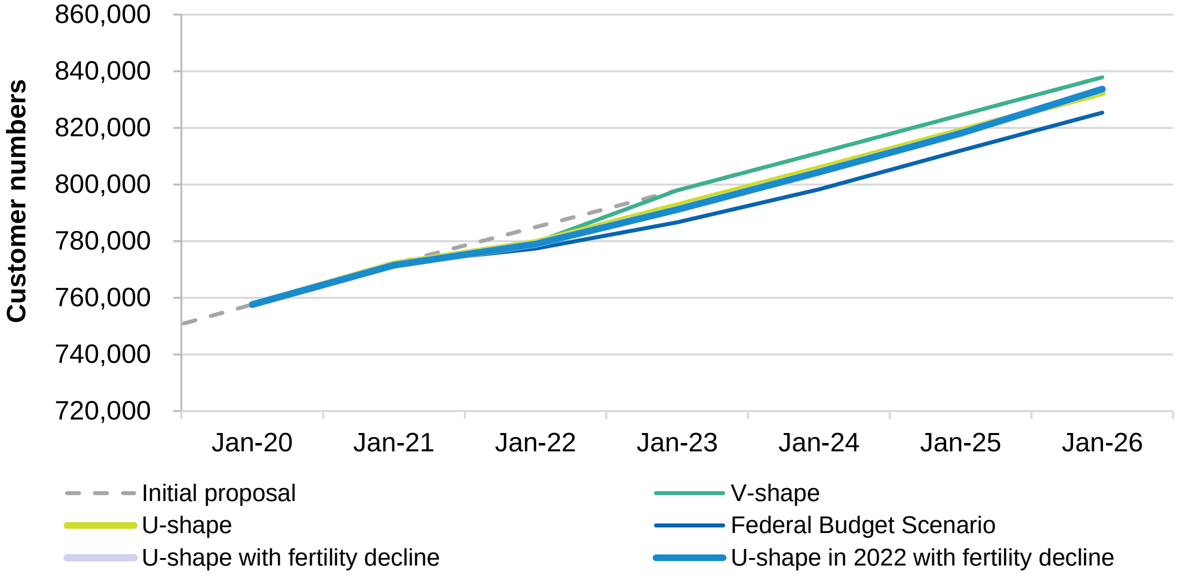
9 AER, Attachment 5: Capital expenditure, Draft Decision – AusNet Services 2021-26, September 2020, p. 16.

10 https://hia.com.au/-/media/HIA-Website/Files/IndustryBusiness/Economic/forecasts/housing-forecasts-apr2020-covid-19.ashx?la=en&hash=48700772F0661BEB23F29B5049AEFF779C692F9B (accessed 8 November 2020)

11 AER, Attachment 5: Capital expenditure, Draft Decision – AusNet Services 2021-26, September 2020, p. 17.

12 Federal Budget Paper No.1, Statement 2: Economic Outlook, October 2020, p. 34, Source: https://budget.gov.au/2020-21/content/bp1/download/bp1_bs2.pdf (accessed 8 October 2020).

Figure 1-1: Customer number forecast scenarios



Source: AusNet Services

In light of our engagement with stakeholders, we consider that a U-shape scenario will most accurately reflect the expected impacts of COVID-19 on our customer numbers. We do not consider that a short sharp return to normal (a V-shaped recovery) or a significant and ongoing negative impact (a Federal Budget scenario) are more likely.

We consider a U-shaped recovery is reasonable as:

- There has been no slowdown in connections or our new estates pipeline;
- The number of residential building permits in 2020 exceed those in 2019; and
- There are low and declining residential vacancy rates in our network.

In addition, based on history, during the period after the GFC (where there was a significant increase in government spending), we experienced record customer number growth.

We briefly explore each of these issues below.

1.3.3.1 Trends in connections and new estate applications

Throughout 2020 we have seen no evidence in our network of a slowdown in connections activity.

Figure 1-2 (below) shows the growth in customers in 2020 since Stage 3 restrictions were enforced in Victoria, compared to the corresponding periods in 2019. It shows that connections are tracking broadly in line with the previous year. In other words, we have yet to see a significant COVID-19 impact on the number of new connections. However, new connections can be considered a lagging indicator, as the decision by customers to invest in these connections are made prior to the physical connection to our network.

Similarly, if we look at the number of requests we receive from developers for new estates – a leading indicator of future connections – we see that since April 2020, there has been no indication to suggest that interest in new estates has declined. In fact, we received more total applications for new estates between April and September in 2020 than we did in the same period last year.

Figure 1-3 (below) shows the applications for new estates in our Central (growth) region in 2020 since Stage 3 restrictions took place in Victoria, against the corresponding time period in 2019.

Figure 1-2: Lagging indicator – growth in customer connections

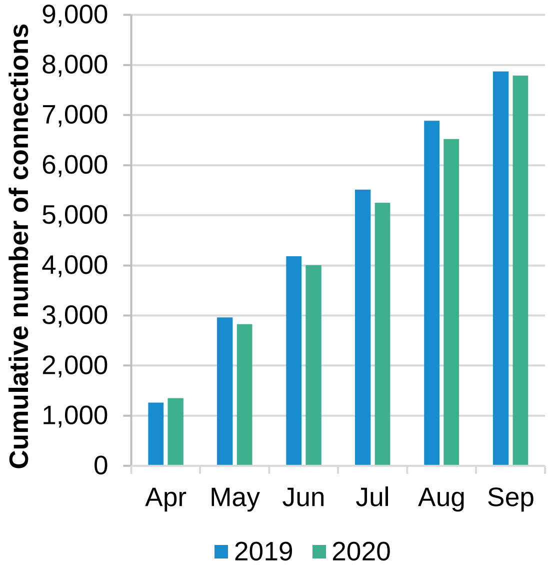
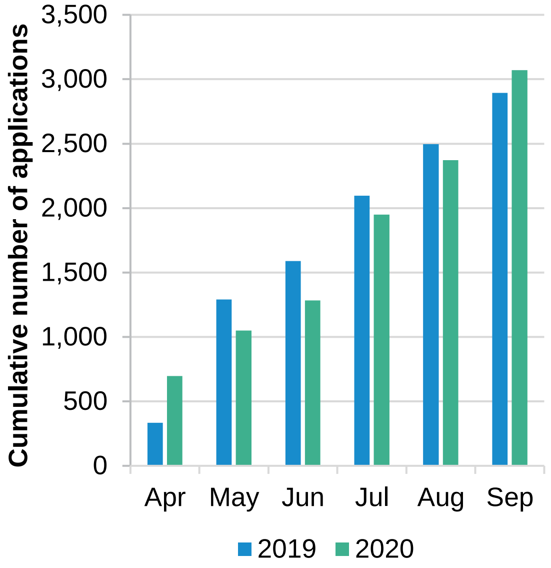


Figure 1-3: Leading indicator – New estate applications



Source: AusNet Services

Our data, therefore, suggests that pushing back the timing of when we will see the impact of COVID-19 on our network is appropriate (and is consistent with the approach proposed by the AER). The data presented above also shows that the 'Federal Budget scenario' is less likely to eventuate. In particular, the recent growth in connections on our network suggests that our future connections are unlikely to be aligned with the projected decline in population growth in the Federal Budget forecasts in the short or medium term. Adopting such a scenario for the 2022-26 regulatory period would, therefore, not be based on the facts currently available to us.

1.3.3.2 New dwellings tracking ahead of 2019

Recent data from the Victorian Building Authority also demonstrates that COVID-19 has not yet impacted the number of residential building permits being issued in Victoria.[13] Rather, the data shows an increase in the number of permits issued simultaneously as the length and severity of various COVID-19 restrictions progressed. Importantly, we see this outcome across both the metropolitan and regional areas of our network, as reflected in Figure 1-4 and 1-5 below.

We have also considered the implications of the Victorian Government's *Big Housing Build* program that was announced as part of the 2020/21 Victorian Budget. This will fund more than 12,000 homes across Victoria.[14] While there is limited information on the locations where construction is expected to take place as well as the nature of the buildings (i.e. whether they are high rise towers, free standing dwellings, etc), we expect the program to contribute to our customer growth over the forthcoming regulatory period, and therefore that our analysis (which was produced before this announcement) is conservative.

13 See: https://www.data.vic.gov.au/, Building permit activity data, includes number of expected new dwellings for Residential and Domestic building use, in the Eastern, South Eastern and Northern sub-regions of Outer Melbourne as well as the Gippsland, North Central, North East regional areas.

14 Victorian Government, '*Victoria's Big Housing Build*', 24 November 2020. Source: https://www.premier.vic.gov.au/victorias-big-housing-build-0 (accessed 24 November 2020).

Figure 1-4 : Number of new dwellings in metro region

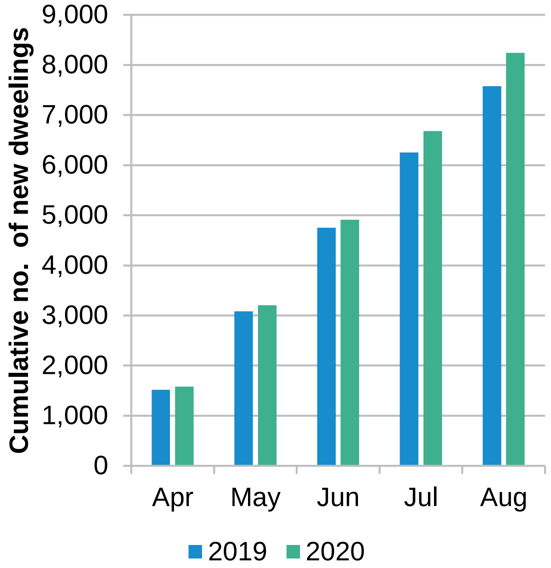
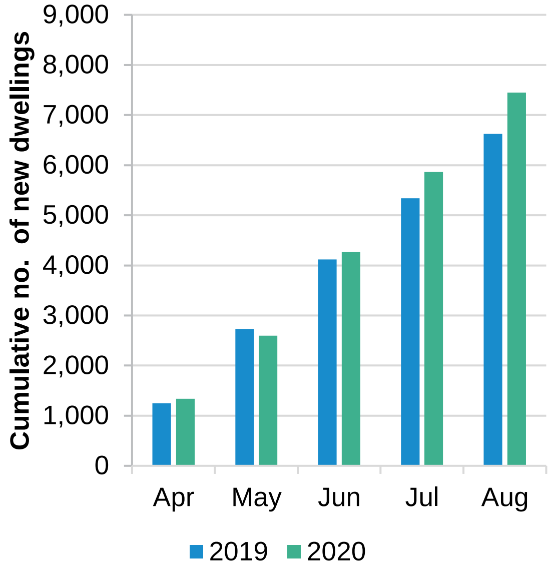


Figure 1-5: Number of new dwellings in regional areas



Source: https://www.data.vic.gov.au/

1.3.3.3 Low and declining vacancy rates

While the Federal Budget anticipates reductions in net overseas migration, in relation to forecasting our customer numbers we need to consider the geographical impact of this decline.[15] Unlike large urban networks, our network, a significant part of which is rural, is likely to see a more moderated impact from a decline in overseas immigration.

For example, the publicly available data[16] on residential vacancy rates – the number of total established dwellings within a given area that are vacant – indicates a stark difference in vacancy rates between the inner city and the outer suburbs/regional areas of Victoria. Low vacancy rates indicate significant rental activity and that rental competition for dwellings is high. Low vacancy rates also suggest strong continued growth in these areas.

Figure 1-6 below shows vacancy rates for four regions in Victoria, and highlights that, of the four regions, only the central business district (CBD) experienced a sharp increase in empty dwellings in early April 2020, likely driven by the impacts of restrictions and absence of international students. Conversely, the low vacancy rates in our network areas, which include parts of south east Melbourne, north east Victoria and Gippsland, suggest that customer growth within our network area has largely been unaffected by the restrictions.

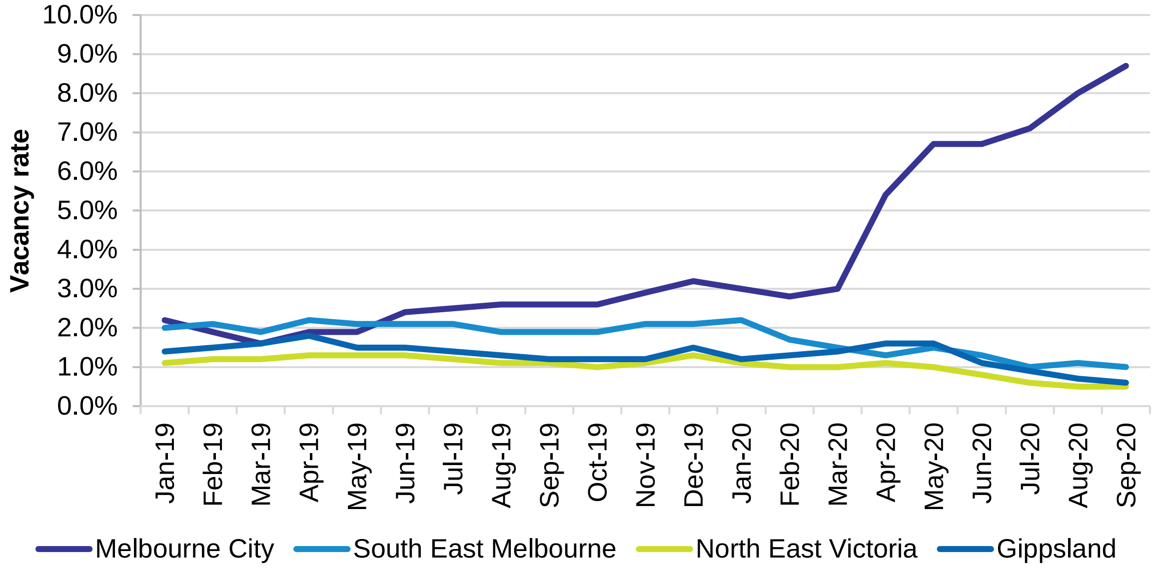
The lower vacancy rates on our network may indicate that a shift in working patterns has occurred for those residential customers whose workplaces would ordinarily be based in the CBD, and who have now moved into other parts of the state. This explanation is further supported by the imbalance between the restrictions applied by the Government to metropolitan Melbourne and regional Victoria, respectively. The pattern of lower vacancy rates in the outer Melbourne suburbs and regional areas of Victoria has continued throughout the duration of the lockdown period, but it is possible that it is temporary and may be corrected once restrictions ease significantly. We have tested this view with our Customer Forum and other customer representatives, who echoed

15 Federal Budget Paper No.1, Statement 2: Economic Outlook, October 2020, p. 34, Source: https://budget.gov.au/2020-21/content/bp1/download/bp1_bs2.pdf (accessed 8 October 2020).

16 Source: https://sqmresearch.com.au/graph_vacancy.php (accessed 24 November 2020).

the feedback that this trend is likely to be temporary and may just as easily reverse once restrictions begin to unwind.

Figure 1-6: Residential vacancy rates



Source: https://sqmresearch.com.au/graph_vacancy.php

1.3.3.4 Record growth after last recession

Victoria's Premier, Daniel Andrews, has outlined that the State Budget:

> *… delivers an unprecedented investment to rebuild our state. At the heart of that effort is getting Victorians back into work. The Andrews Labor Government's Budget funds up to $49 billion in the things that matter to Victorians - and our economic recovery. Central to this investment is our Jobs Plan, which sets an ambitious goal: creating 400,000 jobs by 2025 – half of them by 2022. This is a Budget to rebuild, recover and make us stronger than before.*[17]

This commitment is in addition to the various measures the State and Federal governments have already implemented to help combat COVID-19. We note that, to-date, there has been significant government support provided for employees, business owners, and sole traders who have been adversely affected by COVID-19 and further government support is expected.

We also note that after the last recession, economic recovery was strong and surpassed the level of growth prior to the downturn. For example, after the GFC in 2009, we observed unprecedented levels of connections growth in our network. This is illustrated in the charts below.

[17] Source: https://www.premier.vic.gov.au/budget-puts-people-first, Statement from the Premier, 24 November 2020 (accessed 24 November 2020).

Figure 1-7: Residential connections

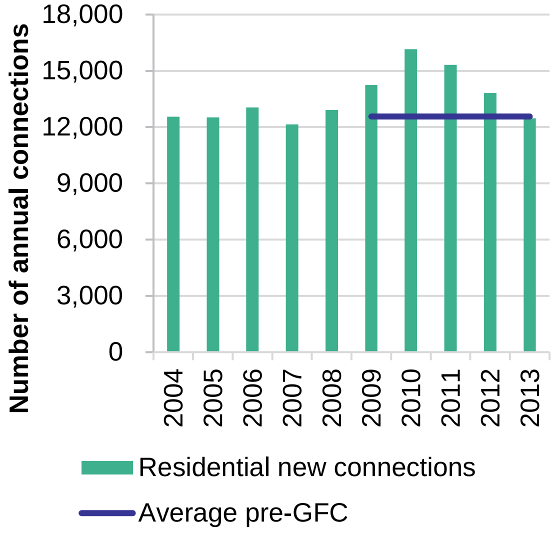
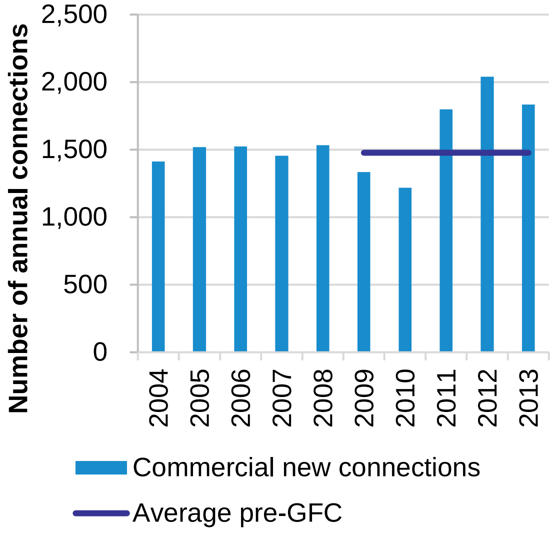


Figure 1-8: Commercial connections



Source: AusNet Services

While we recognise that the drivers of the GFC are different to the current situation, given the level of investment foreshadowed by the Premier and by other levels of Government, it is not unreasonable to suppose a similar recovery in both housing construction and commercial activity once the expected stimulus packages flow through to the pockets of Victorian consumers. However, we acknowledge the restrictions of movement associated with the COVID-19 recession and its differences with the GFC, where these restrictions on migration did not exist. While somewhat dated (and again noting several differences), we note that following the Spanish flu there was a remarkable recovery in the labour market.[18] The potential for a COVID-19 vaccine may also influence government policy on inter-state movement and overseas migration, thereby further aiding the recovery.

Depending on the size of any government stimulus, it is possible that new connections and overall customer growth may exceed current projections. If this happens, the recovery is likely to be more akin to the V-shape discussed above. This is because increased government expenditure is likely to lead to many industries, which have suffered from the COVID-19 pandemic (such as entertainment, hospitality, higher education and tourism in particular), recovering much more quickly than anticipated. The increase in economic activity is likely to improve both consumer and business confidence further driving economic growth which may encourage new entrants in the commercial and industrial sector. Aside from government stimulus, the housing sector is also expected to benefit (all else equal) from record low interest rates and evidence of increased savings during the pandemic.

In summary, the above discussion suggests that the forecast customer numbers may bounce back to pre-COVID levels and growth rates, consistent with a V-shaped recovery. However, on balance we consider it appropriate to assume a U-shaped recovery, which is consistent with the AER's Draft Decision and the views of our customers and stakeholders.

1.3.4 Revised Proposal

We have accepted the AER's adjustment to our customer numbers and have not updated parts of the Draft Decision that apply the AER's customer numbers.

[18] RBA, Economic effects of the Spanish Flu, available at: https://www.rba.gov.au/publications/bulletin/2020/jun/economic-effects-of-the-spanish-flu.html (accessed 8 November 2020).

For completeness, the table below contains our revised customer number forecasts for the 2022-26 regulatory period. These incorporate the AER's adjustment.

Table 1-2: Customer number forecasts

	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	Growth rate p.a.
Residential	698,742	706,136	718,864	731,711	744,736	757,740	1.6%
Commercial	70,368	70,466	70,692	70,924	71,176	71,501	0.3%
Industrial	2,896	2,929	2,986	3,043	3,099	3,147	1.7%
Total	**772,006**	**779,531**	**792,541**	**805,678**	**819,011**	**832,388**	**1.5%**
Growth p.a.	N/A	7,525	13,010	13,137	13,333	13,377	N/A

Source: AusNet Services

1.4 Energy consumption forecasts

1.4.1 Our Initial Proposal

In our Initial Proposal, we forecast that electricity consumption would resume its gradual decline. We considered that the rapid growth in solar connections, plus the ongoing effects of energy efficiency, would continue to drive reductions in residential and commercial energy consumption on both a total and per customer basis. However, we considered this would be moderated by a small increase in consumption by low voltage industrial customers who are servicing residential customer growth.

Our Initial Proposal energy consumption forecasts are reproduced below.

Table 1-3: Initial energy consumption forecasts

	2021-22	2022-23	2023-24	2024-25	2025-26
Energy consumption (GWh)	7,300	7,259	7,229	7,204	7,183

Source: AusNet Services

1.4.2 Draft Decision

The AER considered that our energy consumption forecast accounted for the historical trends of energy consumption and was a reasonable indicator of a prudent and efficient forecast.

1.4.3 Addressing the AER's Draft Decision

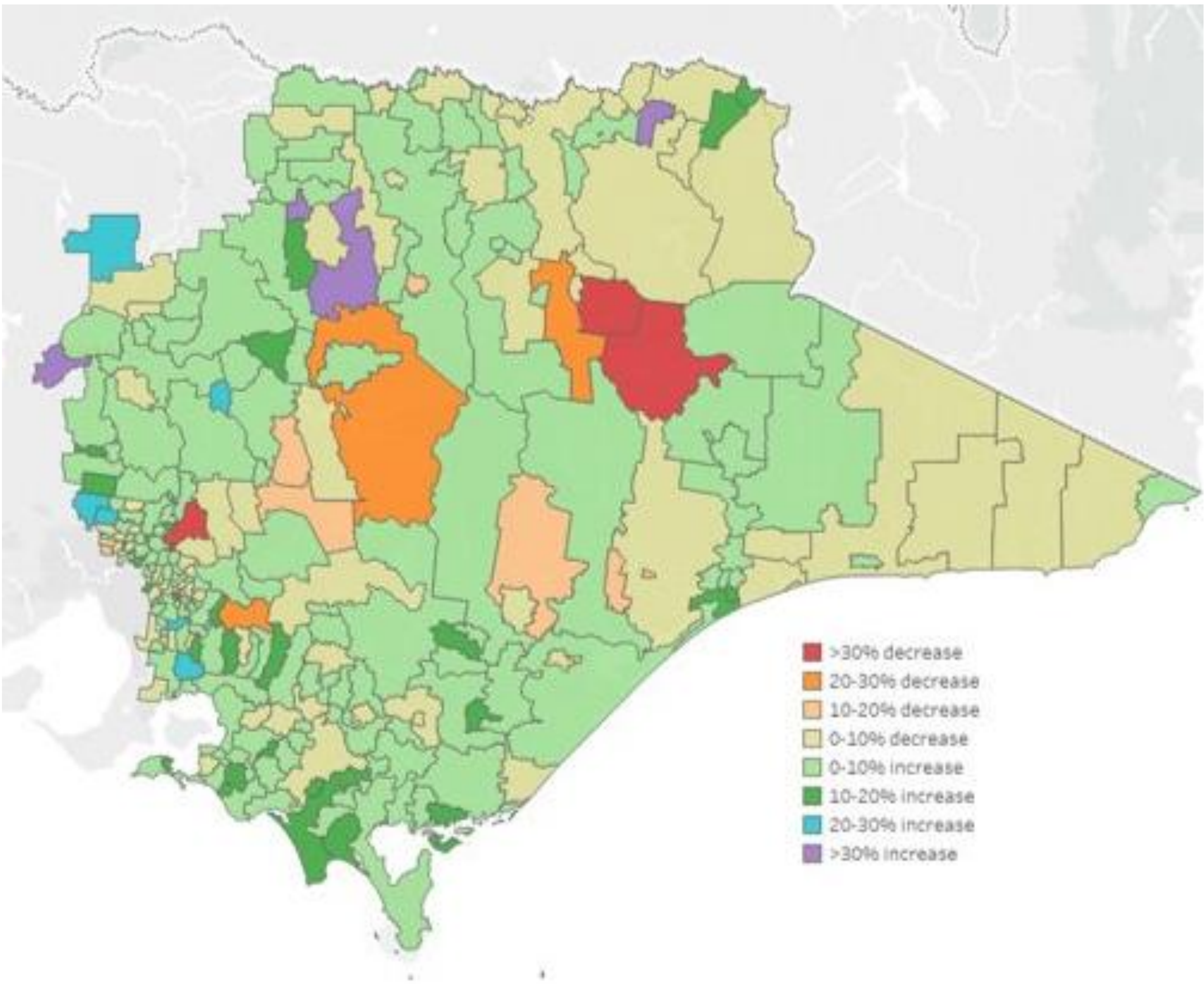
We accept the AER's position in the Draft Decision on our energy consumption forecasts.

In coming to this decision, we have recognised the scope for COVID-19 to have a differential impact on energy consumption across customer groups. For example, residential areas have seen strong consumption which may continue if there is a permanent shift in working patterns and arrangements. Similarly, working from home and colder weather has also contributed to large increases in residential consumption. Conversely, both commercial and industrial customers have exhibited lower consumption. Future government restrictions and stimulus packages are also likely to have an impact on energy consumption levels.

The figures below illustrate the early effects of COVID-19 on energy consumption on our network to date.

The first figure, Figure 1-9, shows that four postcodes within our network experienced an increase of more than 30% in energy consumption between April and September in 2020 compared to the same time period in 2019. At the opposite end of the spectrum, there were three postcodes which experienced a decline in consumption in excess of 30%.

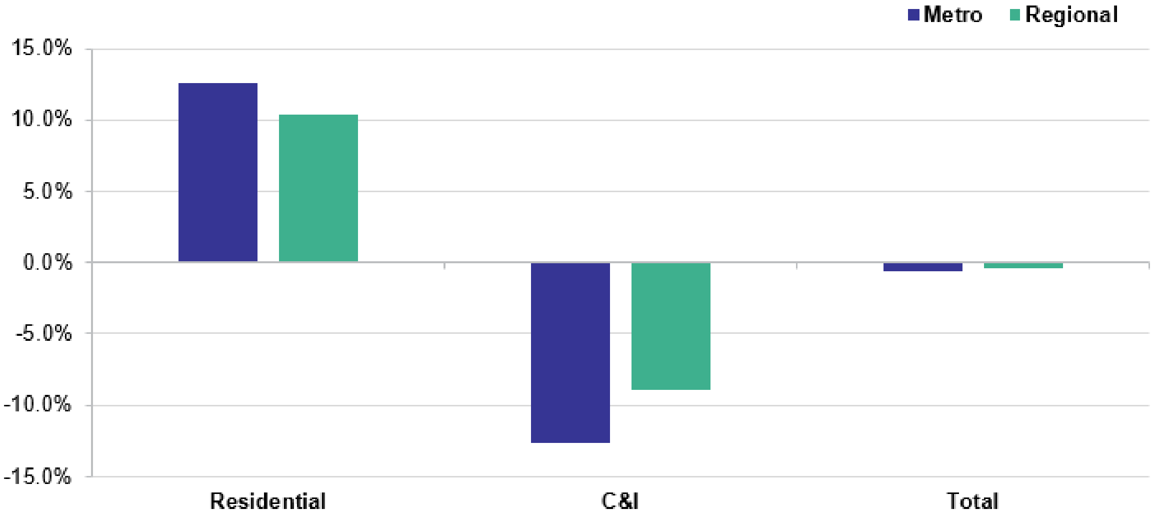
Figure 1-9: Total change in consumption by postcode (1 Apr – 25 Sept 2020 v. 2019)



Source: AusNet Services

Figure 1-10 (below) shows the change in energy consumption by customer group in both metropolitan and regional areas in 2019 and 2020. The impact that COVID-19 has had on consumption is clearly visible.

Figure 1-10: Energy consumption change by metropolitan and regional



Source: AusNet Services

While there have been changes on our network as a result of COVID-19, these changes do not contribute to a material difference from our Initial Proposal. In particular, Figure 1-10 (above), shows that the increases in energy consumption for residential customers in both metropolitan and regional areas has essentially been offset by an equivalent reduction from our commercial and industrial customers. We, therefore, conclude that the movements in energy consumption have not led to an overall shift at the aggregate network level and that this lends weight to accepting the AER's Draft Decision.

1.4.4 Revised Proposal

We have accepted the AER's Draft Decision. Our internal modelling for COVID-19 found that there were no material differences between our own internal updates and the AER's Draft Decision. We, therefore, accept the AER's Draft Decision to use the energy consumption forecast we provided in the Initial Proposal.

The table below contains our energy consumption forecasts for the 2022-26 regulatory period.

Table 1-4: Energy consumption forecasts (GWh, weather corrected)

	2021-22	2022-23	2023-24	2024-25	2025-26	Growth rate p.a.
Residential	2,898	2,848	2,805	2,767	2,733	-1.5%
Commercial	1,320	1,311	1,305	1,299	1,293	-0.5%
Industrial	3,082	3,099	3,119	3,138	3,157	0.6%
Total	**7,300**	**7,259**	**7,229**	**7,204**	**7,183**	**-0.4%**

Source: AusNet Services

1.5 Maximum demand forecasts

1.5.1 Our Initial Proposal

In our Initial Proposal, we anticipated moderate growth in maximum demand over the 2022-26 regulatory period, consistent with the trend in demand growth in the current regulatory period.

Over the 2022-26 regulatory period, we forecast that maximum demand would grow at 1.3% per annum at the network level.

Our maximum demand forecasts from our Initial Proposal are reproduced below.

Table 1-5: Initial maximum demand forecasts

	2021-22	2022-23	2023-24	2024-25	2025-26
Maximum demand (MW)	2,016	2,043	2,071	2,098	2,125

Source: AusNet Services

1.5.2 Draft Decision

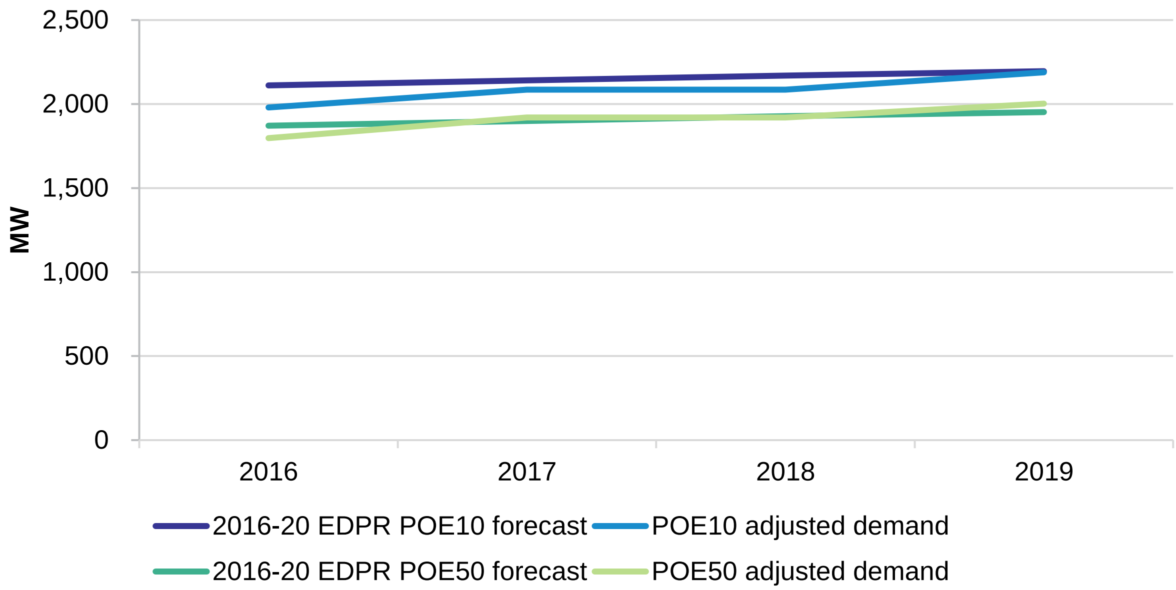
Despite accepting our demand driven augmentation (see Chapter 3), the AER expressed concern with our maximum demand forecast, as it exceeded AEMO's 2019 demand forecasts.[19] It also highlighted it expectation that AEMO's 2020 demand forecasts would be lower than the 2019 forecast, and that the AER will need to assess whether these forecasts warrant further reductions to our already historically low (and Customer Forum agreed) levels of augmentation capex.[20]

The AER also expressed concerns with our forecast of solar photovoltaic (PV) uptake and noted that it may be too low, even when accounting for the adverse economic impacts of COVID-19.

1.5.3 Addressing the AER's Draft Decision

We have a strong track record in forecasting maximum demand. The AER accepted our demand forecasts in the 2016-20 regulatory period and as shown below, the actual (weather corrected) demands have been extremely close to our AER-approved forecasts.

Figure 1-11: 2016-19 forecast v. weather-adjusted actuals (measured at the transmission connection point)



Source: 2016-20 EDPR (forecasts) and economic benchmarking Regulatory Information Notices (weather-adjusted actuals)

19 AER, Attachment 6: Operating expenditure, Draft Decision – AusNet Services 2021-26, September 2020, p. 52.

20 AER, Attachment 5: Capital expenditure, Draft Decision – AusNet Services 2021-26, September 2020, p. 18.

To update our demand forecasts for the latest available information, we applied the same approach we used in the Initial Proposal. This approach combines detailed local knowledge with internal economic analysis. At a high level, our forecast is based on the key premise that higher demand is driven by higher cumulative temperatures.[21] Analysis of historic customer loads and forecast customer growth are also important inputs to our demand forecasts, which are developed at the high voltage feeder, zone substation and terminal station levels.

Since we submitted our proposal, AEMO has released its 2020 forecasts at a terminal station level and these forecasts contain a significant reduction in maximum demand compared to its 2019 forecasts. We would be concerned if the AER looked to apply these forecasts to our proposal as AEMO's 2020 forecasts do not appropriately recognise specific issues and challenges facing our network. In discussions with AEMO, it has confirmed that the large decrease in its 2020 demand forecasts relative to its 2019 forecasts is due to the impact of rooftop PV growth. While supportive of the significant improvements AEMO has made in its forecasting methodology and models, we disagree that rooftop PV will affect maximum demand to the magnitude forecast by AEMO. In particular:

- AEMO's 2020 aggregate forecasts do not align with the trends in actual demand growth seen in our zone-substations in our growth areas;
- Actual data from our network demonstrates that solar has a negligible impact on peak demand and the expected decline in network demand has not occurred;[22] and
- There have been no significant behavioural changes to average demand per customer.

We explore each of these issues in more detail below.

1.5.3.1 Differences in zone substation growth and terminal growth data

As noted, while AEMO's forecasts are credible at the aggregate level for Victoria, using them to inform the AER's assessments of our proposed expenditure at the zone-substation level is not appropriate. For example, the Figure 1-12 and 1-13 below represent AEMO's 2020 forecasts for Cranbourne and South Morang terminal stations, respectively. In both cases, AEMO is expecting that a decade of strong demand growth will be immediately halted and will, in fact, start to decline. However, our more granular smart meter data (at Clyde North and Doreen zone substations which fall within the areas covered by Cranbourne and South Morang terminal stations) show that there is continued strong growth in these areas notwithstanding there is also continued growth of solar (an issue we address in section 1.5.3.2).

AEMO's revised forecast must, therefore, be used appropriately alongside the more granular data we have collected at the zone-substation level.

[21] AusNet Services, Electricity Distribution Price Review 2022-26, Part III, January 2020, pp. 25-27.

[22] CIE, Final Report, Review of AusNet's electricity maximum demand forecasting methodology, November 2019, p. 16.

Figure 1-12: Cranbourne terminal station summer demand

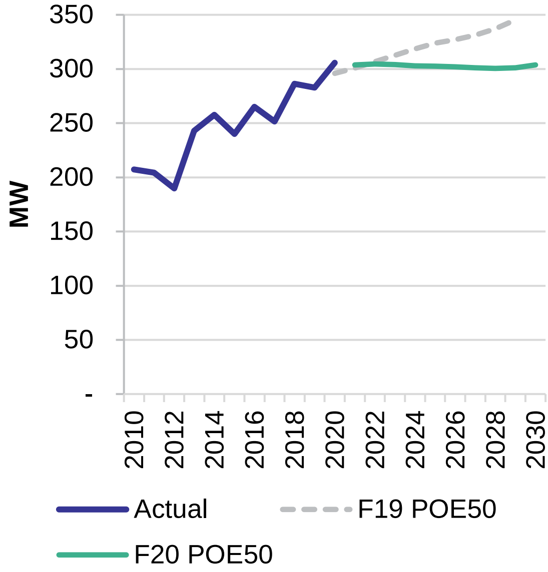
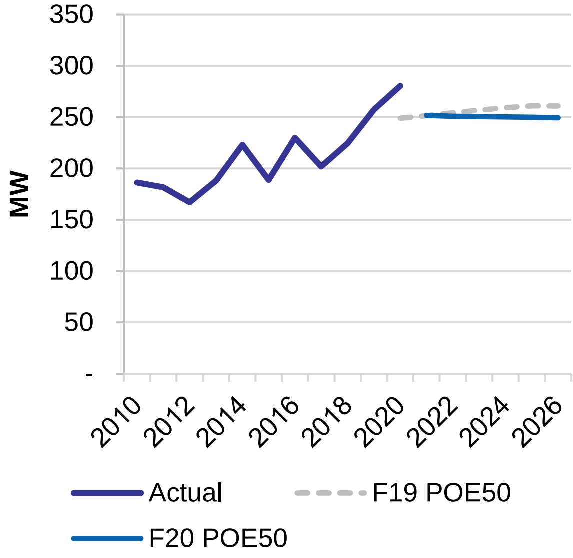


Figure 1-13: South Morang terminal station summer demand



Source: AEMO – F19 POE50 is the 2019 AEMO forecast and F20 POE50 is the 2020 AEMO forecast

1.5.3.2 Increased DER forecasts do not necessarily lead to lower peak demand

As shown in the figures above, AEMO's 2020 forecast suggests a flattening in demand due to continuing DER growth. However, our more granular data suggests that we will see continuing demand growth on our network as well as continuing growth in DER over the forecast period. Therefore, we disagree that higher uptake of DER will reduce our maximum demand forecasts. Rather, we expect to see DER and peak demand both growing over the next regulatory period. Importantly, for our network, peak energy delivered from solar PV in summer does not coincide with peak network demand primarily arising from air conditioning load.

To better understand and address these differing views we have outlined how we developed our forecast and the assumptions that we have used.

Our DER forecasts are based on AEMO's 2019 Electricity Statement of Opportunities[23] Central scenario.[24] Under this scenario:

- The current transition of the energy industry under current policy and technology is expected to continue.
- The transition from fossil fuels to renewables is generally led by market forces and supported by current Commonwealth and State policies.
- No slowdowns or step changes are assumed in the behaviour of market participants under the Central scenario. However, for our residential customers, an alternative scenario was implemented by taking the midpoint of the Central and Step Change scenarios, as this alternative more closely follows the trajectory exhibited by actual residential growth. It is evident that there has been strong growth in solar PV capacity on our network within the last 10 years and that this trend is expected to continue in the forthcoming regulatory period and beyond.

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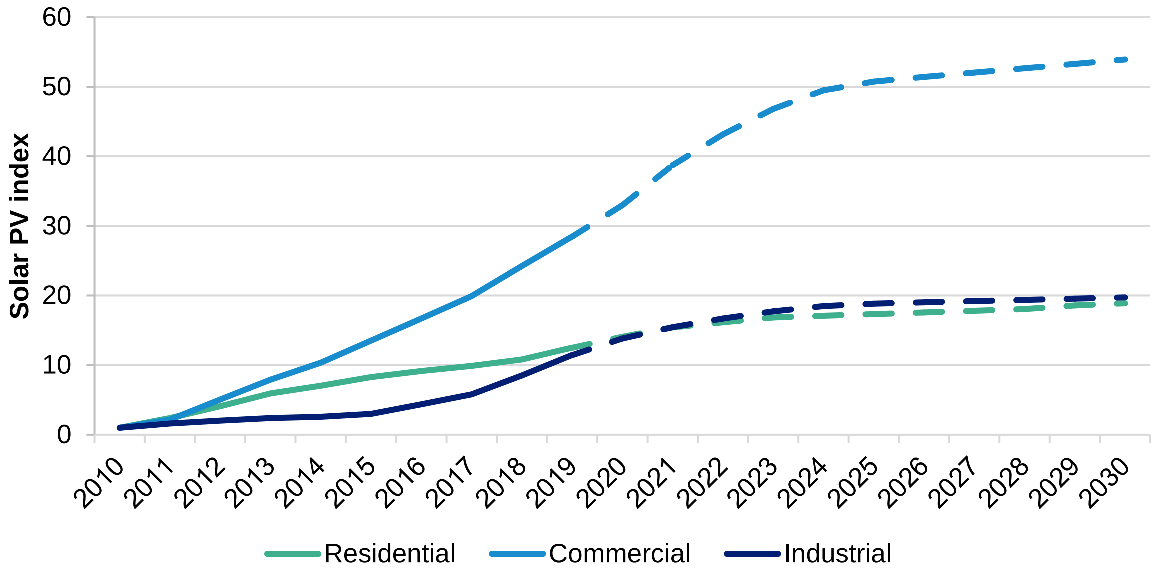
[23] The Electricity Statement of Opportunities provides technical and market data for participants within the National Electricity Market over a 10-year outlook period.

[24] The COVID-19 impacts in the 2020 Electricity Statement of Opportunities are not materially different to our updated forecasts.

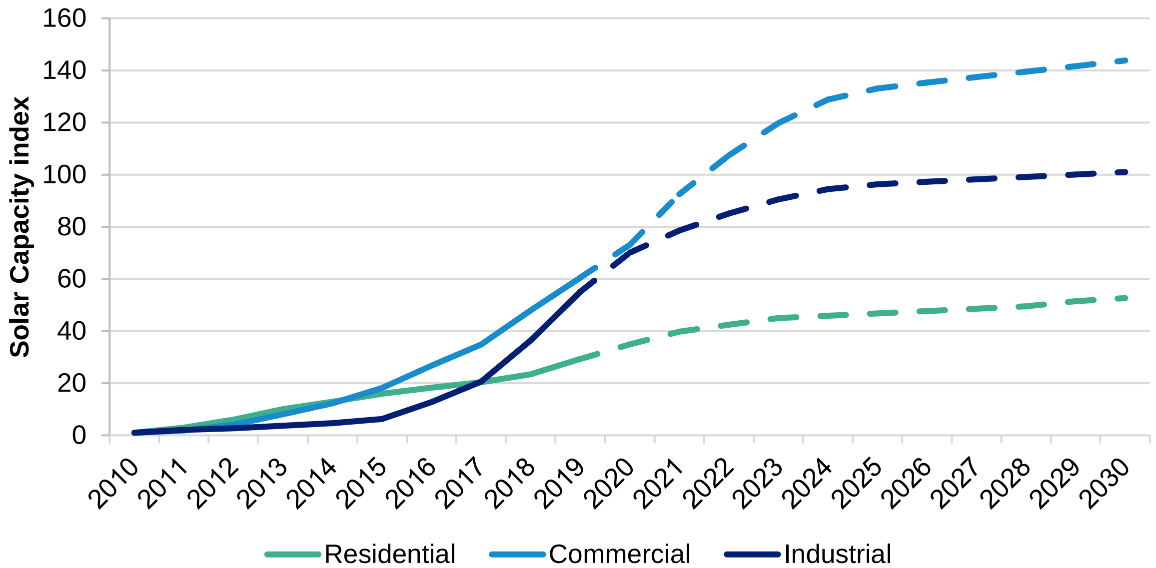
Our analysis, which is outlined below, shows that we expect to see a significant increase in DER going forward, including throughout the next regulatory period.

Figure 1-14: Solar growth 2010-2030, Index = 2010



Source: AusNet Services

Figure 1-15: Solar capacity 2010-2030, Index = 2010



Source: AusNet Services

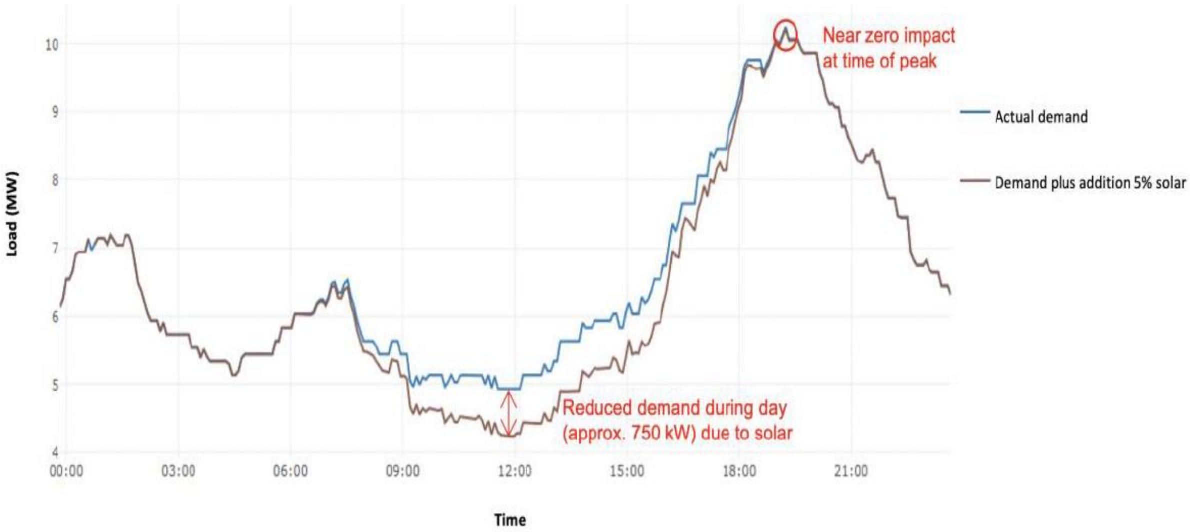
It is evident that there has been strong growth in solar PV capacity within the last 10 years and that this trend is expected to continue in the forthcoming regulatory period and beyond. AEMO's 2020 Electricity Statement of Opportunities has assumed flat demand over the forthcoming regulatory period based on an increased uptake of solar PV and assumed slow growth in both connections and economic improvement within the state. However, AEMO's estimate time of peak demand does not align with the usual time of peak demand in our network, including at our growth corridor zone substations. This is because AEMO produces forecasts at the aggregate state-wide level and is therefore unable to capture the individual nuances of our network. This is a critical distinction, because AEMO assumes the ability of rooftop PV to meaningfully contribute to peak demand reductions. Conversely, our analysis has shown that for our network, which is primarily comprised of residential customers, rooftop PV does not significantly reduce peak demand.

Data submitted in the Category Analysis Regulatory Information Notice (RIN) shows that between 2009-19, the Clyde North zone substation recorded its peak demand at or after 6pm (local time) in nine out of the 11 years. However, in two out of the last three years, peak demand was recorded at 8:30pm. Our other major growth zone substation of Doreen has recorded its peak demand after 6pm in every year since 2009 and in the last two years, after 8pm. At these times, it is impossible for rooftop PV to curtail demand, absent behind the meter batteries (growth of which is not expected to be significant over the next regulatory period). It is, therefore, the difference in the assumptions around the timing of peak demand that is the key factor which differentiates AEMO's forecast and our own, and why we consider there is significantly less ability of rooftop PV to meaningfully contribute to peak demand reductions on our network.

This is not to say that our demand forecasts do not account for the impact of solar. Our existing solar customers on our network are captured in our bottom-up build of maximum demand data, thereby representing an inherent solar penetration rate equivalent to the current level of uptake. Data from our mini grid trials in Yackandandah and Mooroolbark offer valuable insights into the impact of solar on peak demand. Both these projects involved customers of different consumption levels, different demographics, and different roof orientations installing solar PV, thus providing a reasonably representative data set regarding solar production profiles and consumption patterns. Both projects utilised advanced monitoring equipment to achieve a rich data set of granular measurements of both the customer load and the gross solar generation. In Yackandandah, we had the metering technology to understand how much of a customer's demand was being met by rooftop PV over the course of a day.

During the day, a large proportion of actual demand ("demand through the power point") was being met by solar, but at peak times it was negligible. The chart below shows the impact on our Yackandandah feeder of an additional 5% of the customer base connecting to solar. Demand during the day would fall, but at peak times (based on the data collected from Yackandandah customers), the impact would be virtually nil.[25] The impacts of this over 5 years are not material in terms of the maximum demand forecast or network plans that are developed from them. In other words, our trials demonstrate that the impact of solar on peak demand is negligible on our network.

Figure 1-16: Highest feeder demand day across 2018/19 at Yackandandah



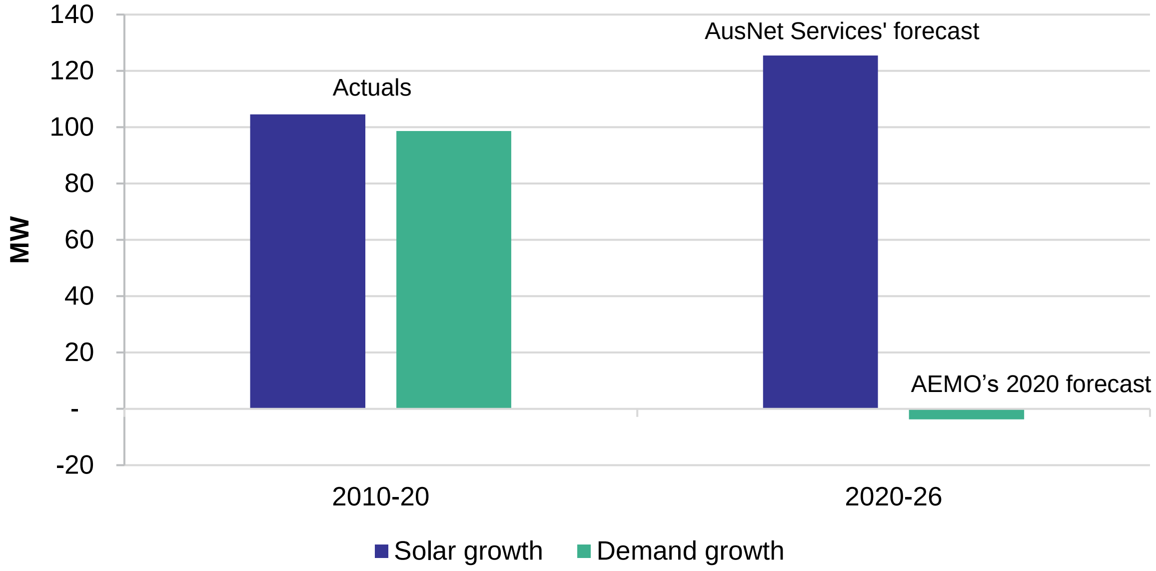
Source: AusNet Services

25 The Mooroolbark trial provided similar findings.

It is relevant to note that our analysis of the collated data does not include the effect of behavioural changes once customers install solar. We know that our solar customers make a higher contribution to peak demand than our non-solar customers.

To further support our view that growth in solar rooftop PV will not necessarily lead to reductions in network demand that AEMO is forecasting, it is instructive to analyse solar growth and maximum demand in one of our major growth corridors, supplied by Cranbourne terminal station (CBTS) as an example. The figure below demonstrates that over 100 MW of solar capacity has been installed in the region serviced by CBTS since 2010. Over the same time period, grid demand has grown by 100 MW. This is a significant subset of data over a 10-year time period that clearly shows that solar growth does not necessarily correlate to reductions in maximum demand. We note this is in stark contrast to AEMO's 2020 forecast, which predicts that CBTS will record reductions in network demand in response to forecasts that solar PV will grow by 126 MW.[26]

Figure 1-17: Cranbourne Terminal Station - solar growth v. demand growth

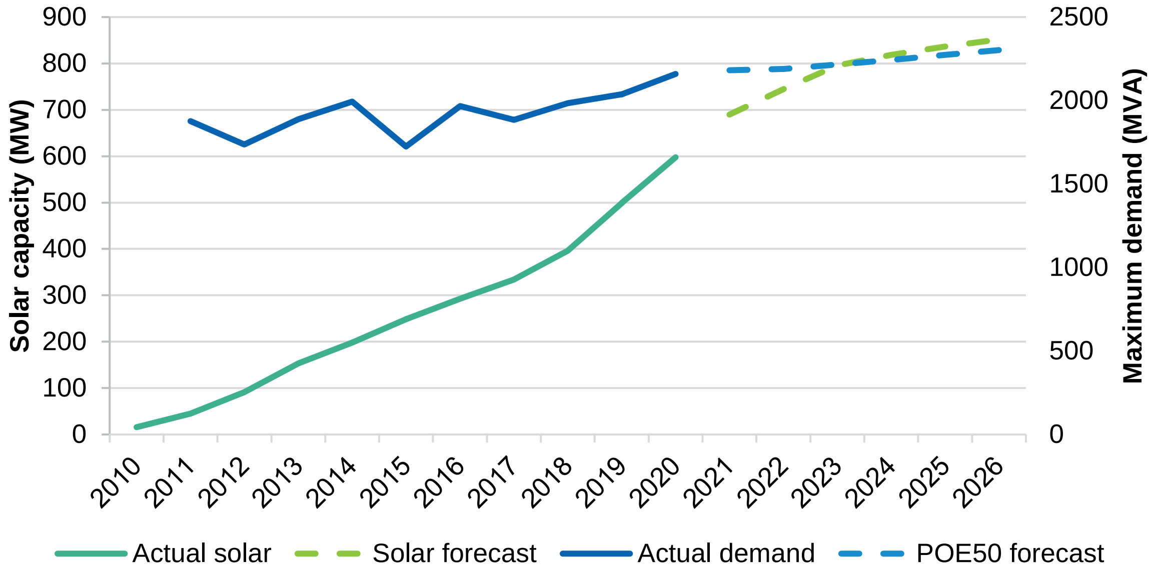


Source: AEMO

Undertaking analysis of this type across our whole network shows a similar trend. The figure below highlights the relationship between the uptake of DER and changes in maximum demand. Over a significant time period, we found that increased DER across our network has not been shown to decrease maximum demand.

[26] Over this time period, AEMO is forecasting total battery storage capacity within Victoria to increase by approximately 200 MW between 2021-26. CBTS currently has 7% of total rooftop PV capacity in Victoria and if this proportion holds for battery capacity, battery storage at both the residential and non-residential segments would increase by approximately 14 MW in CBTS. It is, therefore, unclear how the increase in rooftop PV, coupled with less than 20 MW of battery storage, could result in demand reductions of a similar magnitude which have been modelled by AEMO.

Figure 1-18: Peak demand vs solar capacity



Source: AusNet Services

1.5.3.3 Updated customer number input data

Since the submission of our Initial Proposal we have updated our forecasts to incorporate more up-to-date information and to reflect our expectations of how COVID-19 will impact our maximum demand forecasts.

However, the longer term impacts of COVID-19 on maximum demand will be impacted by the number of new customers connecting to the network and the average demand per customer.

The customer number forecasts are a key input to our maximum demand forecasts. We have accepted the AER's position to apply a downward adjustment to our customer number forecast. For this reason, our maximum demand forecasts need to be adjusted to consider this updated information. This information is available now and will enable the AER's Final Decision to reflect accurate, available data that will better contribute to the attainment of the National Electricity Objective. Adjusting the demand forecasts for the new customer numbers does not materially change the expected growth rate in maximum demand, as it falls slightly from 1.3% per annum to 1.1% per annum. Much of this growth in maximum demand is experienced in our growth corridors serviced by the Clyde North and Doreen zone substations.

While lower customer growth is a negative consequence of COVID-19, it is possible that changing work and travel patterns may, in fact, result in a longer term increase in maximum demand. Interval data collected from our customers has indicated that maximum demand across our network during the period restrictions were in place is marginally higher (approximately 3%) once weather has been accounted for than for the corresponding period in 2019. This increase is driven by higher residential demand and more people being at home and utilising heating/cooling appliances. This increase offsets the reduction in commercial demand by a slight margin.

In addition, a 'COVID-19 summer' has yet to be experienced on our network. Consequently, the residential impacts observed in autumn and winter may increase due to growth in air conditioning demand, noting that the majority of our network is summer peaking. While it is not expected that restrictions will continue until the commencement of the 2022-26 regulatory period, it is possible that COVID-19 could result in a permanent change to working habits. To the extent that this occurs, and more people eventually transition to working from home, this has the potential to increase the maximum demand during the forthcoming regulatory period. We have absorbed this risk by not factoring in an increase to residential demand, which is the primary driver of peak demand on our network.

Our revised demand forecasts have also been updated to factor in data from the 2020 summer, which was not available at the time of submitting our Initial Proposal.

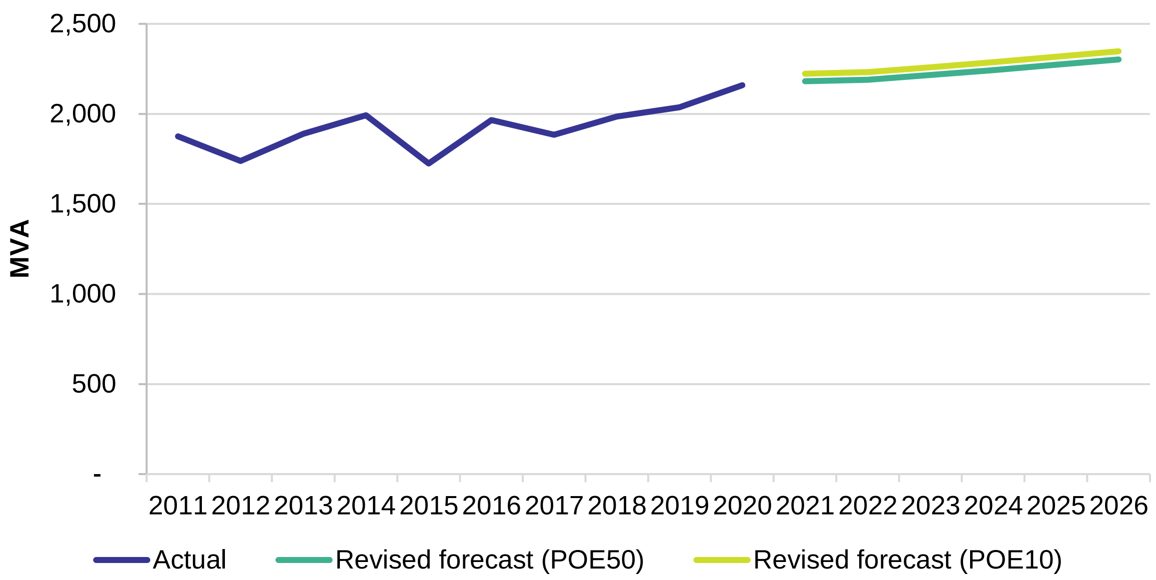
1.5.4 Revised Proposal

Our updated analysis incorporates actual demand (and the associated correlations with temperature) during the 2019-20 summer period and an adjustment for differences in customer numbers and customer behaviour due to COVID-19. This analysis show that our network is expected to experience continued growth in demand and DER notwithstanding the effects of COVID-19 on the Victorian economy.

While we have updated our demand forecasts to reflect COVID-19 we have not factored in a permanent shift in working habits due to COVID-19. This means that our updated demand forecasts are potentially understating future demand, however currently there is not enough evidence to confidently support a higher forecast due to changes in working arrangements.

The chart below depicts our revised demand forecasts. The impact of COVID-19 on connections can be seen in 2021-22, where demand growth is more or less flat in that year.

Figure 1-19: Network peak demand trend



Source: AusNet Services

Further information on our updated augmentation expenditure forecasts are discussed in Chapter 3.

The table below contains our maximum demand forecasts for the 2022-26 regulatory period.

Table 1-6: Maximum demand forecasts (POE50, MW)

	2021-22	2022-23	2023-24	2024-25	2025-26
Maximum demand	2,190	2,215	2,243	2,273	2,302
Growth rate	0.4%	1.1%	1.3%	1.3%	1.3%

Source: AusNet Services

1.6 Supporting models

We have attached the following documents to support the Demand and energy forecasts chapter of the Revised Proposal:

- ASD – EDPR 2022-26 Revised Proposal - Customer Forecast Model – 031220 - PUBLIC
- ASD – EDPR 2022-26 Revised Proposal - Energy Forecast Model – 031220 - PUBLIC
- ASD – EDPR 2022-26 Revised Proposal - Demand Forecast Model – 031220 - PUBLIC

2 Revenue requirement

2.1 Key points

- Our Revised Proposal establishes a total smoothed revenue requirement for SCS of $3,105.4 million ($2021) for the next regulatory period. This is:
    - 2.5% ($80.6 million ($2021)) lower than the revenue we sought in our Initial Proposal; and
    - 2.2% ($66.0 million ($2021)) higher than that proposed by the AER in its Draft Decision.
- This change is driven by:
    - Updating our expected capex for 2020 and the 2021 half year period. This has resulted in:
        - A $32.8 million ($2021) increase in regulatory depreciation compared to the Draft Decision, due to an increased forecast of ICT capex for the 5 minute settlement program (which was not funded through ex ante allowances); and
        - A $16.0 million ($2021) increase in the capital efficiency sharing scheme (CESS) due to the 2020 capex forecast update, partly offset by our proposed REFCL tranche 3 Kalkallo revenue adjustment (-$0.7 million ($2021)).
- Increased forecast opex of $1204.1 million ($2021), which is 1.4% ($16.7 million ($2021)) higher than the Draft Decision. This is primarily due to a new exogenously-driven bushfire liability insurance premium step change ($10 million) and updated labour escalators ($13 million).

2.2 Chapter structure

The remainder of this chapter is structured as follows:

- Section 2.3 provides an overview of our total revenue requirements for the next regulatory period;
- Section 2.4 presents a summary of the building block components of the revised revenue requirement; and
- Section 2.5 provides information on our preferred approach to bill impact analysis.

In the event of any inconsistency between information contained in this chapter and our Initial Proposal, the information contained in this chapter prevails.

2.3 Total revenue

2.3.1 Our Initial Proposal

We proposed a revenue requirement of $3,420.5 million in unsmoothed nominal dollar terms.

In real, smoothed dollar terms, our proposed revenue requirement was $3,186.1 million ($2021), or an average of $637.2 million, which was 2.8% below expected revenue in the 2016-20 regulatory period.

2.3.2 Draft Decision

The AER approved $3252.2 million (nominal) of the $3,420.5 million (nominal) of revenue (unsmoothed) forecast in the Initial Proposal. This was a reduction of $168.2 million or 4.9%. The major cuts to our SCS revenue building blocks proposal included:

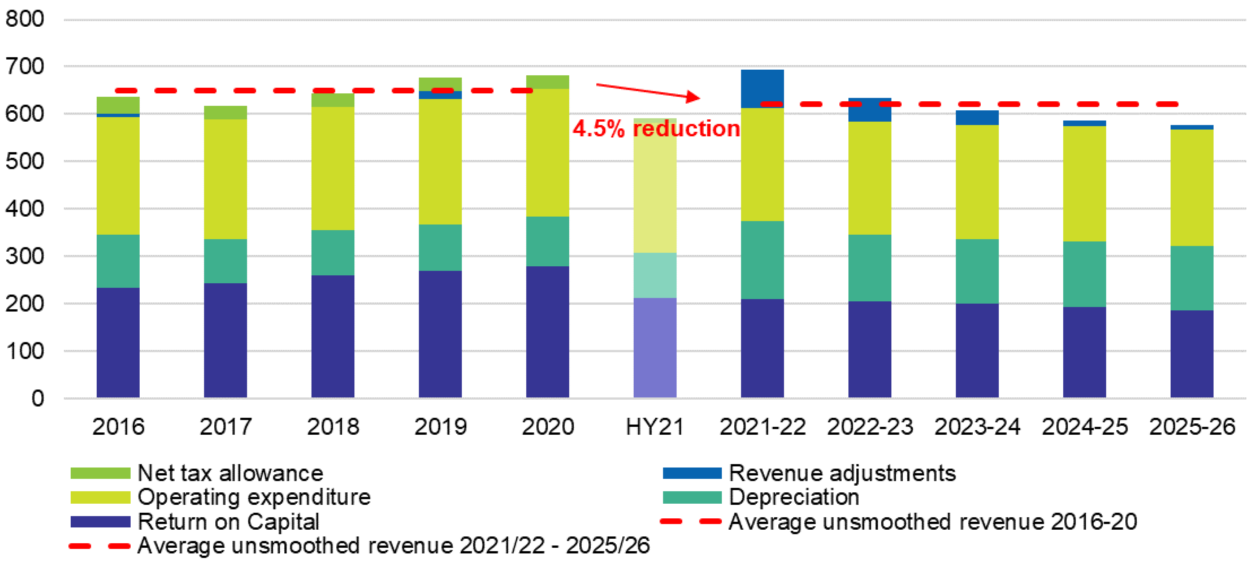
- $93.6 million (nominal) or an 8.1% reduction in the return on capital (capex);
- $50.5 million (nominal) or a 6.4% reduction to our proposed regulatory depreciation allowance; and
- $52.9 million (nominal) or a 4.0% reduction in our proposed opex allowance.

These reductions were partly offset by an increase in revenue adjustments of $28.8 million (nominal), which relate to the operation of the AER's incentive schemes that encourage capital and operating expenditure efficiency improvements.

2.3.3 Revised Proposal

Our smoothed revenue requirements for 2022-26 is $3,105.4 million ($2021) or, on average, $621.1 million per annum ($2021). This is 5.3% below the expected revenue in the 2016-20 regulatory period.

Figure 2-1: Revised revenue requirement CY 2016 to FY 2026 ($m, real 2021)



Source: AusNet Services

Our revised revenue proposal is 2.2% higher than that proposed by the AER in its Draft Decision and 2.5% lower than that proposed in our Initial Proposal.

2.4 Building block components of the revenue requirement

The building block components and our unsmoothed annual revenue requirements for each year of the next regulatory period, under this Revised Proposal, are depicted in the table below.

Table 2-1: Unsmoothed revenue requirement ($m, nominal)

Regulatory year	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Return on capital	215.6	215.1	215.3	212.5	208.1	1,066.6
Depreciation	168.5	146.8	146.4	152.1	155.0	768.7
Operating expenditure	243.0	250.1	257.8	266.3	275.9	1,293.1
Revenue adjustments	84.7	54.1	32.9	12.3	10.2	194.1
Benchmark tax liability	-	-	-	-	-	-
Unsmoothed revenue requirement	**711.7**	**666.1**	**652.3**	**643.2**	**649.2**	**3,322.5**

Source: AusNet Services

The unsmoothed annual revenue requirement is calculated as the sum of the building block components, which are described in the sections below, and detailed in the chapters that follow.

2.4.1 Regulatory Asset Base

Our RAB has been calculated in accordance with the requirements of clause 6.5.1 and Schedule 6.2 of the NER. It reflects the capex forecasts set out in Chapter 5 of this Revised Proposal, the opening RAB based on expenditure in the 2016-2021 regulatory period as detailed in Chapter 5, and depreciation as calculated in Chapter 6. The table below sets out a summary of the derivation of our RAB for the next regulatory period.

Table 2-2: Regulatory Asset Base ($m, nominal)

Regulatory year	2021-22	2022-23	2023-24	2024-25	2025-26
Opening RAB	4,656.5	4,833.1	5,037.0	5,190.1	5,312.8
Net capex	345.1	350.7	299.6	274.8	275.8
Economic depreciation	-168.5	-146.8	-146.4	-152.1	-155.0
Closing RAB	**4,833.1**	**5,037.0**	**5,190.1**	**5,312.8**	**5,433.6**

Source: AusNet Services

2.4.2 Return on capital

Consistent with the requirements of clause 6.4.3(a)(2) of the NER, and in accordance with the AER's Post Tax Revenue Model (PTRM), the return on capital is calculated by applying the post-tax nominal vanilla WACC to the RAB for each year of the regulatory period.

The table below illustrates the calculation of the return on capital building block. The WACC used in this calculation has been determined in accordance with the provisions set out in clause 6.5.2 of the NER. Full details of the WACC calculation are set out in Chapter 7 of this Revised Proposal.

Table 2-3: Return on capital ($m, nominal)

Regulatory year	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Opening RAB	4,656.5	4,833.1	5,037.0	5,190.1	5,312.8	
Return on capital	215.6	215.1	215.3	212.5	208.1	**1,066.6**

Source: AusNet Services

2.4.3 Depreciation

The calculation of regulatory depreciation was carried out in accordance with the AER's PTRM and clause 6.5.5 of the NER, and is detailed in Chapter 6 of this Revised Proposal. Consistent with the requirements of clause 6.4.3(a)(1) and (3) of the NER, we have incorporated an allowance for depreciation in our building block revenue requirement. The table below lists the regulatory depreciation building blocks for each year of the next regulatory period.

Table 2-4: Depreciation ($m, nominal)

Regulatory year	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Nominal depreciation	279.0	261.6	266.0	275.3	281.1	1,363.0
Less indexation	110.6	114.8	119.6	123.2	126.1	594.3
Economic depreciation	**168.5**	**146.8**	**146.4**	**152.1**	**155.0**	**768.7**

Source: AusNet Services

2.4.4 Operating expenditure

Consistent with the requirements of clause 6.4.3(a)(7) of the NER, we have included a forecast of opex in our building block allowance. As explained in Chapter 4 of this Revised Proposal, the opex forecast has been prepared in accordance with all applicable requirements of the NER. The opex forecast is summarised in the table below.

Table 2-5: Operating expenditure ($m, nominal)

Regulatory year	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Operating expenditure	**243.0**	**250.1**	**257.8**	**266.3**	**275.9**	**1,293.1**

Source: AusNet Services

2.4.5 Revenue adjustments

Consistent with the requirements of sub-clauses 6.4.3(a)(5),(6) and (6A), we have incorporated the carryover amounts that have been determined under the Efficiency Benefit Sharing Scheme (EBSS), the CESS and the shared assets guidelines.

The detailed calculation of each of these building blocks was undertaken in accordance with all applicable provisions of the NER, as explained in Chapter 9 – Incentive Schemes. In addition to the incentive schemes, it also includes an amount in relation to DMIA (Chapter 9) and a REFCL tranche 3 Kalkallo adjustment (Chapter 5).

The revenue adjustments under this Revised Proposal are listed in the table below.

Table 2-6: Revenue adjustments ($m, nominal)

Regulatory year	2021-22	2022-23	2023-24	2024-25	2025-26	Total
EBSS carryover	69.8	38.1	16.5	-4.4	-6.9	**113.1**
CESS carryover	14.9	15.2	15.6	15.9	16.3	**77.9**
DMIA	0.8	0.7	0.8	0.8	0.8	**3.8**
REFCL tranche 3 Kalkallo adjustment	-0.7	-	-	-	-	**-0.7**
Total	**84.7**	**54.1**	**32.9**	**12.3**	**10.2**	**194.1**

Source: AusNet Services

2.4.6 Tax liability

Consistent with the requirements of clause 6.4.3(a)(4) of the NER, we have incorporated an allowance for our benchmark tax liability in the building block calculation. The detailed calculation of the cost of tax is presented in Chapter 8 of this Revised Proposal. The cost of tax calculation accords with the requirements of clause 6.5.3 of the NER, and is summarised in the table below.

Table 2-7: Benchmark tax liability ($m, nominal)

Regulatory year	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Tax payable	-	-	-	-	-	-
Less value of imputation credits	-	-	-	-	-	-
Benchmark tax liability	-	-	-	-	-	-

Source: AusNet Services

2.4.7 Smoothed annual revenue requirement

We have calculated a smoothed revenue requirement by applying an X-factor for each year of the next regulatory period as described in the sections below. The proposed smoothing is calculated by adopting the Draft Decision revenue in the first year of the regulatory period and applying a constant X factor thereafter.

X- factor

The proposed X-factors presented in the table below meet the requirements set out in clause 6.5.9 of the NER.

Table 2-8: Proposed X-Factor

Regulatory year	2021-22	2022-23	2023-24	2024-25	2025-26
X-factor	6.04%	1.23%	1.23%	1.23%	1.23%

Source: AusNet Services

Smoothed annual revenue requirement

The application of our X-factors to our 'Unsmoothed revenue requirement' produces the following 'Smoothed revenue requirement'.

Table 2-9: Smoothed revenue requirement ($m, nominal)

Regulatory year	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Unsmoothed revenue requirement	711.7	666.1	652.3	643.2	649.2	**3,322.6**
Smoothed revenue requirement	651.6	658.9	666.3	673.7	681.3	**3,331.8**

Source: AusNet Services

The AER's PTRM attached to this Revised Proposal demonstrates that the smoothed and unsmoothed revenue requirements are equal in net present value terms, in accordance with the requirements of clause 6.5.9(b)(3) of the NER. The smoothed revenue for each year is also net of estimated non-tariff revenue from ACS.

2.4.8 Revenue Requirement adjustment in the current regulatory period

The revenue requirement set out in this chapter will be subject to adjustments in accordance with the AER's control mechanism (as explained in Chapter 12 – Form of Control of the Revised Proposal) to account for:

- The actual CPI, in accordance with the provisions set out in clause 6.2.6(a) of the NER;
- The annual return on debt update;
- Our actual service standard performance, relative to its service standard targets, under the STPIS; and
- Any deemed cost pass though event, as nominated in Chapter 10 of this Revised Proposal along with those pass through events specified in clause 6.6.1 of the NER.

2.5 Bill impacts of Revised Proposal

2.5.1 Bill Impacts

As outlined in the *Executive summary*, the Revised Proposal would reduce revenue per customer (bills) by an average of $138 per customer in real terms in the 2022-26 regulatory period, when compared to 2020 bills.

Bill impacts by tariff type have also been presented in the *Executive summary* and below.

Bill impacts of Revised Proposal (nominal)

Tariff class	Tariff	2020	FY22-26 average	$ change	% change
Residential	Single rate	508	496	-$12	-2.4%
	Two rate	696	580	-$116	-16.6%
	Two rate solar	500	440	-$60	-12.0%
Small Industrial & Commercial (40-160MWh)	Single rate	943	928	-$15	-1.5%
	Two rate	1,470	1,208	-$262	-17.8%
	Two rate plus demand	7,078	6,959	-$119	-1.7%
Industrial & Commercial (>160MWh)	Critical peak demand (160-400 MWh)	23,807	23,518	-$289	-1.2%
	Critical peak demand (750-2,000 MWh)	73,463	72,984	-$480	-0.7%
	Critical peak demand (High voltage)	259,051	255,300	-$3,751	-1.5%

Source: AusNet Services

While customers in all tariff classes are expected to receive a bill reduction, this reduction will vary by tariff class. This is due to differing movements in customer numbers, energy consumption, demand and capacity in particular tariff classes. For example:

- Residential consumption is forecast to decline by 5.2% over the regulatory period, while customer growth is expected to increase by 7.1%; and
- For Industrial and Commercial customers on our critical peak demand tariffs, consumption and customer growth is forecast to increase by 1.6% and 7.4% respectively over the regulatory period. Capacity and Critical peak demand forecasts are forecast to increase by around 7.6%.

The overall impact of these changes is that bills for each residential customer are forecast to decline at a greater rate than Industrial and Commercial customers. However, it is important to note that actual tariff levels, which are set through the annual pricing proposal process, will be set based on annual movements of actual and revised forecast customer numbers, consumption, demand and capacity in each tariff class.

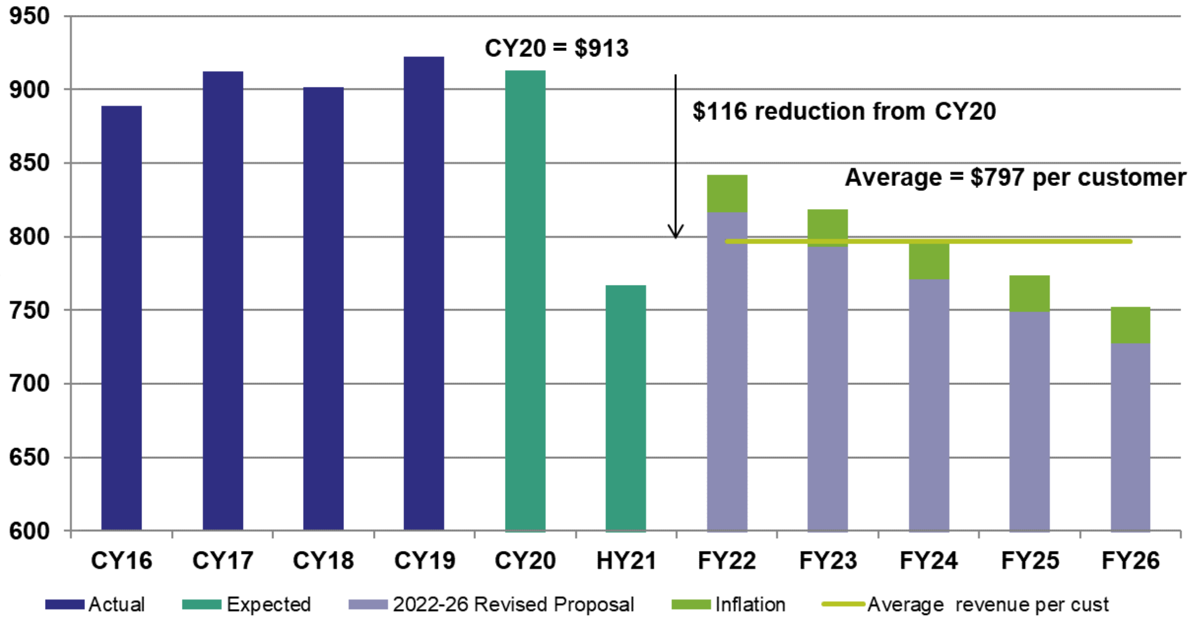
2.5.2 Sensitivity analysis

We have presented analysis of the price impacts of the Revised Proposal in the Executive Summary of this document, expressed in terms of revenue per customer. In addition, we provide a detailed analysis of the price impact by tariff.

The AER has flagged in its Draft Decision that revenues may change by more than would normally be the case between now and its Final Decision as a result of its review of expected inflation and potential updates associated with the economic impacts of COVID-19.

The chart below shows that the immediate application of the AER's Inflation Draft Position to our Revised Proposal would result in an overall annual average revenue reduction of $116 per customer (in real terms). This is a lower price reduction than agreed with the Customer Forum in our Initial Porposal, which was a reduction of $110 per customer. Under the current inflation approach, the overall forecast annual reduction is $138 per customer.

Figure 2-2: Forecast revenue per customer including impacts of the Inflation Draft Decision (real $2021)



Note – smoothing has not been applied to the inflation revenue increment. Does not include bushfire cost pass through, which contributes an additional $4 per annum revenue per customer.

It is important to note that while prices will increase if the inflation review's Draft Position is applied, this change is a move towards an unbiased forecast of inflation and the expected delivery of the efficient nominal rate of return set by the AER. This outcome is in the long-run interests of customers as it will provide incentives for efficient investment to maintain the reliability, safety and security of the network. If this is not expected to be delivered, this distorts investment incentives to the detriment of customers. More information on expected inflation, including the AER's current review, is provided in Chapter 7.

2.5.3 Approach to bill impacts analysis

We have presented analysis of the price impacts of the Revised Proposal in the Executive Summary of this document. This is expressed in terms of revenue per customer and a detailed analysis by tariff is also provided.

We continue to be concerned with the AER's analysis of bill impacts presented in its Draft Decision. The methodology applied was developed when distribution networks were subject to price caps and movements in projected bills are heavily linked to changes in consumption. As we are the only Victorian network to forecast a decline in energy consumption in the next regulatory period, the AER's analysis of the impact of its Draft Decision on customer bills shows a much lower decline for us than for the other distribution networks.

However, under a revenue cap, total revenue to be recovered is fixed over the 5 year period. This means that the more customers that connect to the network, the lower the average bill is for each customer. While an individual customers' consumption will impact the bill they pay, changes in consumption will not impact average bills (that is the average amount paid for network charges by the average customer), because total revenue is fixed.

If bill impacts analysis included in the AER's Draft Decision were accurate, we would significantly breach our revenue cap by over-recovering revenues in the next regulatory period. This is clearly not a feasible outcome. To provide an accurate assessment of customer bill impacts of its Final Decision, we continue to encourage the AER to amend its analysis to be appropriate for revenue capped networks.

3 Capital expenditure forecast

3.1 Key points

- As our Initial Proposal was developed prior to COVID-19 we accept the need for our capex proposal to better reflect current economic conditions.
- We have largely accepted the AER's decisions on our capex proposal. The changes presented in this Revised Proposal are principally limited to updates where the AER has asked for, or invited us to provide, additional information.
- We are proposing net capex of $1,432.9 million excluding disposals for the next regulatory period. This is 4.1% ($63.7 million) higher than that allowed in the Draft Decision.
- The AER accepted our augmentation capex proposal but raised concerns regarding possible changes to network demand that could reduce our future augmentation requirements. We have reviewed our demand forecasts and maximum demand increased in the 2019/20 summer which has consequently increased our internal demand forecasts. Additional augmentation at Doreen zone substation is now economically justified. However, based on stakeholder feedback, we have concluded that our augmentation capex proposal should remain unchanged at $90.7 million, which is 40.3% below the expenditure we expect to incur in the current regulatory period.
- As requested by the AER, we have revised our REFCL driven augmentation proposal. We are now proposing a reduction of $27 million or 25.5% from the Draft Decision, which reflects greater confidence in new approaches to address known challenges at several zone substations. We have also proposed, as invited by the AER, an alternative technically acceptable REFCL solution at Kalkallo zone substation, following agreement with Jemena Electricity Networks (JEN).
- We have accepted the AER's Draft Decision for DER. This is a program that continues to have the support of the Customer Forum and will allow our customers to continue to export energy in a prudent and efficient manner.
- While we have accepted the AER's proposed adjustments to connections volumes (aside for large embedded generators), as flagged in our Initial Proposal we have updated our customer contributions forecast to account for changes in the Weighted Average Cost of Capital (WACC) and have made several other smaller updates. We are now proposing net capex of $242.8 million (including overheads). This increase is largely driven by the significantly lower WACC, which has resulted in a substantial decrease in customer contributions.
- We have accepted the AER's Draft Decision for non-network capex (which includes ICT capex). We are, therefore, forecasting $205 million non-network capex over the next regulatory period.
- As we have not accepted the AER's Draft Decision on the proposed re-allocation of certain type 5 and 6 IT and communications systems expenditures (see Chapter 13), we have revised our repex proposal to capture our preferred re-allocation. Our repex proposal is now 0.6% ($4.2 million) higher than the Draft Decision.
- Our approach to capitalised network and corporate overheads forecasts remain unchanged. However, we have updated our forecast to reflect changes in our overall capex proposal.
- The dollars presented below are stated in real $2021 terms unless noted otherwise.

3.2 Chapter structure

The remainder of this chapter is structured as follows:

- Section 3.3 provides an overview of our total capex proposal;
- Section 3.4 outlines our revised replacement capex proposal;
- Section 3.5 describes our revised connections capex proposal;
- Section 3.6 summarises our revised augmentation capex proposal;
- Section 3.7 outlines our revised approach to metering re-allocation;
- Section 3.8 canvasses our revised non-network capex proposal;
- Section 3.9 sets out our revised forecast for capitalised network overheads;
- Section 3.10 outlines our revised approach for capitalised corporate overheads;
- Section 3.11 describes our revised approach to labour escalation; and
- Section 3.12 identifies our supporting documents for this chapter.

In the event of inconsistency between information contained in this chapter and our Initial Proposal, the information contained in this chapter prevails.

3.3 Total capex

3.3.1 Our Initial Proposal

Following extensive engagement, with key stakeholders and stakeholder groups, including with the Customer Forum, we proposed to invest $1,459.6 million net capex over the next regulatory period.[27] However, following the submission of our Initial Proposal we amended our forecast and proposed $1,432.1 million net capex.[28]

3.3.2 Draft Decision

The AER did not accept our amended capex proposal. It considered that a forecast of $1369.1 million reasonably reflected the capex criteria. While it considered that our forecast was reasonable, it considered that amendments, including ones to reflect changed economic circumstances resulting from COVID-19, were required.

The key changes the AER applied to our forecast were:

- $27.5 million reduction for modelling updates to street lighting replacement expenditure (repex), fleet capex and fleet disposals (reflecting amendments to our proposl that we had proposed);
- $15.4 million reduction to connections capex to reflect the effects of COVID-19;
- $16.0 million reduction for the reallocation of metering costs from SCS to ACS; and
- $31.6 million reduction for updated real cost escalations to internal labour and contract labour and CPI.

27 This included the capex associated with our innovation proposal which is discussed in more detail in our Initial Proposal. This estimate included disposals.

28 Amendments to our Initial Proposal included removing street lighting repex, a reduction in poles repex and amending our fleet forecast.

For the ease of comparison with the Draft Decision, we have used the AER's preferred categories of capex unless otherwise stated.

Table 3-1: Draft Decision annual and total capital expenditure forecast, AER categories ($m, $2021)

	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Replacement expenditure	139.2	140.0	136.6	120.5	111.8	648.2
Connections	60.7	102.6	100.4	101.0	101.6	466.3
Augmentation expenditure	43.1	40.6	38.2	43.5	45.8	211.1
Non-network	53.5	36.8	41.9	37.3	42.3	211.8
Capitalised network overheads	24.3	24.4	24.4	24.4	24.3	121.8
Capitalised corporate overheads	4.6	4.6	4.6	4.6	4.6	23.1
Total gross capex	**325.3**	**349.0**	**346.0**	**331.4**	**330.4**	**1682.2**
Customer contributions	40.6	67.7	65.5	66.0	66.5	306.3
Disposals	1.3	1.3	1.3	1.3	1.3	6.7
Total net capex	**283.4**	**278.6**	**279.2**	**264.0**	**262.6**	**1,369.1**

Source: AER - Draft Decision - AusNet Services distribution determination - 2021–26 - Capex Model - September 2020

While the AER did not make any adjustments to our demand driven augex or REFCL proposals it noted that these two categories of capex were sensitive to updated information. It, therefore, highlighted its expectation that we would, as part of our Revised Proposal provide an update on demand driven augmentation expenditure (augex) and REFCL expenditure. The AER also expected us to reduce our proposed expenditure to take account of the costs we incurred to address the Eastern Victorian bushfires and which were included in our May 2020 Bushfire Pass-through application.[29]

3.3.3 Addressing the AER's Draft Decision

We have carefully considered both the AER's Draft Decision and our stakeholders' views when preparing our Revised Proposal. Despite some concerns with various aspects of the AER's Draft Decision we have largely accepted it and have only updated our proposal where the AER

[29] AusNet Services, 2020 Bushfires Event Pass Through Application, May 2020. Available at: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/cost-pass-throughs/ausnet-services-cost-pass-through-2019-20-bushfire-natural-disaster/initiation (accessed 16 November 2020).

has asked for, or invited us to provide, additional information (including with respect to COVID-19). The key exception to this is that we have updated our capex proposal to reflect our preferred allocation of some metering costs (see Chapter 13), which has resulted in a slight increase in replacement capex (with a matching fall in metering capex).

3.3.4 Revised Proposal

Our Revised Proposal forecast of total required capex for the next regulatory period is below. It is provided in a manner consistent with the AER's preferred categories of cost.

Table 3-2: Revised Proposal annual and total capital expenditure forecast ($m, $2021) – AER categories

	2021-22	2022-23	2023-24	2024-25	2025-26	Total	Change from Draft Decision (%)
Replacement expenditure	139.5	141.1	137.5	121.4	112.8	652.3	0.6%
Connections	73.3	113.7	113.7	114.4	115.0	530.2	13.7%
Augmentation expenditure	82.7	78.3	24.7	17.5	16.5	219.7	4.1%
Non-network	56.3	37.2	41.5	36.6	41.6	205.0	-3.2%
Capitalised network overheads	25.3	25.4	24.3	24.0	23.9	122.8	0.9%
Capitalised corporate overheads	4.8	4.8	4.6	4.5	4.5	23.3	0.9%
Total gross capex	**382.1**	**400.5**	**346.3**	**318.4**	**314.3**	**1761.6**	**4.7%**
Customer contributions	47.3	67.8	68.3	69.0	69.5	321.9	5.1%
Disposals	1.3	1.3	1.3	1.3	1.3	6.7	0.0%
Total net capex	**333.4**	**331.3**	**276.6**	**248.1**	**243.5**	**1,432.9**	**4.1%**

Source: AusNet Services

3.4 Replacement capital expenditure

3.4.1 Our Initial Proposal

We initially proposed expenditure of $702.8 million for replacement expenditure (repex) for the next regulatory period. However, following the submission of our Initial Proposal we amended our forecast to remove expenditure associated with steel poles that were to be used only for public lighting and corrected for an error that resulted in an over-estimation of our poles forecast.

3.4.2 Draft Decision

The AER accepted our repex proposal as several top-down repex metrics demonstrated that our proposed expenditure was reasonable. It proposed a repex allowance of $648.2 million.

3.4.3 Revised Proposal

We have accepted the AER's Draft Decision on repex but have updated for:

- Changes in labour escalators (see section 4.10);
- Changes in overheads to reflect changes to our overall capex proposal (see sections 4.8 and 4.9);
- The removal of future costs savings resulting from work completed to address the Eastern Victorian bushfires which were approved in our May 2020 Bushfire Pass-through application;[30] and
- Additional repex costs associated with our preferred approach to re-allocating some specific metering costs (see Chapter 13) and our alternative REFCL solution at Kalkallo (see section 4.6.4).

Our proposed repex for the Revised Proposal is therefore $652.3 million for the next regulatory period. This is 0.6% ($4.2 million) higher than the Draft Decision and is shown in the table below.

Table 3-3: Revised replacement capex ($m, $2021)

	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Replacement expenditure	139.5	141.1	137.5	121.4	112.8	652.3

Source: AusNet Services

3.5 Connections

3.5.1 Our Initial Proposal

Gross customer connections capex is customer requested expenditure to establish new connections to the shared network. The net customer connections capex removes the part of the cost recovered through upfront customer contributions towards the connection/augmentation work.[31]

We proposed gross new connections expenditure and net connections capex of $562.4 million and $210.2 million respectively (inclusive of capitalised overheads) over the next regulatory period. Excluding overheads, our Initial Proposal was $529.6 million gross and $177.3 million net capex over the 2022-26 regulatory period.

3.5.2 Draft Decision

The AER highlighted that had it not been for COVID-19 our connections forecast would have been considered reasonable. Consequently, it did not accept our connections forecast and adjusted our 2021–22 forecast for the effects of COVID-19. This adjustment was based on the HIA's construction forecasts and resulted in an 8% reduction ($14.6 million) to net connections

30 We removed $0.4 million ($2020) from our repex costs plus an additional $52,000 ($2020) from non-network costs.

31 Our customer connections capex program is required to facilitate network growth and to meet its obligations to connect customers in its distribution area, consistent with the requirements of NER 6.5.7(a)(1) and (2).

compared to our proposed $177.3 million (excluding overheads). For the remaining years of the regulatory period the AER accepted our forecasts.

The AER noted it would incorporate any new information that could materially affect our connections forecasts, including updated construction forecasts for Victoria, any actual 2020 capex data provided by us and any updated information about the likely length of the pandemic.

3.5.3 Response to the AER's Draft Decision

We have accepted the AER's Draft Decision regarding connections volumes (other than for large embedded generators), as it represents a reasonable, albeit conservative, expectation of the impact of COVID-19 on customer numbers (connections).

As discussed in Chapter 1, we have reached this view following consideration of a range of customer growth scenarios which were tested (and amended) following stakeholder (27 October 2020) and Customer Forum (30 October 2020) engagement.

We consider the AER's Draft Decision on connections is conservative as our analysis suggests that:

- Growth in customers in 2020 remains broadly in line with the growth seen in 2019;
- The number of requests for new connections we receive from developers for new estates – a leading indicator of future connections – remains strong and since April 2020, there have been no indications that suggest that interest in new estates has been disrupted;
- Data from the Victorian Building Authority suggests that COVID-19 is yet to have an impact on the number of residential building permits being issued in Victoria;
- The Victorian Government's recently announced 'Big Housing Build' program which funds more than 12,000 new homes across Victoria;[32] and
- Residential vacancy rates in our network have fallen and remain low in outer suburbs/regional areas of Victoria (where most of our customers are).

We also note that after the last recession, economic recovery was strong and surpassed the level of growth prior to the downturn.[33]

While we have accepted the AER's Draft Decision on our connections forecast, we have made several updates as flagged in our Initial Proposal including:

- Updating our 2022-26 customer contributions forecast based on the prevailing real rate of return;
- Updating our forecast unit rates for the various connection types with our 2019 actual unit rate information; and
- An updated forecast of large embedded generation connections (>5MW).[34]

The last item does not impact on forecast 2022-26 net connections capex, since its expenditure forecast is matched with equal and offsetting capital contributions.

One aspect of the Draft Decision on connections volumes that we have not accepted is the application of the COVID-19 adjustment to embedded generation connections.

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32 https://www.vic.gov.au/sites/default/files/2020-11/hv_more_homes_for_more_Victorians_0.pdf

33 Further information on these issues is contained in Chapter 1.

34 We have also updated our forecast of new commercial and industrial connections for the 2022-26 regulatory period by disaggregating our unit rates and volumes into gifted and non-gifted construction forecasts. This as an improvement in our forecasting approach compared with our Initial Proposal. In addition, we have updated our connection policy, which we explore in more detail in Chapter 11.

We discuss each of these issues below.

3.5.3.1 Updated customer contributions forecast

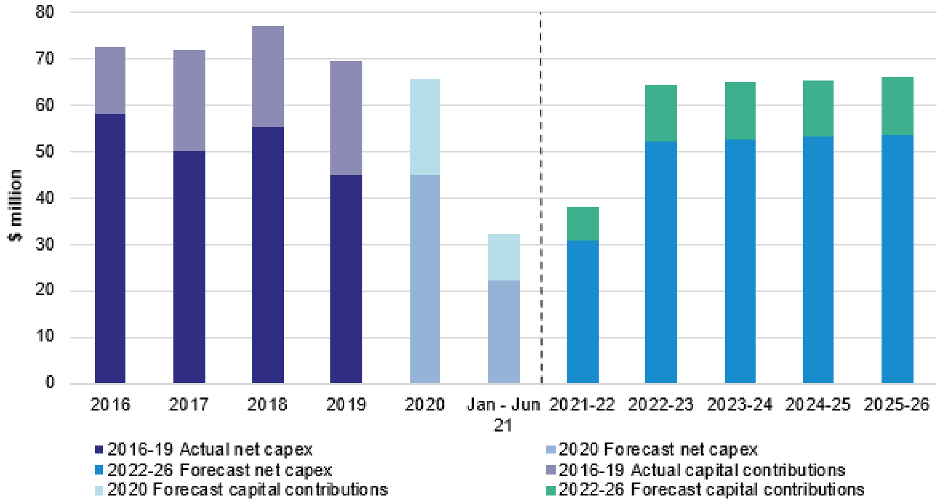
The lower rate of return in the 2022-26 regulatory period reduces the expected amount of capital contributions that new connecting customers will pay towards their connection costs. Our Initial Proposal adopted the same rate of return applied in the 2016-20 regulatory determination and this Revised Proposal incorporates the latest rate of return based on the 2018 Rate of Return Instrument and prevailing market conditions.

We modelled the impact of the lower rate of return across both residential and business connections and found that:

- Business contributions are materially reduced, with a 60% reduction expected compared to contributions received from these customers (on average) in the current regulatory period; and
- For residential connections, we expect much more moderate reductions in customer contributions over the 2022-26 regulatory period.

Excluding gifted assets and large embedded generators (which are fully funded by the customer), the overall impact of this update, before COVID-19 adjustments, is that we expect customer contributions to fall by 46% on average compared to current regulatory period or around $10 million per annum over the 2022-26 regulatory period.

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



Source: AusNet Services

^ Excluding gifted assets and large embedded generation.

Figure 3-1 above compares our updated 2022-26 forecast of capital contributions with current period actual/forecast contributions received from customers. Consequently, our net connections capex forecast has increased by $51.8 million or 27% relative to the Draft Decision.

Our residential connections forecasts reflect amendments to our pole-to-pit standard connection services Model Standing Offer. Overall, we are forecasting lower contributions for these underground services over the 2022-26 regulatory period compared to the current period. Before COVID-19 adjustments, we expect contributions for these services to fall by 38% compared to the current regulatory period actual/forecast. For more information on this and other changes to our connections policy, please refer to Chapter 11.

3.5.3.2 Connection unit rate updates

We have updated our forecast unit rates which increases our gross connections capex for the 2022-26 regulatory period by $14.7 million compared to the AER's Draft Decision.

The main driver of this relates to the increasing cost of High Voltage (HV) network augmentation associated with new residential developments constructed under turnkey arrangements with land developers.

Our Initial Proposal did not factor in the current market construction rates for HV turnkey developments, where we are required to contribute more to the cost of competitively tendered works than in the past. The rising cost of providing these services will be captured in the form of higher average HV rebate payment (per lot) that we will be making to land developers. These changes account for $8.8 million of the total increase in gross expenditures (excluding gifted assets and large embedded generation).

The remainder of the changes relate to updating our historical average unit rates by connection type to reflect our 2019 actual unit rates.

3.5.3.3 Large embedded generation connections

We do not accept the AER application of the COVID-19 adjustment to embedded generation connections in 2021-22 (year 1 of the next regulatory period). The COVID-19 adjustment is based on HIA construction forecast data and should not affect the feasibility or frequency of large-scale embedded generation connections, such as windfarms and solar battery farms proceeding in our Distribution network.

The volume and quantum of large embedded generators are driven by other matters, particularly Government policy. Our revised forecast assumes that the Victorian Renewable Energy Target (VRET) of 40% by 2025 continues including the Victorian Government's Renewable Energy Auction Scheme (VREAS), which has recently been extended[35], to support the achievement of its VRET targets. We, therefore, anticipate significant investment in these renewable energy projects over the 2022-26 regulatory period.

We stated at the time of our Initial Proposal submission that we would review and update these connections based on the latest available information.[36] As shown in the table below, due to ongoing policy support for the connection of large scale renewables, we are no longer forecasting declining expenditure for these type of connections over the regulatory period. We have increased our forecast of these connections compared with our original proposal by $27.5 million or by 40.0%. We note that the trend in our updated forecast aligns with Powercor's which was approved by the AER in the Draft Decision (aside for the first year adjustment to reflect the impacts of COVID-19).

Table 3-4: Revised embedded generation gross capex forecast ($m, $2021)

	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Initial Proposal	$17.0	$14.6	$12.3	$12.4	$12.4	$68.7
Revised Proposal	$19.0	$19.0	$19.2	$19.4	$19.5	$96.2

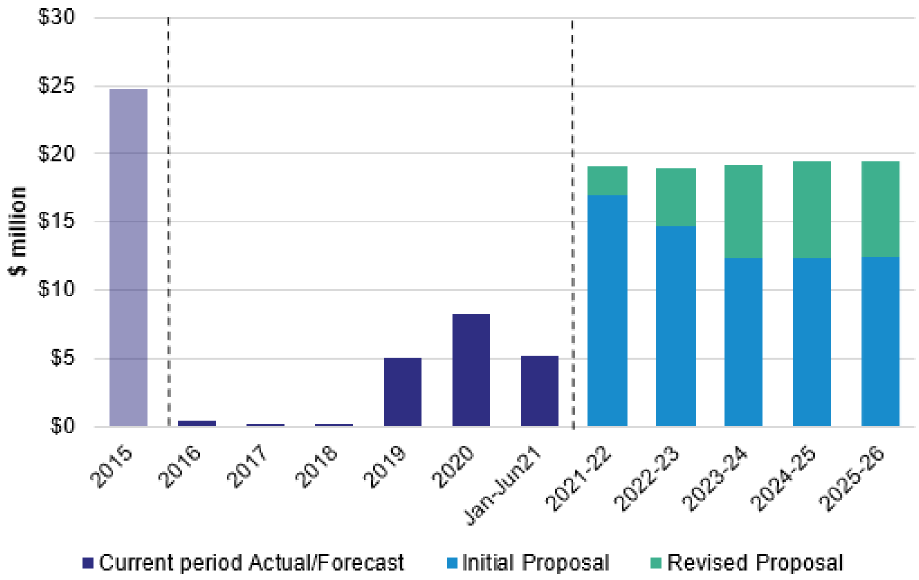
Source: AusNet Services

Figure 3-2 below shows our revised gross capex forecast for the 2022-26 regulatory period together with current regulatory period actual/forecast gross capex.

35 https://www.premier.vic.gov.au/more-renewables-help-drive-victorias-economic-recovery (accessed 2 December 2020).

36 ASD - Connections Capex Forecast model - 2021-26 - 310120 – CONFIDENTIAL.xlsx, January 31, 2020.

Figure 3-2: Large embedded generation connections gross capex ($m, 2021)



Source: AusNet Services

We have also proposed to charge these connections for the net tax cost to AusNet Services associated with these connections. This is currently borne by our wider customer base. Further information on this proposal is provided in Chapter 11.

3.5.4 Revised Proposal

Our revised gross and net connections capex forecast (excluding overheads) is $530.2 million and $208.2 million respectively for the next regulatory period, as shown in the table below. Compared with our Initial Proposal this represents a 0.1% change in gross connections capex (before overheads) and a $30.9 million or 17.4% increase in net connections capex.

Table 3-5: Revised connections forecast (Standard Control Services), excluding overheads ($m, $2021)

	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Gross capital connections	73.3	113.7	113.7	114.4	115.0	530.2
Net capital connections	26.0	45.9	45.4	45.4	45.5	208.2

Source: AusNet Services

3.6 Augmentation capex

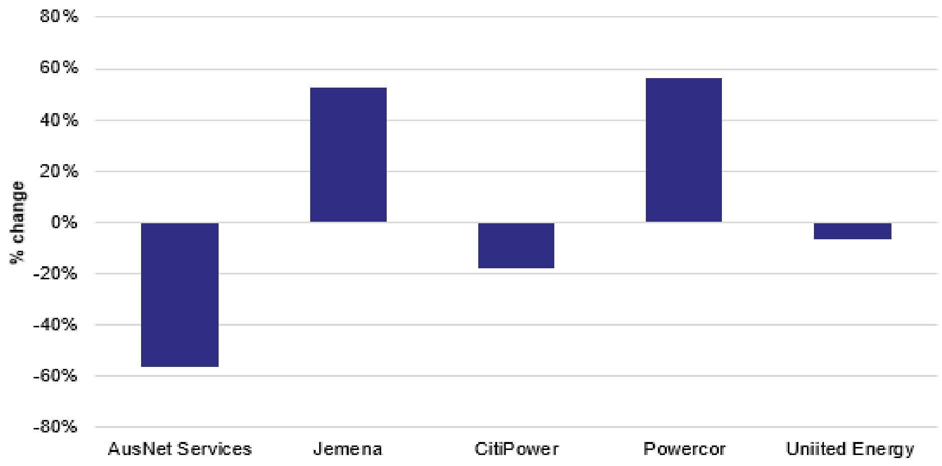
3.6.1 Summary of position

We proposed a significantly lower level of augmentation capex for the next regulatory period compared to the current period. We welcome the AER's Draft Decision to accept our historically low level of augmentation without amendment.

As we have accepted the Draft Decision for augmentation, we have limited our updates to those matters the AER has asked for, or invited us to provide, additional information. As explained below, the AER raised concerns regarding our demand forecast and the prudency of our proposed DER expenditure.

To the extent that the AER's concerns continue, we would welcome the opportunity to engage further with the AER at its earliest convenience in order that they can be resolved as soon as possible. We also note that compared to our Victorian peers, we proposed, and the AER accepted in its Draft Decision, a far more significant reduction in our overall level of augmentation (as shown in the figure below).

Figure 3-4: Vic DNSPs' augmentation (AER classification) – % change between 2016-20 and 2022-26 (Draft Decisions)



Sources: Vic DNSP EDPR 2022-26 Draft Decisions and RINs

3.6.2 Our Initial Proposal

We proposed expenditure of $216.0 million for augmentation capex (augex) for the next regulatory period. This included expenditure for demand driven augmentation and REFCLs, which we captured within our 'Safety' capex category.

We explore each of these issues in more detail below. Importantly, the discussions in these sections use our preferred capex classification categories consistent with the approach the AER used in its discussion of these issues in the Draft Decision.

3.6.3 Demand driven augmentation

3.6.3.1 Draft Decision

The AER accepted our (AusNet Services' classification) augex proposal. It considered that our $92.2 million forecast, which was 39% below the augex we expect to spend in the current regulatory period, did not exceed a prudent and efficient level.[37]

However, in accepting our proposal the AER noted that:

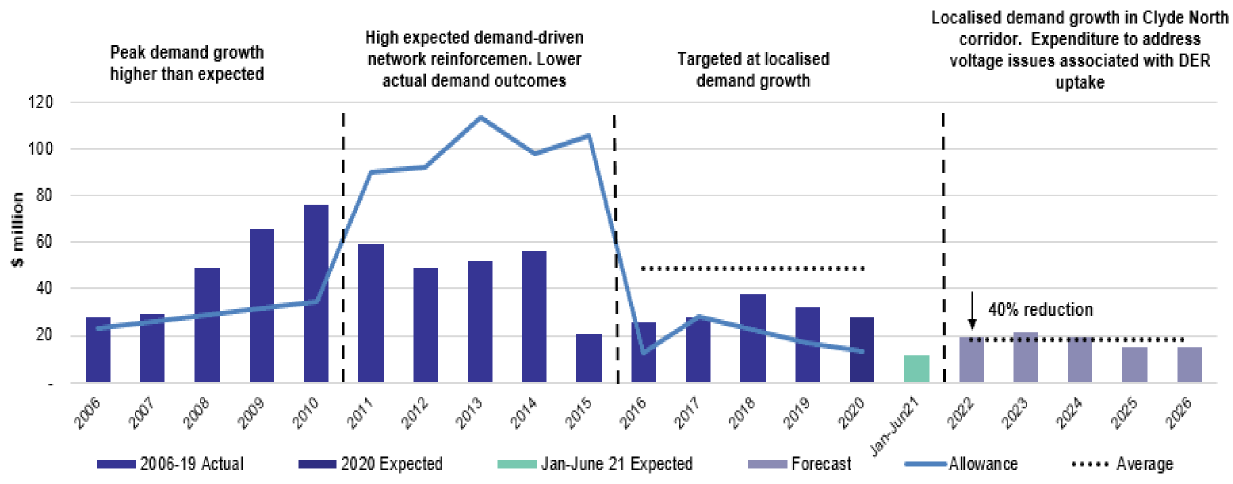
- Our demand forecasts exceeded AEMO's 2019 forecast and AEMO's 2020 terminal station demand forecasts were likely to be lower again (due to COVID-19); and
- It would assess whether AEMO's new forecasts would lead to further reductions to our already (much reduced) augex forecast.

[37] This is the capex we classified as augmentation under our preferred classification and should not be confused with the boarder AER preferred classification for augmentation which captures demand driven augex as well as augex that we would classify as 'Safety' capex.

3.6.3.2 Response to the AER's Draft Decision

We accept the AER's Draft Decision and note that our Revised Proposal forecast remains significantly below the level of augmentation (AusNet Services' classification) we expect to incur in the current regulatory period (see Figure 3-5 below).[38]

Figure 3-5: Revised Proposal augmentation (AusNet Services' classification) 2006 to 2026, incl. overheads ($m, $2021)



Source: AusNet Services

To update our demand forecasts for the latest available information we have applied the same approach we used in the Initial Proposal. This approach combines detailed local knowledge with internal economic analysis. At a high level, our forecast is based on the key premise that higher demand is driven by higher cumulative temperatures. Analysis of historic customer loads and forecast customer growth are also important inputs to our demand forecasts, which are developed at the HV feeder, zone substation and terminal station levels.[39]

Our updated analysis incorporates actual demand during the 2019-20 summer period and includes an adjustment for COVID-19. It shows that:

- We are expected to experience continued growth in demand and DER across our network;
- The impact of DER on peak demand will be negligible over the next regulatory period; and
- Additional augmentation at Doreen zone substation will be economically justified within the next regulatory period.

The Doreen zone substation project was a major network growth project that was outlined in our Draft EDPR Proposal (published in February 2019) and was one of the issues considered by the Customer Forum early in the engagement process. Following extensive review by the Customer Forum (see Box 3.1 below), this project was ultimately removed from consideration due to changes in expected demand.

38 The augmentation presented here is the augmentation under AusNet Services' preferred capex category classification.

39 Further information on our maximum demand forecasts and our forecasting methodology is available in Chapter 1.

Box 3.1: Customer Forum consideration of augmentation at Doreen zone substation

The Customer Forum was actively involved in considering two major augmentation projects at Doreen and Clyde North and provided invaluable assistance to us that ensured a comprehensive analysis of non-network that could resolve or defer the need to augment our network.

Augex deferral review for Clyde North and Doreen zone substations

We engaged WSP to undertake an independent review of the augmentation deferral options for projects at the Clyde North and Doreen Zone Substations.[40] WSP's review assessed the reasonableness of the method, data sources and assumptions used to determine the costs and benefits of the deferral options in the context of our proposed network solution.

As part of the review process the Customer Forum and the AER requested further information in order that they could each satisfy themselves that a robust assessment process had been undertaken and that non-network solutions had been fully considered. The Customer Forum's findings are set out in more detail in its Final Engagement Report.[41]

Customer research

The Customer Forum also commissioned a customer research project into service reliability perceptions and expectations at Doreen and Clyde North.[42] This telephone interview survey of 300 customers assessed (1): the extent customers in those locations were experiencing outages; (2) the impact of those outages on customers; and (3) customers' attitudes to our proposed augmentation options.

This analysis found that (at Doreen):

- 81% of customers had experienced an outage in the last two years (35% within a month of being surveyed), most customers believed an outage frequency of no more than once every two or three months is acceptable, and most customers (59%) consider an outage of at least an hour has a significant impact on them
- Most customers (93%) believe it is very important that current reliability is maintained
- 80% would be willing to pay an additional 3 cents each year on their electricity bill from 2021-2025 to pay for the cost of upgrading the network in their area to avoid the risk of one outage of around 54 minutes occurring over that period and most (71%) believe it is fair that all customers should pay to maintain the reliability in their area
- Awareness of incentive programs was moderate (55%), but following the explanation to all customers they were generally supported in the short to medium term (by ~70% of all Doreen customers) and most customers are willing to participate in a scheme simply to reduce the risk of blackouts in their area (73%) with no other incentive
- Most customers are interested in receiving information when a blackout occurs.

In our view, based on updated demand forecasts, this major network growth project is now warranted to address growing customer needs (including reliability) from the expected growth in large residential developments in Melbourne's urban growth corridors. Our 'in service' target date for this augmentation is by November 2025, which is towards the end of the next regulatory period. Outlined below is information on the expected timing and cost of this major growth project.

40 This report is available at: https://www.ausnetservices.com.au/-/media/Files/AusNet/About-Us/Determining-Revenues/Distribution-Network/Customer-Forum/Week-14/Week-14--WSP-Report-PS113155ADVREP001-RevCPDF.ashx?la=en (accessed 3 November 2020).

41 The Customer Forum's Final Engagement Report is available at: https://www.ausnetservices.com.au/-/media/Files/AusNet/About-Us/Electricity-distribution-network/2020/AusNet-Services-Customer-Forum-Final-Engagement-Report-FINAL.ashx?la=en (accessed 3 November 2020).

42 This survey is available at https://www.ausnetservices.com.au/-/media/Files/AusNet/About-Us/charges-and-revenue/Clyde-North-and-Doreen-Customer-Survey.ashx?la=en (accessed 3 November 2020).

Table 3-6: Augmentation at Doreen zone substation ($m, $2020, direct)

	2021-22	2022-23	2023-24	2024-25	2025-26	Total
3rd transformer and switchboard	0.0	0.4	3.0	3.5	0.5	7.4
New 22 kV feeder	0.0	0.1	1.0	1.2	0.2	2.5
Total	**0.0**	**0.5**	**4.0**	**4.6**	**0.7**	**9.9**

Source: AusNet Services

However, after careful consideration, and following advice from the Customer Forum that we should not look to re-introduce this project, we have excluded it from our proposed augmentation capex. This should provide the AER with confidence that our proposal for (historically low) augmentation capex can be accepted again without modification.

Our revised demand forecasts have also impacted the expected timing of our major augmentation project at Clyde North. While remaining in the next regulatory period, continued strong demand suggests that this project should commence slightly earlier. While we have not updated the planning documents associated with project, we will apply the appropriate degree of flexibility to ensure we can address growing customer needs, including with respect to reliability, in a prudent, efficient and timely manner. The timing of our other augmentation projects, including but not limited to, our Summer Network Readiness Program and Central Region Feeder projects remain largely unchanged as a result of our updated demand forecasts.

3.6.3.3 Revised Proposal

Our revised demand driven augex for the next regulatory period is $90.7 million and is illustrated in the table below. Our forecast augex is 40.3% below the level that we expect to incur in the current regulatory period.

Table 3-7: Revised demand driven augmentation capex ($m, $2021)

	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Augmentation expenditure	19.3	21.5	19.1	15.5	15.2	90.7

Source: AusNet Services

3.6.4 REFCL

3.6.4.1 Draft Decision

The AER did not assess the capex for the $48.6 million REFCL installation program and deferred its decision on the $94.3 million for ongoing compliance at eight zone substations until its Final Decision.

The AER's deferral until the Final Decision was based on its expectations that we would:

- Implement an alternative solution at the Bairnsdale, Eltham and Wodonga zone substations to materially reduce our proposed capex; and
- Pursue exemptions under the *Electricity Safety Act* to enable us to implement our preferred solution at Kalkallo and, to the extent necessary, update our regulatory proposal accordingly.

3.6.4.2 Response to the AER's Draft Decision

As requested by the AER we have provided updates for our REFCL proposal. Our Revised Proposal for ongoing REFCL compliance delivers a reduction of approximately $27 million or 25.5%.

Similarly, having accepted the AER's invitation to continue developing our preferred solution for Kalkallo with JEN, we have proposed a new, cost effective solution. We have also amended the timing of our Kalkallo proposal. We discuss both these issues further below.

Overall (putting aside changes in the timing of Kalkallo), these two partially offsetting adjustments mean that we have reduced our REFCL augmentation forecast by around $17 million.

Ongoing REFCL driven augex: Implementing alternative solutions

One issue of concern to the AER was our decision to limit the number of Ground Fault Neutralisers (GFNs) we install to two per zone substation. A consequence of this decision was that we would be required to build a new zone substation in those locations where we forecast the need for a third GFN.

The AER noted that Powercor has installed three GFNs at one of its zone substations and that it was proposing to install three GFNs at another two zone substations. The AER queried why we could not adopt a similar approach at three of our substations.

In response to the AER's questions, we advised it that we did not consider a three GFN solution was appropriate as this approach had yet been proven to work in Victoria. However, we indicated that we would continue to review the feasibility of our proposed solutions and if a three GFN system was proven to work, we would review our approach.

While uncertainty remains around the use of a three GFN solution, recent testing of this solution undertaken by Powercor has allowed us to be increasingly confident that a third GFN solution is feasible at two of the three sites identified by the AER. Therefore, our proposed REFCL solution for Bairnsdale and Eltham zone substations now incorporates three GFNs.

At the third zone substation identified by the AER as potentially suitable for a third GFN solution (Wodonga Terminal Station (WOTS)), our technical analysis indicates that this solution is not appropriate. Specifically, our analysis shows that installing three GFNs would not address all capacitance issues at that location. Indeed, our capacitance forecast for WOTS indicates that WOTS25 will exceed the maximum feeder capacitance of 80 amperes (A) in 2025. As an additional GFN will not address this issue, it is not a technically appropriate solution and is not a solution that we are looking to implement.

However, we have identified an alternative technically feasible solution at WOTS. Rather than constructing a new REFCL-protected zone substation (and feeders), we have identified a more cost-effective solution involving a remote REFCL and pole mounted isolation substations. Further information on the REFCL projects at these three zone substations is contained in the supporting documents that form part of this Revised Proposal.

In addition, since we submitted our Initial Proposal, we have continued to review our demand forecasts and proposed engineering solutions at other REFCL sites. Consequently, we have identified alternative, innovative solutions at several other REFCL sites, involving the use of:

- Remote REFCLs on feeders greater than 80 amperes capacitance; and
- Pole mounted isolation transformers to isolate sections of underground cable from REFCL operations.

We now consider that a REFCL augmentation program costing $79.0 million is required for the next regulatory period. This is significantly (-25.5%) more cost effective than the expenditure included in the Draft Decision.

This reduced level of REFCL capex does not reflect a lessening of our commitment to safety. Rather, it reflects our commitment to innovate and find the most prudent and efficient way we can:

- Ensure the safety of our customers;
- Meet our regulatory requirements; and
- Meet our customers' ongoing concerns regarding affordability.

Preferred solution at Kalkallo zone substation

The proposed solution for complying with our bushfire mitigation obligations at Kalkallo was considered by the AER as part of our Tranche 3 contingent project application.[43] The solution proposed in that application was to build a new zone substation at Kalkallo (KLO2).[44]

Subsequent to submitting our application, we revised our preferred solution to achieve compliance with our bushfire mitigation obligations and proposed constructing a new zone substation (KLN) to address the technical issues caused by the use of REFCLs at Kalkallo.[45] However, at the time we submitted our updated preferred solution we were unable to present sufficiently detailed costing proposals for the KLN solution, and we were still in negotiations with JEN about how the costs of the project would be shared.

The AER's decision on Tranche 3 did not approve our solution for Kalkallo or our preferred KLN proposal. An important element of the AER's decision to reject our preferred solution was that we had not received the necessary legislative exemptions to be able to implement it. We noted that we were currently pursuing these exemptions with the ESV and, if approved, we would change our proposal to reflect our preferred solution.[46] The AER therefore identified its own least cost technically acceptable option for Kalkallo and approved $24 million ($2019) capex to implement it.

Importantly, the AER did invite us and JEN to continue developing our preferred solution for Kalkallo and to "make a joint application in their regulatory proposals for the forthcoming EDPR."[47] To that end, we have been working closely with JEN to identify an alternative, technically acceptable solution at Kalkallo and we have now completed this work. Our preferred, innovative solution at Kalkallo requires the installation of two remote REFCLs and four 5 MVA isolation substations. Details about our Kalkallo proposal are contained in the supporting documents that form part of this Revised Proposal.

In preparing our revised REFCL augex forecast and developing our Kalkallo solution we have been mindful of the limits of the technical solutions available to us and the need for our proposal to enable us to comply with our bushfire mitigation obligations, including by relying on exemptions from the requirement to comply with these obligations.

Having regard to these matters, our proposal for Kalkallo is based on a key assumption that the ESV will grant us a technical exemption that will enable us to install covered conductor on certain sections of two Kalkallo feeders where geological features prevent undergrounding lines at a reasonable cost. We expect to submit our exemption application to the ESV in December 2020 and we will assist the ESV with any queries it has in relation to our application in order that the application can be determined in advance of the AER's Final Decision.

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43 AER, Final Decision - AusNet Services Contingent Project - Installation of Rapid Earth Fault Current Limiters (REFCLs) – tranche three, 3 October 2019, p. 32.

44 Ibid.

45 Ibid.

46 AusNet Services, Electricity Distribution Price Review 2022-26, Part III, p. 90.

47 AER, Final Decision, AusNet Services Contingent Project, Installation of Rapid Earth Fault Current Limiters (REFCLs) – tranche 3, 3 October 2019, p. 32.

Through a new application of REFCL technology in the distribution feeder (Remote REFCL) we can target developed overhead supply areas of the Kalkallo network. This targeting reduces the need for expenditure to manage the capacitance growth from supplying the flourishing estates in the surrounding areas. Our updated preferred Kalkallo solution is more cost effective than the KLN option we proposed during the contingent project process but does require more capex than the AER allowed. We consider any comparison of the cost of our new Kalkallo solution with the AER's proposed solution is unhelpful as the AER's proposed solution would not address the ongoing challenges associated with this site (capacitance management and network operability). That is why we have been working closely with JEN to find a new, better targeted solution that can better target areas of bushfire risk and can be delivered at a lower cost than the KLN option. In our view, the AER must consider the preferred Kalkallo solution on its own merits in light of the capital expenditure objectives, the Revenue and Pricing Principles and the National Electricity Objective.

As it has taken some time for us to identify an alternative, technically acceptable solution at Kalkallo, expected expenditure has been much more limited to that forecast in the contingent project application tranche 3 Decision. We have, therefore, reduced our revenue forecast to hand back to customers the revenue received for the approved capex in the current regulatory period (totalling $0.70 million) but not spent. We have also reduced the CESS benefit we would have received (see Chapter 5). In addition, we have re-proposed Kalkallo for inclusion in the 2026-26 regulatory period, reflecting the updated solution recently agreed with JEN.

Importantly, our approach to updating Kalkallo ensures that our customers are not paying twice for this project. As the regulatory framework provides some flexibility as to how we can eliminate any potential double-counting, should the AER identify an alternative approach, we would be more than happy to discuss this issue with it.

While we acknowledge the impact that the additional REFCL augex for the new Kalkallo proposal will have on our customers, we have sought to limit the cost impact to the greatest extent possible without jeopardising our ability to comply with current legal requirements. We also note that we have reduced our REFCL proposal by $27 million by adopting innovation solutions to address the challenges we face.

3.6.4.3 Revised Proposal

Our revised REFCL proposal is seeking $79.0 million. This is 25.5% less capex for the next regulatory period compared to the Draft Decision. This outcome reflects the application of innovative solutions at several sites and is outlined below.

Table 3-8: Revised REFCL capex ($m, $2021, excluding IT)

	2021-22	2022-23	2023-24	2024-25	2025-26	Total
REFCL augmentation	30.3	35.4	7.5	3.3	2.5	79.0

Source: AusNet Services

We have also re-proposed a new, technically feasible least cost solution at Kalkallo, which has been agreed with JEN. This means that the proposed REFCL tranches expenditure we expect to incur in the 2022-26 regulatory period is that outlined in the table below. Importantly, as we have made an adjustment to our proposed opening RAB, we are only looking to capture the costs associated with Kalkallo once (see Chapter 5).

Table 3-9: Revised Kalkallo costs (2022-26, $m, $2021, direct)

	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Revised Kalkallo costs	18.5	20.1	-	-	-	38.6

Source: AusNet Services

Note: The incremental costs we are proposing for Kalkallo are $10.0 million ($2018) direct.

3.6.5 Distributed Energy Resources

3.6.5.1 Draft Decision

The AER accepted our DER augex proposal.[48] It found that, in the context of our historical augex levels, our DER proposal formed part of a capex forecast that reasonably met the capex criteria. It also acknowledged stakeholder support for our DER integration capex.

The AER made several comments in the Draft Decision which we address later in this section:

- Our use of the 2019–20 Feed-in Tariff (FiT) is problematic and is likely to overstate the economic benefits of pursuing network augmentation.
- Our forecast of solar PV installations is lower than the forecast provided by the Victorian Department of Environment, Land, Water and Planning (DELWP) and the AER's expectation is that this forecast will remain so, even accounting for an adverse economic scenario due to COVID-19.
- The CSIRO and Cutler-Merz were engaged by the AER to conduct a study into potential methodologies for valuing DER (VaDER) and had extensively engaged with stakeholders, including us, as part of the study.
- The final report on VaDER is due with the AER in early October 2020 and that *"[g]iven the extensive stakeholder engagement in forming the VaDER study's recommendations, we anticipate that consumers will expect Victorian distributors to prepare their revised proposals in the spirit of these recommendations*."[49]
- We have the scope to reduce set voltage and adjusting rather than disabling line drop compensation (LDC) to improve voltage outcomes and increase DER hosting capacity.

3.6.5.2 Response to the AER's Draft Decision

We accept the AER's Draft Decision, accepting $58.9 million on DER. We note that in coming to this decision the AER recognised our DER proposal forms part of a capex forecast that reasonably meets the capex criteria and there is stakeholder support for our proposal.

Our modest DER proposal will allow us to meet most of our customers' expectations that they be able to maximise the value of their DER investment during the 2022-26 regulatory period. Specifically, our DER program will only allow network upgrades to facilitate DER exports where it is economically justified. This means an estimated 7,000 DER customers will remain without any voltage improvement (as it is not economic to upgrade the network to address the constraints they face). We consider, and it has been agreed by our Customer Forum, that such an approach appropriately balances the costs and service outcomes for our customers.

[48] This $58.9 million comprised (1) $20.6 million in Voltage Compliance (augex) – augmentation to address areas currently non-compliant with the Victorian Electricity Code, which requires it to limit customers' DER export capability (2) $20.9 million in Hosting Capacity for DER (augex) – augmentation to address new DER export constraints as they emerge (3) $6.0 million for Customer Supply Compliance (augex) – business-as-usual augex required to maintain power quality, which is mainly voltage compliance. The AER classified this as DER capex although we had not; and (4) $11.4 million in DER ICT capex, to allow more accurate monitoring and understanding of the constraints arising from network and DER operations.

[49] AER, Attachment 5: Capital expenditure, Draft Decision – AusNet Services 2021-26, p. 5-25.

Importantly, our proposal will also allow us to continue to support the Victorian Government's expanded Solar Homes policy (see below) The Victorian Government has expressed its strong support for our DER proposal. We are currently in discussions with the Victorian Government regarding reporting on our efforts to facilitate solar exports. We have also committed to the Customer Forum to report on how this funding has been spent and the customer benefit it has delivered over the 2022-26 regulatory period. These mechanisms will keep us accountable and ensure the funding is spent to maximise customer benefit.

Solar Homes

Solar Homes is a $1.2 billion program to encourage 650,000 Victorian home owners to install solar panels by providing a rebate on installation costs (per household) and low cost finance for the remaining costs. This is a policy that represents a mechanism to build on the 350,000 rooftop solar installations currently in Victoria and to keep pace with the roll out of these new technologies in Queensland and New South Wales.

This program was expanded recently (November 2020), with an additional $191 million provided by the Victorian Government. This expansion will result in 42,000 additional solar rebates being available to customers, which allow these additional customers to install solar panels on their roof at no upfront cost. In addition, and for the very first time, small businesses will be able to apply for these rebates – with 15,000 solar rebates being made available.[50] This expanded Solar Homes program has not been captured in our DER forecasts for the 2022-26 regulatory period, demonstrating the moderate and conservative nature of our DER proposal.

Addressing the AER's comments

While the AER approved our DER proposal it made several comments in the Draft Decision on some of the assumptions we have applied in reaching our forecast. We explore each of these issues below.

The use of the Feed in Tariff (FiT) to value DER

The AER suggested that our use of the 2019–20 FiT was problematic and likely overstates the economic benefits of pursuing network augmentation.[51] The AER also noted that:

- A VaDER report from the CSIRO and Cutler-Mertz was expected in early October 2020; and
- The AER would consider that report's recommendations and formally implement the recommendations it considered appropriate as part of its DER integration expenditure guideline, which is due for completion sometime in 2021.

While we support the potential benefit that may result from DER expenditure guidance, there is currently no 'gold standard' or widely accepted value of DER. We remain of the view that there is a sound rationale for applying the FiT to value DER and this is an issue that was considered and supported by Frontier Economics.[52] The FiT is an independently-derived metric of value, to use for solar exports from small-scale generators that is re-assessed regularly.[53]

We also recognise that there is a difference between the FiT and the (lower) value used by SAPN to assess the benefit of relieving constraints on solar exports in South Australia. However, it does not follow that the SAPN value is appropriate for us. For example, we identified several concerns

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50 Victorian Government media release, 'Helping Victorian pay their power bills', 17 November 2020. Available at: https://www.premier.vic.gov.au/sites/default/files/2020-11/201117%20-%20Helping%20Victorians%20Pay%20Their%20Power%20Bills.pdf (accessed 23 November 2020).

51 We estimate the expected net benefit of our proposed investments by estimating the value of solar generation that is constrained due to voltage non-compliance issues and compare this to the cost of augmentation options.

52 AusNet Services, Expenditure Forecasting Methodology 2021-25, 21 December 2018.pdf.

53 For example, it was reviewed in 2017, when the ESC concluded its detailed inquiry into the true value of distributed generation and it is reviewed in the ESC's yearly FiT setting process, which includes consultation with the industry.

with the HoustonKemp analysis that SAPN relied on to support its proposal, not least that it estimates the average avoided dispatch cost for solar exports in 2018 in South Australia as $50.15/MWh. Frontier Economics on the other hand calculates the actual average solar weighted wholesale price in 2018 in South Australia as $96.70/MWh, which is almost double the estimate provided by HoustonKemp.[54]

Similarly, we identified several concerns with the methodology that underpins the *VaDER Draft Report*.[55] While we have not re-iterated those concerns within this document, it is essential that appropriate stakeholder consultation is undertaken on both the value and the outcomes for customers prior to implementation. This will ensure that any guidance that is ultimately put forward can help deliver outcomes that align with stakeholders' expectations. We look forward to working with the AER on these issues prior to it publishing its guidance on DER.

Forecast of solar PV installations

As discussed in Chapter 1, since the Initial Proposal we have considered the latest available information when developing our forecasts for DER. Our analysis suggests that we will continue to see strong growth of DER on our network. It also shows a higher uptake of DER does not automatically result in lower maximum demand forecasts or lower augmentation. Rather, as we have experienced on our network, solar PV has had a negligible impact on peak demand.

Stakeholder engagement in developing our DER integration capex program

Our DER proposal was developed over a two year process through an extensive technical development process and customer consultation, including reaching agreement on our proposal through negotiations with the Customer Forum. We do not consider that a late change to our proposal is warranted or supported by customers. This could materially impact the experience of all our customers (both DER and non-DER) over the next five years. We also discussed the AER's Draft Decision and our DER proposal with our stakeholders, including during a stakeholder session on 27 October 2020.

On 30 October 2020, we met with the Customer Forum to discuss the 27 October 2020 stakeholder event and how it considered we should reflect customers' preferences in our Revised Proposal. The Customer Forum was clear that it continued to support our proposal.[56] It also noted that if anything, the level of customer support for DER is likely to have increased, given that more people are now working from home and, for those could renovate during the COVID-19 lock-down, more solar panel installation was a possibility.

With respect to a specific concern raised in our 27 October 2020 stakeholder sessions on the period over which a project is considered, our DER proposal is composed of several elements and each element must be justified. For example, our DER ICT (non-network capex) proposal is supported by its own analysis notwithstanding it being closely linked to other parts of our DER proposal involving (network) assets which have significantly longer lives. For network capex, we have adopted a 45 year Net Present Value (NPV) period that matches the life of the asset we are investing in. This is standard practice and its continued use is warranted as (among other issues):

- Customer research has revealed high levels of interest in installing DER and we have no reason to consider that this interest will decrease over time;
- Two way energy flows are likely to become more, not less, common over the next 45 years, particularly if we see the introduction and development of a two sided market; and

54 Frontier Economics, Value of Relieving Constraints on Solar Exports, 16 October 2019, p. 3.

55 Our concerns to this CSIRO and Cutler-Mertz study were outlined in our response to it 'AusNet Services, Value of DER methodology Study Consultation Draft Report, 28 September 2020'. We also note that the final VaDER report was released on 11 November 2020. However, the concerns we identified in our response to the Draft VaDER report still hold.

56 See Appendix 3A.

- Shortening the NPV period would result in a lower level of DER and would undermine the balance we have carefully reached with our stakeholders, including the Customer Forum.

More broadly, our DER proposal represents an important step towards delivering a network with greater control capabilities that will makes it more likely for greater benefits to be delivered over the long term.

Sensitivity analysis

We also undertook some sensitivity analysis (see below) to better understand the potential impact of changes to the value of DER on our customers.

Table 3-10: DER sensitivity analysis

Solar forecast	Moderate DER uptake	High DER uptake with a high DER value	High DER uptake with a low DER value
Value of DER (cents/kWh)	12	12	5
Cost ($M)	38.1	55.6	21.9
Number of customers voltage performance improved by 2025	228,000	154,000	141,000
Number of customers without voltage improvements by 2025	7,000	7,000	20,000
% Export enabled of previously unserved generation over 2022-26	70%	62%	54%
Total export enabled of previously unserved generation over 2022-26 (GWh)	969	663	583
Total unserved generation prior to the program over 2022-26 (GWh)	1380	1075	1075

Source: AusNet Services

This sensitivity analysis shows, among other things, that the assumptions used when estimating a project will have an impact, including with respect to customer outcomes. For example, while reducing the value of the DER will result in a lower level of DER expenditure it will also result in more DER customers experiencing worse outcomes. If we compare the customer outcomes from using a relatively high value, moderate DER uptake with a relatively low value, high volume DER uptake we see:

- 87,000 fewer customers experiencing improved performance;
- A 285% increase in the number of customers without any voltage improvements (from 7,000 to 20,000 customers); and

- An increase in the number of customers unable to export their solar energy. That is, nearly half of all customers' generation will not be able to export.

These are outcomes we know from our customer engagement that our customers do not want. For example, through our additional engagement with the Customer Forum following the release of the Draft Decision, we note that it has expressed continued support for our DER proposal.[57]

Adjusting rather than disabling line drop compensation (LDC) to improve voltage outcomes and increase DER hosting capacity

The Draft Decision indicates we could explore whether reducing set voltage and adjusting, rather than disabling, LDC would improve voltage outcomes and increase DER hosting capacity.

Since 2014 we have lowered float voltages which has resulted in a 15% improvement in voltage compliance. However, in many places on our network, adjusting LDC has run its course and we are now seeing an increase in nonconformance with the lower end of the EDC during peak demands (for heating hot water and summer peaks) as the voltage bandwidth increases.

To lower float voltage further we must address some design issues with our existing Voltage Regulating Relays (VRRs) employed in our network. Without this investment we cannot perform LDC if reverse flow occurs. Today's VRRs perform compensation for forward power flows or are set flat (uncompensated) and hold the bus voltage steady regardless of power flow direction and magnitudes. However, with increasing distributed and passive solar PV being connected, and with more minimum or reverse power flows occurring, this type of control is limiting the hosting capacity of our network (see Box 3.2 below).

Box 3.2: Issues limiting the hosting capacity of our network

With increasing distributed and passive solar PV being connected, and with more minimum or reverse power flows occurring, our existing Voltage Regulating Relays are limiting the hosting capacity of our network in two ways:

Compensated settings limit the hosting capacity for export.

LDCs require existing relays to measure the magnitude of the current and increase the voltage in proportion, overcoming the voltage drop and ensuring a satisfactory voltage is achieved at the end of line.

As existing voltage regulating relays cannot identify the direction of current flow, where reverse flows are present, they can boost voltage levels, adding to the voltage rise and exacerbating non-compliance and limiting hosting capacity. By 2026 we expect that >89% of our zone substations will experience reverse power flow and this type of control will not be suitable for a high solar PV export.

Flat or uncompensated settings limit the hosting capacity for load.

This occurs when voltage levels are optimised lower or mid-range of the allowable steady state range. This lower voltage increases headroom for voltage rise but decreases the amount of load that can be carried and results in an increase in low voltage non-compliance during peak demand days.

Using flat settings, we have already been able to achieve a 15% improvement in compliance with the upper limit of the Victorian EDC. However, we are now observing an increase in low voltage non-compliance which we need to address.

We, therefore, need to increase the functionality of our VRR (by upgrading our equipment) to enable bi-directional voltage control and maintain capacity for demand and increase capacity for

57 See Appendix 3A.

generation exports which we know from our customer engagement is an outcome that our customers want.

We are not proposing additional augmentation without having carefully considered alternatives. We have already adjusted our LDC (as suggested by the AER) and we now need to invest further if we are to continue to deliver outcomes consistent with the known and evolving needs of our customers. This investment will also help us ensure compliance with the Victorian EDC.

3.6.6 Revised Proposal

Our revised DER proposal is $51.0 million (direct costs) for the next regulatory period. This is illustrated in the table below.

Table 3-11: Revised DER capex ($m, $2021, direct costs)

	2021-22	2022-23	2023-24	2024-25	2025-26	Total
DER	9.4	9.8	10.2	10.6	11.0	51.0

Source: AusNet Services

3.7 Metering re-allocation

3.7.1 Our Initial Proposal

In the current regulatory period, a portion of IT and communication metering costs have been allocated 100% to ASC. We proposed to re-allocate some capex from ACS to SCS due to the increasing operational reliance on this data to run the network.

3.7.2 Draft Decision

The AER did not accept our Initial Proposal. While it accepted the reasonableness of reallocating a portion of metering costs from ACS to standard control it rejected our proposed reallocation of 50% of certain type 5 and 6 IT and communications systems expenditures from ACS to SCS, instead substituting its own allocations. Therefore, the AER only reallocated $2.1 million capex from ACS to SCS for those particualr assets.

3.7.3 Our Revised Proposal

As discussed in Chapter 13, we disagree with the AER's proposed re-allocation of certain type 5 and 6 IT and communications systems expenditures. We have therefore proposed a new reallocation of capex that better reconciles with our actual usage of this data. Our Revised Proposal reallocates $15.4 million to SCS capex for metering related IT systems and $14.6 million to SCS capex for metering comms replacement.

3.8 Non-network capex

3.8.1 Our Initial Proposal

We proposed expenditure of $224.6 million for non-network capex in the next regulatory period, including $165.4 million for ICT expenditure. However, following the submission of our

Initial Proposal and further engagement with the AER we removed $5.5 million from our non-network capex proposal prior to the AER's Draft Decision.[58]

3.8.2 Draft Decision

The AER accepted our revised non-network capex proposal. In coming to its decision, the AER noted that:

- From an overall level, our proposed ICT program was below historical costs and was contributing to the productivity gains (1%) reflected in our opex forecast; and
- It had no issue with our overall other non-network capex which was materially below our current period capex.

3.8.3 Revised Proposal

We have accepted the AER's Draft Decision on non-network capex and have updated our proposal to capture the latest available information[59] and to reflect a minor adjustment ($52,000) for expenditure that is no longer required as it was included in our May 2020 Bushfire pass-through application (as discussed in section 2.4.3).

All other aspects of non-network capex have remained unchanged, meaning our forecast remains conservative and well below that which we expect to incur in the current regulatory period. We have taken this approach notwithstanding identifying additional ICT costs (arising from the 5-minute metering and global settlement costs) that would be justified being brought in the current regulatory period.

Our non-network capex forecast is, therefore, $205.0 million for the next regulatory period (including the $6.4 million capex for innovation that was agreed with the Customer Forum).[60]

Our Revised Proposal for non-network capex is, therefore, lower than that allowed in the Draft Decision and remains well below historical levels. Our revised forecast is illustrated in the table below.

Table 3-12: Revised non-network capex ($m, $2021)

	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Non-network capex	56.3	37.2	41.5	36.6	41.6	205.0

Source: AusNet Services

3.9 Capitalised network overheads

3.9.1 Our Initial Proposal

We proposed expenditure of $123.7 million for capitalised network overheads for the next regulatory period.

58 We identified an error in our fleet forecast and therefore reduced our fleet capex by $5.5 million for a total of $51.3 million in other non-network capex.

59 We updated information on our capitalised leases to reflect several updates to SCS leases since the Initial Proposal. However, the key change is that a large CBD lease, which was expected be renewed in 2026, will no longer be renewed.

60 The Customer Forum agreed $7.5 million ($2021) for innovation. This was comprised of $6.4 million ($2021) capex and $1.2 million ($2021) for opex.

3.9.2 Draft Decision

The AER did not accept our capitalised network overheads and replaced it with an alternative forecast of $121.8 million. This 1.6% adjustment reflects the reductions the AER proposed with respect to our overall capex.

3.9.3 Response to the AER's Draft Decision

As we have proposed an alternative total capex forecast, the capitalised network overheads must also be amended. We have therefore not accepted the AER's Draft Decision and have updated our total forecast for capitalised overheads.

3.9.4 Revised Proposal

Our revised forecast for capitalised network overheads is $122.8 million for the next regulatory period. This is 0.8% ($1 million) higher than the Draft Decision and is illustrated in the table below.

Table 3-13: Revised capitalised networks overheads ($m, $2021)

	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Capitalised networks overheads	25.3	25.4	24.3	24.0	23.9	122.8

Source: AusNet Services

3.10 Capitalised corporate overheads

3.10.1 Our Initial Proposal

We proposed expenditure of $23.4 million for capitalised corporate overheads for the next regulatory period.

3.10.2 Draft Decision

The AER rejected our capitalised corporate overheads and replaced it with an alternative forecast of $23.1 million. This 1.6% adjustment reflects the reductions the AER proposed with respect to our overall capex.

3.10.3 Response to the AER's Draft Decision

As we have proposed an alternative total capex forecast, the capitalised corporate overheads must also be amended. We have therefore not accepted the AER's Draft Decision and have updated our total forecast for corporate overheads.

3.10.4 Revised Proposal

Our revised forecast for capitalised corporate overheads is $23.3 million for the next regulatory period. This is 0.8% ($0.2 million) higher than the Draft Decision and is illustrated in the table below.

Table 3-14: Revised capitalised corporate overheads ($m, $2021)

	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Capitalised corporate overheads	4.8	4.8	4.6	4.5	4.5	23.3

Source: AusNet Services

3.11 Labour escalation

In preparing our Initial Proposals we have used external and internal labour cost escalators to help develop our forecast capex. Our approach to these issues is outlined briefly below.[61]

3.11.1 External labour cost escalation

3.11.1.1 Initial Proposal

Consistent with the approach we used in our 2016-20 regulatory proposal, we proposed the use of external labour cost escalation in our Initial Proposal. This was appropriate given our expectation that our contractors' cost will increase in real terms during the next regulatory period. We set our external escalation rates at the same level as our internal labour escalators (see Chapter 4).

3.11.1.2 Draft Decision

In the Draft Decision, consistent with more recent AER distribution decisions, the AER applied CPI to external labour costs.[62]

3.11.1.3 Response to the AER's Draft Decision

While we have not proposed alternative external labour cost escalators in this Revised Proposal, this should not be interpreted as us accepting that the AER's approach to external cost escalation is appropriate for this or other (distribution or transmission) regulatory proposals.

Applying CPI to external labour costs will not necessarily reflect the efficient contract costs a business will incur over a regulatory period, particularly when significant infrastructure development is expected which could bid up wages for skilled labour. We therefore encourage the AER to remain open to alternative, evidence-based approaches to external labour cost escalation that will allow prudent businesses to recover efficient costs.

3.11.2 Internal labour cost escalation

3.11.2.1 Initial Proposal

As we discuss in Chapter 4, we proposed internal labour cost escalators, consistent with the approach previously applied by the AER for the Victorian DNSPs, based on the average of Deloitte's wage price index (WPI) forecasts prepared as part of South Australia Power Network's draft decision,[63] and forecasts of the Victoria utilities sector we commissioned from BIS Oxford Economics in April 2019.

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61 We have also updated for changes in inflation (see Chapter 5).

62 See, for example, https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/sa-power-networks-determination-2020-25/final-decision (accessed 16 November 2020).

63 AER, Draft Decision, SA Power Networks Distribution Determination 2020 to 2025 Attachment 6 Operating expenditure.

3.11.2.2 Draft Decision

The AER did not adopt its usual approach to determining the rate of change for internal labour. Rather, it used its own consultant's labour price growth forecast alone as it was the only available forecast that factored in COVID-19 impacts.

However, the AER noted it would consider averaging its Deloitte forecast with updated BIS Oxford forecasts that account for the changes in the economic outlook and which account for the downward impact on wages resulting from the superannuation guarantee increases.[64]

3.11.2.3 Response to the AER's Draft Decision

In line with the AER's standard approach for distribution businesses, and as foreshadowed in the Draft Decision, we have proposed a revised forecast that reflects an average of the Deloitte forecast with our updated BIS Oxford forecast.

We commissioned BIS Oxford to provide updated forecasts in October 2020. These forecasts account for changes in the economic outlook including the impacts of COVID-19 as well as the downward impact on wages resulting from the superannuation guarantee increases. Further information on our proposed internal labour escalation rates is outlined in Chapter 4.

3.12 Supporting documents

We have included the following documents to support this chapter:

- REFCL Compliance Maintained Planning Reports for 8 Zone Substations
- ASD – EDPR 2022-26 Revised Proposal – Appendix 3A - Customer Forum Memo -031220 - PUBLIC
- ASD – EDPR 2022-26 Revised Proposal – Capex Model (2021-26) – 031220 – CONFIDENTIAL
- ASD – EDPR 2022-26 Revised Proposal – Connections Capex Forecast Model (2021-26) – 031220 – CONFIDENTIAL
- ASD – EDPR 2022-26 Revised Proposal – REFCL KLO Total Cost Model (2021-26) – 031220 – CONFIDENTIAL
- ASD – EDPR 2022-26 Revised Proposal – Updated REFCL Augmentation Total Cost Model (2021-26) – 031220 – CONFIDENTIAL
- ASD – EDPR 2022-26 Revised Proposal – KLO Cost Comparison – 031220 – PUBLIC

64 AER, Draft Decision: AusNet Services 2021–26: Attachment 6: Operating expenditure, pp. 47-48.

4 Operating expenditure forecast

4.1 Key points

- We are proposing operating and maintenance expenditure (opex) excluding debt raising costs of $1,193 million for SCS in the next regulatory period. This is:
  - 1.4% higher than that proposed in the AER's Draft Decision; and
  - 2.4% lower than that proposed in the Initial Proposal.
- We welcome the AER's acceptance of over 96% of our Initial Proposal and note that the AER indicated that it would likely have accepted our proposal if not for COVID-19.
- We have accepted several material aspects of the AER's Draft Decision, including changes to:
  - Our base year opex and the final year increment;
  - Adjustments to retain lease capitalisations within the base year, instead treating it as a non-recurrent efficiency adjustment within the EBSS;
  - The methodology for determining productivity growth and output measures;
  - The 5-minute settlement step change; and
  - Our approach to forecasting the DMIAM.
- As invited by the AER, we have provided more up-to-date information on other aspects of the Draft Decision including:
  - Updating labour growth escalators to ensure our (blended) escalators better reflect expected Victorian labour market conditions;
  - Updating our REFCL step change following ESV's decision to alter the testing regime, reducing costs by $1.5 million;
  - Updating our GSL allowance due to new information from the ESC's review of the EDC.
- We have provided additional information to address the AER's concerns on the following parts of our proposal:
  - The capex/opex tradeoff associated with our proposed cloud step change, which continues to have strong support from the Customer Forum;
  - Proposing a higher allocation of metering costs to standard control; and
  - Proposing to lower our opex forecast by resubmitting our proposed treatment for the ESV levy. We also propose the same approach for AEMO fees that may be allocated to distribution businesses.
- New information has led to the following update to our forecast:
  - We have proposed a new ($10 million) insurance step change in response to changes in insurance markets that are expected to result in significant increase in insurance premiums.

4.2 Chapter structure

The remainder of this chapter is structured as follows:

- Section 4.3 introduces our Revised Proposal opex;
- Section 4.4 considers our proposed base year expenditure;
- Section 4.5 outlines our proposed rate of change;
- Section 4.6 sets out our proposed step changes;
- Section 4.7 outlines category specific expenditures;
- Section 4.8 provides a summary of our Revised Proposal for opex;
- Section 4.9 outlines benchmarking efficient capex; and
- Section 4.10 sets out our supporting documents for this chapter.

In the event of inconsistency between information contained in this chapter and our Initial Proposal, the information contained in this chapter prevails.

4.3 Introduction

4.3.1 Our Initial Proposal

The opex included in our Initial Proposal was negotiated with the Customer Forum as part of the trial of the 'New Reg' process. The resulting forecast was total opex of $1,222 million over the next regulatory period. This amount was 5% lower than the opex allowance for the 2016-2020 regulatory period.[65]

While our general opex requirements are largely unchanged from the Initial Proposal, developments since we published the Initial Proposal relating largely to the impacts of COVID-19 are expected to drive minor increases in expenditure during the current regulatory period.

4.3.2 Draft Decision

The AER approved $1,176 million of the $1,222 million in the Initial Proposal, representing a reduction of $46 million or 3.7%.[66] The AER found our total opex proposal reasonable and indicated that it would likely have been accepted had the impacts of COVID-19 not needed to be taken into account.

The key drivers of the AER's amendments were:

- A $37.9 million reduction due to lower labour and network growth escalators, which had been updated to take COVID-19 effects into account. For the labour growth forecast, the AER used its consultant's forecast alone but indicated it would consider including our consultant's forecast in line with its standard approach if it made available.
- Our proposed $4.7 million cyber security opex step change was rejected. While the AER considered it prudent to meet anticipated cyber security obligations, it concluded that these costs were driven by transmission network requirements.
- The rejection of our proposed $3.6 million ICT cloud step change on the basis that we had provided insufficient evidence to establish an opex/capex tradeoff.

65 For further information refer to Chapter 10 of our Initial Proposal.

66 Figures exclude debt raising costs.

- The AER also rejected our proposal to recover the $4.2 million ESV levy through the annual pricing proposal (through the L factor), instead retaining it in the base year. It also reallocated $21.2 million in metering charges to ACS instead of SCS as we proposed. The net impact of these two changes resulted in a $9 million reduction to our proposal.
- The AER accepted the efficiency of our base year (2018) and accepted our REFCL and 5-minute settlement step changes (with minor adjustments). The AER also accepted our proposed GSL allowance in principle. However, it expected that we would provide any necessary updates arising from the ESC's review of the EDC.

4.3.3 Response to the AER's Draft Decision

We have accepted the AER's Draft Decision with respect to:

- Base year opex and the final year increment;
- Adjustments to retain lease capitalisations within the base year, instead treating it as a non-recurrent efficiency adjustment within the EBSS;
- The methodology for determining productivity growth;
- The output growth forecast;
- The 5-minute settlement step change; and
- The approach to forecasting demand management opex.

We have provided additional or updated information to address queries raised by the AER about some aspects of our proposal including to:

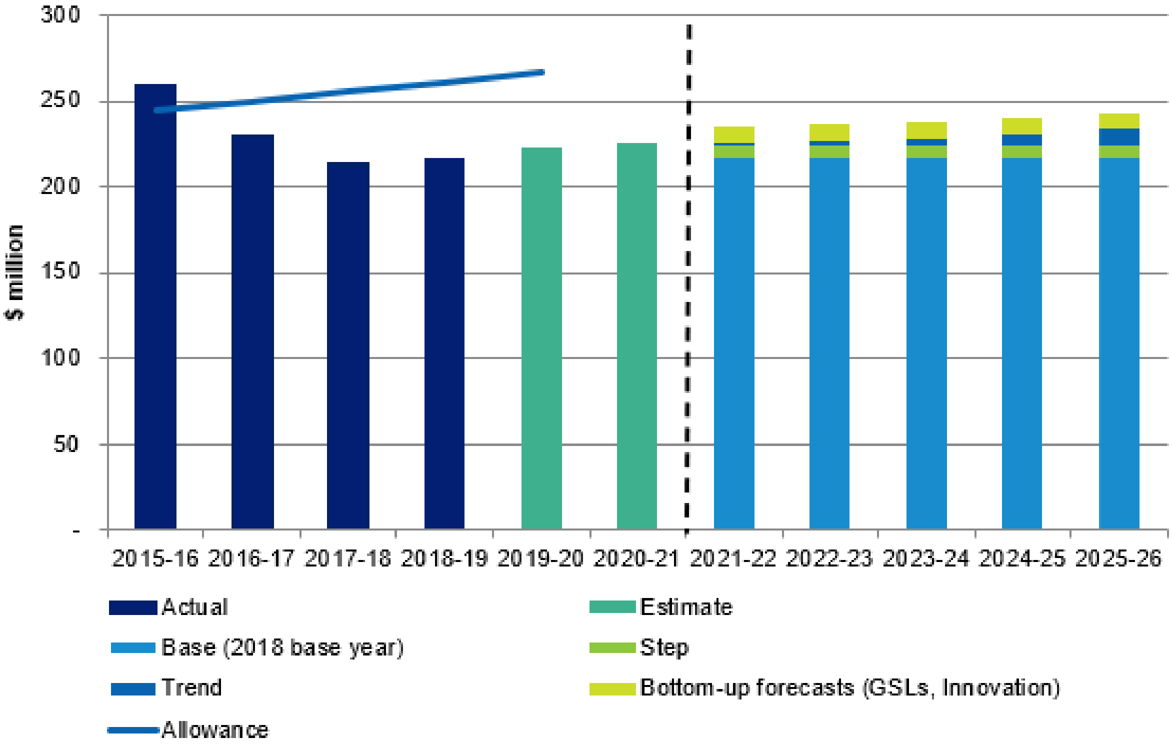
- Revise the labour growth escalators by averaging the AER's and our consultancy's forecast (in line with the AER's standard approach for Victoria) to ensure that our forecast better reflects expected Victorian labour market conditions;
- Update our cloud step change to establish the efficient capex/opex tradeoff;
- Include a new insurance step change resulting from updated information regarding insurance premiums;
- Update our REFCL step change following ESV's decision to alter the testing regime;
- Update our GSL allowance in response to new information arising from the ESC's review of the EDC;
- Propose a higher allocation of metering costs to standard control;
- Reduce our opex forecast to account for ongoing bushfire-related maintenance that was brought forward or superseded in response to the 2020 bushfires; and
- Reduce our opex forecast by resubmitting our proposed treatment for the ESV levy.

Most of these changes are driven by updates required by external circumstances, including COVID-19-related impacts, or where the AER has indicated that more information should be provided.

4.3.4 Revised Proposal

Having regard to the above changes, our revised forecast for SCS opex is $1,193 million, excluding debt raising costs for the next regulatory period. Further information on how this Revised Proposal has been built up is outlined below.

Figure 4-1: Actual and forecast operating expenditure ($m, real $2021)



Source: AusNet Services

4.4 Base year expenditure

4.4.1 Our Initial Proposal

We nominated the 2018 calendar year as the base year for forecasting opex and outlined the adjustments to our actual 2018 expenditure (which was $205.4 million (nominal)) to ensure it was representative of efficient costs. These adjustments involved the removal of the following expenditure items:

- $6.6 million of GSL costs, which are forecast separately using a bottom-up approach to produce a category specific forecast;
- $0.2 million of DMIA expenditure;
- $0.5 million relating to movements in provisions;
- $4.3 million of expenditure on building and motor vehicle leases, which are capitalised from 1 July 2019 consistent with accounting standard AASB 16; and
- $2.3 million of expenditure on the ESV levy (proposed to be recovered through the annual tariff process as a direct pass-through instead).

To forecast the base year opex at the end of the 2016-20 regulatory period (31 December 2020), we also applied the forecast trend from the 2016-20 regulatory period to derive opex in 2020.

Our approach resulted in a base year opex of $215.4 million for the next regulatory period.[67]

[67] For further information refer to Chapter 10 of our Initial Proposal.

4.4.2 Draft Decision

The AER accepted that 2018 was an appropriate base year, finding it representative of the base opex required for the next regulatory period. However, it updated the 2018 base opex with the latest available data for forecast inflation to convert to real 2021 dollars and for movements in provisions. This resulted in the AER revising the 2018 base year to $216.0 million. The AER also provided commentary on our benchmarking performance and wider benchmarking considerations relating to Operating Environment Factors (OEFs) and capitalisation policies which is discussed in more detail in section 4.9 below.

The AER retained the capitalisation of building and motor vehicle leases within the base year, instead treating it as a non-recurrent efficiency adjustment.[68]

The AER also rejected our proposal to remove ESV levy expenditure from the base year. While accepting that there will be in increase in the ESV levy over the 2022-2026 regulatory period, the AER stated that these costs could be managed through existing base opex and the forecast rate of change.[69]

Lastly, the AER provided a $1.6 million base adjustment to reallocate certain metering opex from ACS to SCS.[70] This is discussed in more detail in Chapter 13 Metering.

4.4.3 Revised Proposal

We welcome the AER's acceptance of the efficiency of our base year 2018 and its treatment of the capitalisation of building and motor vehicle leases as a non-recurrent efficiency adjustment. We have several observations regarding the AER's benchmarking analysis outlined in the Draft Decision, which are discussed in more detail in section 4.9.[71] As explained in that section, our relative performance may be understated by the AER's treatment of capitalisation policies.

However, we do not accept the AER's Draft Decision in relation to the treatment of the ESV levy. The decreases to the rate of change to reflect the impacts of COVID-19 illustrate the unsuitability of accounting for the ESV levy and future cost increases through existing base opex and the forecast rate of change, as proposed by the AER. Rather, we consider that it should be recovered as a pass through via the annual pricing process.

Market regulatory bodies are often funded through industry specific levies. Generally, these organisations do not provide forecasts of their expected fees out further than 12 months. Material changes to these bodies' responsibilities and the fees that they levy can also occur through unexpected government action. This can be seen through an unexpected but substantial rise in the ESV levy and a potential change to AEMO's participant fee recovered from the distribution sector as a result of metering changes.

Fortunately, the Victorian regime has a specific process to allow the fair recovery of these costs through adjustments in the annual price setting process. This is currently used to cover the licence fee that is used to fund the ESC and is purpose-built to similarly apply to both the ESV levy and any future AEMO participant fees. The rationale is identical in each case as we have no ability to control these costs. We discuss each of these fees in turn below.

68 AER, Draft Decision, AusNet Services 2021–26: Attachment 6: Operating expenditure, p. 40.

69 AER, Draft Decision, AusNet Services 2021–26: Attachment 6: Operating expenditure, p. 41.

70 In our Initial Proposal we had proposed to reallocate $29.4 million of these costs from ACS to SCS as a category specific forecast.

71 AER, Draft Decision, AusNet Services 2021–26: Attachment 6: Operating expenditure, s 6.4.1.2.

4.4.4 ESV levy

As outlined in our Initial Proposal, the ESV has informed us that our annual levy will increase significantly over the 2022-26 regulatory period as shown in the table below. We therefore proposed to treat the annual ESV levy in the same way as the ESC's annual licence fees, by recovering this opex through an L Factor in our price control formula.[72]

We maintain our earlier submission that this approach is the most appropriate method to account for forecast increases in the ESV levy. This is due to both the materiality of the forecast increases in expenditure and the unsuitability of the rate of change as providing a true reflection of these costs. As shown in the table below, if the 2018 ESV levy allowance increases in line with the rate of change, it will lead to a material under-recovery of the forecast costs. This outcome would be contrary to the revenue and pricing principles in the NEL, which require that we have a reasonable opportunity to recover at least the efficient costs of providing network services.[73]

Table 4-1: Difference between forecast ESV levy and Draft Decision ($m, real $2021)

	2018	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Forecast ESV levy	**2.2**	**2.4**	**2.7**	**3.0**	**3.2**	**3.3**	**3.3**	**3.3**	**3.3**	**16.4**
% yoy		*5.4*	*13.2*	*10.6*	*9.1*	*0.9*	*0.9*	*0.9*	*0.9*	
AER Draft Decision ESV Levy	**2.2**	**NA**	**NA**	**NA**	**2.3**	**2.2**	**2.3**	**2.3**	**2.3**	**11.3**
Difference between forecast and Draft Decision										**5.1**

Note: The 2018 ESV Levy forms base opex and is based on actuals. Forecast ESV levy opex provided by ESV span 2018-19 to 2023-24. We assumed a constant growth rate of 0.9% to determine 2024-25 and 2025-26 ESV levy opex, which mirrors the 2022-23 and 2023-24 growth rate.

The ESV levy is forecast to rise from $2.2 million ($2021) in 2018 to $3.2 million ($2021) by 2021-22, a rise of more than 44%. The ESV Levy is forecast to rise $16.4 million ($2021) over the regulatory period. In contrast, the AER's approach, which uses the 2018 ESV levy and trends it forward using the rate of change, results in a total ESV levy opex of $11.4 million ($2021). This produces a gap of $5.1 million ($2021) for the period, which we are unable to recover.

Comparing forecast increases in the ESV levy to the rate of change between 2018 and 2024 in the table above shows there is no correlation between the rate of change and movements in the ESV levy. This is further highlighted by the impacts of COVID-19, which had a dramatic impact on the AER's forecast rate of change,[74] but which has had no effect on the ESV levy price increases.

Therefore, we propose to allow recovery of the actual costs through a B Factor in our price control formula. This is appropriate given that both the ESV levy and ESC annual licence fees is are affected by exogenous factors and are beyond our control. However, if the AER does not accept this approach, we expect the AER will include a step change to ensure that the true cost increases are appropriately included in the Final Decision.

72 AusNet Electricity Services Pty Ltd, Electricity Distribution Price Review 2022-26, Part III (31 January 2020), p. 136.

73 Section 7A, subsection (2).

74 AER, Draft Decision, AusNet Services 2021–26: Attachment 6: Operating expenditure, p. 74.

As a result, we propose to remove the ESV levy amounts from the opex forecast as an adjustment to the base year of $2.2 million ($, real 2021), resulting in a decrease to the overall opex forecast by $11 million ($2021).

4.4.5 AEMO-allocated fees

Clauses 2.11.1 to 2.11.11 of the NER requires AEMO to:

- Determine the structure of Participant fees;
- Set budgeted revenue requirements; and
- Recover the budgeted revenue requirements through charging registered participants.

AEMO currently charges other registered participants, but does not charge registered DNSPs, metering coordinators or service providers. However, AEMO is proposing new fees to metering coordinators and DNSPs on the basis that these participants are utilising regulated reforms, such as 5-minute settlement, and more frequently updating AEMO-provided systems such as MSATS. In its Draft Determination,[75] AEMO proposed to charge National Electricity Market (NEM) DNSPs approximately $3.3 million ($2021) per annum from 1 July 2023. Depending on our cost allocation survey results, this could equate to us being allocated about $0.3 million of this, which equates to over $0.9 million over the 2022-26 regulatory period.

As we will be required to pay these market fees to fulfil our obligations under electricity legislation as an exogenous requirement, this is not included in our current opex forecast. As the drivers of the AER's rate of change are unrelated to this cost impost it would be inappropriate to apply the opex incentive regime to these costs. Instead we propose to recover these operating expenditures through a L Factor in our price control formula similar to the ESV levy. Likewise, if the AER does not accept this approach, we expect the AER will include a step change in the Final Decision to ensure that we can recover these exogenous cost increases.

4.5 Rate of change

4.5.1 Our Initial Proposal

In our Initial Proposal we outlined our proposed rate of change escalators and the underlying calculations used to derive them, relying on the most up-to-date information of inputs and the AER's standard methodology available at that time. Our proposed rate of change is outlined below.[76]

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75 AEMO, Electricity Market Participant Fee Structure Review (30 November 2020).

76 For further information refer to Chapter 10 of our Initial Proposal.

Table 4-2: Proposed rate of change (2022-26)

Component	2021-22	2022-23	2023-24	2024-25	2025-26
Output growth	1.51%	1.41%	1.54%	1.36%	1.08%
Real price growth	0.57%	0.61%	0.64%	0.56%	0.53%
Productivity growth	-0.5%	-0.5%	-0.5%	-0.5%	-0.5%
Overall rate of change	**1.58%**	**1.52%**	**1.68%**	**1.42%**	**1.10%**

Source: AusNet Services, Electricity Distribution Price Review 2022-26: Part III (31 January 2020), p. 15

4.5.2 Draft Decision

As the AER noted, we broadly applied their standard approach to forecasting the rate of change.[77] However, the AER did not accept the rate of change submitted in the Initial Proposal, and instead proposed to adopt an alternative forecast principally to reflect recent impacts of COVID-19. The key differences were that the AER:

- Used its own consultant's labour price growth forecast alone, rather than averaging it with our consultant's forecast, given it was the only available forecast that factored in COVID-19 impacts;
- Applied input price weights of 59.2% for labour and 40.8% for non labour, to correct a pre-existing error used to determine these weights;[78] and
- Updated the output weights to correct a coding error.

Each of these differences are discussed below.

4.5.2.1 Real price growth

The AER rejected our approach to use an average of Deloitte's wage price index (WPI) forecasts prepared as part of South Australia Power Network's Draft Decision,[79] and forecasts of the Victorian utilities sector we commissioned from BIS Oxford Economics in April 2019. The primary reason for this rejection was that BIS Oxford had not yet included COVID-19 impacts.

Instead, the AER used more recent labour price growth forecasts of the Victorian utilities sector prepared in July 2020 by Deloitte, given this was the only available forecast that factored in COVID-19 impacts. The AER also accounted for the legislated increases in the superannuation guarantee in its adopted labour price growth forecasts, passing on the increase in full, following advice from Deloitte.[80]

However, the AER noted it would consider averaging its Deloitte forecast with updated BIS Oxford forecasts that account for the changes in the economic outlook and which account for the downward impact on wages resulting from the superannuation guarantee increases.[81]

77 AER, Draft Decision, AusNet Services 2021–26: Attachment 6: Operating expenditure, p. 44

78 AER, Draft Decision, AusNet Services 2021–26: Attachment 6: Operating expenditure, p. 46.

79 AER, Draft Decision, SA Power Networks Distribution Determination 2020 to 2025 Attachment 6 Operating expenditure.

80 Deloitte Access Economics, Impact of changes to the superannuation guarantee on forecast labour price growth, 24 July 2020, p. 5.

81 AER, Draft Decision: AusNet Services 2021–26: Attachment 6: Operating expenditure, pp. 47-48.

The AER also applied input price rates of 59.2% for labour and 40.8% for non labour, to correct a pre-existing error used to determine these weights.[82]

4.5.2.2 Output growth

The AER rejected our proposed output growth forecast. While it adopted our circuit length and energy throughput forecasts, it updated the output growth rate forecasts of customer numbers and ratcheted maximum demand as follows:

- The AER updated customer numbers based on the HIA's April 2020 dwelling starts forecasts.
- The AER forecast zero growth in ratcheted maximum demand based on AEMO's 2019 maximum demand forecasts at the transmission connection point. [83]
- The AER also noted that it would update its output growth rate forecasts to reflect the results of the 2020 Annual benchmarking report, scheduled for release in late November 2020.

As noted above, the AER updated the output weights to correct a coding error, which distributed more output weight to ratcheted maximum demand and circuit length and away from customer numbers and energy throughput. The results are shown in the table below.

Table 4-3: AER corrected opex MPFP output weights (%)

	Uncorrected, 2006-2017	Corrected, 2006-2018
Energy throughput	12.46	8.58
Ratcheted maximum demand	28.26	33.76
Customer numbers	30.29	18.52
Circuit length	28.99	39.14

Source: AER, Draft Decision, AusNet Services 2021–26: Attachment 6: Operating expenditure, p. 51

4.5.2.3 Productivity growth

The AER accepted our approach to use the 0.5% p.a. productivity growth adjustment as determined through the productivity review.[84] This includes a 0.37% productivity adjustment for FY22 to account for the 2021 half year period.[85]

4.5.2.4 Overall rate of change

Given the changes identified above, the AER rejected our overall rate of change and considered that the rate of change outlined in the table below was appropriate.

[82] We submitted input price weights of 59.7% for labour and 40.3% for non-labour. See AER, Draft Decision, AusNet Services 2021–26: Attachment 6: Operating expenditure, p. 46.

[83] AER, Draft Decision: AusNet Services 2021–26: Attachment 6: Operating expenditure, p. 52.

[84] AER, Final decision paper, Forecasting productivity growth for electricity distributors, March 2019.

[85] AER Information Request #043; AER, Draft Decision, AusNet Services 2021–26: Attachment 6: Operating expenditure, p. 53.

Table 4-4: AER proposed rate of change (2022-26)

	2021-22	2022-23	2023-24	2024-25	2025-26
Output growth	0.50%	0.84%	1.03%	1.03%	1.02%
Real price growth	0.14%	-0.15%	-0.04%	0.22%	0.59%
Productivity change	0.37%	0.50%	0.50%	0.50%	0.50%
Rate of change, yoy	0.26%	0.18%	0.49%	0.74%	1.11%
Rate of change, cumulative	**0.26%**	**0.45%**	**0.93%**	**1.68%**	**2.80%**

Source: AER

4.5.3 Revised Proposal

We do not accept the AER's Draft Decision on the rate of change. While we accept its new input price weights, output weights, ratcheted maximum demand forecasts and customer numbers, we have updated real price growth to account for more up-to-date information, namely the blending associated with inclusion of BIS Oxford's latest forecasts (as per the AER's standard approach for DNSPs).

4.5.3.1 Real price growth

We do not accept the AER's Draft Decision in relation to real price growth. In line with the AER's standard approach for DNSPs, and as foreshadowed in the Draft Decision, we have proposed a revised forecast that reflects an average of the Deloitte forecast with our updated BIS Oxford forecast.

We commissioned BIS Oxford to provide updated forecasts in October 2020.[86] These forecasts account for changes in the economic outlook including the impacts of COVID-19 as well as the downward impact on wages resulting from the superannuation guarantee increases. BIS Oxford's findings show that:

- COVID-19 has plunged the Australian economy into recession in 2020 with Australian Gross Domestic Product contracting -0.2% in FY20. It is forecast to decrease further in FY21, before recovering in FY22.
- While the labour market is expected to weaken, utilities sector wages are expected to remain higher than the national (all industries) average. This reflects a highly skilled workforce, strong union presence, competition for skilled resources from the mining and construction industries and fewer skilled workers being trained.
- The overall national average is also expected to be lower due to COVID-19 impacting lower skilled sectors such as retail trade, wholesale trade, accommodation, cafés and restaurants. However, the electricity, gas, water and waste services (EGWWS) sector is not anticipated to be adversely impacted to the same extent due to its obligation to provide essential services and therefore the need to retain appropriately skilled labour.

86 BIS Oxford's initial forecasts were updated for inflation, with an accompanying addendum to the Final report. See Appendix 4B Addendum Note on changes to AER treatment of Inflation.

- This utilities sector wages premium is more pronounced in Victoria, with the Victorian EGWWS WPI forecast to outpace the Australian EGWWS WPI average. This is due to the expected continuation of higher EBA outcomes in Victoria's utilities and strong increases in utilities-related engineering construction over FY24 to FY26.[87]

The blended approach including BIS Oxford's results is summarised in the table below.

Table 4-5: Real price growth (2022-26)

	2021-22	2022-23	2023-24	2024-25	2025-26
DAE - Draft Decision	0.24%	-0.25%	-0.07%	0.37%	1.00%
BIS Oxford - Victorian DBs	1.31%	1.24%	1.38%	1.62%	1.62%
Average price growth	**0.78%**	**0.50%**	**0.65%**	**0.99%**	**1.31%**

Note: The DAE and BIS Oxford rates include the 0.5% p.a. increases in the superannuation guarantee rate.

Source: ASD - Labour Price Escalation calculation – 3 December 2020, Attachment 4B Addendum Note on changes to AER treatment of Inflation

4.5.3.2 Productivity growth

We accept the AER's Draft Decision.

4.5.3.3 Overall rate of change

For the reasons outlined above, we consider that the appropriate overall rate of change for the Revised Proposal is set out in the table below.

Table 4-6: Revised rate of change forecast (2022-26)

	2022-23	2023-24	2024-25	2025-26	2026-27
Output growth	0.50%	0.84%	1.03%	1.03%	1.02%
Real price growth	0.46%	0.30%	0.38%	0.59%	0.78%
Productivity change	0.37%	0.50%	0.50%	0.50%	0.50%
Rate of change, yoy	0.58%	0.63%	0.92%	1.11%	1.29%
Rate of change, cumulative	**0.58%**	**1.22%**	**2.14%**	**3.28%**	**4.61%**

Source: AusNet Services, AusNet Services Revised Proposal - 2022-26 - Opex model

87 Appendix 4A, Labour Cost Escalation Forecasts to 2022-26.

4.6 Step changes

4.6.1 Our Initial Proposal

We proposed several step changes driven by new regulatory obligations, namely:

- The introduction of 5-minute settlement in the wholesale market;
- New cyber security laws and guidelines;
- Transition of ICT functionality to the Cloud; and
- Compliance with bushfire safety (i.e. REFCLs).[88]

We also highlighted the $21 million ($2021) of additional cost pressures and step changes we would absorb without any compensating increase in our opex allowance. This decision was a tangible response to the affordability concerns of our customers.

We also noted that we could only absorb these additional cost pressures on the basis that elements of our non-recurrent IT expenditure program were approved, given this program is essential to delivering our productivity gain.[89]

4.6.2 Draft Decision

The AER accepted our proposed step changes for:

- REFCL step change ($5.9 million); and
- 5-minute and global settlement ($3.5 million).[90]

However, the AER noted that it expected the REFCL step change to be updated in the Revised Proposal to reflect any changes resulting from updated forecasts of inflation and any amendments the ESV makes to our annual testing obligations after the publication of the Draft Decision.

The AER did not accept our proposed step changes for:

- Cyber security ($4.7 million); and
- ICT Cloud step change ($2.6 million).

Further, in our recently accepted 2020 Summer Bushfires cost pass through application,[91] we agreed to deduct opex for ongoing bushfire-related maintenances activities over the 2022 to 2026 regulatory period that were instead incurred as a result of or replaced by 2020 bushfire remediation activities.

4.6.2.1 Cyber security

The proposed $4.5 million step change was based on allocating 17% of the incremental cost of achieving Maturity Indicator Level (MIL) 3 of AEMO's Australian Energy Sector Cyber Security Framework (AESCSF) to the distribution network. The cost allocation reflects the customers served by our distribution network as a proportion of all three of our networks.

The AER found that it was prudent for businesses to meet the standards set by the AESCSF, despite the uncertainty around the timing of associated legislation requiring compliance with the AESCSF being introduced. The AER also noted the support of the CCP17 for the step change

88 AusNet Electricity Services Pty Ltd: Electricity Distribution Price Review 2022-26 (31 January 2020), section 10.9.

89 For further information refer to Chapter 10 of our Initial Proposal.

90 These step changes were discounted slightly due to updated inflation forecasts.

91 See AusNet Services, Cost pass through application – 2020 Summer Bushfires (27 May 2020), section 5.4.

and the Victorian Community Organisations' observation that our proposed costs were modest compared to our Victorian counterparts.[92]

However, the AER rejected this step change as it did not consider the proposed allocation of costs to be appropriate. Looking more deeply at this, EMCa (the AER's consultants who provided an in-depth assessment of this step change) noted that our approach to meeting our forthcoming security requirements was efficient, but that the proposed allocation of costs between the networks was not.[93] Instead, EMCa noted that as the requirement to attain MIL 3 arose from our transmission network, not our distribution network, 'AusNet's intention for its Transmission business to enhance its cyber security level towards MIL 3 in the next RCP is likely to represent the actions of a prudent TNSP operator.'[94]

4.6.2.2 ICT Cloud step change

The AER rejected the ICT Cloud step change as it considered that there was insufficient evidence to establish the required capex/opex trade off. In particular, the AER noted that in order to accept this step change it would 'need to be satisfied the proposed expenditure is material, prudent and efficient through robust cost–benefit analysis to demonstrate clearly how increased opex would be more than offset by capex savings.'[95]

4.6.3 Revised Proposal

We accept the AER's Draft Decisions for 5-minute and global settlement, REFCLs, and cyber security. In accordance with the AER's Draft Decision, we have updated our REFCL step change to reflect the expected ESV amendments to our annual testing obligations and to account for updates in inflation.

However, we do not accept the AER's position on our ICT Cloud step change and have provided additional information to support it in order to uphold the agreement we reached with the Customer Forum to absorb the cost of other costs and step changes. We have also proposed an additional step change to capture substantial expected increases in our insurance premium over and above what we anticipated at the time we submitted our Initial Proposal.

Further information on these step changes is outlined below.

4.6.3.1 REFCL step change

We accept the AER's Draft Decision. Consistent with the AER's stated expectation,[96] this Revised Proposal provides updated information that takes into account the ESV's amendments to our annual testing obligations, which are expected to take effect in 2021, following our submission of an application by December 2020), and reflects updates in forecast inflation.

Updated assumptions now reflected in our Revised Proposal are:

- The ESV will grant an exemption to test one feeder per bus at each site in the second year after initial compliance testing. There will still be a requirement to test all feeders the first year after initial compliance testing and each feeder must be tested at least once every 5 years.
- The reduction in annual testing obligations will result in 33 feeders to be tested annually by 2024-25 out of a total 121 feeders across the 22 REFCL-protected networks.

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92 AER, Draft Decision, AusNet Services 2021–26: Attachment 6: Operating expenditure, pp. 56-57.

93 EMCa, AusNet Services - Review of proposed opex ICT-related step changes: Report prepared for: AER (August 2020) Confidential.

94 Ibid, paragraph 34.

95 AER, Draft Decision, AusNet Services 2021–26: Attachment 6: Operating expenditure, pp. 57-58.

96 AER, Draft Decision, AusNet Services 2021–26: Attachment 6: Operating expenditure, p. 60.

These refinements reduce the REFCL step change by $1.3 million ($2021) from the amount accepted by the AER's Draft Decision, as set out in the table below.

Table 4-7: REFCL step change ($m, real 2021)

	2021-22	2022-23	2023-24	2024-25	2025-26	Total
AER Draft Decision	0.8	1.1	1.3	1.3	1.3	**5.8**
Revised Proposal	1.3	0.5	1.2	0.8	0.8	**4.5**

Source: AusNet Services, Attachment REFCL Revised Proposal costings.

The forecasts reflect the following assumptions:

- ESV will grant an exemption to test one feeder per bus at each site in the second year after initial compliance testing. There will still be a requirement to test all feeders the first year after initial compliance testing and each feeder must be tested at least once every 5 years.
- The reduction in annual testing obligations will result in 33 feeders to be tested annually by 2024-25 out of a total 121 feeders across the 22 REFCL-protected networks.

Further information is provided in the following supporting attachment: REFCL Revised Proposal costings.

4.6.3.2 5-minute and global settlement

We accept the AER's Draft Decision relating to 5-minute and global settlement.

4.6.3.3 Cyber security

We accept the AER's Draft Decision and withdraw this step change. Consequently, we have allocated 100% of the incremental costs required to reach MIL 3 to the transmission network, and have included these costs in an equivalent step change in the 2023-2027 Transmission Revenue Reset proposal. In doing so, we note that since the Draft Decision was published, the Department of Home Affairs has released draft legislation to protect Australia's critical infrastructure to secure Australia's essential services for public consultation.[97]

4.6.3.4 ICT Cloud step change

We do not agree with the AER's Draft Decision relating to the two customer-facing Cloud step changes. These are:

- **The Customer Information Management (CIM) program**: this functionality will improve the interactions between AusNet Services, our customers, and external stakeholders, which is achieved by enabling us to visualise our customer's behaviour from their energy usage. It also allows us to remain compliant with increasingly sophisticated regulatory rule changes enhancing our current ability to collect, store and present customer information.
- **The Outage Management (OM) program**: this capability will minimise the impact of planned outages on customers, by using advanced analytics and automation across the workflow to improve process efficiency for the network's planned works.

[97] Security Legislation Amendment (Critical Infrastructure) Bill 2020.

We consider this step change is reasonable and consistent with the opex objectives, and have provided additional information to demonstrate this, as invited by the AER. This analysis of the new option and the capex-opex trade off can be found Appendix 4C Addendum - ICT cloud capex opex trade off.

Revisiting the original Customer Forum agreement is also important background for reaching a final decision on this step change. The basis for this step change agreed with the Customer Forum as part of the New Reg process involved two opposing but carefully balanced parts:

- The Customer Forum considered customers were willing to pay the additional cost for us to move towards Cloud-based software rather than traditional capex solutions for IT equipment and services. This support was important as the regime has difficulty appropriately valuing customer experience improvements as demonstrated by the AER's Draft Decision.
- However, as a condition for securing Customer Forum support for this step change and the broader opex proposal, we committed to absorb all other opex costs associated with the transition to Cloud, specifically related to Corporate Enablement, Corporate Communications, Information Management and Workforce Collaboration. This significant concession was highlighted by the fact that similar step changes have been approved for other Victorian DNSPs.[98]

We consider it is an important principle of the New Reg process that where an agreement with the Customer Forum has involved a trade-off where some costs have decreased but others have been increased, that both the cost reductions and increases should be supported. We note that overall ICT expenditure has reduced from the previous period, with capex spend decreasing 12%.

Secondly, addressing the detail of the AER's concerns regarding the CIM and Outage Management step change, we have added a fourth, alternative option with robust cost-benefit analysis as an addendum to our existing project briefs,[99] which explore the in-house capex-driven solutions used to establish CIM and OM capabilities. As demonstrated in both instances of CIM and Outage Management, our original recommended options are the most prudent for customers as the opex required to implement the solution is less than the corresponding capex-driven solutions. In this way, the AER's required capex/opex trade off is established.

Ultimately, our proposed cloud-based options provide the most prudent and efficient approach for customers. As shown in the table below, our recommended option provides additional benefits of almost $33 million as compared to the proposed capex solutions.

98 See AER, Draft Decision: Powercor Distribution Determination 2021 to 2026: Attachment 6 Operating expenditure (September 2020), p. 56.

99 See ASD - Program Brief - Outage Management - 191119 – PUBLIC and ASD - Program Brief Customer Information Services - 140120 – PUBLIC.

Table 4-8: Comparison of ICT cloud step change NPV of recommended opex solution compared to the new capex solution ($m, real $2021)

	Category	CIM	OM
Opex Step Change Option 2 – *recommended solution*	**NPV**	**$7.61**	**$0.15**
	Costs	$5.48	$11.87
	Benefits	$12.72	$13.95
New Capex Option 4 – *avoided cost solution*	**NPV**	**-$25.14**	**$0.13**
	Costs	$41.44	$11.92
	Benefits	$13.25	$13.95
Incremental Benefit (Option 2 minus Option 4)		**$32.75**	**$0.01**

Note: costs include capex and opex

Source: Attachment Cloud addendum model

We consider that this establishes the requisite capex-opex trade off, and accordingly that the AER should now accept this step change. The step change costs of our recommended option are provided in the table below, which are unchanged from our Initial Proposal.

Table 4-9: ICT cloud step change ($m, real $2021)

	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Revised Proposal	0.5	0.5	0.5	0.5	0.5	**2.6**

Note: numbers may not reconcile due to rounding

Source: AusNet Services

If the information provided in this Revised Proposal does not satisfy the AER that the opex for the CIM and Outage Management Cloud costs qualifies as a step change then we consider the remaining four components should be assessed as step changes by the AER, which would result in a step change of $3.7 million. Information on these four components can be found in the relevant project briefs which were also submitted under our 2023-2027 Transmission Revenue Reset.[100]

4.6.3.5 Bushfire insurance step change

Since we submitted our Initial Proposal we have identified the need for an additional step change relating to the increased premiums for our bushfire insurance.

We operate an extensive overhead network of assets covering large areas of rural and heavily vegetated land, which carry a high level of bushfire risk. As a result, we are exposed to significant bushfire liability risks and must, therefore, ensure we have adequate insurance coverage. Otherwise the full costs arising from bushfire-related events will be borne by customers.

To determine an appropriate level of coverage we obtain independent assessments of our Maximum Foreseeable Loss (MFL). To ensure we have an efficient and diverse level of cover, we seek annual insurance cover for our MFL from a worldwide pool of approximately 50 insurers.

There are significant changes taking place in the insurance market, at both domestic and international levels, which are reducing the number of insurers who can offer cover on terms and

[100] See attachments ICT Program Brief Corporate Telecommunications, ICT Program Brief Information Management, ICT Program Brief Workforce Collaboration and ICT Program Brief Corporate Enablement.

conditions that a prudent network service provider would accept. A number of insurers are increasing their premiums, reducing the scope of the policy's coverage, or exiting the market altogether as the number and severity of bushfire-related events increases the number of claims. One of the key impacts of these changes is that the annual cost of our bushfire liability insurance premiums are increasing markedly year-on-year. See box 4.1 (below) for further information.

While 2019 saw significant increases in insurance costs, total coverage fell, meaning the overall net increases of 25% relative to the 2018 base year (where insurance was $9.5 million).

However, insurance premiums for a similar level of coverage increased in 2020 by 80% relative to the 2018 base year, which would have increased insurance costs by over $36 million in the new regulatory period (at $7.3 million per annum). We did not consider this increase was prudent or efficient and instead chose to raise our deductible from $10 million to $25 million. As a result, this has cut in half the increase in premiums ultimately paid for by customers. However, this also means that the expenditure that we, and ultimately customers, will have to pay when an insurable bushfire-related event occurs will be higher.

Box 4.1: Longer bushfire seasons are increasing risks and pushing up premiums

In Australia and overseas, climate change is causing longer fire seasons with increased bushfire risk and the areas at risk are expanding. In addition, population and property assets are growing in the highest risk areas as they are also generally aesthetically pleasing locations to live.

Fires are burning with higher intensity and over wider areas worldwide:

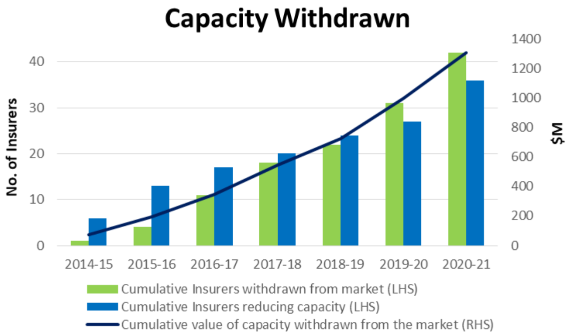
- Victoria – 2009 (AUD$4.4 billion), 2014 (AUD$10 million) and 2017
- California – 2017 (US$20 billion), 2018 (US$24 billion), 2019 and 2020
- Canada – 2017 (largest wild fire ever recorded)
- Spain – 2017 and Greece – 2018

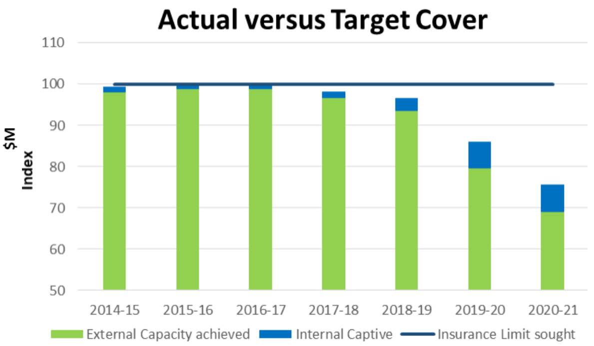
Insurance underwriters are constantly reassessing this risk after each event and are reacting by:

i. Increasing premiums (one underwriter required a $360 million premium for just $800 million of cover in 2018);

ii. Reducing capacity; or

iii. Withdrawing cover from the market (as indicated by the chart below).





Networks have seen significant premium rises over the last decade and have seen a significant amount of capacity withdrawn from the international insurance market.

Consistent with JEN's bushfire insurance premium step change, which the AER assessed favourably,[101] our insurance premium increases have occurred after 2018 and are therefore not reflected in our base, nor are these material increases correlated in any way with the lower rate of change or reasonably likely to be offset by cost reductions on other categories.

101 AER, Draft Decision, Jemena 2021–26: Attachment 3: Rate of return, pp. 60-61.

As a result, we are proposing an opex step change as shown in the table below, which is based on our historic invoices.[102]

Table 4-10: New step change ($m, real 2021)

	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Revised Proposal	2.1	2.1	2.1	2.1	2.1	**10.5**

Source: AusNet Services

We note that our step change assumes that insurance premiums will not rise beyond the 2020 rate rise. This means that if premiums do increase beyond this level, we will absorb any expenditure that does not meet pass through criteria.[103] Using the year-on-year changes in JEN's bushfire insurance premium step change reveals these increases could be significant, resulting in a step change of over $20 million ($2021).[104]

An important corollary to the actions we have taken to limit the immediate cost customers will pay for insurance is an implicit agreement that customers will meet our higher deductible when a pass-through event occurs. This risk trade-off has been tested with customer representatives, stakeholders and Customer Forum members. While they have been careful to emphasise that they do not have technical expertise in this topic and will rely in the AER review, feedback has been clearly supportive of arrangement where customers pay less now with the understanding they may pay more in future. Therefore, all aspects of our proposed sharing of cost and risk should be documented in the Final Decision.

4.6.3.6 2019-20 Summer Bushfires cost pass through avoided costs

Our distribution network incurred significant damage as a result of wide-ranging bushfires that occurred during the 2019-2020 summer fire season. In total 1,000km of powerlines were affected by the fires and 7,000 customers were off supply, both directly because of damage to assets and indirectly as a result of burning trees and other debris falling across power lines. In response to this incident, we applied for and were granted approval from the AER to pass through the additional costs incurred, and expected to be incurred, in the current regulatory period as a result of these bushfires.[105]

However, as a result of the bushfires, some opex for ongoing bushfire-related maintenance activities scheduled over the next eight years was brought forward or superseded because of the remediation activities required in response to the 2020 bushfires. These works included vegetation management and asset inspection activities (and associated repair work).

As discussed in our recently accepted 2020 Summer Bushfires cost pass through application,[106] we have deducted this opex, which will no longer be required, as a negative step change as shown in the table below.

102 See the Operating Expenditure Model for the forecast and Attachment Historic bushfire insurance premium transaction list.

103 As detailed in Chapter 10, we are proposing an 'insurance premium event' cost pass through.

104 AER, Draft Decision, Jemena distribution determination - 2021–26, Opex model, September 2020.

105 See AusNet Services, Cost pass through application – 2020 Summer Bushfires (27 May 2020), p. 1.

106 Ibid., section 5.4.

Table 4-11: Negative summer bushfires step change ($m, real 2021)

	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Revised Proposal	-0.1	-0.1	-0.1	-0.1	-0.9	**-0.5**

Source: AusNet Services

4.7 Category specific forecasts

4.7.1 Our Initial Proposal

We forecast several categories of costs using a category specific forecast, consistent with the approach taken in the 2016-2020 regulatory period. These include:

- GSL payments ($46.0 million ($2021));
- Debt raising costs ($11.8 million ($2021)); and
- Innovation expenditure ($1.2 million ($2021)).

4.7.2 Draft Decision

4.7.2.1 Guaranteed Service Levels

The AER accepted $46 million ($2021) in GSL payments, $0.7 million ($2021) less than we proposed on account of the AER using a slightly different timespan to determine the annual average payment.[107]

However, the AER noted it would update the GSL payment forecasts in the final decision to take into account any changes to the GSL scheme resulting from the ongoing EDC review being conducted by the ESC.

4.7.2.2 Debt raising costs

The AER accepted $11.3 million ($2021) in debt raising costs, which was $0.5 million ($2021) less than we proposed in the Initial Proposal (resulting from changes to the size of the RAB). The Draft Decision accepted our proposed approach, which used an annual rate of 8.16 bppa.[108]

4.7.2.3 Innovation expenditure

The AER accepted our proposed $1.2 million ($2021) innovation expenditure, on the basis that it was supported by customers, mainly through the Customer Forum process but also through our other customer research activities and the CCP17.[109] The AER accepted this as a category specific forecast on the basis that it should not become recurrent expenditure.

[107] We calculated GSL payments using the annual average covering 2014 to 2018 while the AER used the timespan of 2015 to 2019 in their Draft Decision (AER, Draft Decision, AusNet Services 2021–26: Attachment 6: Operating expenditure, p. 60).

[108] AER, Draft Decision, AusNet Services 2021–26: Attachment 3: Rate of return, p. 11.

[109] AER, Draft Decision, AusNet Services 2021–26: Attachment 6: Operating expenditure, p. 63.

4.7.3 Revised Proposal

4.7.3.1 GSLs

The ESC's final decision proposed slightly higher payment rates, slightly lower payment thresholds, and the introduction of Major Event Day (MED) exclusions.[110] To understand the net impact of these changes, we have re-cast our historical data from 2015 to 2019 for the final scheme. Our modelling estimated that if the final scheme had applied during the 2015 to 2019 period, our average GSL payment would have been $6.4 million per year (nominal).

Consistent with the AER's previous approach, and its Draft Decision, we propose to adopt the updated historical average as our forecast for the upcoming regulatory period. This gives rise to the forecast GSL allowance set out in the table below, which shows that our total forecast GSL of $29.8 million ($2021) is 36% less than our Initial Proposal.

Table 4-12: Forecast GSL allowance (excluding transitional arrangements) ($m)

	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Nominal	6.4	6.4	6.4	6.4	6.4	**31.9**
2020-21 dollars	6.2	6.1	6.0	5.8	5.7	**29.8**

Source: AusNet Services

In addition, we have proposed a transitional amount to close out the current scheme. We have calculated our transitional amount based on the difference between:

- Our actual GSL payments (that is the current scheme with the current exclusion threshold); and
- The current scheme with the ESC's exclusion threshold (MED exclusions that are aligned to a 2.5 standard deviation beta threshold) adjusted for MED payments.

The major difference between the current and final scheme is the introduction of MED exclusions. Under the current scheme, the exclusion threshold is set very high thus making it unlikely that an event would be excluded from the DNSP's obligation to make a GSL payment to affected customers. In contrast, the final scheme will introduce MED exclusions that are aligned to a 2.5 standard deviation beta threshold, which is a much lower threshold. As a result, some historical events where we have made significant GSL payments have become excluded under the final scheme and therefore excluded in our GSL allowance cost build up for the 2022-26 regulatory period.

For example, if a major storm occurs in 2016, increasing our GSL payments by $10 million, then the way in which we would normally recover this amount (assuming the current scheme continues) is through a future GSL opex allowance of +$2 million per year over 5 years. By removing this particular event from our forecast cost build up, we are left to self-fund the costs for an event that is out of our control.

The first step in determining the forecast transitional amount, is to create a model that calculates the difference between the current scheme (with the current exclusion threshold) and the current scheme with MED exclusion threshold, adjusted for the $90 MED payments. Under the ESC's final scheme, we are required to make a GSL payment of $90 to customers who have experienced an outage greater than 12 hours on MEDs. As this has been factored into our GSL allowance, we have netted of the impact here. The table below presents the results of our step 1 modelling, where the amounts represent the nominal average over the 2015 to 2019 period.

[110] ESC 2020, Electricity Distribution Code review – customer service standards, Draft Decision, 7 May.

Table 4-13: GSL modelling – step 1 ($, nominal)

Old GSL Scheme - No MED exclusions

Parameter	Threshold	Rate	Customers (5yr Avg)	Amount
Cumulative Duration (Hrs)	20	$ 120	15,343.4	$1,841,208
	30	$ 180	10,912.6	$1,964,268
	60	$ 360	4,243.8	$1,527,768
Sustained Interruptions	8	$ 120	17,943.8	$2,153,256
	12	$ 180	4,727.0	$850,860
	24	$ 360	508.0	$182,880
Momentary Interruptions	24	$ 30	10,836.2	$325,086
	36	$ 40	3,792.2	$151,688
Duration Event	12	$ 80		
	18	$ 80		
				$8,997,014

Old GSL Scheme - excluding 2.5β MEDs

Parameter	Threshold	Rate	Customers (5yr Avg)	Amount
Cumulative Duration (Hrs)	20	$ 120	8,434.0	$1,012,080
	30	$ 180	4,151.8	$747,324
	60	$ 360	516.0	$185,760
Sustained Interruptions	8	$ 120	11,700.0	$1,404,000
	12	$ 180	2,849.0	$512,820
	24	$ 360	96.2	$34,632
Momentary Interruptions	24	$ 30	8,730.4	$261,912
	36	$ 40	2,759.0	$110,360
Duration Event	12	$ 80		
	18	$ 80		
			Less 2.5β MEDs :	**$4,268,888**
			Plus 2.5β MED for NMIs >12Hrs @$90 per NMI:	**$2,028,960**
			TOTAL :	**$6,297,848**
			Difference :	**$2,699,166**

Source: AusNet Services, Attachment GSL forecast 2020

The results from step 1 modelling shows:

- Under the current scheme and current exclusion threshold, our historical average over the 2015 to 2019 period is $9.0 million per year (nominal).
- If the MED exclusion threshold had applied from 2015 to 2019, then our average pay-out would have been $4.3 million per year (nominal).
- If the MED exclusion threshold and $90 MED payment had applied from 2015 to 2019, then our average pay-out would have been $6.3 million per year (nominal).
- The average difference between the two scenarios is $2.7 million per year (nominal).

The next step is to escalate the step 1 modelling result, to convert the $2.7 million into 2020-21 dollars. We have applied the nominal vanilla WACC to account for the time value of money.[111] Based on these assumptions, we have determined that the transitional amount needed to close out the current scheme is $3.2 million per year, or $16.1 million over 5 years. See the table below for further information.

Table 4-14: Forecast of GSL transitional amounts ($m, 2020-21)

	2021-22	2022-23	2023-24	2024-25	2025-26	Total
GSL transitional amount	3.2	3.2	3.2	3.2	3.2	**16.1**

Source: AusNet Services

4.7.3.1.1 Additional information on the GSL allowance and GSL transitional amounts

We have calculated our GSL allowance by taking our 2015 to 2019 historical data, and recasting it for the ESC's final scheme, which included modelling the following features of the ESC's final scheme:

- Lower duration and frequency thresholds;
- Higher duration and frequency payment rates;
- The exclusion of MED events from contributing to the duration and frequency thresholds; and

111 We have applied the nominal vanilla WACC for the years from 2015 to 2020. For 2021, we applied the lagged actual CPI inflation rate.

- The introduction of $90 MED payments.

Our GSL allowance modelling considered all aspects of the ESC's final scheme, which has resulted in our Revised Proposal GSL allowance ($29.8 million) being materially lower than our Initial Proposal allowance ($46.7 million). Our GSL allowance for the 2022-26 regulatory period excludes MED events, which means it simply compensates us for our expected GSL payments over the 2022-26 regulatory period excluding MED events.

Over the 2015 to 2019 period, we made significant GSL payments for events that are outside of our control and which are now excluded in the modelling of our GSL allowance for the 2022-26 period. As such, we have sought a transitional amount to close out the current scheme. The modelling of the transitional amount does not consider all aspects of the ESC's final scheme because if we did, it would be double counting, and simply produce the same result as our GSL allowance of $29.8 million.

Instead, the transitional amount reflects the difference between the two scenarios below, because as noted earlier, the major difference between the current and final scheme is the introduction of MED exclusions.

Scenarios:

- Our actual GSL payments (that is the current scheme with the current exclusion threshold); and
- The current scheme with the ESC's exclusion threshold (MED exclusions that are aligned to a 2.5 standard deviation beta threshold) adjusted for MED payments.

Our historical actuals from 2010-14 was the basis of our allowance for 2016-20 regulatory period.[112] If there were no unusual events in both of these periods, then using the historical actuals from 2010-14 would produce a good forecast for 2016-20 regulatory period that compensates us for our performance. However, there have been 2 particularly large and unusual events during the current regulatory period that could not be forecast and therefore caused us to significantly overspend our allowance. The October 2016 storm was particularly devasting, where the GSL payments attributable to 9 October 2016 alone, was $7.5 million. To put this into perspective, it represented 43% of our overall GSL payments in 2016 ($17.6 million), which were $9.2 million over our allowance of $8.4 million.[113,114] The other significant event was the December 2019 bushfire that triggered $2.4 million in GSL payments.

As similarly large events did not occur over the 2010-14 period that was the basis of our allowance for the 2016-20 regulatory period, we are strongly of the view that we should not have to bear the full costs of these events.

We note that in incentive schemes such as the EBSS and CESS, the costs and benefits of underspends and overspends varies from year to year and are shared between a DNSP and its customers. These schemes operate on the premise that the underlaying parameters are within a DNSP's control, therefore the financial rewards or penalties are warranted. However, the GSL scheme is different in many important ways because:

- The aim is to recognise that some customers have been inconvenienced by outages throughout the year.[115] That is, customers are the sole beneficiaries of GSL expenditure as the GSL payments are made to customers.

112 AER 2016, AusNet Services distribution determination 2016 to 2020, Attachment 7 – operating expenditure, Final Decision, May, p. 7-92.

113 AER 2016, AusNet Services distribution determination 2016 to 2020, Attachment 7 – operating expenditure, Final Decision, May, p. 7-92.

114 The AER included $41.5 million in its final decision opex forecast. This equates to $8.3 million per year in 2014-15 dollars, or $8.4 million in 2015-16 dollars.

115 ESC 2020, Electricity distribution code review – customer service standards, Final Decision, 16 November, p. 62.

- It is a redistribution scheme because it simply transfers payments from all of our customers to a select group of impacted customers. There is no sharing of any benefits/ costs with the DNSP foreseen intended in the scheme's design.
- It is not an incentive scheme because it is not designed to incentivise investment in the network.[116] While our historical GSL actuals and our forecast allowance for the 2022-26 regulatory period is by no means small; it is relatively insignificant when it is placed in the context of the opex and capex that would be required to actively reduce our GSL payments.
- Events that trigger large GSL payments to customers, such as the 2016 storm, are not within our control, therefore the financial penalty that comes with it should not be borne by us. The BOM's monthly report for October 2016 stated:
    - Victoria's strongest recorded wind gusts for October were 137 km/h at Wilsons Promontory Lighthouse on the 4th and at Mount Buller on the 9th
    - Damaging winds associated with the passage of a cold front on the 9th resulted in downed trees, damaged homes and a loss of electricity in parts of the State.[117]

For the reasons above, the GSL scheme should not and does not operate like incentive schemes where there is an intent to share the costs and benefits of un-forecast events between a DNSP and its customers.

4.7.3.2 Debt raising costs

We accept the AER's Draft Decision regarding debt raising costs.

4.7.3.3 Innovation expenditure

We accept the AER's Draft Decision regarding innovation expenditure.

4.8 Total opex forecast

Our revised total opex forecast is $1,193 million excluding debt raising ($2021) or $1,204 million including debt raising costs ($2021) for the next regulatory period.

Table 4-15: Forecast operating expenditure ($m, real $2021)

	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Base opex	217.4	217.4	217.4	217.4	217.4	**1,087.0**
Real price change	1.0	1.7	2.5	3.8	5.5	**14.4**
Output growth	1.1	2.9	5.2	7.5	9.7	**26.3**
Productivity change	-0.8	-1.9	-3.0	-4.1	-5.2	**-15.0**
Step changes	6.8	6.8	6.5	6.3	6.5	**32.9**

116 ESC 2020, Electricity distribution code review – customer service standards, Final Decision, 16 November, p. 62.

117 http://www.bom.gov.au/climate/current/month/vic/archive/201610.summary.shtml (accessed 2 December 2020).

	2021-22	2022-23	2023-24	2024-25	2025-26	Total
GSL payments	9.5	9.3	9.2	9.0	8.9	**45.9**
Innovation expenditure	0.2	0.2	0.2	0.2	0.2	**1.2**
Total excluding debt raising	**235.1**	**236.4**	**238.0**	**240.2**	**243.0**	**1192.7**
Debt raising	2.2	2.2	2.3	2.3	2.3	**11.3**
Total	**237.4**	**238.6**	**240.3**	**242.4**	**245.4**	**1,204.1**

Note: numbers may not reconcile due to rounding

Source: AusNet Services

4.9 Benchmarking efficient opex

As noted in section 4.4.2, the AER provided commentary on our benchmarking performance. This section provides some comments to in response to the AER's observations.

4.9.1 Draft Decision

The AER provided detailed analysis on our benchmarking efficiency performance and found:

- we perform relatively efficiently compared to our peers; and
- our 2018 base year opex is not materially inefficient.

The AER noted that our opex has been decreasing slightly since 2016 and our transformation initiatives had delivered opex efficiency savings. It concluded that we have responded to the incentives provided by the regulatory regime.[118]

The AER also noted that over the period 2006-2018, we had been relatively efficient relative to other businesses in the NEM. Using a range of economic benchmarking models measuring opex efficiency, we ranked six out of 13 DNSPs. Over a shorter time frame (2012-2018), our performance relative to our peers decreased slightly such that we ranked seven out of 13 DNSPs.[119]

Similarly, when conducting opex multilateral partial factor productivity (MPFP) analysis, the AER found that our performance over 2012-2018 decreased slightly compared to 2006-2018 performance although our performance has improved substantially since 2016. The AER noted that our Partial Performance Indicators are favourable as compared to other DNSPs with similar customer density levels, and similar or slightly worse off when considering circuit length and suggest that we have similar levels of efficiency to our peers.[120]

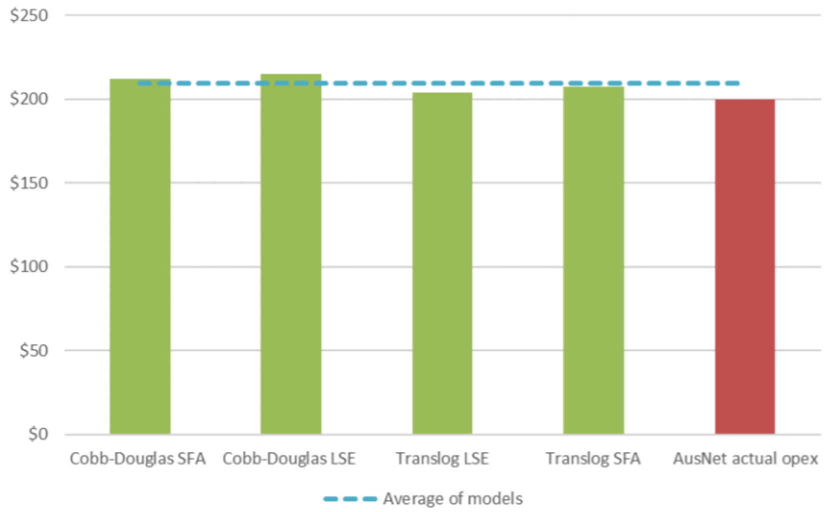
118 AER, Draft Decision, AusNet Services 2021–26: Attachment 6: Operating expenditure, p. 24.

119 AER, Draft Decision, AusNet Services 2021–26: Attachment 6: Operating expenditure, Box 6.1.

120 AER, Draft Decision, AusNet Services 2021–26: Attachment 6: Operating expenditure, pp. 27-29.

The AER undertook further analysis by estimating our efficient base year opex using four econometric models.[121] As shown in the figure below, our 2018 actual opex outperformed against each model's efficiency estimate, which further supports the efficiency of our base year.

Figure 4-2: Estimates of AusNet Services' efficient opex between 2006–18 ($m, real $2021)



Source: AER, Draft Decision, AusNet Services 2021–26: Attachment 6: Operating expenditure, figure 6.8

As part of its benchmarking analysis, the AER also considered differences in DNSPs' operating environments through OEFs. Through analysis of the OEFs, the AER noted that we have a net cost compared to benchmark businesses. It noted that the vegetation management (bushfire) OEF is the only one applied to our Draft Decision in a material way, with a positive adjustment of 5.7% over 2012-2018.[122]

The AER also considered whether capitalisation policies influenced benchmarking results to the extent that they could be a material OEF. This is an issue we and other Victorian businesses raised. The AER considered that capitalisation policies should not only consider the capitalisation of overheads – as we had suggested – but should extend more widely to opex/capex trade-off. However, the AER did not include an OEF adjustment for us for capitalisation practices, considering that it did not materially influence our benchmarking results.

4.9.2 Revised Proposal

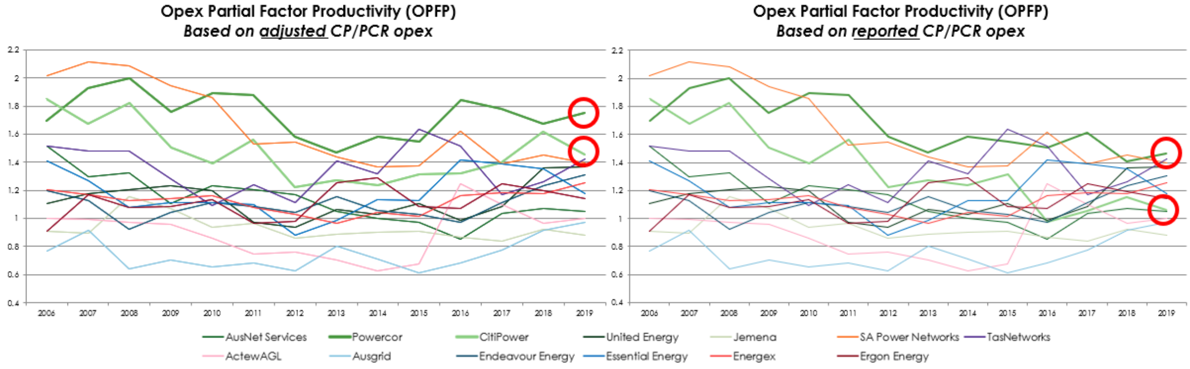
Regarding capitalisation policies, while we welcome the AER's measures to investigate differences in cost allocation and capitalisation approaches, the analysis does not address how different DNSP capitalisation approaches materially impact the AER's opex benchmarking results and yet do not contribute to productivity.

For example, the below charts show Opex Partial Factor Productivity (OPFP) performance of all DNSPs as per the AER's benchmarking report, where Powercor and CitiPower's opex has been adjusted to align with original but no longer used capitalisation policies, and the benchmarking results using DNSPs' actual opex as reported in the RINs (and which are the cost customers actually pay). As can be seen below, the benchmarking results change significantly depending on which capitalisation approach is used, with Powercor's performance decreasing and CitiPower dropping in ranking from second to ninth position and the overall industry productivity converging as expected under a benchmark regime.

121 AER, Draft Decision, AusNet Services 2021–26: Attachment 6: Operating expenditure, pp. 27-29.

122 AER, Draft Decision, AusNet Services 2021–26: Attachment 6: Operating expenditure, pp. 34-35.

Figure 4-3: Differences in benchmarking results with and without changes to capitalisation policies



Source: Draft 2020 benchmarking results for Distribution Network Service Providers, Regulatory Information Notices

We therefore continue to advocate strongly in favour of the AER developing a uniform approach to assessing networks' capitalisation policies.

4.10 Supporting documents

Additional documents provided as part of our Revised Proposal to support our opex forecast include:

- ASD – EDPR 2022-26 Revised Proposal – Opex Model (2022-26) – 031220 – PUBLIC;
- Cloud addendum model;
- ICT Program Brief Corporate Enablement;
- ICT Program Brief Corporate Telecommunications;
- ICT Program Brief Information Management;
- ICT Program Brief Workforce Collaboration;
- Labour price escalation calculation;
- GSL forecast 2020;
- Historic bushfire insurance premium transaction list;
- Addendum - ICT cloud capex opex trade off;
- AusNet Insurance policy consolidated FY2021;
- Labour Cost Escalation Forecasts to 2022-26; and
- Addendum Note on changes to AER treatment of Inflation.
- Revised Proposal Bushfire Passthrough

5 Regulated Asset Base

5.1 Key points

- We largely accept the AER's Draft Decision on the 1 July 2021 opening RAB, including the AER's amendments to our proposed end of period adjustments.
- We have updated our placeholder forecasts for 2020 and the half year period (from January to June 2021), to reflect known material changes in the delivery of our capex programs (some of which relate to the COVID-19 pandemic). The updated information results in an opening RAB which is approximately 1.2% lower than the AER's Draft Decision.
- We have adjusted the Draft Decision CPI escalation in the capex model. This affects the conversion of real $2018 capex inputs into $Jun 2021 which has flow on effects for our revised capex forecast presented in the PTRM.
- In relation to the closing RAB, our Revised Proposal together with the updated forecast data results in a closing RAB value of $5,433.6 million (nominal), which is $24.6 million (nominal) or 0.5% lower than the Draft Decision.

5.2 Chapter structure

The remainder of this chapter is structured as follows:

- Section 5.3 contains the introduction;
- Section 5.4 provides information on our Revised Proposal in relation to the opening RAB;
- Section 5.5 discusses our actual and forecast net capex;
- Section 5.6 concerns regulatory depreciation;
- Section 5.7 sets out our final year adjustments;
- Section 5.8 discusses other modelling inputs;
- Section 5.9 provides information on our revised forecast closing RAB, as at 30 June 2026; and
- Section 5.10 sets out the supporting documents for this chapter.

In the event of inconsistency between information contained in this chapter and our Initial Proposal, the information contained in this chapter prevails.

5.3 Introduction

The AER's Draft Decision determined an opening RAB value for our electricity distribution SCS of $4,709.8 million (nominal) as at 1 July 2021, representing a reduction of $5.3 million (or 0.1%) from the opening RAB value of $4,715.1 million (nominal) contained in our Initial Proposal.

The Draft Decision reflects the AER's consideration of our proposed end of period adjustments, including accelerated depreciation of selected SCADA/Network control assets and decommissioned network assets associated with our REFCL contingent projects. The AER also engaged with us on our adoption of the accounting standard for leases (introduced in 2019) pursuant to which we proposed to capitalise our existing property leases starting from 1 April 2019.[123]

[123] As set out in our Initial Proposal – refer to 'ASD - Appendix 9E Lease Accounting Treatment - 310120 – PUBLIC.pdf', 31 January 2020.

In this Revised Proposal, we now propose an opening RAB value of $4,656.5 million (nominal) as at 1 July 2021, which is:

- $53.3 million (or 1.1%) lower than the AER's Draft Decision; and
- $58.6 million (1.2%) lower than our Initial Proposal of $4,715.1 million (nominal).

Our proposed opening RAB has been calculated in accordance with the NER and the AER's Roll Forward Model (RFM) and PTRM (version 4).

In preparing our revised opening RAB, we accept the AER's Draft Decision in respect of the following final year adjustments[124], including:

- Accelerated depreciation of selected SCADA/Network control assets, including the re-allocation of $196.6 million to the proposed asset class 'Secondary systems (pre 2016)' from existing long-life asset classes;
- Accelerated depreciation of decommissioned network assets associated with our REFCL implementation program, including re-allocation of $3.9 million to the accelerated depreciation asset classes from the 'Distribution system assets' class; and
- The AER's decision to roll in capitalised property leases as at 1 July 2021 (of $34.8 million in total, including forgone return on capital adjustments) and associated amendments in the depreciation tracking model.

We also accept other amendments made by the AER to RFM inputs, including:

- Updating 2018 and 2019 net capex based on available annual RIN information, resulting in nominal net capex changes of -$0.05 million and -$53.5 million respectively;
- Removal of the 'Non-network - Metering related IT' asset class and re-allocation of capex costs associated with these IT assets to the existing 'Non-network general asset - IT' asset class;
- Various amendments in relation to forecast inputs for the half year period; and
- Other minor amendments to forecast straight-line depreciation inputs for the 2016-20 regulatory period.

However, we do not accept the AER's amendments in the Draft Decision capex model in relation to CPI escalation.

5.4 Opening RAB

5.4.1 Our Initial Proposal

We proposed an opening RAB for 1 July 2021 of $4,715 million (nominal). However, we noted at the time that this would be updated in our Revised Proposal to reflect actual data for 2019.[125]

We proposed several opening RAB adjustments that included re-allocations of estimated opening RAB value between existing asset classes and proposed accelerated depreciation asset classes. We discuss these final year RAB adjustments in further detail in section 5.7 below.

[124] AER, Draft Decision, AusNet Services distribution determination 2021-26, Attachment 2 - Regulatory asset base, September 2020, pp. 15-17.

[125] For further information refer to Chapter 12 of our Initial Proposal – 'ASD - EDPR 2022-26 Regulatory Proposal Part III - 310120 – PUBLIC.pdf, p. 185.

5.4.2 Draft Decision

The AER determined an opening RAB of $4,709.8 million (nominal) as at 1 July 2021, which is $5.3 million (or 0.1%) lower than our proposed opening RAB.

While the AER largely accepted our proposed methodology for calculating the opening RAB it made several revisions to our proposed inputs to the roll forward model (RFM), including:

- Updating 2018 and 2019 net capex inputs using the latest available annual RIN information, resulting in nominal net capex changes of -$0.05 million and -$53.5 million respectively;
- Minor updates to the forecast straight-line depreciation inputs for 2016-20 in the RFM;
- Updated our placeholder inflation estimate of 1.00% for the half year period with actual inflation of 1.22% (1-year lagged basis).
- Consolidated the two asset classes for equity raising costs into a single asset class and amended the value for the equity raising costs in 2021;
- Various amendments in relation to forecast inputs for the half year period including WACC, inflation and straight-line depreciation;
- Removed the 'Non-network - Metering related IT' asset class that we proposed to capture IT systems upgrade costs, and re-allocated these capex costs to the existing 'Non-network general asset - IT' asset class.

In addition, the AER approved our proposed final year adjustments in principle (with some modifications) including accelerated depreciation of selected network assets in the next reset period.

5.4.3 Response to the AER’s Draft Decision

As explained in more detail in the remainder of this chapter, we accept most of the adjustments required by the AER’s Draft Decision and we have updated our placeholder forecasts for 2020 and the half year period in the RFM.

Our responses to the AER’s Draft Decision in relation to capitalised leases and final year adjustments are covered in section 5.7 below.

We do not accept one of the AER’s amendments in the Draft Decision capex model in relation to CPI escalation. We discuss this further in section 5.8 below.

5.4.4 Revised Proposal

As shown in Table 5-1 below, our revised roll forward calculation for the 1 July 2021 opening RAB is $4,656.5 million (nominal).

Table 5-1: Revised Proposal opening RAB ($ nominal)

Regulatory year	2016	2017	2018	2019	2020	2021 (first 6 months)
Opening RAB (1 January)	3,442.1	3,610.5	3,809.4	4,067.6	4,308.1	4,517.0
Plus capex, net of disposals and contributions	298.7	332.6	367.3	349.0	348.5	200.1
Less nominal forecast straight-line depreciation	-182.3	-170.6	-182.8	-193.0	-208.2	-100.3
Plus nominal actual inflation on opening RAB	52.0	36.9	73.7	84.5	68.6	55.1
Difference between actual and forecast capex for 2015					-38.1	-38.5
Forgone return on difference					-11.6	-11.7
Final year asset adjustments					-	0
Closing RAB (31 December)	**3,610.5**	**3,809.4**	**4,067.6**	**4,308.1**	**4,467.4**	**4,656.5**

Source: AusNet Services Revised Proposal RFM (2016-21)

5.5 Actual and forecast net capex

5.5.1 Our Initial Proposal

At the time of lodging our Initial Proposal in January 2020, we included placeholder forecasts for both 2019 and 2020 net capex and the half year period. The table below presents our Initial Proposal for current period net capex.

Table 5-2: Net capex, 1 January 2016 to 30 June 2021 ($m nominal) – Initial Proposal

Regulatory year	2016	2017	2018	2019	2020	2021 (first 6 months)
Gross capex	315.2	358.6	412.4	459.2	470.7	222.9
Less disposals	-3.6	-0.4	-0.5	-1.3	-1.3	- 0.7
Less customer contributions	-20.7	-33.5	-54.8	-65.3	-67.9	-35.8
Nominal net capex	290.9	324.7	357.1	392.6	401.4	186.4

Regulatory year	2016	2017	2018	2019	2020	2021 (first 6 months)
Net capex recognised in RAB[126]	**298.7**	**332.6**	**367.4**	**404.0**	**411.9**	**188.5**

Source: AusNet Services Initial Proposal RFM (2016-21)

5.5.2 Draft Decision

In making its Draft Decision, the AER updated 2018 and 2019 net capex inputs using the latest available annual RIN information. However, the AER did not include our reported 2019 capitalised leases of $31.7 million (nominal) as contained in the audited annual financial RIN. We discuss this omission further in section 5.7 below.

The AER made three further changes in the RFM gross capex inputs:

- Rejected and removed our forecast nominal capitalised lease costs for 2020 and the half year period, of $0.3 million and $0.2 million (nominal) respectively;
- Removed the 'Non-network - Metering related IT' asset class and re-allocated capex costs associated with these IT assets to the existing 'Non-network general asset - IT' asset class (which we have already accepted[127]); and
- Consolidated the two asset classes for equity raising costs into a single asset class and amended the value for the equity raising costs in 2021 (Half Year input).

The AER did not make any further updates to our placeholder forecasts for 2020 and the half year period, although it stated that it expects to make updates in the Final Decision (subject to available information).[128]

Table 5-3: Net capex, 1 January 2016 to 30 June 2021 ($m nominal) – Draft Decision

Regulatory year	2016	2017	2018	2019	2020	2021 (first 6 months)
Gross capex	315.2	358.6	412.4	432.2	470.4	222.9
Less disposals	-3.6	-0.4	-0.5	-13.5	-1.3	- 0.7
Less customer contributions	-20.7	-33.5	-54.8	-79.6	-67.9	-35.8
Nominal net capex	290.9	324.7	357.1	339.1	401.1	186.4
Net capex recognised in RAB[129]	**298.7**	**332.6**	**367.3**	**349.0**	**411.6**	**188.7**

Source: AER - Draft Decision - AusNet Services distribution determination - 2021-26 - RFM - September 2020

126 Net capex recognised in RAB includes a half-nominal WACC allowance.

127 Responses to AER information requests IR#028 (25 June 2020) and IR#031 (12 June 2020).

128 AER, Draft Decision, AusNet Services distribution determination 2021-26, Attachment 2 - Regulatory asset base, September 2020, p. 6.

129 Net capex recognised in RAB includes a half-nominal WACC allowance.

5.5.3 Revised Proposal

In preparing our Revised Proposal we have updated our placeholder forecasts for 2020 and the half year period. On a net capex basis and compared with our Initial Proposal:

- Our 2020 forecast has reduced by $61.4 million (nominal); and
- Our half year period forecast has increased by $11.3 million (nominal).

Our 2020 forecast is lower than our Initial Proposal primarily due to:

- The impacts on our capital works programs resulting from significantly reduced planned outages which were designed to minimise inconvenience to customers during COVID-19 lockdown periods. This has affected our planned replacement works including routine asset replacement activities and delays in completing some feeder asset replacements, which form part of our REFCL implementation program; and
- The revised timing of the Kalkallo project which formed part of our REFCL contingent project allowance (tranche 3) in the current regulatory period. We have now fully scoped our preferred solution at Kalkallo and have submitted our revised expenditure forecast as part of this Revised Proposal. The impact on customers is limited to the net cost increase of the Kalkallo solution compared to the allowance approved in the contingent project (+$10.5 million, $Jun-21 real). We are handing back to customers revenues received for Kalkallo (of $0.7 million, $Jun-21 real) and will forgo the CESS payment that would have been received due to deferring this project (of $4.5 million, $Jun-21 real).

Our revised Kalkallo capex forecasts and proposed adjustments for the 2022-26 regulatory period are discussed in chapters 2 and 3 of this Revised Proposal.

We note that our connections capex has not been noticeably impacted by COVID-19 based on our actual year-to-date performance and we therefore expect to meet our original 2020 forecast for connections. Further information on our connections capex proposal for the next regulatory period is contained in Chapter 3.

Our updated half year period (from January to June 2021) capex forecast is higher than our Initial Proposal, primarily because of the IT systems upgrade program required to achieve compliance with the metering requirements for 5-minute market settlement, which is expected to be completed by 2022.

The 5-minute metering project was not included in our 2016-20 regulatory allowances nor did we seek a cost pass through following the Australian Energy Market Commission's (AEMC) final rule change on 28 November 2017. While the capital costs of the program will be recovered through the RAB, we will also bear a CESS penalty on this expenditure.

The table below presents our Revised Proposal for current period net capex.

Table 5-4: Net capex, 1 January 2016 to 30 June 2021 ($m nominal) – Revised Proposed

Regulatory year	2016	2017	2018	2019	2020	2021 (first 6 months)
Gross capex	315.2	358.6	412.4	432.2	409.4	232.0
Less disposals	-3.6	-0.4	-0.5	-13.5	-0.7	-0.7
Less customer contributions	-20.7	-33.5	-54.8	-79.6	-69.1	-33.7
Nominal net capex	290.9	324.7	357.1	339.1	339.7	197.7

Regulatory year	2016	2017	2018	2019	2020	2021 (first 6 months)
Net capex recognised in RAB[130]	**298.7**	**332.6**	**367.3**	**349.0**	**348.5**	**200.1**

Source: AusNet Services Revised Proposal RFM (2016-21)

5.6 Regulatory depreciation

5.6.1 Our Initial Proposal

In our Initial Proposal, we stated that in the current regulatory period we applied depreciation on a forecast basis consistent with the approach required under the CESS. We also highlighted that economic depreciation is calculated by determining the nominal depreciation and offsetting opening RAB indexation for each asset class, consistent with the standard approach.

Our calculation of economic depreciation (nominal straight-line depreciation net of RAB indexation) in our Initial Proposal for the current period is shown below.

Table 5-5: Economic depreciation, 1 January 2016 to 30 June 2021 ($m nominal) – Initial Proposed

Regulatory year	2016	2017	2018	2019	2020	2021 (first 6 months)
Nominal depreciation	182.3	170.6	182.8	193.0	208.2	105.8
RAB indexation	-52.0	-36.9	-73.7	-84.5	-69.5	-46.1
Regulatory depreciation	**130.3**	**133.6**	**109.1**	**108.5**	**138.7**	**59.6**

Source: AusNet Services' Initial Proposal RFM (2016-21)

5.6.2 Draft Decision

The AER's Draft Decision on economic depreciation for the current period reflects updates made by the AER in the RFM, including:

- Updated 2019 net capex (substituting our placeholder forecast with actual as sourced from the annual reporting RIN);
- Updated the half year period inflation forecast with actual;
- Minor updates to the forecast straight-line depreciation inputs for the 2016-20 regulatory period; and
- Amended straight-line depreciation inputs for the half year period (-$6.7 million compared to our Initial Proposal) which uses actual depreciation rather than forecast depreciation.[131]

The AER's calculation of economic depreciation is shown in the table below.

[130] Net Capex recognised in RAB includes a half-nominal WACC allowance.

[131] In line with AER correspondence on the Vic transition for DNSPs for the various reset models (September 2019).

Table 5-6: Economic Depreciation, 1 January 2016 to 30 June 2021 ($m nominal) – Draft Decision

Regulatory year	2016	2017	2018	2019	2020	2021 (first 6 months)
Nominal depreciation	182.3	170.6	182.8	193.0	208.2	99.3
RAB indexation	-52.0	-36.9	-73.7	-84.5	-68.6	-55.9
Regulatory depreciation	**130.3**	**133.6**	**109.1**	**108.5**	**139.5**	**43.5**

Source: AER - Draft Decision - AusNet Services distribution determination - 2021-26 - RFM - September 2020

5.6.3 Revised Proposal

We accept the AER's Draft Decision with respect to the use of actual depreciation inputs sourced from the depreciation tracking model for the half year period. We have updated these inputs in the RFM for this Revised Proposal, based on our updated depreciation tracking model.

We also accept the following amendments in the AER's Draft Decision in relation to regulatory depreciation for the current period:

- The amendments to our forecast straight-line depreciation inputs as sourced from the latest approved PTRM for the current period. We note that these updates were confined to the 'Equity raising costs' asset class for years 2017-20 resulting in an immaterial change to total straight-line depreciation compared with our Initial Proposal; and
- The AER's updated 6-month actual inflation input (1 year lagged) of 1.22% as sourced from the latest ABS information.

The table below contains our revised calculation of economic depreciation.

Table 5-7: Economic depreciation, 1 January 2016 to 30 June 2021 ($m nominal) – Revised Proposal

Regulatory year	2016	2017	2018	2019	2020	2021 (first 6 months)
Nominal depreciation	182.3	170.6	182.8	193.0	208.2	100.3
RAB indexation	-52.0	-36.9	-73.7	-84.5	-68.6	-55.1
Regulatory depreciation	**130.3**	**133.6**	**109.1**	**108.5**	**139.5**	**45.2**

Source: AusNet Services Revised Proposal RFM (2016-21)

5.7 Final year adjustments

5.7.1 Our Initial Proposal

We proposed several opening RAB adjustments associated with accelerated depreciation of existing network assets in the next period. This included the proposed re-allocation of estimated RAB values from existing network asset classes into accelerated depreciation asset classes. This proposal sat alongside information we presented in our depreciation chapter which outlined the types of assets (and their age profile) that were subject to accelerated depreciation including our methodology for estimating their 1 July 2021 opening RAB values and revised remaining lives.

Our accelerated depreciation proposal was comprised of these two main elements (before depreciation offsets to existing asset classes):

- Accelerated depreciation of selected SCADA/Network control assets of $209.1 million over 5.3 years; and
- Accelerated depreciation of decommissioned network assets associated with our REFCL implementation program of $3.9 million (in total) over 2 years.

In addition, we included a re-allocation of 30 June 2021 closing RAB value (nominal) from the 'Distribution system assets' class into accelerated depreciation classes. This approach was consistent with the contingent project decisions (for REFCL Tranches 1, 2 and 3), which accepted the accelerated depreciation of certain assets that were to be replaced under this implementation program. We adopted this approach following our pre-lodgement engagement with the AER on the RFM.[132]

As part of our transition to the new Australian Accounting standard 'AASB16 – Leases', we proposed capex associated with our existing property leases[133], which were included in the RFM along with their remaining lives. In response to an information request, we provided the AER with a confidential copy of our lease accounting model[134] containing the relevant calculations in support of our 2019 opening values and forecasts for RFM and PTRM inputs. In addition, we provided the AER with a confidential copy of our existing property lease listing[135] that reconciled with our proposed base year opex adjustments.

We proposed this capex in the years in which they were expected to be incurred rather than treating it as a final year adjustment.

Our forecast lease capex presented in our Initial Proposal attributed to SCS is reproduced in the table below.

Table 5-8: SCS Buildings and property leases – Capital expenditure ($m nominal)

Regulatory Year	2016	2017	2018	2019	2020	2021 (first 6 months)
Leases capitalised	-	-	-	31.73	0.33	0.16
Weighted average remaining life	-	-	-	10.25	19.55	8.00

Source: AusNet Services' Initial Proposal RFM (2016-21)

5.7.2 Draft Decision

The AER accepted our proposed final year adjustments, subject to a number of amendments including:

- Reducing the opening RAB values for the SCADA/Network control assets (that were re-allocated from existing asset classes) by $12.5 million (nominal) or 6.0% compared to our Initial Proposal; and

132 AER, Prelodgement engagement on AusNet's distribution RFM, 16 November 2018.

133 ASD - Appendix 9E Lease Accounting Treatment - 310120 – PUBLIC.pdf, 31 January 2020.

134 Response to AER information request IR#019, 'ASD - IR019 - Leasee Lease Accounting Model SCS_CONFIDENTIAL.xlsx', 20 May 2020.

135 Response to AER information request IR#019, 'ASD - IR015 - Lease property listing supporting Appendix 9E_CONFIDENTIAL.xlsx', 20 May 2020.

- Revising the timing of accelerated depreciation for the selected SCADA/Network control assets (this is discussed in chapter 6 of this Revised Proposal).

The AER accepted in full our proposed accelerated depreciation of $3.9 million for existing assets that either have been, or are to be, removed and replaced as part of REFCL implementation program, and which were not previously captured in the AER's contingent project decisions. The AER requested further information from us in relation to the opening TAB values for these assets.[136] The opening TAB values are discussed in chapter 8 of this Revised Proposal.

The AER rejected our proposal to allocate capex associated with capitalised leases in the years in which they are incurred in the RFM inputs. The annual capex values were, however, included in the AER's Draft Decision CESS model. We discuss this aspect of the Draft Decision in further detail below.

In relation to the treatment of leases, the AER accepted our proposal to capitalise the value of our existing property leases to reflect the change in accounting standards. The AER stated that:

> *… we have assessed AusNet Services' calculation of the capitalised value and are satisfied that it reflects the present value of future lease payments over the remaining contract terms. We note this calculation method is consistent with the requirements set out in the Australian accounting standard.*[137]

However, the AER rejected our approach, which was to add capex to the RAB in the years where these lease costs are incurred.

The AER noted in its Draft Decision that:

> *… we do not accept AusNet Services' proposal to add the value of these capitalised leases as annual capex over the 2019 to 2021 period allocated to three new asset classes (…) in the RAB roll forward process.*[138]

Rather, the AER's preferred approach is to roll the amounts into the RAB as a final year adjustment in the RFM under a single asset class 'Non-network leasehold land & buildings - 1 July 2021'. The AER's rationale for this approach is that only approved asset classes can be used in the RFM, and therefore any historical/estimated capex that sits outside of this is treated as a final year adjustment.

The AER further states that:

> … *we consider this approach is consistent with the requirements of the RFM and Capital expenditure incentive guideline*.[139]

5.7.3 Revised Proposal

We accept the AER's Draft Decision on our proposed final year adjustments including:

- Accelerated depreciation of selected SCADA/Network control assets, including the re-allocation of $196.6 million to the proposed asset class 'Secondary systems (pre 2016)' from existing long-life asset classes; and
- Accelerated depreciation of decommissioned network assets associated with our REFCL tranches capex program, including re-allocation of $3.92 million to the accelerated depreciation asset classes from existing asset class 'Distribution system assets'.

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136 AER information request IR#041 – Tax Depreciation, 24 June 2020.

137 AER - Attachment 2: Regulatory asset base, Draft Decision, AusNet Services 2021–26, September 2020, p. 16.

138 Ibid.

139 Ibid.

In relation to capitalised leases, we also accept the AER's Draft Decision, although we have raised concerns regarding the exclusion of our reported 2019 actual lease capex from the 5.5 year RFM inputs. In our response to an information request from the AER received prior to the release of the Draft Decision we stated:

> *We have applied section 4.4.1 of the Capital Expenditure Incentives Guideline that applies to the 2016-20 determination. This deals with the circumstances in which an NSP changes its capitalisation policy, and concludes "we will roll into the RAB whatever the NSP has classified as capex at the time of the roll forward of the RAB (subject to this meeting other relevant requirements under the ex post review)"[140]"*[141]

Further, we indicated that:

> *… it does not appear to be a Rules requirement that new categories of assets cannot be added to the RFM during the regulatory period, but it is clear under the Rules that it is only under very narrow circumstances (i.e. an ex post review) that reported capex be excluded from the RAB.*[142]

In the situation where unanticipated capex is incurred within a period which requires a new asset category to be introduced, the current Capital Expenditure Incentives Guideline is ambiguous about whether the timing of this capex rolling into the RAB should match the timing of this capex being recognised in the CESS. We recommend that this issue is clarified in a future review by the AER of its Capital Expenditure Incentives Guideline.

We have included some minor amendments in the depreciation tracking model (2016-21) to reflect our actual reported lease capex incurred in 2019 and their remaining lives, as sourced from published 2019 annual RIN and Economic Benchmarking RIN information. We made further amendments in the CESS model inputs for actual gross capex to reflect our reported 2019 lease capex costs.

Table 5-9 below shows the minor changes compared with the Draft Decision.

Table 5-9: SCS property leases – 2019 Capital expenditure ($0's nominal)

Depreciation tracking model inputs	Draft Decision (Forecast)	Revised Proposal (Actual)
Leases capitalised - CY2019	31,730,578	31,728,430
Weighted average remaining life	10.25	10.18

Source: AER - Draft Decision - AusNet Services distribution determination - 2021–26 - Depreciation model, AusNet Services' Revised Proposal Depreciation model (Confidential)

5.8 Other modelling inputs

The AER's Draft Decision Capex model, published alongside its Draft Decision[143], includes several updates to the inflation table inputs (as expected) and some other structural changes to the indices used to convert $2018 real dollars to $nominal.

Specifically, the AER updated these inputs (as anticipated):

- The half year period inflation forecast of 1.00% with actual inflation of 1.22% (consistent with the RFM input); and

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140 AER capital expenditure incentive guideline – November 2013.pdf, p. 18.

141 Response to AER information request IR#019B – 'ASD - IR019B follow up request Q1 - 20200611 – Public.pdf', p. 1.

142 Response to AER information request IR#019B – 'ASD - IR019B follow up request Q1 - 20200611 – Public.pdf', p. 2.

143 AER, Draft Decision, AusNet Services distribution determination - 2021–26, Capex Model, September 2020 (Public).

- The inflation estimate for the next regulatory period (from 2.45% to 2.37%).

However, we have adjusted the AER's amended formula in the 'Jan-21-Jun-21' column, under row '$2018 to Nominal', which changes the escalation factor used in the model calculations for converting our 'mid-year' $2018 real capex inputs into $Jun-21 real terms. This factor of 1.0621 is slightly higher than our escalation factor of 1.0578 in our Initial Proposal.

Our reasons for adjusting this formula are:

- the AER's amended formula relies partially on 6 months' of the AER's updated inflation forecast for the 2022-26 period, i.e., "…*(1+2.37%)^0.5". We do not agree with this approach because the June 2021 inflation index value is known, based on 1-year lagged CPI data this is 116.2 (as reflected in the Draft Decision).
- Our revised approach outlined below aligns with the AER's Draft Decision capex model for one of the other Victorian DNSP's[144], which applies the escalation factor of 1.0598 to convert Real CY18 (Mid Period) to Real Jan21-Jun21 (End Period).

Our amendments, as shown in Table 5-10 below, produces a revised escalation factor of 1.0598 for converting 'mid-year' $2018 real inputs to $Jun-21 real dollar terms. Factors for the two intervening years have also been updated.

Table 5-10: Inflation index $2018 to $Nominal

Inflation factor	2016	2017	2018	2019	2020	2021 (first 6 months)
Initial Proposal			1.0000	1.0208	1.0370	1.0578
Draft Decision			1.0000	1.0208	1.0370	1.0621
Revised Proposal			1.0000	**1.0201**	**1.0388**	**1.0598**

Source: AusNet Services' Initial Proposal Capex model (2022-26) – Public, AER - Draft Decision - AusNet Services distribution determination - 2021–26 - Capex Model - September 2020 (Public), and AusNet Services' Revised Proposal Capex model (Public)

As a result, and compared with the Draft Decision, this reduces our revised proposal gross capex forecast for 2022-26 by $3.7 million including overheads (and before our proposed changes to real labour cost escalation). We have marked these changes in our revised capex model[145] CPI escalation table, and for consistency, the changes are replicated in our revised connections capex forecast model.

5.9 Forecast closing RAB as at 30 June 2026

5.9.1 Our Initial Proposal

In our Initial Proposal, we explained that the opening RAB as at 1 July 2021 is rolled forward during the 2022-26 regulatory period to reflect our capex forecast, forecast straight-line depreciation and the indexation of the RAB. Our forecast closing RAB, as at 30 June 2026, as presented in our Initial Proposal is reproduced in the table below.

144 AER - Draft Decision - Jemena distribution determination - 2021–26 - Capex Model - September 2020.

145 ASD Revised Proposal Capex Model - 2021-26 – Public.xlsx, 4 December 2020.

Table 5-11: Initial Proposed RAB roll forward 1 July 2021 to 30 June 2026 ($m nominal)

Regulatory year	2021-22	2022-23	2023-24	2024-25	2025-26
Opening RAB	4,715.1	4,898.9	5,061.6	5,225.3	5,370.5
Plus capex, net of contributions and disposals	321.9	312.6	319.8	310.7	319.9
Less straight-line depreciation	-253.7	-269.8	-280.2	-293.5	-306.0
Plus nominal forecast inflation on opening RAB	115.5	120.0	124.0	128.0	131.6
Closing RAB	**4,898.9**	**5,061.6**	**5,225.3**	**5,370.5**	**5,516.0**

Source: AusNet Services' Initial Proposal PTRM 2022-26

5.9.2 Draft Decision

The AER forecast a closing RAB value of $5,458.2 million (nominal) by 30 June 2026. This is $57.7 million (1.0%) lower than the amount we proposed in our Initial Proposal. In real terms, the AER forecast the value of our RAB will increase by $144.1 million ($2020-21) or 3.1% over the next regulatory period. This increase reflected the AER's decision on various inputs for determining the forecast RAB in the PTRM.

The AER noted that to determine this closing RAB value that it amended several inputs. Specifically, the AER amended the PTRM inputs by:

- Reducing our opening RAB value by $5.3 million (nominal) as at 1 July 2021;
- Reducing our proposed forecast capex by $103.0 million (nominal) or 6.5%;
- Reducing our proposed forecast straight-line depreciation by $75.7 million (nominal) or 5.4%; and
- Updating our proposed expected inflation rate of 2.45% for the next regulatory period to 2.37%. This decreased the indexation of the RAB component for the 2021-26 regulatory period by $25.2 million ($ nominal) or 4.1%.

5.9.3 Response to the AER's Draft Decision

As expected, we have updated our closing RAB to reflect our updated position on several inputs in this Revised Proposal, including the 1 July 2021 opening RAB value; forecast straight-line depreciation; and our forecast net capex for the 2022-26 regulatory period. As a result, we do not accept the AER's Draft Decision on the closing RAB value as at 30 June 2026.

We propose a closing RAB value of $5,433.6 million (nominal). This is $26.6 million (nominal) or 0.5% lower than the Draft Decision and $82.4 million (nominal) or 1.5% lower than our Initial Proposal.

5.9.4 Revised Proposal

Our revised proposed forecast closing RAB, as at 30 June 2026, is shown in the table below.

Table 5-12: Revised Forecast Closing RAB ($m nominal)

Regulatory year	2021-22	2022-23	2023-24	2024-25	2025-26
Opening RAB	4,656.5	4,833.1	5,037.0	5,190.1	5,312.8
Plus capex, net of contributions and disposals	345.1	350.7	299.6	274.8	275.8
Less straight-line depreciation	-279.0	-261.6	-266.0	-275.3	-281.1
Plus nominal forecast inflation on opening RAB	110.6	114.8	119.6	123.2	126.1
Closing RAB	**4,833.1**	**5,037.0**	**5,190.1**	**5,312.8**	**5,433.6**

Source: AusNet Services Revised Proposal PTRM 2022-26

5.10 Supporting documents

We have included the following documents to support this chapter:

- ASD – EDPR 2022-26 Revised Proposal – Capex Model (2021-26) – 031220 – CONFIDENTIAL
- ASD – EDPR 2022-26 Revised Proposal – PTRM Model (2022-26) – 031220 - PUBLIC
- ASD – EDPR 2022-26 Revised Proposal – 5.5 year RFM (2016-21) – 031220 - PUBLIC
- ASD – EDPR 2022-26 Revised Proposal – Depreciation Tracking Model (2021-26) – 031220 – CONFIDENTIAL

6 Depreciation

6.1 Key points

- We propose a revised regulatory depreciation forecast for the 2022-26 regulatory period of $768.8 million (nominal), being 4.8% higher than the AER's Draft Decision and 2.1% lower than our Initial Proposal.
- The AER's Draft Decision proposed several adjustments to our forecast depreciation, including as a consequence of changes arising from other aspects of the Draft Decision, most notably the value of our opening RAB and our forecast capex. As expected, we have updated our depreciation forecast to reflect the latest available information, including our updated capex for 2020 and the half year period.
- We accept the Draft Decision in relation to standard asset lives for new additions to the RAB starting from 1 July 2021. We also accept the AER's Draft Decision in relation to the accelerated depreciation of selected SCADA/Network control assets and decommissioned assets associated with our REFCL device rollout program; and
- In preparing our Revised Proposal, we have carefully considered the concerns raised by stakeholders during the AER's consultation process on our accelerated depreciation proposal for selected SCADA/Network control assets. Our Revised Proposal is to accept the adjustments made by the AER, which:
    - Appropriately balance the interests of current and future customers in accordance with the NER requirements; and
    - Help mitigate the potential price impacts of applying the improved inflation forecasting methodology.

6.2 Chapter structure

The remainder of this chapter is structured as follows:

- Section 6.3 provides an introduction
- Section 6.4 outlines our revised proposed opening RAB;
- Section 6.5 discusses our standard asset lives;
- Section 6.6 explains our proposed accelerated depreciation of SCADA/Network control assets;
- Section 6.7 discusses our proposed accelerated depreciation of decommissioned assets – REFCLs;
- Section 6.8 outlines our revised proposed forecast depreciation; and
- Section 6.9 sets out our supporting documents for this chapter.

In the event of any inconsistency between information contained in this chapter and our Initial Proposal, the information contained in this chapter prevails.

6.3 Introduction

The AER approved $733.5 million (nominal) for the depreciation allowance, representing a reduction of $50.5 million, or 6.4% from the depreciation forecast of $784.0 million (nominal) contained in our Initial Proposal.

The major differences between the Draft Decision and our Initial Proposal were due to a lower alternative estimate of the value of assets subject to accelerated depreciation and the consequential impact of other aspects of the Draft Decision, principally a lower opening RAB and reduced capex forecast.

In summary, our Revised Proposal:

- Continues to apply the year-by-year tracking methodology for straight-line depreciation approved by the AER and adopted by us in the current period;
- Accepts the AER's alternative estimate of the value of selected SCADA/Network control assets for which accelerated depreciation is being applied. The AER approved $196.6 million of the $209.1 million we proposed, a 6% reduction. Of this approved amount, we note that $155.3 million is allowed in the 2022-26 period and a further $41.3 million is recoverable in the following regulatory period;
- Includes a revised total regulatory depreciation forecast for the 2022-26 regulatory period of $768.8 million (nominal), which is:
    - $15.2 million (or 1.9%) lower than our Initial Proposal; and
    - $35.3 million (or 4.8%) higher than the Draft Decision.

Further details of our Revised Proposal are presented in the remaining sections of this chapter.

6.4 Opening RAB depreciation

6.4.1 Our Initial Proposal

In our Initial Proposal, we applied straight-line depreciation of the opening RAB using the year-by-year tracking approach. The resulting straight-line depreciation values for the opening RAB are reproduced in the table below.

Table 6-1: Opening RAB depreciation (2022-26), $Jun 2021 – Initial Proposal

Regulatory year	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Opening RAB depreciation	247.6	238.7	227.5	217.6	208.1	1,139.6

Source: AusNet Services

6.4.2 Draft Decision

The AER did not accept our Initial Proposal for the opening RAB depreciation and approved $1,084.9 million, which is $54.7 million (or 4.8%) lower than our proposal and reflects the AER's Draft Decision on several inputs including a lower opening RAB and lower accelerated depreciation compared with our Initial Proposal.

The table below sets out the AER's Draft Decision on the depreciation amount in relation to our opening RAB.

Table 6-2: Opening RAB depreciation (2022-26), $Jun 2021 – Draft Decision

Regulatory year	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Opening RAB depreciation	268.0	226.1	209.1	197.5	184.2	1,084.9

Source: AER - Draft Decision - AusNet Services distribution determination - 2021-26 - PTRM - September 2020

6.4.3 Response to the AER's Draft Decision

We accept most of the adjustments made by the AER's Draft Decision, including the accelerated depreciation of network assets in the 2022-26 regulatory period. We discuss this aspect further in section 6.6 below.

As expected, we have updated the 2022-26 depreciation forecast in relation to our opening RAB to reflect our updated placeholder forecasts for 2020 and the half year period in the RFM. Our proposed opening RAB depreciation has increased by $20.2 million, mainly driven by the 5-minute metering compliance IT systems upgrade program which is reflected in our updated half year period capex forecast in the RFM.

Our revised opening RAB depreciation is set out in the table below.

Table 6-3: Opening RAB depreciation (2022-26), $Jun 2021 – Revised Proposal

Regulatory year	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Opening RAB depreciation	272.5	230.4	213.1	201.2	187.9	1,105.1

Source: AusNet Services Revised Proposal PTRM - 2022-26 - December 2020

6.5 Standard asset lives

6.5.1 Our Initial Proposal

In our Initial Proposal, we did not propose any changes to our standard asset lives in relation to our existing asset classes. However, we proposed two new asset classes in the PTRM to account for forecast capitalised leasing costs for the 2022-26 regulatory period. These capitalised lease costs relate to changes in Australian accounting standards.

Our Initial Proposal standard lives for RAB are shown in the table below.

Table 6-4: Standard asset lives in RAB – Initial Proposal

Asset class	Standard life (Yrs)
Sub-transmission	45
Distribution system assets	50
SCADA/Network control	10
Non-network general assets - IT	5
Non-network general assets - Other	5
Non-network - Metering related IT	7
Land	n/a
Non-network Leasehold Land & Buildings - 2021-22	23.7
Non-network Leasehold Land & Buildings - 2022-23	n/a
Non-network Leasehold Land & Buildings - 2023-24	n/a

Asset class	Standard life (Yrs)
Non-network Leasehold Land & Buildings - 2024-25	n/a
Non-network Leasehold Land & Buildings – 2025-26	5
Equity raising costs (Jan-Jun'21)	46.8
Equity raising costs (2022-26)	44.7

Source: AusNet Services

6.5.2 Draft Decision

The AER accepted our proposed standard asset lives, except for the standard asset lives for the two 'Equity raising costs' asset classes and three unused leases asset classes, all of which the AER removed.

In relation to the 'Equity raising costs' asset class, the AER noted that as no equity raising costs are included in our revenue requirement for the 2016-2020 regulatory period, this asset class is not applicable in the 2022-26 regulatory period. In relation to lease asset classes, the AER accepted our proposal to include two new asset classes and their proposed asset lives, but removed the three unused lease asset classes.[146]

The AER's Draft Decision in relation to our asset classes and standard lives is set out in the table below.

Table 6-5: Standard asset lives in RAB – Draft Decision

Asset class	Standard asset life
Subtransmission	45.0
Distribution system assets	50.0
SCADA/Network control	10.0
Non-network general assets - IT	5.0
Non-network general assets - other	5.0
Land	n/a
Non-network leasehold land & buildings – 2021–22	23.7
Non-network leasehold land & buildings – 2025–26	5.0
Buildings - capital works[a]	40.0
In-house software[a]	5.0
Equity raising costs	n/a

Source: AER analysis.

[146] AER, Draft Decision - AusNet Services distribution determination 2021-26, Attachment 4 - Regulatory depreciation, September 2020, pp. 15-16.

6.5.3 Response to the AER's Draft Decision

We accept the AER's Draft Decision in relation to standard asset lives for new additions to the RAB starting from 1 July 2021.

As noted in the opening RAB chapter of this Revised Proposal, we accept the AER's changes in relation to:

- Inclusion of the new asset class in RFM inputs (and PTRM inputs) that consolidates the three proposed asset classes in the RFM for capitalised leases, including 2019, 2020 and the half year period; and
- Various 'housekeeping' changes relating to asset classes that are no longer being used.

In addition, we accept the inclusion of the new asset classes in the PTRM relating to leases in the 2022-26 regulatory period.

6.6 Accelerated depreciation of SCADA/Network control assets

6.6.1 Our Initial Proposal

In our Initial Proposal, we explained that accelerated depreciation should apply to existing SCADA/Network control assets in the opening RAB in total of $209.1 million and depreciate these assets over a proposed period of 5.3 years in the RAB, starting from 1 July 2021. Our proposal captured the following SCADA, protection and control system assets that were installed in our distribution zone substations prior to 1 January 2016:

- IED protection relays operating at 66 kV and below; and
- Distribution RTUs which interface the physical relay and monitoring devices with the SCADA system.

Our Initial Proposal sought to transfer selected network assets into a new asset class from 1 July 2021 and depreciate them over their calculated weighted average remaining life of 5.3 years.

Table 6-6 below contains our proposed accelerated depreciation of these over the 2022-26 regulatory period.

Table 6-6: SCADA/Network control assets accelerated depreciation (2022-26), $Jun 2021 – Initial Proposal

Regulatory year	2021-22	2022-23	2023-24	2024-25	2025-26	Total
IED protection relays	34.3	34.3	34.3	34.3	34.3	171.3
Distribution RTUs	5.5	5.5	5.5	5.5	5.5	27.4
Total	**39.7**	**39.7**	**39.7**	**39.7**	**39.7**	**198.7**

Source: ASD - Selected Network SCADA assets opening RAB calculation - 310120 – CONFIDENTIAL.xlsx.

We also proposed accelerated depreciation in relation to assets that have been, or are forecast to be, replaced to mitigate bushfire risk, principally as a result of the REFCL implementation program. We discuss this issue in section 6.7.

6.6.2 Draft Decision

The Draft Decision approved $196.6 million of our proposed accelerated depreciation of $209.1 million for SCADA/Network control assets, being a 6% reduction. Of this approved amount, $155.3 million would be recoverable in the 2022-26 regulatory period and a further $41.3 million would be recoverable in the following regulatory period.

The AER accepted our proposal in principle, noting that it is consistent with the NER which provide for assets to be separately depreciated so as to better reflect their economic life.[147] More specifically, in considering our accelerated depreciation proposal the AER accepted:

- Our modelling approach for calculating the opening RAB values for these SCADA/Network control assets and their remaining lives (within the existing historical asset classes);
- Our proposed new asset class 'Secondary systems (pre 2016)' to cater for the opening RAB value transfers from existing assets classes;
- Our proposed 15-year standard life assumption that is required to separate these SCADA/Network control assets from the existing asset classes in the opening RAB;
- Our proposed current replacement unit rate for our Distribution RTUs; and
- Our proposed capitalised overhead rate of 10% applied to the proposed current replacement unit rates.

However, the AER did not accept:

- Our proposed weighted average remaining life of 5.3 years for these assets as at 1 July 2021. The AER applied an alternative tracking approach, based on information we provided in our depreciation tracking model[148], which under the AER's approach defers accelerated depreciation of $30.9 million to the 2026-31 regulatory period; and
- Our proposed current replacement unit rate for IED protection relays, which reduces the estimated opening RAB values for these assets subject to accelerated depreciation by $12.5 million (or 6.0%).

In its Draft Decision, the AER highlighted concerns raised in several submissions with respect to the revenue impacts of our proposed accelerated depreciation. In particular, the Energy Users Association of Australia (EUAA) commented that it was unfortunate that our accelerated depreciation proposal was outside the Customer Forum's scope and that accelerated depreciation offset most drivers for price reductions.[149] In its Draft Decision, the AER suggested that we give further consideration to consumers' views on this issue in preparing our Revised Proposal.[150] We discuss our response to this concern in section 6.6.3.1 below.

The table below sets out the AER's determination of accelerated depreciation for these assets over the 2022-26 regulatory period.

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147 AER, Draft Decision, AusNet Services distribution determination 2021-26, Attachment 4 - Regulatory depreciation, September 2020, p. 13.

148 ASD - Depreciation tracking model (2016-21) - 310120 – CONFIDENTIAL, 31 January 2020, and supporting confidential opening RAB calculation model.

149 EUAA, Submission - AusNet Services EPDR 2021−26, June 2020, p. 2.

150 AER, Draft Decision, AusNet Services distribution determination 2021-26, Attachment 4 - Regulatory depreciation, September 2020, p. 15.

Table 6-7: SCADA/Network control assets accelerated depreciation (2022-26), $Jun 2021 – Draft Decision

Regulatory year	2021-22	2022-23	2023-24	2024-25	2025-26	Total
IED protection relays	48.6	27.2	22.1	18.8	15.1	131.9
Distribution RTUs	14.1	2.9	2.5	2.1	1.8	23.4
Total	**62.8**	**30.1**	**24.6**	**20.9**	**16.9**	**155.3**

Source: AER - Draft Decision - AusNet 2021-26 - Selected Network SCADA assets opening RAB calculation – CONFIDENTIAL.xlsx

6.6.3 Response to the AER's Draft Decision

We accept the AER's Draft Decision of $196.6 million in total accelerated depreciation of the selected SCADA/Network control assets over the next two regulatory periods. In addition, we also accept the AER's Draft Decision that $155.3 million of this accelerated depreciation should be recovered in the 2022-26 period.

The table below shows our revised straight-line depreciation amounts as sourced from our updated depreciation tracking model.

Table 6-8: SCADA/Network control assets accelerated depreciation (2022-26), $Jun 2021 – Revised Proposal

Regulatory year	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Secondary systems (pre 2016)	62.8	30.1	24.6	20.9	16.9	**155.3**

AusNet Services Revised Proposal Depreciation model - 2021-26 - CONFIDENTIAL - December 2020

The AER engaged extensively with us on this aspect of our proposal. In addition to the material presented in our Initial Proposal and in response to several information requests, we provided the AER with:

- Further evidence and support for our current replacement unit costs for installing modern IED protection relays and Distribution RTUs on our network.[151 & 152] This information included our current secondary systems unit rates (provided on a commercial in confidential basis), which underpinned other parts of our proposal, including our 2022-26 capex forecast;
- Further evidence and support for our capitalised overheads rate of 10%[152], which the AER has accepted in its Draft Decision.[153]
- Further supporting evidence pertaining to our 15-year standard life assumption for these assets. In particular, we explained that our proposed 15-year standard asset lives for IED relays and RTUs is based on evidence, reflects our asset management practices and is consistent with the approach of other distribution networks.[154] The supporting evidence we provided included:

151 AusNet Services, Response to Information Request #016 - CONFIDENTIAL, 14 May 2020.

152 AusNet Services, Response to Information Request #016A - CONFIDENTIAL, 29 May 2020.

153 AER, Draft Decision, AusNet Services distribution determination 2021-26, Attachment 4 - Regulatory depreciation, September 2020, p.14.

154 AusNet Services, Response to Information Request #016B - CONFIDENTIAL, 26 June 2020.

- A copy of our updated Asset Management Strategy (AMS) for our protection and control systems,[155] which reflects our current asset management practices;
- An age profile and condition rating for our in-service IED protection relay fleet as at 1 January 2016, their planned replacement under the AMS and the drivers for replacement;[154]
- An age profile and condition rating for our in-service RTU fleet as at 1 January 2016, their planned replacement under the AMS and the drivers for replacement;[154] and
- Evidence from other network businesses that accords with the use of a 15-year standard life for both SCADA - RTU and modern intelligent electronic relay devices.

As noted in our Initial Proposal, our approach was focused on achieving a depreciation schedule that complies with clause 6.5.5(b)(1) of the NER, such that the depreciation schedules used by the DNSP reflect the economic lives of the assets. Furthermore, we consider:

> *…our accelerated depreciation forecast, and the economic lives underpinning it, is robust and consistent with the Rules and the NEO.*[154]

We acknowledge and support the AER's consideration of these elements outlined above in reaching its determination.

In this Revised Proposal, we accept:

- The AER's substituted lower replacement unit rate for IED protection relays; and
- The AER's changes in the updated confidential model[156], including the new section added for implementing the tracking approach for these assets. We have made some minor formatting changes only within this model and submitted this supporting document with our Revised Proposal.[157]

In the next section below, we address concerns raised by some stakeholders in relation to our accelerated depreciation proposal.

6.6.3.1 Response to submissions from stakeholders

As already noted, the EUAA expressed disappointment that accelerated depreciation was outside the Customer Forum's scope and commented that there was no consumer engagement on this issue. The EUAA explained that it did not support the proposal as presented, noting that accelerated depreciation offset most drivers for price reductions.[158]

While the EUAA is correct that the issue of accelerated depreciation was outside the scope of the negotiations with the Customer Forum, its impact was considered. In particular, we kept the Customer Forum informed on each of the building block components and the overall revenue and price implications of changes to those components for customers. Our approach ensured that the Customer Forum could make informed decisions on in-scope issues as well as consider the interests of current and future customers. Importantly, the Customer Forum agreed that our overall proposal, when considered as a package, is reasonable.

EnergyAustralia (EA) also raised concerns regarding our accelerated depreciation, noting that:

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155 ASD - AMS 20-72 Protection and control systems - 300620 - AMENDED – CONFIDENTIAL, 30 June 2020.

156 AER, Draft Decision, AusNet 2021-26 - Selected Network SCADA assets opening RAB calculation – CONFIDENTIAL, September 2020.

157 ASD – Revised Proposal – 2021-26 - Selected Network SCADA assets opening RAB calculation – CONFIDENTIAL, December 2020.

158 EUAA, Submission - AusNet Services EPDR 2021−26 - June 2020, p. 2.

> *… the main factors contributing to price changes [in the next regulatory period], aside from the rate of return and tax, appear to be [amongst others] large increases due to depreciation in the cases of AusNet and United Energy.*[159]

EA expressed a concern about whether these changes to depreciation schedules "are revenue neutral for DNSPs and customers."[160] EA called on the AER to investigate further and confirm that our proposed changes were supported and validated with detailed modelling.

We submitted a detailed confidential model to the AER[161] with our Initial Proposal containing our inputs and calculations[162]. As noted in the above section, the AER engaged extensively with us on several aspects of our proposal before making its determination on accelerated depreciation in relation to the relevant SCADA/Network control assets.

We agree with EA's primary concern that changes in the depreciation schedules for existing assets should be revenue neutral, given that accelerated depreciation only alters the timing of when a DNSP recoups its depreciation costs. In preparing our proposal we have adhered to the provisions contained in NER clause 6.5.5(b)(1), as noted by the AER in its Draft Decision:

> *AusNet Services' proposal changes the depreciation profile for a proportion of these assets, not their value. The proposal aims to better give effect to clause 6.5.5(b)(1) of the NER, developing a depreciation schedule that reflects the assets' economic lives.*[163]

In relation to the economic life of the assets, we consider it important that future customers are not paying for assets that are no longer in service. The NER provisions relating to depreciation schedules and application of accelerated depreciation enable us to avoid this outcome, thereby ensuring that the prices paid by current and future generations of customers are equitable and efficient.

In this regard, we note that the CCP commented that if there are circumstances where reducing lives of assets is appropriate, then the adjustment should be made over two periods, rather than one.[164] We agree with the CCP's sentiment, noting that it is always important to have regard to the price impact on customers. However, it is also important to have regard to the particular circumstances, rather than applying a fixed approach in all cases. As already noted, the AER's Draft Decision will defer part of the approved accelerated depreciation to the subsequent regulatory period (2026-31), which partly addresses the CCP's comments.

As requested by the AER's Draft Decision, we have considered the feedback from stakeholders in preparing our Revised Proposal in relation to accelerated depreciation. We have also taken account of the negotiations with the Customer Forum, which has considered the impact of accelerated depreciation in its consideration of the overall revenue and price impacts. Our view is that the best approach is to accept the AER's Draft Decision, which appropriately applies the NER to ensure that revenues and prices are equitable and efficient.

It is also worth noting that our acceptance of the AER's Draft Decision, which reduces the amount of accelerated depreciation to be recovered in the 2022-26 regulatory period, provides additional headroom for the AER to implement its updated approach to estimating inflation while honouring the price outcomes that were negotiated with the Customer Forum. We look forward to working with the AER to ensure that the combined effect of accelerated depreciation and the AER's

159 EnergyAustralia, Submission on the Victorian Electricity Distribution Regulatory Proposal 2021-26, June 2020, p. 5.

160 EnergyAustralia, Submission on the Victorian Electricity Distribution Regulatory Proposal 2021-26, June 2020, p. 9.

161 ASD - Selected Network SCADA assets opening RAB calculation - 310120 – CONFIDENTIAL, 31 January 2020.

162 ASD, EDPR 2022-26 Regulatory Proposal Part III - 310120 - PUBLIC, pp. 196-205.

163 AER, Draft Decision, AusNet Services distribution determination 2021-26, Attachment 4 - Regulatory depreciation, September 2020, p. 15.

164 CCP17, Advice to the AER on the Victorian Electricity Distributors' Regulatory Proposals for the Regulatory Determination 2021-26, p. 33.

updated inflation approach give effect to the price outcomes negotiated with the Customer Forum, as far as practicable.

6.7 Accelerated depreciation of decommissioned assets – REFCLs

6.7.1 Our Initial Proposal

In our Initial Proposal, we explained that accelerated depreciation of $3.9 million should apply in relation to assets that either have already been, or are planned to be, replaced (ahead of the end of their expected economic and/or technical lives) as part of our safety-related capex programs. In addition, we noted this issue had been considered in the AER's decisions on our REFCL contingent project applications, which necessitated a consistent approach in our Initial Proposal.

The table below shows the proposed accelerated depreciation of existing assets over the 2022-26 regulatory period.

Table 6-9: Accelerated depreciation allowance (2022-26) ($m, $Jun 2021) – Initial Proposal

Regulatory year	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Straight-line depreciation	1.9	1.9	-	-	-	3.9

Source: AusNet Services Initial Proposal PTRM (2022-26)

6.7.2 Draft Decision

The AER accepted our accelerated depreciation proposal in full[165], including accelerating this $3.9 million worth of assets over the first 2 years of the next regulatory period.

Table 6-10: Depreciation allowance (2022-26) ($m, $Jun 2021) – Draft Decision

Regulatory year	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Straight-line depreciation	2.0	2.0	-	-	-	3.9

Source: AER - Draft Decision - AusNet Services distribution determination - 2021-26 - PTRM - September 2020

The AER requested further information from us in relation to the opening TAB values for these assets.[166] The opening TAB values are discussed within Chapter 8 of this Revised Proposal.

6.7.3 Response to the AER's Draft Decision

We accept the AER's Draft Decision on the accelerated depreciation for these assets and accordingly reflected this our updated PTRM.

6.8 Forecast depreciation

6.8.1 Our Initial Proposal

Based on the depreciation methodology described in our Initial Proposal, our total forecast economic depreciation for the forthcoming regulatory period was $784.0 million (nominal), as shown in the table below.

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165 With some minor amendments to opening RAB values, per our response to information request IR#041 – Q.1(b), 29 June 2020.

166 AER informtion request IR#041 – Tax Depreciation, 24 June 2020.

Table 6-11: Forecast economic depreciation ($m, $ nominal) – Initial Proposal

Regulatory year	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Forecast nominal depreciation	253.7	269.8	280.2	293.5	306.0	1,403.2
less RAB indexation	-115.5	-120.0	-124.0	-128.0	-131.6	-619.2
Regulatory depreciation	**138.2**	**149.8**	**156.2**	**165.5**	**174.4**	**784.0**

Source: AusNet Services Initial Proposal PTRM (2022-26)

6.8.2 Draft Decision

As discussed above, the AER did not accept our Initial Proposal and determined a depreciation allowance of $733.5 million (nominal) as shown in the table below.

Table 6-12: Forecast economic depreciation ($m, $ nominal) – Draft Decision

Regulatory Year	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Forecast nominal depreciation	274.3	254.9	257.5	267.1	273.6	1,327.5
less RAB indexation	-111.8	-114.9	-118.6	-122.5	-126.0	-594.0
Regulatory depreciation	**162.5**	**140.0**	**138.9**	**144.5**	**147.6**	**733.5**

Source: AER - Draft Decision - AusNet Services distribution determination - 2021-26 - PTRM - September 2020

6.8.3 Response to the AER's Draft Decision

Based on the amended depreciation methodology described in the sections above, our revised forecast economic depreciation for the forthcoming regulatory period is $768.8 million (nominal), as shown in the table below.

Table 6-13: Forecast economic depreciation ($m, $ nominal) – Revised Proposal

Regulatory Year	2021-22	2022-23	2023-24	2024-25	2025-26	Total
Forecast nominal depreciation	279.0	261.6	266.0	275.3	281.1	1,363.0
less RAB indexation	-110.6	-114.8	-119.6	-123.2	-126.1	-594.3
Regulatory depreciation	**168.4**	**146.7**	**146.2**	**151.8**	**154.7**	**767.8**

Source: AusNet Services Revised Proposal PTRM (2022-26)

6.9 Supporting documents

We have included the following documents to support this chapter:

- ASD – EDPR 2022-26 Revised Proposal – Depreciation Tracking Model (2021-26) – 031220 – CONFIDENTIAL
- ASD – EDPR 2022-26 Revised Proposal – Selected SCADA Network Assets opening RAB calculation – 031220 – CONFIDENTIAL
- ASD – EDPR 2022-26 Revised Proposal – 5.5 year RFM (2016-21) – 031220 – PUBLIC
- ASD – EDPR 2022-26 Revised Proposal – PTRM Model (2022-26) – 031220 - PUBLIC

7 Return on capital and gamma

7.1 Key points

- Our Revised Proposal is prepared to be consistent with the 2018 Rate of Return Instrument. It adopts a placeholder nominal vanilla WACC of 4.63%[167], consistent with the Draft Decision.
- We expect changes to the inflation estimate arising from the AER's Inflation Review will be applied in full in our Final Determination.
- Financeability challenges due to the current low return environment are expected to worsen due to the Reserve Bank of Australia's bond buyback program. This makes it more critical that an accurate expected inflation parameter be applied, without any transition, with effect from the commencement of the regulatory period.

7.2 Chapter structure

The remainder of this chapter is structured as follows:

- Section 7.3 provides an overview of the rate of return applied in this Revised Proposal;
- Section 7.4 covers debt and equity raising costs;
- Section 7.5 outlines our position on expected inflation; and
- Section 7.6 covers financeability pressures created by the low return environment.

In the event of inconsistency between information contained in this chapter and our Initial Proposal, the information contained in this chapter prevails.

7.3 Rate of Return overview

The AER's Rate of Return Instrument published in December 2018 applies to this review. This Instrument is binding on both AusNet Services and the AER in a distribution determination.

In the Initial Proposal we used a rate of return placeholder of 4.84%. In its Draft Decision, the AER updated this with 4.63%, which we have adopted for this Revised Proposal. This placeholder estimate will be updated in the AER's Final Decision to reflect our final rate of return averaging periods.

Table 7-1: Proposed placeholder Rate of Return[1]

	Initial Proposal	Draft Decision	Revised Proposal
Return on equity	4..92%	4.59%	4.59%
Return on debt (yr 1)	4.79%	4.66%	4.66%
Inflation	2.45%	2.37%	2.37%
Gearing	60%	60%	60%

167 4.63% is applied in the first year of the regulatory period. The nominal vanilla WACC varies in each year as debt is updated in each year.

	Initial Proposal	Draft Decision	Revised Proposal
Gamma	0.585	0.585	0.585
Nominal vanilla WACC	4.84%	4.63%	4.63%

(1) Return on equity is estimated using a placeholder averaging period of 1 June – 30 June 2020. This will be updated for AusNet Services' actual averaging period. Return on debt is based on placeholder future observations which will be updated for AusNet Services' actual debt averaging periods for each year in 2022-26.

Our Revised Proposal positions on these rate of return components are discussed below.

Table 7-2: Our approach to the Rate of Return

Component	Approach in Revised Proposal
Debt	We have applied the Draft Decision placeholder return on debt that has been updated by the AER to reflect the actual debt observation (2.55%) that has been applied to the half year period. The AER will update the debt placeholder in its Final Determination to incorporate the latest debt update.
Equity	We have applied the Draft Decision placeholder return on equity which applies a risk free rate of 0.93%. This will be updated by the AER in its Final Determination.
Value of Imputation Credits (Gamma)	We have applied a value of 0.585 as required by the 2018 Rate of Return Instrument.
Expected Inflation	We have adopted the AER's Draft Decision placeholder value for expected inflation of 2.37% in this Revised Proposal. However, as discussed in section 7.4, the AER is currently reviewing its approach to expected inflation. A Final Decision is expected in December 2020 and the outcome will be applied in the Final Determination.
Averaging periods	The AER accepted our proposed averaging periods in its Draft Decision as they comply with the requirements of the 2018 Rate of Return Instrument. We agree with this position.

The rate of return that has been applied in the Revised Proposal for each year of the regulatory period is set out in the Table below.

Table 7-3: Rate of return by year

	2021-22	2022-23	2023-24	2024-25	2025-26
Return on equity	4.59%	4.59%	4.59%	4.59%	4.59%
Nominal pre-tax return on debt	4.66%	4.36%	4.06%	3.76%	3.47%
Gearing	60%	60%	60%	60%	60%
Nominal vanilla WACC	**4.63%**	**4.45%**	**4.27%**	**4.10%**	**3.92%**

7.4 Debt and Equity Raising Costs

7.4.1 Our Initial Proposal

Our Initial Proposal included:

- $11.8 million (or 8.16 bppa) of debt raising cost opex. This was based on the AER's approach for setting debt raising costs, noting that at the time we submitted our Initial Proposal, this was under review as part of SA Power Networks' regulatory determination process; and
- $0 of equity raising costs, reflecting that for the AER's benchmark entity, no equity injection is required within the next regulatory period.

7.4.2 Draft Decision

The AER's Draft Decision accepted our approach to forecasting debt and equity raising costs. It allowed:

- $11.3 million of debt raising cost opex. As our proposed debt raising costs benchmark (8.16 bppa) was not materially different to the AER's estimate (7.9 bppa), it accepted our proposed approach. The reduction in opex compared to our Initial Proposal is due to the lower RAB compared to the Initial Proposal; and
- $0 of equity raising costs. The AER also found that the benchmark entity would not be required to raise equity within the next regulatory period.

We note that the AER has indicated it will issue RINs to collect consistent debt and debt raising cost data from networks starting in 2021. We will engage with the AER on any future review of its debt raising cost benchmark.

7.4.3 Revised Proposal

We accept the AER's Draft Decision with respect to debt and equity raising costs. Our Revised Proposal includes:

- $11.3 million of debt raising cost opex; and
- $0 of equity raising costs.

7.5 Inflation

7.5.1 Our Initial Proposal

We proposed an expected inflation placeholder of 2.45% for the 2022-26 regulatory period, based on the AER's current approach. In doing so, we noted that we had significant concerns with this approach and we will engage in any developments at industry level and consider any changes as part of our Revised Proposal.

7.5.2 Draft Decision

The AER has applied its current approach and updated our inflation placeholder to reflect the Reserve Bank of Australia's August 2020 Monetary Policy Statement to provide a value of 2.37%.

In April 2020, the AER commenced a review of its treatment of inflation. This review is expected to conclude in December 2020. This timing would allow the AER to apply its new approach to inflation in its Final Decision for AusNet Services in April 2021, unless a Rule change is required.

The AER also noted that it would consider our submissions on the suitability of its current approach to estimating inflation as part of that review.

7.5.3 Revised Proposal

We have adopted the Draft Decision value of expected inflation of 2.37% in this Revised Proposal as a placeholder given the AER's Inflation Review is not yet finalised.

7.5.3.1 Application of Inflation Review Outcome

We have engaged with the AER and provided written submissions on our position on expected inflation via its separate Inflation Review consultation process.

The AER's Draft Inflation Position published on 1 October 2020, proposed two changes to the methodology for setting expected inflation:

- Shorten the length of the target term from 5 to 10 years, to match the length of the regulatory period; and
- Apply a linear glide-path from the Reserve Bank of Australia's forecasts of inflation for years 1 and 2 to the mid-point of the inflation target band (2.5%) in year 5.

We support the application of both changes as they will bring the expected inflation parameter towards investor expectations of inflation. This Revised Proposal provides sensitivity analysis of the price impacts of the draft inflation position in Chapter 2.

The AER is consulting on whether a transition is warranted to shorten the length of the target term from 5 to 10 years. As set out in our submission[168] to the Draft Inflation Position, a transition is not warranted for the following reasons:

- Expected shortfalls to investors, compared to the nominal rate of return allowed by the AER, would continue. Applying a forecast of expected inflation that is too high means that investors will not expect the efficient nominal rate of return to be delivered, distorting signals for efficient investment.
- Customers benefit when there are efficient incentives for network investment. The regulatory framework is designed to ensure networks are able to attract the investment capital required for efficient investment. This will reduce service levels in the short term and

168 AusNet Services, Submission to the AER's Draft Position – Inflation Review. Available here: https://www.aer.gov.au/system/files/AusNet%20Services%20-%20Submission%20to%20draft%20position%20-%202020%20inflation%20review%20-%20November%202020.pdf (accessed 2 December 2020).

increase prices over the long term, as networks will have to pay more than would otherwise be efficient to address reduced service levels. It is not in the interests of customers to slow the immediate shift to an improved inflation expectation.

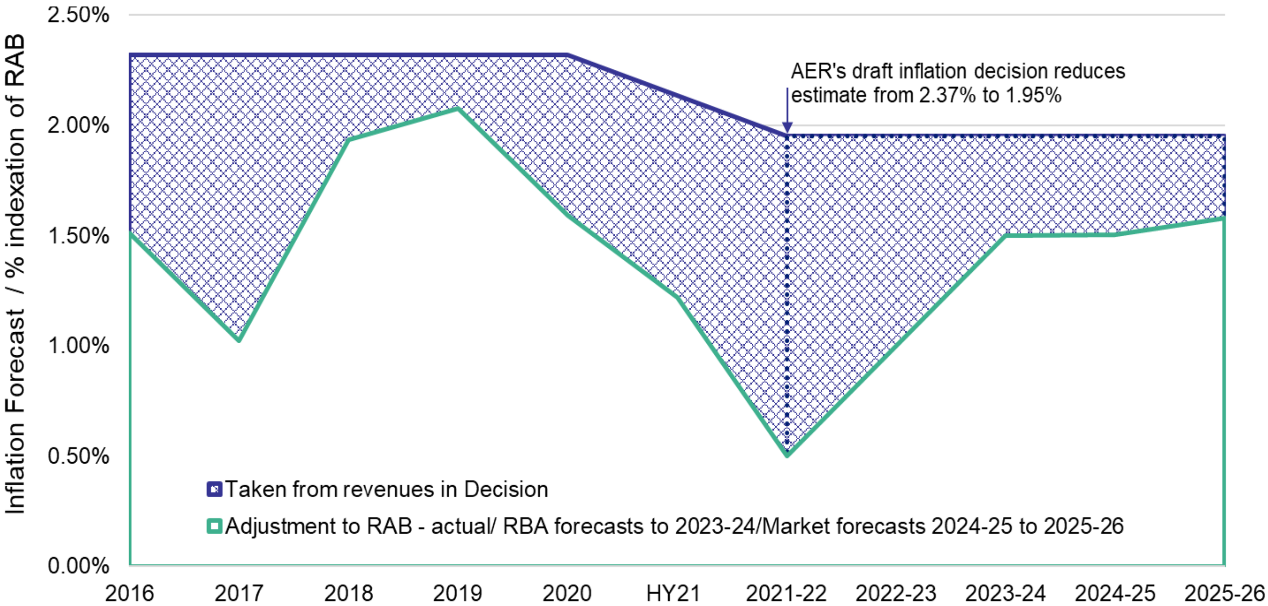
- Applying a transition is not consistent with the NER. The AER must derive a ‘best estimate’ of inflation and must provide networks with a reasonable opportunity to recover at least their efficient costs. It is not clear how applying a transition (which is inconsistent with the NPV=0 principle) meets either of these requirements.

Expected inflation is deducted from cash revenues, while actual inflation as added to the RAB annually via indexation. To ensure the ex ante return is expected to be delivered, the AER’s Draft Position approach is to ‘take out what will be put back in’ – that means the inflation parameter determining the cash revenue reduction should equal actual inflation expected to be added to the RAB over the next 5 years.

However, due to the application of lagged inflation to roll forward the RAB for the Victorian distributors, there is a mismatch between the short term Reserve Bank of Australia’s forecasts used in the AER’s inflation forecasting approach and the CPI series that will be applied to the RAB. There are currently 3 years of Reserve Bank of Australia short term forecasts available for the CPI series that will be used for RAB indexation over the 2022-26 period.

This is shown in the chart below. Even if the AER’s proposed methodology is immediately applied, the inflation deduction from revenues significantly exceeds expected RAB indexation over the 2022-26 regulatory period. A transition to the AER’s new approach to estimating inflation would lead to a widening of this gap, which would be inconsistent with the objectives of the regulatory framework as explained above.

Figure 7-1: AER’s Inflation Draft Position compared to expected RAB indexation



In addition, the application of the regulatory framework in the current low return environment is expected to produce a Net Profit After Tax (NPAT) of -$28 million[169] over the 5 year regulatory period, if the new inflation approach is applied without transition. The NPAT worsens if the proposed inflation approach is transitioned, increasing to a loss for the benchmark entity of $135 million. These outcomes reinforce our position that there is no case for delaying the introduction of the better approach to estimating inflation.

169 Appendix 7A Frontier Economics, *The impact of artificially supressed government bond yields,* 23 November 2020

7.6 The impact of artificially supressed government bond yields

On 3 November 2020 the Reserve Bank of Australia announced that it would be intervening in the market to reduce government bond yields below the level that otherwise would have been set in the market. This intervention is expected to occur over a period of 6 months that overlaps with the Victorian distributors' equity averaging periods for the forthcoming regulatory periods (1 December 2020 – 31 March 2021).

We commissioned Frontier Economics to provide advice on the implications of this program and the low equity return allowances on the financial outcomes of the AER's Draft Decision and summarise the current approach of other regulators in setting equity returns (Appendix 7A). While we acknowledge that the 2018 Rate of Return Instrument is binding, the report explains that the AER's draft inflation position could mitigate (but not solve) some of the financeability problems inherent in the AER's Draft Decision.

Frontier Economics' report provides further evidence to support our view that the new approach to estimating inflation should be applied to our Final Decision without any transition period.

8 Corporate Tax Allowance

8.1 Key points

- We are proposing a zero corporate tax allowance for the next regulatory period, consistent with our Initial Proposal and the Draft Decision.
- We have included an updated forecast of immediately deductible expenditure for the 2022-26 regulatory period based on our revised capex forecasts contained in this Revised Proposal.
- A recent Federal Court ruling on the tax treatment of gifted assets has not been applied in our Revised Proposal, due to timing constraints. We will work with the AER through the Q&A process on how this change should be applied. We note that applying this ruling will not impact the proposed 2022-26 tax allowance.

8.2 Chapter structure

The remainder of this chapter is structured as follows:

- Section 8.3 considers the opening tax asset base;
- Section 8.4 considers standard tax lives;
- Section 8.5 considers immediately deductible expenditure;
- Section 8.6 considers our proposed tax allowance;
- Section 8.7 considers large customers – embedded generators;
- Section 8.8 considers our proposed tax allowance; and
- Section 8.9 outlines the supporting documents for this chapter.

In the event of inconsistency between information contained in this chapter and our Initial Proposal, the information contained in this chapter prevails.

8.3 Opening tax asset base

8.3.1 Our Initial Proposal

We proposed a roll forward of the Tax Asset Base (TAB) using actual and forecast net capex and depreciation as outlined in the table below. However, we noted that:

- net capex for regulatory years 2019, 2020 and the 6 months to June 2021 were forecasts; and
- we would be updating our 2019 net capex with actuals as part of our Revised Proposal.[170]

Table 8-1: Tax Asset Base roll forward to 1 January 2021 ($m nominal) – Initial Proposal

Regulatory year	2016	2017	2018	2019	2020	2021 (first 6 months)
Opening TAB	2,191.8	2,403.8	2,649.8	2,942.4	3,279.3	3,598.2

170 For further information refer to Chapter 15 of the Initial Proposal.

Regulatory year	2016	2017	2018	2019	2020	2021 (first 6 months)
Plus capex, net of disposals	311.7	358.2	411.9	457.9	469.4	222.3
Less straight-line depreciation	-99.6	-112.2	-119.4	-120.9	-150.5	-87.7
Final year asset adjustments						-
Closing TAB	**2,403.8**	**2,649.8**	**2,942.4**	**3,279.3**	**3,598.2**	**3,732.8**

Source: AusNet Services

8.3.2 Draft Decision

The AER accepted our proposed method to establish the opening TAB as at 1 July 2021, but increased the value to $3,733.7 million. This reflects the AER's use of actual 2019 capex rather than the placeholder forecast we used in our Initial Proposal. The AER also made some minor amendments to our 2018 gross capex inputs.

8.3.3 Response to the AER's Draft Decision

We agree with the new regulatory period Opening TAB figure in the AER's Draft Decision. However, the accuracy of our capex forecasts for the remaining years of the current regulatory period continues to improve and we have included our most recent forecasts in our Revised Proposal.

As noted in Chapter 5 of this Revised Proposal, we have updated our placeholder forecasts for 2020 and the half year period.

8.3.4 Revised Proposal

Incorporating the most recent actual and forecast capex information for the current regulatory period, we propose an Opening TAB for the new regulatory period of $3,682.7 million (nominal). This is 1.4% lower than the value established in the AER's Draft Decision.

Table 8-2: Tax Asset Base roll forward to 1 January 2021 ($m nominal) – Revised Proposal

Regulatory year	2016	2017	2018	2019	2020	2021 (first 6 months)
Opening TAB	2,191.8	2,403.8	2,649.8	2,942.3	3,240.1	3,506.5
Plus capex, net of disposals	311.7	358.2	411.9	418.7	408.8	231.4
Less straight-line depreciation	-99.6	-112.2	-119.4	-120.9	-142.4	-82.9
Final year asset adjustments						27.8

Regulatory year	2016	2017	2018	2019	2020	2021 (first 6 months)
Closing TAB	**2,403.8**	**2,649.8**	**2,942.3**	**3,240.1**	**3,506.5**	**3,682.7**

Source: AusNet Services Revised Proposal RFM (2016-21)

8.4 Standard tax lives

8.4.1 Our Initial Proposal

Our proposed standard tax lives for new additions for the forthcoming regulatory period are reproduced in the table below. At the time of our Initial Proposal, these reflected the applicable tax lives contained in the ATO's tax ruling 2018/4, except for capitalised leasing assets, which are aligned with their respective proposed standard RAB lives. For Non-network – Metering related IT assets, we proposed a standard life of 3 years, consistent with the approved standard life for the current regulatory period.

Table 8-3: Proposed Standard Tax Lives for new additions – Initial Proposal

Asset class	Standard life (Years)	DV rate (200%)
Sub-transmission	43.0	4.7%
Distribution system assets	46.0	4.3%
SCADA/Network control	10.0	20.0%
Non-network general assets - IT	4.0	50.0%
Non-network general assets - Other	12.0	16.67%
Non-network - Metering related IT	3.0	66.67%
Land	n/a	n/a
Non-network Leasehold Land & Buildings – 1 July 2021 *	n/a	n/a
Non-network Leasehold Land & Buildings – 2021-22 *	23.7	n/a
Non-network Leasehold Land & Buildings – 2022-23 *	n/a	n/a
Non-network Leasehold Land & Buildings – 2023-24 *	n/a	n/a
Non-network Leasehold Land & Buildings – 2024-25 *	n/a	n/a
Non-network Leasehold Land & Buildings – 2025-26 *	5.0	n/a
Buildings	40.0	n/a

Asset class	Standard life (Years)	DV rate (200%)
In-house software	4.0[171]	n/a
Equity raising costs	5.0	n/a
Equity raising costs 1 Jan – 30 June 2021	5.0	n/a

Source: AusNet Services Initial Proposal PTRM 2022-26

8.4.2 Draft Decision

The AER's Draft Decision accepted our proposed standard tax lives for existing assets, as these are:

- Consistent with our standard tax lives for the 2016-20 regulatory period; and
- Broadly consistent with the tax asset lives prescribed by the Commissioner for Taxation in ATO taxation ruling 2020/3.

However, the AER did not accept:

- Our proposed 'Non-network - Metering related IT' asset class; and
- The standard tax life for 'in-house software' asset class which is a straight-line depreciating class. We proposed a 4 year standard tax life, however, the AER considered this should be 5 years, as this is the guidance provided in the *Income Tax Assessment Act 1997*.[172]

The AER also reviewed the proposed opening TAB remaining tax lives and determined 2 year remaining tax asset lives were appropriate for the 'Accelerated depr - distr assets (contingent project 3)' and 'Accelerated depr - distr assets (other)' asset classes. In our Initial Proposal, there were no remaining tax lives proposed for these asset classes in the TAB, and we had not proposed a reallocation of opening TAB value from existing tax asset classes.

In response to an information request from the AER prior to the Draft Decision[173], we submitted a 2 year remaining tax life from 1 July 2021 consistent with our proposed RAB remaining lives, which the AER accepted in the Draft Decision. We also provided a calculation of the opening TAB value of assets subject to accelerated depreciation, which the AER accepted[174], and accordingly it has reallocated the values for both accelerated depreciation asset classes from 'Distribution system assets' class.

The AER's Draft Decision on standard and remaining tax asset lives as at 1 July 2021 is shown below.

171 The standard life for 'In-house software' class is amended to 5 years in our Revised Proposal.

172 AER, Draft Decision, AusNet Services distribution determination 2021-26, Attachment 7 - Corporate income tax, September 2020, p. 10.

173 AusNet Services, response to information request IR#041, 29 June 2020.

174 AER, Draft Decision, AusNet Services distribution determination 2021-26, Attachment 7 - Corporate income tax, September 2020, p. 19.

Table 8-4: AER's Draft Decision on standard tax lives and remaining tax lives (years)

Asset class	Standard tax asset life	Remaining tax asset lives as at 1 July 2021[b]
Subtransmission	43.0	36.3
Distribution system assets	46.0	35.1
SCADA/Network control	10.0	8.2
Non-network general assets - IT	4.0	3.1
Non-network general assets - other	12.0	7.3
Land	n/a	n/a
Secondary systems (pre 2016)	n/a	5.3
Accelerated depr - distr assets (contingent project 3)	n/a	2.0
Accelerated depr - distr assets (other)	n/a	2.0
Non-network leasehold land & buildings - 1 July 2021	n/a	9.3
Non-network leasehold land & buildings – 2021–22	23.7	n/a
Non-network leasehold land & buildings – 2025–26	5.0	n/a
Buildings - capital works	40.0[a]	n/a
In-house software	5.0[a]	n/a
Equity raising costs	5.0[a]	3.1

Source: AER analysis.

8.4.3 Revised Proposal

We accept the AER's Draft Decision on tax asset lives in the 2022-26 regulatory period, including:

- The 5 year standard tax life for the 'in-house software' asset class proposed by the AER;[175]
- The 2 year remaining tax lives for the two accelerated depreciation asset classes, 'Accelerated depr - distr assets (contingent project 3)' and 'Accelerated depr - distr assets (other)'.

As noted in Chapter 5, we also accept the removal of the 'Non-network - Metering related IT' asset class and re-allocation of capex costs associated with these IT assets to the existing 'Non-network general asset - IT' asset class.

175 See our response to information request IR#041 – Q.2, 29 June 2020.

8.5 Immediately deductible expenditure

8.5.1 Our Initial Proposal

We submitted our forecast for immediately deductible capex for the 2022–26 regulatory period as outlined in the table below.

Table 8-5: Forecast immediately deductible expenditure 1 July 2021 to 30 June 2026 ($m Jun $2021) – Initial Proposal

Asset class	2021-22	2022-23	2023-24	2024-25	2025-26
Sub-transmission	26.7	33.9	33.7	21.4	10.3
Distribution system assets	103.4	97.5	98.0	109.5	124.5
SCADA/Network control	13.8	12.5	12.1	13.0	9.0
Non-network – IT	2.4	2.4	2.4	2.4	2.4
Non-network - Other	0.7	0.7	0.7	0.7	0.7
in-house software	-	-	-	-	-
Total	**147.0**	**147.0**	**147.0**	**147.0**	**147.0**

Source: AusNet Services Initial Proposal PTRM 2022-26

This forecast was provided in the PTRM (Version 4) that was submitted to the AER as part of our Initial Proposal. The aggregate figure for each regulatory year represents the 4 year historical average. This approach was applied because immediately deductible expenditure is, in practice, determined by the tax year in which assets are commissioned into service, rather than the annual capex profile.

We stated that the amount of immediately deductible expenditure fluctuates year on year, reflecting the capital value of assets commissioned in a year, rather than following the annual capex trendline.[176] For this reason, we applied a 4 year historical average approach of immediately deductible expenditure by asset class. We considered this approach to be a reasonable proxy for future years' immediate deductible capex, providing that the current levels of replacement expenditure in the current regulatory period are similar in the next regulatory period.

8.5.2 Draft Decision

In the Draft Decision the AER rejected our forecast immediate expensing of capex over the 2021–26 regulatory period, arguing that it:

- Reflects a simple average of the actual immediately expensed capex claimed over 2015–2019; and
- Provides a forecast for immediate expensing that is disproportionate to overall forecast capex, as it results in a fixed amount irrespective of total forecast capex.[177]

[176] AusNet Services, EDPR 2022-26 Regulatory Proposal Part III, p. 226.

[177] AER, Draft Decision, AusNet Services distribution determination 2021-26, Attachment 7 - Corporate income tax, September 2020, p. 16.

The AER further stated that it disagrees with the proposed approach as it does not take into account the rate of immediate expensing of capex relative to actual capex (immediate expensing rate).[178] Instead, the AER commented that a distributor's actual immediate expensing rate, over the most representative years, should inform its forecast rate. The AER also noted that it is reasonable to expect that the same proportion of capex will also be deducted immediately by AusNet Services during the 2022–26 regulatory period.[179]

In making its decision on the amount of immediate expensing of capex, the AER considered the further information provided by us in response to information requests, including:

- A mapping of our recent immediate expensing proportions applied to the overall proposed forecast capex for the 2022-26 regulatory period;[180] and
- Our current tax principles for determining immediately expensed capex that is attributable to capitalised overheads.[181]

The AER's Draft Decision on immediately expensing capex for the 2022-26 regulatory period is shown in the table below.

Table 8-6: Forecast immediately deductible expenditure 1 July 2021 to 30 June 2026 ($m Jun $2021) – Draft Decision

Asset class	2021-22	2022-23	2023-24	2024-25	2025-26
Sub-transmission	29.5	39.8	40.1	23.1	10.5
Distribution system assets	104.2	107.5	109.3	110.4	118.5
SCADA/Network control	14.4	13.4	13.2	12.9	8.5
Non-network – IT	0.4	0.3	0.4	0.3	0.3
Non-network - Other	-	-	-	-	-
in-house software	2.2	2.3	2.2	2.3	2.3
Total	**150.8**	**163.2**	**165.1**	**149.0**	**140.2**

Source: AER - Draft Decision - AusNet Services distribution determination - 2021-26 - PTRM - September 2020

8.5.3 Response to AER's Draft Decision

Notwithstanding that we do not consider the approach applied by the AER in the Draft Decision will necessarily lead to a better estimate of immediately deductible expenditure, we accept the AER's approach.

8.5.4 Revised Proposal

We have updated the AER's forecast of immediately deductible capex based on our updated capex forecast model (confidential version) which contains an updated forecast of immediately

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178 Ibid.

179 Ibid.

180 AusNet Services, response to information request IR#004-Q7, 14 April 2020.

181 AusNet Services, response to information request IR#026, 9 June 2020.

deductible expenditure (as-incurred basis) for the 2022-26 regulatory period. The amended forecast is set out in the following table.

Table 8-7: Forecast immediately deductible expenditure 1 July 2021 to 30 June 2026 ($m Jun $2021) – Revised Proposal

Asset class	2021-22	2022-23	2023-24	2024-25	2025-26
Sub-transmission	32.1	41.6	39.6	21.6	8.5
Distribution system assets	102.3	106.2	109.8	111.9	120.7
SCADA/Network control	14.9	13.9	13.0	12.5	8.0
Non-network – IT	0.4	0.3	0.4	0.3	0.3
Non-network - Other	-	-	-	-	-
in-house software	2.3	2.3	2.2	2.3	2.3
Total	**151.9**	**164.3**	**165.0**	**148.6**	**139.8**

Source: AusNet Services Revised Proposal PTRM 2022-26

8.6 Final year adjustments

8.6.1 Our Initial Proposal

We proposed several final year adjustments in the RFM for both the RAB and TAB. These adjustments were associated with accelerated depreciation of existing network assets in the 2022-26 regulatory period, which included a proposed re-allocation of estimated TAB values from existing network asset classes to accelerated depreciation asset classes.

We proposed accelerated depreciation in the TAB for selected SCADA/Network control assets including:

- Re-allocation of $122.0 million from existing asset classes into proposed ‘'Secondary systems (pre 2016)' asset class; and
- Depreciating these assets over 5.3 years.

We submitted our supporting calculation for this opening TAB value as part of our Initial Proposal.[182]

Our initial proposal is reproduced in the table below:

Table 8-8: Proposed Final Year Asset Adjustments (30 June 2021), $Nominal

Asset class	Proposed TAB adjustments ($M)	Remaining life of adjustments to TAB (Yrs)
Sub-transmission	-34.9	28.5
Distribution system assets	-87.2	26.2

182 ASD - Opening TAB adjustments - 310120 – PUBLIC, January 2020.

Asset class	Proposed TAB adjustments ($M)	Remaining life of adjustments to TAB (Yrs)
Secondary systems – pre 2016	122.0	5.3
Accelerated Depr - Distr assets (Contingent Project 1)	-	-
Accelerated Depr - Distr assets (Contingent Project 2)	-	-
Accelerated Depr - Distr assets (Contingent Project 3)	-	-
Accelerated Depr - Distr assets (Other)	-	-
Total	**-**	**n/a**

Source: AusNet Services Initial Proposal RFM 2016-21

8.6.2 Draft Decision

The AER's Draft Decision on final year adjustments accepted in principle our proposal to accelerate depreciation in the TAB for the relevant SCADA/Network control assets in the 2022-26 regulatory period.

The AER amended our proposed end of period reallocation for the 'Secondary systems (pre 2016)' asset class, stating that:

> *… we reduced the RAB reallocation for this asset class to $196.6 million from $209.1 million. Consistent with the reasons set out in attachment 4, we have reduced the TAB reallocation to $114.7 million from $122.0 million, reflecting our draft decision reduction to the RAB reallocation.*[183]

In addition, the AER reallocated opening TAB values to the existing asset class 'Accelerated depr – distr assets (contingent project 3)' and the new asset class of 'Accelerated depr – distr assets (other)' in relation to accelerated depreciation of certain high bushfire risk assets, which have been, or are forecast to be replaced.

The AER commented that we did not submit a TAB reallocation for these asset classes in our Initial Proposal, and requested further information from us.[184] After considering our response, the AER agreed that accelerated tax depreciation in the TAB should be considered if accelerated depreciation in the RAB were approved for identified assets associated with proposed 'contingent project 3 (Part B)' and 'other' Distribution system assets."[185]

183 AER, Draft Decision, AusNet Services distribution determination 2021-26, Attachment 7 - Corporate income tax, September 2020, p. 18.

184 AER information request IR#041 – Q.1(a)&(b), 24 June 2020.

185 Response to information request IR#041 – Q.1(a), 29 June 2020.

As part of our response to the AER's information request, we also provided our calculation of the opening TAB values for inclusion in the final year adjustments[186 & 187], which the AER has accepted in its Draft Decision.[188]

The table below contains the AER's Draft Decision for final year adjustments.

Table 8-9: AER's Draft Decision Final Year Asset Adjustments (30 June 2021), $Nominal

Asset class	Proposed TAB adjustments ($m)	Remaining life of adjustments to TAB (Yrs)
Sub-transmission	-32.8	28.5
Distribution system assets	-85.4	26.2
Secondary systems – pre 2016	114.7	5.3
Accelerated Depr - Distr assets (Contingent Project 1)	-	-
Accelerated Depr - Distr assets (Contingent Project 2)	-	-
Accelerated Depr - Distr assets (Contingent Project 3)	2.2	2.0
Accelerated Depr - Distr assets (Other)	1.2	2.0
Total	**-**	**n/a**

Source: AusNet Services Initial Proposal RFM 2016-21

8.6.3 Response to AER's Draft Decision

In response to the AER's Draft Decision on final year adjustments, we accept:

- The AER's amended opening TAB value of $114.7 million for selected SCADA/Network control assets in the next regulatory period (and associated TAB re-allocations from existing asset classes); and
- Depreciating these SCADA/Network control assets over 5.3 years; and
- The inclusion of accelerated depreciation in the TAB over 2 years for existing network assets that will be, or already have been, de-commissioned as part of our REFCL implementation program. This includes the re-allocation of opening TAB values from the 'Distribution system assets' class.

8.6.4 Revised Proposal

Our Revised Proposal is to accept the AER's Draft Decision on these final year adjustments in the TAB as outlined above.

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186 Response to information request IR#041 – Q.1(b), 29 June 2020.

187 ASD - IR041 - Opening tax values calculation – Public, 29 June 2020.

188 AER, Draft Decision, AusNet Services distribution determination 2021-26, Attachment 7 - Corporate income tax, September 2020, p. 19.

8.7 Large customers – Embedded generators

We are proposing to charge large embedded generators the net tax cost to AusNet Services that results from their connection. This is a change to our Connection Policy and is described in Chapter 11 of this Revised Proposal.

This change does not impact on our proposed tax allowance for the 2022-26 regulatory period.

8.8 Proposed tax allowance

8.8.1 Our Initial Proposal

Consistent with the information contained in the PTRM for the current regulatory period (including the 1 January - 30 June 2021 PTRM), our Initial Proposal indicated that we would have no accumulated tax losses as at 1 July 2021. Our forecast of the tax allowance for the 2022-26 regulatory period is outlined below.

Table 8-10: Tax allowance 1 July 2021 to 30 June 2026 ($m nominal) – Initial Proposal

Regulatory year	2021-22	2022-23	2023-24	2024-25	2025-26
Tax payable	-	-	-	-	-
Imputation credits	-	-	-	-	-
Tax allowance	**-**	**-**	**-**	**-**	**-**

Source: AusNet Services Initial Proposal PTRM 2022-26

8.8.2 Draft Decision

The AER's Draft Decision agreed with our assessment and set the cost of corporate income tax at zero for the 2022-26 regulatory period.

Table 8-11: Tax allowance 1 July 2021 to 30 June 2026 ($m nominal) – Draft Decision

Regulatory year	2021-22	2022-23	2023-24	2024-25	2025-26
Tax payable	-	-	-	-	-
Imputation credits	-	-	-	-	-
Tax allowance	**-**	**-**	**-**	**-**	**-**

Source: AER Draft Decision PTRM 2022-26

We note in the following regulatory period (2026-31), the AER's Draft Decision gives rise to a carry forward tax loss as at 30 June 2026 of $266.2 million (nominal), which is $116.4 million higher than our Initial Proposal of $149.8 million (nominal).

8.8.3 Response to AER's Draft Decision and Revised Proposal

Based on our updated inputs in the PTRM model (Version 4), including our updated forecast of immediately deductible capex (as outlined above), the cost of corporate income tax is consistent with our Initial Proposal and AER's Draft Decision, being zero.

We are aware of the 21 October 2020 decision of the Full Federal Court of Australia which relates to the tax treatment of customer contributions. Specifically, for gifted assets, the Court found that there is net nil taxable income for income tax purposes, while the associated rebate should be treated as a tax depreciating asset. The Commissioner of Taxation has not appealed this decision.

Given the timing of this decision, we have not been able to reflect this change in our Revised Proposal. However, as we have not proposed a regulatory tax allowance over the 2022-26 regulatory period, incorporating this change will not impact revenues. It would however impact the value of tax losses. We will work with the AER through the Q&A process if it would like us to incorporate this change.

Table 8-12: Tax allowance 1 July 2021 to 30 June 2026 ($m nominal) – Revised Proposal

Regulatory year	2021-22	2022-23	2023-24	2024-25	2025-26
Tax payable	-	-	-	-	-
Imputation credits	-	-	-	-	-
Tax allowance	**-**	**-**	**-**	**-**	**-**

Source: AusNet Services Revised Proposal PTRM 2022-26

Under this Revised Proposal, the estimated carried forward tax loss at the start of the next regulatory period (2026-31) is $259.3 million (nominal), which is $6.9 million lower than the Draft Decision and $109.5 million higher than our Initial Proposal.

8.9 Supporting documents

We have included the following documents to support this chapter:

- ASD – EDPR 2022-26 Revised Proposal – Capex Model (2021-26) – 031220 – CONFIDENTIAL
- ASD – EDPR 2022-26 Revised Proposal – PTRM Model (2022-26) – 031220 – PUBLIC
- ASD – EDPR 2022-26 Revised Proposal – 5.5 year RFM (2016-21) – 031220 - PUBLIC

9 Incentive schemes

9.1 Key points

We have accepted the AER's Draft Decision for each of the incentive schemes and, as invited by the AER, have updated these schemes to reflect the latest available information.

9.2 Chapter structure

The remainder of this chapter is structured as follows:

- Sections 9.3 to 9.9 responds to the Draft Decision by providing updated information in relation to:
    - The Customer Satisfaction Incentive Scheme (CSIS);
    - The System Target Performance Incentive Scheme (STPIS);
    - The Guaranteed Service Levels (GSLs);
    - The f-factor scheme;
    - The Demand Management Incentive Scheme (DMIS) and Allowance Mechanism (DMIAM);
    - The Efficiency Benefits Sharing Scheme (EBSS);
    - The Capital Efficiency Sharing Scheme (CESS); and
- Section 9.10 sets out our supporting documents for this chapter.

In the event of inconsistency between information contained in this chapter and our Initial Proposal, the information contained in this chapter prevails.

9.3 Customer Satisfaction Incentive Scheme

9.3.1 Our initial proposal

Following extensive engagement with the Customer Forum, we proposed the application of a CSIS in the 2022-26 regulatory period. We considered its adoption would result in a more holistic incentive to improve customer satisfaction. Recognising the interactions with the AER's existing STPIS, we also proposed that the existing telephone answering parameter in the STPIS should not apply to us in the 2022-26 regulatory period.

We also outlined that our CSIS had been agreed with the Customer Forum, was in accordance with the AER's draft CSIS and that, as the final form of the scheme was ongoing, revisions may be necessary.

9.3.2 Draft Decision

The AER accepted our Initial Proposal, noting that the final targets will be set once we provided updated performance data for 2019-20.

9.3.3 Revised Proposal

We have accepted the AER's Draft Decision and, as requested by the AER, have updated the CSIS with the most recent customer satisfaction survey (C-SAT) performance data for 2019-20.

We have also proposed fixed target and deadbands for each year of the next regulatory period and updated the annual reporting template to reflect this. Our proposed targets and deadbands are outlined Table 9-1. We have communicated these to the Customer Forum (30 October 2020).

As a result of our commitment to improving customer service and satisfaction we have recorded higher scores in the Planned outages, New connections and Complaints parameters since we submitted our Initial Proposal. Accordingly, the targets for these three parameters have increased to reflect the use of all available data more accurately. For Unplanned outages, our customer satisfaction performance in this parameter has remained consistent with the target set in our Initial Proposal.

Table 9-1: CSIS parameters, targets and financial components – Revised Proposal

Scheme parameter	Target (out of 10)	Deadband (out of 10)	Reward/penalty for a 1 point change compared to target
Planned outages	7.4	7.3 – 7.5	$484,246
Unplanned outages	6.5	6.3 – 6.7	$484,246
New connections	6.6	6.4 – 6.8	$484,246
Complaints	3.8	3.8 – 5.0	$242,123

Source: AusNet Services

9.4 Service Target Performance Incentive Scheme

9.4.1 Our Initial Proposal

We proposed STPIS targets and incentive rates as outlined in the table below.

Table 9-2: STPIS targets and incentive rates for 2022-26 – Initial Proposal

Measure	Average historic performance	Modification	Proposed targets	Proposed incentive rates
USAIDI				**(%/minute)**
Urban	76.7477	0	76.7477	0.0228%
Rural short	188.0970	0	188.0970	0.0217%
Rural long	270.8687	0	270.8687	0.0093%
USAIFI				**(%/0.01 Interruptions)**
Urban	0.8284	0	0.8284	1.4074%
Rural short	1.9773	0	1.9773	1.3263%
Rural long	2.5821	0	2.5821	0.6547%
MAIFI				**(%/0.01 Interruptions)**
Urban	2.6959	0	2.6959	0.1126%
Rural short	5.7583	0	5.7583	0.1061%

Rural long	10.5565	0	10.5565	0.0524%
Telephone answering				
% of calls will be answered within 30s	82.96%	0	82.96%	-0.040

Source: AusNet Services

In proposing these targets and incentive rates we noted that:

- The telephone answering parameter should be replaced with the CSIS; and
- If the AER does not approve a final CSIS, then the telephone answering parameter should continue to apply in the STPIS.

9.4.2 Draft Decision

The AER accepted the reliability targets set out in our Initial Proposal. However, the AER updated the incentive rates to reflect its Draft Decision revenues and changes to the Values of Customer Reliability (VCR).

The AER's Draft Decision on our STPIS incentive rates and reliability targets are outlined below.

Table 9-3: STPIS incentive rates for 2022-26 – Draft Decision

	Urban	Short rural	Long rural
SAIDI	0.0243	0.0231	0.0099
SAIFI	1.5003	1.4670	0.6922
MAIFI	0.1200	0.1174	0.0554

Source: AER

Table 9-4: STPIS targets for 2022-26 – Draft Decision

	Value
Urban	
SAIDI	76.748
SAIFI	0.828
MAIFI	2.696
Short rural	
SAIDI	188.097
SAIFI	1.977

MAIFI	5.758
Long rural	
SAIDI	270.869
SAIFI	2.582
MAIFI	10.557

Source: AER

9.4.3 Revised Proposal

We have accepted the AER's Draft Decision, noting that we have updated the scheme to reflect our Revised Proposal's revenues, and to reflect inflation. Our revised STPIS targets and incentive rates are outlined in the table below.

Table 9-5: STPIS targets and incentive rates for 2022-26 – Revised Proposal

Measure	Average historic performance	Modification	Proposed targets	Proposed incentive rates
USAIDI				**(%/minute)**
Urban	76.7477	0	76.7477	0.0240
Rural short	188.0970	0	188.0970	0.0229
Rural long	270.8687	0	270.8687	0.0098
USAIFI				**(%/0.01 Interruptions)**
Urban	0.8284	0	0.8284	1.4839
Rural short	1.9773	0	1.9773	1.4509
Rural long	2.5821	0	2.5821	0.6846
MAIFI				**(%/0.01 Interruptions)**
Urban	2.6959	0	2.6959	0.1187
Rural short	5.7583	0	5.7583	0.1161
Rural long	10.5565	0	10.5565	0.0548

Source: AusNet Services.

9.5 Guaranteed Service Levels

9.5.1 Our Initial Proposal

We proposed GSL amounts for the next regulatory period based on the historical average pay-out from 2015 to 2019. However, we noted that the ESC was consulting on changes to the GSL scheme and we would need to:

- Incorporate any changes to the GSL scheme into our Revised Proposal; and
- Ensure relevant transitional arrangements are made to ensure that the existing scheme is appropriately closed out.

9.5.2 Draft Decision

The AER accepted our Initial Proposal and noted that our Revised Proposal will need updating for the ESC's final decision on GSLs.

9.5.3 Revised Proposal

The ESC's final decision proposed slightly higher payment rates, slightly lower payment thresholds, and the introduction of Major Event Day (MED) exclusions.[189] To understand the net impact of these changes, we have re-cast our historical data from 2015 to 2019 for the final scheme. Our modelling estimated that if the final scheme had applied during the 2015 to 2019 period, our average GSL payment would have been $6.4 million per year (nominal).

Consistent with the AER's previous approach, and its Draft Decision, we propose adopting the updated historical average as our forecast for the upcoming regulatory period. This gives rise to the forecast GSL allowance set out in the table below.

We have also proposed transitional payments to close out the current scheme. See Chapter 4 for more details.

Table 9-6: Proposed GSL allowance for 2022-26 – Revised Proposal ($m, nominal)

	2021-22	2022-23	2023-24	2024-25	2025-26	Total
GSL	6.4	6.4	6.4	6.4	6.4	31.9

Source: AusNet Services

9.6 F-factor scheme

9.6.1 Our Initial Proposal

We proposed a f-factor Ignition Risk Units (IRU) target based on the f-factor scheme order 2016[190] and the targets as specified in that scheme. We noted this target and the associated incentive rate will be updated throughout the regulatory period in accordance with any revised Order in Council.

[189] ESC, Electricity Distribution Code review – customer service standards, Draft Decision, 7 May 2020.

[190] http://www.gazette.vic.gov.au/gazette/Gazettes2016/GG2016G051.pdf

9.6.2 Draft Decision

The AER accepted our Initial Proposal. It considered that the adjustment will be a ‘I-factor’ component in the annual revenue requirement calculation formula.

9.6.3 Revised Proposal

Our Revised Proposal is consistent with the AER’s Draft Decision and the f-factor scheme Order is as outlined below.

Table 9-7: Proposed target and incentive rate for 2022-26 – Revised Proposal

Measure	Annual target	Incentive rate
Fire start target	221.1	$15,000

Source: AusNet Services

9.7 Demand Management Incentive Scheme and Innovation Allowance

9.7.1 Our Initial Proposal

In our Initial Proposal, we adopted the new DMIS without modification. The DMIS applies a cost uplift of up to 50% of expected costs of efficient demand management projects, subject to a net benefit constraint and an overall incentive constraint.

In relation to the DMIAM, we proposed an allowance of $3.46 million ($2020–21).

9.7.2 Draft Decision

The AER largely accepted our Initial Proposal, reducing the DMIAM marginally ($0.12 million ($2020–21)) to reflect its Draft Decision revenues. See table below.

In coming to this decision, the AER highlighted the compliance reports and supporting documents requirement associated with the scheme and that it would determine the eligibility and specific incentive payments for each project according to the requirements of the DMIS.

Table 9-8: DMIAM allowance – Draft Decision ($m, real 2020-21)

	2021-22	2022-23	2023-24	2024-25	2025-26	Total
DMIAM	0.7	0.7	0.7	0.6	0.6	3.3

Source: AER

9.7.3 Revised Proposal

We have accepted the Draft Decision, noting that we have updated our proposal to reflect revenues that align with our Revised Proposal (see below). As already noted, the AER will update the allowance in its Final Decision.

Table 9-9: DMIAM allowance – Revised Proposal ($m, real 2020-21)

	2021-22	2022-23	2023-24	2024-25	2025-26	Total
DMIAM	0.7	0.7	0.7	0.7	0.7	3.6

Source: AusNet Services

9.8 Efficiency Benefit Sharing Scheme

9.8.1 Our Initial Proposal

We proposed an EBSS carryover amount of $90.3 million ($2020–21) in our Initial Proposal.

In proposing this carryover amount we noted that:

- A revised accounting standard (AASB 16) applied from 1 April 2019 which meant leases must be treated as capex rather than opex;
- We removed lease costs from the opex used for the EBSS calculation in 2018 to be consistent with the base year used for forecasting opex in the base, step and trend forecasting approach; and
- If the AER did not accept this change to our opex for EBSS purposes, we would need to add the lease amounts back into our opex allowance for the purposes of the base, step and trend forecasting methodology.

9.8.2 Draft Decision

The AER rejected our proposal and approved a carryover amount of $109.3 million ($2020–21) from the application of the EBSS in the 2016-20 regulatory period and the six-month extension period. Key changes made by the AER included:

- Updating for 2019 opex actuals;
- Not excluding the forecast and actual opex of the self-insurance cost category in 2014 and 2015 from total opex;
- Removing different amounts to account for the movement in provisions from actual opex;
- Accounting for the capitalisation policy changes coming into effect from 2019 as a base non-recurrent efficiency adjustment, rather than adjusting reported opex in 2018 as we had proposed; and
- Updating for inflation.

The AER's Draft Decision is reflected in the table below.

Table 9-10: EBSS carryover amount – Draft Decision ($m, 2020-21)

	HY2021	2021-22	2022-23	2023-24	2024-25	2025-26	Total
EBSS carryover amount	12.5	55.2	36.3	15.4	-4.0	-6.2	109.3

Source: AER

9.8.3 Revised Proposal

We have accepted the AER's Draft Decision on the EBSS carryover amount of $109.3 million ($2020–21) as outlined in Table 9-10 above.

Table 9-11 below sets out the proposed opex for the EBSS in the 2022-26 regulatory period.

Table 9-11: Proposed opex for the EBSS in the 2022-26 regulatory period – Revised Proposal ($m, real 2020-21)

	2021-22	2022-23	2023-24	2024-25	2025-26
Forecast opex (excluding DMIA)	237.4	238.6	240.3	242.4	245.4
Less excluded costs					
Debt raising costs	2.2	2.2	2.3	2.3	2.3
GSL	9.5	9.3	9.2	9.0	8.9
Innovation Program	0.2	0.2	0.2	0.2	0.2
Opex for EBSS	**225.4**	**226.8**	**228.6**	**230.9**	**233.9**

Source: AusNet Services

Note: Movements in provisions are not forecast and therefore not excluded for this purpose.

9.9 Capital Efficiency Sharing Scheme

9.9.1 Our Initial Proposal

We proposed a CESS carryover amount of $47.5 million ($2020–21) for the 2022-26 regulatory period as outlined below.

Table 9-12: Proposed CESS carryover amount – Initial Proposal ($m, real 2020-21)

	2021-22	2022-23	2023-24	2024-25	2025-26	Total
CESS carryover amount	9.5	9.5	9.5	9.5	9.5	47.5

Source: AusNet Services

Importantly, and as discussed in section 9.8 (above), we reflected the revised accounting standard (AASB 16) in our calculation of the CESS carryover amount.

9.9.2 Draft Decision

The AER's Draft Decision was to apply a CESS revenue increment of $56.5 million ($2020–21) for the next regulatory period. It also confirmed that the CESS will not apply over the 6 months from 1 January 2021 to 30 June 2021.[191]

The drivers for these changes were the adoption more recent inflation data, an updated WACC and the inclusion of actual capex for 2019.

The AER also indicated that it would update the final decision for further changes to inflation.

191 AER 2020, AusNet Services Distribution Determination 2021 to 2026, Attachment 9 capital expenditure sharing scheme, Draft Decision, September, p. 9-5.

Table 9-13: CESS carryover amount – Draft Decision ($m, real 2020-21)

	2021-22	2022-23	2023-24	2024-25	2025-26	Total
CESS carryover amount	11.3	11.3	11.3	11.3	11.3	56.5

Source: AER

9.9.3 Revised Proposal

We have proposed a CESS revenue increment of $72.6 million ($2020–21) for the next regulatory period, as set out in the table below.

Our proposed CESS numbers are higher than the AER's Draft Decision primarily due to our updated 2020 actual capex being lower than our Initial Proposal, primarily due to COVID-19 impacts on our capital works programs including planned replacement works. See section 5.5.3 for more information.

We have included the net value of capex deferred to the next regulatory period for Kalkallo (see Chapter 3) of $14.5 million ($2021-22) which reduces the potential CESS benefit by $4.5 million. We are forgoing this $4.5 million payment which we would otherwise receive, if not for the revised project timing as outlined in chapter 3. The net value of capex deferred takes into account our actual costs incurred in the current regulatory period that were funded under the approved contingent project. We have included our calculation of this deferred capex as a supporting document to this Revised Proposal.

The table below sets our our revised proposal for the CESS carryover amount.

Table 9-14: CESS carryover amount – Revised Proposal ($m, real 2020-21)

	2021-22	2022-23	2023-24	2024-25	2025-26	Total
CESS carryover amount	14.5	14.5	14.5	14.5	14.5	72.6

Source: AusNet Services.

Our CESS carryover amount of $72.6 million is based on the inputs and calculation outlined in the table below.

Table 9-15: CESS carryover amount inputs and calculation – Revised Proposal ($m, real 2020-21)

	2016	2017	2018	2019	2020
Capex allowance	333.1	418.7	395.4	431.8	416.7
Actual capex	287.9	332.6	367.3	381.6	348.8
Underspend	45.2	86.1	28.1	50.2	67.8
Year 1 benefit		1.7	1.7	1.7	1.7
Year 2 benefit			3.3	3.3	3.2
Year 3 benefit				1.1	1.0

Year 4 benefit					1.8
Year 5 benefit					
NPV underspend	55.9	101.6	31.3	52.8	67.8
NPV financing benefit	0.0	2.0	5.6	6.4	7.8
CESS calculation (post-adjustment)					
Total underspend (NPV) adjusted for deferrals	295.6				
Relevant sharing ratio	30%				
Consumer share	206.9				
NSP share	88.7				
Total NSP financing benefit (NPV)	21.9				
NPV of CESS payments (post-adjustment) as at 31 December 2020	66.8				
NPV of CESS payments (post-adjustment) as at 30 June 2021	68.5				

Source: AusNet Services.

Table 9-16 below sets out our Revised Proposal capex for the CESS in the 2022-26 regulatory period.

Table 9-16: Proposed capex for the CESS in the 2022-26 regulatory period – Revised Proposal ($m, real 2020-21)

	2021-22	2022-23	2023-24	2024-25	2025-26
Forecast Capex	382.1	400.5	346.3	318.4	314.3
Less excluded costs					
Customer Contributions	47.3	67.8	68.3	69.0	69.5
Asset Disposal	1.3	1.3	1.3	1.3	1.3
Equity Raising Costs	0	0	0	0	0
Innovation Program	1.3	1.3	1.3	1.3	1.3
Capex for CESS	**332.1**	**330.0**	**275.4**	**246.8**	**242.2**

Source: AusNet Services

9.10 Supporting documents

We have included the following documents to support this chapter:

- CSAT data, targets and reporting template;
- STPIS incentive rates calculation;
- ASD – EDPR 2022-26 Revised Proposal – DMIA Allowance Calculation (2022-26) – 031220 – PUBLIC;
- ASD – EDPR 2022-26 Revised Proposal – CESS Model (2022-26) – 031220 – PUBLIC; and
- ASD – EDPR 2022-26 Revised Proposal – KLO Cost Comparison – 031220 – PUBLIC

10 Pass through arrangements

10.1 Key points

- We have accepted the AER's Draft Decision in relation to the following pass through events:
    - Insurer credit risk event;
    - Natural disaster event;
    - Terrorism event; and
    - Retailer insolvency event.
- We also welcome the AER's Draft Decision to accept the Insurance Coverage event, and we have suggested minor amendments to the definition. For the Insurance premium event, we have provided additional information to demonstrate that this event is reasonable and should be approved.
- We have proposed two new cost pass through events:
    - An Environment Protection cost pass through event associated with amendments to the *Environment Protection Act 2017.* This event will ensure we can access the pass through framework in the event we incur additional costs in order to comply with the amended environment protection legislation and associated subordinate.
    - A Major Cyber cost pass through event. This event will address the material risk associated with a cyber-attack, as the existing cost recovery frameworks do not afford us the opportunity to recover the totality of the costs associated with such an attack.
- The AER's Draft Decision did not accept the Electric Vehicle uptake nominated cost pass through event. While we are disappointed by this decision, we accept the AER's position
- The information set out in this chapter accords with all the applicable requirements of the NER.

10.2 Chapter structure

The remainder of this chapter is structured as follows:

- Section 10.3 considers the Insurance coverage event;
- Section 10.4 addresses the Insurer credit risk event;
- Section 10.5 discusses the Insurance premium event;
- Section 10.6 addresses the Terrorism event;
- Section 10.7 addresses the Natural disaster event;
- Section 10.8 addresses the Retailer insolvency event;
- Section 10.9 concerns the Electric vehicle uptake event;
- Section 10.10 outlines a new Environment protection event;
- Section 10.11 outlines a new Major cyber event; and
- Section 10.12 sets out the supporting documents for this chapter.

In the event of inconsistency between information contained in this chapter and our Initial Proposal, the information contained in this chapter prevails.

10.3 Insurance coverage event

10.3.1 Our Initial Proposal

In our Initial Proposal, we explained the rationale for the inclusion of an Insurance coverage event to mitigate the risk that we incur liability losses that exceed our insurance coverage.[192]

10.3.2 Draft Decision

The AER accepted the insurance coverage event we proposed and made some minor amendments to ensure consistency with recent AER decisions.

10.3.3 Response to AER's Draft Decision

We have accepted the AER's Draft Decision with respect to the application of an insurance coverage event. However, we propose to make further minor amendments to the Draft Decision's definition, these are highlighted in red below. The scope and intent of the pass through event remains unaltered; these changes have only been made to reflect defined terms.

An insurance coverage event occurs if:

1. *AusNet Services:*
    a) *makes a claim or claims and receives the benefit of a payment or payments under a relevant insurance policy or set of insurance policies; or*
    b) *would have been able to make a claim or claims under a relevant insurance policy or set of insurance policies but for changed circumstances; and*
2. *AusNet Services incurs costs:*
    a) *beyond a ~~relevant~~ policy limit for ~~that~~ the relevant insurance policy or set of insurance policies; or*
    b) *that are unrecoverable under ~~that~~ the relevant insurance policy or set of insurance policies (whether wholly or in part) due to changed circumstances; and*
3. *The costs referred to in paragraph 2 above, either separately or in aggregate, materially increase the costs to AusNet Services in providing direct control services.*
4. *For the purposes of this insurance coverage event:*
    a) *'base year' means the year used by the AER in the distribution determination as the base year to forecast operating expenditure in the 2022-26 regulatory control period.*
    b) *'changed circumstances' means movements in the relevant insurance liability market since the acquisition of the insurance policy or set of insurance policies that applied during the majority of the base year that are beyond the reasonable control of AusNet Services, where those movements result in ~~mean that~~ it ~~is~~ no longer being possible for AusNet Services to take out with a reputable insurer:*
        i. *a~~n~~ relevant insurance policy or,*
        ii. *in the case of a set of insurance policies, one or more layers of insurance within that set (or there are otherwise one or more gaps within the set),*

[192] For further information on this and our other proposed events refer to Chapter 17 of the Initial Proposal.

either at all or on reasonable commercial terms ~~that include some or all of the costs referred to in paragraph 2 above within the scope of that insurance policy or set of insurance policies~~.

c) 'costs' means the ~~costs~~ amount that would have been recoverableed under the relevant insurance policy or set of insurance policies had:

i. the limit not been exhausted; or

ii. those costs not been unrecoverable due to changed circumstances.

d) 'reputable insurer' means an insurer with a current financial security rating of "A-" or better by Standard and Poor's (or the equivalent rating with another reputable rating agency).

e) A relevant insurance policy or set of insurance policies is an insurance policy or set of insurance policies held during the regulatory control period or a previous regulatory control period in which AusNet Services was regulated; and

f) AusNet Services will be deemed to have made a claim on a relevant insurance policy or set of insurance policies if the claim is made by a related party of AusNet Services in relation to any aspect of AusNet Services' network or business; and

g) AusNet Services will be deemed to have been able to make a claim on a relevant insurance policy or set of insurance policies if, but for changed circumstances, the claim could have been made by a related party of AusNet Services in relation to any aspect of AusNet Services' network or business.

Note for the avoidance of doubt, in assessing an insurance coverage event through application under rule 6.6.1(j), the AER will have regard to:

i. the relevant insurance policy or set of insurance policies for the event

ii. the level of insurance that an efficient and prudent DNSP would obtain, or would have sought to obtain, in respect of the event;

iii. any guidance published by the AER on the matters the AER will likely have regard to in assessing any insurance coverage event that occurs; and

iv. any information provided by AusNet Services to the AER about AusNet Services' actions and processes.

10.4 Insurer credit risk event

10.4.1 Our Initial Proposal

We proposed an Insurer credit risk event to cover costs we may incur as a result of an insurer becoming insolvent.

10.4.2 Draft Decision

The AER accepted the Insurer credit risk event definition we proposed. The AER explained that:

- The insurer credit risk event was not already covered by an existing category of pass through event;
- The nature of the insurer credit risk event is clearly identifiable at this time; and

- As a prudent service provider, we cannot reasonably prevent an insurer credit risk event from occurring or substantially mitigate its cost impact and cannot insure (or self-insure) against the insurer credit risk event on reasonable commercial terms.

10.4.3 Response to AER's Draft Decision

We accept the Draft Decision with respect to the insurer credit risk event.

10.5 Insurance premium event

10.5.1 Our Initial Proposal

We proposed an 'Insurance premium event' to allow us to pass through costs where we incur costs above the allowance for insurance premiums included in the forecast opex allowance approved in the AER's final decision.

10.5.2 Draft Decision

The AER did not accept our proposed Insurance premium event because it was not satisfied that it met the nominated pass through considerations under the NER. It also noted that we did not provide sufficient supporting information in the Initial Proposal.[193]

The AER was not persuaded that we had sufficiently demonstrated that:

- The insurance coverage event does not already address key aspects of the unusual and uncontrollable risks faced by AusNet Services in the prevailing insurance liability market; and/or
- The unpredictable, infrequent, and high cost nature of the insurance premium was beyond our control.

10.5.3 Response to AER's Draft Decision

We do not accept the AER's Draft Decision with respect to the Insurance premium event. In this section, we provide additional information to enable the AER to satisfy itself that a cost pass through mechanism is the appropriate regulatory mechanism to recover the cost of materially higher insurance premiums, and to demonstrate that this event meets the nominated pass through event considerations. We have also proposed minor amendments to our original definition of an Insurance premium event to align with the drafting proposed by the other Victorian distributors.

1. *An Insurance premium event occurs if AusNet Services incurs costs ~~in respect of~~ procuring general liability insurance ~~premiums~~ products during the 2022-26 regulatory control period which exceeds the allowance for general liability insurance ~~premiums~~ products included in the forecast operating expenditure allowance approved in the AER's distribution determination for the 2021–26 regulatory control period for the relevant regulatory year.*

   ~~Note: Insurance premiums relate to the costs payable to obtain liability insurance cover during the regulatory control period commencing 1 July 2021 to 30 June 2026.~~

2. *Note: In making a determination on an Insurance premium event, the AER will have regard to, amongst other things:*

193 AER, Draft Decision, AusNet Services 2021–26: Attachment 15: Pass through events, pp. 15-16.

- *the level of general liability insurance cover that ~~a prudent and~~ an efficient and prudent DNSP operating a network similar to AusNet Services' would obtain in respect of liability exposure;*

  ~~(b) whether the insurance premiums allocated to AusNet Services is in accordance with its cost allocation methodology approved under rule 6.15 of the NER; and~~

  ~~(c) any assessment by the AER of AusNet Services' liability insurance cover in making its distribution determination for the 2021–26 regulatory control period.~~

- *any guidance published by the AER on matters the AER will likely have regard to in assessing any insurance premium event that occurs; and*
- *any information provided by AusNet Services to the AER about AusNet Services' actions and processes.*

Owning and operating an electricity distribution network in Victoria exposes the operator to significant bushfire liability risk, as south-eastern Australia is recognised as one of the world's most prone areas to bushfires.[194] As such, we rely on a combination of commercial insurance, self-insurance and regulatory protections to ensure that we have an efficient level of cover.

Businesses seek annual insurance cover from a global pool to address their maximum foreseeable loss (MFL). Therefore, trends in both domestic and international risks influence the price and volume of insurance cover available to Australian businesses. For example, AusNet Services' insurance cover is currently provided by approximately 50 underwriters from around the world. Cover lasts for 12 months (or one fire season) and must be renewed every year. Underwriters look to ensure the client is operating at or better than industry best practice.

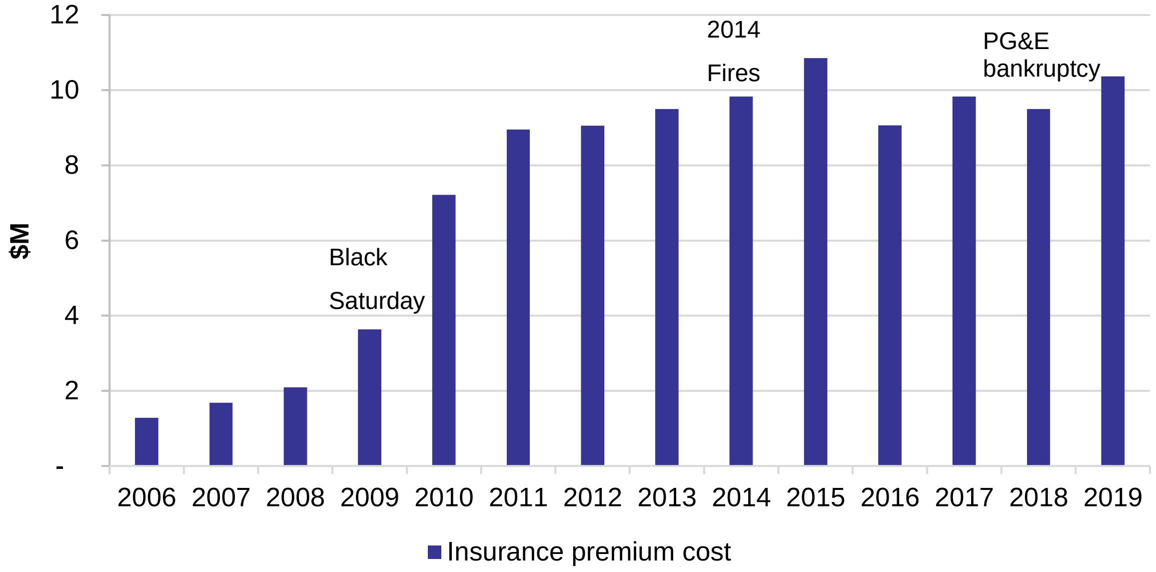
As mentioned in Bushfire insurance step change section 4.6.3.5, bushfire seasons are increasing in their frequency, length and severity, which is greatly exacerbating the risks faced by our network.[195] The upward pressure on insurance premiums has intensified following significant fire events, including those that occur outside of Australia.[196] Figure 10-1 below illustrates this trend over the last 15 years.

194 AON Bushfire Impact study.

195 AER, Draft Decision, AusNet Services 2021–26: Attachment 15: Pass through events, pp. 15-16.

196 For example, following the Californian bushfires in 2017, a number of insurers withdrew their bushfire liability insurance products or substantially increased their premiums and/or deductibles.

Figure 10-1: Distribution insurance premiums 2006-19



In response to the issues raised in the Draft Decision, we acknowledge that the insurance coverage event mitigates some of the uncontrollable risks within the prevailing insurance liability market to a degree. However, the focus of the insurance coverage event is on the recovery of costs that are not covered by the DNSP's insurance e.g. because it could not obtain insurance cover on reasonable commercial terms, or because the preferred level of cover was not available from the market. By its terms, it does not allow the DNSP to recover material increases in its insurance premium costs. Therefore, the insurance premium event is not already covered by an existing category of pass through event.

The trigger for an insurance coverage event is that a DNSP incurs costs beyond the limit of its insurance policy or set of policies and those costs are unrecoverable under that policy or set of policies. In essence, these are the costs that were uninsured or uninsurable. The way the trigger is crafted for the insurance coverage event means that increases in future costs as a result of the event that gave rise to the insurance coverage event (e.g. a bushfire or other event of similar destructive magnitude), are not recoverable under the insurance coverage event. Accordingly, an increase in the cost of insurance premiums in the year following a bushfire to price in the increased risk of similar future events cannot be incorporated into an insurance coverage event pass through application. Therefore, absent an insurance premium cost pass through event, we have no ability to address the unusual and uncontrollable risks in the insurance liability market other than through the distribution review process.

While we cannot influence the price underwriters set for their premiums, we make every effort to procure an efficient and prudent level of insurance at least cost and mitigate the impact of insurance premium increases on our customers. These actions we take include:

- Obtaining regular expert advice on the appropriate levels of cover for the MFL;
- Conducting an annual roadshow to key insurance markets in the UK, other parts of Europe, and China that informs insurers of the considerable asset management improvements and investments in bushfire mitigation technology, including REFCL, ACRs and undergrounding programs;
- Actively seeking out additional sources of insurance to replace insurance providers who are reducing levels of cover or exiting the market. This includes testing international insurance markets; and
- [C-I-C]

In response to the nominated pass through event considerations, we consider:

- The insurance premium event is not covered by any of the prescribed cost pass through events set out in the NER.
- The extent to which we can reasonably prevent an insurance premium event from occurring and/or can substantially mitigate the cost impacts of such an event is limited.
- The nature and type of an insurance premium event can be clearly identified at the time the determination is made for the service provider. Prior to renewal of our annual insurance premiums, we provide a detailed submission to our identified insurance broker outlining our bushfire mitigation practises, which the insurance broker then distributes to insurers. Typically, this submission is presented and provided to insurers in May/June. Since our bushfire insurance matures annually on 30 September, this submission allows for up to three months of negotiations between our broker and potential insurers. We begin to receive feedback in mid-August from our broker on what insurers intend to charge, and hence by the last week in September, our broker has negotiated all the necessary premiums and we bind cover knowing to total. Once we agree to the cost the broker then invoices AusNet Services for the various layers of cover – this invoice will detail the premium, stamp duty, GST, and other appropriate costs. Following this, we expect to receive invoices throughout October and November given we have several different insurers on the program. It is at this point, that an insurance premium event can be identified should there be a significant increase in costs relative to the allowance provided for in the AER's Final Decision.
- There is no market for insurance against increased insurance premiums, and we do not self-insure this risk. However, as outlined above, we already take preventive measures to self-insure risks where premium increases make commercial insurance inefficient. A pass through mechanism provides a more appropriate arrangement for managing the cost impacts in the event that an insurance premium event occurs and causes a material increase in our costs. It also allows us to identify our actual costs rather than predict premium increases using imperfect and asymmetric information. We consider that managing costs through a nominated pass through event is in the long-term interest of consumers.

The AER's Draft Decision explains that cost pass through events should be limited to circumstances where networks can recover potential costs of clearly defined yet highly unpredictable high cost events that are outside of their control.[197] We consider our proposed insurance premium event satisfies these requirements. As demonstrated by the evidence presented above (as well as in the Bushfire insurance step change section 4.6.3.5 in Chapter 4), increases in insurance premiums can give rise to significant costs that are both highly unpredictable and beyond our control. In our view, while we expect insurance premiums to keep increasing significantly more than the rate of change during the 2022-26 regulatory period, it is not possible to prepare a reliable estimate of this magnitude. This therefore makes additional premium costs increase to arise over and above the Bushfire Insurance premium step change increases based on 2021 actuals ill-suited to inclusion in our opex proposal. Therefore, we believe there is merit in nominating an insurance premium pass through event as it provides a reasonable opportunity to recover efficient costs incurred in providing direct control services. For our customers, it means that our opex allowance does not include estimated increases in insurance premiums that may not eventuate.

[197] AER, Draft Decision, AusNet Services 2021–26: Attachment 15: Pass through events, p. 4.

10.6 Terrorism event

10.6.1 Our Initial Proposal

We proposed a Terrorism event to provide cover against any losses caused by terrorism that are incurred above the limits provided by the proposed insurance coverage event. We noted that there is a need for both the insurance coverage and terrorism event coverage because we may incur costs that our insurance policy would not ordinarily cover.

10.6.2 Draft Decision

The AER accepted the terrorism event we proposed. The AER explained that:

- The terrorism event was not already covered by an existing category of pass through event;
- The nature of the terrorism event is clearly identifiable at this time; and
- As a prudent service provider, we cannot reasonably prevent a terrorism event from occurring or substantially mitigate its cost impact and cannot insure (or self-insure) against the terrorism event on reasonable commercial terms.

10.6.3 Response to AER's Draft Decision

We accept the Draft Decision with respect to the terrorism event.

10.7 Natural disaster event

10.7.1 Our Initial Proposal

We proposed a Natural disaster event to provide cover against any losses caused by a natural disaster that are incurred above the limits provided by the proposed insurance coverage event. We noted that there is a need for both the insurance coverage and natural disaster coverage as we may incur costs that our insurance policy would not ordinarily cover.

10.7.2 Draft Decision

The AER accepted the natural disaster event we proposed. The AER included additional factors which it will take into consideration when assessing a natural disaster cost pass through application, and it removed an additional reference to 'cyclone' in the definition. In accepting our natural disaster event, the AER explained that:

- The natural disaster event was not already covered by an existing category of pass through event;
- The nature of the natural disaster event is clearly identifiable at this time; and
- As a prudent service provider, we cannot reasonably prevent a natural disaster event from occurring or substantially mitigate its cost impact and cannot insure (or self-insure) against the event on reasonable commercial terms.

10.7.3 Response to AER's Draft Decision

We accept the AER's Draft Decision with respect to the natural disaster event.

10.8 Retailer insolvency event

10.8.1 Our Initial Proposal

We proposed a Retailer insolvency event to enable us to recover the costs we incur in the event of a retailer failure or insolvency event and the retailer's default on payment of its network charges. Our proposal also ensured consistency with other jurisdictions where a prescribed pass through event of this type is captured in the National Energy Retail Rules.

10.8.2 Draft Decision

The AER accepted the retailer insolvency event we proposed. In accepting our event, the AER explained that:

- The retailer insolvency event was not already covered by an existing category of pass through event;
- The nature of the retailer insolvency event is clearly identifiable at this time; and
- As a prudent service provider, we cannot reasonably prevent a retailer insolvency event from occurring or substantially mitigate its cost impact and cannot insure (or self-insure) against the retailer insolvency event on reasonable commercial terms.

10.8.3 Response to AER's Draft Decision

We accept the AER's Draft Decision with respect to the retailer insolvency event.

10.9 Electric vehicle uptake event

10.9.1 Our Initial Proposal

We proposed an electric vehicle (EV) uptake event to allow us to pass through costs associated with changes in government policy that drive EV uptake, and which impact our electricity distribution network.

10.9.2 Draft Decision

The AER did not accept our proposed EV uptake event because it was not satisfied that it met the nominated pass through considerations under the NER.

The AER was not persuaded that we had sufficiently demonstrated that:

- The risks that we had outlined – regulatory uncertainty, regulatory obligations that fall short of the NEL definition or policies announcements unaccompanied by a change in the law or regulatory instrument – would manifest; and/or
- The range of any such cost impacts is likely to be material.

10.9.3 Response to AER's Draft Decision

While we remain of the view that changes in government policy are likely to drive EV uptake and therefore impact our network, we have accepted the AER's Draft Decision with respect to the electric vehicle uptake event.

10.10 Environment Protection event

10.10.1 Our Revised Proposal

We are proposing a new 'Environment protection event' as part of our Revised Proposal to ensure appropriate protection should additional costs be required to comply with amendments made by the *Environment Protection Amendment Act 2018* to the *Environment Protection Act* 2017 and subordinate instruments made under the amended Act.

This event, while similar to the nominated Contamination remediation pass through event proposed in AusNet Services' 2023-27 Transmission Revenue Reset Proposal, is intended to recover the potential increases in costs in providing direct control services as a consequence of the Environmental Protection Act (EPA) reforms. Given the uncertainty as to the final scope and form of the subordinate instruments, we are not proposing to include any forecasts of operating or capex associated with the EPA Amendments and consider these costs are best addressed via the pass through framework, should they prove to be material.

10.10.1.1 Background and rationale

The amendments by the *Environment Protection Amendment Act 2018* to the *Environment Protection Act 2017* will create new obligations that will require us to take certain actions immediately upon the commencement of the amending legislation on 1 July 2021.

It is expected that the Environmental Protection Authority will create new instruments under the amended legislation prior to the start of the 2022-26 regulatory period. These actions may satisfy the prescribed regulatory change event definition (Section 2D(1)(b)(iii) of the NEL), which specifically refers to legislation or instruments made under that legislation which relate to the protection of the environment. However, we are seeking a nominated pass through event to ensure certainty that any material costs necessitated in order to comply with the reforms are recoverable in the 2022-26 regulatory period once all of the details of the EPA reforms package are known.

There are expected to be new duties associated with the amendment of the Act which involve:

- Identifying, assessing, and testing potential environmental risks of operations, including development and maintenance of a risk assessment framework;
- Testing for historical contamination (incurred before our ownership) and notifying the Environmental Protection Authority of the contaminated land sites; and
- Implementing prevention mechanisms to reduce the risk of contamination or pollution so far as reasonably practicable.

Due to the uncertain nature of the magnitude of expenditure associated with the reforms, we consider it prudent and efficient to nominate an Environment protection pass through event to recover any expenditure assessed to be material. The pass through event is defined as occurring when the DNSP prepares both a compliance plan in response to the reforms, and expenditure forecasts for implementing this plan. This is similar to the approach adopted by the AER for the REFCL contingent projects in the 2016-20 regulatory period. In that case, there was considerable uncertainty as to the costs that would be required to comply with the draft regulations at the time, such that it was not appropriate to include capex forecasts for required works within the building block proposals.[198] We consider the EPA reforms are best dealt with in a similar manner and, therefore, we have not proposed any forecasts in our opex or capex.

We consider that our environment protection event satisfies the nominated pass through event considerations and there is a sound basis for the AER to accept it as a nominated pass through event. It represents the most efficient and appropriate means of managing risk if such an event

[198] AER, Final decision, AusNet Services 2016-20: Attachment 6: Capital Expenditure, pp. 118-119.

occurs and materially increases our costs. This position is consistent with the nominated pass through event considerations:

- The environment protection event is not covered by any of the prescribed cost pass through events set out in the NER.
- The nature and type of the event can be clearly identified at the time that the AER makes its determination for us.
- The extent to which we can reasonably prevent an environment protection event from occurring and/or can substantially mitigate the cost impacts of such an event is limited.
- The relative infrequency and potentially significant financial costs of an environment protection event creates significant practical challenges for self-insuring such events. A pass through mechanism provides a more appropriate arrangement for managing the cost impacts in the event that an environment protection event occurs and causes a material increase in our costs. We consider that managing costs through a nominated pass through event is in the long-term interest of consumers.

Therefore, we consider there is merit in nominating an environment protection pass through event for the forthcoming regulatory period as it provides a reasonable opportunity to recover the efficient costs incurred in providing direct control services, as well as meeting the requirements of the nominated pass through event considerations.

10.10.1.2 Risk mitigation

We have developed sophisticated Health Safety, Environment and Quality (HSEQ) programs for the assessment of potential contamination and associated risks to both human health and the environment for each permanent site.

10.10.1.3 Proposed definition

Our proposed definition of an Environment Protection event is:

1. *An Environment Protection event occurs when AusNet Services has:*

   (a) *prepared, and approved internally, a compliance plan for meeting the requirements of the Amended EPA, including any instrument made or issued under the Amended EPA and any direction, order or notice issued or decision made pursuant to the Amended EPA or instrument made or issued under the Amended EPA; and*

   (b) *prepared a forecast of the capital and operating expenditure required to carry out the compliance plan.*

For the purposes of this environment protection event:

'Amended EPA' means the Environment Protection Act 2017 (Vic) as amended by the Environment Protection Amendment Act 2018 (Vic)

10.11 Major cyber event

10.11.1 Our Revised Proposal

We are proposing a new major cyber event as part of our Revised Proposal to ensure appropriate protection is established to address the material risk associated with a cyber-attack that is not considered an act of terrorism. Nominating this event ensures consistency with the nominated Major cyber event proposed in AusNet Services' 2023-27 Transmission Revenue Reset Proposal. Background information and our proposed definition is outlined below.

10.11.1.1 Background and rationale

The risk, frequency and severity of cyber-attacks is increasing rapidly. The Federal Government has recognised that there have been several cyber-attacks in Australia in recent years that have targeted the Federal Parliamentary network, airports, universities, health organisations, medical research facilities and other key supply chain businesses.[199] The Victorian Government's *Critical Infrastructure Resilience Strategy* acknowledges that cyber-attack is a global risk that is evolving rapidly as new technologies and systems emerge.[200] In light of the significant economic, social, environmental, political and national security costs that a cyber-attack can have, the Government considers cyber-attack is one of the emergency risks for which Victorian critical infrastructure owners and/or operators must prepare.[201]

We consider the probability of an attack to be low (although, as noted above, this probability is steadily increasing) but the consequences to be potentially severe. We play a critical role in supplying electricity to end use customers. As an integrated energy business (with electricity transmission and, gas and electricity distribution businesses) we also play a key role linking generators to our distribution network and the other Victorian-based DNSPs that supply electricity to end use customers, as well as our role in the wider NEM, where cross-border interconnectors link the Victorian transmission network to SA and NSW.

Due to the interdependent nature of our business, many of our information technology systems are used across each of our three regulated businesses. Therefore, a major cyber-attack intended to harm our transmission network is also highly likely to adversely impact our ability to provide direct control services. We consider it prudent to align the nominated Major cyber event for both our regulated transmission and distribution networks.

We acknowledge the AER's view that a major cyber-attack is a standard business risk that an NSP should manage.202 We have implemented a number of measures to avoid such an attack, and to respond quickly in the event that one does in occur in order to mitigate its impact, both operationally and financially.

Despite the preventative and remedial measures we have in place, there remains a material risk that if a cyber-attack occurs, we will not be able to recover the costs associated with the attack. These costs might include the costs incurred to restore the network to full operational capability, expenditure necessary to recreate or restore data and information, and the purchase and installation of additional cyber security tools and software to prevent further attacks. Therefore, we consider it is appropriate to propose a Major Cyber Event for inclusion as a nominated pass-through event in our distribution determination for the 2022-2026 regulatory period.

In addition, we consider that recovering these costs via the pass through framework rather than expenditure forecasts better contributes to the achievement of the National Electricity Objective as NSPs are not incentivised to over invest in infrastructure. Alternatively, mitigating risk via the cost pass mechanism is more likely to provide the lowest overall cost solution to customers. As a result, proposing a nominated Major cyber event contributes to the achievement of the National Electricity Objective.

We note that the AER has considered proposals to include a 'major cyber event' as a nominated pass-through event in a number of recent regulatory decisions.[203] One of the reasons it has not

[199] Department of Home Affairs, Protecting Critical Infrastructure and Systems of National Significance, Consultation Paper, August 2020, p. 6.

[200] Victorian Government, Critical Infrastructure Resilience Strategy, Melbourne, July 2015, 11, available at: https://files-em.em.vic.gov.au/public/EMV-web/Critical-Infrastructure_Resilience_Strategy_Sept-2016.pdf (accessed 02 December 2020).

[201] Ibid.

[202] AER, Draft Decision, Essential Energy distribution, 2019-24, Attachment 14, November 2018, 13; AER, SA Power Networks Distribution Determination 2020 to 2025, Draft Decision, Attachment 14 Pass through events, October 2019.

[203] AER, Draft Decision, Essential Energy distribution, 2019-24, Attachment 14, November 2018; AER, SA Power Networks Distribution Determination 2020 to 2025, Draft Decision, Attachment 14 Pass through events, October 2019; AER, Draft Decision, Powercor Distribution Determination 2021 to 2026, Attachment 15 Pass through events, September 2020; AER, Draft Decision, CitiPower Distribution Determination 2021 to 2026, Attachment 15 Pass through events, September 2020; AER, Draft Decision, United Energy Distribution Determination 2021 to 2026, Attachment 15 Pass through events, September 2020.

accepted the event is that a cyber-attack can amount to terrorism and therefore fall within an NSP's Terrorism Event definition.[204]

We do not agree that the Terrorism Event definition makes adequate provision for a major cyber event of the kind we propose. While there may be cyber events that constitute cyber terrorism and fall within the Terrorism Event definition, this will not always be the case. It could be because the motivation for the cyber event either cannot be determined or does not meet the requirements specified in paragraph 1(a) of the Terrorism Event definition. This leaves a gap in the cost pass-through framework because it prevents an NSP from being able to pass-through the costs of the event because of an inability to determine the motivation of the perpetrator(s) of a major cyber-attack. We do not consider it appropriate that an NSP should be disadvantaged in this way.

To the extent that a major cyber-attack does meet the definition of a Terrorism Event, our proposed event definition ensures the event is covered by only one category of pass-through event.

The AER has also previously commented that it will only accept nominated pass-through events where it is satisfied that event avoidance, mitigation, commercial insurance and self-insurance under approved forecasts of prudent and efficient opex and capex are either unavailable or inappropriate.[205] The longstanding nominated events which have been accepted in previous determinations (such as Natural Disaster and Terrorism) are predominantly designed to protect the physical security of NSP assets from the ever-present physical risks in society. We agree that avoidance, mitigation, and the procurement of insurance for these types of events are unavailable or inappropriate under a prudent and efficient expenditure forecast. However, the transition to a more digital way of working (accelerated further by the COVID-19 pandemic) has led to a shift in the likelihood of risks from physical security to cyber security. This supports the Major Cyber event, as there is no equivalent protection for cyber related assets in the pass-through framework as there is for physical assets.

10.11.1.2 Proposed definition

The proposed definition of a Major Cyber event is as follows:

> *1. A Major Cyber event is any significant and deliberate interference with AusNet Services' technology systems or assets (including, but not limited to, the introduction of malicious or harmful software, code or viruses to computer systems or networks, or to data or communication systems) carried out, directed or otherwise caused by an act of a third party that:*
>
> > *(a) falls into no other category of pass through event; and*
> >
> > *(b) increases the costs to AusNet Services of providing direct control services.*
>
> *2. In assessing a Major Cyber Event pass through application, the AER will have regard to, amongst other things:*
>
> > *(a) the steps AusNet Services took to prevent the event from occurring and to mitigate its consequences; and*
> >
> > *(b) the level and scope of any insurance AusNet Services holds in respect of a Major Cyber Event.*

10.11.1.3 Risk mitigation

In recent regulatory decisions, the AER has disallowed the inclusion of a 'major cyber event' as a nominated pass-through event primarily because it was not satisfied that the proponent could not

[204] AER, Draft Decision, Powercor Distribution Determination 2021 to 2026, Attachment 15 Pass through events, September 2020.

[205] AER, SA Power Networks Distribution Determination 2020 to 2025, Draft Decision, Attachment 14 Pass through events, October 2019.

reasonably prevent or substantially mitigate the cost impact of such an event, or insure or self-insure against such an event. We view cyber-attacks as a key business risk and use several strategies to try and manage them appropriately.[206]

Consistent with the AER's expectation,[207] we currently hold a cyber security insurance policy with an aggregate limit of $20 million.

[C-I-C]

However, while our insurance policies do provide some cover against losses caused by a major cyber event, the cost impact of such an event could exceed the limits or scope of these policies.

Furthermore, although we have been able to secure cover this year, we understand that some property and liability insurers are contemplating applying a cyber exclusion on their policies. If this were to happen, it may be problematic for us to obtain the level of cyber coverage in the future that would be expected of a prudent DNSP. Accordingly, insurance cover cannot be assumed to be available at current levels for the duration of the forthcoming regulatory period.[208]

Other risk mitigation strategies we employ include maintaining detailed Incident Response Plans as part of our wider cyber incident readiness assessment, which we are ready to implement should a major cyber incident occur. We consider this an appropriate and robust framework of risk mitigation to safeguard our systems and assets against the risks and cost impacts of cyber-attacks.

We also undertake prudent and efficient capital and operating expenditure during each regulatory period to ensure we proactively identify, protect, deter, respond to, and recover from cyber security threats. Some of the steps we have taken for this purpose include:

[C-I-C]

As already noted, the AER has disallowed previous 'major cyber event' definitions because it was not satisfied that the NSP could not reasonably prevent or substantially mitigate the cost impact of such an event, or insure or self-insure against such an event.[209] In our view, the actions and strategies outlined in this section demonstrate that we have taken the prudent and efficient steps available to us to deter or mitigate the effects of a major cyber-attack. As such, we believe the nominated pass-through event considerations are satisfied and it is appropriate that the AER accept our Major Cyber Event as proposed.

206 AER, Draft Decision, Essential Energy distribution, 2019-24, Attachment 14, November 2018, 13; AER, SA Power Networks Distribution Determination 2020 to 2025, Draft Decision, Attachment 14 Pass through events, October 2019, p. 13.

207 Ibid.

208 We acknowledge that, were there to be shortfall in available insurance cover below the level that a prudent and efficient DNSP would obtain, there may be a basis for submitting a claim for an Insurance Coverage Event. The drafting of the Major Cyber Event definition ensures the proposed event complies with paragraph (a) of the nominated pass through event considerations.

209 AER, Draft Decision, Essential Energy distribution, 2019-24, Attachment 14, November 2018, 13; AER, SA Power Networks Distribution Determination 2020 to 2025, Draft Decision, Attachment 14 Pass through events, October 2019, pp. 14-15.

10.12 Supporting documents

We have attached the following documents to support the Cost pass through chapter Revised Proposal:

- Appendix 10A: AON – Australian Bushfire Impact Study; and
- Appendix 10B: Insurance Certificate of Currency.

11 Connection policy

11.1 Key points

- We have accepted the majority of the AER's proposed changes to our connections policy, including:
    - Specifying the use of an average, diversity factor and peak, coincidental demand in determining the connection applicant's contribution; and
    - An updated augmentation threshold of 100 amperes (A) in total on 3 phase low voltage supply with no more than 40A per phase.
- We have not updated the augmentation threshold of 10 kilovolt amperes (kVA) on single-wire earth return (SWER) lines, as this change would enable customers to upgrade existing distribution transformers at no cost and therefore increase cross-subsidisation.
- We have also proposed additional amendments to our connection policy to better reflect the cost of extending High Voltage (HV) feeders connected to REFCL feeders.
- We have proposed a change to ensure that embedded generators pay the tax costs associated with their connection, so that other customers do not unfairly incur these costs.
- We have proposed updated Model Standing Offers (MSOs) that would replace existing MSOs for basic and standard connection services.

11.2 Chapter structure

The remainder of this chapter is structured as follows:

- Section 11.3 considers various policy issues associated with our connections policy;
- Section 11.4 sets out the supporting documents for this chapter.

In the event of inconsistency between information contained in this chapter and our Initial Proposal, the information contained in this chapter prevails.

11.3 Connection policy issues

11.3.1 Our Initial Proposal

As part of our Initial Proposal we submitted a connection policy that outlined our connection services, when connection charges may be payable by our retail customers and how those charges are calculated. Our connection policy had only minor changes from our previous policy, which was published in 2017.

11.3.2 Draft Decision

The AER did not approve our connection policy. It considered that it:

- Did not contain a classification for public lighting services; and
- Contained some conditions that were inconsistent with the AER's connection charge guidelines and the Victorian standards.

The AER provided an amended connection policy for us to consider and noted that its proposed changes were the minimum necessary to enable our policy to be approved in accordance with the NER.

11.3.3 Response to AER's Draft Decision

We have updated our connections policy to address most of the concerns identified by the AER. However, we have not updated the augmentation threshold of 10 kilovolt amperes (kVA) on single-wire earth return (SWER) lines or 100 amperes (A) in total on 3 phase low voltage supply with no more than 40A per phase.

As well as addressing the Draft Decision, we have also updated our policy to:

- Better capture the higher marginal cost of reinforcement in REFCL areas. This means that customers connecting in higher bushfire risk areas pay a cost commensurate with the network cost of that connection. It reduces cross-subsidisation of connection costs between different retail customers.
- Enable the net tax liability generated by the capital contribution of large embedded connections to be charged to these generators, rather than borne by our wider customer base. This reduces cross-subsidies and reflects charging arrangements for transmission-connected generators.
- Refer to our updated MSOs for micro Embedded Generation (EG) basic connection services and Standard Connection Services. These revised MSOs have been submitted for AER approval alongside this Revised Proposal.
- Amend the language used in our connections policy to improve its overall readability.

We explore each of these issues below.

11.3.3.1 Augmentation threshold

In the Draft Decision, the AER highlighted its concern that our proposed augmentation threshold was unreasonably low compared to its connection charge guideline, which recommends that the threshold should be 100A per each of the three-phase supply except SWER (SWER 25kVA). The AER proposed changes to our connections policy to ensure greater consistency between our proposed policy and its guideline on this matter.

Our 2018 ESC approved deemed connection agreements (and earlier agreements) maximum load limit for customers on SWER lines or customers supplied from single phase substations to 40A, unless otherwise agreed in writing. It is important to ensure customer expectations are consistent between jurisdictional and national frameworks. Therefore, the deemed connection agreement effectively establishes that the 10kVA augmentation threshold for SWER lines.

Adopting the AER's change would lead to significant cross subsidy, as existing customers would be able to request a larger capacity connection (up to 25kVA) at no additional cost. Our preliminary estimate is the additional connections capex would be $3-5 million per year for each year of the forthcoming regulatory period to replace 10 kVA transformers with 25 kVA transformers. Our strongly preferred approach is to avoid this additional cost by retaining our proposed threshold.

11.3.3.2 REFCL MCR update

In our Revised Proposal, we propose updates to our connection policy that apply different Marginal Cost of Reinforcement (MCR) unit rates for HV and zone sub-station connections in network areas subject to REFCL technical requirements.

A supply fed from a zone substation supported by REFCL technology or its transfer feeders may require additional works to maintain the required capacity prescribed by the Electricity Safety (Bushfire Mitigation) Regulations 2013. REFCL technology adds new inductance constraints and costs for network extensions that apply to the extension of HV feeders connected to REFCL assets, while extensions of the LV network connected to REFCL assets do not materially impact the REFCL technical requirements.

Each new individual load at HV level contributes to the eventual need to upgrade the REFCL connected distribution system. The application of REFCL specific MCR unit rates is the mechanism for customers to contribute to that future cost.

Our approach in calculating these REFCL specific MCR unit rates is consistent with the approach that the AER approved in our electricity distribution determination for the 2016-20 regulatory period.

We propose to include the MCR with REFCL variations in each connecting customer's Capital Contribution. The MCR concept, and underlying basis for calculation, aligns with the Incremental Cost Shared Network (ICSN) component of the Customer Contribution Formula. In parts of our network where REFCL technology is operating, the cost of augmentation for new HV connected load contributes to the eventual need to upgrade the connected distribution system REFCL technology.

The introduction of MCR REFCL unit means new HV customers would make an appropriate contribution to the costs of maintaining compliance with the REFCL Electricity Safety (Bushfire Mitigation) Regulations 2013 through their connection contributions. In our view, this approach will reduce cross subsidy by ensuring that all new HV connections on REFCL networks have regard to the incremental cost of their connection.

11.3.3.3 Large embedded generators tax charge

As outlined in our Revenue Proposal, we consider large embedded generator connections (>1.5MW) should not be classified as SCS. This is appropriate for the following reasons:

- These connections are bespoke and generally only benefit the individual application;
- The wider customer base currently pays the tax costs associated with these connections. This is a cross-subsidy that we do not believe is well-understood or intended; and
- Both AusNet Services and its customers are exposed to forecasting risk regarding these connections. That is, if the forecast is too high, a higher amount of tax contribution will be paid by customers than is required. If the forecast is too low, we will bear tax costs for which it will not be compensated.
- There is a high degree of uncertainty over the volume of these connections. These are very lumpy and heavily influenced by Government policy support for renewable generation in Victoria which contributes to the uncertainty around these forecasts; and
- Generators connecting to our transmission network contribute to the economic tax cost borne by us on the capital portion of their connection. Applying the same charges to distribution-connected generators achieves parity in this respect.

We note that the AER has classified large embedded generator connections as Alternative Control in both the SA Power Networks decisions and its Service Classification Guidelines. While the Victorian F&A did not specifically classify these services, the Victorian distributors included these in their SCS expenditure forecasts in their revenue proposals and the AER accepted this approach in its Draft Decision.

As outlined in our Initial Proposal, our preference would be for these services to be classified as ACS, contingent on AusNet Services being able to recover economic the tax costs being added into the formula for quoted services. However, we recognise there are restrictions around movements from F&A classifications. Therefore, we consider the best outcome for customers would be:

- Connections to remain SCS;
- We charge the economic tax costs to the embedded generator (equal to the tax costs arising from the provision of the service to a customer, netting off the present value of the reverse cash flow resulting from the depreciation of the capital contribution); and

- The tax charge is included in the contribution reported in our regulatory accounts, which means it would be deducted from the RAB. This will lower the RAB compared to the status quo approach, as the tax cost of these connections will be met by the connecting party rather than other customers. Over time this will lower prices for the wider customer base.

We have reflected appropriate wording in our Revised Connections Policy to give effect to our proposal. If accepted, we welcome the AER's input regarding the appropriate treatment from a regulatory accounting perspective. We also plan to engage with stakeholders on this issue prior to the due date for stakeholder submissions to the AER, being 8 January 2021.

If the AER accepts our proposal as reflecting the long run interests of our customers, to assist with regulatory accounting audits we request the AER to state that the tax charge should be included in the contribution in the regulatory accounts, and therefore be netted off the RAB this in its Final Determination.

11.3.3.4 Updated Model Standing Offers

In our Revised Proposal, we submit an updated micro Embedded Generation (EG) basic connection services and Standard Connection Services MSO for approval.

This new MSO will supersede our Micro EG basic connection services MSO that was established and approved updated in 2018. These MSOs have been developed to comply with Chapter 5A of the NER. They apply to the establishment or upgrade of micro embedded generation at a premise.

The updated MSO would provide applicants with greater discretion to install larger 10 kVA inverter energy systems (needed for battery storage system) on SWER lines subject to an assessment on a case by case basis.

The new pole-to-pit connections MSO for Standard Connection Services would supersede the new pole-to-pit and service joint-to-pit connections MSO with updated pre-calculated capital contribution amounts. These new amounts reflect our updated costs, MCR unit rates and other relevant factors for the forthcoming regulatory period.

11.3.3.5 Improved language

We have also made minor changes to the document to improve its readability. Apart of the issues discussed above, these changes do not alter the substance of our connections policy. A marked-up version of the amended policy has been provided to the AER to allow it to review the proposed changes.

11.4 Supporting documents

We have attached the following document to support this chapter:

- Connections policy – Appendix 11A;
- Model Standing Offer for basic connection services - Basic Micro Embedded Generation (Inverter Energy System – Battery, Solar, Wind); and
- Model Standing Offer for Standard Connection Services - Pole to Pit Connections

12 Control mechanism

12.1 Key points

We have accepted the AER's Draft Decision for control mechanisms, except in relation to the AER's decision to exclude:

- The annual ESV levies and AEMO fees from being included in the B-factor;
- Revenues that we have intentionally under-recovered to be counted as an under recovery for the purposes of the under and overs account; and
- Tax in the price cap formula for quoted ACS.

12.2 Chapter structure

The remainder of this chapter is structured as follows:

- Section 12.3 explores the control mechanisms for SCS; and
- Section 12.4 explores the control mechanisms for ACS.

In the event of inconsistency between information contained in this chapter and our Initial Proposal, the information contained in this chapter prevails.

12.3 Revenue cap Standard Control Services

12.3.1 Our Initial Proposal

In our Initial Proposal we outlined revenue cap formulae for SCS that:

- Were consistent with the control mechanisms set out in the AER's F&A, with amendments made to allow for a transition to a financial year regulatory period; and
- Ensure we have no scope to recover more revenue from our tariffs than the total revenue allowed by the AER.

We also noted that several terms, the calculation of CPI and the X-factor needed to be decided in the AER's Final Decision.[210]

We also proposed the inclusion of annual levies from the ESV in the B-factor.

12.3.2 Draft Decision

The AER rejected the inclusion of annual levies from the ESV in the B-factor.

The AER also said that in the event of an intentional under-recovery, this revenue will not be counted as an under recovery for the purpose of the under and overs account and by extension will therefore not subsequently increase the total allowable revenue in future years.

12.3.3 Revised Proposal

We accept the AER's Draft Decision as it concerns SCS, other than in relation to the exclusion of:

- Annual levies from the ESV and AEMO fees from the B-factor; and

210 For further information refer to Chapter 18 of the Initial Proposal.

- Revenues that we have intentionally under-recovered to be counted as an under recovery for the purposes of the under and overs account.

12.3.3.1 Levies and fees

We maintain our earlier submission that the B-factor is the most appropriate method to account for forecast increases in the ESV levy. This is due to both the materiality of the forecast increases in expenditure and the unsuitability of the rate of change as providing a true reflection of these costs. We have provided more details in Chapter 4 of this Revised Proposal.

Additionally, AEMO is proposing new fees on metering coordinators and DNSPs on the basis that these participants are utilising regulated reforms. As we will be required to pay these market fees to fulfil our obligations under electricity legislation as an exogenous requirement, we propose to recover these operating expenditures through the B-factor. We have provided more details in Chapter 4 of this Revised Proposal.

As a result of our positions above, we propose that the B-factor should be defined as:

B_t is the sum of annual adjustment factors for year t. It includes:

- the true-up for any under or over recovery of actual revenue collected through DUoS charges calculated using the following method:

  $DUoS\ Under\ and\ Overs\ True\text{-}Up_t = -(Opening\ Balance_t)(1+WACC_t)^{0.5}$

  where:

  $DUoS\ Under\ and\ Overs\ True\text{-}Up_t$ is the true-up for the balance of the DUoS unders and overs account in year t.

  $Opening\ Balance_t$ is the opening balance of the DUoS unders and overs account in year t as calculated by the method in Appendix A.

  $WACC_t$ is the approved weighted average cost of capital (WACC) used in regulatory year t in the DUoS unders and overs account in Appendix A. This WACC figure will be a nominal WACC figure that reflects actual inflation rather than forecast inflation. To calculate this nominal WACC, the real vanilla WACC from the annual update PTRM will be escalated for actual inflation.

- The license fee, annual levy and participant fee charges incurred by the Victorian businesses, payable to the Victorian Essential Service Commission, Energy Safe Victoria and the Australian Energy Market Operator respectively. The recovery of license fee, annual levy and participant fee charges will occur on a two-year lag, and will therefore be indexed by two years interest, calculated using the following method:

  $L_{t-2} \times (1+WACC_t) \times (1+WACC_{t-1})$

  where:

  L_{t-2} is the sum of: the license fees paid by the distributor to the Victorian Essential Services Commission; the annual levy paid by the distributor to Energy Safe Victoria; and the participant fees paid by the distributor to the Australian Energy Market Operator, relating to regulatory year t-2.

If our proposed approach is accepted, the ESV levy will be excluded from EBSS outcomes from 2019-20 onwards.

12.3.3.2 Intentional under-recovery

Our practice is to waive Critical Peak Demand charges for some our customers because they have made the requests based on valid reasons. We propose to continue this practice in the next regulatory period and have outlined criteria that we will take into account when assessing these applications. Where CPD revenue is waived for specific customers we propose that this should not be treated as intentional under-recovery and should be included in the unders and overs account.

If the AER's Final Decision is to exclude waived CPD revenue from being counted towards the over and unders account, then we would discontinue this practice, to the detriment of CPD customers.

See our Revised Tariff Structure Statement Compliance Document for more information.

12.4 Alternative control services

12.4.1 Our Initial Proposal

In our Initial Proposal, we outlined price cap formulae for ACS that was consistent with the AER's final F&A.

We also proposed adding tax and margin factors into the formulae for ACS other than for 'type 5 and 6 services' – quoted services.

12.4.2 Draft Decision

The AER rejected the inclusion of tax and margin factors in the formulae for ACS other than for 'type 5 and 6 services' – quoted services.

12.4.3 Revised Proposal

We accept the AER's Draft Decision as it concerns ACS, other than in relation to the exclusion of tax from price cap formula for quoted services. While we agree to the exclusion of margin from the price cap formula for quoted services, we have included a margin in the labour rate. We discuss our position in relation to the tax and margin factors in Chapter 14 of this Revised Proposal.

13 Metering services

13.1 Key points

- We accept most aspects of the AER's Draft Decision for metering services for the next regulatory period. However, we disagree with AER's proposed reallocation of certain type 5 and 6 IT and communications systems expenditures from ACS to SCS.
    - The AER provided an allocation based on meter data volumes of 6% for SCS and 94% to ACS but invited us to submit further information justifying an alternative allocation.
- We have submitted a revised allocation for our Mesh (UIQ)-WiMax licenses and Telstra Backhaul, with supporting justifications which results in:
    - $78.1 million ($2021) in metering capex, a reduction of $4.3 million ($2021) compared to the Draft Decision;[211] and
    - $73.3 million ($2021) in metering opex, $4.4 million ($2021) lower than the metering opex forecast set out in the Draft Decision under a revealed cost approach.[212]
- This expenditure has been re-allocated to SCS. Distribution capex and opex has therefore increased by $4.3 million and $4.4 million respectively.

13.2 Chapter structure

The remainder of this chapter is structured as follows:

- Section 13.3 outlines our approach to type 5 and 6 meters, including smart meters, unmetered installations and auxiliary metering services; and
- Section 13.4 sets out our supporting documents for this chapter.

13.3 Metering approach

13.3.1 Our Initial Proposal

Based on the forecast annual revenue requirements and meter volumes outlined in the Initial Proposal we proposed the following the indicative metering charges in the upcoming regulatory period. We proposed a revenue requirement for type 5 and 6 (including smart metering) services for the 2022–26 regulatory period of $292.9 million ($ nominal) or $272.1 million ($2021).

Table 13-1: Indicative alternative control metering services charges ($ nominal)

Meter type ($)	2021-22	2022-23	2023-24	2024-25	2025-26
Single phase single element	59.53	60.46	61.39	62.38	63.39
Single phase two element with contractor	71.30	72.60	73.92	75.27	76.64

211 This includes IT, communications, metering capex, capitalised leases and equity raising costs.

212 AER, Draft Decision: AusNet Services 2021–26: Attachment 16: Alternative control services, p. 45.

Meter type ($)	2021-22	2022-23	2023-24	2024-25	2025-26
Multiphase	85.90	87.30	88.72	90.17	91.64
Multiphase with contractor	95.20	96.80	98.43	100.08	101.76
Multiphase CT connected	118.00	119.20	120.41	121.64	122.87

Source: AusNet Services

We proposed exit fees for each of our relevant meter categories, for each year of the forthcoming regulatory period, which are outlined below.

Table 13-2: Proposed exit fee by meter type ($ nominal)

Meter type ($)	2021-22	2022-23	2023-24	2024-25	2025-26
Single phase single element	390.38	367.78	341.94	314.89	287.57
Single phase two element with contractor	387.01	364.86	339.46	312.84	287.57
Multiphase	388.91	366.53	340.89	314.03	287.57
Multiphase with contractor	388.91	366.53	340.89	314.03	287.57
Multiphase current transformer connected	389.10	366.68	341.02	314.14	287.57

Source: AusNet Services

In our Initial Proposal, we outlined that the charges for the provision of unmetered supply services have two components: a charge in respect of each NMI for which the data stream is calculated, and a charge for each light that is recorded on the Inventory table of lights for each public lighting customer. Consistent with historical practice, we proposed that the charges for both parts be adjusted by the CPI each year. We proposed the following Type 7 metering charges for unmetered supplies including public lighting customers.

Table 13-3: Proposed Type 7 metering charges ($ nominal)

Type 7 metering charge ($)	2021-22	2022-23	2023-24	2024-25	2025-26
Per NMI	30.00	30.74	31.49	32.26	33.05
Per light	1.78	1.82	1.86	1.91	1.96

Source: AusNet Services

Lastly, we proposed the following auxiliary metering services charges in line with the AER's Final F&A for the Victorian Electricity Distributors.[213] This included proposing to abolish fees associated with remote re-energisation and de-energisation services.

Table 13-4: Proposed auxiliary metering services charges ($ nominal)

Name of Service ($)	2021-22	2022-23	2023-24	2024-25	2025-26
Remote Special Meter Read	1.16	1.18	1.21	1.24	1.27
Remote Re-energisation	N/A	N/A	N/A	N/A	N/A
Remote De-energisation	N/A	N/A	N/A	N/A	N/A
Remote Meter Reconfiguration	15.11	15.49	15.86	16.25	16.65
Field Officer Visit Business Hours (Mon- Fri)	34.80	35.66	36.53	37.43	38.34
Field Officer Visit After Hours (Mon- Fri)	69.61	71.31	73.06	74.85	76.69
Manual Meter Reading Fee (per annum)	34.80	35.66	36.53	37.43	38.34
Priority Re-energisation	33.69	34.71	35.74	36.67	37.79
Non-standard AMI data subscription (per month)	0.00	15.08	1.58	0.85	0.61

Source: AusNet Services

13.3.2 Draft Decision

The AER did not accept our Initial Proposal. Specifically, it rejected our proposed:

- Reallocation of 50% of certain type 5 and 6 IT and communications systems expenditures from ACS to SCS, instead substituting its own allocations;
- Revenues for type 5 and 6 metering services, instead substituting its own proposed revenues for type 5 and 6 metering services;[214] and

213 See AusNet Services, Electricity Distribution Price Review 2022-26 Electricity Distribution Price Review 2022-26 Part IV (31 January 2020), p. 25.

214 This included adjusting the 2021 opening metering asset base to reflect the AER's December 2016 AMI transition charges applications final decision (as opposed to , updating 2019 forecast data with actuals, incorporating the impacts of COVID-19 on metering volume forecasts, applying alternative cost reallocation calculations and applying our Draft Decision rate of return, labour escalators, and inflation forecast (AER, Draft Decision: AusNet Services 2021–26: Attachment 16: Alternative control services, pp. 11-12).

- Metering exit fees, instead providing alternative charges reflecting adjustments to the building block components for type 5 and 6 (including smart metering) revenue.[215]

The AER also maintained a revenue cap for type 5 and 6 (including smart metering) services and maintained its final F&A position to apply price caps to auxiliary metering services (such as metering exit fees) as the form of control.

Regarding fee-based and quoted services, the AER also determined we should offer remote special read fees without charge, in line with the other Victorian distributors,[216] and provided a recommenced revised calculation and cost for non-standard AMI data requests.

This resulted in an overall revenue requirement of $297.0 million ($ nominal) or $276.6 million ($2021), with $82.5 million ($2021) in metering capex and $78.1 million ($2021) in metering opex.[217]

13.3.2.1 Cost allocations

In the current regulatory period, a portion of IT and communication metering costs have been allocated 100% to ASC. We proposed to allocate $29.8 million ($2021) in opex and $17.6 million ($2021) in capex from ACS to SCS due to the increasing operational reliance on this data to run the network. Accordingly, we proposed new allocations based on meter data volumes in our Initial Proposal.

The AER accepted the reasonableness of reallocating a portion of metering costs from ACS to SCS and the appropriateness of our causal indicator based on meter data volumes.

However, the AER revised the allocation of certain IT and communications metering costs based on substituted meter data volume requirements. It reallocated $8.1 million opex from ACS to SCS and $2.1 million capex from ACS to SCS.[218] In doing so, the AER challenged the assumptions we used to derive proposed allocations relating to power quality data usage and noted:

> *Collecting power quality data from one per cent of meters instead of 85% of meters and meter alarm data from ten per cent of meters instead of from every meter results in an allocation based on meter data volumes of 94:6 ACS:SCS.*[219]

The AER also noted that:

- Their technical experts considered that most of this data would be unlikely to be of any value in managing network power quality and as a result that one alarm from 10% of the meter population per day would be relevant and meaningful to the management of power quality. The AER did not provide any further details or accompanying reports of this expert analysis.
- Distribution businesses may want to collect power quality data from a small number of sites per low voltage feeder in areas of high DER penetration due to the associated voltage issues, but that this would represent a very small proportion of the network.

As a result, the AER substituted its own assumption that resulted in an allocation based on meter data volumes of 6% for SCS (essentially a sampling approach), with the remaining 94% be allocated to ACS for Mesh (UIQ)-WiMax licenses and Telstra Backhaul.[220] However, the AER invited us to provide further information to justify an alternative allocation, stating:

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215 AER, Draft Decision: AusNet Services 2021–26: Attachment 16: Alternative control services, p. 26.

216 AER, Draft Decision: AusNet Services 2021–26: Attachment 16: Alternative control services, p. 18.

217 AER, Draft Decision: AusNet Services 2021–26: Attachment 16: Alternative control services, pp. 43, 45.

218 AER, Draft Decision: AusNet Services 2021–26: Attachment 16: Alternative control services, p. 42.

219 AER, Draft Decision: AusNet Services 2021–26: Attachment 16: Alternative control services, p. 41.

220 AER, Draft Decision: AusNet Services 2021–26: Attachment 16: Alternative control services, p. 42.

> *We encourage AusNet Services in its revised proposal to provide more details on the volumes of data it is seeking to collect in regards to power quality management, to describe how it will use that data (the objectives), and to provide details on how it has determined the extent of data required to achieve the objectives stated.*[221]

13.3.3 Response to AER's Draft Decision

We accept most aspects of the AER's Draft Decision. However, we disagree with the AER's proposed reallocation of certain type 5 and 6 IT and communications systems expenditures from ACS to SCS. As a result, we are proposing the following reallocations shown in the table below.

Table 13-5: Reallocation of AMI IT and Comms capex and opex

	Draft Proposal	Revised Proposal	Basis of reallocation
Mesh (UIQ) Licensing Opex and Mesh network asset maintenance (Capex)	• 94% ACS • 6% SCS	• 80%ACS • 20%SCS	UIQ & Mesh licenses cover annual support and maintenance costs UIQ and SIQ. As SIQ licence is used solely within our business for SCS purposes we propose to allocate this licence component to SCS.
Telstra Mesh 'Backhaul'	• 94% ACS • 6% SCS	• 64% ACS • 36% SCS	Telstra charges cover the transport of all data collected from our meters back to our internal systems. We propose a revised allocation based on data volumes, of 64% ACS and 34% to SCS; while more data is collected by SIQ (which is used exclusively for SCS purposes), the size of the data is much smaller.

Source: AusNet Services

We have also accepted the AER's Draft Decision in relation to fee-based and quoted services, which is outlined in more detail below.

Lastly, we have updated the model for changes that have occurred since the Draft Decision relating to the rate of change, labour escalators and inflation in alignment with SCS opex. We have also updated the model to correct for an escalation error provided in the Draft Decision which resulted in a $4.3 million ($2021) capex reduction and a $4.3 million ($2021) opex reduction to the 2022-26 metering forecasts as compared to the Draft Decision. Further details of this correction can be found in section 5.8 of the opening RAB chapter.

13.3.3.1 Cost allocations

As noted above, we disagree with this finding as it does not reconcile with our actual usage of this data; a full utilisation of this power quality data is essential to increasing the accuracy of our modelling and reporting capabilities. The table above provides our revised allocations, which are based on the associated meter data volumes used by ACS and SCS accordingly. See Attachment EDPR Revised Allocation Metering for further information. Note the other expenditure allocated to SCS remains there. For example, we reversed the opex model Draft Decision

221 Ibid.

metering adjustment but instead added a metering step change (although we do not object to final decision allocation adjustments being put through as a base year adjustment).[222]

An alternative sampling approach would degrade the effectiveness of these capabilities. For example, collecting meter alarm data on only 10% of meters may lead to a lack of detection of critical safety issues on our network. Further, the collection of power quality data from only 1% of meters, as the AER suggested, would create several issues including:

- Less accurate assessments of DER capacity for customers via our online solar approval tool;
- Reduced ability to detect energy theft, leading to potential increases in unaccounted for energy;
- Reduced ability to detect loss of neutral across our customer base, potentially leading to serious electrocution incidents;
- Reduced accuracy to detect cross-referencing issues, which may cause customer outage notification breaches;
- Inability to implement future customer and safety initiatives e.g. real-time outage detection, fuse-candling detection; and
- Reduced ability to ensure network stability through a reduction in our capability to perform phase detection for all our meters.

13.3.3.2 Fee-based and quoted services

We accept the AER's proposal regarding the following ancillary network service fees:

- Remote Special Meter Read – This service will be included free of charge to all customers to align to other Victorian Network businesses. Our ancillary service charge model will be updated to remove this fee.
- Non-standard AMI data subscription service (monthly) – This service charge will be updated in the ancillary service charge model to reflect the AER's Draft Decision on pricing for this service.

13.3.4 Revised Proposal

As a result of our revised allocations, we propose a revenue requirement of $291.1 million ($ nominal) or $271.1 million ($2021), with $78.1 million ($2021) in metering capex and $73.3 million ($2021) in metering opex. We propose the following indicative metering charges for the next regulatory period.

222 See AusNet Services Revised Proposal - 2021-26 - Opex model.

Table 13-6: Revised Proposal indicative alternative control metering services charges ($ nominal)

	2021-22	2022-23	2023-24	2024-25	2025-26
Single phase single element	62.12	62.57	63.02	63.58	64.02
Single phase two element with contactor	71.60	72.10	72.60	73.00	73.62
Multiphase	83.45	83.90	84.42	84.90	85.40
Multiphase with contactor	91.54	92.00	92.50	92.90	93.40
Multiphase CT connected	114.46	115.89	116.00	116.80	117.20

Source: AusNet Services

We propose the following exit fees for the next regulatory period.

Table 13-7: Revised Proposal exit fee by meter type ($ nominal)

	2021-22	2022-23	2023-24	2024-25	2025-26
Single phase single element	365.02	349.59	331.07	310.00	287.23
Single phase two element with contactor	361.97	346.93	328.81	308.12	287.23
Multiphase	363.69	348.45	330.11	309.22	287.23
Multiphase with contactor	363.69	348.45	330.11	309.22	287.23
Multiphase CT connected	363.86	348.59	330.23	309.32	287.23

Source: AusNet Services

13.4 Supporting documents

We have included the following documents to support this chapter:

- ASD – EDPR 2022-26 Revised Proposal - Metering capex model – 031220 – CONFIDENTIAL;
- ASD – EDPR 2022-26 Revised Proposal - Metering opex model - 031220 – PUBLIC;
- ASD – EDPR 2022-26 Revised Proposal - Metering RFM model - 031220 – PUBLIC;
- ASD – EDPR 2022-26 Revised Proposal - Metering Depreciation Model - 031220 – PUBLIC;
- ASD – EDPR 2022-26 Revised Proposal - Metering charges model - 031220 – PUBLIC;
- ASD – EDPR 2022-26 Revised Proposal - Metering PTRM model - 031220 – PUBLIC; and
- ASD – EDPR 2022-26 Revised Proposal - Attachment Metering Reallocation Calculations – 031220 – CONFIDENTIAL;

14 Alternative Control Services

14.1 Key points

14.1.1 Fee based and quoted services

- We have accepted the Draft Decision on ACS for fee based and quoted services, except for labour escalation, minor changes to several charges for fee-based services and adding a new hourly rate for senior engineers.
- We have accepted the Draft Decision that after-hour charges for fee based services should be limited to 175% of the business hour charges.
- We have accepted the AER's decision to remove our proposed margin from quoted fees. We also agree with the AER's consultant's view that a margin should be included in labour rates, providing that the total allowance is subject to benchmarking. In response to the Draft Decision we have proposed:
    - Minor changes to the single-phase underground and overhead connection rates to include contractor's charges costs;
    - The introduction of an hourly rate for senior engineers to manage the increased number of large connections on the distribution network; and
    - To include a margin in our labour rates, providing that the total amount does not exceed the benchmark set by the AER's consultant.

14.1.2 Public lighting services

- As requested by the AER, we have undertaken additional consultation over three meetings with our public lighting customers (Local Governments (LG)) to understand whether the Draft Decision or an alternative model meets their needs.
- Through this process we have agreed a co-funding program for exchanging mercury vapour (MV) lights with efficient light-emitting diode (LED) lights, and an improved approach to smart street lighting. Our Revised Proposal incorporates these outcomes, as they better reflect the preferences of our public lighting customers.
- We also agreed that LGs should be given the opportunity to coordinate their lighting exchange program using AusNet Services' and the Municipal Association of Victoria's approved resources.
- We have accepted the AER's Draft Decision amendments to our public lighting model, except for labour escalation rates and the amendments to the T5 replacement and repair daily rates that were inconsistent with the benchmark comparisons.

14.2 Chapter structure

The remainder of this chapter is structured as follows:

- Section 14.3 considers fee based and quoted services;
- Section 14.4 considers public lighting;
- Section 14.5 considers the form of control; and
- Section 14.6 sets out our supporting documents for this chapter.

In the event of inconsistency between information contained in this chapter and our Initial Proposal, the information contained in this chapter prevails.

14.3 Fee based and quoted services

14.3.1 Introduction

In our Initial Proposal explained the basis of our proposed fees for:

- ACS for connections - fee based;
- ACS for network ancillary services - fee based; and
- Quoted Services.

In addition to the existing services, we also explained that we would be open to offering new services during the forthcoming regulatory period subject to the AER's approval as part of our annual pricing proposal.

We consider each of these service categories in turn below.

14.3.2 Alternative Control Services for connections - fee based

14.3.3 Our Initial Proposal

Consistent with the classification in the AER's F&A, we proposed fee-based connection services for ACS in the forthcoming regulatory period. These proposed fees would enable us to recover our costs of providing these services from those customers requesting the service.

Our proposed prices for fee-based services were based on competitive tendered contract rates. As these rates are market tested, we explained that they represented the efficient cost of providing fee-based ACS services. We also noted that our market tested, after-hours rate was higher than our business-hours rate. This higher rate reflected longer travel times between jobs and limited opportunities to bundle connections in close geographical proximity.

The table below reproduces the connection service fees we proposed in our Initial Proposal.

Table 14-1: Alternative Control Services for connection fees (real 2021 $s) – Initial Proposal

Connection service	2020	2021-22
Single Phase Overhead – Business Hours	437.66	482.29
Single Phase Overhead – After Hours	527.77	1276.03
Single Phase underground – Business Hours	227.30	209.63
Single Phase underground with a directly connected meter on group metering panel – Business Hours	NA	460.94
Single Phase underground – After Hours	290.74	1276.03
Multi-phase overhead with a directly connected meter – Business Hours	467.75	552.80
Multi-phase overhead with a directly connected meter – After Hours	564.06	1276.03
Multi-phase overhead with a CT connected meter – Business Hours	627.98	1055.42
Multi-phase overhead connection with a CT connected meter – After Hours	758.16	1778.65

Connection service	2020	2021-22
Multi-phase underground with a directly connected meter – Business Hours	340.14	338.81
Multi-phase underground with a directly connected meter on group metering panel – Business Hours	NA	590.12
Multi-phase underground with a directly connected meter – After Hours	421.27	1276.03
Multi-phase underground with a CT connected meter – Business Hours	490.75	841.42
Multi-phase underground connection with a CT connected meter – After Hours	607.79	1778.65
95mm^2 overhead service from LVABC – Business Hours	721.27	832.10
95mm^2 overhead service from LVABC – After Hours	903.55	2108.14
Establish temporary supply connection – Business Hours	368.25	482.29
Establish temporary supply connection – After Hours	467.70	1276.03
Appointment – inspection of group or CT metering prior to connection – Business Hours	NA	502.62
Service truck - Disconnect / Reconnect at pole or pit – Business Hours	368.25	553.84
Service truck - Disconnect / Reconnect at pole or pit – After Hours	467.70	NA

14.3.4 Draft Decision

The AER's Draft Decision accepted most of our proposed business hour prices for fee-based services. However, the AER limited increases in charges for after-hours fee-based services to 175% on the basis of advice from Marsden Jacobs that the average after hours labour rate is likely to be between time and a half and double time.

In relation to wasted truck fees, an issue arose in relation to when these fees are applied. In an information request the AER asked that we clarify in our Revised Proposal whether we intend to apply other wasted visit charges for other types of services besides fee-based ancillary network services or fee-based connection-related services.

The table below presents the network ancillary services and fee-based services where the Draft Decision price was different to the proposed price in our Initial Proposal.

Table 14-2: Alternative Control Services for after hour fees (real 2021 $s) – Draft Decision

Connection service	Our Initial Proposal after hour rate 2021-22	AER's Draft Decision after hour rate 2021-22
Single Phase Overhead – After Hours	1,276.03	844.01
Single Phase underground – After Hours	1,276.03	209.63
Multi-phase overhead with a directly connected meter – After Hours	1,276.03	967.40
Multi-phase overhead connection with a CT connected meter – After Hours	1,778.65	1,778.65
Multi-phase underground with a directly connected meter – After Hours	1,276.03	592.92
Multi-phase underground connection with a CT connected meter – After Hours	1,778.65	1,472.49
95mm^2 overhead service from LVABC – After Hours	2,108.14	1,456.18
Establish temporary supply connection – After Hours	1,276.03	844.01
Auxiliary metering services		
Field metering services	67.94	59.45

14.3.5 Response to AER's Draft Decision

We have accepted the adjustments made in the AER's Draft Decision to our fee-based connection and network ancillary services, including the limiting of after hour service charges to 175% of business hour charges.

However, we have identified additional costs that we incur to deliver some of our highest volume connection services and we have updated our fees for single phase connections accordingly.

Specifically, when connections need to be prioritised due to customer service issues or in response to weather related cancellations, our contractor charges us an additional fee for priority customer connections for rescheduling their works program to complete the new connection. Rescheduling occurs often enough to increase the average cost by between 1.6% and 3.7%.

We consider it is appropriate that our contractor's charges are reflected in our fees. We note that our high-volume connection services for which this change applies are priced significantly lower than other Victorian Distribution Business, even after the minor price increases proposed in this Revised Proposal are applied.

14.3.6 Revised Proposal

For the reasons set out above we submit the following fee based ACS for connection fees.

Table 14-3: Alternative Control Services for connection fees (real 2021 $s) – Revised Proposal

Connection service	2021-22
Single Phase Overhead – Business Hours	490.13
Single Phase Overhead – After Hours	857.73
Single Phase underground – Business Hours	217.47
Single Phase underground with a directly connected meter on group metering panel – Business Hours	460.94
Single Phase underground – After Hours	380.58
Multi-phase overhead with a directly connected meter – Business Hours	552.80
Multi-phase overhead with a directly connected meter – After Hours	967.40
Multi-phase overhead with a CT connected meter – Business Hours	1,055.42
Multi-phase overhead connection with a CT connected meter – After Hours	1,778.65
Multi-phase underground with a directly connected meter – Business Hours	338.81
Multi-phase underground with a directly connected meter on group metering panel – Business Hours	590.12
Multi-phase underground with a directly connected meter – After Hours	1276.03
Multi-phase underground with a CT connected meter – Business Hours	841.42
Multi-phase underground connection with a CT connected meter – After Hours	1,472.49
95mm^2 overhead service from LVABC – Business Hours	832.10
95mm^2 overhead service from LVABC – After Hours	1,456.18
Establish temporary supply connection – Business Hours	482.29
Establish temporary supply connection – After Hours	844.01
Appointment – inspection of group or CT metering prior to connection – Business Hours	502.62
Service truck - Disconnect / Reconnect at pole or pit – Business Hours	553.84
Service truck - Disconnect / Reconnect at pole or pit – After Hours	NA

14.3.7 Alternative Control Services for network ancillary services - fee based

14.3.8 Our Initial Proposal

We proposed fee based network ancillary services for ACS in the forthcoming regulatory period to recover the costs of providing these services directly from those customers requesting these services (see the table below). Our proposed prices were consistent with bottom up cost assessment presented in our ACS fee based model, which was submitted as a supporting document. Consistent with the section 5.3 of the Electricity Customer Metering code, we committed that meter equipment test fees are charged only if metering equipment is not found to be defective or non-compliant.

Table 14-4: Network ancillary services - fee based (real $2021) – Initial Proposal

Network ancillary services	2021-22
Meter equipment test – Single Phase	297.72
Meter equipment test – Single Phase - each additional meter at same site	66.40
Meter equipment test – Multi Phase	359.85
Meter equipment test – Multi Phase - each additional meter at same site	98.37
Wasted Truck Visit – customer not ready for their requested works	205.99
Manual assessment of PV & small generator installation enquiry, 4.6kW to 15kW.	318.00
Manual assessment of PV & small generator installation enquiry, 15kW to 30kW.	318.00

14.3.9 Draft Decision

The AER's Draft Decision accepted our proposed fees for fee-based network ancillary services for ACS in the forthcoming regulatory period. We note Table 16.3 in Attachment 16 of the Draft Decision incorrectly stated our proposed wasted truck fee which is corrected in Table 16.26 of the same document.

14.3.10 Response to AER's Draft Decision

We have accepted the AER's Draft Decision in relation to our network ancillary services and propose no further changes to our proposed prices. However, consistent with the AER approved F&A we have included a fee-based network ancillary service for security and watchmen lights with a fee equal to the average MV light.

14.3.11 Revised Proposal

We submit the following fee-based ACS for network ancillary services.

Table 14-5: Network ancillary services - fee based (real $2021) – Revised Proposal

Network ancillary services	2021-22
Meter equipment test – Single Phase	297.72

Network ancillary services	2021-22
Meter equipment test – Single Phase - each additional meter at same site	66.40
Meter equipment test – Multi Phase	359.85
Meter equipment test – Multi Phase - each additional meter at same site	98.37
Wasted Truck Visit – customer not ready for their requested works	205.99
Manual assessment of PV & small generator installation enquiry, 4.6kW to 15kW.	318.00
Manual assessment of PV & small generator installation enquiry, 15kW to 30kW.	318.00
Security and watchmen lights	60.66

14.3.12 Quoted Services

14.3.13 Our Initial Proposal

Quoted services are customer specific or customer requested services for which the labour and materials costs vary from job to job. A customer's final charge consists of a regulated charge per hour for each labour type used plus any materials and any vehicle costs (otherwise reflected in the underlying hourly rate).

For quoted services, we proposed amending the quoted services formula to include margin and tax consistent with the principle of competitive neutrality with the following formula:

Price = Labour + Contractor Services + Materials + Margin + Tax

Where *Labour* consists of all labour costs directly incurred in the provision of the service which may include labour on-costs, fleet on-costs and overheads. *Labour* is escalated annually by CPI.[223]

Outlined in the table below are quoted ACS rates we proposed for FY2022.

Table 14-6: Quoted Alternative Control Services rates for FY2022 (real 2021 $s) – Initial Proposal

Labour category	Service description	2021-22 business hours	2021-22 after hours
Labour—wages	Construction Overhead Install	114.12	138.61
Labour—wages	Construction Underground Install	111.47	135.38
Labour—wages	Construction Substation Install	111.47	135.38
Labour—wages	Electrical Tester Including Vehicle & Equipment	199.28	224.68

223 For further information, refer to the Initial Proposal.

Labour category	Service description	2021-22 business hours	2021-22 after hours
Labour—wages	Planner Including Vehicle	153.20	N/A
Labour—wages	Supervisor Including Vehicle	153.20	N/A
Labour—design	Design	130.81	158.87
Labour—design	Drafting	100.52	122.08
Labour—design	Survey	118.40	143.81
Labour—design	Tech Officer	118.40	143.81
Labour—design	Line Inspector	114.12	138.61
Labour—design	Contract Supervision	118.40	143.81
Labour—design	Protection Engineer	130.81	158.87
Labour—design	Maintenance Planner	118.40	143.81

14.3.14 Draft Decision

The AER's Draft Decision accepted our proposed labour rates, except the rate for "electricity tester including vehicle and equipment" of $199.28. The AER reduced this rate to $171.75.

The AER engaged Marsden Jacob to assess whether our proposed labour rates were efficient. In its report for the AER, Marsden Jacob's calculated maximum rates based on:

- raw labour rates using Hays salary data for Melbourne;
- on-costs to cover basic leave entitlements and standard on-costs including superannuation, workers compensation and payroll tax; and
- overheads to cover all additional costs, including an explicit profit margin benchmarked within the overall overhead allowance.

The AER also determined that including a tax or margin component in the price cap formula to apply to quoted ancillary network services was not required as it was not included in the AER approved F&A. Additionally, it highlighted the need for us to continue to apply good industry practice and provide itemised invoices to our customers.

14.3.15 Response to AER's Draft Decision

We accept the AER's Draft Decision to remove the margin from our quoted services formula. However, we are proposing to apply the margin to our quoted ACS rates and for consistency with the Marsden Jacob's maximum recommended total hourly rates. The Marsden Jacob accepted the inclusion of an explicit profit margin within the overall overheads rate.[224] The application of margin to labour rates enables for the consistent application of benchmark prices, and ensures

[224] Marsden Jacob (2020), *Review of ancillary network services: CitiPower, Powercor, United Energy, Jemena and AusNet Services*, p. 9.

our prices are treated no differently to a contestable service provider that charges a reasonable margin to the extent the price remains competitive with benchmark prices.

We have also proposed a new labour rate for Senior Engineer for large distribution connected projects. We consider this is appropriate as our distribution business is processing a higher volume of more complicated distribution connections.

14.3.16 Revised Proposal

We have proposed revised fees that include a margin, where these rates are below Marsden Jacob's maximum recommended total hourly rates, and a new labour rate for senior engineer for large connections.

With greater incentives for renewable projects, large and complicated projects are occurring more frequently, there is an increasing labour market demand for senior engineers.

AEMO publishes charge out rates for engineers to undertake work for connection applicant connecting to the transmission network. AEMO's valuation for such engineering resources is $270 per hour.[225] As the skills required to connect a large, customer connecting to our distribution network at the sub-transmission level broadly are similar to the skills required to connect a large generator connecting to the transmission network, we consider the AEMO rate reflects our cost of acquiring senior engineers with commensurate skill levels.

We consider in establishing the new labour rate for senior engineering staff, regard must be given to AEMO's valuation and other benchmark hourly rates. Therefore, we are proposing to average the Marsden Jacob's maximum recommended total hourly rate and AEMO's engineer hourly rates to establish our proposed rates for the new labour rate for senior engineers.

We are therefore proposing the following quote ACS labour rates. We note that where these services are used, we will apply good industry practice and will provide itemised invoices to customers (or applicants).

Table 14-7: Quoted ACS rates for FY2022 (real June 2021 $s) – Revised Proposal

Labour category	Service description	2021-22 business hours	2021-22 after hours
Labour—wages	Construction Overhead Install	124.87	144.98
Labour—wages	Construction Underground Install	121.96	141.60
Labour—wages	Construction Substation Install	121.96	141.60
Labour—wages	Electrical Tester Including Vehicle & Equipment	171.75	235.01
Labour—wages	Planner Including Vehicle	167.62	N/A
Labour—wages	Supervisor Including Vehicle	167.62	N/A
Labour—design	Design	143.12	166.17
Labour—design	Drafting	109.98	127.70

225 Source: https://aemo.com.au/-/media/files/about_aemo/energy_market_budget_and_fees/2020/fy21-final-aemo-electricity-revenue-requirement-and-fee-schedule.pdf?la=en (accessed 19 November 2020).

Labour category	Service description	2021-22 business hours	2021-22 after hours
Labour—design	Survey	129.55	150.43
Labour—design	Tech Officer	129.55	150.43
Labour—design	Line Inspector	124.87	144.98
Labour—design	Contract Supervision	129.55	150.43
Labour—design	Protection Engineer	143.12	166.17
Labour—design	Maintenance Planner	129.55	150.43
Labour—design	Senior Engineer	245.27	295.03

14.3.17 New services offered during the forthcoming regulatory period

14.3.18 Our Initial Proposal

We proposed that where a new service is identified that falls within an existing ACS service group classification, we would be able to commence offering that service during the regulatory period, and new quoted services would be provided to the AER for approval as part of our annual pricing proposal.

14.3.19 Draft Decision

The AER accepted our Initial Proposal that new quoted services may be established, subject to AER's approval as part of our annual pricing proposal. It noted that our annual pricing proposal must provide a detailed description of any new service along with how the new service would be charged.

14.3.20 Revised Proposal

As the AER accepted our Initial Proposal, our proposal for new services offered during the forthcoming regulatory period remains unchanged from that outlined in the Initial Proposal, as described above.

14.4 Public lighting

14.4.1 Our Initial Proposal

In our Initial Proposal for public lighting services we proposed:

- Changes to our public lighting model to reflect our higher revenue requirements based on updated competitively tendered unit rates. This increased public lighting revenues to meet our expected revenue requirements over the period.
- The deployment of more energy efficient lights across our network, including a collaborative funding of MV lights with LED lights with four large Councils with greater than average numbers of MV lights contributing to the exchange program.
- Progressive replacement of failed and 20 year plus poor condition high pressure sodium (HPS) lights with LED lights.

- A change to our modelling approach for public lighting to make it more consistent with the approach for SCS.
- Price and unit rate changes that increase our average public lighting prices, on average, by 11% per year, noting that the overall bill impact would be off-set by energy usage reductions, given the superior efficiency of the new lighting.

Our proposed prices are set out in the table below.

Table 14-8: Public lighting fees (2021 $s) – Central – Initial Proposal

Central Region	2020	Jan-Jun 21	2021-22	2022-23	2023-24	2024-25	2025-26
Mercury Vapour 80W	$47.17	$46.67	$61.41	$43.82	$43.95	$44.16	$44.12
HP Sodium 150W	$110.66	$109.48	$112.11	$91.04	$90.95	$91.16	$91.24
HP Sodium 250W	$111.77	$110.57	$113.96	$92.46	$92.21	$92.30	$92.38
Mercury Vapour 50W	$72.17	$71.40	$93.96	$67.05	$67.24	$67.57	$67.50
Mercury Vapour 125W	$69.34	$68.60	$90.28	$64.42	$64.60	$64.92	$64.85
Mercury Vapour 250W	$117.36	$116.10	$119.65	$97.08	$96.82	$96.92	$97.00
Mercury Vapour 400W	$121.83	$120.53	$124.21	$100.78	$100.51	$100.61	$100.69
HP Sodium 100W	$118.41	$117.14	$119.96	$97.41	$97.32	$97.54	$97.63
HP Sodium 400W	$158.71	$157.01	$161.82	$131.29	$130.94	$131.07	$131.18
Metal Halide 70W	$205.90	$203.70	$268.08	$191.28	$191.84	$192.78	$192.57
Metal Halide 100W	$264.22	$261.40	$267.68	$217.37	$217.16	$217.67	$217.86
Metal Halide 150W	$300.18	$296.97	$304.10	$246.95	$246.71	$247.28	$247.50
Energy Efficient Lights							
T5 2X14W	$38.10	$37.69	$56.79	$61.69	$60.05	$60.94	$61.19
T5 2X24W	$44.94	$44.46	$59.11	$61.18	$62.63	$63.35	$62.64
LED 18W standard power	$17.72	$17.53	$33.13	$35.98	$37.91	$39.19	$39.52

Central Region	2020	Jan-Jun 21	2021-22	2022-23	2023-24	2024-25	2025-26
LED 14W low output non-standard	$17.72	$17.53	$35.26	$38.11	$40.03	$41.31	$41.65
LED 70W-125W (L1)	$25.67	$25.40	$44.49	$50.09	$53.95	$56.48	$57.09
LED 155W-250W (L2)	$26.46	$26.18	$46.50	$52.85	$57.22	$60.09	$60.77
LED 275W-400W (L4)	$28.11	$27.81	$57.92	$65.01	$69.86	$73.06	$73.81
Compact Fluorescent 32W	$33.81	$33.45	$49.96	$54.26	$52.82	$53.60	$53.83
Compact Fluorescent 42W	$33.81	$33.45	$49.96	$54.26	$52.82	$53.60	$53.83

Source: AusNet Services

Table 14-9: Public lighting fees June 2021 $s) – North and East – Initial Proposal

North & East	2020	Jan-Jun 21	2021-22	2022-23	2023-24	2024-25	2025-26
Mercury Vapour 80W	$53.52	$52.95	$70.43	$49.03	$49.15	$49.28	$49.31
HP Sodium 150W	$125.81	$124.47	$131.83	$109.14	$106.35	$107.95	$108.03
HP Sodium 250W	$124.47	$123.14	$130.54	$107.68	$105.18	$105.26	$105.34
Mercury Vapour 50W	$79.21	$78.36	$104.23	$72.56	$72.74	$72.93	$72.98
Mercury Vapour 125W	$79.21	$78.36	$104.23	$72.56	$72.74	$72.93	$72.98
Mercury Vapour 250W	$129.44	$128.06	$135.76	$111.99	$109.39	$109.47	$109.56
Mercury Vapour 400W	$133.18	$131.76	$139.68	$115.22	$112.54	$112.63	$112.72
HP Sodium 100W	$134.62	$133.18	$141.06	$116.78	$113.79	$115.51	$115.59
HP Sodium 400W	$176.74	$174.85	$185.36	$152.91	$149.36	$149.47	$149.59
Metal Halide 70W	$203.61	$201.43	$267.93	$186.52	$186.98	$187.48	$187.60
Metal Halide 100W	$266.48	$263.63	$279.22	$231.17	$225.25	$228.65	$228.82
Metal Halide 150W	$302.75	$299.51	$317.22	$262.63	$255.90	$259.76	$259.96
Energy Efficient Lights							

North & East	2020	Jan-Jun 21	2021-22	2022-23	2023-24	2024-25	2025-26
T5 2X14W	$43.39	$42.92	$66.85	$69.59	$67.53	$68.17	$68.42
T5 2X24W	$51.11	$50.56	$70.33	$72.31	$70.95	$71.50	$70.95
LED 18W standard power	$18.21	$18.02	$36.31	$39.15	$40.43	$41.71	$42.04
LED low output non-standard	$18.21	$18.02	$38.13	$40.97	$42.19	$43.46	$43.80
LED 70W-125W (L1)	$26.29	$26.00	$49.99	$55.59	$58.59	$61.12	$61.73
LED 155W-250W (L2)	$27.07	$26.78	$52.00	$58.34	$61.87	$64.73	$65.40
LED 275W-400W (L4)	$28.68	$28.38	$66.65	$73.73	$76.88	$80.08	$80.84
Compact Fluorescent 32W	$38.61	$38.19	$58.80	$61.22	$59.40	$59.96	$60.19
Compact Fluorescent 42W	$38.61	$38.19	$58.80	$61.22	$59.40	$59.96	$60.19

Source: AusNet Services

Table 14-10: Private security lighting fees (prices quoted in terms of June 2021 $s)

North & East	2020	Jan-Jun 21	2021-22	2022-23	2023-24	2024-25	2025-26
Security and watchmen lights	0.00	$0.00	$30.49	$29.64	$28.92	$28.34	$27.54

Source: AusNet Services

14.4.2 Draft Decision

The AER substantially amended our public lighting proposal including our modelling approach. However, the Draft Decision accepted our approach of establishing light fault data over several years and several unit rate updates based on competitively tendered contract rates that were comparable to other Victorian distribution business' prices.

The AER amended our proposed input cost assumptions in relation to operations and maintenance expenditure and LED luminaire costs. Specifically, it highlighted that it had:

- Amended our LED luminaire unit costs to reflect benchmarked rates from the other Victorian distribution businesses.
- Amended our proposed unit costs for Elevated Platform Vehicles (EPVs), patrol vehicles, replacement and repair daily rates on the basis that our comparable benchmark rural distribution business, Powercor, had more efficient rates.
- Amended the public lighting model we submitted to:
  - Reflect the historical cost approach used previously;
  - Incorporate updated CPI growth, WACC and wage growth figures;

- Address inconsistencies with the annual RIN data;
- Correct an error in the failure rate calculation for LEDs; and
- Replace 2020 prices with the approved public lighting charges 2020.

The AER also rejected the proposed replacement deployment of more-energy efficient lights across our network, including a collaborative funding of MV lights with LED lights. The AER requested that we work closely with our public lighting customers to reach agreement on a program to replace the lights.

The Draft Decision model included funding to replace existing MV lights with mercury free substitute lights. These lights would be funded by the existing lighting regulated asset base and would still eventually need to be replaced by Councils.

The AER accepted the replacement of other failed lights with LED lights, including HPS lights.

The below table outlines the AER's Draft Decision on public lighting prices.

Table 14-11: Public lighting fees (2021 $s) – Central – Draft Decision

Central Region	2021-22	2022-23	2023-24	2024-25	2025-26
Mercury Vapour 80W	$51.00	$51.14	$46.36	$47.35	$47.64
HP Sodium 150W	$100.66	$100.70	$103.94	$105.88	$106.57
HP Sodium 250W	$102.36	$102.40	$105.84	$107.82	$108.52
Mercury Vapour 50W	$78.03	$78.24	$70.93	$72.45	$72.88
Mercury Vapour 125W	$74.97	$75.17	$68.15	$69.61	$70.02
Mercury Vapour 250W	$107.48	$107.52	$111.13	$113.21	$113.95
Mercury Vapour 400W	$111.58	$111.62	$115.37	$117.52	$118.29
HP Sodium 100W	$107.71	$107.75	$111.22	$113.29	$114.03
HP Sodium 400W	$145.36	$145.41	$150.30	$153.10	$154.10
Metal Halide 70W	$222.62	$223.22	$202.36	$206.70	$207.94
Metal Halide 100W	$240.35	$240.45	$248.19	$252.80	$254.45
Metal Halide 150W	$273.05	$273.17	$281.96	$287.20	$289.07
T5 2X14W	$44.80	$45.34	$45.77	$46.19	$46.68
T5 2X24W	$47.79	$48.34	$48.78	$49.22	$49.72
LED 18W standard power	$26.15	$26.64	$27.02	$27.35	$27.68
LED low output non-standard	$27.31	$27.79	$28.17	$28.51	$28.85
LED 70W-125W (L1)	$35.71	$36.47	$37.05	$37.58	$38.12
LED 155W-250W (L2)	$36.24	$37.04	$37.65	$38.20	$38.76

Central Region	2021-22	2022-23	2023-24	2024-25	2025-26
LED 275W-400W (L4)	$49.70	$50.81	$51.65	$52.42	$53.24
Compact Fluorescent 32W	$39.41	$39.88	$40.26	$40.63	$41.06
Compact Fluorescent 42W	$39.41	$39.88	$40.26	$40.63	$41.06

Source: AER Draft Decision public lighting model with prices converted from Nominal to Real FY21 $s

Table 14-12: Public lighting fees (prices quoted in terms of June 2021 $s) – North and East – Draft Decision

North & East	2021-22	2022-23	2023-24	2024-25	2025-26
Mercury Vapour 80W	$56.30	$56.43	$50.04	$51.04	$51.34
HP Sodium 150W	$118.32	$118.33	$120.08	$122.05	$122.86
HP Sodium 250W	$117.23	$117.36	$119.54	$121.55	$122.35
Mercury Vapour 50W	$83.33	$83.51	$74.06	$75.53	$75.98
Mercury Vapour 125W	$83.33	$83.51	$74.06	$75.53	$75.98
Mercury Vapour 250W	$121.92	$122.05	$124.32	$126.42	$127.25
Mercury Vapour 400W	$125.44	$125.57	$127.91	$130.06	$130.92
HP Sodium 100W	$126.60	$126.61	$128.48	$130.60	$131.46
HP Sodium 400W	$166.47	$166.64	$169.75	$172.61	$173.74
Metal Halide 70W	$214.20	$214.68	$190.37	$194.17	$195.31
Metal Halide 100W	$250.61	$250.62	$254.33	$258.51	$260.22
Metal Halide 150W	$284.71	$284.73	$288.94	$293.69	$295.64
T5 2X14W	$49.48	$50.01	$50.44	$50.87	$51.37
T5 2X24W	$52.90	$53.44	$53.88	$54.32	$54.85
LED 18W standard power	$28.23	$28.71	$29.09	$29.43	$29.76
LED low output non-standard	$29.32	$29.80	$30.18	$30.52	$30.86
LED 70W-125W (L1)	$40.52	$41.28	$41.85	$42.39	$42.96
LED 155W-250W (L2)	$41.06	$41.85	$42.45	$43.01	$43.60
LED 275W-400W (L4)	$57.09	$58.18	$59.01	$59.80	$60.67
Compact Fluorescent 32W	$43.52	$43.99	$44.37	$44.75	$45.19

North & East	2021-22	2022-23	2023-24	2024-25	2025-26
Compact Fluorescent 42W	$43.52	$43.99	$44.37	$44.75	$45.19

Source: AER Draft Decision public lighting model with prices converted from Nominal to Real FY21 $s

14.4.3 Response to AER's Draft Decision

We have accepted most of the adjustments made by the AER in the Draft Decision. To address the issues raised in the Draft Decision we have:

- Amended LED luminaire unit costs to reflect benchmarked rates as it applies to standard fittings. However, we have not applied this approach to non-standard fittings. As discussed with our public lighting customers, the cost of replacing a MV light in a non-standard (decorative) fitting is three times higher than replacing a standard fitting.
- Amended the unit costs for EPVs, patrol vehicles, replacement and repair daily rates. However, as the AER's amendments to T5 replacement and repair daily rates were higher than Powercor's and therefore are inconsistent if the approach of applying comparing our replacement/repair rates with comparable benchmarks of other distribution businesses. We have replaced the Draft Decision replacement/repair rates for T5 lights with Powercor's T5 replacement/repair rates.
- Amended our public lighting model approach to:
  - Reflect the historical cost approach used previously;
  - Incorporate updated CPI growth;
  - Address inconsistencies with the annual RIN data;
  - Correct an error in the failure rate calculation for LEDs; and
  - Replace 2020 prices with the approved public lighting charges 2020.
- Worked closely with our public lighting customers to reach agreement on a program to replace the lights, noting that the alternative draft decision funding model to replace existing MV lights with mercury free substitute lights needs to incorporate Powercor's unit cost for replacing a MV luminaire, as the mercury free substitute lights are more expensive than the initially proposed rate (which assumed a like-for-like mercury vapour replacement).
- Replaced other failed lights with LED lights, including HPS lights.
- As explained in relation to our opex forecasts, we have not accepted the AER's proposed labour escalation rates in its Draft Decision. Instead, we have adopted the average of our and the AER's consultant's forecasts, consistent with previous regulatory decisions.

As requested by the AER, we also undertook additional consultation on the key concerns raised by the LG's submission to our Initial Proposal. We convened three meetings, including:

- An initial forum with more than 20 LG representatives on 20 October 2020; and
- Two representative working groups on 30 October 2020 and 9 November 2020.

14.4.4 Continued engagement with public lighting customers

In our meetings with LG representatives, we discussed:

- Alternative arrangements for efficient MV light replacements under the Minamata Convention, including the approach in our Initial Proposal, and that included in the AER's Draft Decision which would have funded fewer energy efficient LED globes.[226] The LGs stated the Draft Decision approach would result in higher long term costs.

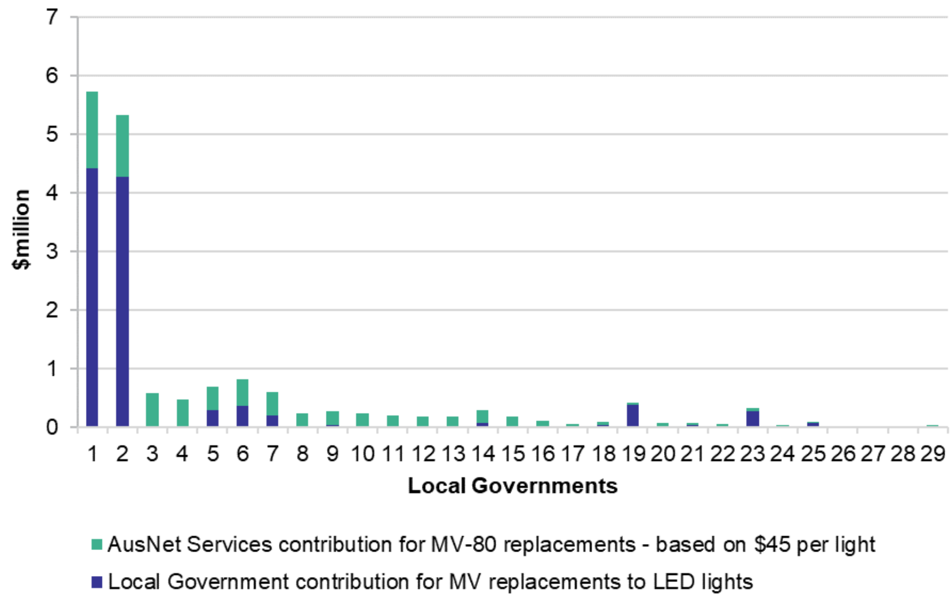
- Implications of the higher non-standard (decorative) replacement unit costs and the need for LGs to understand expected costs. If the replacement unit costs used in the model does not reflect the higher cost non-standard (decorative) replacement (which is around times greater than standard), public lighting customers would pay less in the 2022-26 regulatory period and pay higher prices in the following regulatory period (2027-31). The LG representatives wanted an accurate understanding of the costs over the next 20 years and not limited to the forthcoming regulatory period.
- MV efficient light replacements must ensure equity between LGs and enable effective coordination with larger Councils and the representatives from regional Shires.
- Approaches to smart lighting for major road LED lights, resolving data and billing issues.

After meeting with Local Government (LG) representatives we proposed an option to replace all Mercury Vapour luminaires by 2026, with the cost partially funded by our regulated capital expenditure, resulting in a moderate growth in the capital charges for lights in the efficient light class (LEDs, CFLs, T5s) for the following 20 years. This option discussed involved:

- Exchanging MV lights with efficient LED lights, where 18 out of the 29 LGs would fund $6.9 million replacement costs, with LGs funding $10.2 million. We would co-fund, up to $45 per light for each LGs, and (where relevant) the LG would fund the remaining capital cost ensure all MV lights are replaced. The funding for $6.9 million replacement costs would be from the efficient lighting regulated asset base and paid for by public lighting customers through their ACS public lighting tariffs.
- This approach provides equity for LGs that have already invested in efficient lighting replacements and ensures the Mercury Vapour lights will be replaced. Figure 14-1 below shows our and the 29 LGs expected contributions to the efficient lighting replacement program. Where we determine that the LG has not substantially received the full value of their $45 per light efficient light allocation, we will work with the LG to fund the replacement of additional aged HPS lights in their area.

226 Instead of replacing a MV-80 LED luminaire globe with an LED 18W, it would be replaced with 35W globe replacement that fits in the MV-80 luminaire. The substitute replacement uses more electricity to operate and is more expensive in the long term.

Figure 14-1: MV replacement contributions by AusNet Services and LGs (nominal $s)



- Councils will be given the opportunity to coordinate their lighting exchange program using AusNet Services' and the Municipal Association of Victoria's approved resources, including project manager and tendered service providers. Regional or smaller LGs will be given the opportunity to work together with nearby LGs and engage the same project manager and tendered service provider to organise a single program across municipalities.
- An approach to providing smart street lighting by creating new public lighting prices for major road smart lighting, with higher costs for software as a service and more expensive smart cells. This approach allows to offer IT systems and smart lighting services without increasing the prices for LGs that have not invested in smart lighting. It contrasts with alternative approaches of not providing smart lighting services or providing smart lighting services to all customers with the higher costs of more expensive smart Photo Electric (PE) cells and IT systems. However, it means paying higher unit rates for smart PE cells due to lower volumes.

Following the meeting we provided LG representatives a written position for circulation to the greater group of representatives from all geographically relevant municipalities. The representative working groups provided 'in principle support' of the above approach to efficient replacements.

14.4.5 Revised Proposal

We commit to meeting our above commitments to LGs and propose the public fees set out in the following tables.

Our public lighting fees include three new public lighting prices for major road smart lighting, with higher costs for Itron's Street Light Vision Solution software as a service hosted in an Australian data centre, our IT costs, and more expensive smart cells. Our service offering is based upon vendor pricing that assumes higher volumes. Until we coordinate our IT works, and a substantial uptake of smart lighting products with public lighting customers, we will delay offering the products. We anticipate commencing after 1 July 2022, subject to IT system delivery and a level of commitment by LGs in migrating to smart lighting.

Table 14-13: Public lighting fees (2021 $s) – Central – Revised Proposal

Central Region	2021-22	2022-23	2023-24	2024-25	2025-26
Mercury Vapour 80W	$58.74	$58.47	$59.63	$63.34	$63.13
HP Sodium 150W	$109.56	$109.35	$109.60	$114.15	$114.35
HP Sodium 250W	$112.34	$112.12	$112.52	$117.18	$117.37
Mercury Vapour 50W	$89.87	$89.45	$91.24	$96.91	$96.59
Mercury Vapour 125W	$86.35	$85.95	$87.66	$93.11	$92.80
Mercury Vapour 250W	$117.95	$117.73	$118.15	$123.04	$123.24
Mercury Vapour 400W	$122.45	$122.21	$122.65	$127.73	$127.94
HP Sodium 100W	$117.22	$117.01	$117.27	$122.14	$122.35
HP Sodium 400W	$159.52	$159.21	$159.78	$166.40	$166.67
Metal Halide 70W	$256.41	$255.21	$260.31	$276.47	$275.56
Metal Halide 100W	$261.58	$261.10	$261.69	$272.55	$273.03
Metal Halide 150W	$297.18	$296.63	$297.29	$309.64	$310.18
T5 2X14W	$50.31	$52.07	$53.44	$54.59	$55.33
T5 2X24W	$53.73	$55.54	$56.96	$58.15	$58.93
LED 18W standard power	$28.56	$29.95	$31.00	$31.84	$32.31
LED non-standard low power ~14W	$30.35	$31.74	$32.79	$33.64	$34.12
LED 70W-125W (L1)	$47.50	$50.06	$52.03	$53.62	$54.56
LED 155W-250W (L2)	$48.13	$50.83	$52.90	$54.57	$55.55
LED 275W-400W (L4)	$53.72	$57.68	$60.71	$63.09	$64.42
Compact Fluorescent 32W	$44.25	$45.80	$47.01	$48.02	$48.67
Compact Fluorescent 42W	$44.25	$45.80	$47.01	$48.02	$48.67
Smart lighting L1	$58.21	$60.77	$62.73	$64.33	$65.27
Smart lighting L2	$58.83	$61.53	$63.61	$65.28	$66.26
Smart lighting L4	$64.43	$68.38	$71.41	$73.80	$75.13

Source: AusNet Services public lighting model

Table 14-14: Public lighting fees (prices quoted in terms of June 2021 $s) – North and East – Revised Proposal

North & East	2021-22	2022-23	2023-24	2024-25	2025-26
Mercury Vapour 80W	$64.59	$64.26	$63.35	$67.07	$66.88
HP Sodium 150W	$128.40	$128.23	$126.66	$131.35	$131.73
HP Sodium 250W	$128.21	$128.11	$126.96	$131.72	$132.05
Mercury Vapour 50W	$95.59	$95.11	$93.76	$99.26	$98.99
Mercury Vapour 125W	$95.59	$95.11	$93.76	$99.26	$98.99
Mercury Vapour 250W	$133.34	$133.23	$132.04	$136.99	$137.33
Mercury Vapour 400W	$137.18	$137.07	$135.85	$140.94	$141.29
HP Sodium 100W	$137.39	$137.20	$135.52	$140.54	$140.95
HP Sodium 400W	$182.05	$181.91	$180.28	$187.04	$187.50
Metal Halide 70W	$245.72	$244.48	$241.02	$255.17	$254.45
Metal Halide 100W	$271.97	$271.59	$268.26	$278.20	$279.01
Metal Halide 150W	$308.98	$308.55	$304.77	$316.06	$316.98
T5 2X14W	$56.04	$57.81	$59.20	$60.37	$61.15
T5 2X24W	$60.01	$61.83	$63.27	$64.49	$65.31
LED 18W	$30.64	$32.02	$33.07	$33.92	$34.40
LED non-standard low power ~14W	$32.35	$33.74	$34.80	$35.65	$36.14
LED 70W-125W (L1)	$54.89	$57.46	$59.45	$61.09	$62.09
LED 155W-250W (L2)	$55.51	$58.22	$60.32	$62.04	$63.08
LED 275W-400W (L4)	$61.10	$65.07	$68.13	$70.56	$71.95
Compact Fluorescent 32W	$49.29	$50.85	$52.07	$53.11	$53.79
Compact Fluorescent 42W	$49.29	$50.85	$52.07	$53.11	$53.79
Smart lighting L1	$65.90	$68.47	$70.46	$72.10	$73.10
Smart lighting L2	$66.52	$69.23	$71.33	$73.05	$74.09
Smart lighting L4	$72.11	$76.08	$79.14	$81.57	$82.96

Source: AusNet Services public lighting model

14.5 Form of control

14.5.1 Fee based services

14.5.1.1 Our Initial Proposal

In our Initial Proposal we explained that we accepted the AER's formula for fee based ACS set out in the F&A, which is reproduced below:

$\bar{p}_t^i \geq p_t^i$ $\quad$ *i*=1,...,n and *t*=1,2,3,4

$\bar{p}_t^i = \bar{p}_{t-1}^i (1+\Delta CPI_t)(1-X_t^i)+A_t^i$

Where:

$\bar{p}_t^i$ is the cap on the price of service *i* in year *t*

p_t^i is the price of service *i* in year *t*. The initial value is to be decided in the distribution decision.

$\bar{p}_{t-1}^i$ is the cap on the price of service *i* in year *t*-1

t is the regulatory year

ΔCPI_t is the annual percentage change in the ABS consumer price index (CPI) All Groups, Weighted Average of Eight Capital Cities from the December quarter in year *t*–2 to the December quarter in year *t*–1.

X_t^i is the X-factor for service *i* in year *t*, incorporating annual adjustments to the PTRM for the trailing cost of debt where necessary.

A_t^i is the sum of any adjustments for service *i* in year *t*. Likely to include, but not limited to adjustments for any approved cost pass through amounts (positive or negative) with respect to regulatory year *t*, as determined by the AER.

14.5.1.2 Draft Decision

The AER accepted our ACS price cap formulas for fee-based services.

14.5.1.3 Revised Proposal

As the AER accepted our Initial Proposal in the Draft Decision, our Revised Proposal remains as per our Initial Proposal (set out above).

14.5.2 Quoted services

14.5.2.1 Our Initial Proposal

In our Initial Proposal we proposed the following formula should apply to quoted ACS:

Price = Labour + Contractor Services + Materials + Margin + Tax

Where:

Labour consists of all labour costs directly incurred in the provision of the service which may include labour on-costs, fleet on-costs and overheads. *Labour* is escalated annually by:

$(1+\Delta CPI_t)(1-X_t^i)$

Where:

ΔCPI_t is the annual percentage change in the ABS consumer price index (CPI) All Groups, Weighted Average of Eight Capital Cities from the December quarter in year *t*–2 to the June quarter in year *t*–1.

X_t^i is the X factor for service *i* in year *t*, incorporating annual adjustments to the PTRM for the trailing cost of debt where necessary.

Contractor Services reflect all costs associated with the use of external labour including overheads and any direct costs incurred. The contracted services charge applies the rates under existing contractual arrangements. Direct costs incurred are passed on to the customer.

Materials reflect the cost of materials directly incurred in the provision of the service, material storage and logistics on-costs and overheads.

Margin is an amount equal to AusNet Services' nominal vanilla WACC applied to the total cost of Labour, Contractor Services and Materials.

Tax is an amount, if any, equal to the tax costs in present value terms arising from the provision of the service to a customer, net of the value attributed to imputation credits in the AER's Rate of Return Guideline.

14.5.2.2 Draft Decision

The AER did not accept our proposed inclusion of margin and tax, and determined the following formula applies to quoted services that are quoted services:

- Price = Labour + Contractor Services + Materials

Where:

Labour consists of all labour costs directly incurred in the provision of the service which may include labour on-costs, fleet on-costs, overheads and margin. *Labour* is escalated annually by:

$(1+\Delta CPI_t)(1-X_t^i)$ where:

ΔCPI_t is the annual percentage change in the ABS consumer price index (CPI) All Groups, Weighted Average of Eight Capital Cities from the December quarter in year *t*–2 to the June quarter in year *t*–1.

X_t^i is the X factor for service *i* in year *t*, incorporating annual adjustments to the PTRM for the trailing cost of debt where necessary.

Contractor Services reflect all costs associated with the use of external labour including overheads and any direct costs incurred. The contracted services charge applies the rates under existing contractual arrangements. Direct costs incurred are passed on to the customer.

Materials reflect the cost of materials directly incurred in the provision of the service, material storage and logistics on-costs and overheads.

14.5.3 Revised Proposal

We do not agree with the removal of a tax allowance from the formula for quoted services. To establish parity with SCS where the wider customer base currently pays tax costs we seek to retain the tax allowance in the formula for quoted services.

We have therefore proposed a formula for quoted services that includes a tax allowance. This is consistent with the approach used in the Marsden Jacob report and relied on by the AER.

Our formula for quoted services is:

Price = Labour + Contractor Services + Materials + Tax

Where *Labour* consists of all labour costs directly incurred in the provision of the service which may include labour on-costs, fleet on-costs, overheads and margin. *Labour* is escalated annually by:

$$(1+\Delta CPI_t)(1-X_t^i)$$

Where:

ΔCPI_t is the annual percentage change in the ABS consumer price index (CPI) All Groups, Weighted Average of Eight Capital Cities from the December quarter in year *t*–2 to the June quarter in year *t*–1.

X_t^i is the X factor for service *i* in year *t*, incorporating annual adjustments to the PTRM for the trailing cost of debt where necessary.

Contractor Services reflect all costs associated with the use of external labour including overheads and any direct costs incurred. The contracted services charge applies the rates under existing contractual arrangements. Direct costs incurred are passed on to the customer.

Materials reflect the cost of material directly incurred in the provision of the service, material storage and logistics on-costs and overheads.

Tax is an amount, if any, equal to the tax costs in present value terms arising from the provision of the service to a customer, netting off the net present value of the reverse cash flow resulting from the depreciation of the capital contribution.

14.6 Supporting documents

We have included the following documents to support this chapter:

- ASD – EDPR 2022-26 Revised Proposal - Alternative Control - ANS fee based model – 031220 - CONFIDENTIAL; and
- ASD – EDPR 2022-26 Revised Proposal - Public lighting model - 031220 - PUBLIC

Glossary

Abbreviation	Full name
ACS	Alternative Control Services
AEMO	Australian Energy Market Operator
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
AESCSF	Australian Energy Sector Cyber Security Framework
AMI	Advanced Metering Infrastructure
AMS	Asset Management System
ARENA	Australian Renewable Energy Agency
ATO	Australian Taxation Office
Augex	Augmentation capital expenditure
CBD	Central Business District
Capex	Capital Expenditure
C&I	Commercial and Industrial
CBTS	Cranbourne terminal station
CCC	Customer Consultative Committee
CCP	Consumer Challenge Panel
CESS	Capital Efficiency Sharing Scheme
CIM	Customer Information Management
CPI	Consumer Price Index
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CSIS	Customer Satisfaction Incentive Scheme
CY	Calendar Year
DER	Distributed Energy Resources
DELWP	Department of Environment, Land, Water and Planning

Abbreviation	Full name
DMIA/DMIAM	Demand Management Innovation Allowance/ Demand Management Innovation Allowance Mechanism
DNSP	Distribution Network Service Provider
DUoS	Distribution Use of System
EBA	Enterprise Bargaining Agreement
EBSS	Efficiency Benefit Sharing Scheme
ECA	Energy Consumers Australia
EDC	Electricity Distribution Code
EG	Embedded Generation
EGWWS	Electricity, Gas, Water and Waste Services
ENA	Energy Networks Australia
EPA	Environment Protection Act
EPV	Elevated Platform Vehicles
ESC	Essential Services Commission
ESOO	Electricity Statement of Opportunities
ESV	Energy Safe Victoria
EUAA	Energy Users Association of Australia
EV	Electric Vehicle
FiT	Feed-in Tariff
F&A	AER's Framework and Approach paper
GFC	Global Financial Crisis
GFN	Ground Fault Neutraliser
GSL	Guaranteed Service Level
GWh	Giga Watt hour
HIA	Housing Industry Association
HPS	High Pressure Sodium
HV	High Voltage

Abbreviation	Full name
ICT	Information and Communication Technology
IED	Intelligent Electronic Devices
IRU	Ignition Risk Unit
IT	Information Technology
JEN	Jemena Electricity Networks
KLO	Kalkallo
kVA	Kilovolt Amperes
LED	Light Emitting Diode
LDC	Line Drop Compensation
LG	Local Government
LV	Low Voltage
MAIFI	Momentary Average Interruption Duration Index
MCR	Marginal Cost of Reinforcement
MED	Major Event Day
MFL	Maximum Foreseeable Loss
MIL 3	Maturity Indicator Level 3
MSO	Model Standing Offer
MV	Mercury Vapour
MW	Mega Watt
NEM	National Electricity Market
NEO	National Electricity Objective
NER (or the Rules)	National Electricity Rules
NPV	Net Present Value
NSP	Network Service Provider
OEFs	Operating Environment Factors
OM	Outage Management

Abbreviation	Full name
Opex	Operating and Maintenance Expenditure
PE	Photo Electric
POE	Probability of Exceedance
PTRM	Post Tax Revenue Model
PV	Photovoltaic
RAB	Regulatory Asset Base
RBA	Reserve Bank of Australia
REFCL	Rapid Earth Fault Current Limiter
Repex	Replacement expenditure
RFM	Roll Forward Model
RIN	Regulatory Information Notice
RTU	Remote Terminal Unit
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAPN	SA Power Networks
SCADA	Supervisory Control and Data Acquisition
SCS	Standard Control Services
STPIS	Service Target Performance Incentive Scheme
SWER	Single Wire Earth Return
TAB	Tax Asset Base
TSS	Tariff Structure Statement
VaDER	Value of Distributed Energy Resources
VRET	Victorian Renewable Energy Target
VRR	Voltage Regulating Relays
WACC	Weighted Average Cost of Capital
WPI	Wage Price Index