AusNet Transmission Group Pty Ltd

Transmission Revenue Review 2023-2027

Revised Revenue Proposal

PUBLIC

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About AusNet

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

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

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Glossary

Abbreviation	Full Name
ACSR	Aluminium Cable Steel Reinforced
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AESCSF	Australian Energy Sector Cyber Security Framework
AMS	Asset Management System
APD	Alcoa Portland
ASRR	Annual Service Revenue Requirement
BAU	Business-as-usual
BLTS	Brooklyn Terminal Station
BOM	Bureau of Meteorology
CAP	Customer Advisory Panel
CB	Circuit Breaker
CBD	Central Business District
capex	Capital Expenditure
CESS	Capital Efficiency Sharing Scheme
CGS	Commonwealth Government Security
CT	Current Transformer
CVT	Capacitive Voltage Transformer
DAE	Deloitte Access Economics
DAPR	Distribution Annual Planning Report
DC	Direct Current
DDTS	Dederang Terminal Station
DI	Dispatch Intervals

Abbreviation	Full Name
DMIA	Demand Management Innovation Allowance
DNSP	Distribution Network Service Provider
EBSS	Efficiency Benefit Sharing Scheme
ECA	Energy Consumers Australia
EGWWS	Electricity, Gas, Water and Waste Services
EMV	Emergency Management Victoria
EPA	Environment Protection Authority
EPDM	Ethylene Propylene Diene Monomer
ERP	Enterprise Resource Planning Platform
ERTS	East Rowville Terminal Station
ESMS	Electricity Safety Management Scheme
ESV	Energy Safe Victoria
FAS	Fall Arrest System
FCAS	Frequency Control Ancillary Service
GIS	Gas Insulated Switchgear
GNTS	Glenrowan Terminal Station
GST	Goods and Services Tax
GW	Ground Wire
GWh	Gigawatt Hours
HOTS	Horsham Terminal Station
HWPS	Hazelwood Power Station
HWTS	Hazelwood Terminal Station
HYTS	Heywood Terminal Station
IAP2	International Association of Public Participation
ICT	Information and Communication Technology
ISP	Integrated System Plan

Abbreviation	Full Name
ISRAT	Infrastructure Security Risk Assessment Tool
IT	Information Technology
KTS	Keilor Terminal Station
LYPS	Loy Yang Power Station
MAR	Maximum Allowed Revenue
MIC	Market Impact Component
MLTS	Moorabool Terminal Station
MPLS-TP	Multiprotocol Label Switching - Transport Profile
MVA	Mega Volt Amps
MVT	M Voltage Transformer
MWTS	Morwell Terminal Station
NCC	Network Capability Component
NCIPAP	Network Capability Incentive Parameter Action Plan
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
NPV	Net Present Value
NSP	Network Service Provider
OH&S	Occupational Health and Safety
Opex	Operating and Maintenance Expenditure
OPGW	Optical Fibre Ground Wire
PCRs	Protection & Control Requirements
PPIs	Partial Performance Indicators
PTRM	Post Tax Revenue Model
RAB	Regulatory Asset Base

Abbreviation	Full Name
RCTS	Red Cliffs Terminal Station
RDP	REZ Development Plan
repex	Replacement expenditure
RERT	Reliability and Emergency Reserve Trader
REZ	Renewable Energy Zone
RIN	Regulatory Information Notice
RIS	Renewable Integration Study
RIT-T	Regulatory Investment Test for Transmission
ROTS	Rowville Terminal Station
SAIP	Smart Aerial Image Patrol
SAUR	Shared Asset Unregulated Revenues
SCADA	Supervisory Control and Data Acquisition
SDH/PDH	Synchronous digital hierarchy/plesiochronous digital hierarchy
SHTS	Shepperton Terminal Station
SMTS	South Morang Terminal Station
STPIS	Service Target Performance Incentive Scheme
SVTS	Springvale Terminal Station
SYTS	Sydenham Terminal Station
TAB	Tax Asset Base
TNSP	Transmission Network Service Provider
TSTS	Templestowe Terminal Station
TTS	Thomastown Terminal Station
TUOS	Transmission Use of System
VAPR	Victorian Annual Planning Report
VCR	Value of Customer Reliability
VRET	Victorian Renewable Energy Target

Abbreviation	Full Name
VT	Voltage Transformer
WACC	Weighted Average Cost of Capital
WARL	Weighted Average Remaining Life
WMTS	West Melbourne Terminal Station
WOTS	Wodonga Terminal Station
WVTP	Western Victorian Transmission Project
WPI	Wage Price Index
XLPE	Crossed Linked Polyethylene
YPS	Yallourn Power Station

Overview

This Revised Revenue Proposal covers the ongoing replacement and maintenance of Victoria's core transmission network. Government policy and system developments mean that, in future, a much larger component of total Victorian transmission prices will be determined outside of this regulated revenue setting process. This is highlighted by our analysis of expected prices over the 2023-27 regulatory control period showing that while we are decreasing our component of prices, overall Victorian transmission prices are expected to moderately increase.

A key finding from our engagement has been that one of stakeholders' primary concerns is that the costs and benefits arising from these developments are made transparent and be subject to similar scrutiny by stakeholders and regulators, as AusNet's are through regulated processes.

AusNet is also acutely aware of the importance of increasing efficiency in our operations. The Revised Proposal reduces opex and capex funding costs from that proposed in the Initial Proposal. This will challenge the business but demonstrates our commitment to being a constructive part of the energy transition while building the trust and support of customers.

The remainder of this section provides an overview of our Revised Proposal including required revenues and price impacts, 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.

The dollars presented in this Revised Proposal are stated in real $2021-22 terms unless noted otherwise.

Context for the Revised Proposal

In October 2020, AusNet submitted our Initial Revenue Proposal setting out our revenue requirements for the five years from 1 April 2022.

Since then, there have been significant announcements and developments for the Victorian transmission system. Many of these developments support the energy transition to enable customers access to renewable, low-cost energy, supporting the Victorian Government's net zero objectives and reducing customer bills. While the Revised Revenue Proposal is limited in scope to maintenance and replacement, it accounts for interactions with these developments where possible.

The key drivers of change to the Initial Proposal are:

- New AEMO demand forecasts outlining both higher maximum demands and materially lower minimum demands on the Victorian network. Lower minimum demand is exacerbating operational challenges across the network.
- The release of the Victorian Government's $1.6 billion energy budget in November 2020 and the Renewable Energy Zone Development Plan (RDP) Directions Paper in February 2021. These set out proposed generation and transmission network investments supporting the Victorian Government Climate Change Strategy commitment to reduce carbon emissions by 45-50% by 2030 and to net zero by 2050.
- The formation of a new entity, VicGrid, tasked with coordinating the overarching planning and development of Victorian renewable energy zones (REZ). This new entity is expected to manage the $540 million of REZ funding that will be used to strengthen the grid and unlock the potential for new renewable generation as part of the $1.6b energy budget.

- AEMO indicated it would include the Victorian Government's budget initiatives affecting REZs in all scenarios used to develop the next Integrated System Plan (ISP) to be released in July 2022.
- The announcement by Energy Australia in March 2021 that the closure of the 1480MW Yallourn Power Station would be brought forward from 2032 to 2028.
- Significant changes to rates, taxes and AEMO fees.

The way we have addressed these drivers has been heavily influenced by a deep and extended engagement with stakeholders, outlined in the next section.

Effective targeted engagement on the issues that matter

In anticipation of several of the announcements above and potential changes to electricity usage arising from the COVID-19 pandemic, AusNet has conducted a significant customer and stakeholder deep dive engagement phase to ensure customer preferences are heard on the complex transmission system issues arising in Victoria and, in turn, influence the changes to our Revised Proposal. This included an initial canvassing of what issues stakeholders wished to discuss.

Stakeholders were clear that they wanted our engagement to focus on:

- Ensuring efficient and transparent coordination of the investments proposed by the various planners and governments with AusNet's replacement and maintenance activities;
- Avoiding duplication and over-investment in long term solutions to potentially transitory problems;
- Maintaining the security of the system in the face of a deteriorating operational environment.

Seven collaborative deep dive sessions were undertaken on the key issues and uncertainties resulting from the developments highlighted above. In many instances, both AusNet and stakeholders recognised there was uncertainty with respect to the impact on our forecasts and the co-design workshops focused on the best way to address that uncertainty given the regulatory framework.

What emerged from these sessions as the overwhelming concern for stakeholders was the long-term effect on Victorian transmission prices of the substantial investments outlined in the ISP and RDP. Stakeholders value transparency on costs and benefits and opportunities to test and challenge proposed assumptions and solutions through the ISP and RDP processes in which they are being set, outside of this review process.

We have responded to these concerns in our Revised Proposal by:

- Removing any duplication identified. This includes removing projects from our Revised Proposal that have been identified in the RDP as well as engaging with Victorian Government to ensure they are removing potential duplication from the RDP.
- Ensuring replacement projects are coordinated in scope and timing with ISP and RDP projects where clear sequencing is required. Any resulting synergies have been used to reduce costs.
- Where future costs are uncertain, preferring solutions that meet customers' strong preference to only pay actual costs such as pass-through provisions and contingent projects.
- Further reducing the operating costs under our control to more than offset the increases flowing from external factors outside our control such as rates and taxes.

Therefore, the Revised Proposal comprehensively reflects stakeholder preferences in what has or has not been included in expenditure forecasts and how risk and uncertainty arising from the significant changes discussed above are managed. We are confident that stakeholders will provide strong support to those aspects of our Revised Proposal.

Nonetheless, we recognise the continuing uncertainty surrounding the effects of system strength shortfalls, minimum demand and growing volumes of large-scale renewable generation and small-scale distributed energy resources, and the investment required to address these issues. As such, we have made a commitment to our stakeholders to continue the conversations started during this regulatory review process, to ensure collaboration continues and end users can express views on addressing these challenges. This will be achieved through the continuation of the TRR Customer Advisory Panel as a business-as-usual engagement forum for transmission issues.

Victorian Transmission Prices

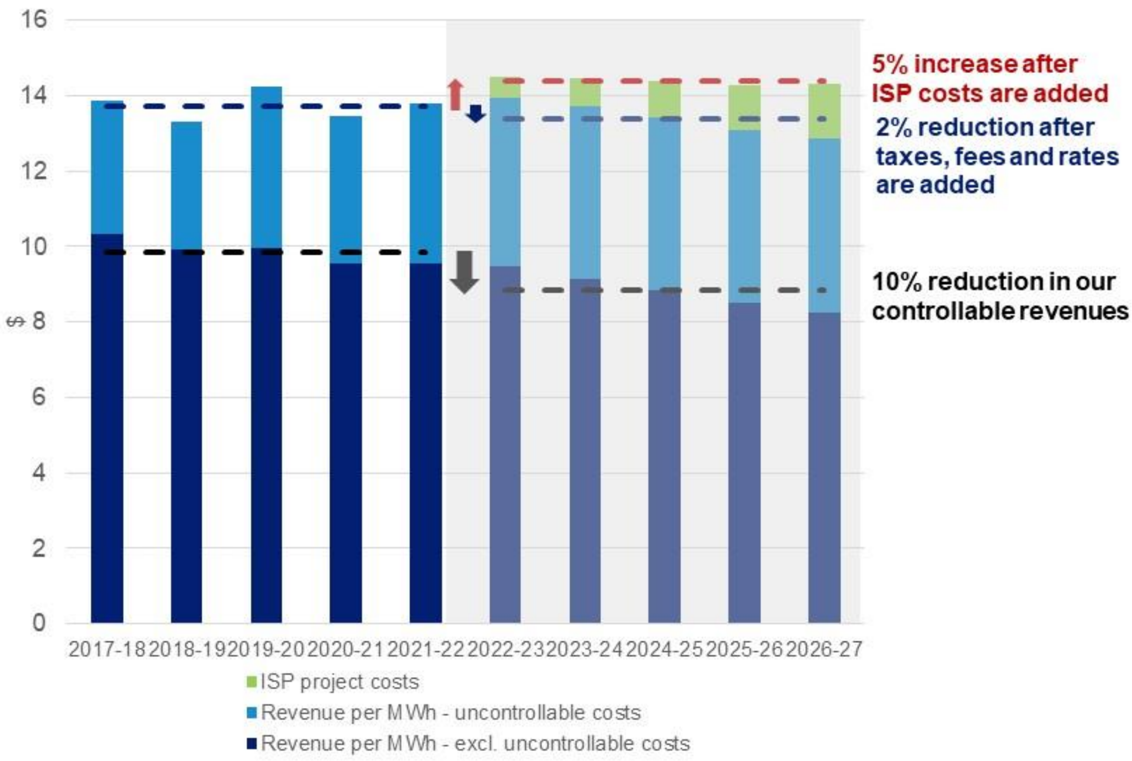
Total Victorian transmission charges, levied by AEMO, contain significant costs in addition to the revenue covered by this review. Therefore, in constructing this Revised Proposal, we have been conscious to minimise the costs of maintaining the existing Victorian transmission network to provide space for the record investment in growth expected over the next decade.

Excluding uncontrollable costs, such as easement land tax levied on the network by the Victorian Government, we have reduced our revenue per MWh by 10% in real terms (most relevant to large customers) and by 19% in revenue per customer terms (most relevant to residential customers). Including uncontrollable costs, our total transmission charges are expected to fall by 2% in $/MWh terms and by 12% in $/customer terms.

In response to stakeholder requests for transparency on future price paths, we have also estimated total Victorian transmission prices that include an indicative cost forecast for AEMO's functions and additional ISP investments, noting that AusNet does not determine which investments proceed or how and by whom they are funded.

This analysis shows that prices (expressed in $/MWh terms) are expected to rise by 5% in real terms after these costs are incorporated over the 2023-27 regulatory control period. We would also note however, that with the possible addition of further material ISP and RDP projects over the second half of the decade, transmission prices could increase markedly after 2026-27.

Actual and forecast revenue per MWh ($ real 2021-22)[1]



Source: AusNet

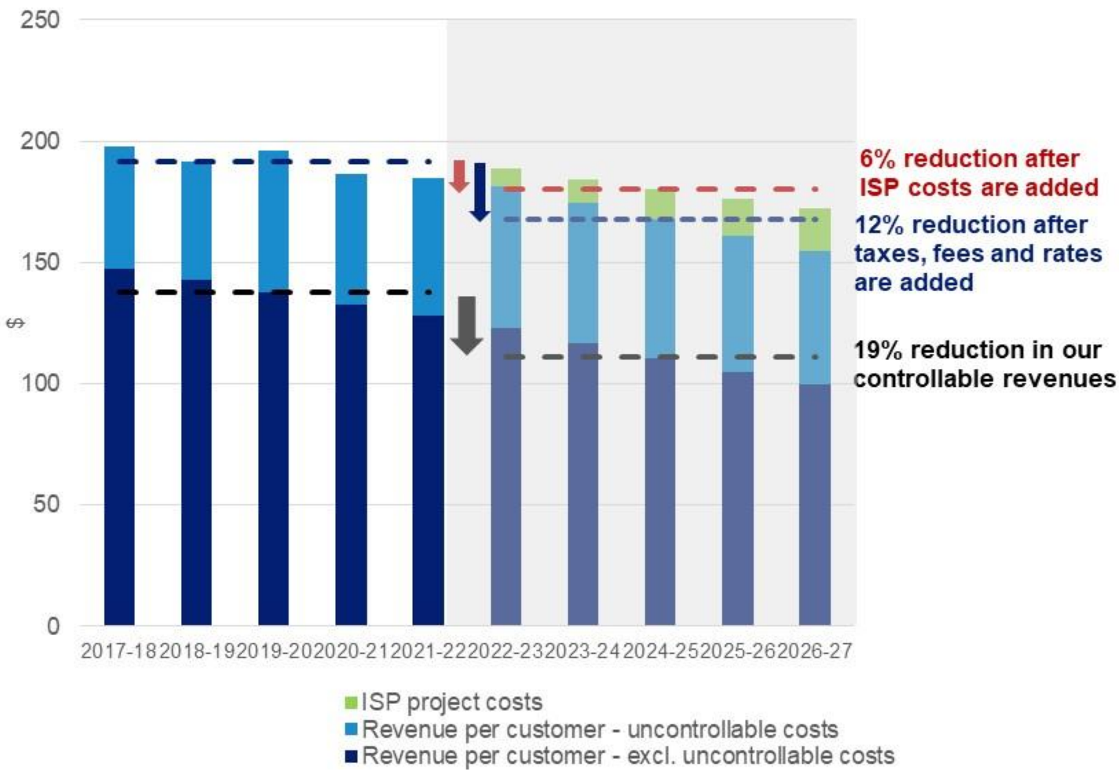
Note: Uncontrollable costs include the easement land tax, the Mental Health and Wellbeing Levy, AEMO participant fees and increases in council rates and land taxes.

As forecasts of the key inputs underpinning these price paths evolve, such as energy forecasts and the costs of ISP and RDP projects, we will continue to engage with our Customer Advisory Panel to provide transparency on the outlook for total Victorian transmission charges.

After incorporating an indicative cost forecast for AEMO's functions and additional ISP investments, prices (expressed in $/customer terms) are expected to fall by 6% in real terms over the 2023-27 regulatory control period.

[1] To isolate the effect of changes in our costs since the Initial Proposal, this figure reflects AEMO's 2019 energy forecasts, which were also used to estimate the future price paths shown in our Initial Proposal. Based on AEMO's 2020 forecasts, which are significantly lower than the 2019 forecasts, prices are expected to increase by 14% in real terms. AEMO's 2020 energy forecasts have been applied to develop the Revised Proposal's expenditure forecasts.

Actual and forecast revenue per customer ($ real 2021-22)



Source: AusNet

Note: Uncontrollable costs include the easement land tax, the Mental Health and Wellbeing Levy, AEMO participant fees and increases in council rates and land taxes.

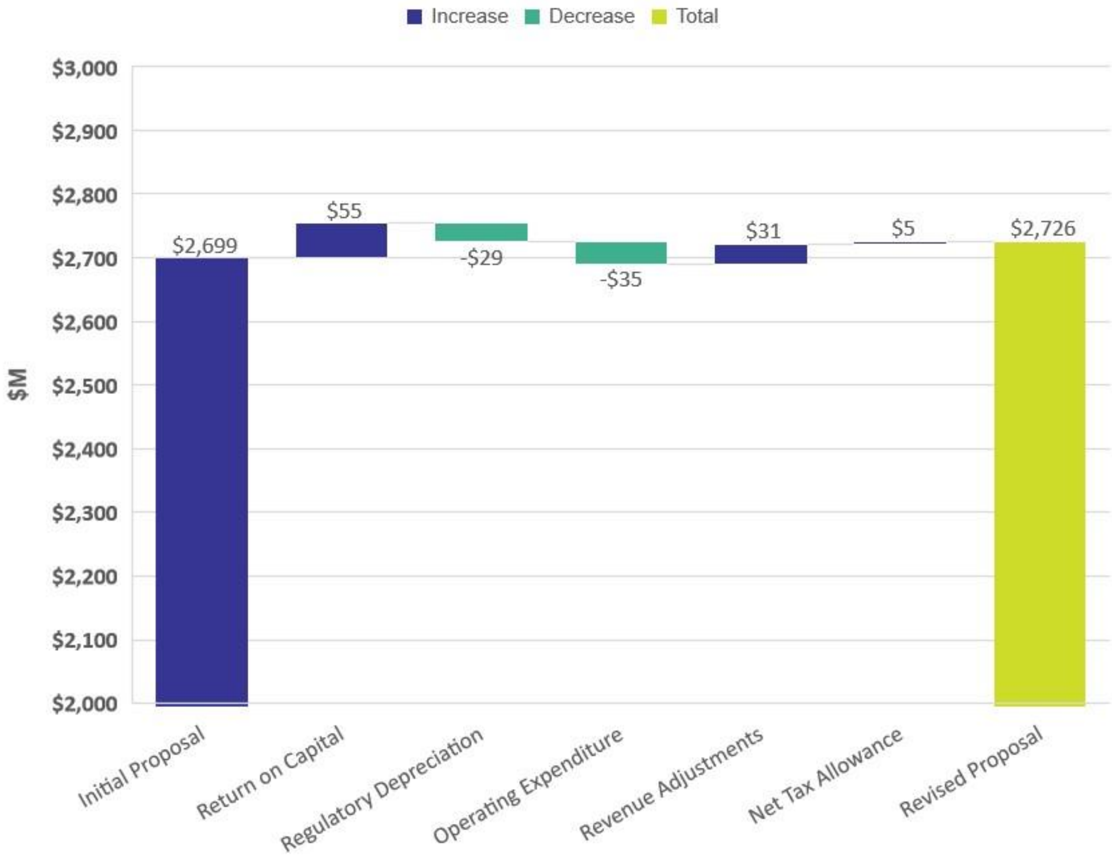
The Revised Proposal

Our revenue forecast

Revenue is required to fund the operating and capital costs needed to maintain the reliability, security and safety of the existing transmission network. Between the Initial and Revised Proposals, AusNet has been conscious to maintain stable revenue forecasts despite the substantial changes that have occurred since October 2020.

The figure below shows the difference between the Initial and Revised Revenue Forecasts for the 2023-27 regulatory control period. The major drivers of the difference between the Initial and Revised Proposals are higher interest rates and incentive payments, offset by lower opex and lower depreciation due to higher inflation and slower RAB growth from deferral of capex.

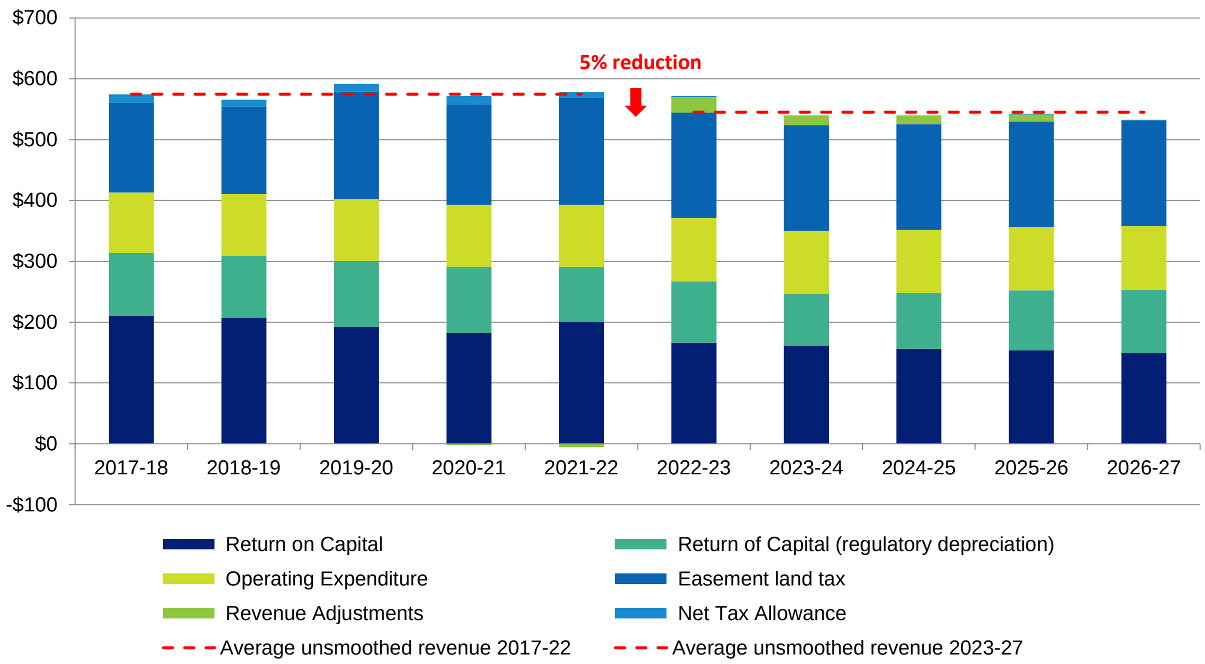
Initial and Revised Proposal Revenue Requirements ($M, real 2021-22)



Source: AusNet

After accounting for our expenditure forecasts, lower interest rates and AER decisions that lower the cost of capital, the figure below shows that our average revenue requirement will be 5% lower in real terms over the 2023-27 regulatory period. As the total number of electricity customers is expected to increase, the average charge per customer will be 12% lower in real terms.

Unsmoothed revenue requirement ($M, real 2021-22)



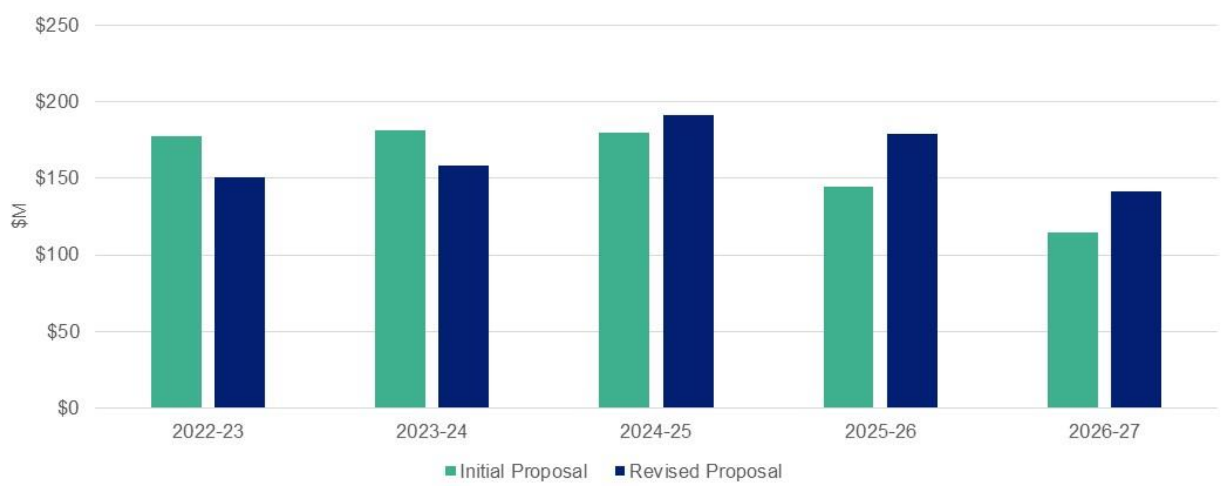
Source: AusNet

Our capital expenditure forecast

Our revised forecast contains several changes, both increasing and decreasing capex, to account for the changed circumstances arising from the various updates and announcements affecting the future development and operation of the Victorian grid. The net effect of these changes leaves the total capex forecast slightly higher, but the associated revenue allowance is smaller due to a more back-ended delivery profile. This means customers will pay less to fund our updated capex forecast.

We are proposing total capex of $820 million (real 2021-22) over the forthcoming regulatory control period, which is $23 million or 3% higher than our Initial Proposal. However, the forecast is back-ended reflecting the deferral of several projects, reducing the revenue paid by customers to fund our capital program by $5 million. The figure below shows the difference between the initial and revised capex forecasts for the 2023-27 regulatory period.

Revised Proposal versus Initial Proposal capital expenditure ($M, real 2021-22)



Source: AusNet

The key changes are:

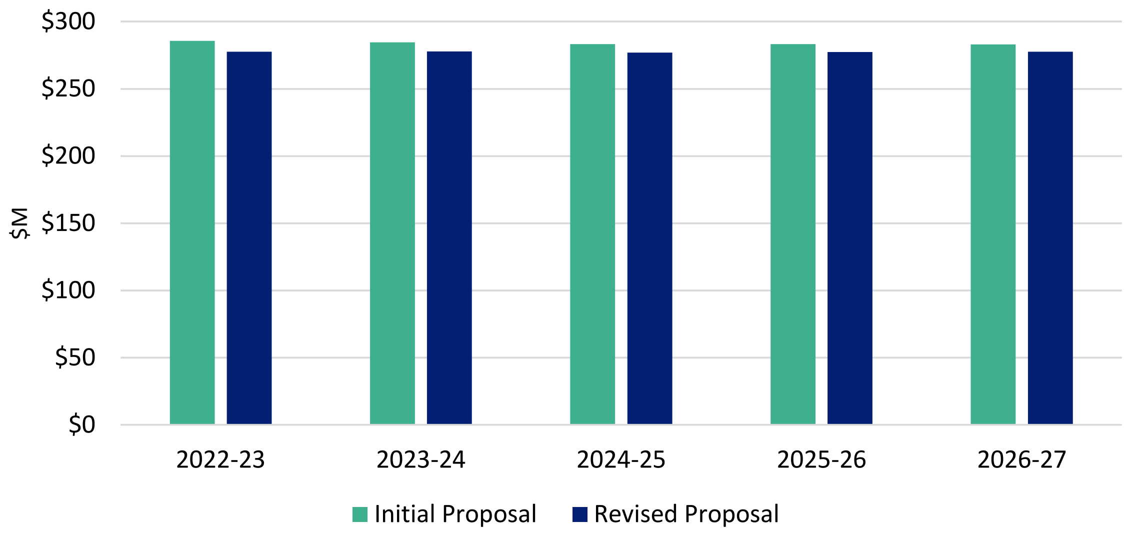
- The removal of duplication with the projects announced under phase 1 of the RDP. This includes removing the Horsham SVC replacement project from our forecasts and ensuring the removal of the South-West communications loop replacement project from the RDP;
- Deferral and coordination of the Sydenham Terminal Station rebuild with the connecting ISP Western Victoria Transmission Network Project;
- Inclusion of a circuit breaker replacement project in the Latrobe Valley designed to lower network risk on the key Loy Yang generation pathways, now more important with the early closure of the Yallourn Power Station;
- Incorporation of the new AEMO demand forecasts and market modelling into our economic analysis;
- New project cost estimate that account for recent scope changes and more accurate cost estimates that have become available for several projects, including those that have progressed through the Regulatory Investment Test process; and
- Inclusion of a contingent project associated with new generation connecting in the Gippsland renewable energy zone.

Our operating expenditure forecast

Since the Initial Proposal, new costs from external factors outside our control have or will be imposed, including higher rates and taxes, AEMO charges and Directions, increased cyber security obligations, and bushfire liability insurance costs that have been heavily impacted by climate change risk. Despite this, by focusing on reducing opex costs that we do control, we have reduced the opex forecast in the Revised Proposal relative to the Initial Proposal.

The figure below shows the difference between the Initial and Revised Proposal opex forecasts for the 2023-27 regulatory period. Our Revised Proposal opex forecast is $1,387 million, which is $35 million or 2% lower than our Initial Proposal.

Revised Proposal versus Initial Proposal operating expenditure ($M, real 2021-22)



Source: AusNet

In addition to the major step changes in the Initial Proposal for cyber security, council rates increases and new environmental obligations, the drivers of recent new opex costs in the Revised Proposal are:

- Changes to State taxes including the new Mental Health and Wellbeing Levy and higher land taxes;
- The reallocation of AEMO participant fees to transmission businesses;
- An AEMO Direction to install and maintain more advanced real time monitoring/metering equipment; and
- Higher expected premiums for bushfire liability insurance caused by increased climate change risks.

These have been more than offset by:

- A $6 million reduction in controllable opex costs in 2020/21 (saving approximately $26 million over the forthcoming period). AusNet has invested heavily in new technology to drive efficiencies in its inspection and maintenance practices. In 2019, new outsourced maintenance arrangements were put in place to leverage these improvements. These improvements are reflected in the reported costs that form the basis of the 2020-21 base year;
- A $28 million reduction in expected council rates increases, following detailed discussions and challenge of the Valuer-General of Victoria's proposed valuation approach.

Again, consistent with stakeholder preference to pay only for actual costs in our opex forecasts, we will rely on the pass-through arrangements to recover any network support costs incurred to facilitate access to the system for planned outages, to undertake maintenance and replacement works. The efficiency of these costs will be subject to an independent assessment undertaken by AEMO before they are incurred.

Incentive Regimes

The Market Impact Component (MIC) of the Service Target Incentive Performance Scheme encourages a TNSP to minimise the disruption to the wholesale market from its planned outages. Over the last four years, the rapid energy transition has resulted in a step change in the number of outages constraining the market as large, centralised generation in strong parts of the network has been replaced by distributed large scale renewable generators in weaker parts of the network. The current MIC scheme design did not envisage the changes we are seeing in our operating environment.

During the current 2017 to 2021 regulatory period, where constraints due to this transition have increased exponentially, the scheme's ability to continue to provide an incentive has been dependent on the AER pragmatically applying the exclusion regime in our annual performance assessment.

Our Proposal largely seeks to codify existing AER practice in our determination, while also addressing emerging issues and maintaining competitive neutrality for contestable transmission projects. Our approach would form a transparent, transitional arrangement put in place pending a review and redesign of the scheme.

This approach will maximise the long-term benefit to customers by:

- Maintaining the incentive for AusNet to optimise its outages to deliver wholesale market price benefits for customers; and
- Not unduly penalising AusNet for the exponential change in operating conditions, all outside of our control, that have arisen since 2017 and provide us an opportunity to recover

our efficient costs. This ensures investors have confidence in the fairness of the framework and continue to provide the funding required for a successful energy transition for customers.

Conclusion

Our Revised Proposal has taken explicit account of our customers' views and focused particularly on providing transparency of our own plans and costs and how they interact with transmission plans and costs not explicitly covered by this review and managed by other parties. Controllable real revenues have been cut by 10% in $/MWh terms and 19% in $/customer terms. Whilst our capex forecast has been comprehensively updated to address new information and opex is changing due to external factors, less revenue is required to fund the revised forecasts compared to the Initial Proposal.

We look forward to discussing the modifications we have made to the Initial Proposal with the AER.

1 Stakeholder engagement

1.1 Key points

- In preparing this Revised Proposal, we have engaged extensively with our customers and stakeholders to ensure that their views and preferences are reflected in our updated plans.
- This engagement primarily took place through seven collaboration workshops we held between 20 April and 6 August 2021. The format, timing, topics, participants, and frequency of engagement activities undertaken were chosen in response to customer and stakeholder preferences. A broad range of stakeholders participated in these workshops, including customer advocates and directly-connected customers.
- These workshops allowed for a deep consideration of the relatively narrow set of issues highlighted by our stakeholders as likely to have the most material impact on the Revised Proposal (e.g., the release of the Victorian Government's REZ Development Plan).
- As a result of this further engagement, customer and stakeholder views and preferences have heavily influenced key aspects of our Revised Proposal. In particular, the Revised Proposal comprehensively reflects stakeholder preferences in what has or has not been included in expenditure forecasts and how risk and uncertainty arising from the significant changes discussed above are managed. We are confident that stakeholders will provide strong support to those aspects of our Revised Proposal.
- We have made a commitment to our stakeholders to continue the conversations started during this regulatory review process, to ensure collaboration continues and end users can express views on addressing these challenges. This will be achieved through the continuation of the TRR Customer Advisory Panel as a business-as-usual engagement forum for transmission issues.

1.2 About our Post-Lodgement Engagement Program

The development of our Revised Proposal has been underpinned by a comprehensive and collaborative stakeholder engagement program, involving directly-connected customers; residential and business customer advocacy groups; clean energy bodies; generators; AEMO; and the Victorian distribution businesses.

We have been working closely with our customers and stakeholders to understand and accurately reflect their views and preferences in our Revised Proposal and ensure that our Revised Proposal meets the long-term interests of consumers. Our customers and stakeholders bring different viewpoints, experiences and knowledge to this planning process. We are grateful for the time customers and stakeholders have given this process which has influenced and improved our Revised Proposal considerably.

The COVID-19 pandemic significantly impacted our engagement program in 2020 due to the uncertainty it created about the operating environment for our transmission network in 2023-27. Subsequent government policy developments across a range of issues and operational challenges, including deteriorating system strength and minimum demand issues, and the accelerated closure of Yallourn Power Station, have introduced additional substantive issues and increased the importance of our post-lodgement engagement program.

Our post-lodgement engagement has addressed a wide range of topics including system strength, the Renewable Energy Zone development, the Integrated System Plan (ISP) and its impact on replacement programs, the impending closure of the Yallourn Power Station and its impact on the transmission network, the operation of incentive schemes, cyber security, insurance and many other topics. Some of these topics were suggested by us and others were identified by stakeholders. We strongly encouraged stakeholders to table relevant matters that they wanted to discuss or influence in the context of the TRR. This co-design process resulted in a series of workshops, each one targeted to cover one or two issues in great depth. The series was expanded where stakeholders needed or requested further discussion or information.

The views, ideas and preferences of our customers and stakeholders on these issues are reflected throughout this Revised Proposal. The engagement activities we have undertaken post-lodgement, our key findings and how this Revised Proposal responds to these findings are outlined below and explained in more detail in the relevant Chapters of this Revised Proposal.

1.3 Developing our Post-Lodgement Engagement Approach

Stakeholders and the AER's Consumer Challenge Panel (CCP23) requested that we undertake further engagement on several topics relevant to our 2023-2027 transmission plans; identify those aspects of our proposal that stakeholders can influence; and explain how stakeholders' views have been reflected in our Revised Proposal.

In light of the request for further engagement, in close collaboration with our customers and other stakeholders, we developed a relevant and fit-for-purpose post-lodgement engagement program. The format, timing, topics, participants, and frequency of engagement activities undertaken were chosen in response to customer and stakeholder preferences.

In response to feedback from stakeholders and the CCP23, we endeavoured to make the voices of our customers and other stakeholders much clearer in our Revised Proposal. This included deliberate efforts to move toward the Involve, Collaborate and Empower levels of the IAP2 Public Participation Spectrum2 when creating the post-lodgement engagement program. We were determined to communicate openly and honestly about the potential for customers and other stakeholders to influence key components of our Revised Proposal and reflect their views to the greatest extent possible.

Most of our post-lodgement engagement activities have been at the Involve or Collaborate level. We did not undertake any engagement at the Empower level during the development of our Revenue Proposal as we did not feel there were any genuine opportunities for stakeholders to influence our updated plans to this extent, and as final decision making power rests with the AER. Stakeholders indicated that they support this approach, and much prefer networks to be open and honest about what stakeholders can and cannot influence rather than attempting to engage at the Empower or Collaborate level but be limited in practice to Informing or Involving.

To ensure that our post-lodgement engagement plan was optimally designed, we sought input from stakeholders through the following process:

- A first draft of the post-lodgement engagement plan was prepared, based on feedback from stakeholders and the CCP23;

[2] The IAP2's Public Participation Spectrum is designed to assist with the selection of the level of participation that defines the public's role in a community engagement program. The IAP2 spectrum, ordered by level of direct influence that the public has on a decision is Inform, Consult, Involve, Collaborate and Empower.

- We discussed the draft plan with an IAP2 accredited specialist; and
- Before finalisation of the plan, feedback was sought from the CCP23 and the CAP on our proposed approach.

In response to feedback received stakeholders, we designed a workshop series in conjunction with KPMG as independent facilitators. The approach was designed to ensure a deep consideration of the relatively narrow set of issues highlighted by our stakeholders as likely to have the most material impact on the Revised Proposal.

The first Collaboration Workshop held on 20 April 2021 was designed to provided sufficient background on each issue to allow an informed discussion in the subsequent workshops and reveal where more information was required by stakeholders to be able to engage on the subject matter.

Flexibility was built into the process, so where a workshop was unsuccessful in terms of informing stakeholders or obtaining feedback because information, as presented, was too complex or customer input was not clear, further workshops were added to the program. In particular, multiple workshops were held on the complex operational challenges we are facing due to low system strength, eventually yielding strong customer preferences that have informed our Revised Proposal's approach to this issue.

Commenting on our approach through surveys held during the process, stakeholders observed that they liked:

- AusNet's willingness to adapt the program and add additional sessions as required;
- The engaging format (being regular 2-hour workshops on specific topics), and for using a format that is respectful of stakeholders' time;
- AusNet's willingness to discuss tough topics and our openness and honesty during these conversations;
- The workshops striking the right balance between being informative and collaborative, and providing participants with the background knowledge needed to participate effectively; and
- The iterative approach and AusNet's genuine commitment to responding to feedback and reflecting stakeholder input in its proposal.

Nonetheless, recognising uncertainty would be feature of the Victorian transmission environment for some time, stakeholders considered that opportunities to discuss, review and challenge topical transmission issues should continue past lodgement of the Revised Proposal. As such, we have made a commitment to continue the conversations started during this process, to ensure collaboration continues and end users can express views on addressing the challenges and opportunities facing the sector. This will be achieved through the continuation of the TRR Customer Advisory Panel as a business-as-usual engagement forum for transmission issues.

1.4 Post-Lodgement Engagement Activities

This section describes the dedicated customer and stakeholder engagement activities we undertook following the lodgement of our Initial Proposal, which underpin this Revised Proposal.

To view our pre-lodgement engagement activities, please refer to our Initial Proposal.

The following activities were central to our post-lodgement engagement program:

- **Regular meetings of the Customer Advisory Panel (CAP)**. We established the CAP to provide us with advice and guidance on various aspects of our proposal and has been meeting regularly since early 2019. The role of the CAP is to provide:
    - Advice on electricity customer needs, issues and services and how these should be addressed or incorporated in the Revenue Proposal;
    - Feedback on the design of our customer research and engagement program, and comment on findings and insights from this program; and
    - Feedback on our Revenue Proposal to ensure it adequately reflects customer views and preferences.

  CAP members encompass a broad spectrum of stakeholders, which is essential in developing a robust and credible proposal, including:
    - Consumer advocates;
    - Directly-connected customers;
    - Victorian electricity distribution businesses; and
    - Generators.

  Most CAP members have been involved in a range of activities in the pre- and post-lodgement engagement programs, including participating in workshops and briefing sessions.

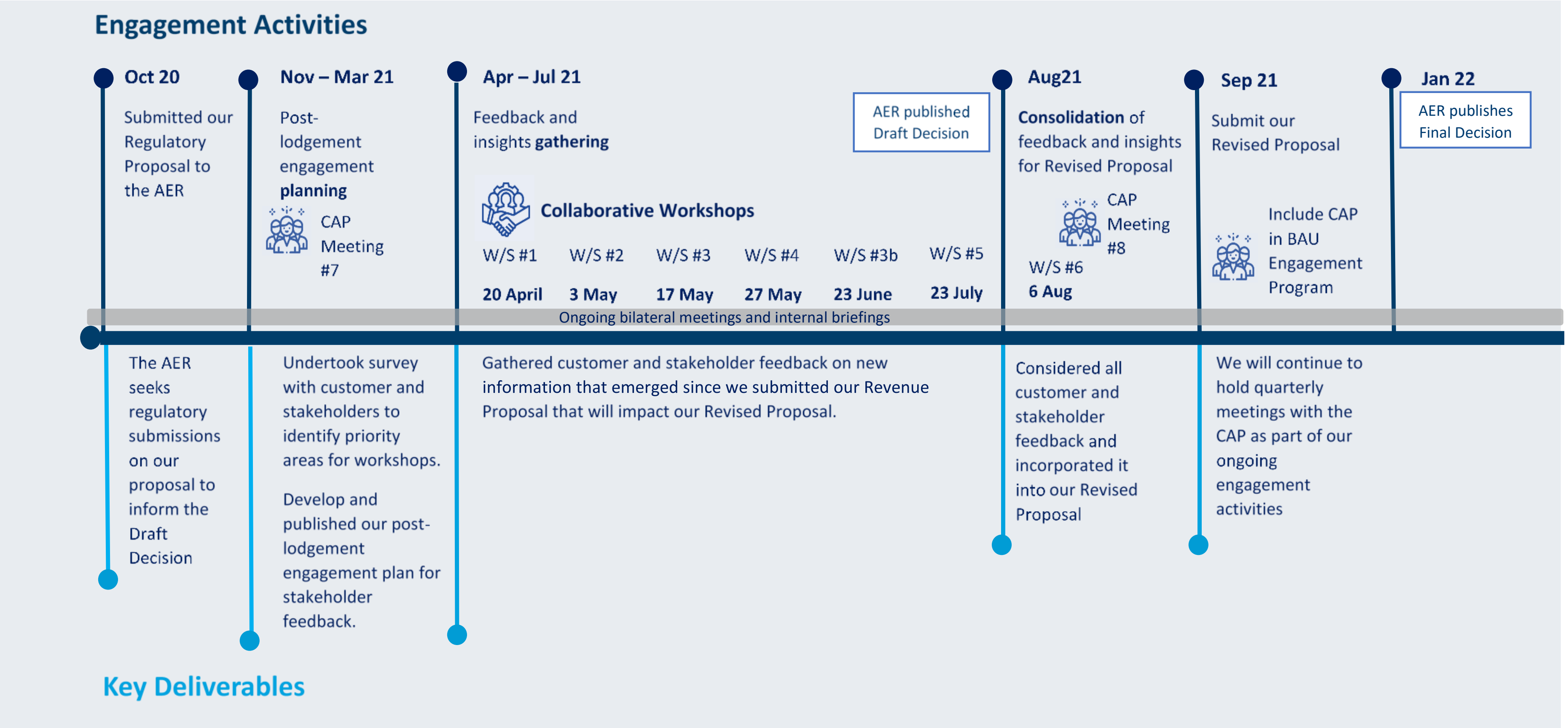
- **Collaborative stakeholder workshops.** As discussed above, these workshops were the central focus of our post-lodgement engagement. As shown in the figure below, we held seven workshops on a wide range of issues between 20 April and 6 August 2021, including additional workshops and issues that were added to our initial scope in response to stakeholder requests. We engaged KPMG to independently facilitate the workshops and prepare summary reports of the key outcomes. A broad range of stakeholders participated in these workshops, including customer advocates and directly-connected customers. We invited additional stakeholders attend workshops where they have a stake or special interest in a particular topic being discussed. Typically, workshop attendees included:
    - Directly-connected customers;
    - Customer advocates representing the interests of both residential and business customers;
    - Victorian electricity distribution businesses;
    - AER staff;
    - AEMO staff;
    - DELWP staff;
    - Generators; and
    - Advocates for generators and retailers.

Figure 1–1: Our Collaborative Stakeholder Workshop Series

The following timeline demonstrates how these collaboration workshops formed part of our broader post-lodgement engagement activities.

1.4.1 Timeline of Post Lodgement Engagement Activities

Figure 1–2: Post-Lodgement Engagement Activities



1.5 Post-Lodgement Engagement Outcomes

The table below summarises our post-lodgement engagement activities including:

- An overview of the activity;
- The key topics discussed; and
- Actions taken to reflect stakeholder input regarding AusNet's Revised Proposal.

The Collaborative Workshop summary reports have been provided as attachments to this Revised Proposed.

Further information on the feedback we received from stakeholders, and how this has been addressed in our Revised Proposal, is provided in Chapters 3 (Capital Expenditure), 4 (Operating Expenditure) and 9 (Incentive Schemes).

Table 1-1: Summary of stakeholder engagement outcomes

Revised Proposal component	What we heard from stakeholders	How we responded
Capital expenditure (Discussed further in Chapter 3)	**Interactions with other network planning processes** Costs to customers should be minimised by ensuring coordination and removing any overlap between AusNet's asset replacement capital program, AEMO's ISP and the Victorian Government's REZ Development Plan.	In developing our Revised Proposal's capex forecast, we have: • Reflected synergies of $10 million in our Sydenham Terminal Station project cost estimate due to its interaction with the Western Victoria Transmission Upgrade Project, and • Removed the $31 million Horsham Terminal Station SVC replacement project from our forecast, to avoid overlap with the REZ Development Plan (RDP). We have also worked with the Victorian Government to remove overlap of up to $8 million from the RDP associated with the South-West Comms Loop project, which our Revised Proposal proposes to fully fund.
	Network support costs to manage declining system strength While additional network support costs needed to manage declining system strength are largely outside of AusNet's control, the economic timing of the major station projects should account for these costs. As it is difficult to forecast the network support costs accurately, customers would prefer to pay actual costs where these are prudent and efficient and needed to deliver AusNet's major projects.	We have not included network support costs in our capex forecast and will instead use cost pass through arrangements to recover these costs. However, we have accounted for network support costs in our major station project economic assessments where these costs may be incurred. This has deferred the $26 million Moorabool Terminal Station project by two years compared to our Initial Proposal.
	Implications of the early closure of Yallourn Power Station Stakeholders are comfortable with the approach AusNet has taken to assessing the impacts of the early closure of Yallourn Power Station and acknowledged the challenge in planning to address multiple uncertainties. Given these uncertainties, stakeholders would prefer AusNet to use contingent project	We have included $16 million of expenditure for asset replacement at Loy Yang Power Station and Hazelwood Terminal Station, where our economic assessment shows this is prudent and efficient, given Yallourn's expected closure in 2028. For the other $105 million of potential projects that we discussed with stakeholders, we have: • Assessed, but not proposed, expenditure where the efficient timing for project

Revised Proposal component	What we heard from stakeholders	How we responded
	arrangements to manage the costs of new projects, rather than expenditure allowances.	delivery remains after 2028 ($60 million); and • Proposed a contingent project where the expenditure is dependent on the connection of significant new renewable generation in the region ($45 million).
	Addressing new information in AusNet's total capex forecast Stakeholders acknowledged that while changes to our forecast may be needed to address new information since the Revenue Proposal, the total materiality of the changes should be considered in determining our approach for the Revised Proposal.	Despite the significant external changes that have occurred since we prepared our original forecast, our Revised Proposal's total capex forecast is a slightly increase on the Initial Proposal. The updated forecast is also back ended compared to the original forecast, reflecting the deferral of several major projects (due to new information) and smoothing adjustments we have made to manage deliverability risk. The net effect of all these changes is a $5 million reduction in the revenue required to fund our proposed capital program.
Operating expenditure (Discussed further in Chapter 4)	**Network support costs to manage declining system strength** Consistent with the views expressed on network support costs for major station projects, stakeholders would prefer to pay for actual costs where these are prudent and efficient and needed to deliver AusNet's maintenance program.	We have not included network support costs in our opex forecast and will instead use cost pass through arrangements to recover these costs. This approach has reduced our Revised Proposal's opex forecast by approximately $50 million.
	Bushfire insurance premiums increases Given the market-driven nature of these increases, and the AER's decision to approve a bushfire insurance step change for the Victorian electricity distributors, stakeholders did not express concern about funding the increases through a step change.	We have included an $8 million step change in our Revised Proposal's opex forecast to fund these increases. We will work with the AER to update our forecast before the Final Decision, should our September 2021 insurance renewal process suggest a lower step change is needed.
	Increases in externally driven costs Stakeholders expressed concerns about industry being used as a revenue raising tool by Governments. Stakeholders also emphasised the need for increased governance and scrutiny of AEMO's costs.	We recognise stakeholders' concerns regarding the increases in externally driven costs which it has been necessary to include in our Revised Proposal's opex forecast, such as council rates, the new mental health and wellbeing levy, land tax increases and AEMO participant fees. Offsetting these increases, we have: • Achieved significant cost savings in our base year, which have reduced our efficient opex requirements in the next regulatory period by approximately $26 million compared to the Initial Proposal; • Chosen to fund $4 million of step changes through further efficiency savings in the next period; and • Engaged with the Valuer-General Victoria to challenge and minimise expected increases in our council rates costs, reducing our forecast by $28 million relative to our Initial Proposal.

Revised Proposal component	What we heard from stakeholders	How we responded
		While not an opex cost, we have also chosen to fund, through efficiency savings, additional capex of approximately $20 million in the next regulatory period. This relates to cost increases for current period projects and new projects that were identified during the preparation of our updated capex forecast. Recognising that these costs were not flagged with stakeholders during our post-lodgement engagement process due to timing, and our stakeholders' strong affordability concerns, we have elected not to include these costs in our Revised Proposal.
Incentives **(Discussed further in Chapter 9)**	**Application of the Market Impact Component (MIC) of the Service Target Performance Incentive Scheme in next regulatory control period** Stakeholders felt that the current MIC scheme is not fit-for-purpose and that the current scheme should be used as a "transitionary arrangement" until it can be modified to suit the current operating environment. Stakeholders suggested that AusNet seek a "statement of joint understanding" with the AER to implement this. Some stakeholders questioned whether AusNet was only proposing to review the scheme because it wasn't consistently receiving rewards under the scheme.	Our Revised Proposal presents an approach to applying the MIC that will maintain the incentive for us to continue to manage the wholesale market price impact of our planned outages, benefiting customers. This approach codifies existing AER practice and will not result in windfall gains, consistent with the current period where we have received both bonuses and penalties under the scheme. We sought support from our Customer Advisory Panel for a transparent application of our proposed transitional approach by the AER during the next regulatory period, until the MIC is subject to a comprehensive review by the AER.

1.6 Supporting documentation

We have included the following documents to support this chapter:

- Summary Reports from all Collaboration Workshops.

2 Revenue requirement and pricing impact

2.1 Key points

- Our Revised Proposal establishes a total smoothed revenue requirement of $2,724.8 million ($2022) for the 2023-27 regulatory control period, which is:
    - 1.0% ($26.6 million ($2022)) higher than the revenue we sought in our Initial Proposal; and
    - 1.9% ($50.1 million ($2022)) higher than that proposed by the AER in its Draft Decision.
- The principal changes from the Draft Decision are:
    - We have updated our actual and expected capital expenditure for 2020-21 and 2021-22 that forms part of the opening RAB;
    - We have revised our capex forecasts to address the issues raised in the Draft Decision and to reflect new information in relation to major stations capex forecasts for 2023-27, including the latest demand forecasts, updated cost estimates, the expected early closure of Yallourn Power Station and the publication of the Victorian Government's REZ Development Plan. These updates have increased major stations capex by $22.8 million ($2022). We have also included the SW Comms Loop Upgrade project and asset replacement risk allowances, which the Draft Decision did not accept, increasing the capex forecast by $35.8 million ($2022) compared to the Draft Decision;
    - We have revised our opex forecasts to recover new externally imposed costs, in total adding $22.6 million ($2022). Our council rates step change has reduced by $28.1 million ($2022) since our Initial Proposal based on updated analysis and advice from the Valuer-General Victoria. An overall increase of $68.9 million ($2022) in opex is sought in this Revised Proposal compared with the Draft Decision. This comprises a revised council rates step change of $43.3 million, a cyber security step change of $28.2 million, offset by base year opex adjustments of -$25.5 million; and
    - An increase in the EBSS incentive scheme outcome of $24.0 million ($2022) as reflected in the updated EBSS model.[3]
- As a result of the above changes, consequential changes have been made to our regulatory asset base, return on capital, depreciation and corporate tax allowance.
- On average, our proposed revenue requirement is $545.0 million ($2022) per annum over the 2023-27 regulatory control period. This is 5% lower than our expected revenue for the current regulatory period.
- Excluding easement land tax and other uncontrollable costs,[4] our proposed average annual revenue requirement is $360.0 million ($2022). This is 13% less than expected revenue in the current period. We estimate that after these uncontrollable costs, AEMO's costs and customer growth are taken into account, the average transmission charge per customer will fall by 6% in real terms.

[3] ANT Revised Proposal - TRR 2023-27 Model Efficiency Benefit Sharing Scheme - PUBLIC

[4] Uncontrollable costs include the easement land tax, the Mental Health and Wellbeing Levy, AEMO participant fees and increases in council rates and land taxes

2.2 Chapter structure

The remainder of this chapter is structured as follows:

- Section 2.3 provides an overview of our total revenue requirement for the 2023-27 regulatory control period;
- Section 2.4 presents a summary of the building block components of the revised revenue requirement; and
- Section 2.5 provides a summary of our smoothed revenue requirement;
- Section 2.6 sets out our average transmission charges; and
- Section 2.7 provides a summary of our supporting documentation.

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

In our Initial Proposal, we calculated our revenue requirement for the 2023-27 regulatory control period to be $2,647 million in unsmoothed, real 2021-22 dollars, or $2,885 million in nominal terms.

We explained that our average total annual revenue requirement of $529 million ($2022 dollars) would be approximately 8% lower than the current regulatory control period. In addition, we noted that excluding easement land tax and council rates increases, which are uncontrollable, our proposed average annual revenue requirement would be $352 million ($2022 dollars), which is 15% lower than the current period.

2.3.2 Draft Decision

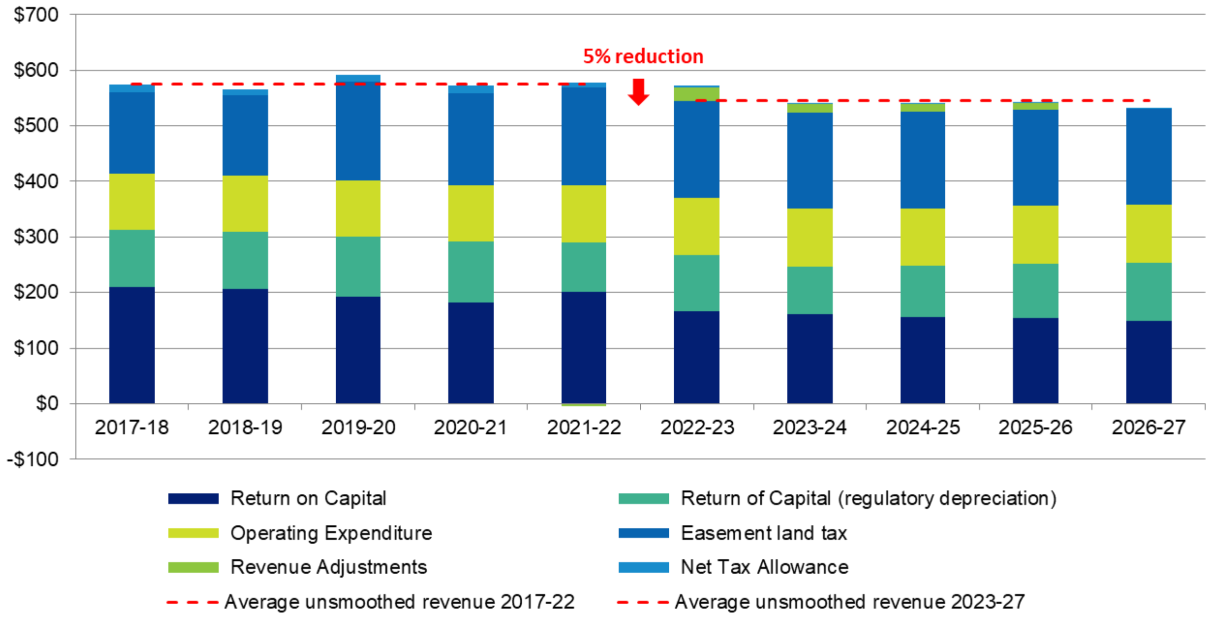
The AER's Draft Decision calculated a total annual building block revenue requirement of $2,838.1 million ($nominal, unsmoothed), which represents a reduction of $47.0 million ($nominal) or 1.6 per cent compared to our Initial Proposal. The AER's Draft Decision reflects a number of changes to our proposed building block components, including the following changes (in nominal terms):

- an increase in the return on capital of $47.2 million or 6.0%;
- an increase in the regulatory depreciation of $15.1 million or 2.8%;
- a reduction in our opex forecast of $121.7 million or 8.0%;
- an increase in corporate income tax of $10.1 million compared to our Initial Proposal of $0.1 million; and
- an increase in the revenue adjustments of $2.5 million or 6.9%.

2.3.3 Revised Proposal

Our smoothed revenue requirement for the 2023-27 regulatory control period is $2,724.8 million ($2022) or, on average, $545.0 million per annum ($2022). This is 5.2% below our expected revenue for the current regulatory control period, as shown in the figure below.

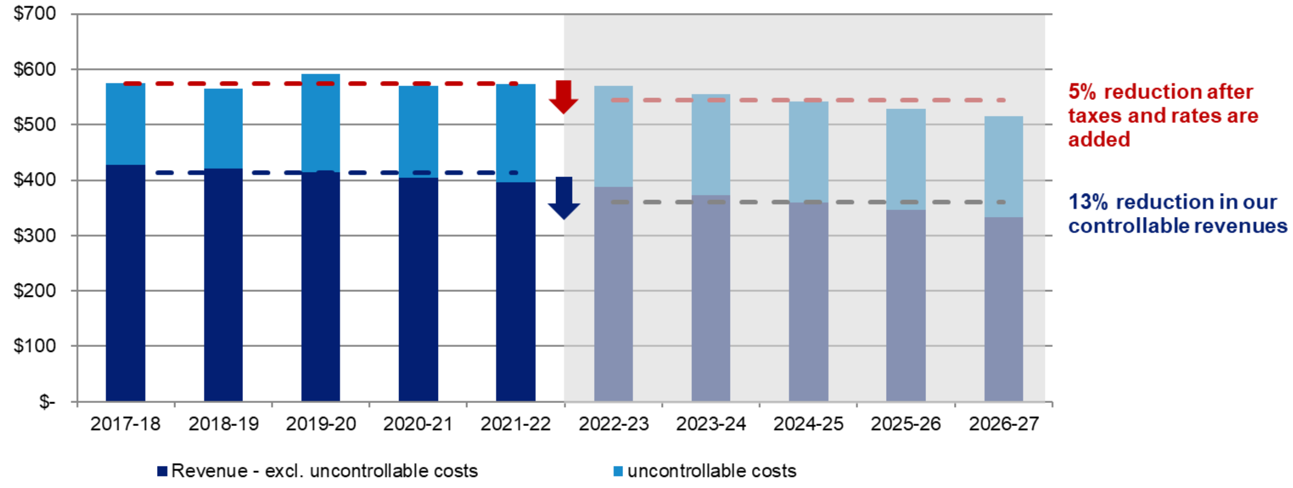
Figure 2-1: Actual, expected and forecast revenue requirement ($M, real 2021-22)



Source: AusNet

Our Revised Proposal calculates a total revenue requirement that is 1.9% higher than the AER's Draft Decision and 1.0% higher than our Initial Proposal. The figure below shows our revenue requirement with easement land tax and other uncontrollable costs shown separately. Excluding these uncontrollable costs, our proposed average annual revenue requirement is 13% lower than the current period.

Figure 2-2: Actual, expected and forecast revenue ($M, real 2021-22)



Source: AusNet

2.4 Building block components of the revenue requirement

The building block components and our unsmoothed annual revenue requirement for each year of the 2023-27 regulatory control period, as proposed in this Revised Proposal, are depicted in the table below.

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

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Return on capital	170.1	168.3	167.5	167.8	167.1	**840.8**
Regulatory depreciation	103.0	88.9	98.1	107.9	116.4	**514.3**
Operating expenditure excluding ELT	106.3	109.0	110.5	113.5	116.3	**555.6**
Easement land tax	177.5	181.5	185.6	189.8	194.0	**928.4**
Revenue adjustments	25.6	15.8	14.4	12.7	-0.2	**68.2**
Net tax allowance	2.1	0.7	0.9	1.2	1.5	**6.4**
Total	**584.6**	**564.2**	**576.9**	**592.9**	**595.0**	**2,913.7**

Source: AusNet

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.

Consistent with the requirements of clause 6A.5.4(a)(2) of the NER, and in accordance with the AER's PTRM, the return on capital is calculated by applying the post-tax nominal vanilla WACC to the opening RAB for each year of the regulatory control period. Table 2-2 summarises the calculation of the return on capital component of the building block approach.

Full details of the WACC calculation for this Revised Proposal are set out in Chapter 7.

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

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Opening RAB	3,575.7	3,628.7	3,706.4	3,814.8	3,904.2	
WACC (% per annum)	4.77%	4.66%	4.55%	4.45%	4.34%	
Return on capital	**170.1**	**168.3**	**167.5**	**167.8**	**167.1**	**840.8**

Source: AusNet

Our return on capital in Table 2-2 is based on a RAB that we have calculated in accordance with the requirements of clause 6A.6.1 and schedule 6A.2 of the NER. It reflects our revised capex forecast as set out in Chapter 3 of this Revised Proposal, our opening RAB (Chapter 5) and our depreciation (Chapter 6). Table 2-3 summarises our revised RAB for the 2023-27 regulatory control period.

Table 2-3: Regulatory asset base ($M, nominal)

	2022-23	2023-24	2024-25	2025-26	2026-27
Opening RAB	3,575.7	3,628.7	3,706.4	3,814.8	3,904.2
Net capital expenditure	155.9	166.7	206.5	197.3	158.9
Straight-line depreciation	-183.4	-170.6	-181.5	-193.7	-204.2
Indexation on opening RAB	80.4	81.6	83.4	85.8	87.8
Closing RAB	**3,628.7**	**3,706.4**	**3,814.8**	**3,904.2**	**3,946.7**

Source: AusNet

2.4.1 Regulatory depreciation

We have calculated regulatory depreciation in accordance with the requirements of clauses 6A.6.3, 6A.5.4.(a)(1) and (3) of the NER, and the AER's PTRM. Table 2-4 summarises our revised regulatory depreciation for the 2023-27 regulatory control period.

Table 2-4: Regulatory depreciation ($M, nominal)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Straight-line depreciation	183.4	170.6	181.5	193.7	204.2	**933.4**
Indexation on opening RAB	-80.4	-81.6	-83.4	-85.8	-87.8	**-419.1**
Total	**103.0**	**88.9**	**98.1**	**107.9**	**116.3**	**514.3**

Source: AusNet

2.4.2 Operating expenditure

Consistent with the requirements of clause 6A.5.4(a)(6) of the NER, we have included our revised forecast opex for the 2023-27 regulatory control period. Our revised opex forecast addresses the issues raised in the Draft Decision, as explained in Chapter 4 of this Revenue Proposal. Table 2-5 provides a summary of our revised forecast opex.

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

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Controllable opex (base, step and trend)	104.6	107.3	108.7	111.6	114.4	**546.4**
Easement land tax	177.5	181.5	185.6	189.8	194.0	**928.4**
Debt raising cost	1.8	1.8	1.8	1.9	1.9	**9.2**
Total	**283.8**	**290.5**	**296.1**	**303.3**	**310.3**	**1,484.0**

Source: AusNet

2.4.3 Revenue adjustments

Consistent with the requirements of clauses 6A.5.4(a)(5) and (5A) of the NER, we have incorporated the amounts that have been determined under the efficiency benefits sharing scheme (EBSS), the capital efficiency sharing scheme (CESS), and the Shared Assets Guidelines. The detailed calculation of each of these components was undertaken in accordance with all applicable provisions of the NER, as explained in Chapter 9 of this Revised Proposal.

We have updated the EBSS and CESS models to reflect the latest available information for the 2018-22 period. We have accepted the AER's Draft Decision amendments to our proposed Shared Assets revenue decrements. Table 2-6 provides a summary of our revenue adjustments in this Revised Proposal.

Table 2-6: Other revenue adjustments ($M, nominal)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
EBSS	24.9	15.3	14.0	12.6	-	**66.8**
CESS	1.7	1.8	1.8	1.9	1.9	**9.1**
Shared assets	-1.8	-2.0	-2.3	-2.6	-3.0	**-11.6**
DMIA allowance	0.8	0.8	0.8	0.8	0.8	**4.0**
Total	**25.6**	**15.8**	**14.4**	**12.7**	**-0.2**	**66.2**

Source: AusNet

2.4.4 Tax allowance

Consistent with the requirements of clause 6A.5.4(a)(4) of the NER, we have incorporated a benchmark tax allowance in our building blocks revenue requirement. The detailed calculation of the cost of tax is explained in Chapter 8 of this Revised Proposal. The cost of tax calculation in this Revised Proposal accords with the requirements of clause 6A.6.4 of the NER and is summarised in Table 2-7.

Table 2-7: Benchmark tax allowance ($M, nominal)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Tax payable	5.0	1.7	2.1	3.0	3.6	**15.4**
Value of imputation credits	-2.9	-1.0	-1.2	-1.7	-2.1	**-9.0**
Tax allowance	**2.1**	**0.7**	**0.9**	**1.2**	**1.5**	**6.4**

Source: AusNet

2.5 Smoothed revenue requirement

The application of our X-factors in conjunction with our unsmoothed revenue requirement produced our smoothed revenue requirement for this Revised Proposal is set out in Table 2-8.

Table 2-8: Smoothed annual revenue requirement ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Unsmoothed annual revenue requirement	571.8	539.7	539.7	542.4	532.4	**2,725.9**
Smoothed annual revenue requirement	571.8	558.0	544.6	531.6	518.8	**2,724.8**
X-factor (%)	**-1.27%**	**2.40%**	**2.40%**	**2.40%**	**2.40%**	

Source: AusNet

Our PTRM attached to this Revised Proposal demonstrates that the smoothed and unsmoothed revenue requirements are equivalent in net present value terms, as mandated by clause 6A.6.8(c)(1) of the NER.

Clause 6A.6.8(c)(2) requires the X factor to be set to minimise, as far as reasonably possible, the gap between smoothed and unsmoothed revenue in the final year of the regulatory control period. Our PTRM satisfies this clause because our smoothed revenue in 2026-27 is within 3.0% per cent of the unsmoothed revenue for that year.

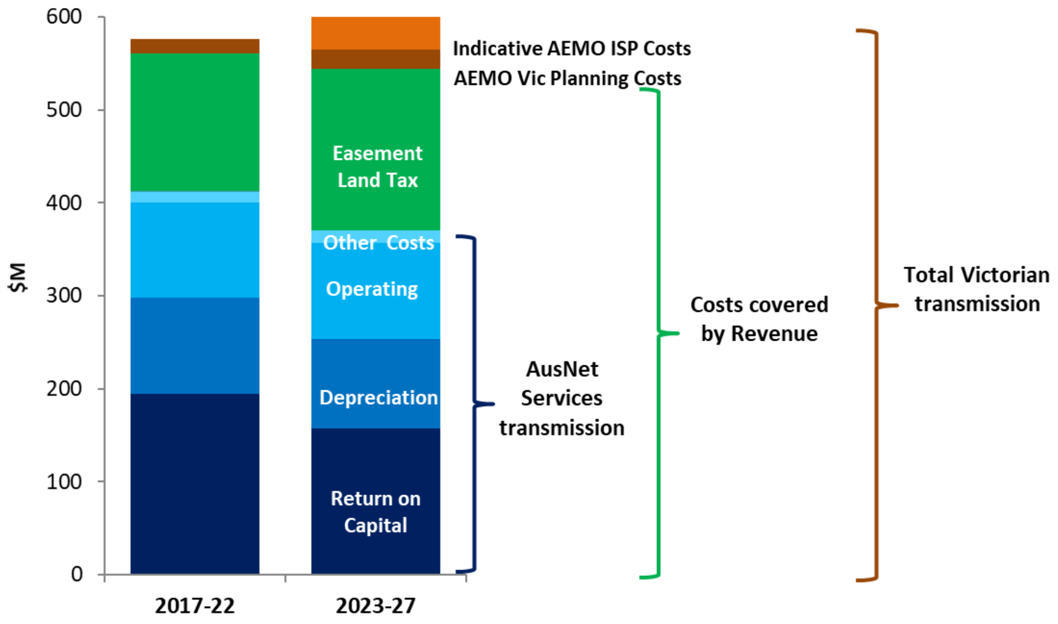
Our revenue requirement will be updated annually to reflect:

- Actual CPI, consistent with clause 6A.5.3(c)(3) of the NER;
- The annual return on debt update, in accordance with the AER's *Rate of return instrument*;
- Our actual service standard performance, relative to our service standard targets, under the Service Target Performance Incentive Scheme; and
- Any approved cost pass-through amount resulting from a pass-through event specified in clauses 6A.7.2 or 6A.7.3 of the NER or nominated in Chapter 10 of this Revised Proposal and accepted by the AER.

2.6 Average transmission charges

AEMO calculates final Victorian transmission charges. As demonstrated by the figure below, these charges will include the costs of AEMO's Victorian planning responsibilities, and any future costs associated with AEMO's 2020 Integrated System Plan (ISP). As explained in our Initial Proposal, our focus is to ensure that those costs that are within our control are managed efficiently and prudently in the long-term interests of our customers. The fall in our costs will help offset the future costs of the major transmission upgrades planned for Victoria, which will be included in the total transmission charges that customers will pay.

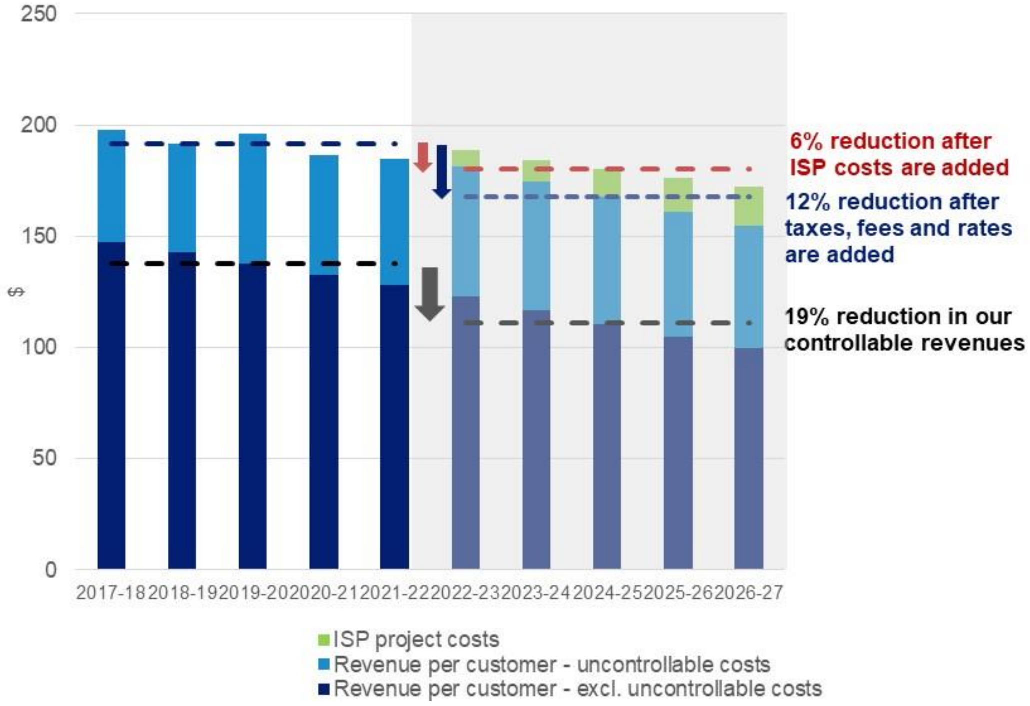
Figure 2-3: Total average annual Victorian transmission revenue by component ($M, real 2021-22)



Source: AusNet

As the total number of electricity customers in Victoria is expected to increase, average revenue per end-use customer for our transmission costs (excluding uncontrollable costs) is forecast to be approximately 19% lower in the 2023-27 regulatory control period, falling from $138 to $111 per annum, as shown in the figure below. Including uncontrollable costs, average revenue per customer is forecast to fall by 12%, from $191 to $168 per annum. Adding our estimate of AEMO ISP costs, average revenue per customer is forecast to fall by 6%, from $191 to $180 per annum.

Figure 2-4: Revenue per customer ($ real 2021-22)

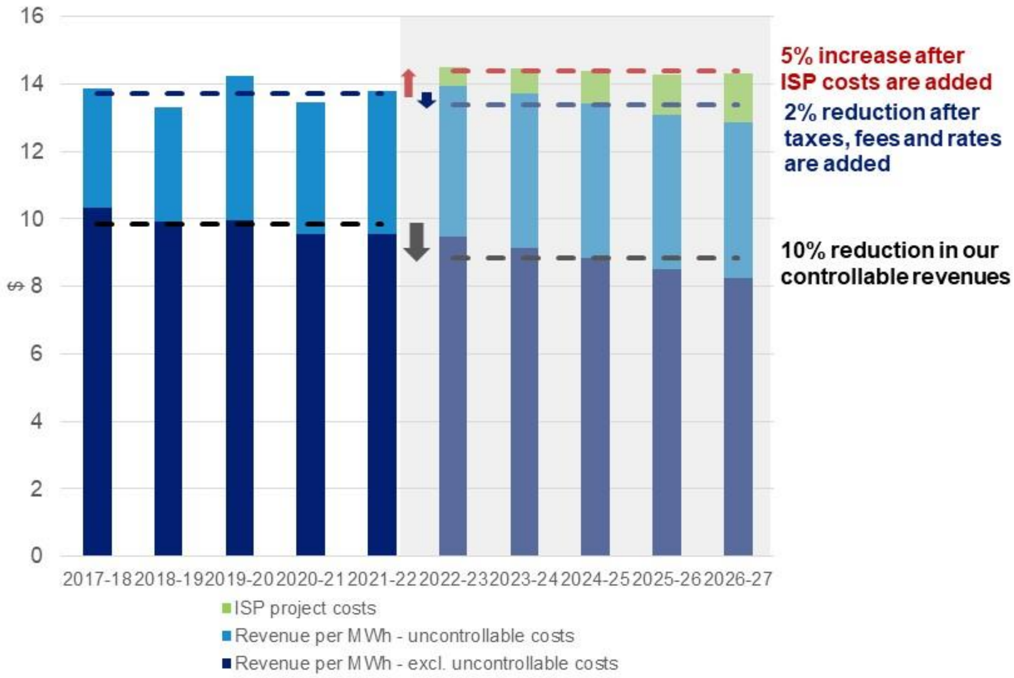


Source: AusNet

Note: ISP costs are included for illustrative purposes only because it is AEMO, not AusNet, that is responsible for procuring and recovering the costs of contestable ISP projects through AEMO's Victorian transmission charges.

On a per MWh basis, controllable revenue is forecast to fall by 10% in the 2023-27 regulatory control period. Including uncontrollable costs and AEMO ISP costs, revenue per MWh is forecast to increase by 5%.

Figure 2-5: Revenue per MWh ($ real 2021-22)

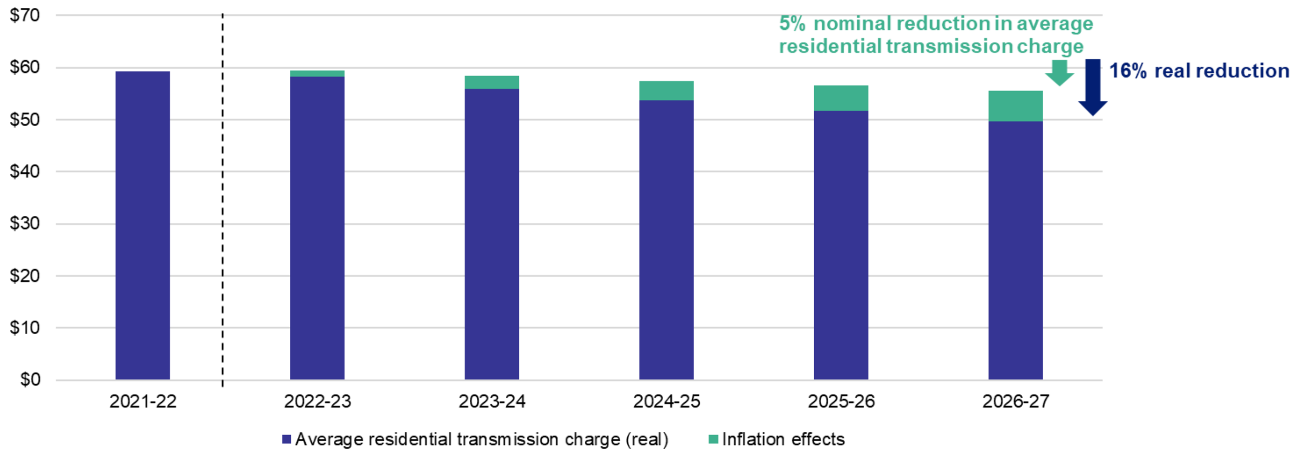


Source: AusNet

Note: ISP costs are included for illustrative purposes only because it is AEMO, not AusNet, that is responsible for procuring and recovering the costs of contestable ISP projects through AEMO's Victorian transmission charges.

For residential customers, and taking account of customer growth, we estimate that our Revised Proposal will provide a 16% reduction in the transmission component of the average bill, between 2021-22 and the end of the 2023-27 regulatory control period. Accounting for the effects of expected inflation, our plans provide for a 5% reduction in the transmission component of the average residential bill.

Figure 2-6: Transmission component of average residential customer bill



Source: AusNet

2.7 Supporting documentation

We have included the following documents to support this chapter:

- Post Tax Revenue Model;
- Roll Forward Model;
- Standalone Depreciation Model;
- Operating Expenditure Model;
- Efficiency Benefit Sharing Scheme model;
- Capital Expenditure Forecast Model;
- Capital Expenditure Sharing Scheme model; and
- Appendix 2A Model Document DMIA allowance calculation

3 Capital expenditure

3.1 Key points

- The AER's Draft Decision largely accepted the forecast capex in our Initial Proposal, but did not accept the South-West Comms Loop Upgrade project; removed the proposed risk allowance from our replacement capex program; and made reductions to our external labour escalation rates. The overall impact of the Draft Decision was to reduce our proposed capex by $44 million, or 5.5%, over the 2023-27 regulatory control period.
- In addition to addressing the issues raised by the AER in its Draft Decision, we have also considered the impact of recent policy developments and updated forecasts that were not reflected in our Initial Proposal. In deciding how best to address these recent developments, we have engaged extensively with stakeholders to ensure that their views and preferences are reflected in our updated capex forecasts in this Revised Proposal. We noted our intention to undertake this further consultation in our Initial Proposal, so that we could take account of new information, including the impact of COVID-19, in a manner that reflected our customers' preferences. As a result of this further engagement, customer and stakeholder views and preferences have heavily influenced our updated major stations capex forecast.
- In relation to our major station projects capex, a new contingent project and significant changes to the scope and timing of some projects are required, primarily in response to the Victorian Government renewable projects announcement and the expected early closure of the Yallourn Power Station. We have also updated the forecast to reflect more accurate cost estimates that have become available for several projects. Despite this, the net effect of these changes on the portfolio is modest. In particular, our Revised Proposal indicates that $444.8 million is required to maintain the safety, reliability and security of our major station assets, compared to $424.2 million in our Initial Proposal. Our updated capex forecasts for major stations, therefore, provide for an increase of $20.7 million or 5% compared to our Initial Proposal.
- In relation to the South-West Comms Loop Upgrade project, the proposed driver for this project is the replacement of poor condition, legacy communications equipment with a modern equivalent. The existing communications technology is more than 35 years old and has degraded to unacceptable levels of reliability. This asset replacement project is, therefore, required to maintain reliability and comply with our NER obligations relating to the performance of our communications network. While offering some ancillary benefits, the installation of optical fibre to support modern equivalent communications technology is the lowest cost replacement option and consistent with our historical asset replacement practices. Furthermore, no funding for this project has been provided for in the REZ Development Plan. For these reasons, the proposed expenditure should be reinstated.
- In relation to the risk allowances for our replacement program, we have provided further information in this Revised Proposal to show that the inclusion of these allowances is consistent with providing an efficient and prudent capex allowance. In particular, our historical data shows that such an allowance is warranted, as our actual capex on replacement programs has, on average, been in line with our cost estimates (including a risk allowance). On this basis, the AER's contention that risk allowances are not required for our replacement programs is not supported by the historical data.
- Our Revised Proposal includes a new project – the installation of Phasor Monitor Units (PMUs) – which was not included in our Initial Proposal. This project has been included in our updated forecast in response to recent advice from AEMO that it intends to issue a Direction under clause 4.11.1(d) requiring AusNet to install PMUs at specified locations on

our network, to allow AEMO to discharge its power system security obligations. The majority of the required expenditure will be incurred in 2022-23.

- In preparing our updated capex forecast, we have also taken the opportunity to review the optimal timing of our proposed expenditure, having regard to deliverability risks and the aforementioned changes in the timing of several major station projects. We have smoothed our major station projects forecast to minimise deliverability risk, consistent with the approach we agreed with stakeholders for our Initial Proposal.
- Our total capex for the 2023-27 regulatory control period is $820.5 million, compared to the Draft Decision which allowed $753.8 million. For the reasons set out in this chapter and supporting documents, we consider our revised capex is prudent and efficient and should be accepted by the AER.

3.2 Chapter structure

The remainder of this chapter is structured as follows:

- Section 3.3 provides an overview of our Revised Proposal's total capex forecast, including a summary of our Initial Proposal; the principal changes requested by the AER's Draft Decision; and our response as set out in this Revised Proposal;
- Section 3.4 provides an overview of how customer preferences and feedback has been addressed in our Revised Proposal;
- Section 3.5 presents our revised capex for major stations, having regard to recent policy developments and announcements in Victoria and feedback from our stakeholders;
- Section 3.6 sets out our response to the AER's Draft Decision in relation to our replacement programs, specifically addressing the concerns raised by the AER regarding the South-West Comms Loop project and the inclusion of a risk allowance in our forecasts;
- Section 3.7 presents our revised forecasts in relation to safety, security and compliance capex;
- Section 3.8 sets out our revised capex requirements for Information and Communication Technology (ICT);
- Section 3.9 sets out our revised forecasts for non-network capex;
- Section 3.10 addresses the issues raised by the AER's Draft Decision in relation to our proposed external labour escalation rates;
- Section 3.11 discusses a contingent project we are proposing for the 2023-27 regulatory control period;
- Section 3.12 provides a summary of our Revised Proposal's total capex forecast;
- Section 3.13 explains how our updated capex forecast satisfies the relevant NER requirements; and
- Section 3.14 identifies the supporting documents that provide further substantiation of our Revised Proposal's capex forecast.

3.3 Overview

3.3.1 Our Initial Proposal

In our Initial Proposal, we proposed to invest $797.7 million (real $2021-22) of net capex over the 2023-27 regulatory control period. Our proposed capex in relation to major station projects accounted for over half of our forecast total capex.

As a result of the COVID-19 pandemic, our Initial Proposal was prepared and consulted on during a time of significant uncertainty. As part of the initial consultation, we explained to our customers and stakeholders how our plans may be impacted by COVID-19 and Government announcements relating to the development of the Victorian transmission system. In particular, we explained that our proposed capital program may need to change to reflect new demand forecasts incorporating the effects of COVID-19, as well as changes to other key inputs to our plans that are heavily dependent on economic conditions, such as wage growth forecasts.

To ensure new information, including COVID-19 effects, could be addressed in our Revised Proposal in a manner consistent with customer preferences, we committed to undertaking further, extensive engagement following lodgement of the Initial Proposal. The views and preferences expressed by our customers and stakeholders during this consultation process, which took place between April and July 2021, have heavily influenced the capex forecast set out in the remainder of this chapter.

While this engagement focussed heavily on how our capex forecast should account for new information, it has also informed the approach to managing new operating costs (discussed in Chapter 4) and to the future operation of the Market Impact Component of the STPIS (discussed in Chapter 8).

3.3.2 Draft Decision

The AER did not accept our capex proposal. Instead, it considered that a total allowance of $753.8 million would provide a prudent and efficient level of capex for the 2023-27 regulatory control period.

While the AER did not accept our Initial Proposal's capex forecast, it was broadly supportive of our forecasting approach and considered that it provided a reasonable basis for determining a prudent and efficient forecast. The AER also commented that our risk-based approach is consistent with its *2019 Industry Practice application note for asset replacement planning* and with good industry practice. As such, the AER's Draft Decision accepted our capex proposal with the exception of the following specific projects:

- Our proposed South-West Comms Loop Upgrade project ($23 million), which the AER did not consider was linked to an asset replacement need;
- Our proposed risk allowances for asset replacement programs ($14 million), which the AER considered could be mitigated or avoided; and
- Our proposed approach to external labour escalation ($7 million), which the AER considered was not supported by sufficient evidence and resulted in forecast costs that could be mitigated through management of contracted services.

With the exception of adjustments for external labour escalation, the Draft Decision accepted our proposed capex for:

- Major station projects;
- Safety, security and compliance;
- ICT; and
- Non-network.

The AER's Draft Decision on our capex forecast is shown in the table below.

Table 3-1: Draft Decision annual and total capital expenditure ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Major Station Projects	102.2	105.0	101.5	71.7	41.6	**422.0**
Replacement Programs	27.6	33.9	36.9	34.1	40.7	**173.1**
Safety, Security and Compliance	8.9	8.2	10.3	15.8	10.5	**53.7**
ICT	18.0	18.4	19.2	14.8	12.7	**83.0**
Non Network	3.8	5.3	4.8	3.9	4.2	**22.0**
Total	**160.5**	**170.7**	**172.7**	**140.2**	**109.6**	**753.8**

Source: AER - Draft Decision - AusNet Services transmission determination - 2022–27 - Capex Model – June 2021

In making its Draft Decision on our capex proposal, the AER recognised that there may be material changes to our capex forecast as a result of our further consultation process, in particular to incorporate the effects of new information on our proposed major stations capex. In this context, the AER highlighted its expectation that our Revised Proposal would include an updated forecast of major stations expenditure that is fully informed by all available information on the prudent investment needs of the network, including the views of our customers and stakeholders.

The Draft Decision also identified several areas where the AER required further information in our Revised Proposal, including more detail on how we have determined our failure rate assumptions, before it could be wholly satisfied with the outputs of our asset replacement methodology. We have worked with the AER to address this request as part of preparing this Revised Proposal and identified in this chapter where further information has been provided to address the AER's concerns.

3.3.3 Response to the AER's Draft Decision

For the reasons set out in this chapter, we consider that the South-West Comms Loop Upgrade project and the risk allowance for our capex replacement program should be reinstated. We have provided additional information to explain why the proposed expenditure satisfies the NER requirements, which only allows prudent and efficient expenditure to be included in our capex forecasts. In this Revised Proposal, we have sought to address the information gaps identified in the Draft Decision by providing additional supporting evidence.

In addition to the specific issues raised by the AER, our Revised Proposal also addresses a number of significant announcements and developments relating to the Victorian transmission system that were not known when we prepared our Initial Proposal. These include:

- New AEMO demand forecasts outlining both higher maximum demands and materially lower minimum demands on the Victorian network, exacerbating system strength challenges across the network.
- The release of the Victorian Government's $1.6 billion clean energy package in November 2020 and the Renewable Energy Zone (REZ) Development Plan (RDP) in February 2021.[5] These initiatives set out proposed generation and network investments in support of the Victorian Government Climate Change Strategy commitment to reduce carbon emissions by 45-50% by 2030 and to net zero by 2050.

[5] Victorian Government, Victorian Renewable Energy Zones Development Plan Directions Paper, February 2021

- The formation of a new entity—VicGrid—tasked with coordinating the overarching planning and development of Victorian REZs. This new entity will also ultimately manage the $540 million REZ fund that will be used to strengthen the grid and unlock the potential of the REZs.
- Interaction of the RDP with the new iteration of the Integrated System Plan (ISP) released in July 2020.
- The announcement by Energy Australia in March 2021 that the closure of the 1,480 MW Yallourn Power Station would be brought forward from 2031 to 2028.[6]

Our stakeholder engagement on these issues was timed to provide input to this Revised Proposal, while also providing an opportunity to discuss the most up to date information. In consultation with the AER, it was agreed not to address any of these issues in its Draft Decision but await the Revised Proposal review stage. Nonetheless, we have kept the AER informed of new developments throughout the process to allow them to begin their own consideration of these issues.

Therefore, while we have accepted large components of the Draft Decision, we have also incorporated changes that respond to these new issues and stakeholder feedback. Section 3.5 explains how these developments have impacted our major stations forecast and describes how we have taken account of stakeholder views in preparing the updated forecast.

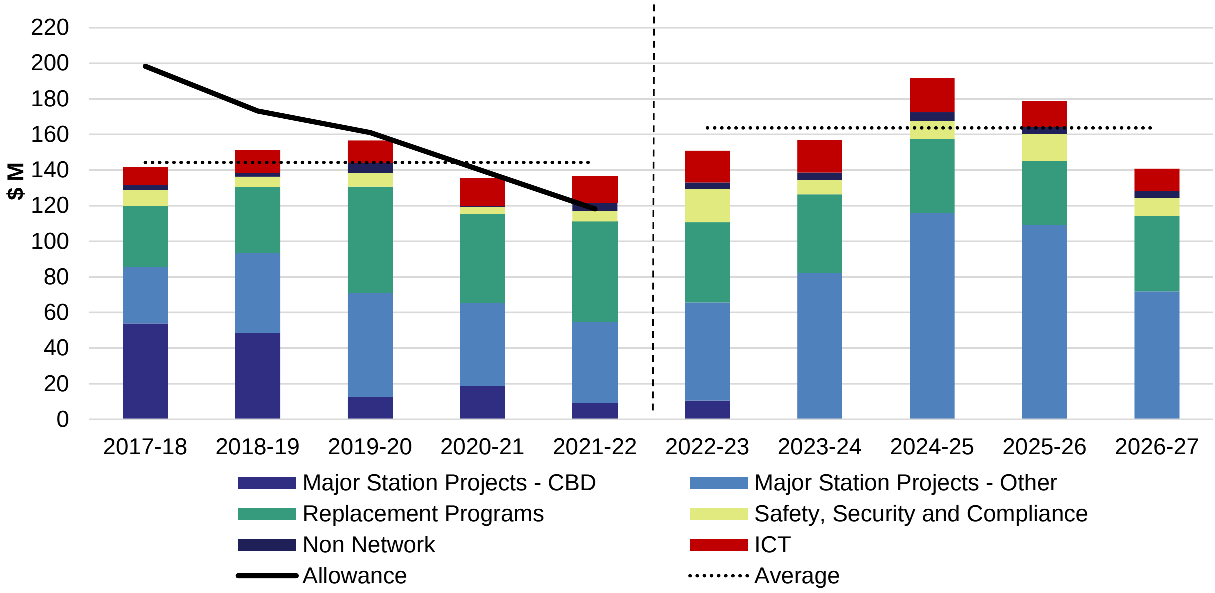
In response to the expected early closure of Yallourn Power Station, our Revised Proposal includes a new contingent project at Hazelwood Terminal Station (HWTS) and a new major station project at HWTS and Loy Yang Power Station (LPYS). As discussed further in section 3.5.3.3, our Revised Proposal's use of contingent project arrangements and ex ante expenditure allowances to manage these new costs is consistent with the views expressed by our customers and stakeholders. The proposed contingent project is discussed further in section 3.11.

Our Revised Proposal also includes a new project – the installation of Phasor Monitor Units (PMUs) – which was not included in our Initial Proposal. This project has been included in our updated forecast in response to recent advice from AEMO that it intends to issue a Direction under clause 4.11.1(d) requiring AusNet to install PMUs at specified locations on our network, to allow AEMO to discharge its power system security obligations. This project is discussed further in section 3.7.3.1.

The figure below shows our Revised Proposal capex forecast alongside actual/expected expenditure in the current period.

[6] EnergyAustralia, *EnergyAustralia powers ahead with energy transition*, 10 March 2021

Figure 3-1: Actual, expected and Revised Proposal capex forecast ($M real 2021-22)



Source: AusNet

3.3.4 Revised Proposal

Taking account of the changes outlined above, our Revised Proposal forecast of total required capex for the next regulatory period is $820.5 million.

Table 3-2: Revised Proposal capital expenditure forecast ($M, real 2021-22)

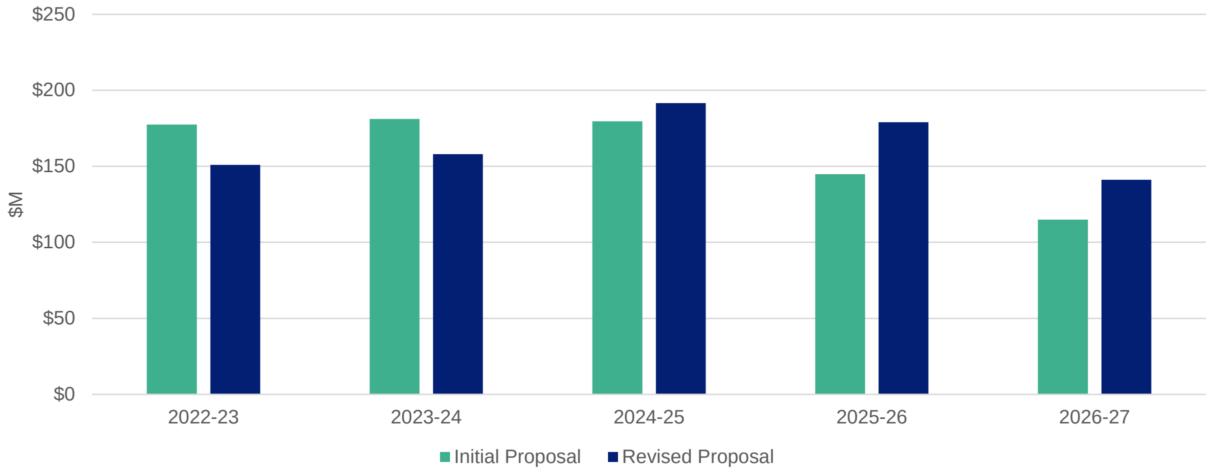
	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Major Station Projects	65.7	82.3	115.7	109.2	71.9	**444.8**
Replacement Programs	45.1	44.0	41.7	35.8	42.4	**208.9**
Safety, Security and Compliance	18.6	8.1	10.2	15.4	10.1	**62.5**
ICT	17.9	18.2	19.1	14.7	12.6	**82.4**
Non Network	3.7	5.3	4.8	3.8	4.1	**21.8**
Total	**151.0**	**158.0**	**191.5**	**178.9**	**141.1**	**820.5**

Source: AusNet

Note: Capitalised leases are included in Non-Network.

Despite the significant external changes that have occurred since we prepared our original forecast, our Revised Proposal's total capex forecast is a modest increase on the Initial Proposal. However, the updated forecast is weighted towards the second half of the regulatory control period compared to the original forecast, due to the deferral of several major station projects in response to the announcements and developments outlined above. The original and updated total capex forecasts are shown in the figure below. Consistent with the approach taken in our Initial Proposal, we have also smoothed our major station projects forecast to minimise deliverability risk (discussed further in section 3.5.3.6). The net effect of these deferrals and adjustments is a $5 million reduction in the revenue required to fund our proposed capital program, compared to our Initial Proposal.

Figure 3-2: Initial Proposal and Revised Proposal capex forecast ($M, real 2021-22)



Source: AusNet

3.4 Incorporating customer preferences and feedback

In the lead up to our Initial Proposal, we conducted several Deep Dive workshops and Customer Advisory Panel meetings with stakeholders on issues important to this review. As stated in our Initial Proposal, a key outcome of our stakeholder engagement on capex was the application of a a top-down smoothing adjustments to our network capex to manage deliverability risks while also ensuring our customers' expectations of reliable supply are met. This adjustment resulted in the deferral of expenditure for some major station projects. As reflected in this Revised Proposal, similar smoothing adjustments have been applied to our updated forecast.

In its advice to the AER, the Consumer Challenge Panel (CCP23) outlined its support for our proposed investment in major station projects to support AEMO's ISP program, as well as our asset replacement programs, which the CCP considered reflected a mature condition and risk-based planning approach. However, this support was subject to the outcomes of the AER's assessment of the efficiency and prudency of individual projects and the outcomes of the regulatory investment test (RIT-T) process for each major project. The CCP also identified concerns with aspects of our proposed labour escalation approach.[7]

The major stations and asset replacement program capex included in this Revised Proposal is broadly consistent with our Initial Proposal, notwithstanding the updates that have been made to individual major station projects to reflect new information. We have updated our internal labour escalation approach to reflect more recent forecasts, consistent with the AER's standard approach. We have adopted the Draft Decision's approach to external labour escalators, which assumes no real increases over the next regulatory control period. However, we have flagged our intent to revisit this issue at the next reset, when we expect further tightening of the labour market for skilled construction workers due to the significant ISP projects that will be in the delivery phase.

As discussed further in the following section, we have engaged extensively with stakeholders to ensure that their views and preferences are reflected in our updated capex forecasts. As a result of this further engagement, customer and stakeholder views and preferences have heavily influenced our updated major stations capex forecast.

[7] CCP23, *Advice to the AER on AusNet Services electricity transmission revenue proposal 1 April 2022 to 31 March 2027 and AER Issues Paper*, p.2, February 2021

3.5 Major station projects

3.5.1 Our Initial Proposal

We initially proposed expenditure of $424.2 million for major station projects over the 2023-27 regulatory control period, which accounted for 53% of our Initial Proposal's total capex forecast. The major stations forecast included several existing projects and 15 new projects at terminal stations where, based on asset condition, it is economic to replace assets during the next regulatory period.

Several of these projects (accounting for 28% of the total capex forecast) involve replacing assets at switching stations that form the backbone of the Victorian transmission network or support interconnectors. These stations are important nodes in the national, interconnected transmission system and, therefore, the dependable operation of assets is critical to the reliability and security of the power system. The criticality of these assets has fundamentally increased as a result of the closure of Hazelwood and Victoria becoming a net importer of electricity. The expected early closure of Yallourn Power Station in 2028 is expected to further increase the criticality of these assets. The implications of this increased criticality for our expenditure plans are discussed further in section 3.5.3.3.

3.5.2 Draft Decision

The Draft Decision accepted our proposed capex for major station projects. The AER considered that our proposed expenditure for major station projects reflected a prudent asset replacement methodology that is consistent with good industry practice. Accordingly, the Draft Decision approved major station capex of $422 million, which is $2.2 million less than our Initial Proposal. The variance is due to the AER's rejection of our external labour forecasting approach.

The Draft Decision also requested the underlying data and statistical calculations that form the basis for our failure rates, as well as other supporting information to show that the resulting failure rates reflect the realistic likelihood that an asset will fail.

3.5.3 Response to the Draft Decision

As discussed in section 3.3, we have updated our forecast capex for major station projects to reflect a range of new information that has become available since we lodged our Initial Proposal in October 2020. While there have been significant changes in the cost and economic timing of several projects, as well as the addition and removal of a small number of projects, the net impact on our total forecast major station projects capex is an increase of 5% ($20.7 million), from the $424.2 million included in our Initial Proposal to $444.8 million. Despite this increase, as mentioned above, the revenue required to fund our proposed capital program has reduced by $5 million compared to our Initial Proposal, due to the deferral of some expenditure to later in the regulatory control period.

The table below compares the forecast major stations expenditure included in our Initial and Revised Proposals.

Table 3-3: Initial and Revised Proposal, forecast major stations expenditure ($M, real 2021-22)

Major station project	Initial Proposal	Revised Proposal	Change
HOTS SVC Replacement	31.4	0.0	-31.4
MLTS Circuit Breaker Replacement	18.1	28.2	10.1
RCTS Transformer and Switchgear Replacement	22.5	22.7	0.2

Major station project	Initial Proposal	Revised Proposal	Change
LYPS and HWTS 500kV Circuit Breaker Replacement Stage 2	0.0	16.4	16.4
SMTS 330/220kV Transformer Replacement - Stage 2	43.7	43.1	-0.6
ERTS Redevelopment - Stage 2	23.0	21.6	-1.4
WOTS Spare Transformer	3.8	1.3	-2.5
TSTS Transformer and 66kV Circuit Breaker Replacement	40.6	38.0	-2.6
SYTS 500kV GIS Replacement	63.2	79.7	16.5
BLTS 66kV and 22kV Circuit Breaker Replacement	13.9	13.9	0.0
SMTS 500kV GIS Replacement	17.9	17.6	-0.2
SHTS B2 and B3 Transformer Replacement	17.0	37.1	20.1
TTS 66kV Circuit Breaker Replacement	13.9	11.4	-2.4
KTS A4 500/220kV Transformer Replacement	71.3	70.4	-1.0
WMTS Redevelopment Project	10.5	10.5	0.0
SVTS Redevelopment Project	17.1	17.1	0.0
HWPS 220kV CB Replacement - Stage 4	2.7	2.7	0.0
L1 & L2 DDTS & SMTS Disconn/E SW Repl.	3.0	3.0	0.0
GNTS 66 kV CB Replacement	3.7	3.6	-0.1
HOTS 66kV Circuit Breaker Replacement	3.8	3.6	-0.2
FTS 66kV Circuit Breaker Replacement	3.0	2.8	-0.1
Total	**424.2**	**444.8**	**20.7**

Source: AusNet

To address the matters raised in the Draft Decision, we have provided the additional information sought by the AER in relation to our failure rate assumptions (see Appendix 3A). This information demonstrates that these assumptions, which underpin both our Initial and Revised Proposals, are robust and consistent with a prudent and efficient forecast of replacement capex.

As foreshadowed in our Initial Proposal, we undertook an extensive program of stakeholder engagement as part of preparing this Revised Proposal. This engagement focussed heavily on how our Revised Proposal's capex forecast should account for new information. Specifically, we hosted several Collaboration Workshops between April and July this year, to provide an opportunity for stakeholders to work with us to assess the net impact on our major projects capex as a result of the following recent developments and updated analysis:

- Interactions between AusNet's replacement projects and the Victorian Government's REZ Development Plan and AEMO's 2020 Integrated System Plan;
- The declining system strength on the Victorian transmission network, which raises significant operational challenges;
- The expected early closure of Yallourn Power Station in 2028; and
- Updated demand forecasts, which were published by AEMO in November 2020 and take account of COVID-19 effects;
- Updated market modelling, reflecting AEMO's November 2020 energy forecasts; and
- Updated project scopes and cost estimates for several projects that have progressed further through the Regulatory Investment Test process and, therefore, have been refined.

The sequence in which we consulted on the above topics is shown in the figure below. The presentation materials for each of the Collaboration Workshops are located **here** and the Summary Reports have been provided as supporting documents.

Figure 3-3: Post-lodgement engagement on major station projects

Source: AusNet

At the first Collaboration Workshop on 20 April 2021, we presented an overview of each development and explained how, and which of, our major station projects may be impacted as we worked through these changes. The purpose of this initial workshop was to provide stakeholders with a common overview of our capital program prior to working through the more detailed, project-specific changes that were to be discussed at the subsequent workshops. We also sought preferences from stakeholders as to which issues should be the focus areas for the remaining workshops, as summarised below.

Table 3-4: How stakeholder feedback on preferred engagement topics was addressed

What we heard in Workshop 1…	…and how we propose to address it
Stakeholders are interested in the coordination between AusNet, AEMO, and VicGrid, and the impact of ISPs	Coming up today, in Workshop 2
Stakeholders seek to understand the impacts of the REZ Development Plan on AusNet's Revenue Proposal	Coming up today, in Workshop 2
Stakeholders wish to explore the impacts of system strength in more depth	Key agenda item for Workshop 3
Stakeholders wish to understand the impact of Yallourn's closure on AusNet's Revenue Proposal	Key agenda item for Workshop 4
There is some interest in reviewing the impacts of changed demand forecasting and market modelling, but this is a lower priority for most stakeholders	Brief agenda item for Workshop 4
Stakeholders take a long-term view of the impacts	We will speak about the long-term impacts of each change
Stakeholders are interested in the impact to end consumers, particularly bill impacts	We will present indicative customer bill impacts at the final workshop

Source: AusNet

Further information on how stakeholders' views on each topic have been reflected in our updated capex forecast is provided in the sections below. Chapter 1 of this Revised Proposal and the workshop Summary Reports provide further detail on the topics, issues and insights from each of the Collaboration Workshops we held.

As stakeholders did not express interest in exploring updated project scopes and cost estimates in detail, we did not make it the focus of a Collaboration Workshop. However, as part of presenting the net effects of the other changes at Workshop 6, we explained to stakeholders how changes in individual project cost estimates had been reflected in our updated capex expenditure forecast. We also presented customer bill impacts at this session to address stakeholder's desire for transparency on the affordability impacts on end-users of the transmission investment planned over the long-term, including our asset replacement projects.

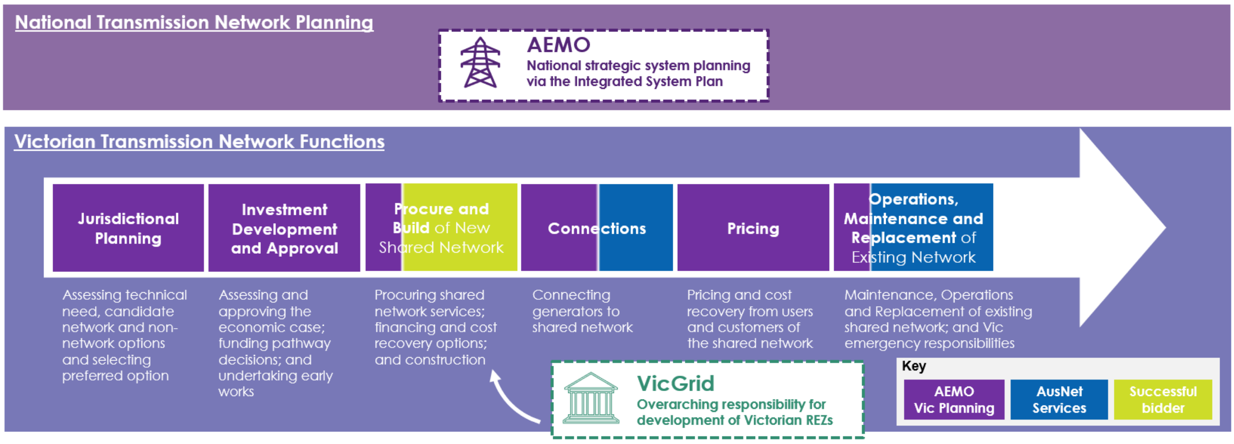
As we had engaged with customers on the deliverability of our total capex forecast as part of preparing our Initial Proposal, we did not consult further on this topic during the Collaboration Workshops. However, we have smoothed our updated major station projects forecast to minimise deliverability risk consistent with the approach we agreed with stakeholders for our Initial Proposal. This is discussed further in section 3.5.3.6 below.

3.5.3.1 Interactions with the Victorian Government's REZ Development Plan and AEMO's ISP

New information discussed

At Collaboration Workshop 2, we explained the different roles and responsibilities of AusNet, AEMO, VicGrid and the Victorian DNSPs, and how the operation, maintenance and planning of the Victorian transmission network is shared between these parties. The functions of each entity is depicted in the figure below.

Figure 3-4: Roles and responsibilities for Victorian transmission



Source: AusNet

During the workshop, stakeholders expressed concern that the multiple planners, planning processes and transmission projects planned in Victoria (as shown in the figure below) have the potential to result in sub-optimal outcomes for energy customers, if projects and processes are not coordinated carefully and delivered in an efficient manner. We recognised the importance of this issue and the importance of ongoing collaboration with AEMO and other participants to manage this risk.

Figure 3-5: AusNet major station projects, ISP projects and REZ Development Plan (Stage 1 and Stage 2) projects

Source: AusNet

During the workshop, we provided information to demonstrate that we carefully considered the interactions between our replacement projects, ISP projects and the RDP in developing our forecast capex. The table below summarises the information that we shared with stakeholders to illustrate the linkages between these projects.

Table 3-5: Interactions between ISP and AusNet major station projects

ISP Project	Geographically related AusNet Services replacement projects	Impact of ISP on proposed replacement project
Energy Connect	RCTS Transformer Replacement Project	No impact. Transformer provides connection service for local distribution
Western Vic	SYTS 500 kV gas insulated switchgear replacement – Integrated project	Options being reviewed to combine project activities to minimise overall costs and reduce system outages.
VNI-Minor	SMTS F2 Transformer replacement	SMTS F2 Tx delayed by more than five years due to decreased consequences of failure resulting from the 2nd transformer installation as part of VNI-Minor upgrade from AEMO's ISP. Therefore $33M of expenditure has been deferred out of the TRR forecast period
	SMTS 500 kV gas insulated switchgear replacement – Stage 1	No impact. 500 kV switchyard not impacted
VNI-West	SHTS Transformer & switchgear replacements	No Impact. SHTS is the main transmission service connection point for distribution of electricity to approximately 72,525 customers in Shepparton, Echuca, Mooroopna, Yarrawonga, Kyabram, Cobram, Numurkah, Tatura, Rochester, Nathalia, Tongala, and Rushworth. The ISP shared transmission network investments does not impact on the asset renewal investment proposed at SHTS
Marinus	No geographically related asset replacement project during 2022 to 2027 revenue period	

Source: AusNet

What we heard from stakeholders

Stakeholders expressed a strong desire that we should ensure that costs to customers are minimised by ensuring that there is efficient coordination between TNSPs and other network planners.

For example, stakeholders supported the integrated delivery of the Western Victoria Transmission Network Project (WVTNP) and our Sydenham Terminal Station 500kV GIS replacement project, to ensure synergies between these two projects are maximised. Stakeholders also sought assurance that our Revised Proposal did not overlap with the RDP Directions Paper, the latter of which was released after lodgement of our Initial Proposal.

Stakeholders also considered that:

- We should not attempt to forecast and account for interactions (for example, overlaps or synergies) with RDP Stage 2 projects (slated for 2025-30) and instead manage this risk/uncertainty through our regulated capex allowance.
- When RDP Stage 2 projects reach their planning and delivery phases, the planner of these projects should account for interactions with our plans, through consideration of the projects, costs, scopes and timing that are assumed in this Revised Proposal. Stakeholders accepted that, because Stage 2 projects will be funded through more flexible arrangements than regulated capex allowances, they are more adaptable to changing circumstances.

How we have responded in our Revised Proposal

Where there is potential locational overlap between our replacement projects, RDP Stage 1 projects, and the ISP, we have ensured that our replacement project timings and scope are aligned with the RDP and ISP and that overlaps have been removed. This has been achieved by:

- For the Sydenham Terminal Station rebuild, we identified synergies of approximately $10 million which are reflected in the updated project cost estimate included in this Revised Proposal. Integrated delivery with the WVTNP will also allow for a 20% smaller footprint than separate developments, as well as reduced network outages and system risks, thereby benefiting customers.

- We have removed the Horsham Terminal Station SVC replacement project from our expenditure plans, reducing our Revised Proposal capex forecast by $31 million. This change reflects Stage 1 of the RDP, which was announced by the Victorian Government on 3 August 2021 and is expected to implement a long-term, non-network solution that will provide voltage control in North-West Victoria.[8] The RDP non-network solution means it would not be prudent for AusNet to replace the SVC in the next regulatory period; it will instead be retired. We discuss below our approach to managing the risk associated with failure of the SVC, which is in poor condition, until the RDP solution comes online.
- For the SW Comms Loop project, we have worked with the Victorian Government to ensure the RDP does not overlap with our asset replacement plans. This has led to $8 million of "bring forward" costs from the RDP, which had been included in the RDP Directions Paper released in February 2020 to ensure the SW Comms Loop project was delivered as soon as practicable. However, because AusNet's proposed economic timing reflects the earliest possible completion date, no provision is required in the RDP. Consistent with this, the SW Comms Loop has not been included in the Stage 1 RDP projects announced on 3 August 2021.

The RDP Stage 2 projects are currently subject to significant uncertainty in terms of their scope, costs and timing. Accordingly, we propose to manage the risk and uncertainty associated with these projects within this Revised Proposal's capex allowance and, therefore, we have not adjusted the forecast to reflect any potential interactions. As discussed above, this is appropriate because the RDP Stage 2 projects will be funded through more flexible arrangements than regulated capex allowances and, therefore, are more adaptable to changing circumstances.

Horsham Terminal Station SVC replacement

As stated above, the Victorian Government's announcement of the REZ Development Plan Stage 1 projects includes a long-term, non-network solution to increase the capability to connect up to 600MW of additional generation in Western Victoria REZ. The Victorian Government initiated the tender process for this solution in August 2021 and is targeting an implementation date of on or before 31 December 2024.

While it is not yet a committed solution, the RDP solution is expected to address the identified need of our HOTS SVC RIT-T (currently at PADR stage) in the long-term and means it would not be prudent to replace the SVC in the next regulatory period, as assumed in our Initial Proposal. Instead, the SVC will be retired during the next regulatory period.

However, until such time as the RDP solution comes on-line, there remains an ongoing need for the voltage control and voltage oscillation damping services the HOTS SVC provides. Due to the deteriorated condition of the SVC and most of the core components, which are in C4 (poor) or C5 (very poor) condition, there is considerable network risk associated with the continued operation of the SVC. In addition to no longer being able to support effective voltage control in the area, failure of the SVC would constrain Murraylink and a significant amount (approximately 1.2 GW) of renewable generation in North-West and Western Victoria, leading to higher wholesale prices for customers and penalties for AusNet under the MIC.

Given these significant consequences, as part of our RIT-T we are assessing whether an economic and technically feasible non-network solution is available to manage the asset failure risk of the SVC in the short-term until the RDP solution is operational. If a non-network option that meets these requirements is found to be available, we may retire the SVC and enter into a non-network services agreement. Depending on the precise nature of the non-network services

8 https://www.energy.vic.gov.au/__data/assets/word_doc/0038/536699/Renewable-Energy-Zones-Stage-One-projects-Fact-sheet-UPDATED.docx

that are required, responsibility for entering into such an agreement may rest with AEMO Victorian Planning, rather than AusNet.

If an economic and technically feasible solution is not identified as part of the RIT-T, we intend to adopt a 'run to failure' approach for the SVC until the RDP solution is operational and the SVC is retired. Should the SVC fail during this time, options to mitigate the impacts include procuring voltage control and voltage oscillation damping services from a non-network provider (either by AusNet or AEMO Victorian Planning) or AEMO Operations issuing Directions in accordance with its power system security obligations.

Due to their uncertainty, we have not included the non-network expenditures associated with either of these scenarios in our operating expenditure forecast. Instead, we propose to recover these costs via the network support cost pass through arrangements. Consistent with our approach to using these arrangements to manage planned outages, any costs we propose to pass through will be supported by economic analysis demonstrating the efficiency of the proposed solution.

3.5.3.2 Operational impacts of declining network system strength

New information discussed

At Collaboration Workshop 3b, we explained that responsibilities for maintaining system strength in Victoria is split between four bodies, as shown in the figure below.

Figure 3-6: Management of system strength in Victoria

AEMO	National Planning	• Sets zones for system strength • Declares system strength shortfalls
	Victorian Planning *(and VicGrid)*	∆ *Planning to meet system strength standards* ∆ *Planning to keep system accessible for maintenance* ∆ *Responsible for procuring system strength solutions, including in response to a declared shortfall and Network Support Control Ancillary Services (NSCAS)*
	Operations	• Responsible for operating the system in a secure state ∆ *Must assess outage impacts on system operations (unique to Victoria) and prevent planned outages that threaten system security including system strength shortfalls* • Can direct generation to provide system strength services
AusNet		• Responsible for forward planning of outages • Must cancel outages at AEMO Ops' request • Incentivised to limit market constraints from planned outages

• Largely consistent across Australia
∆ *Unique to Victoria*

• Largely consistent across Australia

∆ Unique to Victoria (recognising that Victorian transmission arrangements overall are unique in the NEM)

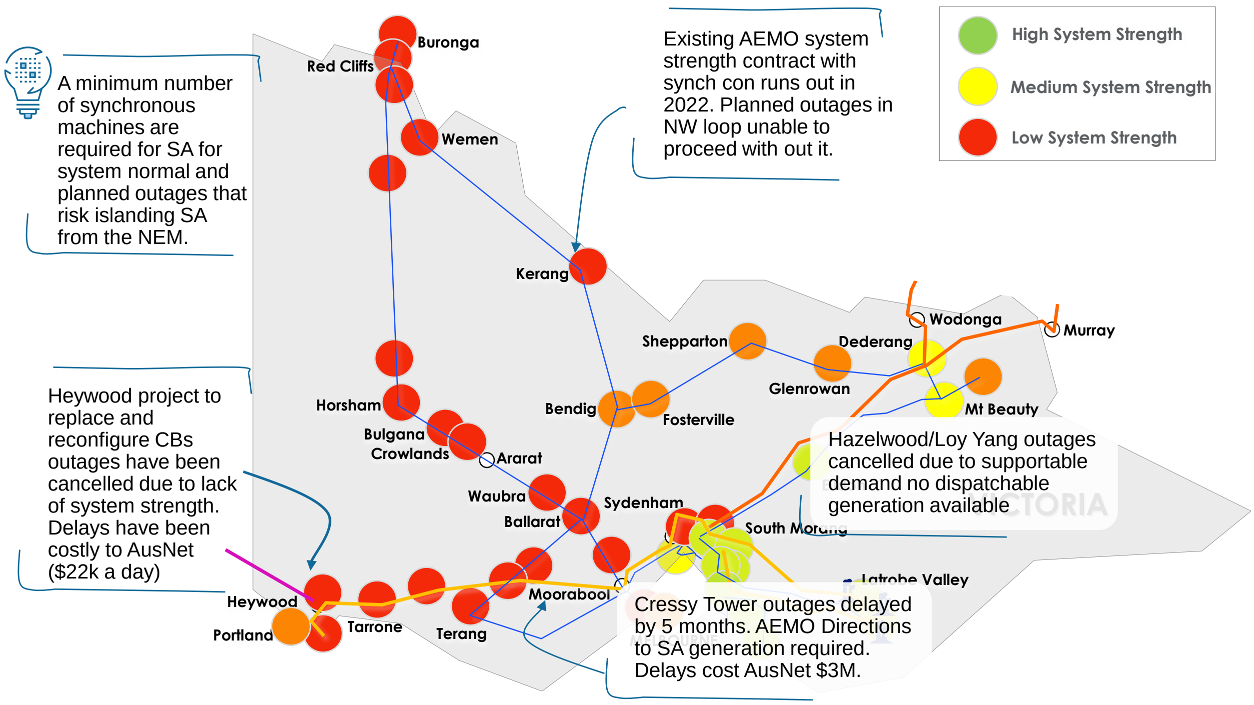
In this framework, we explained that we are responsible for forward planning of outages; required to cancel outages at AEMO Operations' request; and incentivised to limit market constraints caused by planned outages through the Market Impact Component of the STPIS. Given our role, we noted that the following issues were outside the scope of this workshop:

- Augmentations to address system strength, which are managed by AEMO Victorian Planning and VicGrid; and
- The AEMC rule change review on the efficient management of system strength on the power system, which may have implications for system strength in Victoria during the next period.

We explained that as system strength declines, we experience more significant operational impacts. For example, access for maintenance and asset replacement work will become increasingly difficult, which in turn will tend to increase our costs. We also noted that an increasing number of generation dispatch intervals are being constrained by network outages, which has adversely affected our performance under the Market Impact Component of the STPIS.

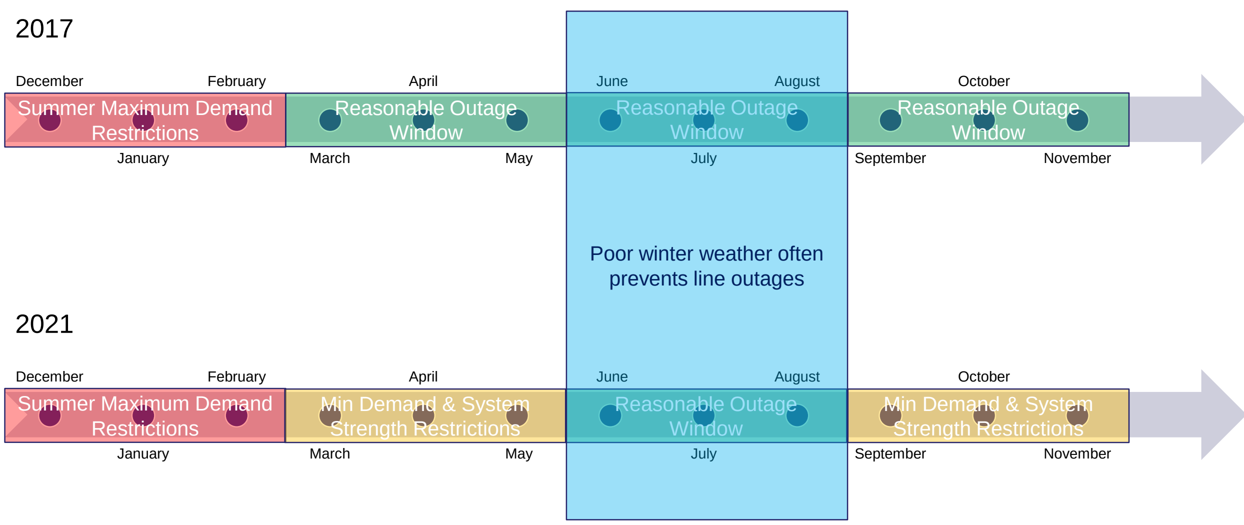
Using the information depicted in the figures below, we emphasised the effect low system strength is having on our ability to obtain the outages needed to maintain our network and replace assets, which has led to a significant narrowing of the outage windows during which we can access the network.

Figure 3-7: Operational impacts of low system strength



Source: AusNet

Figure 3-8: Declining outage windows due to low system strength



Source: AusNet

As shown in the figure below, we presented the operational solutions available to maintain system strength during outages, given the operating challenges described above. We explained the different customer impacts of these options in terms of their effects on costs and reliability, as well as whether responsibility to take preventive or correction action rests with AusNet or AEMO.

Figure 3-9: Operational solutions to manage system strength

Defer the Work	• Critical safety maintenance or replacement cannot be deferred • Lack of maintenance and replacement capex increases risk of failure i.e. service standards penalties • Lack of access to augment and implement long term solutions • Unplanned outages impact the market and may require expensive Directions – cannot optimise timing of unplanned outages
Obtain Network Support	• Network support contact costs are reliant on Wholesale market conditions and are highly variable and, therefore, difficult to forecast. Generation generally has to be dispatchable (i.e. not intermittent) • Needs to be supported by AEMO Vic planning analysis showing this is the most efficient solution
AEMO Direction	• The NER allow AEMO to issue Directions to registered market participants to take action to maintain or re-establish the power system to a secure, satisfactory or reliable operating state. • Used for Western Transmission (Cressy) Tower Rebuild project outages

Who is responsible?
AEMO
AusNet Services

Source: AusNet

On the basis that critical work cannot be deferred without creating unacceptable risks to safety, security and reliability, we presented different options for the recovery of network support costs (where these have been identified by AEMO as the most efficient solution) or AEMO Direction costs.

The options presented are shown below. We sought customer and stakeholder views on which of these options they would prefer during the next regulatory period and, therefore, reflected in our Revised Proposal.

Figure 3-10: Cost recovery options for network support and AEMO Direction costs

AusNet Pays for Network Support Agreements using expenditure allowances	• AusNet passes through forecast costs to transmission charges • Must pass AEMO economic test • AusNet hold cost recovery risk, may over or under recover
AusNet pays for Network Support Agreements using pass-through	• AusNet passes actual costs through to transmission charges • Must pass AEMO economic test
AEMO pays for Network Support Agreements	• AEMO passes actual costs through to transmission charges • Must pass AEMO economic test
AEMO uses Directions	• AEMO passes actual costs through to transmission charges

Source: AusNet

What we heard from stakeholders

Stakeholders also highlighted the complex issues relating to system strength from their perspective, and the challenges of reaching a consensus given these complexities. Stakeholders also made a wide range of comments and queries during the workshop, including the following:

- System strength will likely continue to be an issue as the use of renewable energy continues to rise.
- Does maintenance work in winter and working outside normal trading hours (as is more often required for unplanned outages) result in higher labour costs?
- The high level of uncertainty must make it challenging for AusNet to plan, so is the cost of cancelled outages built into our opex forecasts?
- System strength could improve in the next regulatory period due to the upgrade of new synchronous condensers and batteries.
- Changes in the network's system strength should be considered in conjunction with AusNet's planned maintenance schedule in order to reduce the need for network services agreements and AEMO directions.

Notwithstanding the complexities of the issue and the above comments and questions, stakeholders expressed a strong desire to pay for actual network support costs, rather than for a forecast of these costs to be included in this Revised Proposal. Stakeholders considered this approach should apply to network support costs required for both network maintenance and asset replacement projects. This position reflected the high level of uncertainty around what AusNet's efficient network support costs will be during the next regulatory period, making them difficult to forecast accurately. Stakeholders stated their preference is for AusNet to recover its actual network support costs using cost pass through arrangements, provided that AEMOs undertake an independent assessment to confirm that obtaining network support is the most efficient option to manage system strength during an outage.

Stakeholders also considered that, in determining the economic timing for our major station projects, we should account for network support costs where there is a reasonable likelihood of them being incurred, but these costs should not be factored into this Revised Proposal's proposed major stations capex due to their uncertainty.

How we have responded in our Revised Proposal

We welcome stakeholders' comments on system strength issues. We explained during the workshop that system strength issues begun to have an increasingly material impact on the operation of our network approximately 18 months ago. We also explained that decisions to address system strength issues will be based on each location's specific circumstances. For the purposes of the Revised Proposal, we note our focus is the use of network support to address system strength during outage conditions or, in the case of the HOTS SVC replacement project discussed above, to manage asset failure risk.

Consistent with stakeholder preferences, we have accounted for network support costs in our economic assessments for those major station projects where there is a reasonable likelihood they will be incurred, but we have not included these costs in this Revised Proposal's capex forecast. Instead, we will manage these costs using cost pass through arrangements in the next regulatory period. The following table identifies the projects where we have included estimated network support costs in our economic assessments and how these costs have impacted our proposed economic timing for the MLTS project. Our intended use of the cost pass through arrangements to manage network support costs during the forthcoming regulatory period is discussed further in Chapter 10 (Cost Pass Through).

Table 3-6: Impact of estimated network support costs on major station projects

Major station project	Estimated network support costs ($M, real 2021-22)	Economic timing excluding network support costs*	Proposed economic timing (including network support costs
Moorabool Terminal Station Circuit Breaker Replacement	$15.7	2022-23	2026-27
South Morang Terminal Station 500kV GIS Replacement – Stage 1	$1.7	2024-25	2024-25
Sydenham Terminal Station 500kV GIS Replacement	$2.4	2025-26	2025-26

Source: AusNet

Note: Economic timing reflects completion date

* May not align with the proposed timing included in the Initial Proposal due to deliverability adjustments made in the Initial Proposal

3.5.3.3 The expected early closure of Yallourn Power Station

New information discussed

At Collaboration Workshop 4, we explained that the early closure of Yallourn Power Station (YPS) in 2028 will increase the criticality of network assets connecting other generation sources (including interconnectors). We further explained that the earlier closure would not affect projects that were already included in our Initial Proposal, but it has the potential to bring forward projects that our most recent 10-year asset renewal plan[9] assumed will be required in the subsequent regulatory control period commencing on 1 April 2027. In particular, we identified four projects that required detailed re-assessments in light of the early closure of YPS:

- Moorabool Terminal Station (MLTS) A1 Transformer, Shunt Reactor and Circuit Breaker Replacement (indicative project cost of $50 million);
- Wodonga Terminal Station (WOTS) 330kV and 66kV Circuit Breaker Replacement ($13 million);
- Loy Yang Power Station (LYPS) and Hazelwood Terminal Station (HWTS) 500kV Circuit Breaker Replacement ($99 million); and
- HWTS A2, A3 and A4 Transformer Replacement ($45 million).

We explained that our analysis showed that the economic timing for the first two projects remained outside of the next regulatory period, while further analysis was needed to determine whether the LYPS/HWTS and HWTS projects are economic in the next regulatory period. We explained that this investigation would consider, among other things:

- The very poor condition of the LYPS/HWTS circuit breakers and the risk these assets pose to reliability and security; and
- The dependency of the HWTS project on new generation connecting in the Latrobe Valley, increasing the criticality of the transformer assets once YPS closes.

[9] AusNet maintains a 10-year asset renewal plan, which is updated annually as part of the Victorian Annual Planning Report process led by AEMO Vic Planning. The 10-year renewal plan contains approximately 70 asset replacement projects and programs that may be economic between 2021 and 2030. The 10-year period aligns with the planning horizon AEMO must apply to its Victorian Annual Planning Report. Our Revised Proposal capex forecast comprises projects from the renewal plan that are economic to deliver within the 2023-27 regulatory control period.

We sought views from stakeholders on how they would like us to address the uncertainty in relation to these projects in our Revised Proposal, including which of the following approaches may be most appropriate:

- Ex ante capital expenditure;
- Ex ante capital expenditure, with project staging;
- Contingent projects; or
- A combination of the above.

What we heard from stakeholders

Stakeholders raised a wide range of issues relating to the early closure of YPS, which we discussed during the workshop. They were supportive of our approach to reassessing the identified projects. In terms of the options for managing the uncertainty regarding the potential projects at HWTS and LYPS, stakeholders preferred that the costs of these projects be managed through contingent project arrangements, rather than ex ante expenditure allowances, unless economic analysis could demonstrate that the investment is prudent and efficient in the next regulatory period.

How we have responded in our Revised Proposal

Consistent with stakeholder preferences around how the impacts of YPS' expected early closure should be managed, we have:

- Proposed a contingent project for asset replacement work at HWTS that is dependent on new generation connecting (discussed further in section 3.11), avoiding the need for an additional $45 million of expenditure in our Revised Proposal's capex forecast;
- Proposed $16 million[10] of expenditure for asset replacement project at HWTS/LYPS that, due to the expected closure of YPS in 2028, is now economic to complete by 2028-29; and
- Assessed, but not proposed in this Revised Proposal, the two potential projects worth over $60 million at MLTS and WOTS, on the basis that there is insufficient evidence to economically justify these investments during the next regulatory control period.

3.5.3.4 Updated demand forecasts

New information discussed

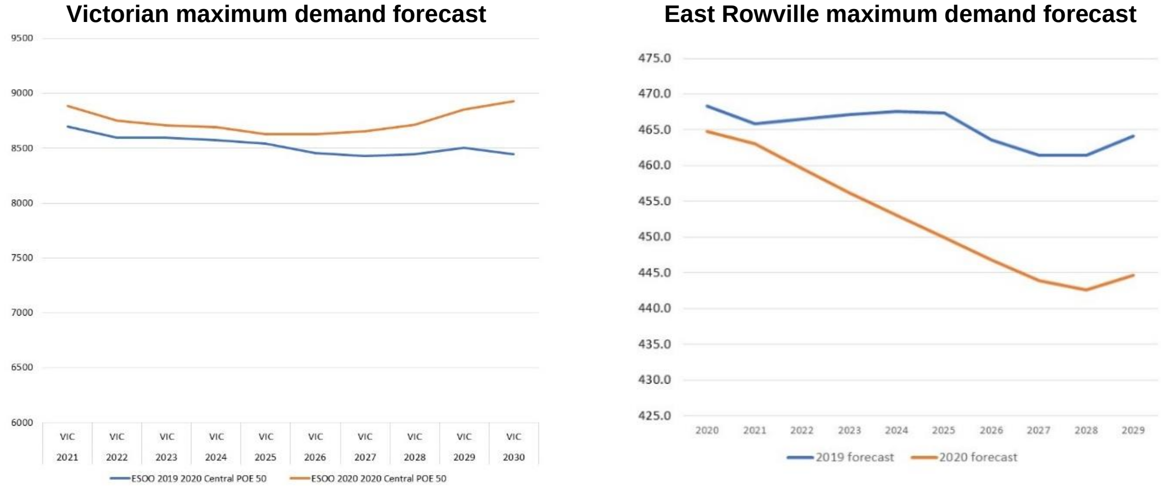
At Collaboration Workshop 4, we presented AEMO's 2019 forecasts, which were reflected in our Initial Proposal, alongside AEMO's 2020 forecasts, which were released in December 2020. We explained that updated demand forecasts may impact the economic timing of proposed projects at Terminal Stations that directly supply customer load (known as Connection Stations). For example, a reduction in forecast demand at a terminal station decreases supply risk and, therefore, defers the economic timing of a major project at that station. We explained that, as a result, it is changes in **locational** demand forecasts that can impact economic timing, rather than changes in **total Victoria** demand.

We discussed with stakeholders that while AEMO's state-wide 2020 forecasts are higher than the 2019 forecasts, changes in locational demand on the specific parts of the network where AusNet's proposed replacement projects are located are not sufficient to change the economic timing of any of these projects, except for our proposed project at East Rowville Terminal Station (ERTS). Here, AEMO has forecast a decrease in maximum demand, reflecting a combination of higher rooftop PV forecasts and changes to assumptions for energy efficiency, primarily driven by the

[10] This amount reflects the share of this project's total costs (approximately $60 million) that are forecast for the next regulatory period.

Vic Government's Victorian Energy Upgrades program. The 2019 and 2020 demand forecasts for Victoria and at ERTS are shown in the figures below.

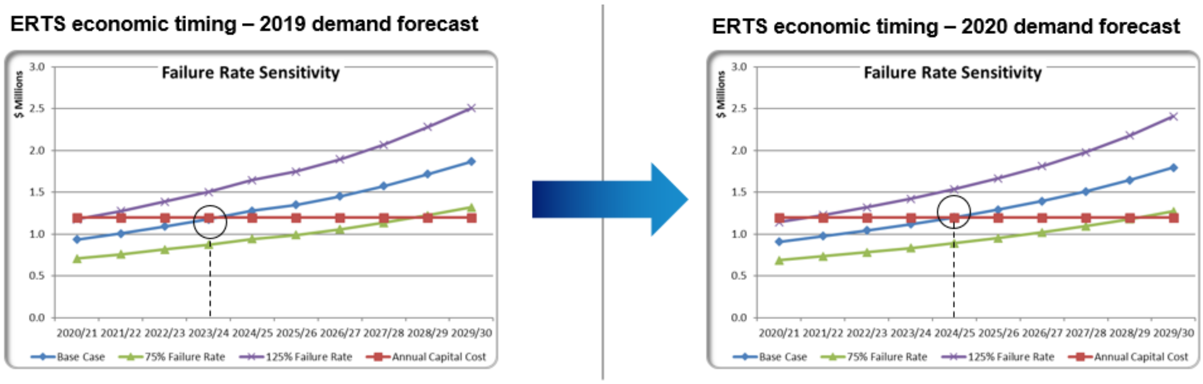
Figure 3-11: AEMO 2019 and 2020 demand forecasts, Victoria and East Rowville (MW)



Source: AusNet

We explained to stakeholders that the impact of the reduction in demand at East Rowville would ordinarily lead to the deferral of the project by one year, from 2023-24 to 2024-25, as shown in the figure below. However, our Initial Proposal had already deferred this project to 2024-25 in order to manage deliverability risk. We therefore noted that the forecast reduction in demand at East Rowville should not affect the timing of our proposed works at that station as presented in our Initial Proposal.

Figure 3-12: Effect of 2020 demand forecasts on economic timing for ERTS project



Source: AusNet

For other stations, we also explained to stakeholders that AEMO's updated demand forecasts did not affect the timing of these proposed works in our Initial Proposal.

What we heard from stakeholders

Stakeholders considered that AusNet's Revised Proposal's capex forecast should reflect AEMO's 2020 demand forecasts, being the most recently available information. Stakeholders recognised the relatively minor impact this update has on the economic timing of projects.

How we have responded in our Revised Proposal

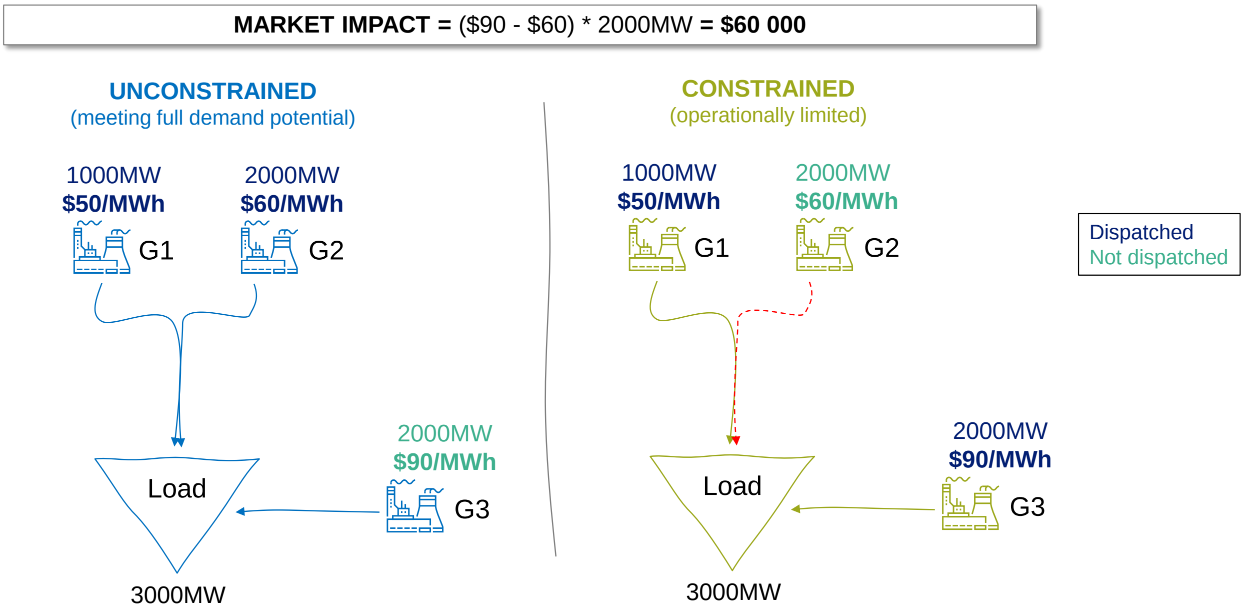
AusNet has updated the economic assessment for our major station projects to reflect AEMO's 2020 demand forecasts. However, as discussed above, this update has not changed the proposed timing of any major station projects.

3.5.3.5 Updated market modelling

New information discussed

At Collaboration Workshop 4, we explained that updated energy forecasts are an input into the market modelling we undertake to determine the impact on the wholesale market of an asset failure. This is known as the 'market impact' and it is an important determinant of the economic timing for asset replacement at Switching Stations, which form the backbone of the Victorian transmission network and are important nodes in the national transmission system. For example, an increase in market impact calculated at a particular Switching Station increases network risk and, therefore, brings forward the economic timing of a major project at that station. Conversely, a decrease in the market impact would tend to defer the optimal timing of a project.

Figure 3-13: Illustrative example of market impact calculation

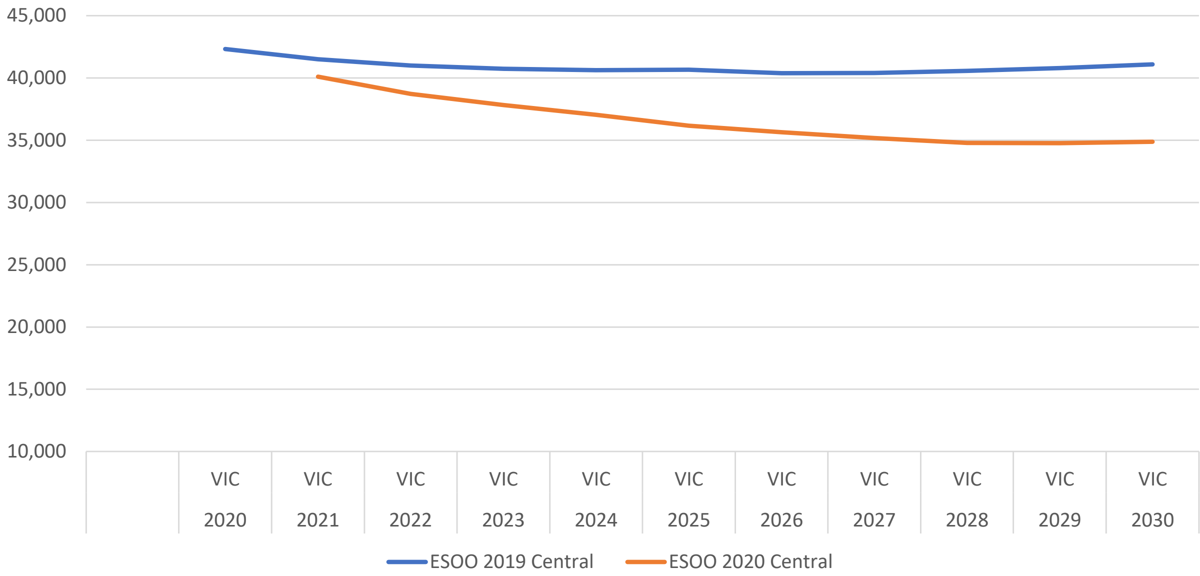


Source: AusNet

AEMO's 2020 energy forecast is lower than its 2019 forecasts, largely due to the inclusion of Victoria's Solar homes program for distributed PV in the 2020 ESOO Central scenario.[11]

[11] AEMO, *2020 Electricity Statement of Opportunities*, p. 106

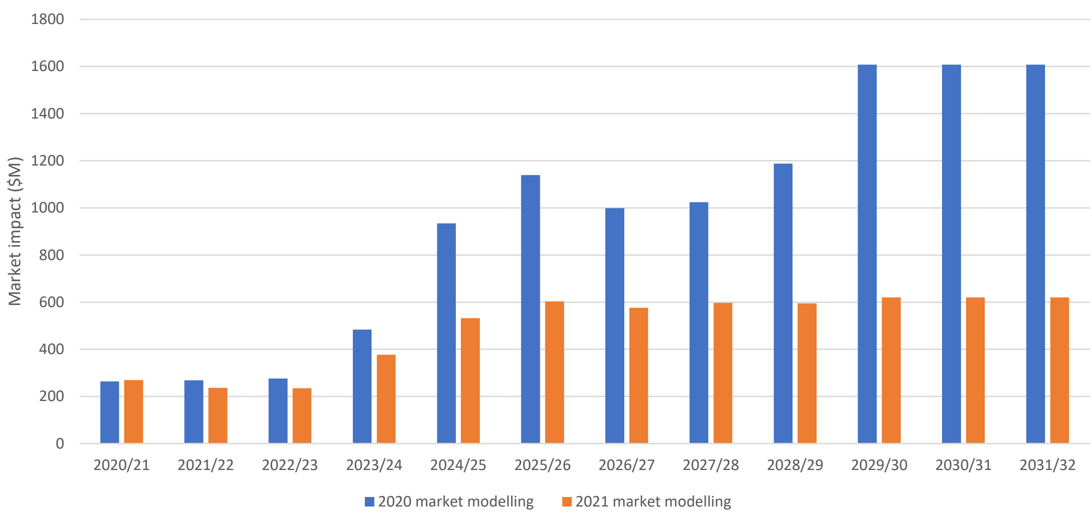
Figure 3-14: AEMO 2019 and 2020 energy forecasts, Victoria, Central Scenario (GWh)



Source: http://forecasting.aemo.com.au/

The reduction in AEMO's energy forecasts resulted in a decrease in the market impact calculated at Sydenham Terminal Station (SYTS). The figure below shows the change in market impact at SYTS between the 2020 market modelling (based on AEMO's 2019 energy forecasts and reflected in our Initial Proposal) and the 2021 modelling (based on AEMO's 2020 energy forecasts). This reflects a reduction in the consequences of an asset failure at SYTS, due to the reduced energy flows reflected in the 2020 energy forecasts.

Figure 3-15: Impact of 2020 forecasts on Sydenham Terminal Station market impact



Source: AusNet

What we heard from stakeholders

Stakeholders were comfortable that our approach to market modelling is reasonable. In addition, stakeholders noted that the timing and the scale of market impacts have been appropriately considered in our expenditure plans.

How we have responded in our Revised Proposal

As a result of the reduced market impact shown in the 2021 modelling, the economic timing for our proposed SYTS 500Kv GIS replacement project has been deferred by one year, from 2024-

25 to 2025-26. Note that this updated timing also reflects the effects of estimated network support costs on economic timing, as discussed above in section 3.4.3.2. Stakeholders were supportive of adopting the updated timing in our Revised Proposal, noting that this timing would also allow synergies with the Western Victorian Transmission Project to be realised, as discussed above in section 3.4.3.1.

3.5.3.6 Deliverability

As discussed earlier in this chapter, we have smoothed our major station projects forecast to minimise deliverability risk, consistent with the approach we agreed with stakeholders for our Initial Proposal. This involved the following steps:

1. Maintaining the following deferrals (relative to economic timing) that were reflected in our Initial Proposal's capex forecast:
   - RCTS Transformer and Switchgear Replacement (**deferred by one year**)
   - SMTS 330/220 kV Transformer Replacement - Stage 2 (**deferred by two years**)
   - SMTS 500 kV GIS Replacement (**deferred by two years**).
   - KTS A4 500/220 kV Transformer Replacement (**deferred by two years**).
2. Smoothing the expenditure profile (without changing the assumed completion date) of the following projects:
   - RCTS Transformer and Switchgear Replacement
   - KTS A4 500/220 kV Transformer Replacement
   - SYTS 500kV GIS Replacement

The TTS 66 kV Circuit Breaker Replacement project was deferred by one year in the Initial Proposal (from 2024-25 to 2025-26) to manage deliverability risk. However, deferral of this project is no longer required on deliverability grounds as its economic timing has been deferred to 2028-29 due to a substantial increase in its cost estimate. Our capex forecast reflects this revised economic timing.

Our updated project deferrals and smoothing adjustments in this Revised Proposal effectively manage the deliverability risk associated with our capex program, without creating unacceptable increases to reliability, safety and security risks.

3.5.4 Revised Proposal

Our revised major station projects forecast for the next regulatory period is $444.8 million, as shown in the table below.

Table 3-7: Revised Proposal major station projects capex forecast ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Major station projects	65.7	82.3	115.7	109.2	71.9	**444.8**

Source: AusNet

3.6 Replacement programs

3.6.1 Our Initial Proposal

We initially proposed expenditure of $213.4 million for asset replacement programs, which accounted for 27% of our Initial Proposal's capex forecast. As with major station projects, asset replacement programs are economic when the consequence of failure exceeds the cost of replacement. However, unlike major station projects, which target the replacement of deteriorated assets at a single location, replacement programs typically involve the replacement of specific types of assets across multiple locations our network.

3.6.2 Draft Decision

The Draft Decision did not accept our proposed capex for replacement programs. While the AER considered that we had adopted a relatively prudent approach to forecasting our replacement programs capex, it did not consider that our proposed South-West Comms Loop Upgrade project was driven by an asset replacement need.

In relation to our proposed inclusion of a risk allowance for our asset replacement program, the AER commented that this type of allowance is more relevant to major station projects. In discussing each source of risk or uncertainty, the AER argued that they were symmetrical so that the downside risk (leading to higher costs) was equally likely to be offset by upside risk (leading to lower costs). The AER therefore rejected our proposed risk allowance in relation to our replacement program.

For the reasons set out above, the Draft Decision did not accept these two components of our proposed replacement programs capex. According, the Draft Decision proposed to substitute an allowance for asset replacement programs of $173.1 million.

3.6.3 Response to the Draft Decision

We do not accept the AER's Draft Decision on either the South-West Comms Loop Upgrade project or the risk allowances for asset replacement programs. We consider that these expenditures are necessary to form a forecast that reflects the prudent and efficient costs we expect to incur during the next regulatory period. In particular, the South-West Comms Loop Upgrade is strongly linked to asset replacement and compliance needs, rather than an augmentation need, as the AER has stated. Furthermore, this project has not been funded in the REZ Development Plan, as explained above in section 3.5.3.1 and in the next section.

We have also provided further information to support our proposed risk allowances. This information shows that, for a portfolio of asset replacement projects, our actual costs incurred have, on average, been broadly in line with our P50 cost estimates, which themselves have been developed on a consistent basis with our proposed replacement programs unit rates. This demonstrates that, in practice, asset replacement programs are exposed to the same risks as major station projects and, therefore, a risk allowance is warranted to ensure the recovery of our efficient costs.

Each of these issues is discussed further below.

3.6.3.1 South-West Comms Loop Upgrade

Background

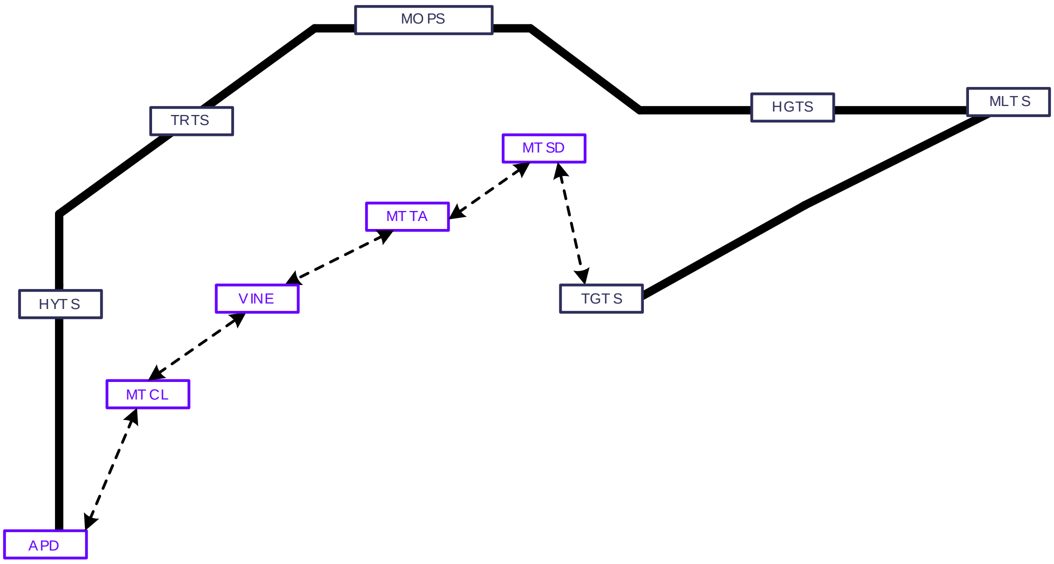
The South-West Comms Loop provides critical services for on an increasingly important part of the Victorian transmission network, including protection, control SCADA and operational communications. Included in the Loop are

- 220kV lines from Moorabool and Ballarat to Terang;
- 500kV lines from Moorabool and Portland Alcoa to Terang; and
- 275kV lines from Heywood to South Australia.

A reliable communications pathway on the SW Loop is required for AusNet to comply with all NER requirements on an increasingly important part of the transmission network, including enabling adequate redundancy and protection fault clearance times.

As shown by the figure below, optical fibre (in the form of optical ground wire carrier (OPGW)) covers the majority of the South-West Loop (solid line). The section between Terang (TGTS) and Portland (APD) relies on microwave radio (dashed line). These technologies represent the physical layer of the communications path. Currently, SDH/PDH (synchronous digital hierarchy/plesiochronous digital hierarchy) equipment is used to process and transmit data throughout the Loop as a whole.

Figure 3-16: Technologies currently deployed on SW Comms Loop



Source: AusNet

The SDH/PDH equipment has reached end-of-life and is in poor (C4) or very poor (C5) condition. The increasing risk presented by the existing equipment is demonstrated by the number of asset failures in recent years: 22 communication equipment failures in the last 6 years. Continued failures in these assets have the potential to adversely affect the reliability and security of the transmission network.

The scope of the proposed SW Comms Loop Upgrade project is to replace:

- The existing SDH/PDH equipment with a more modern equivalent, MPLS-TP (Multiprotocol Label Switching - Transport Profile);
- The existing microwave radio towers with underground optical fibre; and
- Batteries and chargers to support optical fibre carrier.

As discussed in the sections below, this replacement project is required to provide a reliable communications pathway and enable us to comply with our NER obligations during the next regulatory period.

We are progressively replacing legacy communications equipment to prudently manage risk

In addition to its advanced age and deteriorating performance, SDH/PDH is now regarded as a legacy technology (having been used on the network for over 35 years) and equipment of this technology is becoming increasingly harder to source from suppliers and maintain. The equipment model used in our network is no longer supplied and supported in Australia and overseas. This has created the additional risk of being unable to meet future critical service requirements, particularly as additional generation connects in the region. Accordingly, like-for-like replacement of the SDH/PDH equipment would not be prudent or practical, as it would pose an unacceptable risk to the reliability of the transmission network over the long-term.

Given these issues, we are progressively replacing all SDH/PDH (based on condition) on our network with MPLS/TP equipment, consistent with our prudent management of the risks presented by this legacy technology over the long-term.[12] The majority of our broader communications network relies on OPGW as a result of our progressive, condition-based replacement of ageing ground-wire with OPGW throughout our network. OPGW is capable of supporting MPLS-TP equipment as it provides the bandwidth needed for it to operate reliably. As a result, installation of further optical fibre is not required to support widespread replacement of SDH/PDH with MPLS-TP equipment on parts of our network where OPGW exists or, as discussed further below, where microwave radio technology provides sufficient capacity.

In this context, the Draft Decision raises the following concerns in relation to our proposed project:

> "In the current regulatory period, AusNet Services replaced more than half of its existing radio devices, which still appear to remain an important component of its communications network. Furthermore, only four radio devices are due for replacement out of a total population of 85 based on asset condition. This suggests that condition-based replacement is not the primary driver for this new optic fibre. "

In response to the AER's comments, we confirm that our approach is to meet our compliance obligations by replacing assets based on condition and at the lowest total life cycle costs. Microwave radio continues to be a cost-effective communication technology on our network. In some instances, the lowest cost option may be the continued use of this technology. For example, where bandwidth requirements are relatively small and optical fibre installation cost is high, we will continue to undertake condition-based replacement of microwave radio towers and, where additional capacity is needed to maintain services, construct additional towers.

As with all asset replacement investment, the driver is to identify the replacement option that allows us to maintain reliability at lowest cost. In relation to the South-West Comms Loop, the lowest cost replacement option is to install optical fibre. We acknowledge that, in this case, the lowest cost replacement option will also provide additional capacity on this part of the communications network, benefiting customers and other users of the network at no additional cost. As demonstrated by the options analysis below, the construction of additional microwave

[12] SDH/PDH and MPLS-TP equipment play an important role in processing, multiplexing and transmitting data and communications signals throughout our network. They are the interface between the protection, control, SCADA and communication devices etc. deployed on our network over the physical (or virtual physical) communications asset layer (e.g. optical fibre, microwave radio). SDH/PDH and MPLS-TP equipment therefore support the transmission of data between the communication devices throughout our network. SDH/PDH technology is considered end of life and equipment is no longer developed for this technology. As a result, it does not integrate efficiently with modern 'packet switch' protection, control, SCADA and communication end devices. In contrast, MPLS-TP is a packet transport technology that incorporates congruent paths, fault management, and network visibility. As end devices are moving toward packet switch technology, MPLS-TP is considered a leading connection-oriented packet transport networking technology that efficiently integrates with modern protection, control, SCADA and communication end devices.

towers is not the lowest cost solution to maintaining a reliable communications pathway in the South-West region of the transmission network.

Our proposed option will efficiently maintain reliability and security

The existing microwave radio towers located on the SW Comms Loop between TGTS and APD have reached full capacity and are unable to meet the bandwidth requirements of the modern equivalent MPLS/TP equipment. To ensure that we can provide a reliable communications pathway and meet our NER obligations, we considered two broad options:

- Constructing additional microwave towers to increase capacity; or
- Replacing existing microwave towers with optical fibre cable.

As depicted in Figure 3-16 below, we considered variations of these options based on the number of SDH/PDH assets replaced each year.

The first option – constructing additional microwave towers – has several disadvantages, most notably that it is a more expensive solution. In addition, it relies on a less reliable technology and faces potential long-term capacity constraints compared to optical fibre. As a modern equivalent physical layer, optical fibre has scope to support further data processing capacity through ongoing investment in MPLS/TP digital equipment.

While not the primary driver for this project, the additional capacity enabled by MPLS/TP in conjunction with optical fibre will allow this increasingly important part of the Victorian transmission network to accommodate additional generation, in turn providing wider community benefits. This increased capacity is an ancillary benefit that often occurs with the replacement of old IT and communication technology with new, as newer technologies tend to offer inherently better performance and/or capability at no additional cost.

The figure below sets out the full range of options considered, as set out in AMS 10-56 submitted with our Initial Proposal. AusNet's proposed option (Option 4) has a materially lower cost compared to the construction of additional microwave towers (Option 3). The 'do nothing' option creates significant risk and, therefore, is also not preferred. This significantly higher risk reflects the higher likelihood of equipment failure if the existing assets are not replaced, potentially leading to outages in the region affecting both 220kV and 500kV lines, including the Vic-South Australia interconnector.

Other options involving different replacement rates and/or deferred timing also have higher PV cost options and, hence, are not preferred.

Figure 3-17: South-West Comms Loop options analysis

Option Number	Option Description	Capex	Opex	Risk Cost	Present Value	PV Cost Ratio (compared to BAU)
Option 1	BAU - Do nothing different	$0	$318,654	$56,146,101	$37,836,944	1.000
Option 2	Replace 10 assets per year add new optical fibre link	$21,000,000	$96,000	$10,054,915	$31,237,126	1.211
Option 3	Replace 20 assets per year add additional radio links	$26,000,000	$67,500	$7,069,862	$34,936,968	1.083
Option 4	Replace 20 assets per year add new optical fibre link	$21,000,000	$67,500	$7,069,862	$29,936,968	1.264
Option 5	Replace 20 assets per year add additional radio links start year 5	$26,000,000	$157,500	$16,496,345	$35,208,613	1.075
Option 6	Replace 20 assets per year add new optical fibre link start year 5	$21,000,000	$157,500	$23,330,546	$36,327,974	1.042

Source: AusNet

The South-West Comms Loop Upgrade project is consistent with our historical replacement practices

AusNet does not currently have large amounts of underground fibre installed on its network, as the AER observes. However, as discussed above, significant volumes of OPGW have been installed progressively throughout our network. This is discussed in AMS 10-79 (submitted with our Initial Proposal), which states the following:[13]

> *"AusNet Services has implemented extensive ground wire replacement programs over the last two decades. Replacement programs have been primarily driven by the need to upgrade the network's communications systems to meet the performance specifications of the National Electricity Market. Communication upgrades resulted in the replacement of 30 per cent of ground wire with OPGW. Steel and ACSR ground wire make up the remaining 40 per cent and 30 per cent respectively of the total ground wire route length."*

Furthermore, a $36 million communication upgrade project involving the replacement of ageing physical communications layer with optical fibre was delivered during the current regulatory control period, between 2017 and 2020. This project involved the replacement of an ageing Power Line Carrier (PLC), with a combination of optical fibre and microwave radio in the North-West loop of the Victorian transmission network. The PLC technology, although renewed over the last 20 years, was at its functional limit and no longer compatible with modern digital protection and communication devices. After engaging extensively with AEMO Vic Planning on this project, it was concluded that an augmentation RIT-T was not required, demonstrating that the driver for the project was asset replacement, not augmentation. The similarities between this project and the proposed South-West Comms Loop project indicates that the proper regulatory treatment of the two projects should be the same.

The South-West Comms Loop project is consistent with our historical replacement practices and is not a significant augmentation of our communications network. It is consistent with previous asset replacement projects that have involved the replacement of ageing, poor condition communications assets that present a risk to ongoing reliability with more modern equivalents. While these modern equivalents offer additional capacity in some cases, this is typically the case with investment in IT and communications equipment. Due to the rapid advancements in communication technologies, modern equivalents are being introduced in an increasingly shorter timeframe, often at lower cost. As demonstrated above, continued use of existing SDH/PDH equipment, or the installation of additional microwave radio capacity as an alternative to optical fibre, would both produce higher total cost outcomes compared to the preferred option.

Conclusion

As discussed earlier in this chapter, the RDP Directions Paper included the 'bring forward' costs of the South-West Comms Loop Project, on the basis that our intended delivery timeframe did not reflect the earliest possible completion date. After engagement with DELWP to clarify that our proposed timing reflects the earliest possible completion date, the bring forward costs have been removed from the RDP. This revision to the RDP costs ensures there is no cost duplication between our proposed project and the works that are being undertaken as part of the RDP. This approach tested positively with stakeholders who expressed a strong desire to avoid duplication between our asset replacement plans and the RDP.

We note that the Draft Decision approved AusNet's proposed Latrobe Valley Comms Upgrade project, which involves the replacement of SDH/PDH with MPLS-TP and the installation of OPGW to provide the required bandwidth. We also note that this project was not funded in the RDP

[13] AusNet Services, *AMS 10-79, Transmission Line Conductors and Ground Wires*, July 2020

Directions Paper. For consistency, the Final Decision should also approve the proposed South-West Comms Loop Upgrade project.

In summary, the proposed driver for this project is the replacement of poor condition, legacy communications equipment with a modern equivalent. The existing communications technology is more than 35 years old, is no longer supported and has degraded to unacceptable levels of reliability. This asset replacement project is, therefore, necessary to maintain reliability and comply with our NER obligations relating to the performance of our communications network. While offering some ancillary benefits, the installation of optical fibre to support the modern equivalent communications technology is the lowest cost replacement option. Furthermore, no funding for this project has been provided for in the REZ Development Plan. For these reasons, the proposed expenditure meets the requirements of the opex objectives and the opex criteria, and should be accepted by the AER.

3.6.3.2 Risk allowances

In its Draft Decision, the AER explained that it considers that a cost risk allowance is appropriate for our major station projects, but not our asset replacement program, for the following reasons:

- **Volume risk**. The AER argued that the volume risk relating to asset condition should be symmetrical, which means that unexpected increases in volume at one location will be offset by lower volume at another location.
- **Price risk**. The AER commented that the unit prices for replacement activities may vary from forecast. Similar to volume risk, however, the AER does not expect the overall variation in prices to be asymmetrical such that the prices of assets will, on average, be higher than forecast.
- **Scope and delivery risk**. The AER noted that the largest risk factors for major station projects are the impact of changes in project scope, contractor delay and weather. However, the AER commented these factors are unlikely to significantly affect our replacement program, as we can adjust the timing and order of our replacement activities to maintain overall costs and avoid cost over-runs across the period.

We broadly accept the AER's reasoning in its Draft Decision in relation to volume and price risks for our asset replacement program. In particular, while actual volumes and unit prices may be higher than forecast for some elements of our asset replacement program, it is possible that these increases are offset by lower volumes and/or prices for other elements. One exception relates to condition assessments, where our experience indicates that this volume-related risk is likely to be asymmetric as assets are found to be in an unacceptable condition once works commence.

More significantly, as explained below, we do not agree with the AER's reasoning in relation to scope and delivery risks. Our experience is that our asset replacement program is affected by these risks in a similar manner to our major station program. In particular, there are site specific issues that arise in relation to our asset replacement program that affect the cost outcomes asymmetrically (i.e. there is more downside risk than upside).

Moreover, for the 2023-27 regulatory control period, delivery risks are increasing as system strength issues and other AEMO system security concerns make it more difficult and costly to obtain outages. For example, ongoing cancellation of the outages required to deliver our LYPS/HWTS CB Replacement (Stage 1) project, due to low system strength, are resulting in additional costs of approximately $10,000 per day.

As a further example, additional expenditure of $3.3 million (compared to our cost estimate) is required for an in-flight major station replacement project at Heywood Terminal Station involving the replacement of circuit breakers. While several factors have contributed to the cost increase, outage cancellations due to low system strength account for $0.7 million of the increase, translating to 5% of the original cost estimate of $14.5M or approximately two-thirds of the project's total risk allowance.

These examples demonstrate the materiality of the cost impositions on AusNet due to low system strength and other power system security issues outside of our control, which are having broader impacts on the cost and timely delivery of our asset replacement activities.

We provide additional information below to explain the risks our asset replacement projects are exposed to, drawing on specific asset replacement project examples where appropriate. Our response concludes with recent data which shows that our 7.5% risk allowance for our asset replacement program is appropriate. In our view, this further information should be sufficient for the AER to accept that the proposed risk allowance is prudent and efficient.

Our forecasting approach for asset replacement programs

For the purposes of our Initial Proposal and this Revised Proposal, we have adopted different forecasting approaches for our asset replacement program and our major stations projects risk allowances, as follows:

- For major stations, our proposed risk allowances reflect the outcome of Monte Carlo analysis which provides a granular quantification of the asymmetric risks in delivering the required works; and
- For our asset replacement program, we have proposed a broad-based 7.5% risk allowance, which is included in our proposed unit rates.

The difference in these forecasting approaches reflects the less detailed information that is currently available for the individual projects that comprise our asset replacement programs. In contrast, our major stations projects have more detailed project design and scope information available that allows Monte Carlo analysis to be undertaken. In contrast, this information only becomes available for asset replacement programs as part of the detailed design and cost estimating phase and, at this point, Monte Carlo analysis is undertaken to derive project-specific risk allowances. We confirm that, on average, these risk allowances historically have generally been in line with the 7.5% risk allowance included in our proposed unit rates.

While there are differences in the forecasting approaches for major station projects and replacement programs, both categories of expenditure are similarly affected by factors that are more likely to lead to higher costs than forecast, rather than lower costs. The purpose of including a risk allowance is to ensure that our risk adjusted expenditure forecasts reflect our best estimate of delivering the required works prudently and efficiently.

Asset replacement programs are exposed to similar risks as major station projects

As the Draft Decision explains, compared to distribution networks, transmission projects are generally exposed to more risk because they:[14]

- Typically involve longer planning and construction lead times than distribution projects. This lag may result in greater divergence between the assumptions used in the forecast and the actual cost because circumstances change; and
- May be unique or with limited precedent compared with distribution projects. Hence, cost items used in the estimation process may be based on relatively less experience.

We agree with the AER's comments. Furthermore, we also agree with the AER that asset replacement programs will typically involve unit costs that are comparatively well understood compared to the works at major stations. However, there are number of other factors that asymmetrically affect the costs of delivering the asset replacement program that warrant the inclusion of a risk allowance, including:

[14] AER, Draft Decision, p.24

- New design standards, requiring different equipment to ensure compliance with the standards;
- Management of latent site conditions to address asbestos, contaminated soil or other safety and environmental hazards;
- Technology change or obsolescence;
- Asset condition risk; and
- System strength issues, which are creating outage management and cancellation risks that impact crew mobilisation/demobilisation costs.

The additional costs of addressing these types of risks are not accounted for in the direct cost component (i.e., excluding the risk allowance) of our proposed unit rates. Instead, these risks are only quantifiable once detailed design is undertaken and site-specific checks are conducted during the preparation of business case cost estimates, or during project delivery. The nature of the above factors is that they have a strong tendency to surprise on the downside (for example, asbestos is identified at a specific location, as was the case with the recent Brooklyn Terminal Station works to facilitate the Westgate Tunnel Project) leading to higher actual costs compared to the P50 estimates.

It is not possible to offset these cost increases by deferring our asset replacement programs. The objective of our asset replacement programs is underpinned by the need to maintain the safety and reliability of our network by replacing assets where and when it is economic to do so. Our proposed capex forecast has been developed to maintain services through the timely and efficient replacement of assets. In this context, it neither possible nor appropriate to seek to manage the asymmetric risk in forecasting the costs of these programs by delaying or cancelling the required works. Our approach, which is consistent with acting prudently and efficiently, is to include a risk allowance that reflects our best estimate of the actual program costs.

Specific examples of asymmetric risks in our replacement program

To illustrate the practical consequences of the asymmetric factors described above, we set out some specific examples of recent asset replacement projects where our actual costs have been adversely affected compared to the P50 cost estimates:

- A wavelength-division multiplexing (WDM) communications replacement project was adversely affected by the vendor unexpectedly discontinuing the existing WDM communication equipment series. This is an example of technology change or obsolescence, which in this instance led to a twofold increase in cost relative to the P50 cost estimate.
- A secondary asset replacement project at Rowville Terminal Station experienced an 82% increase in cost due to the expansion of scope necessary to replace primary and secondary components that were found to be in poor condition or faulty.
- The Western Transmission (Cressy) Tower Rebuild resulted in a $3.3 million cost overrun as additional costs were incurred by AusNet as a result of extensive delays associated with cancelled outages due to AEMO’s system security concerns. These costs arose principally from the additional crew demobilisation and remobilisation costs, additional landowner compensation, and additional line inspection costs.

These examples illustrate the practical implications of the asymmetric risk that adversely affects the costs of delivering the asset replacement program. In addition to these examples, there will be countless smaller scale impacts on the asset replacement program, as site specific issues or delivery risks crystalise. The best way to understand the net impact of these asymmetric risks is to examine the latest data, which is presented in the next section.

Our asset replacement project cost estimates broadly align with our actual costs

To demonstrate the robustness of our forecasting approach for asset replacement programs, we compared P50 cost estimates (including a risk allowance) with actual/expected costs for a portfolio of approximately 80 asset replacement projects totalling $280 million. This data has been provided in Appendix 3B and is summarised in the table below. Both actual and estimated costs are inclusive of overheads.

Table 3-8: Comparison of actual vs estimated costs, asset replacement programs

	P50 cost estimate (incl. risk allowance)	Estimate at completion
$M, nominal, incl. OHDs	**$280.8**	**$285.0**
%	**100%**	**101%**

Source: AusNet

This analysis shows that the total actual cost (including estimated actual costs for works in progress) for delivering a portfolio of approximately 80 asset replacement projects is around 1 percent higher than our P50 cost estimates of $280.8 million, which include risk allowances. This data demonstrates that the inclusion of the risk allowance is appropriate.

In further considering the reasonableness of our proposed risk allowance, it is appropriate to ask whether the factors driving the asymmetric cost outcomes are likely to persist in the 2023-27 regulatory control period. In that regard, we note that the cancellation of outages due to system strength issues (or other AEMO power system security concerns, such as lack of reserve, solar shake-off and minimum demand) may drive increased costs in future compared to recent experience.

AusNet has not included an allowance for these costs in any other part of this Revised Proposal. As discussed in Chapter 10, we propose to use cost pass through arrangements to recover efficient network support costs where these are required to manage low system strength during outages. Despite this, cancellation of outages due to AEMO power system security concerns remains a risk, and may drive additional costs, during the next regulatory period. For example, where it is more efficient to defer an outage than incur network support costs due to prevailing wholesale market conditions, or the required network support cannot be obtained within the timeframes needed to support the outage. This further demonstrates the need for our risk allowance considering the uncertainty and costs associated with outage cancellations are not accounted for in our capex forecast.

Conclusion

In summary, the above analysis shows a close alignment, on average, between cost estimates and actual/expected costs across a portfolio of projects of similar value to our proposed asset replacement programs. The historical data does not support the AER's contention that risk allowances are not required for our replacement programs, due to their supposed lower exposure to inherent and contingent risks. The existence of a minor under-forecasting bias demonstrates our replacement program cost estimating processes are robust and conservatively understated. The inclusion of the proposed risk allowance in our asset replacement unit rates is, therefore, necessary to ensure the total capex forecast reflects a realistic expectation of the cost inputs required to achieve the capital expenditure objectives.

In reaching this conclusion, we have explained that the same kind of scope and delivery risks accounted for in the major stations risk allowance also apply to our asset replacement program and described the factors that drive downside risk in relation to the costs of delivering the replacement program. In addition, we have provided specific examples where these factors have led to material increases in the costs of delivering particular projects in our replacement program.

Furthermore, our analysis of the recent costs of delivering replacement works demonstrates that the proposed 7.5% risk allowance is reasonable.

While we broadly accept the points raised by the AER in its Draft Decision in relation to price and volume risk, it would not be appropriate or effective to seek to manage delivery and scope risk by deferring elements of the replacement program. As a prudent TNSP, we are required to undertake the planned works to meet our NER obligations, unless circumstances change in a way that means the work is no longer required. Our assessment is that the asset replacement program in this Revised Proposal is warranted, and that the 7.5% risk allowance is required in order to provide a best estimate of the efficient costs of delivering this program.

3.6.4 Revised Proposal

Our revised replacement programs forecast for the next regulatory period is $208.9 million, as shown in the table below.

Table 3-9: Revised Proposal replacement programs capex forecast ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Replacement programs	45.1	44.0	41.7	35.8	42.4	**208.9**

Source: AusNet

3.7 Safety, Security and Compliance

3.7.1 Our Initial Proposal

Our Initial Proposal contained a total capex forecast for Safety, Security and Compliance of $54.2 million over the 2023-27 regulatory control period. The Initial Proposal explained that this capex forecast was 47% higher than the expenditure we expect to incur in the current regulatory control period. The increase in forecast expenditure reflects:

- The need to replace deteriorated assets that, based on the likelihood and consequence of failure, are economic to replace. This included a $29 million program to replace a number of our insulator assets based on their condition and criticality, which is a key driver of the proposed increase;
- The increased expenditure requirement for communications assets, driven by a step up in security and compliance driven communications equipment replacement. Underpinning this requirement is the replacement of critical communications and monitoring equipment, as well as end of life DC systems and site security improvements required to protect the communications and SCADA equipment; and
- The costs of implementing several safety-driven initiatives which are required to ensure we meet our safety obligations as under the Occupational Health and Safety Regulations 2007.

Our Initial Proposal also explained that while the forecast capex is 47 per cent higher than current regulatory control period, it is 40 per cent lower than the annual average for the earlier 2014–17 regulatory control period.

3.7.2 Draft Decision

The AER noted that although we proposed an increase in capex for insulators and communications assets in the 2023-27 regulatory control period, we had also forecast a significant decrease in other costs compared to our historical expenditure in areas such as fall arrest systems and instrument transformer replacements.

The AER stated that these reductions in capex reflect our pursuit of efficiencies and synergies in our capex programs, which provides confidence that our overall forecast reflects the prudent activities required to maintain network safety.

The AER noted that we adopted an economic based cost-benefit approach to forecasting the Safety, Security and Compliance capex, similar to our asset replacement program. The AER found that we apply a prudent methodology to identify the prudent need and timing for these works and the efficient costs of doing so.

Accordingly, the Draft Decision contains an allowance of $53.7 million for Safety, Security and Compliance capex, the variance from the Initial Proposal reflecting a minor adjustment to external labour costs.

3.7.3 Response to the Draft Decision

The Draft Decision's capex allowance for this category is $0.5 million (or 0.9%) below the forecast contained in our Initial Proposal. As noted above, this small difference reflects the AER's adjustment of our proposed escalation of external labour costs, which we have accepted for the purpose of this Revised Proposal (see section 3.10.3).

We accept the Draft Decision's allowance of $53.7 million for Safety, Security and Compliance capex, with the exception of a new project involving the installation of PMUs, which has been included in our updated forecast in anticipation of an AEMO Direction, and adjustments to reflect updated labour escalators.

3.7.3.1 Phasor Monitoring Units

AEMO and AusNet have been in discussions regarding a notice (to be issued by AEMO under NER 4.11.1(d)) (**Notice**) that would require us to upgrade or replace 1 PMU and install 19 new PMUs at various locations on the transmission network to allow AEMO to discharge its market and power system security functions. Specifically, the PMUs will allow AEMO to remotely monitor, identify and investigate current and potential power system security issues.

AEMO has shared a draft of the Notice with us. The draft Notice sets out the following obligations on AusNet:

- The existing PMU at Rowville Terminal Station is to be upgraded, modified or replaced.
- New PMUs are to be installed at specified locations by 30 June 2022. Specifically:
    - 11 PMUs are to be installed and 1 PMU upgraded by 31 March 2022; and
    - A further 8 PMUs are to be installed by 30 June 2022.
- The PMUs must comply with the performance specifications attached to the Notice and be subject to a maintenance standard that is in accordance with section 6 of AEMO's Power System Data Communication Standard.

AEMO's final Notice will be issued pursuant to clause 4.11.1(d) of the NER. Clauser 4.11.1(e) requires that we comply with the Notice within 120 business days or such other date specified in the notice. Failure to do so exposes AusNet to a potential civil penalty.

We note that the timing of issuance of the Direction is not confirmed, and we understand AEMO and the AER are currently discussing the economic analysis that is required to support this Direction. However, we expect that the Direction will be issued in the coming months and most of the required expenditure will be incurred in the 2022-23 regulatory year.

Therefore, this Revised Proposal includes forecast capex of $10 million for PMU installation, in line with the specifications set out in AEMO's Draft Direction (see Appendix 3C –Draft AEMO Direction to install Phasor Monitoring Units).

3.7.4 Revised Proposal

Our revised safety, security and compliance forecast for the next regulatory period is $62.5 million, as shown in the table below.

Table 3-10: Revised Proposal safety, security and compliance capex forecast ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Safety, security and compliance	18.6	8.1	10.2	15.4	10.1	**62.5**

Source: AusNet

3.8 Information and Communication Technology

3.8.1 Our Initial Proposal

Our Initial Proposal contained a forecast of $83.8 million for ICT expenditure for the 2023-27 regulatory control period. We explained that this is 14% higher than the expenditure we expect to incur in the current period for the following reasons:

- The forecast expenditure in this category compared with previous regulatory periods is in line with long term historical levels;
- New cyber security requirements and an increasingly complex operating environment are driving the overall increase in forecast expenditure requirements; and
- ICT expenditure is cyclical in nature, reflecting the timing of major upgrades (e.g. SAP) and the lifecycle replacement of ICT systems.

3.8.2 Draft Decision

The Draft Decision explained that our ICT program is shared between our transmission and distribution businesses, with project costs allocated between the two. The AER accepted our proposed distribution ICT capex in its April 2021 distribution revenue determination, and consequently the AER accepted the transmission component of this program in its Draft Decision.

The Draft Decision noted that an important difference between the distribution and transmission businesses is forecast capex for cyber security and intelligent network operations systems. The 14% increase in our ICT capex reflects an additional $16.7 million to comply with new cyber security requirements that are specific to our transmission business.

The AER noted that we conducted cost benefit analysis for our proposed cyber security program. The AER said that its review indicated that that there are likely positive benefits for the proposed capex projects, and on that basis the AER considered that the cybersecurity capex is reasonable.

The Draft Decision contains an allowance of $83.0 million for ICT expenditure.

3.8.3 Response to the Draft Decision

The Draft Decision's allowance is $0.8 million (0.9%) lower than our Initial Proposal, reflecting the AER's acceptance of our ICT capex forecast and its adjustment to our proposed escalation of external labour costs, which we have accepted for the purpose of this Revised Proposal (see section 3.10.3).

As discussed in Chapter 4, we have re-proposed a step change for the efficient costs of reaching and maintaining the MIL-3 cyber security maturity level during the next regulatory period. However, this has not required changes to our Initial Proposal's cyber security capex requirements, which were accepted in the Draft Decision and are sufficient to fund the systems and technology required for MIL-3 compliance.

Accordingly, we accept the Draft Decision's ICT capex allowance of $83.0 million. Our Revised Proposal is therefore consistent with the Draft Decision, except for adjustments we have made to reflect updated labour escalators.

3.8.4 Revised Proposal

Our revised ICT capex forecast for the next regulatory period is $82.4 million, as shown in the table below.

Table 3-11: Revised Proposal ICT capex forecast ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
ICT capex	17.9	18.2	19.1	14.7	12.6	**82.4**

Source: AusNet

3.9 Non-network

3.9.1 Our Initial Proposal

Our Initial Proposal contained a forecast for non-network capex totalling $22.2 million for the 2023-27 regulatory control period. This represented a 17% increase compared to the expenditure we expect to incur in the current regulatory period, reflecting modest increases in motor vehicle purchases and buildings capex. We explained that our proposed vehicles capex forecast reflects a switch from vehicle leasing to an ownership model, requiring an increase in capex. Our Initial Proposal explained that a reduction in our base year opex would offset the additional vehicle capex.

3.9.2 Draft Decision

The Draft Decision noted that although our forecast non-network capex is slightly more than the current period actual costs, it is significantly lower than the AER's forecast of the prudent and efficient non-network capex for the current regulatory period. The AER considered that this reflects efficiencies that we have been able to achieve for expenditure on motor vehicles and tools and equipment due to outsourcing. The AER noted that these efficiencies are reflected in our proposal for the 2023-27 regulatory control period, which lends support to the forecast.

The AER also noted that our proposal to increase the proportion of owned rather than leased vehicles is consistent with the practice of other electricity service providers in Australia and may result in cost efficiencies.

Accordingly, the Draft Decision provides an allowance of $22.0 million for non-network capex.

3.9.3 Response to the Draft Decision

The Draft Decision's allowance is $0.2 million (0.9%) lower than our Initial Proposal, reflecting the AER's acceptance of our non-network capex forecast and its adjustment to our proposed escalation of external labour costs, which we have accepted for the purpose of this Revised Proposal (see section 3.9.3).

We accept the Draft Decision's non-network capex allowance of $22.0 million. Our Revised Proposal is therefore consistent with the Draft Decision, except for adjustments we have made to reflect updated labour escalators and capitalised leases.

3.9.4 Revised Proposal

Our revised non-network capex forecast for the next regulatory period is $21.8 million, as shown in the table below.

Table 3-12: Revised Proposal non-network capex forecast ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Non-network capex	3.7	5.3	4.8	3.8	4.1	**21.8**

Source: AusNet

Note: Includes capitalised leases

3.10 Labour escalation

3.10.1 Our Initial Proposal

In our Initial Proposal, we applied a forecast of the EGWWS (Electricity, Gas, Water and Waste Services) Wage Price Index to forecast the costs of internal labour, and a forecast of the Construction Wage Price Index to the forecast costs of labour in our external contracts.

We explained that we expect our external contracted costs to increase above current estimates because:

- Our primary contractors had confirmed that the labour costs in actual recent project costs increased by between 3 and 4 per cent per annum;
- Approximately half of our transmission capex forecast comprises major station projects that will span three to four years. In these circumstances, we consider we have limited ability to adjust our use of contracted services to address changes in the labour market and/or economic climate;
- We expect there to be a material increase in demand for skilled workers that will be needed to deliver large-scale energy infrastructure projects (including those set out in the ISP) during the 2023-27 regulatory control period; and
- In light of the unprecedented scale of infrastructure development taking place prior to and during the 2023-27 regulatory control period, a departure from the contracted labour cost escalation approach set out in the AER's recent distribution determinations is required for the transmission revenue reset.

The total contribution of our real labour cost escalation to our capex forecast was $9 million, of which $2.1 million related to internal labour and $6.9 million related to external labour.

3.10.2 Draft Decision

The Draft Decision accepted our proposed internal labour escalation rates.

However, the AER did not accept our proposal to escalate the labour component of our external contracted costs. The AER noted that our proposal is a departure from its historical practice and recent AER decisions for distribution businesses (including for AusNet), in which escalation has not been applied to external contracted labour costs for distribution or transmission capex forecasts. The Draft Decision stated that the AER considers that compelling evidence is required to alter this position, and it was not satisfied the information currently available supports an increase in our expected external contracted costs.

3.10.3 Response to the Draft Decision

This Revised Proposal adopts the AER's Draft Decision in relation to internal labour cost escalation, which is consistent with our Initial Proposal. However, we have updated our internal labour escalators applied to reflect a more recent forecast we have obtained from BIS Oxford Economics. This update is discussed further in Chapter 4 (Operating Expenditure).

In relation to external labour costs, consistent with the information presented in our Initial Proposal, we consider there are reasonable grounds to expect real increases in these costs over the 2023-27 regulatory period. However, for the purpose of our Revised Proposal we have adopted the Draft Decision's approach of applying zero real cost escalators to external labour.

We maintain our view that as several, significant ISP projects move into their delivery phase, there is likely to be upward pressure on external labour costs, and this may well result in a need to apply real cost escalation to external labour costs in future transmission revenue resets. We therefore propose to revisit this issue at the next reset.

This is consistent with the AER's commentary in the Draft Decision that it '*acknowledge the potential for some demand and supply pressures on suitably skilled construction workers in the near term…*'.[15]

Similarly, the Reserve Bank of Australia (RBA), in its most recent Statement on Monetary Policy (August 2021), recognised that wage pressures are likely to result in non-residential private investment (which is the type of investment we undertake) and public investment over the coming years. Consistent with the explanation we provided in our Initial Proposal, this upward pressure is due to the expected volume of investment activity.[16] Specifically, the RBA has stated that:

> *Capacity constraints could also become more prominent in parts of the economy, particularly in residential and non-residential private and public investment where a large amount of activity is forecast over coming years. This volume of investment activity could result in price and wage pressures emerging more quickly than anticipated; restricted interstate labour mobility would exacerbate this.* [17]

We also note that while the CCP23's submission did not support AusNet's proposal on external costs, this was based on the then most recent RBA publication, which had a forecast for very slow growth in wages.[18, 19] Since February 2021 (the date of the CCP23's submission), the RBA has had more time to consider the potential impact of COVID-19 (amongst other factors) on the Australian economy and has highlighted that the expected volume of investment activity could result in price and wage pressures emerging more quickly than anticipated (see above).

Importantly, the RBA recognises that capacity constraints could result in projects being rationed or delayed. This is an outcome that the AER appears to suggest is appropriate in the next regulatory period:

> *… [It] consider that sufficient flexibility exists for AusNet Services to manage its overall pool of contracted services to manage costs. This can involve altering the timing of individual projects and programs within its overall portfolio of works.*[20]

[15] AER, TRR Draft Decision, Attachment 5, p. 30.

[16] AER, TRR Draft Decision, Attachment 5, p. 30.

[17] https://www.rba.gov.au/publications/smp/2021/aug/economic-outlook.html (accessed 23 August 2021).

[18] CCP23, Advice to the AER on AusNet Services electricity transmission revenue proposal 1 April 2022 to 31 March 2027 and AER Issues Paper, p. 47.

[19] The RBA's February 2021 base line forecast includes a wage price index of: 1.25 (Dec 2020), 1 (Jun 2021), 1.5 (Dec 2021), 1.75 (June 2022), 1.75 (Dec 2022) and 2 (June 2023). In contrast, the RBA's August 2021 base line forecast had a (higher) wage index of 1.75 (Dec 2020), 2.25 (Jun 2021), 2.25 (Dec 2021), 2.5(June 2022), 2.5 (Dec 2022) and 2.75 (June 2023).

[20] AER, TRR Draft Decision, Attachment 5, p. 30.

While we accept that delaying a project can help mitigate costs in some circumstances, however, where external contracts reflect expected increases in labour costs, no savings will be realised from adjusting (delaying) the timing of those projects. Importantly, if external labour costs continue to tighten, delaying a project is likely to result in our costs increasing if there is no easing of the demand-side pressures on skilled construction workers.

Our ability to defer projects to manage external labour cost increases in the manner suggested by the AER is also limited given our obligations to maintain safety and reliability by replacing assets where it is economic to do so. Our proposed capex forecast has been developed to maintain services through the timely and efficient replacement of assets.

The AER has also highlighted that we are better placed than consumers to control the price of its external contracted services and should bear the majority of the cost of any such risk. We agree that typically we would be in a better position to manage such risks, and actively do so in response to the expenditure incentives we face. However, given the circumstances we are forecasting and which the AER (and RBA) recognise (increasing external labour costs due to the tightening labour market for skilled construction workers), the AER's current position is only allowing us the option to either absorb these costs or defer projects.

The Draft Decision notes that we were unable to provide vendor quotes at the time of preparing the cost estimates included in our revenue proposal, or evidence that the forecast growth in the construction wage price index will be representative of the growth in the costs of its contracts going forward. While this is true, we have provided forecasts from a suitably qualified, third-party consultancy to support of our proposal. This is consistent with the evidence base on which the AER has made its decision on internal labour escalators.

Given the above, and noting the evidence base we have already provided, we see merit in the application of real cost escalation for external labour. While we appreciate the value the AER may see on precedence with recent decisions, we also see the value and importance of approaches evolving over time to reflect market conditions.

3.11 Contingent projects

A contingent project is a capital project that is reasonably required to achieve any of the capex objectives[21] but is not certain to be undertaken (or commenced) in the next regulatory control period. For this reason, such projects are not included in the capex forecast. Rather, the NER allow TNSPs to propose such projects for approval as contingent projects for the relevant regulatory control period. If the project is approved as a contingent project in the transmission determination, the TNSP may recover the capital expenditure for the project if pre-defined trigger events are satisfied and the AER approves an application to amend the revenue determination.

3.11.1 Our Initial Proposal

At the time we submitted our Initial Proposal, we had not identified any contingent projects for the 2023-27 regulatory control period.

3.11.2 Draft Decision

The Draft Decision did not require AusNet to convert any of its proposed capex projects to contingent projects for the forthcoming regulatory control period.

[21] NER, 6A.8.1(b)(1).

3.11.3 Response to the Draft Decision

On 20 March 2021, well after our Initial Proposal was submitted, EnergyAustralia announced it would retire Yallourn Power Station in mid-2028 instead of 2032. This announcement required AusNet to reassess our asset replacement plans because withdrawing Yallourn's installed generation capacity of 1,450 MW earlier than expected increases the criticality of network assets connecting other generation sources (including interconnectors and grid-scale batteries).

As discussed earlier in this chapter, this assessment demonstrated that it is economic to bring forward a major station project to replace circuit breakers at LYPS and HWTS (included in this Revised Proposal's capex forecast), and that it may be economic to replace transformer assets at HWTS depending on the extent of new generation that connects in the region.

Given their dependency on external factors, to manage the costs of transformer replacement at HWTS, we propose it as a proposed contingent project in our Revised Proposal. We consider this approach appropriately balances uncertainty and our obligations to deliver safe and reliable transmission services at the lowest cost. Our proposed HWTS contingent project is discussed further in the sections below.

3.11.3.1 Background

The shortfall in generation capacity created by the Yallourn Power Station's early retirement will need to be replaced by renewable generation. As Yallourn operates as a base load power station, the amount of renewable generation required is much greater than 1,450 MW to ensure sufficient capacity is available to compensate for the semi-scheduled and intermittent nature of renewable generation.

The Victorian Transmission System was designed to transmit large amounts of generation from the large brown coal resource in the Latrobe Valley, where the Yallourn Power Station is located, to the load centre in Melbourne. Therefore, the network within the Latrobe Valley and the transmission flow paths between it and Melbourne do not present the same connection and network constraint challenges as other parts of the transmission system where renewable generation has, to a large extent, already utilised the available capacity. As such, a significant amount of new generation is expected to seek to connect in the Latrobe Valley where the network has a large capacity for new generation connections. The interest in connecting in this area is likely to be heightened by further anticipated coal fired generation retirements in the Latrobe Valley.

New generation connections in this area would form part of the Gippsland REZ shown in the figure below.

Figure 3-18: Location of potential new generation connections in the Latrobe Valley

Source: https://www.energy.vic.gov.au/renewable-energy/renewable-energy-zones

HWTS is a major 500/220 kV switching station located in the Latrobe Valley. It comprises four 500/220 kV transformers that connect the 500 kV and 220 kV transmission networks in the area.

Power transmission across the 500 kV transmission backbone between the Latrobe Valley and Melbourne has significantly lower network losses than transmission via the 220 kV transmission flow path, which contributes to a more secure and reliable electricity supply for Melbourne.

To ensure the Melbourne load centre continues to receive a reliable electricity supply and benefits from the anticipated new renewable energy connections in the Latrobe Valley, it is essential that the HWTS transformers continue to operate reliably. Three of the four 500/220 kV transformers have been in service since 1970 and are now in poor condition. When the asset failure risk of these transformers exceeds the cost of replacement, it will be economic to replace them, at a total estimated cost of approximately $45 million (real $2021-22). The connection of new renewable generation in the region will significantly increase the consequences of failure of these transformers and bring forward the point at which it is economic to replace them.

We estimate that committed generation capacity of 1,550 MW prior to the closure of YPS, or 3,000 MW after the closure of YPS, to the 220kV network in the Latrobe Valley would mean it is economic to replace the HWTS transformers during the next regulatory control period. As discussed above, while further new generation is likely to connect in the Latrobe Valley within the next decade, the capacity that will become committed prior to and after the closure of YPS is currently uncertain. This means we cannot be certain about the precise point in time at which it becomes economic to replace the transformers. Given this uncertainty, we consider that it is appropriate to use the contingent project arrangements to manage the costs of transformer replacement at HWTS. Our customers and stakeholders were supportive of using contingent project arrangements, rather than ex ante expenditure allowances, to recover the efficient costs of this project if it proceeds.

Should circumstances during the next regulatory control period suggest that investment is required to maintain reliable transmission services on the Latrobe Valley 220 kV transmission network, AusNet will undertake a RIT-T to determine the most efficient solution to address the identified need. This will involve an assessment of the transformer replacement option that is the subject of this proposed contingent project, as well as other credible options to maintain the reliability of the flow path between Melbourne and the Latrobe Valley for new generation connecting to the 220 kV section of the region’s network. We propose that the trigger event for this contingent project should include reference to the outcome of the RIT-T, to ensure that any contingent project application is supported by an economic assessment of the associated expenditure.

3.11.3.2 Project description

The scope of this proposed contingent project is the replacement of the A2, A3 and A4 transformers and the associated primary and secondary equipment at HWTS with new assets providing similar service levels.

3.11.3.3 Proposed trigger event

As already noted, a proposed contingent project must specify trigger events that describe the circumstances in which the project would be reasonably necessary in order to achieve the capital expenditure objectives. In determining whether a trigger event is appropriate, the AER must have regard to the matters listed in NER 6A.8.1(c). As noted above, the NER require AusNet to conduct a RIT-T to identify the preferred credible option to maintain the reliability of the transmission flow path between Melbourne and the Latrobe Valley for new generation connecting to the 220 kV section of the Latrobe Valley transmission network. We propose that the trigger for the HWTS proposed contingency project be linked to outcome of the RIT-T. Therefore, we propose the following trigger event for the proposed HWTS contingent project:

1. New generation capacity exceeding an aggregate of 1,550 MW (prior to the closure of Yallourn Power Station) or 3,000 MW (after the closure of Yallourn Power Station) is committed at the current or future connection points on the 220 kV Latrobe Valley transmission network.

2. Completion of a RIT-T to address the identified need of "maintain reliable, safe and secure prescribed transmission network services having regard to current and projected generation connections to the Latrobe Valley 220 kV transmission network" where the preferred credible option demonstrates that network investment at Hazelwood Terminal Station is economic during the 2023-27 regulatory control period.
3. The AER determines that the proposed investment satisfies the RIT-T.
4. A commitment from AusNet to proceed with the project, subject to the AER amending the revenue determination pursuant to the NER.

This trigger event complies with the requirements of NER 6A.8.1(c). In particular, it is verifiable by reference to specific, objective and observable events, and relates to conditions and events that generate increased costs at a specific location on our network.

3.11.3.4 Estimated contingent project expenditure

The cost (direct plus overheads) of replacing the three transformers and associated primary and secondary equipment with new assets providing similar level of service is estimated to be $45 million (real $2021-22).

To satisfy the cost threshold of a contingent project, the proposed expenditure must be more than $30 million, or 5% of the proposed MAR in the first year of the next regulatory control period (i.e. $29 million), whichever is greater. This means $30 million is the applicable threshold, which the proposed project cost exceeds.

3.11.3.5 Compliance with the Rules

Replacing the transformers when it is economic to do so is consistent with the capital expenditure objectives.[22] Ensuring reliable operation of the Latrobe Valley transmission network is necessary to meet or manage the demand for prescribed transmission services; it is also essential to maintaining the safety, reliability and security of the transmission system. The RIT-T process will ensure the cost of the project is prudent, efficient and realistic.[23]

The proposed contingent project also complies with NER 6A.8 for the following reasons:

- As demonstrated above, the proposed project meets the cost threshold of $30 million.
- The economic case for undertaking the proposed contingent project during the next regulatory control period depends on an uncertain event occurring – whether new generation meeting specific capacity thresholds is committed to connect to the Latrobe Valley 220 kV network during the next regulatory control period.
- The costs associated with the proposed contingent project are not sufficiently certain to justify their inclusion in the capital expenditure forecast, as the economic case for the expenditure is dependent on new generation becoming committed.
- As noted above, the trigger event is specific, capable of verification, sufficiently uncertain and meets the other requirements set out in 6A.8.1(c).
- The expenditure estimates represent prudent expenditure to achieve the capital expenditure objectives (NER 6A.6.7) – this project is required to maintain the reliability, safety and security of the transmission system. Expenditure has been estimated by applying AusNet Services' standard expenditure forecasting approach. The expenditure forecasting methodology is described in Chapter 4 of our Initial Proposal.

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[22] NER 6A.6.7(a).

[23] NER 6A.6.7 (c)

- The project is not otherwise provided for in the capital expenditure forecast – no expenditure to replace transformer assets at HWTS has been included in this Revised Proposal's capex forecast.

3.12 Total capex forecast

Our revised total capex forecast for the 2023-27 regulatory control period is $820.5 million. This is $23 million higher than the capex forecast in the Initial Proposal. However, as mentioned earlier in this chapter, the revenue required to fund our proposed capex forecast has reduced by $5 million compared to the Initial Proposal.

Table 3-13: Revised Proposal – Total capex forecast ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Major Station Projects	65.7	82.3	115.7	109.2	71.9	**444.8**
Replacement Programs	45.1	44.0	41.7	35.8	42.4	**208.9**
Safety, Security and Compliance	18.6	8.1	10.2	15.4	10.1	**62.5**
ICT	17.9	18.2	19.1	14.7	12.6	**82.4**
Non Network	3.7	5.3	4.8	3.8	4.1	**21.8**
Total	**151.0**	**158.0**	**191.5**	**178.9**	**141.1**	**820.5**

3.13 Why our capex forecasts satisfy the NER requirements

NER S6A.1.1 requires a Revenue Proposal to identify the categories of transmission services which are to be provided by the assets associated with the capital expenditure forecast. The assets associated with the Hazelwood Power Station 220kV CB Replacement - Stage 4 and LYPS and HWTS 500kV Circuit Breaker Replacement Stage 2 projects provide both prescribed entry connection services and prescribed shared transmission services. All other assets provide either prescribed shared transmission services to AEMO, and prescribed connection (exit) services to Victorian DNSPs.

Among other things, the NER also require the AER to assess the prudency and efficiency of our capex, having regard to 'capital expenditure factors'. These factors include:

- The AER's most recent annual benchmarking reports;
- The actual and expected capex in previous regulatory periods;
- The extent to which the forecasts address the concerns of electricity consumers;
- The relative prices of operating and capital inputs;
- The substitution possibilities between opex and capex;
- Whether the forecast is consistent with the applicable incentive schemes;
- Whether the forecast reflects arrangements that are not on arm's length terms;
- Whether the capex forecast includes an amount relating to a project that should more appropriately be included as a contingent project;
- The extent to which we have considered, and made provision for, efficient and prudent non-network options; and
- Any relevant final project assessment report, as required by the regulatory investment test for transmission procedures.

As the AER is required to consider these factors in determining whether it is satisfied that the forecasts reasonably reflect the capex criteria, we have considered all those factors in developing our forecasts. This is demonstrated in the NER Compliance Checklist submitted with this Revised Proposal, as well as the information set out in our Initial Proposal and this chapter regarding why our updated capex forecast reasonably reflects the capex criteria. In the event of any inconsistency between the Initial and Revised Proposals, the information contained in the Revised Proposal prevails.

Furthermore, as discussed in Chapter 1 and in section 3.5 of this chapter, our approach to customer engagement in the lead up to and the preparation of our Revised Proposal reflects our continued and ongoing commitment to deep stakeholder engagement on the issues that matter to our customers. As a result of this engagement, we are confident that our updated forecasts address the concerns of electricity consumers.

3.14 Supporting documents

We have included the following documents to support this chapter:

- Appendix 3A – Supplementary information on Likelihood of Asset Failure;
- Appendix 3B – Asset replacement programs cost data; and
- Appendix 3C – Draft AEMO Direction to install Phasor Monitoring Units.

A significant number of other documents and models, including the Capex Model, Planning Reports, Cost Estimates, Business Cases and Economic Models support our updated capital expenditure proposal.

4 Operating expenditure

4.1 Key points

- Since the Initial Proposal, several categories of unforeseen costs have been imposed on our business by external parties, including the Victorian Government and AEMO. In the face of these uncontrollable external drivers of increased costs, our continued success in driving down the internal costs under our control has become particularly important. Our success has allowed us to achieve sufficient cost savings to offset the externally-driven increases, and decrease the proposed opex allowance in our Revised Proposal.
- We are proposing operating and maintenance expenditure (opex) excluding easement land tax and debt raising costs of $511 million for the next regulatory period. This is:
    - 16% higher than that proposed in the AER's Draft Decision; and
    - 6% lower than that proposed in our Initial Proposal.
- We welcome the AER's acceptance of over 93% of our initial opex proposal. In relation to the costs that were not accepted in its Draft Decision, the AER indicated that our cyber security, council rates, and EPA opex step changes are likely to be prudent, but the AER was unable to determine the efficient costs at that time. The AER therefore invited us to provide further information, which we have done in this Revised Proposal.
- We have also identified and proposed several new step changes:
    - AEMO's participant fees;
    - Bushfire insurance premiums;
    - Land tax;
    - Mental health and wellbeing levy; and
    - Phasor Monitoring Units (PMUs).
- We presented our Revised Proposal opex step changes to consumers at our fifth collaboration workshop held on 23 July 2021. Our consumers understand that the majority of our opex step changes are driven by external factors and, therefore, outside of our control, and on this basis, they did not raise objections to the position we are presenting in this Revised Proposal subject to the AER's review of efficient costs.
- We have accepted several aspects of the AER's Draft Decision including:
    - Updating Deloitte Access Economics' (DAE) Wage Price Index (WPI) forecast;
    - Adjusting BIS Oxford Economics' WPI forecast to exclude superannuation guarantee increases past 30 June 2026; and
    - The approval of our 5-minute settlement and cloud step changes.
- As invited by the AER, we have provided more up-to-date information on other matters raised in the Draft Decision, including updating our labour growth escalators.

4.2 Chapter structure

The remainder of this chapter is structured as follows:

- Section 4.3 provides an overview of our forecast opex in our Initial Proposal, the AER's Draft Decision and our Revised Proposal;

- Section 4.4 provides a summary of our Revised Proposal's forecast opex;
- Section 4.5 provides a brief description of our forecasting approach;
- Section 4.6 describes how we have incorporated customer preferences and feedback into our forecast opex;
- Section 4.7considers our proposed base year expenditure;
- Section 4.8 outlines our proposed rate of change;
- Section 4.9 sets out our proposed step changes;
- Section 4.10 outlines our category specific forecasts;
- Section 4.11 provides a summary of our Revised Proposal opex forecast;
- Section 4.12 explains why our opex forecasts satisfy the NER requirements; and
- Section 4.13 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 Overview

4.3.1 Our Initial Proposal

We proposed a total opex forecast of $1,423 million[24] over the 2023-27 regulatory control period. This amount is 15% higher than our opex allowance for the 2017-22 regulatory period. However, if we exclude our step changes, easement land tax, growth assets and debt raising costs, our Initial Proposal opex forecast was $411 million or 15% lower than our approved controllable opex allowance for the 2017-22 regulatory control period.

In addition to providing a detailed explanation of our opex forecasts, our Initial Proposal noted that the base year opex (2020-21) would be updated in our Revised Proposal to reflect our actual expenditure for that year. We also explained that our forecast WPI would be updated to reflect the latest data.

4.3.2 Draft Decision

The AER approved a total opex allowance for the 2023-27 regulatory control period of $1,319 million of the $1,423 million in our Initial Proposal, representing a reduction of $104 million or 7%. This reduction primarily reflects the AER's position that insufficient evidence was provided at the Draft Decision stage to establish the efficient costs of our cyber security, council rates and EPA step changes.

4.3.3 Response to the AER's Draft Decision

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

- The choice of the base year opex and final year increment;
- Adjusting our escalation approach by pegging the conversion to real 2021-22 dollars to the March 2022 inflation figure;[25]

[24] This amount reflects our revised Initial Proposal opex forecast and includes easement land tax and debt raising costs.

[25] In our Initial Proposal, we escalated costs to 2021-22 dollars by pegging it to the April 2022 data, rather than March 2022. This was an error on our part which has been corrected in this Revised Proposal.

- DAE's updated WPI forecast;
- Adjusting BIS Oxford Economics' (BISOE) WPI forecast to exclude superannuation guarantee increases past 30 June 2026; and
- Re-calculating debt raising cost based on 8.0 basis points per annum.

We have re-proposed our cyber security, council rates and EPA opex step changes and, in support of these step changes, provided additional information to address the queries and concerns raised by the AER.

We have also been subject to a number of new and externally imposed costs, resulting in the need for several new opex step changes:

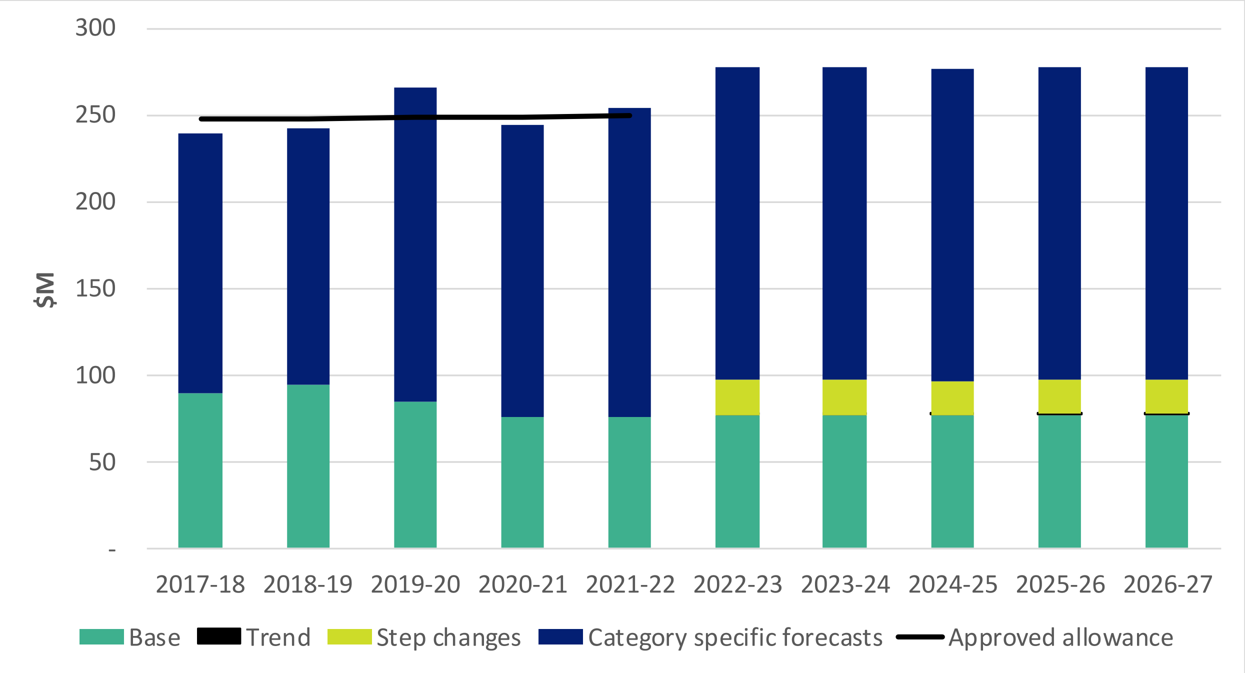
- AEMO's participant fees;
- Bushfire insurance premiums;
- Land tax;
- Mental health and wellbeing levy; and
- Phasor Monitoring Units (PMUs).

In addition to the above changes, we have also updated our BISOE's WPI forecast based on the latest data.

4.3.4 Revised Proposal

Having regard to the above changes, our opex forecast for the 2023-27 regulatory control period is $511 million, excluding easement land tax and debt raising costs. Further information on how this Revised Proposal has been built up is outlined below.

Figure 4-1: Actual and forecast operating expenditure ($M, real $2022)



Source: AusNet.

4.4 Summary of operating expenditure forecast

In 2020-21, we achieved significant efficiency savings of $24 million (real 2021-22), which being the base year of our base-step-trend forecasting approach, will lead to over $100 million less opex in the 2023-27 regulatory control period.

The application of the base-step-trend approach to our efficient base year opex produces a total opex forecast that is prudent and efficient, and consistent with the AER's usual approach and the expenditure objectives in the NER. With customers focusing on affordability, our proposed opex minimises costs while also meeting new regulatory obligations without compromising the reliability and safety of our network services.

Following extensive consultation with stakeholders, we are forecasting total opex of $1,387 million over the 2023-27 regulatory control period. The total annual opex forecast is set out below.

Table 4-1: Revised Proposal – Total opex forecasts ($M, real 2022)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Opex excl ELT and debt-raising cost	102.3	102.5	101.7	102.1	102.3	510.9
Easement land tax	173.6	173.6	173.6	173.6	173.6	868.1
Debt-raising cost	1.7	1.7	1.7	1.7	1.7	8.5
Total	277.6	277.8	277.0	277.4	277.6	1,387.4

Source: AusNet.

4.5 Forecasting approach

We continue to apply the forecasting approach used in our Initial Proposal, which is the revealed cost base-step-trend approach set out in the AER's Expenditure Forecast Assessment Guideline. This is an appropriate methodology to forecast opex requirements for an efficient transmission network service provider. We have, therefore, developed our revised opex forecast on this basis.

Our base year costs and the costs used to develop the opex forecast have been allocated in accordance with AusNet's approved Transmission Cost Allocation Methodology (CAM). AusNet's application of the CAM is audited annually during the regulatory accounts approval process.

Our opex forecast will be sufficient to maintain – but not improve – current service performance. That is, the current level of reliability risk, monetised using the value of customer reliability, will be maintained over the forthcoming period. This approach is consistent with AusNet's network planning framework and the design of the AER's Service Target Performance Incentive Scheme (STPIS).

4.6 Incorporating customer preferences and feedback

In the lead up to our Initial Proposal, we conducted an extensive customer satisfaction and research program and held Customer Advisory Panel meetings and deep dives with stakeholders on issues important to this review. As stated in our Initial Proposal, a key outcome of our stakeholder engagement has been our decision to absorb $4.3 million in opex over the 2023-27 regulatory control period, in relation to transformer oil issues and an increase in RIT-T processes undertaken. As reflected in this Revised Proposal, we maintain our commitment to absorbing these costs.

In its advice to the AER, the Consumer Challenge Panel (CCP23) said that the cyber security, council rates and EPA opex step changes are responses to external regulatory requirements and that its support for these step changes is conditional on the costs being efficient. With respect to the cyber security step change, the CCP23 also said that it would be important for consumers to be satisfied that these costs are allocated appropriately between our distribution and transmission networks. As a result, we have revisited our assumptions and reviewed our costs forecasts in relation to cyber security, which is discussed further in section 4.9.3 of this Revised Proposal.

We presented the following new opex step changes to consumers at our fifth collaboration workshop held on 23 July 2021:

- AEMO's participant fees;
- Bushfire insurance premiums;
- Land tax;
- Mental health and wellbeing levy; and
- Phasor Monitoring Units (PMUs).

Our consumers accepted that the majority of the new opex step changes are clearly driven by external factors and therefore outside of our control. On this basis, they did not raise objections to the position we are presenting in this Revised Proposal subject to the AER's review of efficient costs. As a result, we have included these step changes into our forecast of operating expenditure.

4.7 Base year expenditure

4.7.1 Our Initial Proposal

We nominated 2020-21 as the base year for forecasting opex, which involved using a placeholder forecast (as the 2020-21 actual was not available at the time of our Initial Proposal) and then adjusting for easement land tax.

To forecast base opex for the last year of the 2017-22 regulatory control period (2021-22), we took the base year opex for 2020-21, and then applied the forecast trend of our approved opex allowance.

Our approach resulted in a base opex of $82 million for the 2023-27 regulatory control period.

4.7.2 Draft Decision

The AER accepted that 2020-21 is an appropriate base year, as it represents an efficient starting point for the purpose of forecasting opex for the 2023-27 regulatory control period. The AER also accepted our adjustment for easement land tax, which is forecast on a category-specific basis.

The Draft Decision updated the 2020-21 base opex with the latest inflation data, to convert it to real 2021-22 dollars. Additionally, the AER adjusted our escalation approach by pegging the conversion to real 2021-22 dollars to the March 2022 inflation figure.[26] This resulted in the AER applying a modest $0.1 million adjustment to our proposed base year opex.

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

- When assessing opex Multilateral Partial Factor Productivity (MPFP), we perform relatively efficiently compared to our peers;
- A single major reliability incident was primarily responsible for the opex MPFP negative growth we experienced in 2019;

[26] In our Initial Proposal, we escalated costs to 2021-22 dollars by pegging it to the April 2022 data. This was an error on our part as we meant to escalate it to March 2022.

- When assessing Multilateral Total Factor Productivity (MTFP), we are grouped with the bottom performers over time. However, the AER relies more heavily on our opex MPFP rather than MTFP results when assessing the efficiency of our base year opex;
- Our partial performance indicator (PPI) results are mixed depending on the PPI, but the AER noted these results are to be expected given the characteristics of our network. We have the lowest total cost per end user, likely driven by our denser transmission network relative to other TNSPs. On the other hand, the AER considered our higher cost per kilometre of transmission circuit length to be reasonable, as we have the lowest circuit length amongst the 5 TNSPs.

4.7.3 Revised Proposal

We welcome the AER's acceptance of the efficiency of our base year 2020-21. However, as stated in our Initial Proposal, we have updated our 2020-21 reported opex to reflect actual expenditure. This results in a base year opex of $77 million for the 2023-27 regulatory control period, which is a material cost saving for customers compared to the estimate in our Initial Proposal.

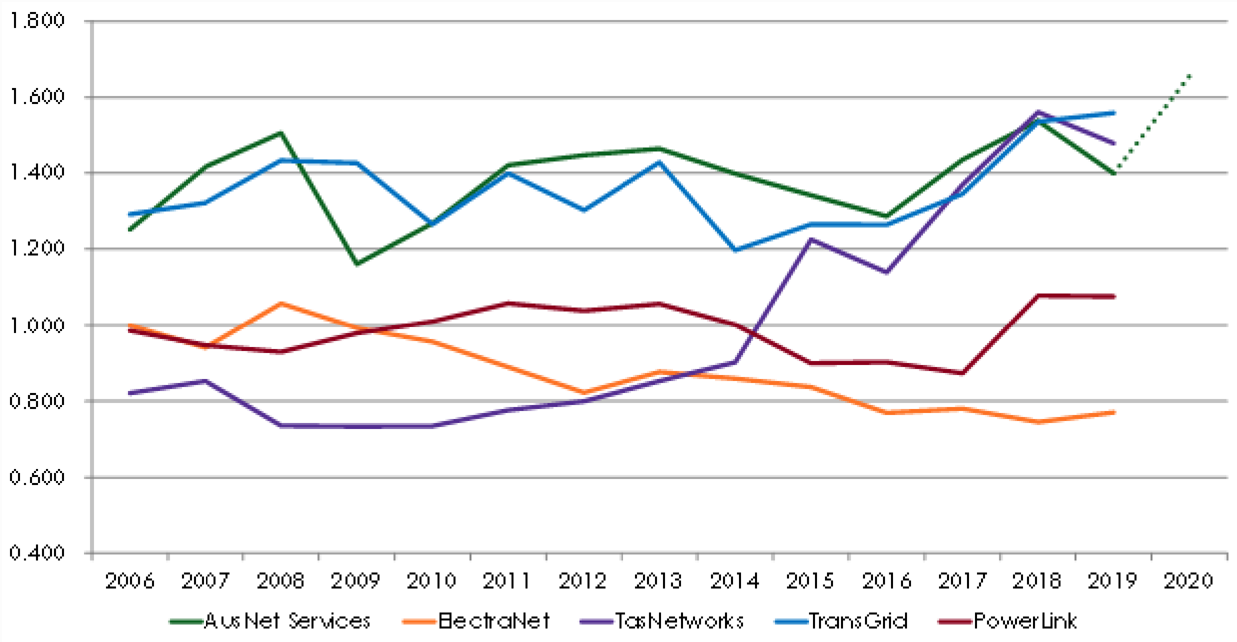
In our recent correspondence with the AER, the AER requested that we adjust the presentation of the base year calculation inputs to exclude NCIPAP opex on the basis that it's an excludable category. We agree that the exclusion of NCIPAP opex is appropriate as it is not accounted for in the opex allowance approved at last reset. We have therefore excluded the NCIPAP opex from the 2017-18 opex total (2017-18 is the only year in the current regulatory control period to be impacted by this adjustment). While consistent with the AER's framework, this does not impact the opex allowance as the 'base' component of the base-step-trend framework is dependent on reported base year (2020-21) opex, which does not include any NCIPAP expenditure.

As shown in the Figure 4-2, we have delivered improved opex productivity performance since 2006, but with a recent dip in 2019. This dip was driven by a significant network outage and the transition costs of implementing a new and more efficient maintenance arrangement.

Since the Draft Decision, the 2019-20 RINs have become publicly available, enabling us to calculate our indicative opex MPFP. Our calculation is based on reproducing the AER's existing methodology and using raw and publicly available RIN data combined with our internal forecasts. As such, our indicative opex MPFP is not definitive and exclude any adjustments that the AER may apply when undertaking their own benchmarking exercise. Our indicative results show a significant increase in opex productivity as the one off factors described above fall away, reinforcing AusNet's record of increasing opex productivity.

As outlined in our Initial Proposal, we have invested heavily in new technology to drive efficiencies in our inspection and maintenance practices. In 2019, new outsourced maintenance arrangements were put in place to leverage these improvements. These improvements are reflected in the regulatory accounts for the 2020-21 base year. As a result, the base year is materially below that forecast in the Initial Proposal, which passes on the benefits of these efficiencies to customers through a lower proposed opex allowance. Once projected forward, the revised base year results in a $26 million reduction in total operating costs to customers over the 2023-27 regulatory control period (when compared to our Initial Proposal).

Figure 4-2: Opex MPFP index, actual and forecast



Source: AusNet

4.8 Rate of change

4.8.1 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 and inputs and the AER's standard methodology available at that time. The inputs into the proposed rate of change, outlined in the table below, include:

- **Output growth**: The opex forecast for the upcoming regulatory control period did not account for system growth as these costs are initially handled outside of the revenue cap because of the division of TNSP functions in Victoria. Therefore, consistent with the AER's Final Decision for the current regulatory period, we have not included an output growth component in our opex forecast.
- **Real price growth**: We used the average of DAE's WPI forecast and BISOE's WPI forecast that was produced for our EDPR 2021-26 Revised Proposal to calculate our labour escalators. We forecast that our materials costs will increase at the same rate as CPI, i.e. no real change in non-labour costs for the forthcoming regulatory period.
- **Productivity growth**: Consistent with the AER's preferred methodology and the views of the Customer Advisory Panel, we included a forecast of productivity improvements of 0.31% per annum in our forecast opex. The forecast growth in productivity reflects the annual productivity growth rate that the transmission industry has been able to achieve over the long term and as such is a reasonable estimate of productivity growth over the 2023-27 regulatory control period.

Table 4-2: Initial Proposal - Rate of change

	2022-23	2023-24	2024-25	2025-26	2026-27
Output growth	0	0	0	0	0
Real price growth	0.30%	0.28%	0.48%	0.68%	0.68%
Productivity growth	0.31%	0.31%	0.31%	0.31%	0.31%
Rate of change, yoy	-0.01%	-0.03%	0.17%	0.37%	0.37%
Rate of change, cumulative	**-0.01%**	**-0.04%**	**0.13%**	**0.49%**	**0.86%**

Source: AusNet

4.8.2 Draft Decision

The AER noted that we broadly applied their standard approach to forecasting the rate of change. However, the AER did not accept the rate of change submitted in the Initial Proposal and instead proposed an alternative forecast, as detailed below.

4.8.2.1 Output growth

The AER accepted our output growth of 0% real increase.

4.8.2.2 Real price growth

The AER accepted the approach of averaging the DAE and BISOE's WPI forecasts. However, the AER:

- Updated DAE's WPI forecast published in April 2021 and applied the data series to March to align with AusNet's reset period; and
- Adjusted BISOE's WPI forecast to exclude superannuation guarantee increases past 30 June 2026, consistent with the legislated super guarantee percentage increases.

4.8.2.3 Productivity growth

The AER accepted our 0.31% p.a. productivity growth forecast.

4.8.2.4 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.

Table 4-3: Draft Decision - Rate of change

	2022-23	2023-24	2024-25	2025-26	2026-27
Output growth	0	0	0	0	0
Real price growth	0.50%	0.36%	0.38%	0.54%	0.53%
Productivity growth	0.31%	0.31%	0.31%	0.31%	0.31%
Rate of change, yoy	0.19%	0.04%	0.07%	0.23%	0.22%
Rate of change, cumulative	**0.19%**	**0.24%**	**0.31%**	**0.54%**	**0.75%**

Source: AER

4.8.3 Revised Proposal

4.8.3.1 Output growth

We accept the AER's draft decision on output growth, which adopted our Initial Proposal.

4.8.3.2 Real price growth

While we the accept the AER's Draft Decision on real price growth, we have updated our BISOE's WPI forecast for the latest data. See Appendix 4A for BISOE's report.

4.8.3.3 Productivity growth

We accept the AER's Draft Decision on productivity growth.

4.8.3.4 Overall rate of change

Given the changes identified above, we consider that the rate of change outlined in the table below is appropriate for this Revised Proposal.

Table 4-4: Revised Proposal - Rate of change

	2022-23	2023-24	2024-25	2025-26	2026-27
Output growth	0.00%	0.00%	0.00%	0.00%	0.00%
Real price growth	0.44%	0.30%	0.37%	0.58%	0.52%
Productivity growth	0.31%	0.31%	0.31%	0.31%	0.31%
Rate of change, yoy	0.13%	-0.01%	0.05%	0.27%	0.21%
Rate of change, cumulative	**0.13%**	**0.12%**	**0.17%**	**0.44%**	**0.66%**

Source: AusNet.

4.9 Step changes

4.9.1 Our Initial Proposal

We proposed the following step changes in our Initial Proposal:

- IT cloud – to migrate some applications to the cloud as a capex/opex trade-off.
- 5-minute settlement – to comply with the amended NER which require operational dispatch and financial settlements to align and occur at five-minute intervals (new regulatory obligation).
- Cyber security – to uplift our cyber security capability to the highest level of maturity of the Australian Energy Sector Cyber Security Framework (AESCSF), i.e. Maturity Indicator Level or MIL-3 (new regulatory obligation).
- Council rates – to address a change in our council rates calculation, which will significantly increase this cost category (new regulatory obligation).
- EPA – to comply with amendments to the *Environment Protection Amendment Act 2017,* which came into effect on 1 July 2021, and now requires AusNet to take a proactive approach to minimising the risks of harm to human health and the environment (new regulatory obligation).

In addition to the step changes above, we said that our Revised Proposal may:

- Introduce a step change as a result of changes to the transmission ring-fencing guideline. We explained that we would assess the need for this step change once the AER's review is more advanced.
- Adjust our opex forecasts for network support costs if a pass-through mechanism cannot be applied.

The table below shows the step changes we proposed in our Initial Proposal.

Table 4-5: Initial Proposal - Step changes ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
IT cloud	0.45	0.45	0.45	0.45	0.45	2.27
5-minute settlement	0.86	0.86	0.86	0.63	0.63	3.86
Cyber security	7.52	6.41	5.02	4.74	4.18	27.87
Council rates	14.30	14.30	14.30	14.30	14.30	71.48
EPA	0.56	0.60	0.64	0.68	0.72	3.19
Total	**23.69**	**22.62**	**21.27**	**20.80**	**20.29**	**108.67**

Source: AusNet.

It should be noted that our 5-minute settlement costs were subsequently revised down to a total of $0.9 million ($2021–22), as the $3.9 million ($2021–22) originally proposed had not removed the base year costs and therefore overstated the step change.

4.9.2 Draft Decision

The AER accepted our proposed step change for IT cloud and 5-minute settlement step change. The AER also indicated that while our cyber security, council rates, and EPA opex step changes are likely to be prudent, we should provide further information in our Revised Proposal to enable the AER to determine the efficient costs of each step change. As a consequence, the AER's Draft Decision only allowed a subset of our proposed step changes as shown in the table below.

Table 4-6: Draft Decision - Step changes ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
IT Cloud	0.45	0.45	0.45	0.45	0.45	2.27
5 minute settlement	0.17	0.17	0.17	0.17	0.17	0.87
Cyber Security	0.00	0.00	0.00	0.00	0.00	0.00
Council Rates	0.00	0.00	0.00	0.00	0.00	0.00
EPA	0.00	0.00	0.00	0.00	0.00	0.00
Total	**0.63**	**0.63**	**0.63**	**0.63**	**0.63**	**3.14**

Source: AER.

4.9.2.1 IT Cloud

The AER accepted our opex step change for IT cloud, as the capex/opex trade-off results in a forecast expenditure that is likely to be prudent and efficient. While the AER raised some possible areas of concern in relation to the cost estimates, it did not regard these issues as material. The AER concluded that the proposed step change meets the requirements for a capex/opex trade off and is the lowest cost option in order for AusNet to achieve its cloud migration program.

4.9.2.2 5-minute settlement

The AER accepted our opex step change for 5-minute settlement because the updated proposed costs are reasonable, and they consider AusNet's response to the new regulatory obligation to be prudent and efficient.

4.9.2.3 Cyber security

As already noted, the AER has requested further information to justify our proposed step change in relation to cyber security. Specifically, the AER queried how our proposed costs address the capability gap between our current level of cyber maturity and MIL 3 across each of the 11 domains under the Australian Energy Sector Cyber Security Framework.

4.9.2.4 Council rates

The AER's draft decision did not approve our proposed step change in relation to council rates because:

- The AER has been unable to establish a clear timeframe for introducing the change in the Victorian Valuer-General's methodology for council rates, which is driving the step change;
- The details of the new methodology are not available; and
- Given the above, it is not possible to determine the reasonableness of AusNet's estimated council rate costs over the 2023-27 regulatory control period.

4.9.2.5 EPA

While the AER considered it prudent for AusNet to comply with the new requirements of the Environmental Protection Act 2017 and agree that a step change may be required, an efficient cost could not be determined in its Draft Decision. Specifically, the AER made the following points:

- Some of the proposed activities and associated costs may be a part of AusNet's business as usual activities.
- It is not satisfied that our proposed actions and costs are an efficient response to the new regulatory obligation.
- AusNet's assumptions regarding the proposed level of monitoring and environmental risk assessment of sites may be disproportionate and not risk-based or evidence-based. For example, the need for annual groundwater testing is not based on a detailed assessment of groundwater contamination and the risk of harm to human or environmental health.
- The case for hiring noise testing contractors may not be warranted, as proactive asset inspections and maintenance work could include noise monitoring at no material increase in cost. In addition, the AER considered we did not demonstrate that noise pollution has been a concern and therefore that our proposed approach is proportionate, based on risk and historical evidence.

4.9.3 Revised Proposal

We accept the AER's Draft Decision for IT cloud, and 5-minute settlement.

In accordance with the Draft Decision, we have provided additional information on costs for cyber security, council rates and EPA and recalculated the step change amounts to reflect the latest information available. We have provided updated and new information to support our step changes which addresses the AER's concerns described in its Draft Decision. Additionally, several new cost imposts have arisen since submission of our Initial Proposal and we have included these as new step changes. These new costs relate to:

- AEMO's participant fees;
- Bushfire insurance premiums;
- Land tax;
- Mental health and wellbeing levy; and
- Phasor Monitoring Unit (PMU) opex.

We presented our Revised Proposal opex step changes to stakeholders and consumers at our fifth collaboration workshop held on 23 July 2021. Our stakeholder accepted that the majority of our opex step changes are driven by external factors and, therefore, outside of our control, and on this basis, they did not raise objections to the position we are presenting in this Revised Proposal, subject to the AER's review of efficient costs.

Table 4-7: Revised Proposal - Step changes ($M, real 2021-22)

Step change	Driver	Total over 5 years
Cloud	Capex/opex trade off	2.3
5-minute settlement	New regulatory obligation	0.9
Cyber Security	New regulatory obligation	28.2
Council Rates	New regulatory obligation	43.3
EPA	New regulatory obligation	2.0
AEMO's participant fees	New regulatory obligation	6.5
Bushfire insurance premiums	Material externally driven cost increase	7.6
Land tax	New regulatory obligation	3.3
Mental health and wellbeing levy	New regulatory obligation	3.6
PMU opex	New regulatory obligation	1.5
Total		**99.3**

Source: AusNet.

4.9.3.1 Cyber security

We welcome the AER's recognition that it is prudent for us to improve our cyber security capabilities and that a step change is required to fund additional investments to achieve this outcome. We accept that further information is required to demonstrate that the step change amount is prudent and efficient. We have therefore provided additional information in this Revised Proposal.

Our electricity transmission network is a part of Australia's national critical infrastructure as defined under the *Security of Critical Infrastructure Act 2018 (Cth)*. The safety and reliability of electricity supply is integral to Victorians' standard of living and Victorian businesses operations.

In recognition of the growing threats to cyber security, AEMO, in collaboration with industry and government stakeholders including the Australian Cyber Security Centre, Critical Infrastructure Centre, and the Cyber Security Industry Working Group, developed the Australian Energy Sector Cyber Security Framework (AESCSF).

In December 2020, the Minister for Home Affairs introduced the *Security Legislation Amendment (Critical Infrastructure) Bill 2020* to Parliament. The Bill seeks to expand the scope of the Act to include critical infrastructure entities in a wider range of sectors, as well as:

- Accelerating the need for AusNet to reach a Maturity Indicator Level (MIL) of MIL3 or an equivalent standard; and

- Having broader cost impacts on AusNet, as it will introduce new security measures across governance, physical security, supply chain and personnel.

As the Bill has not yet passed through Parliament, we have not proposed an opex step change to address the broader cost impacts noted above. However, we have proposed an allowance to reflect the efficient costs of increasing our Maturity Indicator Level from MIL2 to MIL3, as this is a known requirement that will be introduced. We expect that either the commencement of the Act or, more likely, the making of electricity industry-specific rules by the Minister under the Act, will trigger a regulatory change pass through event and we may need to submit a cost pass through application to fund these broader security requirements, and any more stringent cyber requirements beyond those anticipated in this Revised Proposal.

As invited to do so by the AER, we have provided additional information to demonstrate the prudency and efficiency of our opex step change:

- **Appendix 4B** provides detailed responses to the AER's concerns and questions, including our updated maturity level as at July 2021;
- **Appendix 4C** contains our updated gaps analysis and cost build-up mapped to the 11 domains. Specifically, it clearly states the inputs and assumptions that substantiate an updated cost estimate of $33.7 million. However, instead of proposing an updated step change of $33.7 million (which would be justified as this amount reflects a forecast of the prudent and efficient costs of MIL3 compliance), we have retained the estimate from our Initial Proposal of $28.2 million (see Table 4-8). That is, we have used the opportunity to update our estimate of prudent and efficient costs to validate the estimate included in our Initial Proposal.
- **Appendix 4J** provides PwC's independent letter of endorsement.
- **Appendix 4K** provides PwC's independent benchmarking report that concluded firms in a similar situation to us would require an additional [C-I-C] million to uplift their maturity from MIL2 to MIL3.[27] Importantly, both our Initial Proposal forecast ($28.2 million) and our updated estimate ($33.7 million) fall within PwC's acceptable range, which clearly demonstrates the efficiency of our proposed forecast.

The key drivers for increase in the overall step-change is from an increase in both requirements and costs for services and labour. However, the same systems and technology will be needed to uplift cyber security to and sustain MIL3 as embedded in the capex. Therefore, we have accepted the AER's Draft Decision on ICT cyber capex.

A cost increase due to the need to reach MIL3 meets the AER's definition of a forecast opex step change as it is an externally imposed change in the scope or scale of required opex driven by new compliance requirements. As noted above, the step change amount in this Revised Proposal is unchanged from our Initial Proposal, even though a higher cost of $33.7 million is justified as prudent and efficient on the basis of the additional information and analysis presented in this Revised Proposal.

Table 4-8: Revised Proposal - Cyber security step change ($M, real 2021-22)[28]

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Cyber security	7.6	6.5	5.1	4.8	4.2	28.2

Source: AusNet.

[27] Includes PwC's recommended contingency.

[28] These numbers reflect our Initial Proposal forecast, albeit updated for the latest inflation data.

4.9.3.2 Council rates

In response to the Draft Decision, we have undertaken further work to understand the likely impact and timing of the change in the valuation methodology on our council rates over the 2023-27 regulatory control period and completed a detailed assessment of the rateable Capital Improved Value (CIV), as explained below.

4.9.3.2.1 Background

As a result of a 2017 amendment to the *Valuation of Land Act 1960*, the Valuer General of Victoria (VGV) is now the sole valuation authority to conduct annual valuations of all rateable land in Victoria for council rating and taxing purposes. This change took effect in December 2017.

For the valuations as at 1 January 2018 and 2019, the VGV continued to use the council's historical approach, whereby the CIV is not reflective of the value of infrastructure improvements.

At the time of the Initial Proposal, the VGV advised that the valuations as at 1 January 2020 (for the rates notice for 2020-21) would be the first year that the VGV would have sufficient resources to conduct valuations for utility infrastructure sites, including for AusNet. However, following the submission of our Initial Proposal, the VGV revised its timelines as explained in the next section.

4.9.3.2.2 Current status

C-I-C

4.9.3.2.3 Relevance to the opex step change

In our Initial Proposal, we proposed a council rates step change of $71.5 million based on a total CIV of $3.3 billion. [C-I-C] [C-I-C]We have since recalculated the CIV based on the written down book value (WDBV) of our assets in the FAR as at May 2021, and only included assets that are fixed and serve the direct purpose of supplying and controlling the flow of electricity and associated activities. We have excluded assets that are removable, lines and easements, and locations where council rates would not be payable by the transmission network. The updated CIV is $1.9 billion.

C-I-C

Therefore, the CIV underpinning our step change estimate is the same as that will be submitted to the VGV for valuation purposes.

To ensure our step change satisfies the opex criteria, we have forecast our 2022-23 council rates by:

- Calculating and then applying the historical 5-year average rating factor and Fire Services Property Levy (FSPL) to the WDBV of each transmission site; and
- Netting off our base year (2020-21) actual council rates costs ($1.3 million).

We also used this methodology to forecast our council rates expenditure for the subsequent years of the 2023-27 regulatory control period. We consider the historical 5-year average rating factors to be appropriate because our analysis shows that they are not subject to major deviations from previous years. Additionally, we have assumed that the CIV will remain constant over the 2023-27 regulatory control period, as the value of new capex entering each site will be largely offset by depreciation. We consider that this assumption is reasonable on the basis that our forecast straight-line depreciation is broadly in line with our forecast capex.

Our supporting calculation spreadsheet provides a full breakdown of our cost build up.

A cost increase attributable to higher council rates meets the AER’s definition of a forecast opex step change as it is an exogenous change in the scope or scale of required opex driven by a new compliance requirement. The step change is allocated to the Taxes and Charges expenditure category. We have categorised this cost as recurrent expenditure, on the basis that it relates to an ongoing compliance requirement with periodic expenditure. It does not result in an increase in the output growth parameters nor does it deliver productivity benefits to us as it required solely to comply with our taxation obligations.

Table 4-9: Revised Proposal – Council rates step change ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Council rates	8.7	8.7	8.7	8.7	8.7	43.3

Source: AusNet.

4.9.3.3 Environmental Protection Act amendments

As requested by the Draft Decision, we have provided further information to explain why our proposed step change amount for the 2023-27 regulatory control period in relation to our EPA obligations is prudent and efficient.

After the publication of the AER’s Draft Decision, AER staff provided us with an opportunity to ask questions and clarify the issues outlined in the AER’s Draft Decision. We would like to extend our thanks to the AER opex team for their time. During this meeting, AER staff suggested that a formal industry benchmarking exercise could be one way to determine and potentially justify the efficiency of our costs.

We support the AERs' suggested application of a benchmarking approach. However, the level of understanding and implementation across the various affected industries and businesses is not sufficiently mature to support a robust benchmarking approach. For that reason, we have not adopted an industry benchmarking approach to justify our cost forecasts arising from the new EPA obligations. Instead, and more appropriately, we have taken a risk-based approach to estimate the EPA step change that reflects the costs of managing the specific risks facing our business.

We have also confirmed with various environmental consultants that our risk-based approach (described in Appendix 4N) is consistent with the applicable EPA standards and guidelines and the approaches adopted by other Victorian electricity networks.

In support of our EPA step change, we have provided:

- Appendix 4N, 4O, and 4P which contains further information that addresses the AER's Draft Decision concerns and questions; and
- A spreadsheet that contains all the assumptions and calculations that we used in our updated cost build-up.

Based on the information provided in Appendix 4N, we have estimated our EPA opex step change at $2.0 million over the 2023-27 regulatory control period (see Table 4-10 below). Our updated cost estimate is less than the estimate from our Initial Proposal because we have since refined our calculations. We are confident that our updated cost estimate reflects the prudent and efficient costs arising from the EPA obligations, in accordance with the NER requirements.

Table 4-10: Revised Proposal – EPA step change ($M, real 2021-22)

Item	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Internal resource	0.05	0.05	0.05	0.05	0.05	0.24
Preliminary investigations	0.16	0.26	0.21	0.15	0.10	0.88
Detailed site investigations & remediation	0.57	nil	nil	nil	nil	0.57
Annual groundwater and EMP updates	nil	0.03	0.06	0.10	0.13	0.31
Noise testing	0.02	0.02	0.02	0.02	0.02	0.12
Sub-total	**0.79**	**0.36**	**0.34**	**0.32**	**0.30**	**2.12**
FY21 actuals	0.03	0.03	0.03	0.03	0.03	0.14
Opex step change	**0.77**	**0.33**	**0.32**	**0.29**	**0.28**	**1.98**

Source: AusNet.

4.9.3.4 AEMO's participant fees

AEMO recently completed its Electricity Fee Structure Review, whereby it determined to reallocate a portion of its core NEM fees from market customers to TNSPs for the first time. This change will be applied from 2023-24 and will result in AEMO invoicing AusNet for an allocation of its core NEM fees on an annual basis.

Importantly, this change will not increase the end cost of electricity to customers, as the recovery of participant fees will simply be transferred from market customers (who have historically on-charged the cost to end use customers) to TNSPs, including AusNet.

The expenditure AusNet will incur in response to AEMO's change in approach satisfies the requirements for an opex step change because the expenditure is required to comply with a regulatory obligation or requirement associated with the provision of prescribed transmission services (NER 6A.6.6(a)(2)). In forecasting the step change, we used the latest data available and the parameters stated in AEMO's Final Determination, thereby ensuring that our forecast opex is efficient and corresponds with the costs that a prudent operator would require to achieve the opex objectives.

AEMO has not prepared a forecast of what each TNSP's likely contribution to participant fees will be, and TNSPs will not know their actual contribution until 15 February each year. It was therefore necessary for us to develop our own approach to forecasting these costs which, as discussed below, is robust.

We wrote to AEMO seeking a forecast to include in our Revised Proposal. AEMO verified that the assumptions and forecasting approach that we have adopted are appropriate. That is, it is appropriate to forecast AEMO's fees by applying a 1.7% allocation to AEMO's allocated NEM forecasts and then trending this forward based on historical increases.[29] However, we note that the 1.7% allocation to AusNet provided in AEMO's Final Determination is only indicative, as the actual allocation will be based on the latest energy consumption data available at the time the allocation is made. Additionally, AEMO has confirmed that the 1.7% allocation applied to the allocated NEM forecast captures AusNet's portion of AEMO's digital and regulatory compliance programs.

We note that Energy Networks Australia, on behalf of the TNSPs, recently submitted a rule change request to the AEMC, which would enable TNSPs to recover the actual costs of AEMO's participant fees. As the rule change process will not conclude for some time and there is no guarantee that the AEMC will make the rule as proposed (or, indeed, any rule at all), it is necessary that we include a step change for AEMO's participant fees in our Revised Proposal. If the rule change is made prior to the AER's Final Decision, we would ask the AER to disregard this opex step change. If the rule is made after the Final Decision, we will adjust our revenue recovery, either positively or negatively, to ensure that only the actual costs are recovered from customers.

We have included our opex step change calculation as a supporting documentation to this Chapter.

Our forecast in the table below ($6.5 million) is less the forecast that we presented at the fifth collaboration workshop ($10.7 million). This is due to AEMO clarifying the approach that we should adopt. AEMO stated that instead of applying the 1.7% allocation to the total NEM forecast, as we did to estimate the amount presented at the fifth collaboration workshop, it is more appropriate to apply the 1.7% allocation to the allocated NEM forecast, which is a lesser amount than the total NEM forecast.

Table 4-11: Revised Proposal – AEMO's participant fees step change ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
AEMO's participant fees	0.0	1.4	1.6	1.7	1.8	6.5

Source: AusNet.

4.9.3.5 Bushfire liability insurance premiums

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

[29] The allocation to AusNet and other TNSPs will commence 2023-24

The background for this step change is similar to our EDPR bushfire liability insurance premiums step change, in that the transmission network also operates 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, as a prudent network operator, ensure we have adequate insurance coverage. Otherwise there is a risk that the full costs arising from bushfire-related events will be borne by customers.

Our insurance premiums are determined for the business as a whole and then allocated to the individual networks in accordance with our cost allocation methodology. As such, the premium increases we allocate to our transmission network are determined by the share of the total premium allocated to the transmission business.

Significant changes are 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 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. From 2018-19 to 2019-20, our transmission network's bushfire insurance costs increased by 16%. Between 2019-20 and 2020-21, it increased by a further 26%. See the box below for more details.

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.

For example (bracketed amounts reflect pay out when known):

- Victoria – 2009 (AUD$4.4 billion), 2014 (AUD$10 million) and 2017
- Eastern Australia 2019-20 summer
- California – 2017 (US$20 billion), 2018 (US$24 billion), 2019 and 2020

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

I. Increasing premiums (PG&E required a $360 million premium for just $800 million of cover in 2018);
II. Reducing capacity; and/or
III. Withdrawing cover from the market.

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

The AER recently approved a bushfire insurance premium opex step change for our EDPR 2021-26. The AER approved this step change on the basis that their expert consultant, Taylor Fry, concluded that the AON forecasts are directionally consistent with Taylor Fry's expectations of future premiums, given its understanding of the prevailing market conditions, and can therefore be considered reasonable.

In its EDPR Final Decision, the AER stated the following:

> *We also consider that when the step change is added to the other elements of the opex forecast, the total opex amount meets the opex criteria based on the information we have available. In reaching this position we took into account stakeholder submissions summarised below.*

ElectraNet recently included an opex step change for bushfire insurance in its Preliminary Revenue Proposal with an indicative forecast of $6-8 million.[30] This example, along with the recent approvals for bushfire insurance premiums in the electricity distribution space (in Victoria), clearly demonstrates that the frequency and magnitude of bushfire insurance premium increases is a material issue for Australian electricity distribution and transmission network businesses: our circumstances are not unique.

For the reasons set out above, and importantly in the face of increasing bushfire liability insurance, we are proposing a step change to reflect the expected increases in our insurance costs during the 2023-27 regulatory control period. For the Revised Proposal, we have proposed a bushfire insurance premiums opex step change based on increasing our 2020-21 insurance premium by the same growth factor as the EDPR 2021-26. This is an appropriate growth factor as the AER approved the same amount for the bushfire insurance premiums step change in our EDPR 2021-26. Additionally, as stated earlier, our insurance premiums are determined for the business as a whole and then allocated to the individual networks. As such, the growth factor for the transmission network is likely to be similar to that approved for the distribution network.

However, as agreed with stakeholders at Collaboration Workshop 5, we plan on updating our forecast post-lodgement to reflect the outcome of our upcoming September 2021 insurance renewal process if it leads to a lower step change. If the renewal process reveals that a higher step change is appropriate, then we will retain the step change in this Revised Proposal and fund the additional cost through efficiency improvements.

A cost increase attributable to bushfire insurance premiums meets the AER's definition of a forecast opex step change as the expenditure is essential to ensuring we have adequate cover in the event of bushfires, particularly large and catastrophic bushfires (NER 6A.6.6(a)(3)(iv)) following a bushfire.

We have included our opex step change calculation as a supporting documentation to this Chapter.

Table 4-12: Revised Proposal – Bushfire insurance premiums step change ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Bushfire insurance premiums	0.7	1.1	1.5	1.9	2.4	7.6

Source: AusNet.

4.9.3.6 Land tax

The Victorian Budget 2021-22 recently announced that, from the 2022 land tax year, land tax rates will increase by:

- 0.25 percentage points (from 1.3% to 1.55%) when the taxable land value is between $1.8 million and $3 million; and
- 0.30 percentage points (from 2.25% to 2.55%) when the taxable land value is above $3 million.[31]

These changes were passed into law by the *State Taxation and Mental Health Acts Amendment Act 2021* (Vic)[32], which amended (amongst other Acts) the *Land Tax Act 2005* (Vic).[33]

[30] ElectraNet 2021, Preliminary Revenue Proposal 2024-2028, July, p. 37.

[31] https://www.sro.vic.gov.au/state-budget-2021-22-announcements

[32] Section 31.

[33] The changes appear as a new clause 1.5 in Schedule 1 to the *Land Tax Act 2005*.

We have calculated our step change as a result of increased land tax rates by:

- Trending forward our 2020-21 total taxable value for transmission (actual) by a historical growth rate of 1.7% per annum (the forecast taxable value);
- Calculating the land tax that would have been payable under the current tax rates by applying the current tax rates to the forecast taxable value (the current land tax payable);
- Calculating the land tax that would be payable under the new tax rates by applying the new tax rates to the forecast taxable value (the new land tax payable); and
- Taking the difference between the new land tax payable and the current land tax payable (the opex step change amount).

In calculating the opex step change, we have assumed that the new land tax rates will be applied to the taxable value that we own as at 31 December 2021.

A cost increase attributable to land tax meets the AER's definition of a forecast opex step change as it is a payment that we must make to comply with our regulatory obligations or requirements associated with the provision of prescribed transmission services (NER 6A.6.6(a)(2)). Our forecast costs in relation to this step change are efficient because they reflect the impact of the change in the taxable rates, as announced in the Victorian budget.

We have provided our supporting calculation as an attachment.

Table 4-13: Revised Proposal – Land tax step change ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Land tax	0.7	0.7	0.7	0.7	0.7	3.3

Source: AusNet.

4.9.3.7 Mental health and wellbeing surcharge

The Victorian Budget 2021-22 also introduced a mental health and wellbeing surcharge. The surcharge will take effect on 1 January 2022 and be imposed on businesses by way of a payroll tax surcharge on wages paid in Victoria. A rate of 0.5% will be levied on businesses with a national payroll above $10 million, with an additional 0.5% for businesses with a payroll above $100 million. Our national payroll is above $100 million, so a total rate of 1% will apply to us.

We have calculated a step change to reflect the costs of the mental health and wellbeing levy by:

- Applying the average of DAE and BISOE's WPI forecasts to our 2020-21 total taxable wages and payments made in Victoria (actual) to forecast our total taxable wages and payments over the 2023-27 regulatory control period; and
- Applying a mental health and wellbeing levy of 1% to our forecast taxable wages and payments.

The surcharge was passed into law by amendments made to the *Payroll Tax Act 2007* (Vic) by the *State Taxation and Mental Health Acts Amendment Act 2021* (Vic).[34]

An opex increase to fund the mental health and wellbeing surcharge meets the AER's definition of a forecast opex step change because the surcharge is a payment that we must make to comply with our regulatory obligations or requirements associated with the provision of prescribed transmission services (NER 6A.6.6(a)(2)). Our forecast costs are efficient because they are based on our actual 2020-21 total taxable wages and payments made in Victoria and calculated using formula specified in the Payroll Tax Act and the actual rate (1%) that will be applied to us.

[34] See Division 4 of Part 6 of the *State Taxation and Mental Health Acts Amendment Act 2021*.

We have provided our supporting calculation as an attachment.

Table 4-14: Revised Proposal - Mental health and wellbeing levy step change ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Mental health and wellbeing surcharge	0.7	0.7	0.7	0.7	0.7	3.6

Source: AusNet.

4.9.3.8 Phasor Monitoring Units (PMUs)

AEMO and AusNet have been in discussions regarding a notice (to be issued by AEMO under NER 4.11.1(d)) (**Notice**) that would require us to upgrade or replace 1 Phasor Monitoring Unit (PMU) and install new PMUs at 19 locations on the transmission network to allow AEMO to discharge its *market and power system security functions*. Specifically, the PMUs will allow AEMO to remotely monitor, identify and investigate current and potential power system security issues. This issue is also explained in Chapter 3 – Capital Expenditure (section 3.7.3.1).

AEMO has shared a draft of the Notice with us. The draft Notice sets out the following obligations on AusNet:

- The existing PMU at Rowville Terminal Station is to be upgraded, modified or replaced by 31 March 2022;
- New PMUs are to be installed at 11 high-priority locations by 31 March 2022; and
- New PMUs are to be installed at 8 medium-priority locations by 30 June 2022.
- The PMUs must comply with the performance specifications attached to the Notice and be subject to a maintenance standard that is in accordance with AEMO's Power System Data Communication Standard (section 6).

We have estimated that the on-going maintenance cost for these PMUs is $0.3 million per year. This estimate is based on the following:

- We need to maintain a total of 21 PMUs made up of the existing PMU at Rowville Terminal Station, 19 new PMUs, plus one extra since Loy Yang power station (one of the 19 locations) has two separate switchyards (several hundred meters apart) and each switchyard requires its own separate PMU.
- Maintaining 2 Phasor Data Concentrators (PDCs). The maintenance of PDCs is necessary and related to the operation of PMUs. Data collected by the PMUs will be transmitted to the PDCs, which provide redundancy (as required by AEMO's Power System Data Communication Standard) for onward data transmission to AEMO Sydney, AEMO Brisbane and AusNet engineering access.
- Carrying our planned maintenance at the following intervals:
    - 21 units of PMU with maintenance intervals of 6 years.
    - 2 units of PDC with maintenance intervals of 6 months.
    - Hard disk replacement for 2 units of PDC at intervals of 5 years.
    - 2 units of router/firewall with maintenance interval of 1 year.
    - 14 units of switches with maintenance interval of 1 year.

- At 2 locations (Kerang Terminal Station and Alcoa Portland), we have assumed a fixed rental and services Telstra charge of $6,000 per month.[35] The rental of Telstra's communication links provides the redundancy required by AEMO's Power System Data Communication Standard.

AEMO’s final Notice will be issued to us under clause 4.11.1(d) of the NER, and we are required to comply with it within 120 business days or such other date specified in the notice by clause 4.11.1(e). Failure to do so exposes AusNet to a potential civil penalty. We expect the Notice to be issued in the coming months.

The cost of complying with AEMO’s forthcoming Notice meets the AER’s definition of a forecast opex step change as it is an operating expenditure that we must incur to comply with our regulatory obligations or requirements associated with the provision of prescribed transmission services (NER 6A.6.6(a)(2)). Given the specificity and the prescriptive nature of the obligations imposed by the draft Notice, we expect the final Notice will provide little or no scope for AusNet to exercise any discretion in delivering the project. This may affect our ability to select the least cost opex options. However, AusNet, as a prudent network operator, will use its best endeavours to ensure that opex is kept as low as possible.

We have provided our supporting calculation as an attachment.

Table 4-15: Revised Proposal – PMUs step change ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
PMUs opex	0.30	0.30	0.30	0.30	0.30	1.50

Source: AusNet.

4.9.3.9 Network Support

Our Initial Proposal noted that we may include a step change in our Revised Proposal for expected network support costs. This is the cost of network support services required to enable system access to deliver capital works and maintenance.

As explained in Chapter 3 (Capital Expenditure), cost recovery mechanisms for network support were a key part of our stakeholder engagement program. Consistent with stakeholder preferences, we intend to utilise the Network Support Pass Through to recover efficient network support costs in the next regulatory period, rather than an opex step change. More information on our proposed use of the Network Support Pass Through is in Chapter 10 (Cost Pass Through).

4.9.3.10 Transmission ring-fencing

Our Initial Proposal noted that we may include a step change in our Revised Proposal for changes to transmission ring-fencing guideline, as foreshadowed in the AER Discussion Paper released in November 2019.

Due to the COVID-19 pandemic, this review was placed on hold. However, the AER has resumed this review and at the time of this Revised Proposal submission, it is our understanding that the Draft Guideline will be published in September 2021, with consultation scheduled for October 2021, and submissions on the Draft Guideline due 6 weeks after publication. The publication date for the Final Guideline has not been confirmed.

As the Draft Guideline is not yet available, we are unable to estimate the costs of complying with potential changes to existing transmission ring-fencing arrangements and, as a result, we have not proposed a step change. However, we will assess the need for this step change, post-lodgement, once the AER’s Draft Guideline becomes available.

[35] This unit rate assumption was provided by Telstra by way of a quote.

4.10 Category specific forecasts

4.10.1 Our Initial Proposal

In our Initial Proposal, we proposed the following category specific forecasts:

- **Easement land tax:** Our easement land tax forecast was based on the assumption that the tax will increase at the same rate as CPI throughout the 2023-27 regulatory control period. Over the period, any positive or negative variation between the actual tax paid and the forecast approved by the AER will be recovered from, or reimbursed to, customers via the pass-through mechanism outlined in NER 6A.7.3. This arrangement ensures that AusNet will only recover the actual tax paid over the period.
- **Growth assets:** Growth assets, or augmentations to the transmission network (formerly referred to as Group 3 roll-in assets), are non-contestable capital expenditure works that AusNet undertakes at the direction of AEMO in its capacity as the Victorian transmission network planner or the Victorian distribution businesses as the planners of transmission connection assets. At each revenue reset, the growth assets constructed since the last revenue reset are rolled in to the RAB for the first time. As a consequence, the operating expenditure allowance must increase to manage the higher volume of assets that must be inspected, condition assessed and maintained. We forecast the opex related to these growth assets in accordance with current recovery rates specified under existing contracts with AEMO and Victorian distribution businesses. In a small number of cases where these recovery rates are not available (unknown projects), we applied the average percentage of known growth assets opex as compared to the total roll in amount (equalling 1.4%) to the unknown projects to determine the associated opex.
- **Debt-raising costs:** Our debt-raising costs were forecast by applying 8.50 basis points per annum to the debt raised, in accordance with the AER's determination for SA Power Networks.

The table below summarises our category specific forecasts in our Initial Proposal.

Table 4-16: Initial Proposal – Category specific forecasts ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Easement land tax[36]	173.61	173.61	173.61	173.61	173.61	868.05
Growth assets	5.23	5.23	5.23	5.23	5.23	26.13
Debt-raising costs	1.74	1.74	1.74	1.75	1.73	8.70
Total	**180.58**	**180.57**	**180.58**	**180.58**	**180.56**	**902.88**

Source: AusNet.

4.10.2 Draft Decision

The AER accepted our easement land tax and growth asset forecasts. While the AER accepted our methodology for forecasting debt-raising costs, it applied a factor of 8.0 basis points per annum to the debt raised (instead of 8.5 bppa).

[36] This reflects our updated Easement Land Tax forecast based on our FY22 actuals. We provided this information to the AER following our Revenue Proposal.

Table 4-17: Draft Decision – Category specific forecasts ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Easement land tax[37]	173.61	173.61	173.61	173.61	173.61	868.05
Growth assets	5.23	5.23	5.23	5.23	5.23	26.13
Debt-raising costs	1.70	1.69	1.70	1.70	1.68	8.48
Total	**180.54**	**180.53**	**180.54**	**180.54**	**180.52**	**902.66**

Source: AER.

4.10.3 Revised Proposal

We accept the AER's Draft Decision on the easement land tax and debt-raising costs. While we welcome the AER's Draft Decision on growth assets opex, we have updated the 2023-27 opex forecast to reflect the minor adjustments to the roll-in value of growth assets discussed in Chapter 5. Our category specific forecasts for the 2023-27 regulatory control period are shown in the table below.

Table 4-18: Revised Proposal – Category specific forecasts ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Easement land tax[38]	173.6	173.6	173.6	173.6	173.6	868.1
Growth assets	5.2	5.2	5.2	5.2	5.2	25.8
Debt-raising costs	1.7	1.7	1.7	1.7	1.7	8.5
Total	**180.5**	**180.5**	**180.5**	**180.5**	**180.5**	**902.4**

Source: AusNet.

4.11 Total opex forecast

Our revised total opex forecast for the 2023-27 regulatory control period is $1,379 million excluding debt raising costs, or $1,387 million including debt raising cost. This is $35.4 million lower than the opex forecast in the Initial Proposal.

[37] This reflects our updated Easement Land Tax forecast based on our FY22 actuals. We provided this information to the AER following our Revenue Proposal.

[38] This reflects our updated Easement Land Tax forecast based on our FY22 actuals. We provided this information to the AER following our Revenue Proposal.

Table 4-19: Revised Proposal – Total opex forecasts ($M, nominal)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Base opex	76.9	76.9	76.9	76.9	76.9	384.6
Real price change	0.3	0.6	0.9	1.3	1.7	4.8
Output growth	-	-	-	-	-	-
Productivity change	-0.2	-0.5	-0.7	-1.0	-1.2	-3.6
Step changes	20.1	20.3	19.4	19.7	19.7	99.3
Category specific forecasts	178.8	178.8	178.8	178.8	178.8	893.9
Total excluding debt raising cost	275.9	276.1	275.3	275.7	275.9	1,379.0
Debt raising cost	1.7	1.7	1.7	1.7	1.7	8.5
Total	**277.6**	**277.8**	**277.0**	**277.4**	**277.6**	**1,387.4**

Source: AusNet.

4.12 Why our opex forecasts satisfy the NER requirements

As explained throughout this Chapter, we consider each of the forecast opex categories complies with the operating expenditure criteria. Therefore, we consider the total opex forecast for the 2023-27 regulatory control period must necessarily also comply with the NER requirements because the forecast reasonably reflects each of the operating expenditure criteria, namely:

- The efficient costs of achieving the operating expenditure objectives (which are set out in NER 6A.6.6(a));
- The costs that a prudent operator would require to achieve the operating expenditure objectives; and
- A realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.

As such, the AER's obligation to make decisions that are consistent with the achievement of the NEO as they pertain to a prudent transmission network service provider are satisfied by its acceptance of the opex forecasts presented in this chapter.

In addition, as noted in section 4.5, the cost inputs used to develop the opex forecast have, where required, been allocated to our transmission business in accordance with AusNet's approved Transmission CAM.

In satisfaction of NER S6A.1.2(7), which requires a Revenue Proposal to contain actual opex for the first three regulatory years of the current regulatory control period, and expected opex for the last two regulatory years of that regulatory control period categorised in the same way as the opex forecast, we provide the following table.

Table 4-20: Actual and expected opex ($M, real 2021-22)

	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	Service categories
Opex excluding ELT and debt-raising cost	89.3	88.3	87.8	76.4	74.2	102.3	102.5	101.7	102.1	102.3	All categories*
Rebates under the Availability Incentive Scheme	0.1	0.2	0.3								Shared network services
Easement land tax	147.1	144.8	178.0	166.0	175.4	173.6	173.6	173.6	173.6	173.6	Shared network services
Merits review opex	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	All categories*
Movements in provisions	-2.1	-2.1	-2.0	-2.0	-2.0	0.0	0.0	0.0	0.0	0.0	All categories*
NCIPAP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	All categories*
Total	**234.5**	**231.3**	**264.1**	**240.3**	**247.7**	**275.9**	**276.1**	**275.3**	**275.7**	**275.9**	

Source: AusNet.

*Service categories involve three categories: entry services, exist services and shared network services.

Note: Movement in provisions are not forecast. Where available actuals have been used for the current period, 2021-22 forecast is based on approved budget.

4.13 Supporting documentation

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

- Opex model;
- Appendix 4A - BISOE's labour cost escalation forecasts to FY2027;
- Appendix 4B - AusNet's cyber security response to the AER's Draft Decision;
- Appendix 4C - AusNet's updated cyber security cost forecast and gaps/FTE analysis;
- Appendix 4D - AusNet's cyber security enterprise architecture;
- Appendices 4E to I - Vendor quotes to support the cyber security opex step change;
- Appendix 4J - PwC's letter of endorsement to support the cyber security opex step change;
- Appendix 4K - PwC's cyber security benchmarking report;
- Appendix 4L - PwC's under the lens (the energy sector) report;
- Appendix 4M - VGV's advice to support the council rates opex step change; and
- Appendix 4N - AusNet's EPA response to the AER's Draft Decision.

Several other documents, including our calculation spreadsheets, have been provided to support our updated opex forecast.

5 Regulatory asset base

5.1 Key points

The key points in this chapter are:

- Our Initial Proposal adopted the standard regulatory approach to setting the RAB, which was accepted by the AER in its Draft Decision. As explained in our Initial Proposal, we anticipated that updates would be made to our RAB to reflect the latest data, such as our actual capex for 2020-21 and inflation.
- The AER's Draft Decision made a number of relatively minor adjustments to our opening RAB for the latest data and to correct minor cell referencing errors. The AER also made adjustments to our closing RAB to reflect its Draft Decision in relation to forecast capex, depreciation and inflation. The AER also applied version 5 of its PTRM, which was not available at the time of lodging our Initial Proposal.
- In this Revised Proposal, we accept the AER's approach to setting the opening RAB and the adjustments that reflect our actual data. However, the treatment of capitalised leases should be amended to be consistent with the approach in the AER's final decision for the AusNet Services Electricity Distribution opening RAB (2021-26).
- We have updated the calculated roll-in value of Growth Assets to reflect the latest available data, resulting in a 1.9% reduction compared to the Draft Decision.
- We accept the application of version 5 of the PTRM to establish the closing RAB value as at 31 March 2027.
- Our RAB calculations differ from those presented in the Draft Decision by applying the latest available data and forecast capex, depreciation and inflation as explained in this Revised Proposal. As a result of this updated information:
    - Our opening partially as-incurred RAB is $3,575.7 million (nominal) as at 1 April 2022, which is $29.8 million (nominal) or 0.8% higher than the Draft Decision; and
    - Our closing partially as-incurred RAB is $3,946.7 million (nominal) as at 31 March 2027, which is $155.7 million (nominal) or 4.1% higher than the Draft Decision.

5.2 Chapter structure

The remainder of this chapter is structured as follows:

- Section 5.3 explains our opening RAB and the components of this calculation;
- Section 5.4 sets out the calculation for the forecast RAB over the 2023-27 regulatory control period and our forecast closing RAB as at 31 March 2027; and
- Section 5.5 lists the relevant supporting documents.

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

5.3 Opening RAB

5.3.1 Our Initial Proposal

In our Initial Proposal, we calculated an opening RAB of $3,581.9 million as at 1 April 2022. Our Initial Proposal explained that this calculation requires the following steps[39]:

- Adopt the approved opening RAB as at 1 April 2017;
- Add actual and forecast capex (net of disposals) for the 2017-22 regulatory control period;
- Deduct forecast straight-line depreciation for the 2017-22 regulatory period;
- Add RAB indexation for the 2017-22 regulatory period;
- Adjust for the difference between actual and forecast capex (net of disposals) in 2016-17; and
- Add in the final year adjustments, which primarily relate to the roll-in of growth assets.

Our Initial Proposal explained that the opening RAB would be updated in our Revised Proposal to reflect our actual capex for 2020-21 and the latest inflation forecast.

5.3.2 Draft Decision

The AER largely accepted our proposed method for calculating the opening RAB, but made the following adjustments:

- Corrected a number of minor cell referencing errors in relation to the inputs for the final year adjustments, including the residual values of the proposed capitalised leases as at 31 March 2022 (being the end of current regulatory control period);
- Updated the proposed value of the growth assets to be rolled into the RAB, based on information that we provided following the lodgment of the Initial Proposal; and
- Updated inputs to the Roll Forward Model (RFM) to reflect the latest available information, including the actual inflation for 2020–21, the updated nominal WACC and straight-line depreciation inputs.

As a result, the Draft Decision calculated an opening RAB value of $3,545.9 million ($nominal) as at 1 April 2022, which is $35.9 million or 1.0% lower than our Initial Proposal.

In addition to the updates described above, the AER proposed a different treatment of capitalised leases, which entered the RAB for the first time as a result of a change to the lease accounting standard applicable to annual reporting periods on or after 1 January 2019. The AER concluded that capitalised leases should be addressed through the final year adjustments, rather than allocating capex associated with capitalised leases in the years in which they are incurred in the standard RFM inputs as we had proposed. The annual capex values were, however, included in the AER's Draft Decision CESS model calculation.

5.3.3 Response to the Draft Decision

Our Initial Proposal applied the standard regulatory approach to setting the opening RAB, which has been accepted in the Draft Decision. The changes proposed by the AER principally relate to the adoption of updated information, which are uncontroversial and have been accepted in this Revised Proposal.

[39] NER S6A.2.1(f).

We also accept the AER's changes to our final year adjustments, including the AER's preferred treatment of capitalised leases. However, a forgone return on capital adjustment should be added to the value of lease assets rolling into RAB as at 31 March 2022. Our proposed adjustment is consistent with the approach used by the AER in setting the closing value of leases in the Depreciation tracking model in its recent Electricity Distribution Price Review (EDPR) for AusNet Electricity Services[40]. This adjustment will ensure that the capital expenditure incentive framework is properly applied, given there is a lag between the year capitalised leases are reported (and a CESS penalty incurred) and the point at which a return on and of is received for these assets.

We expressed our concerns to the AER about its the treatment of capitalised leases during the EDPR 2021-26 both in our response to an information request[41] and in our Revised Proposal[42]. We noted an apparent disconnect between the AER's position and section 4.4.1 of the Capital Expenditure Incentive Guideline, which deals with the circumstances where an NSP changes its capitalisation policy (within period) 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)*".[43]

We suggested the AER consider addressing this issue in a future review of its Capital Expenditure Incentive Guideline to be clear about whether the timing of unanticipated capex (incurred within a period) rolling into RAB should match the timing of this capex for assessment under the AER's CESS.

The need for further minor updates have been identified since the Draft Decision, which have been reflected in the calculation of the opening RAB in this Revised Proposal. These include:

- Minor changes to the closing asset values and remaining lives for capitalised leases in the final year asset adjustments, in addition to the forgone return on capital adjustments;
- Updating the placeholder net capex forecasts for 2020-21 with actuals based on information sourced from the annual regulatory accounts (as-incurred, as-commissioned basis);
- Updating our placeholder net capex forecast for 2021-22 using updated information (as-incurred, as-commissioned basis); and
- Updating the calculated roll-in value of Growth Assets as part of final year adjustments to reflect updates to quarterly CPI inputs and minor changes to contract values.

5.3.4 Revised Proposal

In accordance with the calculation in Table 5-1, our opening RAB as at 1 April 2022 is $3,575.7 million.

[40] AER - Final Decision - AusNet Services distribution determination- 2021–26 - Depreciation model - April 2021

[41] Response to AER information request IR#019B – 'ASD - IR019B follow up request Q1 - 20200611 – Public.pdf', p.1.

[42] AusNet Services - Revised Regulatory Proposal – 2021-26 – December 2020 – PUBLIC, p.108.

[43] AER capital expenditure incentive guideline – November 2013.pdf, p.18.

Table 5-1: Regulatory asset base roll forward, as incurred, to 1 April 2022 ($M, nominal)

	2017-18	2018-19	2019-20	2020-21	2021-22
Opening RAB (1 April)	3,170.0	3,188.1	3,221.4	3,249.2	3,229.9
Capex (net of disposals)	131.0	147.6	156.5	144.3	137.8
Forecast straight-line depreciation	-170.9	-174.3	-182.7	-186.1	-167.9
RAB indexation	58.0	60.1	53.9	22.5	96.4
Difference between actual and forecast capex from 2016-17	0.0	0.0	0.0	0.0	-45.5
Forgone return on difference	0.0	0.0	0.0	0.0	-12.9
Final year adjustments[44]	0.0	0.0	0.0	0.0	338.0
Closing RAB (31 March)	**3,188.1**	**3,221.4**	**3,249.2**	**3,229.9**	**3,575.7**

Source: AusNet

The sections below explain the above calculation in more detail.

5.3.4.1 Capex (net of disposals)

The RAB roll forward calculation requires a combination of actual and forecast capex (net of disposals) as shown in Table 5-2. Actual costs and disposals information reconcile with the nominal values reported in the Annual Regulatory Accounts.

Table 5-2: Proposed capex net of asset disposals, as incurred ($M, nominal)

	2017-18	2018-19	2019-20	2020-21	2021-22
Gross capex	133.7	144.5	155.3	141.7	133.9
Disposals	-6.0	-0.6	-2.6	-0.1	-0.2
Capex net of disposals	127.7	143.8	152.7	141.6	133.7
Net capex recognised in RAB	**131.0**	**147.6**	**156.5**	**144.3**	**137.8**

Source: AusNet

5.3.4.2 Depreciation and RAB indexation

We have sourced the straight-line depreciation forecasts (in 2016-17 dollars) by asset class from the most recent PTRM for the current regulatory control period. The PTRM containing these forecasts includes the annual cost of debt updates and our approved expenditure allowances for the January 2020 transmission tower collapse cost pass-through event. We input these forecasts into the AER's RFM and adjusted them for actual and forecast inflation. The table below shows the calculation.

Table 5-3: Forecast straight-line depreciation ($M, nominal)

	2017-18	2018-19	2019-20	2020-21	2021-22
Forecast straight-line depreciation (real $2016-17)	168.7	169.0	173.8	174.2	156.0
Actual / forecast inflation	2.2	5.3	8.9	11.9	11.9
Forecast straight-line depreciation	**170.9**	**174.3**	**182.7**	**186.1**	**167.9**

[44] The final year adjustments primarily reflect the roll-in of growth assets and capitalised leases.

Source: AusNet

Clause 6A.6.1(e)(3) of the NER requires that the RAB be adjusted for actual outturn inflation in accordance with the method that was used in our previous regulatory determination. We have therefore used actual and forecast CPI to escalate the RAB over the current regulatory control period in accordance with the approach outlined in the AER's determination for this period.

The AER's final decision for the current regulatory control period defined a change in CPI to be the annual percentage change in the ABS CPI all groups, weighted average of eight capital cities from the September quarter in year t–2 to the September quarter in year t–1.[45] See Table 5-4 for the CPI values we used to escalate the RAB.

Table 5-4: Actual and forecast inflation

	2017-18	2018-19	2019-20	2020-21	2021-22
Partially lagged inflation	1.83%	1.89%	1.67%	0.69%	2.98%

Source: AusNet

To perform the roll forward calculation we applied the partially lagged inflation approach for both opening RAB indexation and converting 2016-17 dollars to nominal values.[46] Table 5-5 contains our proposed RAB indexation using the partially lagged inflation approach.

Table 5-5: RAB indexation ($M, nominal)

	2017-18	2018-19	2019-20	2020-21	2021-22
RAB indexation	58.0	60.1	53.9	22.5	96.4

Source: AusNet

Using the above information, our proposed regulatory depreciation amounts for the current period are those set out in Table 5-6.

Table 5-6: Regulatory depreciation ($M, nominal)

	2017-18	2018-19	2019-20	2020-21	2021-22
Forecast straight-line depreciation	170.9	174.3	182.7	186.1	167.9
RAB indexation	-58.0	-60.1	-53.9	-22.5	-96.4
Regulatory depreciation	**113.0**	**114.2**	**128.7**	**163.6**	**71.5**

Source: AusNet

5.3.4.3 Final year adjustments

We have accepted the AER's changes to final year adjustments and have further updated the adjustments to reflect the latest available information, as shown in Table 5-7 below.

We have included an updated roll-in value of Growth Assets in this Revised Proposal of $291.5 million (nominal), as at 31 March 2022, which is $6.0 million or 2.0% lower compared to the Draft Decision. This reduction is due to:

- Updates to the CPI tables contained in the Growth Assets calculation model reflecting actual ABS quarterly CPI data up to and including the June 2021 quarter; and

[45] AER 2017, *AusNet Services transmission determination 2017-22*, April, pp. 6, 8.

[46] The partially lagged inflation approach uses inflation lagged by one year for some elements within the RFM.

- Revisions to the contract values (in $real terms) and in-service dates for twelve completed projects to reflect finalised costs, producing a combined reduction of $1.4 million (before escalation adjustments)

We have attached a copy of the supporting confidential model reflecting these changes as part of this Revised Proposal.

In addition, we made some minor changes to the calculated closing asset values for capitalised leases and remaining lives based on the latest available actual data for 2020-21. We have also calculated the foregone return on capital adjustment for these lease assets consistent with the approach used in the recent EDPR 2021-2026 Final Decision[47].

Table 5-7: Final year adjustments

Asset class	RAB (As Incurred) ($M, nominal)	RAB (As Commissioned) ($M, nominal)	Remaining asset life of adjustments to RAB (years)
Secondary	25.3	25.3	10.1
Switchgear	53.3	53.3	41.1
Transformers	60.0	60.0	39.7
Reactive	13.4	13.4	34.7
Towers and Conductor	-41.0	-41.0	23.8
Establishment	43.7	43.7	39.6
Communications	0.4	0.4	9.7
other (non-network)	2.9	2.9	4.2
Inventory Adjustment (Other non-network)	-1.9	-	-
Insulators - Already Decommissioned	8.4	8.4	1.0
Insulators - Decommission 2023-2027	2.9	2.9	5.0
Insulators	103.5	103.5	13.4
Instrument Transformers - Already Decommissioned	13.1	13.1	1.0
Instrument Transformers - Decommission 2023-2027	4.4	4.4	5.0
Instrument Transformers	-	-	-
Lease L&B 2019-20 < 20 years rem life	20.5	20.5	7.7
Lease L&B 2019-20 > 20 years rem life	22.4	22.4	46.0
Lease L&B 2020-21	6.7	6.7	6.0
Total	**338.0**	**339.9**	

Source: AusNet

47 AER - Final Decision - AusNet Services distribution determination- 2021–26 - Depreciation model - April 2021

5.4 Forecast RAB over the 2023-27 regulatory control period

5.4.1 Our Initial Proposal

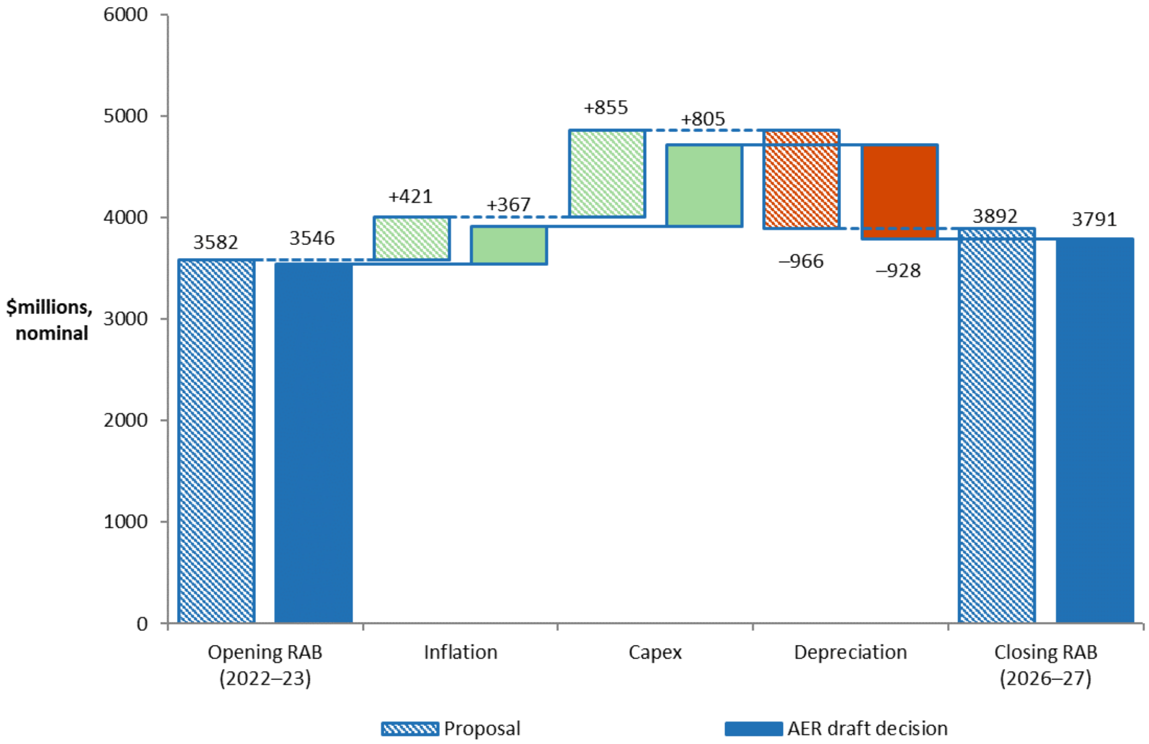
In our Initial Proposal, we rolled forward the RAB over the 2023-27 regulatory control period to reflect our capex forecast, straight-line depreciation forecast and the indexation of the RAB. We applied the AER's RFM and PTRM (Version 4) to calculate a closing value for the RAB of $3,892.2 million (nominal) as at 31 March 2027.

5.4.2 Draft Decision

In its Draft Decision, the AER amended our forecast RAB to reflect other relevant components of its decision, including forecast capex, inflation and depreciation. As a consequence, the AER calculated the closing RAB to be $3,791.0 million (nominal) as at 31 March 2027, which represents a reduction of $101.2 million (or 2.6 per cent) compared to our Initial Proposal. In calculating the forecast RAB, the AER applied version 5 of the PTRM, which was not available to us at the time we submitted our Initial Proposal.

The figure below shows the differences between our Initial Proposal and the AER's Draft Decision.

Figure 5-1: Key drivers of changes in the closing RAB ($M, nominal)[48]



Source: AER

5.4.3 Response to the Draft Decision

As noted in the Draft Decision, the calculation of the forecast RAB reflects other aspects of the AER's decision. Similarly, our Revised Proposal in relation to the forecast RAB reflects our updated forecasts for capex, inflation and depreciation as presented in this Revised Proposal. In

48 AER, Draft Decision, Key drivers of changes in the RAB, Attachment 2, Regulatory Asset Base, June 2021, page 20.

addition to these changes, we have also applied the AER's version 5 of the PTRM in accordance with the Draft Decision.

In our Initial Proposal we did not propose the depreciation approach we intended to use to roll forward the RAB to the commencement of the 2027–32 regulatory control period. We accept the AER's position in its Draft Decision that the forecast depreciation approach should be used to establish the opening RAB as at 1 April 2027. This is consistent with the depreciation approach that we have applied in the current regulatory control period in combination with the AER's CESS incentive scheme.

5.4.4 Revised Proposal

Our forecast RAB for the 2023-27 regulatory control period is set out in the table below.

Table 5-8: Forecast RAB over the 2023-27 regulatory period ($M, nominal)

	2022-23	2023-24	2024-25	2025-26	2026-27
Opening RAB	3,575.7	3,628.7	3,706.4	3,814.8	3,904.2
Capex net of disposals	155.9	166.7	206.5	197.3	158.9
Straight-line depreciation	-183.4	-170.6	-181.5	-193.7	-204.2
RAB indexation	80.4	81.6	83.4	85.8	87.8
Closing RAB	**3,628.7**	**3,706.4**	**3,814.8**	**3,904.2**	**3,946.7**

Source: AusNet

In accordance with clause S6A.2.1(f)(4) of the NER, only actual and estimated capex properly allocated to the provision of prescribed transmission services in accordance with our approved CAM is included in the RAB.

5.5 Supporting documents

We have included the following documents to support this chapter:

- Post Tax Revenue Model;
- Roll Forward Model;
- Standalone Depreciation Model;
- Capital Expenditure Forecast Model; and
- Growth Assets Calculation Model - Confidential.

6 Depreciation

6.1 Key points

The key points in this chapter are:

- Our Initial Proposal applied standard regulatory practice in calculating our regulatory depreciation allowance for the 2023-27 regulatory control period. An important aspect of our Initial Proposal was the inclusion of accelerated depreciation for insulators and instrument transformers to better reflect the economic life of these assets. We also proposed new asset classes relating to property leases, as a result of a change in the accounting standards.
- The AER's Draft Decision accepted our methodology for calculating regulatory depreciation, but did not fully accept our proposal in relation to accelerated depreciation. The calculation of our regulatory depreciation allowance was also updated by the AER to reflect its Draft Decision on various input parameters, including our opening RAB, forecast capex and inflation. The net effect of these changes increased our total regulatory depreciation allowance over the 2023-27 regulatory control period by $15.1 million (or 2.8%) to $560.2 million ($nominal).
- In this Revised Proposal, we have accepted the AER's position in relation to accelerated depreciation and we have updated our proposed standard asset lives accordingly. We have also updated our regulatory depreciation allowance for the 2023-27 regulatory control period to reflect the updated input parameters included in this Revised Proposal.
- In summary, our regulatory depreciation allowance for the 2023-27 regulatory control period is $514.3 million (nominal) which is $45.9 million or 8.2% lower than the AER's Draft Decision, which allowed $560.2 million (nominal).

6.2 Chapter structure

The remainder of this chapter is structured as follows:

- Section 6.3 discusses the methodology for calculating the regulatory depreciation allowance and the relevant inputs for the 2023-27 regulatory control period;
- Section 6.4 discusses our Initial Proposal relating to accelerated depreciation, which the AER has not fully accepted in its Draft Decision;
- Section 6.5 concludes by setting out our Revised Proposal in relation to the standard asset lives and our regulatory depreciation allowance for the 2023-27 regulatory control period; and
- Section 6.6 lists the relevant supporting documents.

6.3 Depreciation methodology and inputs

6.3.1 Our Initial Proposal

Our Initial Proposal adopted the following methodology and inputs to determine the regulatory depreciation allowance for the 2023-27 regulatory control period:

- We employed straight-line depreciation in accordance with the AER's PTRM;
- We adopted the closing RAB value at 31 March 2022 in accordance with the AER's RFM;
- Our RAB was rolled forward to include our forecast capex for the 2023–27 regulatory control period;

- We adopted an inflation forecast of 2.25 per cent per annum for the 2023–27 regulatory control period;
- We applied the asset classes and standard asset lives in accordance with those approved by the AER for the 2017–22 regulatory control period. For the 2023-27 regulatory control period, we proposed:
    - six new asset classes and associated asset lives relating to the accelerated depreciation of insulators and instrument transformers;
    - new asset classes relating to property leases to address the new accounting standards;
- To address the 2018 tax review, we reallocated a proportion of our forecast capex relating to buildings and IT assets for the 2023–27 regulatory control period into two new asset classes for 'Buildings - capital works' and 'In-house software'; and
- We adopted the AER's year-by-year tracking module in the RFM for depreciation of existing assets for the 2023–27 regulatory control period.

We provided detailed information to support our proposal to introduce six new asset classes in relation to insulators and instrument transformers. The purpose of this proposed change was to ensure that these assets are depreciated over a timeframe that is consistent with their economic lives, as required by clause 6A.6.3(b)(1) of the NER. In particular:

- For insulators and instrument transformers that we have already decommissioned, we proposed to fully depreciate their residual values in the first year of the 2023-27 regulatory control period (2 new asset classes).
- For insulators and instrument transformers that we plan to decommission during the 2023-27 regulatory control period, we proposed to fully depreciate their residual values by the end of that control period (2 new asset classes).
- For the balance of insulators and instrument transformers (i.e. in-service assets and new assets), we proposed a depreciation profile that reflects an economic life of 40 years and 38 years respectively (2 new asset classes).

For capitalised leases, we proposed four new asset classes and standard asset lives as set out in the table below (i.e. for each year of the 2023-27 regulatory control period, with the exception of 2024-25).

Table 6-1: Capitalised leases, as incurred ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27
Leases capitalised ($m)	0.04	1.1	-	0.1	0.3
Proposed asset lives (years)	25.0	19.0	n/a	31.8	15.4

Source: AusNet

6.3.2 Draft Decision

The AER's Draft Decision accepted our approach to depreciation, including the year-by-year tracking method. The AER also accepted our proposed approach to standard asset lives and the introduction of new asset classes, with the exception of two new classes relating to insulators and instrument transformers (which is discussed in further detail in section 6.4).

While largely accepting our proposed methodology, other aspects of the AER's Draft Decision are inputs to the depreciation calculation and, therefore, affect the regulatory depreciation allowance. In particular, the AER's Draft Decision adopted different values from those set out in our Initial Proposal for our opening RAB, forecast capex and inflation, each of which has an impact on regulatory depreciation.

The net effect of the AER's revisions in its Draft Decision produced an increase in the total allowance for regulatory depreciation of $15.1 million (or 2.8%) to $560.2 million ($nominal) over the 5 year regulatory control period, compared to our Initial Proposal. While a number of the AER's revisions reduced our proposed depreciation allowance, these effects were more than offset by the reduction in forecast inflation from our Initial Proposal of 2.25% per annum to 2.0% in the AER's Draft Decision. A lower inflation rate increases regulatory depreciation, other things being equal.

6.3.3 Response to the AER's Draft Decision

The AER's Draft Decision accepted the methodology we proposed for calculating regulatory depreciation, which is consistent with standard regulatory practice. The revisions set out in the Draft Decision principally reflect the AER's different views on input parameters, such as the opening RAB, forecast capex and inflation, that affect the calculation of regulatory depreciation.

In this Revised Proposal, we have updated the inflation estimate of 2.00% contained in the Draft Decision to 2.25% for the 2023-27 period in line with the revised approach (in version 5 of the PTRM). We discuss this aspect of our Revised Proposal in section 7.10 of the Return of return and forecast inflation chapter.

We have also made updates to other key input parameters in response to the AER's Draft Decision. For that reason, the forecast regulatory depreciation in this Revised Proposal differs from the amount set out in the AER's Draft Decision. These updates are mainly associated with changes in our proposed opening RAB as at 31 March 2022 and the capex forecast for 2023-27. These changes are discussed further within the Opening RAB and Capex chapters.

An important difference of view between our Initial Proposal and the AER's Draft Decision relates to our proposal for accelerated depreciation. We discuss this issue in further detail in the next section.

6.4 Accelerated depreciation

6.4.1 Our Initial Proposal

Our Initial Proposal explained that the current standard asset lives that apply for insulators (60 years) and instrument transformers (45 years) do not reflect their economic lives, noting that:

- We have decommissioned a number of insulators and instrument transformers before the end of their nominal lives; and
- We plan to decommission an additional number of insulators and instrument transformers during the 2023-27 regulatory control period in advance of their nominal remaining lives.

In order to meet the requirements of clause 6A.6.3(b)(1) of the NER, which requires that the depreciation schedules must reflect the economic lives of the relevant assets, we proposed to introduce:

- Four new asset classes for $28.9 million (real $Mar 2022) of insulators and instrument transformers that have been decommissioned or will be decommissioned by the end of the 2023–27 regulatory control period; and
- Two new asset classes for $442.4 million (real $Mar 2022) of existing insulators and instrument transformers that would provide services beyond the 2023–27 regulatory control period, and for new insulators and instrument transformers acquired during the 2023–27 regulatory control period and beyond.

The table below summarises our proposed approach to depreciating insulators and instrument transformers in our Initial Proposal.

Table 6-2: Depreciation methodology for insulators and instrument transformers

Type	Asset	Replacement status	Depreciation method
Assets in the opening RAB	Insulators	Decommissioned	Fully depreciate in 2022-23
		Planned for decommissioning during the 2023-27 control regulatory period	Fully depreciate their residual values by the end of the 2023-27 regulatory control period
		Balance, in-service	Depreciate this group of assets over an average remaining life of 18.1 years that reflects an economic life of 40.1 years
	Instrument transformers	Decommissioned	Fully depreciate in 2022-23
		Planned for decommissioning during the 2023-27 regulatory control period	Fully depreciate their residual values by the end of the 2023-27 regulatory control period
		Balance, in-service	Depreciate this group of assets over an average remaining life of 26.1 years that reflects an economic life of 37.8 years
	All other assets	N/A	Depreciate over a remaining asset life that reflects the standard asset life approved in the current determination
New capex in the capex program	Insulators		Depreciate over an economic life of 40.1 years
	Instrument transformers		Depreciate over an economic life of 37.8 years
	All other assets		Depreciate over the standard asset life approved in the current determination

Source: AusNet

In conjunction with these changes in the RAB, we reallocated portions of opening Tax Asset Base (TAB) values from existing asset classes into the new asset classes as at 31 March 2022.

6.4.2 Draft Decision

In its Draft Decision, the AER accepted the introduction of our four new asset classes to address the insulators and instrument transformers that we have either decommissioned or plan to decommission during the 2023-2027 regulatory control period. However, the AER did not accept our proposed approach for depreciating existing and new insulators and instrument transformers that would provide services beyond the 2023–27 regulatory control period. Instead, the AER's Draft Decision:

- Adopted an asset life for polymeric insulators of 35 years, but did not accept a shorter asset life for other types of insulators. The AER concluded that glass and porcelain insulators should remain in the broader 'Towers and conductors' asset class, reflecting its view that their asset lives are largely consistent with that broader asset class.
- Adopted an asset life for instrument transformers of 45 years, which is consistent with the broader 'Switchgear' asset class. Accordingly, the AER did not accept the creation of a separate asset class for instrument transformers and the shorter asset lives in our Initial Proposal.

The AER explained that the changes in its Draft Decision would reduce the accelerated depreciation relating to these assets from approximately $37 million ($2021–22) to approximately $28 million ($2021–22) over the 2023-27 regulatory control period.

In addition to making these changes, the AER highlighted concerns raised by the Consumer Challenge Panel that we did not consult consumers in relation to our proposal to accelerate depreciation for insulators and instrument transformers. The AER explained that it expected us to raise issues with consumers that affect network charges, such as the treatment of depreciation.

6.4.3 Response to the AER's Draft Decision

In this Revised Proposal we have accepted the AER's Draft Decision in relation to accelerated depreciation. In accepting the AER's Draft Decision we acknowledge that the AER's technical advice differs from the views expressed in our Initial Proposal. While we accept the AER's findings for the purpose of the 2023-27 regulatory control period, we maintain our view that:

- 25 years is an appropriate asset life for polymeric insulators; and
- 40 years is an appropriate asset life for instrument transformers (increased from 37.8 years in our Initial Proposal).

As new information becomes available, it may be appropriate to revisit the AER's preferred asset lives for these assets in future regulatory periods. We therefore propose to keep these asset lives under review during the 2023-27 regulatory control period.

We also acknowledge the comments of the Consumer Challenge Panel and the AER in relation to consumer engagement regarding depreciation. On a like-for-like basis[49], we would observe that our original proposed depreciation amount for 2023-27 was lower than the previous period allowance (in real $2020-21 terms) and considered at the time that the depreciation assessment was a technical matter that should be assessed in the light of engineering evidence, as illustrated by the AER's assessment of our Initial Proposal in its Draft Decision. Nevertheless, we accept the perspectives of the AER and the Consumer Challenge Panel, including the importance of explaining to consumers the drivers of changes in network prices. For the engagement process leading into the Revised Proposal we tested which topics, included depreciation, stakeholders wanted to focus on. Stakeholder feedback did not highlight depreciation as a key area of concern.

6.5 Revised Proposal

In light of the information presented in sections 6.3 and 6.4, we set out the standard asset lives and forecast regulatory depreciation for this Revised Proposal below.

6.5.1 Standard asset lives

The table below shows our standard asset lives for new assets in this Revised Proposal, which is consistent with the AER's Draft Decision.

Table 6-3: Standard asset lives for new capex

Asset Class	Standard asset life (years)
Secondary	15.0
Switchgear	45.0

[49] Excluding forecast depreciation associated with capitalised leases included in our Initial Proposal for 2023-27, which is not relevant to the 2018-22 control period.

Asset Class	Standard asset life (years)
Transformers	45.0
Reactive	40.0
Towers and Conductor	60.0
Establishment	45.0
Communications	15.0
Inventory	n/a
IT	5.0
Vehicles	7.0
Other (non-network)	10.0
Premises	10.0
Land	n/a
Easements	n/a
Equity raising costs (2003-08)	n/a
Polymeric insulators	35.0
Lease L&B 2022-23	25.0
Lease L&B 2023-24	19.0
Lease L&B 2025-26	31.8
Lease L&B 2026-27	15.4
Buildings	40.0
In-house software	5.0
Equity raising costs	34.8

Source: AusNet

6.5.2 Depreciation allowance

Based on the depreciation methodology described in earlier sections, our revised total forecast straight-line depreciation for the 2023-27 regulatory control period is set out in the table below.

Table 6-4: Straight-line depreciation ($M, real 2021-22)

		2022-23	2023-24	2024-25	2025-26	2026-27	Total
Existing assets in the RAB	Insulators decommissioned	8.4	-	-	-	-	**8.4**
	Insulators to be decommissioned over 2023-27 regulatory control period	0.6	0.6	0.6	0.6	0.6	**2.9**
	Polymeric insulators	7.7	7.7	7.7	7.7	7.7	**38.7**
	Instrument transformers decommissioned	13.1	-	-	-	-	**13.1**
	Instrument transformers to be decommissioned over 2023-27 regulatory control period	0.9	0.9	0.9	0.9	0.9	**4.4**
	All other assets (including other Insulator types and Instrument transformers)	148.6	146.2	142.8	142.0	138.1	**717.7**

New capex	Polymeric Insulators	-	0.2	0.3	0.5	0.6	**1.6**
	All other assets (including other Insulator types and Instrument transformers)	-	7.5	17.5	25.5	34.8	**85.3**
Total straight-line depreciation		**179.4**	**163.1**	**169.8**	**177.2**	**182.7**	**872.2**

Source: AusNet

To calculate regulatory depreciation, we must remove the effects of indexation on the RAB. As a result, our revised total regulatory depreciation allowance for the 2023-27 regulatory control period is shown in Table 6-5**:**. Our proposed allowance of $514.3 million (nominal) is $45.9 million or 8.2% lower than the AER's Draft Decision, which allowed $560.2 million (nominal).

Table 6-5: Revised proposal for regulatory depreciation ($M, nominal)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Straight-line depreciation	183.4	170.6	181.5	193.7	204.2	**933.4**
RAB indexation	-80.4	-81.6	-83.4	-85.8	-87.8	**-419.1**
Regulatory depreciation	**103.0**	**88.9**	**98.1**	**107.9**	**116.3**	**514.3**

Source: AusNet

6.6 Supporting documentation

We have provided the following documents in support of this chapter:

- Post Tax Revenue Model;
- Roll Forward Model; and
- Standalone Depreciation Model.

7 Rate of return and forecast inflation

7.1 Key points

- Our Initial Proposal estimated the return on capital in accordance with the AER's Rate of Return Instrument[50]. As a binding instrument, the Rate of Return Instrument sets out the key parameter values and the method to be applied in estimating the rate of return. It also establishes a gamma value of 0.585, which is applied in calculating the tax allowance for revenue setting purposes.
- Our Initial Proposal explained that our estimates of the cost of equity and debt would be updated in the AER's draft and final decisions to reflect the nominated averaging period for estimating the risk free rate. We also noted that the AER had not yet completed its inflation review, the conclusions of which would apply in the AER's Final Decision.
- The AER's Draft Decision updated our estimates of the cost of equity and debt to reflect more recent market data in relation to the risk free rate. The Draft Decision also adopted an updated placeholder estimate for inflation of 2.00% for the forthcoming regulatory control period compared to our estimate of 2.25% in the Initial Proposal.
- In this Revised Proposal:
    - We continue to apply the Rate of Return Instrument and have adopted the placeholder value in relation to the cost of equity in accordance with the Draft Decision. In relation to the cost of debt, we have updated the Draft Decision's placeholder estimates for the 2023-27 regulatory control period to reflect our estimate of the average cost of debt for the May 2021 observation period. We note that both the cost of equity and cost of debt will be updated in the AER's Final Decision.
    - We note that the AER has accepted our averaging periods for both debt and equity, and reflect this timing in our Revised Proposal.
    - We have updated the inflation estimate for the 2023-27 regulatory control period using December CPI forecasts contained in the August 2021 RBA statement of monetary policy. This sets the inflation estimate to 2.25% in the PTRM (version 5) compared with the Draft Decision placeholder of 2.00%.
- The AER accepted our Initial Proposal in relation to equity and debt raising costs. On that basis, we have maintained our earlier approach to these costs in this Revised Proposal.

7.2 Chapter structure

The remainder of this Chapter is structured as follows:

- Section 7.3 provides a brief commentary on the AER's Rate of Return Instrument;
- Sections 7.4 and 7.5 explain our estimated cost of equity and debt, having regard to the AER's Draft Decision;
- Section 0 summarises our estimated weighted average cost of capital (WACC) for this Revised Proposal;

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50 AER, *Rate of Return Instrument, December 2018 (Rate of Return Instrument)*., available at: https://www.aer.gov.au/system/files/2018%20Rate%20of%20Return%20Instrument%20%28Version%201.02%29_1.pdf.

- Sections 0 and 7.8 present our estimated equity raising and debt raising costs, which are unchanged from our Initial Proposal and the AER's Draft Decision;
- Section 7.9 notes the value of gamma adopted for the 2023-27 regulatory control period in accordance with the Rate of Return Instrument;
- Section 7.10 explains our approach to forecast inflation, which reflects the AER's latest methodology and placeholder estimate in its Draft Decision; and
- Section 7.11 lists the 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.

7.3 Rate of Return Instrument

Our Initial Proposal explained that the National Electricity Law was amended in November 2018 to require the AER to make a binding rate of return instrument.[51] The instrument must set out the precise value for the rate of return, or a method for calculating the rate of return that can be applied automatically without exercise of discretion. The AER published its Rate of Return Instrument and an accompanying explanatory statement in December 2018.[52]

The AER has published two rate of return annual updates, which provide stakeholders with information on rate of return data, particularly time series market data, showing changes since the publication of the 2018 Rate of Return instrument.[53] Although the Rate of Return Instrument will be revised in December 2022, the current version will apply throughout our 2023-27 regulatory control period.

The Rate of Return Instrument maintains its long-standing regulatory approach of determining a nominal vanilla weighted average return on equity and debt, weighted by the gearing ratio. The AER's Rate of Return Instrument therefore defines the allowed rate of return as follows:

$$k_t = (1\text{-}G) \times k^e + k_t^d \times G$$

where:

k_t is the rate of return in regulatory year t;

k^e is the allowed return on equity for the regulatory period and is calculated in accordance with clause 4 of the instrument;

$k_t{}^d$ is the allowed return on debt for the regulatory year t, and is calculated in accordance with clause 9 of the instrument; and

G is the gearing ratio and is set at a value of 0.6.

In accordance with the NER[54], this Revised Proposal calculates the allowed rate of return for each regulatory year of the 2023-27 regulatory control period. This approach is unchanged from our Initial Proposal and the AER's Draft Decision, which also applied the 2018 Rate of Return Instrument.

51 National Electricity Law, Part 3, Division 1B.

52 Available at: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rate-of-return-instrument-2018.

53 AER, *Rate of Return Annual Update*, December 2020– available at: https://www.aer.gov.au/system/files/AER%20-%20Rate%20of%20return%20annual%20update%20-%202%20December%202020%20FINAL%2811739206.2%29.pdf

54 National Electricity Rules, SA6.1.3(4A).

7.4 Return on Equity

The AER's explanatory statement adopts the Sharpe-Lintner CAPM (SLCAPM) to calculate the return on equity. Within the SLCAPM formula, the AER sets fixed values for the market risk premium and equity beta and establishes a formula for calculating the risk free rate. Clause 4 of the Rate of Return Instrument defines the return on equity as follows:

$$k^e = k^f + \beta \times MRP$$

where:

k^f is the allowed risk free rate of return expressed as an effective annual rate percentage;

β is the allowed equity beta and is set to a value of 0.6; and

MRP is the allowed market risk premium and is set to a value of 6.1% per annum.

As the values of the equity beta and market risk premium have been set by the Rate of Return Instrument, the Draft Decision adopted these values. We had adopted the same values in our Initial Proposal and continue to apply them in this Revised Proposal.

The Rate of Return Instrument requires us to estimate the risk free rate using a formula based on yields on 10-year Commonwealth Government Securities (CGS). The formula requires the risk free averaging period to be:

- Over a period of between 20 and 60 business days;
- Start no earlier than 7 months prior to the commencement of the regulatory period; and
- Finish no later than 3 months prior to the commencement of the regulatory period.[55]

In accordance with the Rate of Return Instrument, we nominated our averaging periods in a confidential letter to the AER. In our Initial Proposal, we provided an estimate of the risk free rates based on 21 consecutive business days ending 30 June 2020, which results in a risk free rate of 0.93%. In its Draft Decision, the AER updated the risk free rate and the resulting cost of equity, noting that it would be further updated in its Final Decision.

For the purpose of this Revised Proposal, we have adopted the estimated risk free rate in the Draft Decision noting that this will be updated in the Final Decision together with the parameters in the Rate of Return Instrument, as set out in the table below.

Table 7-1: Revised cost of equity parameters

Parameter	Proposed value	Basis of parameter value
Risk fee rate (nominal)	1.68%	This is a placeholder value consistent with the Draft Decision, which reflects the yield on ten year Commonwealth bonds measured over the period ending 30 April 2021. The risk free rate used in the AER's final Decision will be measured over the nominated periods selected in accordance with clause 8 of the Rate of Return Instrument.
Equity beta	0.6	This value is consistent with clause 4(b) of the Rate of Return Instrument.

55 AER, *Rate of Return Instrument*, clause 8.

Market risk premium	6.1%	This value is consistent with clause 4(c) of the Rate of Return Instrument.
Cost of equity	5.34%	The cost of equity is estimated in accordance SLCAPM, as specified in clause 4 of the Rate of Return Instrument.

Source: AusNet

7.5 Cost of debt

The cost of debt comprises the following key elements:[56]

- A benchmarking approach, based on debt yield data from third party data providers and benchmarks for term of debt and credit rating;
- A 10-year trailing average approach with an annual update; and
- A 10-year transition to the 10-year trailing average approach, noting that where a transition has commenced in a previous determination, the AER will continue that transition.

In its final decision for our 2017-22 regulatory control period, the AER adopted an 'on-the-day' approach for the first regulatory year and commenced a 10-year transition to a trailing average approach. The trailing average approach operates as follows:

- For 2017, the estimated cost of debt reflected the prevailing market rates near the commencement of the 2017-22 regulatory period.
- For each subsequent year, 10% of the return on debt is updated to reflect the prevailing market conditions in that year.

In our Initial Proposal, we maintained this transitional approach in accordance with the Rate of Return Instrument, and proposed an average placeholder portfolio cost of debt of 4.35%, which incorporated a placeholder prevailing cost of debt of 2.75%.[57] In its Draft Decision, the AER updated the cost of debt in accordance with the Rate of Return Instrument and using the averaging period for the risk free rate over the period ending 30 April 2021.

For the purpose of this Revised Proposal, we have updated the AER's placeholder cost of debt to reflect our estimate of the average cost of debt for the May 2021 observation period. The table below shows our updated cost of debt over the 2023-27 regulatory control period, noting that this will be further updated in the AER's Final Decision. The AER's cost of debt (nominal pre-tax) was 4.36% for 2023 compared to our Revised Proposal which is 4.37%.

Table 7-2: Revised estimated benchmark cost of debt

	2022-23	2023-24	2024-25	2025-26	2026-27
Nominal pre-tax return on debt	4.37%	4.17%	3.97%	3.77%	3.57%

Source: AusNet

7.6 Nominal vanilla WACC

The table below summarises the nominal vanilla WACC or the 'allowed rate of return', in accordance with clause 3 of the Rate of Return Instrument for this Revised Proposal. It should

56 Ibid.

57 Based on a placeholder averaging period of 28 January 2020 to 14 February 2020.

be noted that this estimate will be updated in the AER's Final Decision to reflect the averaging period and latest market data, and then updated annually to reflect movements in the cost of debt.

As noted above, we have accepted the AER's placeholder cost of equity in its Draft Decision for the purposes of this Revised Proposal, but we have updated the cost of debt to reflect the latest trailing average calculation.

Table 7-3: Revised estimated nominal vanilla WACC

	2022-23	2023-24	2024-25	2025-26	2026-27
Return on equity	5.34%	5.34%	5.34%	5.34%	5.34%
Nominal pre-tax return on debt	4.37%	4.17%	3.97%	3.77%	3.57%
Gearing	60%	60%	60%	60%	60%
Nominal vanilla WACC	**4.76%**	**4.64%**	**4.52%**	**4.40%**	**4.28%**

Source: AusNet

7.7 Equity raising costs

Equity raising costs are the transaction costs incurred when network service providers raise new equity in order to fund capital investment. Accordingly, the AER provides a benchmark allowance to reflect the efficient costs of raising equity, if equity raising is required to maintain the benchmark gearing of 60%.

Our Initial Proposal explained that our equity raising costs are derived from the PTRM and the AER's benchmarking approach, which includes a distribution rate of 0.9, consistent with the Rate of Return Instrument. We explained that our modelling showed that under the AER's approach no external equity injection is required to maintain the benchmark capital structure over the 2023-27 regulatory control period.

In its Draft Decision, the AER confirmed that no equity raising costs are required. In this Revised Proposal, we have maintained our earlier view, consistent with the AER's Draft Decision, that no equity raising costs are required in the 2023-27 regulatory control period.

7.8 Debt raising costs

Debt raising costs are transaction costs incurred each time debt is raised or refinanced. These costs may include arrangement fees, legal fees, company credit rating fees and other transaction costs.

The AER provides a benchmark allowance for debt raising costs as a component of our operating expenditure allowance. The AER's historical approach to debt raising costs has been informed by a report from the Allen Consulting Group, commissioned by the ACCC in 2004.[58] The AER subsequently updated Allen Consulting Group's analysis to reflect more recent market data provided by PricewaterhouseCoopers during the 2013 rate of return guideline process.[59]

In our Initial Proposal, we calculated a debt raising cost allowance based on the AER's recent approach to setting benchmark debt raising costs, as set out in the Final Decision for SA Power

58 Allen Consulting Group, *Debt and Equity Raising Transaction Costs*, December 2004.

59 PWC, *Energy Networks Association: Debt financing costs*, June 2013.

Networks, published in June 2020. This resulted in an annual rate of 8.50 bppa, which we included in our operating expenditure forecasts in our Initial Proposal.

The AER's Draft Decision accepted the method for estimating debt raising costs that we proposed in our Initial Proposal, which uses an annual rate of 8.50 bppa. In accepting our method, the AER noted that it had previously received submissions questioning the suitability of Chairmont's estimate of the arrangement fee. As a result, the AER concluded that Bloomberg is likely to be the most suitable source of information for the 'arrangement fee' at this time, which implied a slightly lower debt raising cost of 8.0 bppa.

The AER also noted that the level of imprecision and materiality in estimating debt raising costs should be taken into account in assessing our Initial Proposal. For this Revised Proposal, we accept the Draft Decision that uses an annual rate of 8.0 bppa to calculate our estimated debt raising costs.

7.9 Imputation Credit Value (Gamma)

Under the Australian imputation tax system, investors receive imputation credits for tax paid at the company level. For eligible shareholders, imputation credits offset their Australian income tax liabilities. The AER takes account of the value of imputation credits (known as gamma or 'γ') to recognise that imputation credits benefit equity holders, in addition to any dividends or capital gains they receive.

As the regulatory framework applies a post-tax WACC, the value of imputation credits is not a WACC parameter. Instead, the value of imputation credits is a direct input into the calculation of a network service provider's benchmark tax allowance. In accordance with the Rate of Return Instrument, in our Initial Proposal we adopted a value for imputation credits of 0.585, which the AER accepted in its Draft Decision. In this Revised Proposal, we have maintained this estimate of gamma in accordance with the Rate of Return Instrument.

Our calculation of our benchmark tax allowance for the 2023-27 regulatory control period for this Revised Proposal is provided in Chapter 8.

7.10 Forecast inflation

In our Initial Proposal, we adopted an inflation placeholder of 2.25% for the 2023-27 regulatory control period. This estimate reflected the AER's approach at that time, which estimated the average annual rate of inflation expected over a ten year period, by applying:

- The RBA's inflation forecasts for the first two years of the relevant regulatory control period, which is the limit of this forecast series; and
- The mid-point of the RBA's target band for inflation (currently 2.5%) to extend the series out to ten years.

At the time of our Initial Proposal, we noted that the AER was reviewing its approach to estimating inflation. In making this observation, we highlighted our concern that the AER's method systematically overstated forecast inflation.

The Draft Decision has implemented the conclusions of the AER's inflation review, which found that:

- the target inflation horizon should be shortened from ten years to a term that matches the regulatory period (typically five years); and
- a linear glide-path should apply from the RBA's forecasts of inflation for year 2 to the mid-point of the inflation target band (2.5 per cent) in year 5.

In applying this methodology, the AER established a placeholder inflation forecast of 2.00% compared to our Initial Proposal of 2.25%. The AER also noted that its Final Decision will update the inflation forecast to take account of the November 2021 RBA Statement of Monetary Policy, which should contain CPI forecast for an additional year (year-ending December 2023).

In this Revised Proposal, we have updated the AER's placeholder forecast for inflation to 2.25%, based on the latest available inflation forecast data within the RBA's August Statement of Monetary Policy[60] and we expect this will be updated in the AER's Final Decision.

7.11 Supporting documentation

The following documents are provided in support of this chapter:

- Rate of Return Build up model.

[60] Available at: https://www.rba.gov.au/publications/smp/2021/aug/economic-outlook.html

8 Corporate tax allowance and gamma

8.1 Key points

- Our Initial Proposal explained that the corporate tax allowance is a component of the annual building block revenue requirement. The estimated cost of corporate income tax is an output from the PTRM.
- In our Initial Proposal, we explained that we had adopted the standard regulatory approach to estimating corporate tax, updated to reflect the AER's 2018 tax review. This review concluded that the benchmark allowance should account for the immediate expensing of some capex items and the application of the diminishing value method to others.
- In its Draft Decision, the AER accepted most elements of our tax calculation in our Initial Proposal, including our proposals in relation to:
    - The method to establish the opening tax asset base (TAB) as at 1 April 2022.
    - The weighted average method to calculate the remaining tax asset lives as at 1 April 2022;
    - The standard tax asset lives for all existing asset classes for the 2023–27 regulatory control period;
    - The remaining tax asset lives for the new asset classes associated with capitalised leases, and the accelerated depreciation of insulators and instrument transformers that are to be decommissioned; and
    - The method to calculate forecast immediate expensing of capex.
- The principal changes applied by the AER to our corporate tax allowance in its Draft Decision reflect its findings in relation to:
    - Our depreciation proposal and our RAB roll forward, which have consequential impacts on the calculation of the corporate tax allowance;
    - Other aspects of our building block revenue requirements, including the updated return on equity and capex forecasts, which affect our corporate tax requirements by changing our annual revenue; and
    - Reductions in the amount of immediately deductible capex in the PTRM to reflect the AER's alternative forecasts.
- In accordance with the Rate of Return Instrument, in our Initial Proposal we adopted a value for imputation credits of 0.585, which the AER accepted in its Draft Decision.
- The net effect of the AER's Draft Decision was to increase our corporate tax allowance to \$11.2 million over the 2023-27 regulatory control period compared to our proposed allowance of \$1.1 million.
- In this Revised Proposal, we have updated our calculation of corporate tax allowance to reflect our updated annual revenue requirement as presented in this Revised Proposal. This includes our proposed changes to forecast capex, the opening RAB, depreciation and the cost of capital. As a consequence of these changes, in this Revised Proposal our corporate tax allowance over the 2023-27 regulatory control period is \$6.4 million (nominal), which is \$4.8 million or 42.9% lower than the AER's Draft Decision.

8.2 Chapter structure

The remainder of this chapter is structured as follows:

- Section 8.3 addresses the opening TAB as at 1 April 2022;
- Sections 8.4 and 8.5 present our remaining tax lives and standard tax lives inputs respectively for this Revised Proposal;
- Sections 8.6 and 8.7 presents the company income tax rate and value of imputation credits inputs, which remain unchanged;
- Section 8.8 summarises our forecast of immediately deductible expenditure for the 2023-27 regulatory control period for this Revised Proposal;
- Section 8.9 sets out the proposed tax allowance for this Revised Proposal; and
- Section 8.10 lists the supporting documentation for this chapter.

8.3 Opening tax asset base as at 1 April 2022

8.3.1 Our Initial Proposal

In our Initial Proposal, we explained that we used a combination of actual and forecast net capex and straight-line depreciation to establish our opening TAB as at 1 April 2022, noting that our net capex values for 2020-21 and 2021-22 would be updated in our Revised Proposal. We also explained that we had adopted the weighted average remaining life approach to calculate the opening TAB.

Our proposed opening TAB included a number of final year adjustments, primarily relating to the depreciation of insulators and instrument transformers, and the roll-in of Growth Assets.[61]

8.3.2 Draft Decision

In its Draft Decision, the AER accepted our proposed method to establish the opening TAB. The AER made the following adjustments to our calculation, consistent with its Draft Decision in relation to our RAB roll forward calculation which we discuss in Chapter 5:

- Amended the proposed tax value of the final year adjustment, which reflected the updated information we provided;
- Removed the proposed annual capex entries with respect to three new asset classes we proposed for leases; and
- Amended the calculation for the residual tax value of 2019–20 capitalised leases to account for asset disposals for that year.

As a consequence of applying these adjustments, the AER's Draft Decision set an opening TAB of $2,842.8 million ($nominal), which is $0.9 million or less than 0.1% lower than our Initial Proposal.

8.3.3 Revised Proposal

In this Revised Proposal, we have continued to apply the methodology described in our Initial Proposal to determine the opening TAB, noting that this approach has been accepted by the AER in its Draft Decision. We have accepted the AER's preferred treatment of capitalised leases in the RFM, which rolls in the undepreciated value of leases as part of the final year adjustments.

[61] Previously known as Group 3 assets.

We discuss this approach in more detail in Chapter 5 of this Revised Proposal. In addition to the amendments made by the Draft Decision, we have updated the closing asset values and remaining lives for capitalised leases in the final year asset adjustments to reflect the latest available actual data.

In addition, we have updated our opening TAB to reflect:

- The actual capex for 2020-21 based on information sourced from the annual regulatory accounts; and
- Our updated capex forecasts for 2021-22 as contained in our updated forecast capex model.

Our revised opening TAB for the 2023-27 regulatory period is set out in the table below.

Table 8-1: Tax asset base roll forward ($M, nominal)

	2017-18	2018-19	2019-20	2020-21	2021-22
Opening TAB	2,418.2	2,403.1	2,392.3	2,447.0	2,468.2
Capex net of disposals	105.0	116.0	177.5	144.6	195.1
Straight-line depreciation	-120.1	-126.9	-122.8	-123.4	-131.2
Final year asset adjustments (capitalised leases)	-	-	-	-	38.2
Final year asset adjustments (growth assets)	-	-	-	-	245.8
Closing TAB	**2,403.1**	**2,392.3**	**2,447.0**	**2,468.2**	**2,816.1**

Source: AusNet

8.4 Remaining tax asset lives

8.4.1 Our Initial Proposal

Our Initial Proposal set out the remaining tax lives for our existing assets by applying the weighted average method, which is a standard regulatory approach. In addition to calculating the remaining tax lives for our existing assets, we also proposed remaining tax asset lives to reflect our proposed new asset classes for insulators and instrument transformers, and for leases to reflect the new accounting standard.

8.4.2 Draft Decision

The AER's Draft Decision largely accepted our proposed remaining tax asset lives. In particular, the AER accepted the proposed remaining tax lives for the new asset classes of:

- 'Lease L&B 2019-20 < 20 years rem life', 'Lease L&B 2019-20 > 20 years rem life' and 'Lease L&B 2020-21'; and
- 'Insulators - Already decommissioned ', 'Insulators - Decommission 2022-2027', 'Instrument transformers - Already decommissioned', 'Instrument transformers - Decommission 2022-2027' related to removed (or expected to be removed) assets.

However, the AER's Draft Decision did not accept the following elements of our Initial Proposal in relation to remaining tax asset lives:

- Our proposal to shorten the remaining tax asset life of other existing instrument transformers; and

- Our proposed remaining tax asset life of 18.1 years for insulators, which the AER reduced to 13.4 years to reflect its decision to limit the accelerated depreciation to polymeric insulators.

The AER also explained that for the proposed new asset classes of 'In-house software', 'Buildings - capital works', 'Lease L&B 2022-23', Lease L&B 2023-24', Lease L&B 2025-26' and 'Lease L&B 2026-27', it had not assigned remaining tax asset lives as there are no opening tax values for these asset classes, and only forecast capex is being allocated to these asset classes over the 2023–27 regulatory control period. The AER therefore recorded 'n/a' in the PTRM for these asset classes.

8.4.3 Revised Proposal

We have updated the remaining tax asset lives, to reflect our updated inputs for actual 2020-21 capex, forecast 2021-22 capex and final year adjustments. Our revised remaining tax asset lives are set out in the table below.

Table 8-2: Remaining tax lives for existing asset classes

Asset type	Remaining life (years)
Secondary	8.1
Switchgear	29.4
Transformers	28.3
Reactive	23.3
Towers and Conductor	25.0
Establishment	31.3
Communications	8.9
Inventory	n/a
IT	2.7
Vehicles	6.5
other (non-network)	6.1
Premises	14.5
Land	n/a
Easements	n/a
Polymeric insulators	13.4
Insulators - Already decommissioned	1.0
Insulators - Decommission 2022-2027	5.0
Instrument transformers - Already decommissioned	1.0
Instrument transformers - Decommission 2022-2027	5.0
Lease L&B 2019-20 < 20 years rem life	7.7
Lease L&B 2019-20 > 20 years rem life	46.0
Lease L&B 2020-21	6.0
Lease L&B 2022-23	n/a
Lease L&B 2023-24	n/a
Lease L&B 2025-26	n/a
Lease L&B 2026-27	n/a
Buildings - capital works	n/a
In-house software	n/a

Source: AusNet

8.5 Standard tax lives

8.5.1 Our Initial Proposal

In our Initial Proposal, we maintained the standard tax lives that were adopted in the 2018-22 regulatory control period. In addition, we proposed tax lives in relation to the new asset classes that we presented in the RAB and depreciation chapters in our Initial Proposal. As already noted, these new asset classes related to insulators, instrument transformers and capitalised leasing assets.

8.5.2 Draft Decision

The AER's Draft Decision accepted our proposed standard tax lives, apart from our proposal to shorten the standard tax life of future instrument transformers and new insulators. The AER rejected our proposal to shorten the standard life for instrument transformers to 37.8 years[62] in a new class and instead kept these assets in the existing broader asset class of 'Switchgear', which has a 40 year standard tax life (and 45 year standard asset life in the RAB).

The AER proposed a standard tax asset life of 35 years for a new 'Polymeric insulators' asset class, reflecting its findings in relation to our depreciation proposal (which is discussed in Chapter 5 of this Revised Proposal). The AER rejected our proposed standard tax life of 25 years for polymeric insulators for new assets in this class, but accepted this standard life for the purposes of accelerated depreciation when determining the remaining life of existing assets in the opening RAB and TAB. For other insulator types, the AER rejected our proposal to depreciate these assets in a new class as part of our accelerated depreciation proposal, transferring the value of the assets back to the existing broader asset class of 'Tower and Conductor'.

With the exception of these changes, the AER accepted our proposed standard tax lives for new capex.

8.5.3 Revised Proposal

In this Revised Proposal, we have adopted the AER's Draft Decision in relation to standard tax lives, as shown in the table below.

Table 8-3: Standard tax lives for new capex

Asset type	Proposed standard tax life (years)	DV rate
Secondary	12.5	16%
Switchgear	40.0	5%
Transformers	40.0	5%
Reactive	40.0	5%
Towers and Conductor	47.5	4%
Establishment	40.0	5%
Communications	12.5	16%
Inventory	n/a	n/a
IT	3.5	57%

[62] After lodging our Initial Proposal, we updated our proposed standard life for new assets in the 'Instrument Transformers' class from 37.8 years to 40 years in both the RAB and TAB.

Asset type	Proposed standard tax life (years)	DV rate
Vehicles	8.0	25%
other (non-network)	10.0	20%
premises	20.0	10%
Land	n/a	n/a
Easements	n/a	n/a
Equity raising costs (2003-08)	n/a	n/a
Inventory Adjustment (Other non-network)	-	n/a
Polymeric Insulators	35.0	6%
Lease L&B 2022-23	25.0	8%
Lease L&B 2023-24	19.0	11%
Lease L&B 2025-26	31.8	6%
Lease L&B 2026-27	15.4	13%
Buildings	40.0	n/a
In-house software	5.0	n/a
Equity raising costs	5.0	n/a

Source: AusNet

8.6 Company income tax rate

In accordance with clause 6A.6.4 of the NER, the expected statutory income tax rate is the rate as determined by the AER. The AER's latest PTRM model (version 5) defines the company income tax rate as 30%. Therefore, this parameter is unchanged from our Initial Proposal and the AER's Draft Decision.

8.7 Value of imputation credits (gamma)

For the purposes of the 2023-27 regulatory control period, the value of gamma is specified in the AER's 2018 rate of return instrument (version 1.02), which states that the value of imputation credits is 58.5%. This parameter is unchanged from our Initial Proposal and the AER's Draft Decision, and has been adopted in calculating the benchmark tax allowance in this Revised Proposal.

8.8 Forecast of immediately deductible expenditure

The PTRM (version 5) requires a forecast for immediately deductible capex to be provided for each regulatory year of the 2023–27 regulatory control period. In our Initial Proposal, we presented our forecasts for immediately deductible capex, which reflected our forecast amount of capitalised overheads. The AER accepted this approach in its Draft Decision, although the immediately deductible amount was amended to reflect its Draft Decision in relation to our capex allowance (and overheads) for the 2023–27 regulatory control period.

Table 8-4 presents our updated forecasts of immediately deductible capital expenditure over the 2023–27 regulatory control period for this Revised Proposal.

Table 8-4: Forecast of immediately deductible expenditure ($M, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Secondary	1.0	0.9	0.5	0.9	0.6	**3.9**
Switchgear	1.0	2.6	1.4	3.4	1.4	**9.7**

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Transformers	0.4	2.4	1.3	3.4	1.1	**8.7**
Towers and Conductor	0.6	0.7	0.5	0.7	0.7	**3.3**
Establishment	0.4	1.3	0.7	1.8	0.7	**4.9**
Communications	1.1	1.1	0.9	0.9	1.2	**5.2**
IT	0.1	0.1	0.1	0.1	0.1	**0.4**
Premises	-	-	-	-	-	**-**
Polymeric Insulators	0.3	0.3	0.3	0.3	0.4	**1.5**
Buildings – capital works	-	-	-	-	-	**-**
In-house software	0.3	0.3	0.3	0.3	0.3	**1.5**
Total	**5.1**	**9.8**	**6.1**	**11.7**	**6.5**	**39.1**

Source: AusNet

8.9 Summary of tax allowance

Table 8-5 summarises our forecast TAB roll forward for the 2023-27 regulatory control period for this Revised Proposal.

Table 8-5: Tax asset base roll forward ($M, nominal)

	2022-23	2023-24	2024-25	2025-26	2026-27
Opening TAB	2,816.1	2,765.9	2,829.7	2,805.9	2,867.4
Net Capex	115.4	225.9	148.4	242.9	143.2
Tax Depreciation	-165.6	-162.2	-172.1	-181.5	-190.0
Closing TAB	**2,765.9**	**2,829.7**	**2, 805.9**	**2,867.4**	**2,820.6**

Source: AusNet

In preparing our Revised Proposal in relation to our benchmark tax allowance, we have accepted the AER's modifications to our tax calculation. In addition, we have updated our calculation of corporate tax allowance to reflect our updated annual revenue requirement, as presented in this Revised Proposal. Our updated benchmark tax allowance for the 2023-27 regulatory control period for this Revised Proposal is presented in Table 8-6.

Table 8-6: Proposed tax allowance ($M, nominal)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Tax payable	5.0	1.7	2.1	3.0	3.6	**15.4**
Imputation credits	-2.9	-1.0	-1.2	-1.7	-2.1	**-9.0**
Total	**2.1**	**0.7**	**0.9**	**1.2**	**1.5**	**6.4**

Source: AusNet

We confirm that, consistent with our final PTRM for the current 2017-22 regulatory control period, we will not have any accumulated tax losses as at 1 April 2022.

8.10 Supporting documentation

The following documentation is provided in support of this chapter:

- Roll Forward Model
- Capital Expenditure Forecast Model

9 Incentive Schemes

9.1 Key points

- We accept the Draft Decision's approach to calculating the Service Component targets, caps and floors and have updated these parameter values to reflect the latest available information.
- We do not accept the Draft Decision on the Market Impact Component and propose that a pragmatic and transparent approach to exclusions must be applied. This will largely codify existing AER practice while also addressing emerging issues and maintaining competitive neutrality for contestable transmission projects. Without this, the Market Impact Component should not be applied to AusNet, as to do so would condemn us to bearing the full penalty under the scheme each year, contravening both the STPIS objectives and the Revenue and Pricing Principles.
- We accept the Draft Decision in respect of the Network Capability Component and have proposed a new priority project.
- We accept the Draft Decision on the Demand Management Innovation Allowance Mechanism.
- We accept the Draft Decision's approach to calculating the Efficiency Benefit Sharing Scheme carryover amount.
- We accept the Draft Decision with respect to the Capital Expenditure Sharing Scheme.

9.2 Chapter structure

The remainder of this chapter is structured as follows:

- Sections 9.3 to 9.6 respond to the Draft Decision by providing updated information in relation to:
    - The Service Target Performance Incentive Scheme (STPIS);
    - The Demand Management Innovation Allowance Mechanism (DMIAM);
    - The Efficiency Benefits Sharing Scheme (EBSS);
    - The Capital Expenditure Sharing Scheme (CESS); and
- Section 9.7 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 Service Target Performance Incentive Scheme

The Service Target Performance Incentive Scheme (STPIS) comprises the following three components:

- The Service Component (SC);
- The Market Impact Component (MIC); and
- The Network Capability Component (NCC).

We discuss each of these components in turn below.

9.3.1 Service Component

9.3.1.1 Draft Decision

9.3.1.1.1 Performance Targets

The AER's Draft Decision determined targets for each SC parameter for the 2023-27 regulatory control period based on average performance from 2015-19. However, the AER explained that its Final Decision will be based on 2016-20 performance data, and therefore requested that we provide our 2020 data in this Revised Proposal.

The AER did not accept our view that an alternative method for calculating the large loss of supply sub-parameter should be adopted if we incurred zero events in 2020. We had proposed a change of methodology to ensure that the scheme provides scope for an incentive payment, rather than acting as a 'penalty only' scheme.

In its Draft Decision, the AER explained that the scheme is designed so that a TNSP can only keep its reward under the STPIS if its previous service level improvement is retained in subsequent regulatory control periods. On that basis, the AER argued that it was not appropriate to change the methodology, as to do so would allow AusNet to obtain benefits from the scheme in circumstances where its service performance is not maintained.

9.3.1.1.2 Caps and floors

The AER's Draft Decision determined caps and floors for each SC parameter for the forthcoming period. The AER applied the Kolmogorov-Smirnov (K-S) fit statistic to 2015-19 data to determine its preferred distributions and set caps and floors equal to the 5th and 95th percentiles, respectively. As with the performance targets, the AER considered the Final Decision caps and floors should be based on 2016-20 data.

The AER considered that selected distributions should have a fixed lower bound of zero, and that the K-S statistic was the most appropriate fit statistic. This differed from our Initial Proposal, which used a combination of the K-S and Anderson-Daring (A-D) fit statistics. The AER stated:

> *"AusNet Services used both the Anderson-Daring (A-D) statistic and the Kolmogorov-Smirnov (K-S) statistic in order to choose a distribution for obtaining caps and collars for the sub-parameters. It submitted that the A-D statistic was preferred due to data being concentrated in the middle of the distribution or due to data being concentrated closer to the centre and near tails of the distribution. We do not consider that strong claims that data is more in the middle or the tails of a distribution are able to be supported when there are only five data points. On balance we consider the K-S fit statistic to be preferred due to its simplicity, especially when there is no evidence to suggest the A-D fit statistic is more appropriate in this setting."*[63]

9.3.1.2 Response to the AER's Draft Decision

In this Revised Proposal, we have adopted the Draft Decision's approach to calculating SC targets, caps, and floors for the forthcoming period. Accordingly, we have:

- Calculated targets based on average performance from 2016-20;
- Selected distributions using a fixed lower bound of zero; and
- Used the K-S fit statistic to set caps and floors equal to the 5th and 95th percentiles of the best fit distribution, except in cases where this differs from the AER's preferred approach.

[63] AER, AusNet Services Draft Decision, June 2021: Attachment 10 – Service target performance incentive scheme, p. 11-12.

We do not agree with the AER's reasons for rejecting our proposed adjustments to the large Loss of Supply parameter target. However, because the average of 2016-20 data produces an identical target to that applying in the current period, we are not proposing an adjustment in this Revised Proposal. While we acknowledge the AER's observations in its Draft Decision, we maintain our view that an effective incentive scheme should always provide an opportunity for rewards as well as penalties. We therefore encourage the AER to address the case where a TNSP's performance is approaching the performance frontier in its upcoming incentive schemes review.

The table below sets out our proposed SC targets, caps, floors, and distributions. The key differences between our Revised Proposal and the Draft Decision result from the use of 2016-20 data, which represents the most up-to-date information. Appendix 9A sets out the detailed analysis underpinning the proposed values.

Table 9-1: Proposed SC values

Parameter	Distribution	Cap	Target	Floor
Average circuit outage rate				
Lines event rate – fault	Gamma	12.43%	17.09%	22.37%
Transformer event rate – fault	Erlang	6.49%	11.97%	18.80%
Reactive plant event rate – fault	Dagum	14.90%	20.67%	30.43%
Lines event rate – forced	FatigueLife	3.82%	10.14%	20.74%
Transformer event rate – forced	Burr12	7.54%	11.97%	15.88%
Reactive plant event rate – forced	Burr12	19.65%	27.78%	34.66%
Loss of Supply Event Frequency				
Number of events greater than 0.05 system minutes per annum	Poisson	0	1	4
Number of events greater than 0.30 system minutes per annum	Poisson	0	1	2
Average Outage Duration				
Average Outage Duration	Rayleigh	10.6	42.3	80.8
Proper Operation of Equipment				
Failure of protection system	Poisson	22	31	40
Material failure of SCADA	Geometric	0	1	3
Incorrect operational isolation of primary or secondary equipment	Poisson	3	6	11

Source: AusNet

9.3.2 Market Impact Component

9.3.2.1 Draft Decision

9.3.2.1.1 MIC parameters

The AER's Draft Decision determined a placeholder MIC target for the 2023-27 regulatory control period of 1,236 constrained dispatch intervals (DIs)[64], and an unplanned outage event limit of 210 DIs. These targets were based on an average of the median five years of performance for the seven years from 2013-19. The AER stated that the performance target to apply from April 2022 will be based on average performance of the median five years from the seven year period 2014-20.

9.3.2.1.2 Exclusions

The Draft Decision set out the AER's interpretations of the exclusions which we had raised in our Initial Proposal. Our Initial Proposal identified several exclusion codes (1, 3A, 4, 6 and 11) and explained that a pragmatic interpretation and application of these exclusions was necessary to enable us to participate meaningfully in the MIC. The AER stated it would continue to work with us to clarify how it would interpret and apply these exclusions prior to the commencement of the 2023-27 regulatory control period.

In our response below, we explain the importance of adopting a more pragmatic approach to applying the MIC so that it is 'fit for purpose' as a service target performance incentive.

9.3.2.2 Response to the AER's Draft Decision

9.3.2.2.1 The Energy Transition is Challenging the Operation of the Market Impact Component

The MIC was designed to minimise the impact of outages at times that have the greatest influence on the spot price. To date, we have made significant operational efforts to optimise outage planning to minimise the impacts of outages on the wholesale market. These efforts include:

- Aligning outages of different works programs impacting the same network in the interests of operational effort and cost;
- Hire necessary, but expensive, equipment to perform live line work on constrained parts of network;
- Align critical works to generator outages – which is often sub-optimal for AusNet resourcing;
- Separate other outages that cause binding constraints; and
- Constantly reviewing outages to reduce outage times.

We believe our efforts have resulted in material wholesale price benefits for customers. We want to ensure that our incentive to optimise outage planning is maintained over the 2023-27 regulatory control period as it is in the interests of our customers for us to continue this work.

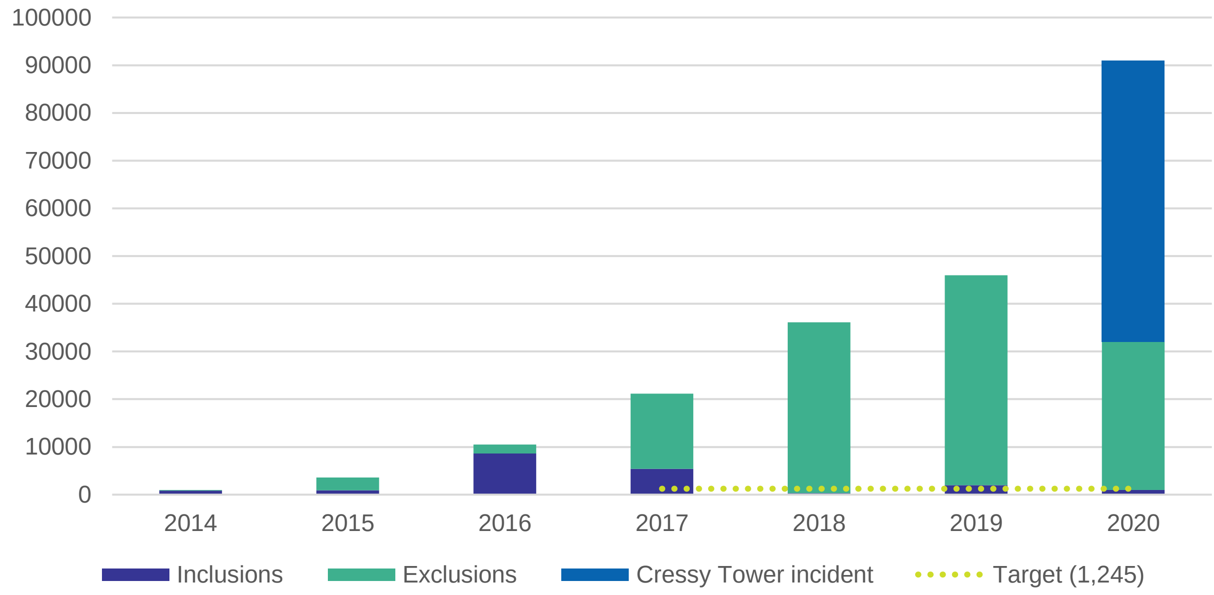
However, the connection of a very large number of renewable generators in Victoria and South Australia and the operational challenges caused by minimum demand, low system strength in parts of the network, and high penetration of renewables in both the transmission and distribution networks in recent years has made managing and applying the MIC extremely challenging.

The figure below illustrates the rapid increase of the number of constrained dispatch intervals (DIs) each year since 2014. The significant change in the composition of the generation mix in

[64] The number of DIs fixed in the MIC is the maximum number of dispatch intervals where an outage on AusNet's transmission network can result in a network outage constraint with a marginal value greater than $10/MWh. Constrained DIs in excess of this number may result in a MIC penalty for AusNet.

the transmission network has led to operational challenges that have directly contributed to the step change in the number of constrained dispatch intervals AusNet records annually.

Figure 9-1: Counted Dispatch Intervals



Note: 2014-16 reflects STPIS V4, 2017-20 reflects STPIS V5

Source: AusNet

Figure 9-1 demonstrates that the number of DIs has increased rapidly year-on-year since the beginning of the current regulatory control period. The extraordinary variance between our MIC target (the dotted yellow line) and the number of constrained DIs underscores the significant challenges our network operations face in identifying outage windows that will not cause a market constraint. The success of the MIC in delivering appropriate incentives that scheme participants respond to is heavily reliant on having a workable exclusion regime. In 2020, over 99% of our constrained DIs were excluded from the final performance measure. This reflects the adoption of a pragmatic approach to the interpretation and application of the exclusions by AusNet and the AER, which allowed the scheme to operate to incentivise behaviour as intended. The sheer volume of the exclusions necessary to keep the scheme functioning as intended calls into question whether it is fit for purpose. In our view, it is a clear indicator that the MIC requires a fundamental redesign.

The high–and growing–number of constrained DIs recorded during the current regulatory period makes the current MIC unworkable because, without taking an expansive approach to the available exclusions, the historic average cannot be reasonably used to set forward targets for the scheme as it will materially underestimate the number of constrained DIs that will be recorded in the new period.

As these challenges began to emerge, in February 2018 AusNet requested that the AER undertake a review of the MIC.[65] In July 2019, we sought the AER's clarification on whether the AER intended to consult on the scheme as part of this review process.[66] Energy Networks Australia submitted a request for a review of the MIC in February 2020.[67] We also raised this in

[65] AusNet Services, ANT Letter AER Service Standards 1 Feb 2018.

[66] AusNet Services, *AusNet Services Transmission Revenue Determination 2023-27 Framework and Approach Initiation*,30 July 2019.

[67] Energy Networks Australia, 20200203 ENA Letter to AER – STPIS Review final, February 2020.

our response to the Framework and Approach paper for this reset the same month.[68] This was not deemed to be a priority by the AER at the time.[69] We urge the AER to revisit its position and include a thorough review of the Market Impact Component in its upcoming Incentive Schemes review to ensure the MIC can provide appropriate incentives in current operational conditions.

To ensure the MIC incentivises AusNet during the 2023-27 regulatory control period as the scheme intends, it is essential that the AER consider transitional measures as part of this review process. We present our proposal for such measures in the following section.

9.3.2.2.2 Our Proposed Approach to Exclusions for 2023-27

Consistent with our Initial Proposal, we are proposing a pragmatic and transparent application of MIC exclusions in the 2023-27 regulatory control period, which largely codifies existing AER approach.

We explained the significant issues affecting the scheme to stakeholders during our engagement processes and tested with them our proposed approach to applying the exclusions to enable the scheme to remain functional and to continue to provide the intended incentives. Stakeholders were supportive of the need for a continued incentive to encourage AusNet to optimise outage planning. They also acknowledged that the benefits of reducing wholesale market prices were likely to outweigh the rewards available to AusNet under the MIC (which is a maximum of 1% of revenues, or around $5.5 – 6.0m per annum).

Stakeholders considered that the first best option would be to review the incentive scheme. Absent that, stakeholders accepted that a transitional approach was required, and requested further information on our historical performance and our proposal to codify the current approach to interpreting the exclusion criteria in the MIC.

In response to this feedback, we circulated a detailed note (Appendix 9E – AusNet's Proposed Transitional Approach to the Market Impact Component) to stakeholders on 6 August 2021 which set out our proposed application of the exclusion clauses in the next regulatory control period. We have sought stakeholder feedback on this proposal.

In the table below, we set out our proposed interpretation of the exclusions most relevant to outage planning and explain the rationale for our approach, having regard to the objectives of the scheme. This table should be read alongside Appendix 9E and section 7.3.1.5 of our Initial Proposal.

Table 9-2: Key Exclusions

Exclusion definition	Proposed to be extended to include:	Rationale/comment
Exclusion 1 **Force majeure events** **Force majeure events are defined as any event, act or circumstance or combination of events, acts, and circumstances which (despite the observance of good electricity industry practice) is beyond the reasonable control of the**	• AEMO-imposed Frequency Control Ancillary Services (FCAS) constraints for outages on assets associated with the VIC-SA interconnector • Fixed limit constraints below 250MW.	The new AEMO constraints are beyond our reasonable control and should be excluded from our performance metrics. It is consistent with the approach the AER has been applied during the current regulatory control period, as well as its Final Determination on the application of the Market Impact Component at the 2017-22 TRR, where two specific constraints were identified as exclusions, with the introduction of new

[68] AusNet Services, *AusNet Services Transmission Revenue Reset 2023-27: Submission to Preliminary Framework and Approach*, 3 February 2020.

[69] Australian Energy Regulator, *Framework and Approach AusNet Services Regulatory control period commencing 1 July 2022*, April 2020, 10.

Exclusion definition	Proposed to be extended to include:	Rationale/comment
party affected by any such event.		constraints arising due to changes in AEMO policies and practices to be assessed over the period.[70] **Codifies current AER approach.**
Exclusion 3A **Any planned outage of an asset that is providing prescribed transmission services shown to be primarily caused by or initiated for the connection of a new asset that is not providing prescribed transmission services as requested by a third-party or by AEMO**	All AEMO or VicGrid-initiated contestable and non-contestable projects, including those that will provide prescribed transmission services.	In Victoria, AEMO-initiated work can be contestable or non-contestable. In addition, AEMO-initiated works may be for assets providing prescribed transmission services (e.g., non-separable augmentations). As we have no control over the timing and nature of this work, and therefore limited control over the duration and timing of the outages we are required take in order to deliver it, outages required for AEMO-initiated projects should be excluded from our performance (and have been during the current period). This would put us on a like-for-like footing with other jurisdictions where TNSPs with the jurisdictional planning function determine the nature and timing of the equivalent work. Consistency between jurisdictions has been a key consideration of the AER in relation to this exclusion in the previous STPIS review, as noted in the Draft Decision.[71] We encourage the AER to clarify its approach in its final decision to provide certainty about how outages for non-contestable works will be treated under the MIC in order to streamline contractual negotiations between AusNet and AEMO over the next regulatory control period. We have extended the exclusion to apply to work initiated by VicGrid, although we note VicGrid's functions are to be determined. **Codifies current AER approach.**

[70] AER, Final Decision, AusNet Services transmission determination 2017-2022, Attachment 11 – Service target performance incentive scheme, April 2017, p. 15-16.

[71] AER, Draft Decision, AusNet Services transmission determination 2022-27, Attachment 10 – Service target performance incentive scheme, June 2021, p. 19.

Exclusion definition	Proposed to be extended to include:	Rationale/comment
Exclusion 4 **Outages on assets that are not providing prescribed transmission services**	O&M outages taken by AusNet's contestable business on assets it owns.	Outages associated with ongoing operation and maintenance of contestable works post-commissioning should be excluded from the MIC. Currently, these are only included when the TNSP is AusNet's contestable transmission business. If another transmission business, such as TransGrid, owned and operated contestable assets, these outages would be excluded. Including outages relating to contestable assets arrangement unfairly penalises AusNet during the contestable tendering process by raising our costs relative to our competitors and should be excluded to ensure competitive neutrality. We have raised this issue in previous STPIS reviews[72] and continue to consider the current treatment is inequitable. **Change required for competitive neutrality.**
Exclusion 6 **Outages that are only for the purpose of assisting with operational security**	Outages on assets required by AEMO to manage operational security to enable a concurrent outage to proceed.	As the level of renewable generation on the network continues to increase, so too does the risk of operational power system security. This means that during outages for essential maintenance, AEMO may require that additional assets also be taken out of service, thereby increasing the MIC constrained DI count beyond our control. AEMO Operations began to advise us of this potential need in September 2020 and our MIC target has not been adjusted to account for it (nor have we previously made an exclusion claim to the AER on this matter). We propose to interpret this exclusion in line with its intent, which is to exclude from the MIC count outages of assets that AEMO directs, instructs, or requests us to remove from service in order that we can take the planned outage on the target asset.

[72] AusNet Services, ANT Letter AER Service Standards 4 Feb 2019; AusNet Services, ANT Letter AER Service Standards 31 January 2020; AusNet Services, ANT Letter AER Service Standards 29 January 2021.

Exclusion definition	Proposed to be extended to include:	Rationale/comment
		By way of example, if AEMO dictates that in order to take circuit X out (e.g., for the purposes of essential maintenance), circuit Y must also be taken out in the interests of operational security, circuit X should be included in our performance, but not circuit Y. This is because we would not have taken out circuit Y but for AEMO's request. **New proposal to deal with emerging issue.**
Exclusion 11 **Transmission connection agreements where a lower service standard has been negotiated giving the TNSP the right to disrupt service under certain network conditions where the constraint only affects the parties subject to the agreement**	Any constraint that constrained an individual participant.	Generators in Victoria and South Australia may continue to bid into the market during an outage. This triggers an individual participant constraint to be placed on the generator. Multiple individual participant constraints can bind simultaneously. Due to the large number of renewable generators in parts of our network a single 8 hour outage can result in up to 2,112 binding DIs. Therefore, a single outage can cause us to exceed our annual MIC target. We have no control over, or visibility of, the constraints that can bind individual generators – due to the Victorian transmission arrangements and the fact that these generators can be in NSW or connected to a distributor, we do not have contracts with these generators. The AER has excluded constrained DIs that arise in this situation during the current period. The severity of the impact of this issue has grown materially in recent years and will only increase over time as more renewable generators connect. **Codifies current AER approach.**

The approach to interpreting exclusions 1, 3A and 11 outlined in the table above in large part codifies the AER's approach to applying the exclusions during the current regulatory control period.

Importantly, our proposed approach is not seeking any adjustments to the way the scheme embeds rewards, as new targets would continue to be set using historical performance (net of our proposed exclusions). Therefore, consistent with other incentive schemes, we would have to improve on historic performance to receive a bonus and would be penalised for any drop in performance. Our proposed approach would not result in additional bonus payments if upcoming transmission network developments reduced the impact of the issues currently being experienced. A change in operational constraints that reverses some of the challenges that have arisen in recent years would merely reduce the number of excluded DIs under our proposed approach, rather than impacting our performance count.

We consider that our approach will result in a transparent, transitional arrangement that can be appropriately applied until such time as the scheme is reviewed and updated. This approach will drive more efficient outcomes for customers by maintaining the incentive for us to optimise our outages to deliver wholesale market price benefits for customers.

9.3.2.2.3 Consequences of maintaining the current approach

In the event that the AER does not adopt the pragmatic approach to the exclusion regime we outline above, the high number of constrained DIs means we will be guaranteed to receive the maximum penalty under the scheme for each year of the 2023-27 regulatory control period. This would result in a total penalty of approximately $29.1M. In these circumstances, we would have no incentive to respond to the scheme, as the actions we undertake to optimise outage planning would have no effect on the outcome. In addition, these actions are costly, and expenditure incurred to respond to the scheme would expose us to additional penalties under the expenditure incentive schemes.

Therefore, it is not reasonable to assume that we would continue to optimise planning outages, at our own cost and for no reward, while also bearing the full MIC penalty of 1% of revenues. We do not consider this would be consistent with:

- The principles underpinning the STPIS, which state that it must 'provide incentives …. to improve and maintain the reliability of those elements of the transmission system that are most important to determining spot prices' [6A.7.4(b)(ii)]. As explained above, the application of the MIC without a pragmatic exclusion regime will provide no positive incentive to AusNet; or
- The Revenue and Pricing Principles, which require a network to be provided with a reasonable opportunity to recover at least the efficient costs it incurs in providing prescribed transmission services.[73] Condemning us to bear a full penalty under this scheme will automatically reduce annual revenues by between $5.5m and $6m below the revenue cap set by the AER in this determination, derived from an assessment of our efficient costs. Such an outcome is wholly inconsistent with, this principle.

Allowing the MIC to persist in its current form and to continue to deliver perverse regulatory outcomes does not contribute to the achievement of the National Electricity Objective (NEO). As explained above, if the MIC fails to incentivise AusNet to minimise market constraints, the cost of the constraints will be borne by electricity customers through higher wholesale market prices. This is clearly not in their long term interests.

For these reasons, if the AER is not minded to adopt our proposal regarding the interpretation of exclusions, it should take steps to disapply the MIC to AusNet as a matter of urgency until such time as the scheme is reviewed.

9.3.2.2.4 Proposed Target

While the exclusion regime undoubtedly requires updating and clarification, we accept the AER's methodology for calculating the MIC parameters. Accordingly, AusNet has calculated its proposed target for the forthcoming period based on the average of the median five years of performance from 2014-20, using adjusted performance measures that are consistent with the interpretation of the exclusions that we intend to apply.

Importantly, should the AER not accept our interpretation of the exclusions above, the target will need to be recalculated to reflect this. That is, the target and the exclusion regime must be determined consistently.

[73] NEL, section 7A(2)(

In accordance with version 5 of the STPIS, the proposed cap and floor are equal to zero and twice the performance target, respectively, while the unplanned outage event limit is equal to 17% of the target. The table below sets out our proposed MIC parameters.

Table 9-3: Proposed MIC parameters

Calendar year	Adjusted performance measure
2014	858
2015	906.5
2016	~~7,826~~
2017	3,040
2018	~~318~~
2019	1,506
2020	728
Parameter	**Dispatch intervals**
Performance Target	1,408
Cap	0
Floor	2,816
Unplanned outage event limit	240
Dollar per dispatch interval ($/DI)	$4,153/DI

Source: AusNet

9.3.3 Network Capability Component

9.3.3.1 Draft Decision

The AER noted that no NCIPAP projects were submitted.

9.3.3.2 Response to the AER's Draft Decision

As mentioned in our Initial Proposal, AEMO plays an important role in the NCIPAP process in Victoria because of its role as the jurisdictional planner. In this capacity, AEMO is responsible for identifying and scoping projects and working with us to quantify project benefits.

We continued to work with AEMO following the completion of the 2020 Victorian Annual Planning Report (VAPR) and network demand forecasts, to identify any potential NCIPAP projects. Upon further investigation, we identified a potential project that could facilitate improvements in the capability of transmission assets that would result in improved capability of the transmission system when users place the greatest value on its reliability.[74] The RealTime System Restoration Manager (RTSRM) will improve the predictions of real-time system conditions. This project will facilitate the reduction in restoration times and improved predictions of system conditions, which may avoid the need for additional network capacity by reducing network constraints. At a capital cost of $0.8M, the RTSRM is expected to deliver market benefits of approximately $3.92M. AEMO agrees with AusNet's project need, improvement target and likely material benefit.[75] Correspondence from AEMO setting out its assessment of this project is provided as an Appendix.

[74] AER, STPIS, clause 5.2(a)(2).

[75] AEMO, AusNet NCIPAP proposal – letter, 27 August 2021.

9.4 Demand Management Innovation Allowance Mechanism

The Demand Management Innovation Allowance Mechanism (DMIAM) is a new incentive scheme for TNSPs designed to promote innovation in non-network solutions, which the AER finalised in May 2021.[76]

9.4.1 Draft Decision

The AER's Draft Decision is to apply the DMIAM to AusNet during the 2023-27 regulatory control period, without any modification. In the Final Decision, the AER will determine the exact amount of the DMIAM allowance based on the Final PTRM.

9.4.2 Response to the AER's Draft Decision

We accept the AER's Draft Decision to apply the DMIAM for the 2023-27 regulatory control period, which applies the mechanism as set out in the F&A paper. In particular, the AER has proposed a maximum allowance of $200k + 0.1% total annual building block revenue requirement. We have included the DMIAM allowance in our revenue requirement for this Revised Proposal, calculated in accordance with the scheme.

Table 9-4: DMIAM Allowance ($m, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
Allowance	0.77	0.74	0.74	0.74	0.73	**3.73**

Source: AusNet

The demand management innovation projects proposed for the 2023-27 regulatory period are shown in the table below. We have assessed the DMIAM requirements and consider that the projects outlined are eligible, reasonable and will provide benefits to customers. These projects:

- Will either research, develop, or implement demand management capability/capacity;
- Are innovative;
- Have the potential to reduce long-term network costs; and
- Will be subject to public consultation, where we will share the learnings with all relevant parties.

Table 9-5: Proposed demand management innovation projects for the 2023-27 regulatory control period

Project name	Project description
Demand management at scale	This project tests whether small scale distribution demand management (DM) programs (such as GoodGrid) can be expanded to the transmission network. If successful, it may be possible to encourage reduced connection point demand during peak periods and help determine the reliability of DM at the transmission level.

[76] AER, Demand management innovation allowance mechanism, Electricity transmission network service providers, May 2021.

Project name	Project description
Integration of DM into control room operations	This project will review the available systems that forecast the need for DM, integrate the information into the control room, and automate the data dispatch and reconciliation process. It may also incorporate key information during both critical peak demand (CPD) tariff events and DM events.
Aggregation platform for DNSP DM, retailer DM and virtual power plants (VPPs)	This project will test whether DM resources held by DNSPs, retailers and other aggregators such as VPPs can be drawn upon, assuming the necessary commercial structures and technical systems integration to these other resources are in place. Ideally, the transmission network would be able to identify the characteristics and draw upon generation from these multiple sources and observe the reaction to system disturbances.
Hydrogen electrolyser load control	On the assumption that large-scale hydrogen production from renewables eventuates, this project would explore the potential for this significant load to be utilised to provide DM to the transmission network and better integrate renewables.
Smart EV charging	This project could capture both residential charging and public fast charging in the one program, given the larger scope to provide this service at the transmission network level. This project may minimise the amount of network investment required to accommodate increases to the future EV fleet.
Optimising Special Protection Schemes (SPSs)	There are several SPSs across the Victorian Transmission Network. This project would examine the effectiveness of these schemes, given increasing DER penetration. The project will also consider how we could leverage DER-related capability within those schemes to benefit system security. This work would likely be undertaken in conjunction with AEMO (which is responsible for SPS design requirements).
Management of the interface between transmission and distribution	This project would explore the interactions between the distribution system operator (DSO) and transmission system operator (TSO). It would focus on the management of minute to minute operational aspects across both transmission and distribution networks accounting for active DER. Benefits may include reduced network losses and improved long-term planning for voltage management and reactive power requirements.

9.5 Efficiency Benefits Sharing Scheme

9.5.1 Our Initial Proposal

9.5.1.1 2017-22 regulatory control period EBSS carryover amount

In our Initial Proposal, we proposed an EBSS carryover amount of $38.1 million from the application of the EBSS in the 2017-22 regulatory control period. We excluded the following costs categories from our EBSS calculation:

- Debt raising costs;
- Easement land tax;

- Self-insurance from 2014-15 and 2016-17;
- Rebates under the Availability Incentive Scheme;
- Priority projects approved under the STPIS network capability component;
- Merits review opex; and
- Movements in provisions related to opex.

Table 9-6 below outlines how the EBSS carryover amount from the 2017-22 regulatory control period will be recovered over the forthcoming regulatory period.

Table 9-6: EBSS carryover amount from the 2017-22 regulatory control period

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
FY18	8.5	0.0	0.0	0.0	0.0	
FY19	1.5	1.5	0.0	0.0	0.0	
FY20	1.6	1.6	1.6	0.0	0.0	
FY21	5.5	5.5	5.5	5.5	0.0	
FY22	0.0	0.0	0.0	0.0	0.0	
Total carryover amount	**17.1**	**8.5**	**7.1**	**5.5**	**0.0**	**38.1**

Source: AusNet

9.5.1.2 Application of the EBSS in the 2023-27 regulatory control period

We proposed to apply the same treatment to the EBSS in the forthcoming period as outlined for the 2017-22 regulatory control period above. This involves excluding, where applicable:

- Easement land tax;
- Debt raising costs;
- Priority projects approved under STPIS network capability component;
- Rebates under the Availability Incentive Scheme; and
- Movements in provisions related to opex.

9.5.2 Draft Decision

9.5.2.1 2017-22 regulatory control period EBSS carryover amounts

The AER's Draft Decision approved an EBSS carryover amount of $39.5 million from the application of the EBSS in the 2017-22 regulatory control period. This is $1.4 million higher than our Initial Proposal, as a result of the following adjustments:

- The AER updated our actual and forecast figures for 2014-15 and 2016-17 to reflect the values reported in our economic benchmarking regulatory information notices, and the AER's final decision on our forecast opex for the 2017-22 regulatory control period.
- The AER did not exclude self-insurance costs from actual and forecast opex for 2014-15 and 2016-17.
- The AER adjusted our total reported opex for actual self-insurance costs over the 2014-15 to 2018-19 period.
- The AER used updated inflation figures to convert amounts into 2021-22 dollars.

Table 9-7 below shows how the AER's Draft Decision EBSS carryover amount from the 2017-22 regulatory control period will be recovered over the 2023-27 regulatory control period.

Table 9-7: EBSS carryover amount from the 2017-22 regulatory period

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
EBSS carryover amount	18.2	8.6	7.1	5.6	0.0	39.5

Source: AER

9.5.2.2 Application of the EBSS in the 2023-27 regulatory control period

In relation to the application of the EBSS for the 2023-27 regulatory control period, the AER's Draft Decision confirmed that it will continue to apply version 2 of the EBSS. In accordance with the terms of the scheme, the AER noted that it will exclude debt raising costs and easement land tax on the basis that they are category-specific forecasts and are expected to remain so over the 2027-32 regulatory control period. In relation to growth asset opex, the AER explained that while this opex is also forecast on a category specific basis, it proposed not to exclude these costs from the EBSS so that any efficiency gains or losses we make in respect of these costs are passed on to customers.

The AER's Draft Decision also noted that other adjustments will be made as permitted by the EBSS, such as removing movement in provisions and rebates under AEMO's Availability Incentive Scheme.

Table 9-8 below outlines the AER's forecast total opex for purposes of applying the EBSS over the 2023-27 regulatory control period.

Table 9-8: Forecast total opex for the EBSS

	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27
Forecast total opex	247.0	247.5	263.5	263.6	263.6	263.8	264.0
Less debt raising costs	-1.7	-1.7	-1.7	-1.7	-1.7	-1.7	-1.7
Less easement land tax	-145.9	-145.9	-173.6	-173.6	-173.6	-173.6	-173.6
Forecast total opex for the EBSS	**99.4**	**99.9**	**88.2**	**88.3**	**88.3**	**88.5**	**88.7**

Source: AER

9.5.3 Revised Proposal

9.5.3.1 2017-22 regulatory control period EBSS carryover amounts

We accept the adjustments outlined in the AER's Draft Decision. However, we have updated the EBSS calculation to reflect our 2020-21 actuals and the latest inflation data from the ABS and RBA. We have also made minor corrections to our opex actuals to reflect the small discrepancies that the AER identified through information request #16. The table below presents our EBSS calculation.

Table 9-9: EBSS carryover amount from the 2017-22 regulatory control period

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
FY18	9.7					
FY19	1.5	1.5				
FY20	1.6	1.6	1.6			
FY21	11.5	11.5	11.5	11.5		

FY22	0.0	0.0	0.0	0.0	0.0	
Total carryover amount	**24.3**	**14.6**	**13.1**	**11.5**	**0.0**	**63.6**

Source: AusNet

9.5.3.2 Application of the EBSS in the 2023-27 regulatory control period

While we accept the AER's Draft Decision on how the EBSS will apply over the 2023-27 regulatory control period, we have updated the forecast opex for the EBSS in the 2023-27 regulatory period (**Table 9-10**) to reflect our Revised Proposal's forecast opex as set out in Chapter 4.

Table 9-10: Forecast total opex for the EBSS

	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27
Forecast total opex	248.9	249.4	277.6	277.8	277.0	277.4	277.6
Less debt raising costs	-1.7	-1.7	-1.7	-1.7	-1.7	-1.7	-1.7
Less easement land tax	-147.1	-147.1	-173.6	-173.6	-173.6	-173.6	-173.6
Forecast total opex for the EBSS	**100.1**	**100.7**	**102.3**	**102.5**	**101.7**	**102.1**	**102.3**

Source: AusNet

9.6 Capital Efficiency Sharing Scheme

9.6.1 Our Initial Proposal

We proposed a CESS carryover amount of $6.4 million ($2021–22) for the 2023-27 regulatory period as outlined below.

Table 9-11: Proposed CESS carryover amount – Initial Proposal ($m, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27	Total
CESS carryover amount	1.3	1,3	1.3	1.3	1.3	**6.4**

Source: AusNet

Our calculation reflected the revised accounting standard (AASB 16), in relation to the capitalisation of leases.

9.6.2 Draft Decision

The AER's Draft Decision was to apply a CESS revenue increment of $5.1 million ($2021–22) for the next regulatory period. The drivers for the difference with our Initial Proposal were due to the Draft Decision's application of:

- More recent inflation data; and
- An updated WACC.

Table 9-12: CESS carryover amount – AER's Draft Decision ($m, real 2021-22)

	2021-22	2022-23	2023-24	2024-25	2025-26	Total
CESS carryover amount	1.0	1.0	1.0	1.0	1.0	**5.1**

Source: AER

9.6.3 Revised Proposal

We have proposed a CESS revenue increment of $8.6 million ($2021–22) for the next regulatory period, as set out in the table below.

Our proposed CESS numbers are slightly higher than the AER's Draft Decision, primarily because our actual 2020-21 capex is lower than the estimate included in our Initial Proposal and the AER's Draft Decision. The lower forecast principally reflects the impact of COVID-19 on our capital works programs, which led to some planned expenditure being deferred.

Table 9-13: CESS carryover amount – Revised Proposal ($m, real 2021-22)

	2021-22	2022-23	2023-24	2024-25	2025-26	Total
CESS carryover amount	1.7	1.7	1.7	1.7	1.7	**8.5**

Source: AusNet

Our proposed net capex for the application of the CESS in the 2023-27 regulatory control period is $815.6 million ($2021–22). This updated amount is consistent with our net capex forecast in this Revised Proposal.

Table 9-14: Proposed capex for the CESS – Revised Proposal ($m, real 2021-22)

	2022-23	2023-24	2024-25	2025-26	2026-27
Forecast net capex	150.7	157.6	191.0	178.6	140.8

Source: AusNet

Separately, we would welcome a discussion with AER staff regarding the implications of the capitalised lease accounting standards change for the operation of the CESS. We are concerned that this accounting change may adversely impact the scheme's ability to appropriately share cost savings between networks and consumers. Specifically, it is unclear how the benefits of a capital investment that has not been funded through expenditure allowances and avoids future lease costs (such as a property purchase occurring during a regulatory period that does not immediately result in reduced lease expenses at other properties) will be realised by a network. The unfunded capex will attract a CESS penalty, however there will be no corresponding reward under the EBSS for the reduced lease expenses. This would not have been the case if lease expenses had continued to be reported as opex, as the base-step-trend opex forecasting approach works with the EBSS to reward lower lease costs.

9.7 Supporting documents

The following appendices are provided to support this chapter:

- Appendix 9A – Fitting probability distributions to Service Component data;

- Appendix 9B – RTSRM Network Capability Incentive Parameter Action Plan;
- Appendix 9C – A completed calendar year 2020 Market Impact Component data template;
- Appendix 9D – AEMO letter of NCIPAP support; and
- Appendix 9E – AusNet's Proposed Transitional Approach to the MIC.

10 Cost Pass Through

10.1 Key points

- We have accepted the AER's Draft Decision in relation to the following pass through events:
    - Insurance Coverage event;
    - Terrorism event;
    - Natural disaster event;
    - Insurer credit risk event; and
    - Victorian Energy Minister's power to direct augmentation event.
- For the nominated 'contamination remediation event', we have provided additional information to demonstrate that this event is reasonable and should be approved.
- The AER's Draft Decision did not accept the nominated 'major cyber event'. While we are disappointed by this decision, we accept the Draft Decision, subject to the AER approving our cyber security opex step change.
- We intend to use the Network Support Pass Through in the Rules to recover network support costs required to take outages to support our capital and maintenance works in the forthcoming regulatory period, consistent with customer preferences to pay no more than our actual costs.
- 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 addresses the insurance coverage event;
- Section 10.4 addresses the terrorism event;
- Section 10.5 addresses the natural disaster event;
- Section 10.6 addresses the insurer credit risk event;
- Section 10.7 addresses the contamination remediation event;
- Section 10.8 addresses the major cyber event;
- Section 10.9 addresses the Victorian Energy Minister's power to direct augmentation event; and
- Section 10.10 sets out our intended use of the Network Support Pass Through.

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.[77]

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 the AER's Draft Decision

We accept the AER's Draft Decision with respect to the application of an insurance coverage event. However, we note that the definition of an insurance coverage event refers to the provision of "direct control services". We consider that this is a carryover of the definition for distribution businesses and that the definition should be updated to reflect the provision of "prescribed transmission services".

10.4 Terrorism event

10.4.1 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.

10.4.2 Draft Decision

The AER accepted the terrorism event we proposed and updated the definition to replace "increase the costs" with "changes the costs" to reflect the symmetry between positive and negative cost pass through events in accordance with the Rules.

10.4.3 Response to the AER's Draft Decision

We accept the Draft Decision with respect to the terrorism event. However, we note that the definition of a terrorism event refers to the provision of "direct control services". We consider that this is a carryover of the definition for distribution businesses and that the definition should be updated to reflect the provision of "prescribed transmission services".

10.5 Natural disaster event

10.5.1 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 while our insurance coverage provides protection against loss and damage as a result of natural disasters, there is still a need for the natural disaster pass through event as we may incur costs that our insurance policy would not ordinarily cover.

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[77] For further information on this and our other proposed events refer to Chapter 12 of the Initial Proposal

10.5.2 Draft Decision

The AER accepted the natural disaster event we proposed and updated the definition to replace "increase the costs" with "changes the costs" to reflect the symmetry between positive and negative cost pass through events in accordance with the Rules.

10.5.3 Response to the AER's Draft Decision

We accept the Draft Decision with respect to the natural disaster event. However, we note that the definition of a natural disaster event refers to the provision of "direct control services". We consider that this is a carryover of the definition for distribution businesses and that the definition should be updated to reflect the provision of "prescribed transmission services".

10.6 Insurer credit risk event

10.6.1 Our Initial Proposal

We proposed an insurer credit risk event to cover costs we may incur as a result of an insurer becoming insolvent.

10.6.2 Draft Decision

The AER accepted the insurer credit risk event we proposed.

10.6.3 Response to the AER's Draft Decision

We accept the Draft Decision with respect to the insurer credit risk event.

10.7 Contamination remediation event

10.7.1 Our Initial Proposal

The amended *Environmental Protection Act 2017* (New EP Act) has altered a number of our environmental obligations or introduced new ones, including requiring us to test for historical contamination and notify the EPA of any contaminated land sites. We proposed an opex step change to cover the new testing regime and a contamination remediation nominated pass through event to enable us to recover any material costs we incur as a result of managing a site found to be contaminated by that testing regime. Detailed information about the change in the nature and scope of our obligations following the amendments to the *Environmental Protection Act 2017* is included in Attachment 4N, which supports our opex step change.

10.7.2 Draft Decision

The AER rejected the contamination remediation event we proposed. The Draft Decision indicated that we had not sufficiently demonstrated that:

- We could not reasonably prevent the event from occurring or substantially mitigate the costs;
- Our obligations to manage land remediation have changed under the New EP Act and examples of the likely impacts; and
- Any future contamination remediation costs should be managed through a nominated pass through event.

The AER considered that while the event meets some of the considerations when deciding to accept a nominated pass through event, it would be reasonable for AusNet to manage the amended EPA obligations without the use of a cost pass through event.

10.7.3 Response to the AER's Draft Decision

We do not accept the Draft Decision with respect to the contamination remediation event. In this section, we provide additional information to address the issues raised by the AER. We expect that this further information, together with the background information in Attachment 4N, will enable the AER to satisfy itself that a contamination remediation event is the most appropriate regulatory mechanism to recover the cost of material contamination remediation costs, having regard to the nominated pass through event considerations.

As noted above, the AER raised specific concerns in the Draft Decision about the contamination remediation event. Our response to these concerns is set out here.

1. AusNet must demonstrate that we could not reasonably prevent the event from occurring or substantially mitigate the costs.

   The pass through event addresses the risk of contamination that already occurred, including prior to privatisation and AusNet ownership. As such, the pass through event relates to contamination that we identify but did not have prior knowledge of or we were not otherwise in a position to either prevent or mitigate.

   One of the key requirements of the New EP Act is the duty to manage contaminated land. If we detect contamination on any of our sites, the costs of remediation could be significant. For example, if we carry out testing and investigation that uncovers asbestos-contaminated soil at one of our sites. In order to fulfil our obligations under the New EP Act, the duty to manage contaminated land would require us to implement immediate and practical measures to minimise the risks of the asbestos contamination to our employees and any other reasonable person associated with the site (human health), as well as the surrounding land users, groundwater users and ecosystem adjoining the site (environment). Discharging these obligations may be in the form of engaging external expert contaminated land advisory organisations, conducting extensive groundwater sampling, providing adequate information to any affected parties, as well as other necessary clean-up and removal activities. These actions (and potentially others) are required in order that we comply with our legislative obligations under the new risk-based framework established by the New EP Act.

   Because it is not possible for us to identify with certainty those sites which may be affected by historic contamination, we cannot forecast with any certainty whether we will incur remediation costs in the forthcoming regulatory control period and, if we do, what the magnitude of those costs might be. In addition, depending on the degree of the contamination, these remediation measures may be on-going in nature and require routine maintenance in future, further contributing to a need for additional resources and/or investment. The quantum of these remediation costs can only be known once contamination is discovered, and the corresponding remediation response is formulated and costed.

   While we would always act prudently to assess the extent of the remediation activities necessary to comply with our obligations under the New EP Act and incur only efficient costs in carrying out those activities, this example demonstrates that our remediation actions would not be considered a 'business-as-usual' approach, as the potential costs to remediate are driven by the New EP Act and are beyond the control of AusNet's ordinary business operations.

2. Demonstrate AusNet Services' obligations to manage land remediation have changed under the amended Act and examples of the likely impacts.

   The change is fundamental and material, with our obligations changing from reactive investigation and mitigation of our own actions that may have caused environmental harm since privatisation, to proactive investigation and mitigation of previous historic harm under SECV and other preceding entities' ownership.

Under the *Environment Protection Act 1970* (the 1970 Act), there was no obligation to proactively investigate and manage contaminated land. Rather, the legislative framework focused on how to respond to an imminent threat to human health or the environment, or to manage pollution once it has occurred. It did not require businesses to take positive steps to identify and prevent and/or remediate environmental risks and hazards. As such, the risk mitigation measures that AusNet had in place under the 1970 Act focused primarily on preventing further contamination by deciding whether to undertake remediation if contamination was identified during site-related works, or when an incident occurred that required remediation. In some instances, our knowledge of previous land use/activities on site may have warranted us undertaking soil/groundwater contamination investigations to manage corporate risk. However, the 1970 Act did not impose on us–or any other entity–an obligation to look proactively for environmental impacts. Rather, it only required a response to actual or suspected pollution where this was subject to a regulatory instrument.

This is no longer the case. Under the New EP Act, it is no longer sufficient to act after a pollution event is detected: AusNet must proactively assess and manage contamination that we 'reasonably ought to have known' about. As the Minister for Energy, Environment and Climate Change explained to the Parliament, the new regulatory model "focusses on preventing harm, rather than acting to clean up after a pollution incident has occurred."[78] In practical terms, this means we must now take positive steps to assess and manage the inherent and residual risks to human health and/or the environment if we have reasonable grounds for believing there may be contamination. This exposes us to an additional class of potential costs that we have not previously been exposed to.

Examples of legacy contamination that may be uncovered through the enhanced testing regime required under the EP Act include:

- Oil containing equipment (polychlorinated biphenyls, mineral and/or hydraulic oil);
- Asbestos (in soil);
- SF6 (sulphur hexafluoride) gas cylinders; or
- Chemicals (herbicides, pesticides, solvents etc).

The response necessary to manage contaminated land will be informed by risk assessments.[79] Required actions could range from regularly monitoring wells, through to partial remediation (e.g., capping contaminated land so the pathway to affected parties is managed) or full site remediation, which may involve contaminated soil being cleaned on site and/or removed from the site. Depending on the nature and level of contamination and size/volume of the site, the costs of this could be significant and exceed the materiality threshold.

3. Explain why any future contamination remediation costs should be managed via a nominated pass-through event and actions we have taken to manage and mitigate such risks.

The contamination remediation event is exactly the type of nominated event that the pass-through protection is designed for. As noted above, the costs remediation may give rise to are clearly uncertain as they will not be incurred if no contaminated land is detected. In addition, if contaminated land is uncovered, there is no reliable way to forecast the remediation costs with sufficient certainty to allow them to be included in the opex forecast. The costs

[78] Parliament of Victoria, Parliamentary Debates (Hansard), Legislative Assembly: fifty-eight parliament, 20 June 2018, 2084.

[79] See Appendix 4O: EPA - Contaminated Land Risk Assessment.

could be incidental (and therefore absorbed by AusNet), or they may be material and exceed the pass-through materiality threshold, in which case the Revenue and Pricing Principles permit AusNet a reasonable opportunity to recover them.[80] The materiality threshold within the pass-through framework ensures that only significant events (those of which have a low likelihood of occurrence and high cost) are covered. This is an efficient form of risk management, as it automatically precludes frequent low cost events which would be better managed via the expenditure allowances.

Furthermore, the need to incur land management or remediation costs is largely out of our control because the contamination has already happened, but the New EP Act requires us to remediate. Therefore, although the quantum of the expenditure on land management or remediation is, to some degree, within our control, we have no control over the historic events that resulted in the contamination.

10.7.3.1 Conclusions

We consider the contamination remediation event to be wholly consistent with the objectives of the pass through framework in that a contaminated site which requires remediation is a low probability/high cost event. The uncertainty about whether contaminated land will be discovered coupled with the cost of managing that land (which may include remediation), means that a risk of this nature is most appropriately addressed by a nominated contamination remediation pass-through event.

10.8 Major cyber event

10.8.1 Our Initial Proposal

We proposed a major cyber event to ensure appropriate protection is established to address the material risk associated with a cyber-attack that is not considered an act of terrorism.

10.8.2 Draft Decision

The AER rejected the major cyber event we proposed because it considered cyber security risk is a key business risk that an energy network service provider faces. The Draft Decision stated that networks are best placed to manage these risks, rather than consumers bearing the risks via a pass through event.

The AER also noted that, consistent with the decisions for distribution businesses, the nominated terrorism event could include cyber-terrorism.

10.8.3 Response to the AER's Draft Decision

We acknowledge that the AER's Draft Decision considers that cyber security risk should be managed by networks and not passed to consumers via a pass through event. However, we also note that the AER recognises that being funded to reach Maturity Indicator Level (MIL) 3 is a key consideration in being able to manage this risk. Our electricity transmission network is a key part of Australia's national critical infrastructure as defined under the Security of Critical Infrastructure Act 2018 (Cth). As a result, as a transmission network service provider, we face higher cyber security related risks than distributors.

The AER also considered it prudent for us to improve our cyber maturity and acknowledged that a step change in expenditure is required. The AER requested further information on how our proposed costs address the capability gaps between our current level of cyber maturity and MIL 3. We welcome the AER's recognition that it is prudent for us to improve our cyber security and

[80] NEL, section 7A(2).

that a step change is required to fund additional investments to achieve this outcome. We also agree with the AER that further information is required to demonstrate that the step change amount is prudent and efficient. We have therefore provided additional information in section 4.9.3.1 of this Revised Proposal. A cost increase due to the need to reach MIL3 meets the AER's definition of a forecast opex step change as it is an externally imposed change in the scope or scale of required opex driven by new compliance requirements.

Accordingly, we have proposed an opex step change for cyber security costs for $28.2M. This expenditure will enable us to adequately invest in the appropriate technologies and infrastructure to withstand and respond to cyber-attacks. In summary, we accept the Draft Decision in relation to the nominated major cyber cost pass through event, subject to the AER approving our cyber security opex step change of $28.2M.

10.9 Victorian Energy Minister's power to direct augmentation event

10.9.1 Our Initial Proposal

We proposed a Victorian Energy Minister's power to direct augmentation event to cover costs we may incur as a result of an augmentation Order made under the *National Electricity (Vic) Act 2005* (NEVA) which may not allow us to access the prescribed regulatory change cost pass through event. A nominated event would allow AusNet to recover the efficient costs incurred in the event we had to comply with an Order.

10.9.2 Draft Decision

The AER accepted the Victorian Energy Minister's power to direct augmentation event that we proposed. The AER clarified that the event definition should be updated to ensure that we only recover the efficient costs associated with an Order once, and that references to AEMO or other third parties are removed as they were not considered relevant. In accepting the nominated event, the AER explained that:

- The Victorian Energy Minister's power to direct augmentation event was not already covered by an existing category of pass through event;
- The nature of the Victorian Energy Minister's power to direct augmentation event is clearly identifiable at this time; and
- As a prudent service provider, we cannot reasonably prevent a Victorian Energy Minister's power to direct augmentation event from occurring or substantially mitigate its cost impact and cannot insure (or self-insure) against the event on reasonable commercial terms.

10.9.3 Response to the AER's Draft Decision

We accept the Draft Decision with respect to the Victorian Energy Minister's power to direct augmentation event.

10.10 Network Support Pass Through

The rapid energy transition has created operational challenges, such as poor system strength in certain parts of the network. This has led to requests from AEMO Operations to engage network support services to facilitate access to the system for certain planned outages, required to undertake maintenance and replacement works. While we have not engaged network support to date, we anticipate we will require it during the next regulatory period in order that we can progress certain projects.

During our stakeholder engagement program, we consulted on whether we should forecast network support costs to support planned outages in our Revised Proposal or seek to recover these using the Network Support Pass Through mechanism.[81] Stakeholders expressed strong support for the use of pass throughs, given the high degree of uncertainty in forecasting network support costs.

There is a lack of specification in the Rules as to whether AusNet or AEMO Victorian Planning should be the party to enter into network support agreements to support planned outages. We have requested the AEMC clarifies this through the 'Efficient Management of System Strength on the Power System' Rule Change process it is currently consulting on. We consider that the Victorian Planner should be responsible for engaging network support for planned outages, as it allows a holistic assessment of the costs and benefits of augmentation versus network support agreements to enable planned outages to proceed, which will help deliver the lowest cost solutions for customers. This would be consistent with the policy intent underpinning the Victorian transmission arrangements.

Notwithstanding the above, the AER has advised that AusNet is able to access the Network Support Pass Through (NER 6A.7.2) where the network support service agreement is the optimal and preferred solution as the means of addressing system strength issues. Any application would need to be supported by AEMO analysis of available options (including augmentation and directing generation on) to confirm this was the case.

We have provided detailed information on upcoming outage plans, including timing and duration, to AEMO Victorian Planning to enable it to refine its analysis to confirm whether network support is the optimal and preferred solution to allow system access for these critical works over the next regulatory period. In the event that it is necessary for us to obtain network support, we propose to recover these costs via the Network Support Pass Through mechanism.

[81] NER 6A.7.2

11 Pricing methodology and Negotiating framework

11.1 Key points

This chapter sets out our response to the AER's Draft Decision with respect to the proposed pricing methodology and Negotiating Framework as set out in Attachments 12 and 14 of the Draft Decision. The key points in this chapter are:

- Our Initial Proposal included a proposed pricing methodology that addressed the NER requirements. The AER's Draft Decision accepted our proposed pricing methodology.
- Subsequent to lodging our Initial Proposal, AEMO proposed changes to its method for setting locational charges. If accepted by the AER, AEMO's updated pricing methodology will have implications for the shared exit services section of our proposed pricing methodology.
- At the time of preparing this Revised Proposal, we cannot be certain whether AEMO's updated pricing methodology will be approved by the AER or not. We have therefore amended our proposed pricing methodology to accommodate both AEMO's revised methodology and its current approach, noting that we will adopt whichever method is approved by the AER.
- We request that the AER approve our updated pricing methodology, which is submitted as an appendix to this Revised Proposal.
- We have re-submitted the joint negotiating framework with AEMO submitted in our Initial Proposal. This follows consultation with the AER and AEMO regarding the implications of the Transmission Connection and Planning Arrangements Rule change in Victoria.

11.2 Chapter Structure

The remainder of this chapter is structured as follows:

- Section 11.3 provides an overview of the proposed pricing methodology for the next regulatory period.
- Section 11.4 provides an overview of the Negotiating Frameworks for the next regulatory period.
- Section 11.5 refers to the supporting documents related to this chapter.

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

11.3 Pricing methodology

11.3.1 Our Initial Proposal

The NER requires a TNSP to submit a proposed pricing methodology for the prescribed transmission services that are provided by means of, or in connection with, a transmission system that is owned, controlled or operated by that TNSP.

The proposed pricing methodology must satisfy the principles and guidelines established under the NER. Specifically, NER 6A.10.1(e) requires the proposed pricing methodology to:

1. give effect to and be consistent with the Pricing Principles for Prescribed Transmission Services (that is to say, the principles set out in NER 6A.23); and
2. comply with the requirements of, and contain or be accompanied by such information as is required by, the pricing methodology guidelines made for that purpose under NER 6A.25.

NER 6A.24.1(b) describes the purpose of the pricing methodology. It states that the pricing methodology is a methodology, formula, process or approach that, when applied by a TNSP:

1. allocates the aggregate annual revenue requirement (AARR) for prescribed transmission services provided by the TNSP to each category of prescribed transmission services;
2. provides for the manner and sequence of adjustments to the annual service revenue requirement (ASRR);
3. allocates the ASRR to transmission network connection points; and
4. determines the structure of the prices that a TNSP may charge for each category of prescribed transmission services under 6A.23.4(a).

Consistent with the above requirements, AusNet submitted a proposed pricing methodology which addressed all of the matters required in the NER.

11.3.2 Draft Decision

The AER accepted AusNet's proposed pricing methodology.

11.3.3 Response to the AER's Draft Decision

As previously mentioned in our Initial Proposal, AusNet will take into account AEMO's intended pricing methodology in our Revised Proposal. AEMO has since proposed to change the method of setting locational charges from the MD10 to the 365 day method, which are explained below:

- In AEMO's current pricing methodology, the estimated proportionate use is the average of a transmission customer's half-hourly maximum demand on the 10 weekdays, between the hours of 11:00 and 19:00 when system demand was highest in the last 12 months (the MD10 method). Hence, transmission connection points with higher maximum demands on the 10 days of system maximum demand would be allocated a relatively a higher lump sum dollar amount under the MD10 method.

- AEMO is proposing to replace the MD10 method with the 365 day method. Under this method, AEMO would use the average of the transmission customer's half-hourly monthly maximum demand over a period of 365 days. Under this method, AEMO would allocate the ASRR for prescribed locational TUOS services using the average monthly maximum demand at each transmission connection point.

As a result of this development, we have updated the shared exit services costs section in our proposed pricing methodology to ensure that the method used to determine shared exit services costs aligns with AEMO's methodology for setting locational charges. We note that other proposed changes to AEMO's pricing methodology will have no impact on our pricing methodology. As the AER's review of AEMO's pricing methodology will not be complete by the time we submit our Revised Proposal, we have drafted alternative text for both methods in our proposed pricing methodology and will adopt whichever drafting corresponds to the method approved by the AER in AEMO's pricing methodology.

In addition, we have updated our proposed pricing methodology to reflect our proposed treatment of shared exist services costs for non-distributor connection customers who share in the use of prescribed connection assets.

In light of the above amendments, we request that the AER approve our updated proposed pricing methodology which is provided as an attachment to this Revised Proposal.

11.3.4 Revised Proposal

In our Revised Proposal, the proposed pricing methodology has been updated to reflect the changes mentioned in section 11.3.3. A copy of this document has been provided in Appendix 11A.

With the recent change to the Victorian distribution regulatory control period from calendar to financial years, the Victorian distribution businesses are required to submit their annual pricing proposal three months before commencement of the second and subsequent regulatory years of the 2022-26 Electricity Distribution Price Review (EDPR) period. This has resulted in a misalignment between the Victorian distribution annual pricing process and AusNet's transmission pricing process and means that our transmission revenue will not be finalised prior to the Victorian distribution businesses submitting their pricing proposals.

This is due to the current timing of the AER's assessment of AusNet's Easement Land Tax (ELT) cost pass through application, and the review of AusNet's performance against transmission service standards performance incentive scheme (STPIS). Historically, AusNet would submit the ELT and STPIS performance report around early February and the AER would then finalise its decisions by April each year.

We would like to work with the AER on whether the ELT and the STPIS approval processes can be finalised by early March, enabling both AusNet and AEMO to finalise and publish their respective transmission charges by 15 March annually. Alternatively, if the existing approval process timelines remain unchanged, AusNet could provide the Victorian distribution businesses with indicative prescribed transmission connection charges on 15 March (in which they can use as part of their annual pricing process)[82], and subsequently provide finalised prescribed transmission charges on or before 15 May[83].

We plan to engage further with the AER, the Victorian distribution businesses, and AEMO on this matter.

11.4 Negotiating Framework

11.4.1 Our Initial Proposal

The NER requires certain transmission services (negotiated transmission services) to be provided on terms and conditions that are negotiated between the TNSP and the service applicant. Negotiated transmission services are a class of service defined in Chapter 10 of the NER. They broadly include services provided in relation to generation or direct connect customer connection to the shared transmission network.

Our Initial Proposal stated that the 2017 Transmission Connection and Planning Arrangements Rule change[84] removed the requirement for a negotiating framework from all other jurisdictions except Victoria.

Due to the split transmission arrangements in Victoria, AusNet and AEMO have historically proposed a joint (and co-branded) negotiating framework to enhance simplicity for service applicants seeking a negotiated transmission service with either AEMO or AusNet.

[82] Under this approach the Victorian distribution businesses would be exposed to short term cash flow risk, and will true up any differences in charges via their respective unders and overs account in subsequent years.

[83] AEMO would still finalise and publish transmission prices on 15 March and will true up any difference in revenue from the ELT and STPIS decisions in the subsequent year.

[84] AEMC, *Rule Determination, National Electricity Amendment (Transmission Connection and Planning Arrangements) Rule 2017*, 23 May 2017.

11.4.2 Draft Decision

The Draft Decision did not approve AusNet's proposed negotiating framework. While the AER considered the substance of the proposed negotiating framework met the requirements of the Rules, it required editorial amendments to clarify that the propose negotiating framework only applies to AusNet. This included removing AEMO branding and consequential references to AEMO throughout the framework.

The Draft Decision explained that these amendments were required because following the 2017 Transmission Connection and Planning Arrangements Rule change, AEMO was no longer required to submit a negotiating framework to the AER for approval.

In addition, the AER will apply the Negotiated Transmission Services Criteria published on 17 May 2021 to AusNet.

11.4.3 Response to the AER's Draft Decision

Since the Draft Decision we have had further discussions with AEMO and the AER regarding the implications of the 2017 Rule change in Victoria.

We acknowledge the AER's and AEMO's view that AEMO no longer needs to submit a negotiating framework to the AER for approval. Notwithstanding this, AEMO will still have a negotiating framework and there remain simplicity benefits for service applicants if AusNet and AEMO continue to have a joint, co-branded, negotiating framework.

While AEMO may not be required to submit a negotiating framework to the AER for its approval, this should not prohibit the AER from approving a negotiating framework for AusNet, which is shared with AEMO. The AER's formal approval will only apply to AusNet and not to AEMO.

We accept the application of the Negotiated Transmission Services Criteria set out in the Draft Decision.

11.4.4 Revised Proposal

For the reasons set out above, we re-submit the negotiating framework (jointly with AEMO) that formed part of our Initial Proposal. We consider this approach is compliant with the Rules, and we recognise that only AusNet, and not AEMO, will be bound by the AER's decision in respect of this document.

11.5 Supporting documents

The following Appendices are relevant to this chapter:

- Appendix 11A – Revised Proposed Pricing Methodology (1 April 2022 – 31 March 2027); and
- Appendix 11B - Victorian Negotiating Framework.