Tasmanian Transmission and Distribution Revised Proposals 2019 - 2024

Regulatory Control Period
1 July 2019 to 30 June 2024

29 November 2018

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Amendments and Version History

Version No.	Date of Revision	Authorised by	Details of amendment
0.1	10 October 2018	Program Leader Revenue Resets	Initial draft
0.2	12 November 2018	Revenue Reset TLT	Endorsement
0.3	22 November 2018	Revenue Reset Committee	Endorsement
1.0	22 November 2018	TasNetworks Board	Approval
1.1	29 November 2018	Program Leader Revenue Resets	Cleared for submission

Amendments to each version of this document will be tracked through TasNetworks' document management system.

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Executive Summary

Purpose of this document

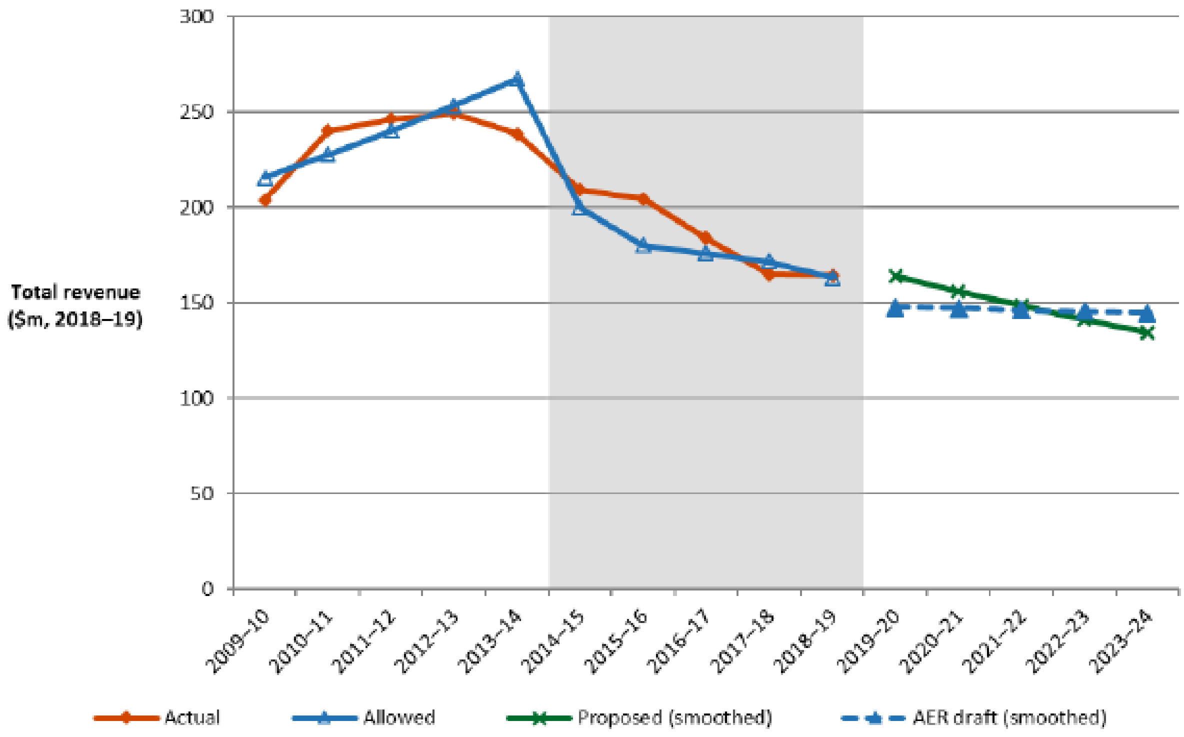
In January 2018 we submitted our combined transmission and distribution Revenue and Regulatory Proposal for the period 1 July 2019 to 30 June 2024. The AER published its draft decision on that Proposal on 27 September 2018.

This document is our combined revised Revenue and Regulatory Proposal (**revised Regulatory Proposal**) prepared in response to the AER's draft decision.

Background: The AER's draft decision

The figures below (which are reproduced from the AER's draft decision) show how the AER's draft decision compares with our original proposed revenues for transmission and distribution[1]. Historical revenues are also shown for comparison purposes.

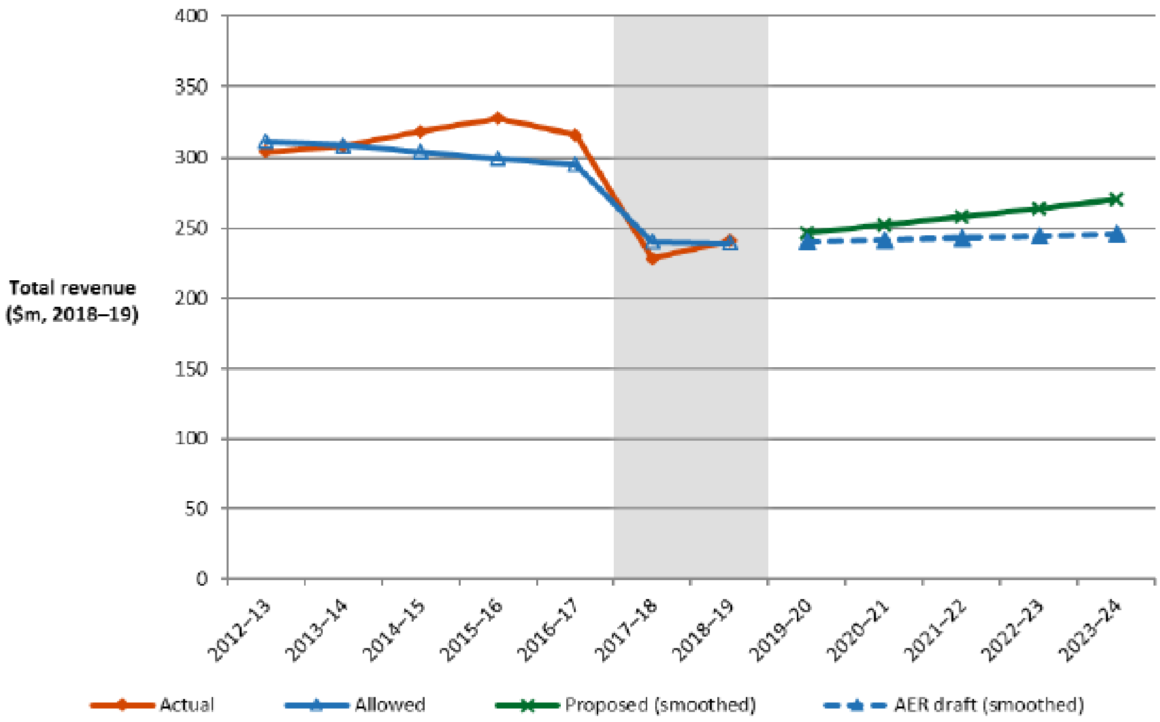
Figure 1: Transmission revenues - historical, proposed and draft decision (June 2019 $m)



Source: AER analysis, smoothed revenue.

[1] AER, draft decision, TasNetworks Transmission and Distribution Determination 2019 to 2024, Overview, Figures 1 and 2.

Figure 2: Distribution revenues - historical, proposed and draft decision (June 2019 $m)



Source: AER analysis, smoothed revenue.

As shown in the figures above, the AER's draft decision proposed a slightly lower overall revenue for transmission with a flatter profile than we originally proposed. For distribution, the AER's draft decision imposes a materially lower revenue and a flatter profile. In summary, the AER's draft decision set the following total revenues over the 5 year regulatory period:

- total transmission revenues of $787.5 million (nominal), which is 1.5 per cent lower than our originally proposed transmission revenues of $799.6 million.
- total distribution revenues of $1,308.3 million (nominal), which is 6.1 per cent lower than our originally proposed distribution revenues $1,392.7 million.

The AER's proposed changes in our total revenues are largely attributable to its decision on our rate of return and reductions in our proposed capital expenditure. The AER explained that if the draft decision were implemented it would require[2]:

- A nominal reduction of 10.2 per cent in TasNetworks' transmission revenues in 2019–20 compared to the current, 2018–19 level. This reduction would be followed by average annual increases of 1.8 per cent over the remaining four years (2020–21 to 2023–24).
- A nominal increase of 1.8 per cent in TasNetworks' distribution revenues in 2019–20 compared to 2018–19, followed by annual average increases of 2.8 per cent over the remaining four years.

The AER commented that its proposed reduction in our distribution revenues will lead to a nominal increase of 0.6 per cent in the average annual electricity bill in 2019–20 compared to the current,

2 AER, draft decision, TasNetworks Transmission and Distribution Determination 2019 to 2024, Overview, page 13.

2018–19 level, followed by annual average increases of 1.0 per cent over the remaining four years (2020–21 to 2023–24).

As explained in this revised Regulatory Proposal, TasNetworks does not accept all aspects of the AER's draft decision. In particular, our further analysis shows that the AER's proposed reductions in our capital expenditure plans cannot be achieved without posing considerable risks to the reliability and safety of supply, which would be contrary to our regulatory obligations and our customers' preferences.

As a consequence, our assessment is that our future expenditures and prices should be slightly higher than indicated by the AER's draft decision. Our revised Regulatory Proposal, however, keeps strong downward pressure on electricity prices.

At the start of the next regulatory period, our proposed network charges for a typical residential customer will be 22 per cent lower in real terms compared to our charges in 2013-14. The reduction for a typical small business customer over the same period will be even greater at 39.6 per cent in real terms. These are significant savings, especially in the context of an uncertain and changing operating environment.

External changes since January 2018

The electricity supply industry is facing significant technological change and uncertainty, which has led to numerous reviews and policy developments to ensure that the National Energy Rules (the **Rules**) and the regulatory framework continue to be 'fit for purpose'. In particular, the following reviews, plans and policy initiatives were active when, or have been initiated since, our original Regulatory Proposal was submitted in January 2018:

- The proposed Retailer Reliability Obligation;
- AEMO's Integrated System Plan;
- The AER's development of binding Rate of Return Guidelines;
- The AER's review of the regulatory tax allowance; and
- The ACCC's report on retail pricing.

While only some of these matters will have a direct impact on our revenue requirement in the forthcoming regulatory period, each creates particular challenges that must be addressed. Our approach, which is reflected in this revised Regulatory Proposal, is to ensure that we are appropriately equipped to address the challenges ahead, while continuing to provide the affordable, safe and reliable services that our customers expect.

Our response to the draft decision

We summarise briefly below the key elements of our response to the AER's draft decision.

Operating expenditure

Our original Regulatory Proposal explained that we adopted the AER's 'base-step-trend' method in preparing our transmission and distribution operating expenditure forecasts. For this determination, we proposed using 2017–18 as the base year for the purpose of forecasting both our transmission and distribution operating expenditure.

The AER's draft decision accepted our forecasting approach, but employed inputs that differed slightly from our original proposal. Overall, however, the AER's draft decision concluded that both our proposed transmission and distribution operating expenditure were lower than the AER's alternative forecast. In effect, the AER accepted our operating expenditure forecasts because our proposal was lower than its own estimate of efficient costs[3].

An important change in this revised Regulatory Proposal is that our estimates for transmission and distribution operating expenditure for the base year, 2017-18, have been updated in accordance with standard regulatory practice to reflect our actual audited expenditure. Our actual total operating expenditure across the two business activities is closely aligned with the estimated total in our original Regulatory Proposal. Within this total operating expenditure, however, our actual transmission operating expenditure is lower than expected, while our distribution operating expenditure is higher. These differences reflect the changing mix of activities across our business, which operates flexibly across transmission and distribution.

We have updated our operating expenditure forecasts to reflect the updated actual information in relation to the base year. Our revised operating expenditure allowances for our transmission and distribution services continue to benchmark well against our peers. We have continued to apply productivity targets and we have partially absorbed the cost of step changes in the forthcoming regulatory period, as explained in our original Regulatory Proposal.

We are confident that our revised operating expenditure forecasts continue to satisfy the Rules requirements and therefore should be approved by the AER in its final decision. As with our original Regulatory Proposal, our revised operating expenditure forecasts deliver a very good outcome for our customers.

Capital expenditure

We have considered all of the matters raised by the AER in its draft decision and we have revisited our transmission and distribution capital expenditure forecasts accordingly. We have undertaken significant additional work to quantify risk and its associated costs to justify our revised expenditure plans and address the matters raised by the AER's draft decision. Our review has found that full implementation of the AER's draft decision would expose customers to unacceptably higher risks in terms of reliability and safety.

The consistent feedback from our customers is that they prefer a sustainable level of expenditure, which does not accrue problems for future customers. We have therefore concluded that the expenditure reductions proposed in the draft decision are not consistent with our customers' preferences, nor our regulatory obligation to maintain safety and reliability.

We have identified areas, however, where the AER's draft decision in relation to some capital expenditure programs can be accommodated without unduly compromising service performance, safety or sustainability. We have therefore adopted these changes and also updated our forecasts for the latest available information. For some expenditure categories, however, we have found it necessary to increase our capital expenditure forecasts from the level originally proposed.

[3] AER, draft decision, TasNetworks Transmission and Distribution Determination 2019 to 2024, Overview, page 42.

Our revised total transmission capital expenditure is $260.4 million over the 5 year period, which is similar to our original forecast[4]. Our revised distribution capital expenditure is $706.8 million over the 5 year period, which is $32 million or 4.3 per cent below our original forecast. Our revised transmission and distribution capital expenditure forecasts represent the minimum efficient investment we need to meet our compliance obligations and to maintain the appropriate balance between safety and reliability and cost.

We are confident that our revised forecast expenditure complies with the Rules requirements.

Contingent Projects

Contingent projects are significant network augmentation projects that are relatively uncertain to proceed in the forthcoming regulatory period. We originally proposed five contingent projects. However, two projects - the rationalisation of the Upper Derwent 110 kV Network and augmentation of the 110 kV transmission system between Burnie and Smithton (for which a cheaper option has been identified) - are no longer expected to proceed in the forthcoming regulatory control period. Therefore, these two projects are not included in this revised Regulatory Proposal.

In its draft decision, the AER rejected our contingent project proposals on the basis that the project triggers were not sufficiently specific and the projects would probably not be required during the forthcoming regulatory period[5].

To address the concerns raised in the AER's draft decision, we have undertaken considerable additional analysis for each of the three remaining contingent projects, including additional background on each project and an explanation of why each project would deliver a net economic benefit if the specified trigger events occur. For Marinus Link, we have also recognised the importance of ensuring that Tasmanian customers pay no more than their 'fair share' of the project costs, commensurate with the benefits they receive. In particular, we will consider new interconnector funding and pricing measures that recognise national benefits and see beneficiaries paying their fair share of the costs.

The inclusion of the three contingent projects in our revised Regulatory Proposal secures funding only in the event that the projects can demonstrably deliver a net benefit. If this hurdle is satisfied, the AER will scrutinise our proposed expenditure in accordance with the contingent project provisions in the Rules. Those provisions require the AER to apply a prudency and efficiency test to ensure that customers pay no more than necessary for the proposed projects.

Given these observations, the AER's acceptance of the three contingent projects in this revised Regulatory Proposal is unequivocally in our customers' interests. A decision to reject a contingent project would deny us the required funding in circumstances where the project benefitted customers. Furthermore, our customers will not face any additional costs unless a project is shown to deliver net benefits and the AER has approved the project costs.

We therefore expect the AER to approve the contingent projects and the updated trigger events, as submitted in this revised Regulatory Proposal. As noted above, we have undertaken further work to ensure that we have addressed the AER's concerns and satisfied the Rules requirements.

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[4] As noted in section 1.4, unless stated otherwise, monetary values are presented in June 2019 dollars.

[5] AER, draft decision, TasNetworks Transmission and Distribution Determination 2019 to 2024, Overview, page 39.

Regulatory Asset Base

The AER's draft decision updated our regulatory asset base to reflect its lower capital expenditure forecast[6]. In this revised Regulatory Proposal, we have also updated our regulatory asset base to reflect our actual capital expenditure in 2017-18 and our revised capital expenditure plans.

Depreciation

The AER's draft decision accepted our proposed approach to depreciation, which is the more accurate 'year-on-year' tracking approach. The AER also accepted the resulting depreciation, subject to a number of minor changes, which we have adopted in this revised Regulatory Proposal.

Our forecast regulatory depreciation has been updated to reflect our actual capital expenditure and our revised capital expenditure plans.

Rate of Return

The AER's draft decision proposes a rate of return in accordance with its draft 2018 Rate of Return Guidelines[7].

In our original Regulatory Proposal, we explained that a Rule change[8] was made by the AEMC in September 2017 to clarify that the 2013 Guidelines should apply. However, we understand that likely legislative change will ultimately require the 2018 Guidelines to be applied in the AER's determination.

The AER's 2018 Guidelines will not be finalised until December. In submissions to the AER, Energy Networks Australia has raised significant concerns regarding the WACC parameters in the draft Guidelines. We note that the AER has indicated that it will address these submissions in its final version of the 2018 Guidelines.

While we strongly support Energy Networks Australia's submissions, we have decided to accept the AER's draft decision in relation to rate of return for the purpose of this revised Regulatory Proposal. We only accept the rate of return in the AER's draft decision on the basis that:

- it will be updated to reflect the AER's finalised Guidelines; and
- legislation is enacted requiring the 2018 Guidelines to apply to our 2019-24 determination.

Subject to the above caveats, our proposed rates of return are 5.77% for transmission and 5.51% for distribution, which reflect the AER's draft decision[9].

Corporate Tax

The AER has commenced a review of its approach to setting the regulatory allowance for corporate tax. The review was initiated by the Federal Minister for Energy, who raised concerns that the amount of tax paid by energy companies was lower than the regulatory tax allowance. The AER's

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6 AER, draft decision, TasNetworks Transmission and Distribution Determination 2019 to 2024, Overview, pages 31 and 32.

7 AER, draft decision, TasNetworks Transmission and Distribution Determination 2019 to 2024, Overview, page 33.

8 AEMC, Rule Determination, National Electricity Amendment (Application of rate of return guidelines to TasNetworks) Rule 2017, 26 September 2017.

9 AER, draft decision, TasNetworks Transmission and Distribution Determination 2019 to 2024, Overview, page 34.

review is expected to be completed in December 2018. At this stage, it is unclear whether the AER will recommend any change to the current approach. For the purpose of this revised Regulatory Proposal, we have therefore calculated our corporate tax allowance in accordance with the AER's current regulatory approach.

In its draft decision, the AER rejected our proposed value of 0.4 for gamma and instead imposed a value of 0.5, which has the effect of reducing our tax allowance[10]. We originally proposed a gamma value of 0.4 because it was consistent with the AER's most recent determinations and a recent decision by the Federal Court.

For the purpose of this revised Regulatory Proposal, and subject to the caveats noted above in relation to the rate of return, we have accepted the AER's proposed value for gamma. In adopting this approach, we note that a gamma value of 0.5 is consistent with the AER's draft 2018 Guideline and will be updated to reflect the final version of the Guideline, which is expected to be published in December 2018.

Our revised transmission revenue requirements

The table below summarises our revised transmission revenue building block calculation for each year of the forthcoming regulatory period, alongside the final year of the current period (2018-19).

Table 1: Summary of our Transmission Revenue Requirements and X Factors ($m nominal)

	2018–19	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Return on Capital	95.70	84.0	86.5	88.8	90.8	92.2	442.3
Regulatory Depreciation	26.78	16.3	22.5	25.6	27.3	32.5	124.2
Operating expenditure (incl. Debt Raising)	48.90	30.8	31.7	32.6	33.6	34.6	163.2
Efficiency carry over[11]	-	18.6	9.9	10.9	5.1	0.9	45.5
Net tax allowance	4.44	1.4	1.9	2.1	2.3	3.0	10.7
Transmission Requirement (unsmoothed)	175.83	**151.1**	**152.4**	**160.0**	**159.0**	**163.3**	**785.9**
Transmission Revenue Requirement (smoothed)	**168.13**	**151.1**	**154.1**	**157.1**	**160.2**	**163.4**	**785.9**
X factors (percentage)[12]		**12.28%**	**0.47%**	**0.47%**	**0.47%**	**0.47%**	**-**

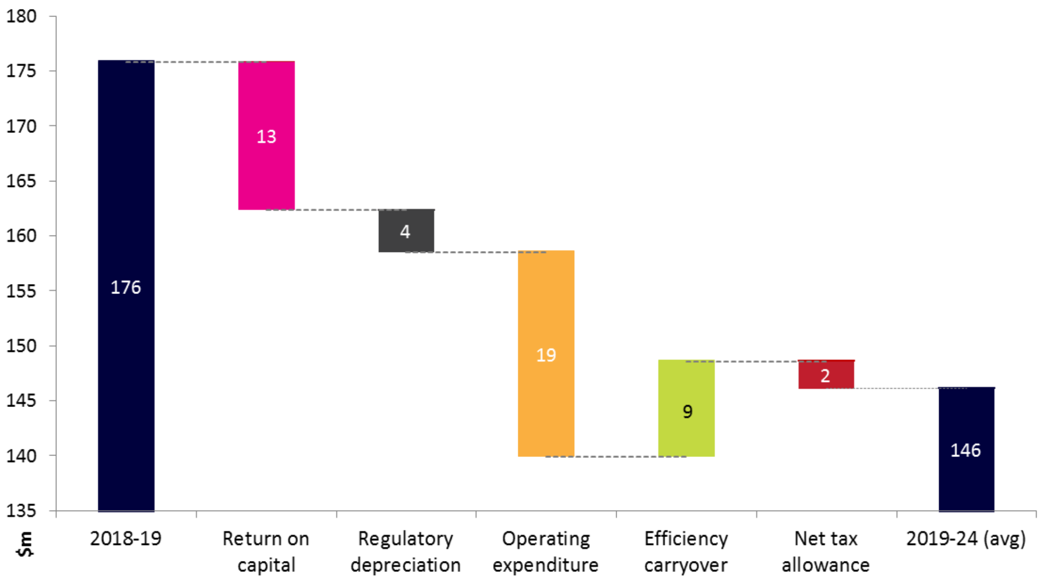
The figure below shows the change in our revised transmission revenue requirements from the current to the 2019-24 period. It shows our average annual transmission revenue for the 2019-24 period (the right-hand blue bar) compared to our transmission revenue for 2018-19 (the left-hand blue bar). The intermediate coloured bars show each of the drivers that lead to the lower average revenue in the 2019-24 period, expressed in real terms.

10 AER, draft decision, TasNetworks Transmission and Distribution Determination 2019 to 2024, Overview, page 34.

11 This includes the allowances provided under the Demand Management and Embedded Generation Connection Incentive Scheme (formerly the Demand Management Incentive Scheme, or DMIS).

12 The X factor applies in the revenue cap CPI-X formula, which means that the percentage shown is the proposed annual reduction in revenue expressed in real terms.

Figure 2: Transmission revenue requirements from 2018-19 to 2019-24 (average) (June 2019 $m)



Our revised distribution revenue requirements

The table below summarises our revised distribution revenue building block calculation for each year of the forthcoming regulatory period alongside the final year of the current period, which is 2018-19.

Table 2: Summary of our Distribution Revenue Requirements and X Factors ($m nominal)

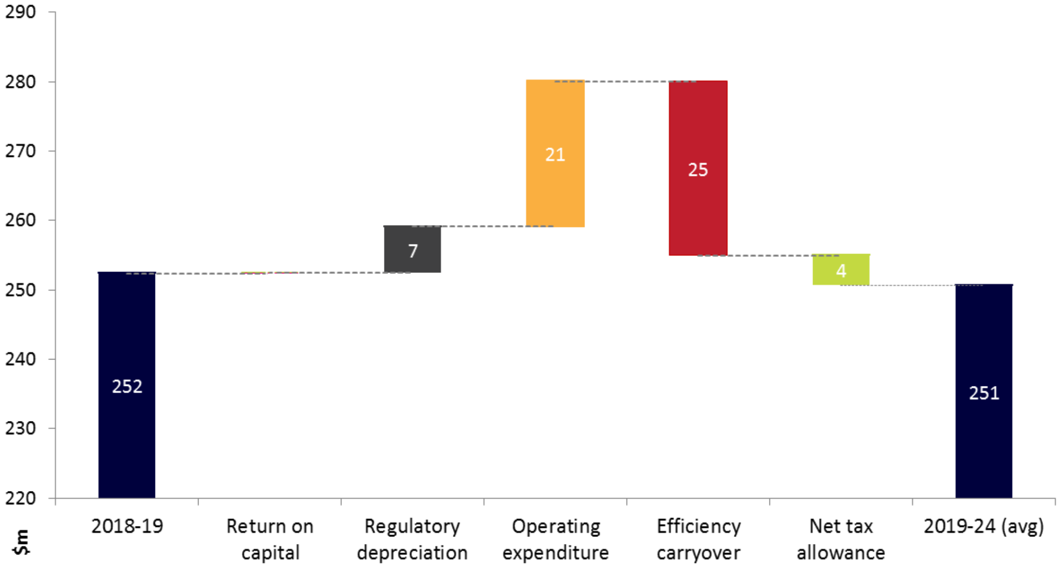
	2018–19	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Return on Capital	101.33	99.26	104.98	109.86	113.81	118.11	546.0
Regulatory Depreciation	57.64	56.80	62.92	70.16	75.75	81.20	346.8
Operating expenditure (incl. Debt Raising)	68.42	92.96	94.80	96.19	97.59	99.02	480.6
Efficiency carry over[13]	12.83	-21.19	-21.70	-22.23	2.86	-2.23	-64.5
Net tax allowance	12.16	7.64	7.98	8.38	8.90	9.67	42.6
Distribution Requirement (unsmoothed)	252.39	235.48	248.98	262.37	298.91	305.77	1,351.5
Distribution Revenue Requirement (smoothed)	**241.01**	**249.99**	**259.31**	**268.96**	**278.97**	**289.34**	**1,346.6**
X factors[14]		**-1.25%**	**-1.25%**	**-1.24%**	**-1.24%**	**-1.24%**	**-**

The figure below shows the change in distribution revenue requirements from the current to the forthcoming regulatory period, expressed in real terms.

13 This includes the allowances provided under the Demand Management and Embedded Generation Connection Incentive Scheme (formerly the Demand Management Incentive Scheme, or DMIS).

14 The X factor applies in the revenue cap CPI-X formula, which means that the percentage shown is the proposed annual reduction in revenue expressed in real terms.

Figure 3: Distribution revenue requirements from 2018-19 to 2019-24 (average) (June 2019 $m)

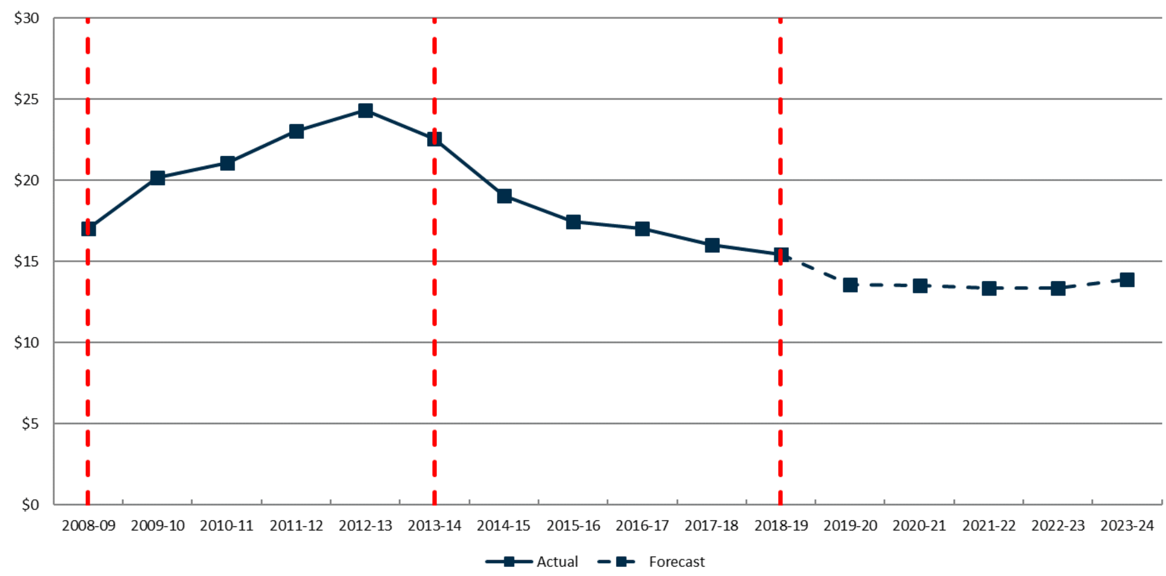


The combined effect of our revised proposals is that our total transmission and distribution revenues over the 5 year regulatory period will increase by $36.7 million[15] or 1.75% above the AER's draft decision. This is a relatively modest difference, given the complexity and uncertainty associated with planning expenditure over a 5 year period.

Customer pricing outcomes

The reducing transmission revenue profile means that transmission prices (in real terms) should drop at the end of the current regulatory period and then remain relatively consistent over the 2019-24 period in nominal terms and therefore continue to fall in real terms. This is shown in the figure below. The transmission revenue profile translates to an average price of $13.55 per MWh over the forthcoming regulatory period, which is 20 per cent lower than the current five year period.

Figure 4: Indicative average transmission charges ($/MWh) (June 2019 $)



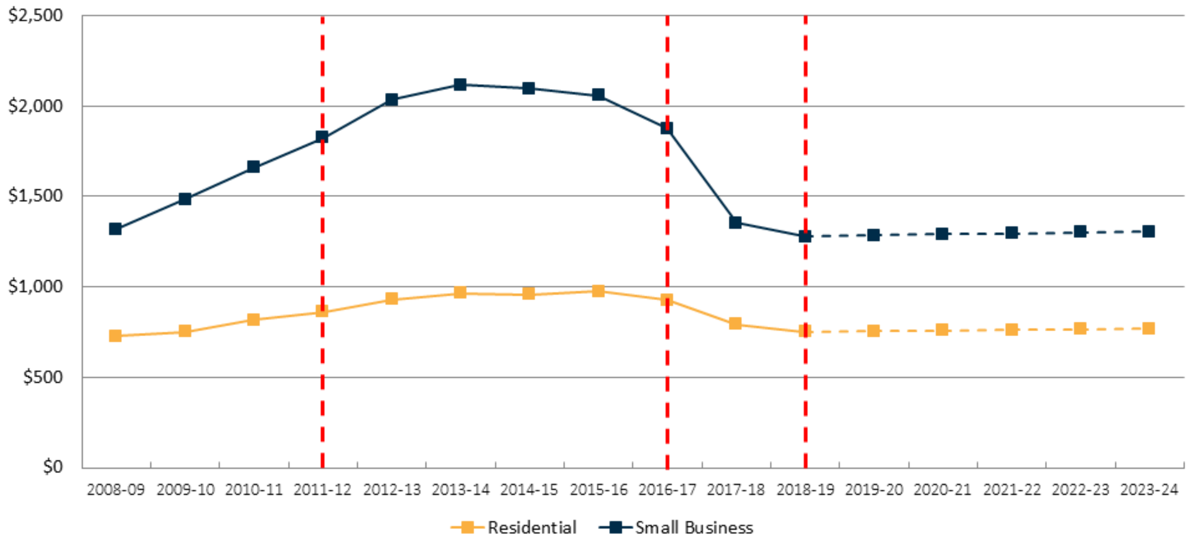
15 $37.7 million is the difference in total revenues over the 5 years, expressed in nominal terms.

The distribution revenue allowance for each year, together with the applicable share of the transmission network charges (around 55 per cent), is recovered from our distribution customers. Our combined transmission and distribution charges are recovered through a framework of network pricing "tariffs" which are applied to each customer and charged to retailers.

Transmission and distribution network costs presently make up around 43 per cent of the typical Tasmanian residential and small business customer's electricity bill. The chart below shows the projected annual network charges for typical residential and small business customers, based on our revised expenditure proposals.

The forecast average network charges per annum for residential and business customers are set out below. The network charges include forecast transmission and distribution charges, assuming no over or under-recoveries or incentive adjustments.

Figure 5: Indicative average annual network charges per annum (June 2019 $)



1 Introduction

1.1 Purpose of this document

Under the National Electricity Law (**NEL**) and the National Electricity Rules (**the Rules**), the AER is responsible for the economic regulation of electricity transmission and distribution services.

In accordance with the Rules, the AER conducts a periodic review to determine our revenue requirements and other matters relating to the provision of regulated electricity transmission and distribution services. The AER has now published its draft decision following a detailed review of our Regulatory Proposal, which we submitted on 31 January 2018, covering the 5 year period commencing on 1 July 2019.

This document is our revised Regulatory Proposal, which includes:

- an overview paper explaining the revised Regulatory Proposal in plain language and how our customer engagement has informed our revised proposal;
- an updated tariff structure statement, which explains how we propose to set our network tariffs and prices for a range of regulated distribution services; and
- supporting information to address detailed issues raised in the AER's draft decision. The accompanying supporting information are identified with a specific "TN" document reference number, which are cross-referenced in this document.

1.2 Structure of this Revised Regulatory Proposal

This revised Regulatory Proposal is presented in four parts, as explained below.

- Part One describes our approach to this revised Regulatory Proposal;
- Part Two focuses on our transmission and distribution services that are subject to revenue cap regulation. We present updated total revenue requirements for the forthcoming regulatory period, taking account of the AER's draft decision on our expenditure plans and revenue requirements. This part also revisits our proposed tariff structures, following the AER's feedback that we should accelerate the transition to more cost reflective tariffs;
- Part Three addresses the AER's draft decision on Alternative Control Services, which include legacy metering services, public lighting, and customer-requested services such as special meter reads or new connections; and
- Part Four addresses other matters raised in the AER's draft decision, including our connections policy. This section also addresses the confidentiality and certification requirements in the Rules.

This revised Regulatory Proposal is consistent with AEMO's Integrated System Plan, published in June 2018, which subsumes the National Transmission Network Development Plan.

We do not claim confidentiality in relation to any part of this document. Where confidentiality is claimed in respect of any appendices or supporting documents, a redacted version has been provided, along with details of the claim for confidentiality.

1.3 Global assumptions

In preparing this revised Regulatory Proposal, we have adopted a number of assumptions and guiding principles in relation to our capital and operating expenditure forecasts. It should be noted that these assumptions have been updated from those presented in our original Regulatory Proposal to reflect the latest available information. Our updated assumptions and principles are:

- The direction outlined in TasNetworks' *Strategy on a Page 2017-18* and *TasNetworks' Transformation Roadmap 2025* will underpin our strategic direction across the forthcoming regulatory period.
- We will adopt an innovative approach to network development and operation that delivers sustainable customer outcomes at the lowest sustainable price for our business.
- We will meet our compliance obligations, including those relating to reliability requirements, physical security, safety, environment, risk and other matters.
- Our expenditure plans reflect our customers' preferences in relation to reliability and price trade-offs.
- Our asset management plans and strategies are consistent with good asset management practice and reasonably reflect our future expenditure requirements.
- We will have the resources and capability to deliver the programs forecast for the forthcoming regulatory control period.
- Our forecasts of escalation rates are reasonable.
- Any material cost changes arising from amendments to the legislative and regulatory framework in the forthcoming regulatory period will be eligible for pass-through. Therefore, our forecasts do not include provision for any such changes.
- We will procure, as necessary, agreements for the provision of inertia services and seek recovery of our costs as an inertia shortfall event cost pass through (as provided by Rule 6A.7.3). We note that the definition of "network support payment" includes payments made by a TNSP under an inertia services agreement so that the costs we incur are recoverable as a cost pass through.
- There will be no changes to the Tasmanian rules and laws regarding the ownership of private infrastructure.

In accordance with the Rules' requirements, the Board of TasNetworks has certified that these assumptions are reasonable. Assumptions that only apply to either operating or capital expenditure are set out in the relevant chapters of this revised Regulatory Proposal.

1.4 Presentation of costs

The actual and forecast expenditures in this revised Regulatory Proposal reflect our cost allocation methodology as approved by the AER, and are consistent with:

- our capitalisation policy, which remains unchanged from the current regulatory period; and

- the application of the AER's incentive schemes that encourage cost and service efficiencies over time.

The Rules require the AER to have regard to whether expenditure forecasts include any transactions with related parties. As noted in our original Regulatory Proposal, we can confirm that our expenditure forecasts do not contain any costs arising from transactions with related parties.

In terms of the financial data presented in this submission, it should be noted that:

- all monetary values presented exclude GST;
- unless stated otherwise, monetary values are presented in June 2019 dollars;
- where data is presented in nominal terms, an inflation forecast of 2.45 per cent per annum has been applied; and
- numbers in tables may not add up due to rounding.

Part One:

Background

Part One of this revised Regulatory Proposal discusses:

- Our engagement approach, including our further engagement with customers and stakeholders following the submission of our original Regulatory Proposal on 31 January 2018.
- The matters raised by customers and stakeholders in response to the AER's Issues Paper and our original Regulatory Proposal.

We conclude Part One with a summary of what we have heard and how we have responded in this revised Regulatory Proposal.

2 Customer engagement

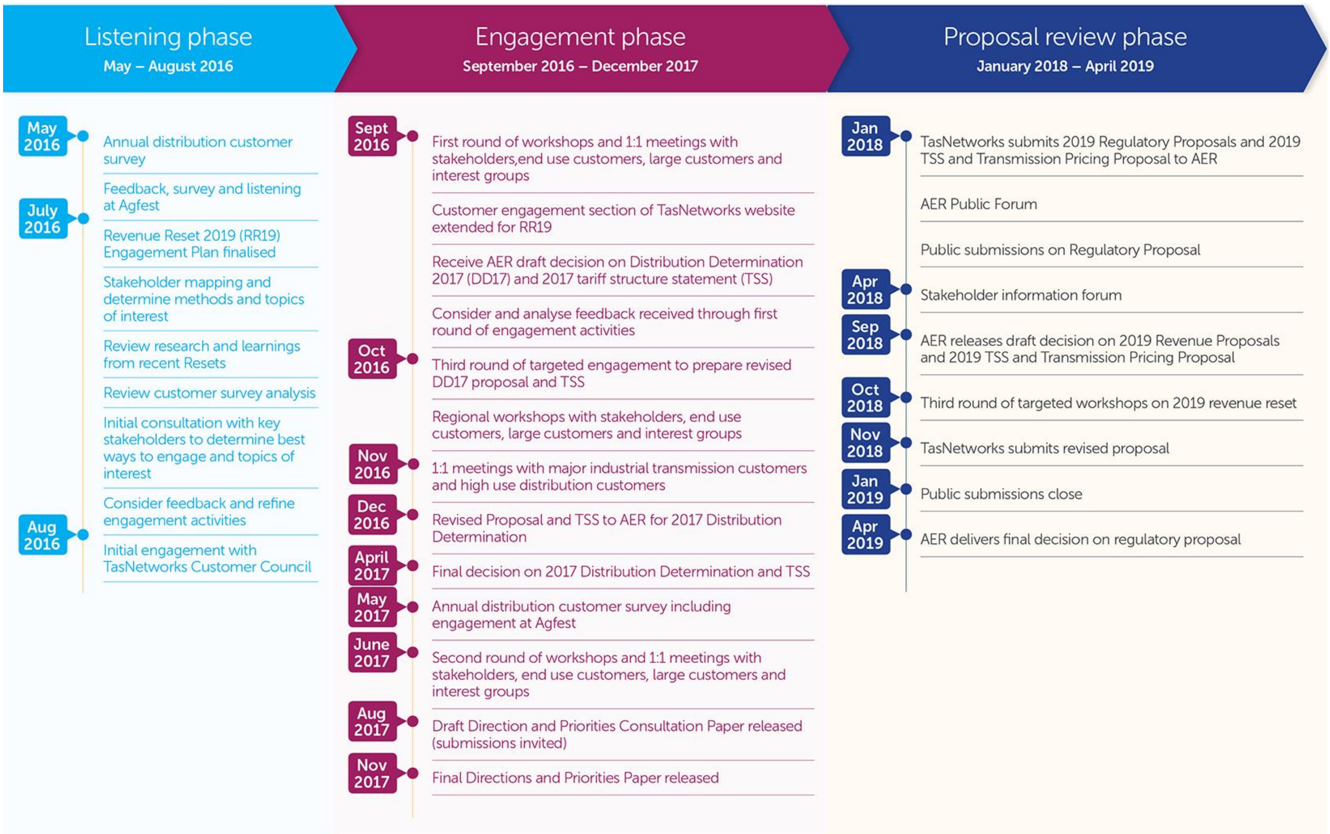
2.1 Our original Regulatory Proposal

In developing our original Regulatory Proposal, we implemented a three phase engagement process:

- A listening phase, from May to August 2016;
- An engagement phase, from September to December 2017; and
- A proposal review phase, commencing in January 2018.

The figure below shows the extensive engagement program we undertook in relation to each of these phases.

Figure 2-1: Our on-going engagement program and activities



Our original Regulatory Proposal explained that we developed our expenditure plans in light of the feedback we received. We believe that our original Regulatory Proposal balanced the competing objectives raised by our customers and stakeholders, having regard to the condition of our assets and our overarching obligation to provide safe and reliable network services.

The engagement process enabled us to draw out the following themes that shaped our original Regulatory Proposal.

Table 2-1: Key themes from our original engagement process

Customer group	Key themes
Transmission customers	• Positive feedback that our costs have remained stable over the past few years. • Sustained low cost is important for forecasting and future viability. • Greater risk to businesses if power is interrupted - reliability is still a key focus. • TasNetworks should demonstrate the benefits from investing in technology. • Engaging with customers before making investment decisions has been appreciated.
Distribution customers	• We are meeting most customers' needs from an overall reliability perspective. • While improvements in reliability and outage response could strengthen satisfaction, customers are not willing to pay higher prices. • Continual improvement in the quality of our communication with customers is critical. • Customers recognise that technology is changing the electricity industry, particularly in relation to solar panels, battery storage and electric vehicles. • Customers are interested in distributed energy resources and using the network to trade energy. • The majority of our customers are concerned about affordability, but some customers are willing to pay more for new technologies and/or better outcomes.

We are pleased that the Consumer Challenge Panel[16] (the **Panel**) commended us for a "committed, well planned and well executed consumer engagement process". The Local Government Association of Tasmania (**LGAT**) also provided positive feedback on our consultation process, as did the Tasmanian Small Business Council (**TSBC**). However, we also acknowledge TSBC's comments that our approach to date is 'consultative' rather than 'collaborative'.

We welcome the positive feedback from the Panel, the LGAT and the TBSC, noted above. We are committed to continuing to improve our consumer and stakeholder engagement processes. We will build on the significant improvements achieved to date by continuing to use a wide range of communication channels to engage meaningfully with customers and stakeholders on issues that are important to them.

2.2 On-going engagement and updated feedback

Following the publication of our original Regulatory Proposal, we have continued to engage with our customers and stakeholders. In addition to meeting with industrial and business customers to discuss their specific issues, we have also held meetings with the following organisations and customer representatives, as well as workshops and industry forums:

- AER Panel members
- AER Stakeholder Forum
- Anglicare Tasmania
- Aurora Energy

[16] Consumer Challenge Panel, Sub-Panel no.13, Issues Paper – TasNetworks electricity network revenue proposal 2019 - 24, 16 May 2018, page 4.

- Customer information sessions (Hobart and Launceston)
- Hydro Tasmania
- LGAT
- Office of the Tasmanian Energy Regulator
- Residential customers
- Stakeholder information sessions (Hobart and Launceston)
- TasCOSS
- Tasmanian Farmers and Graziers Associations
- Tasmanian Renewable Energy Alliance
- TasNetworks Customer Council
- TasNetworks Pricing Reform Working Group
- TSBC

In broad terms, the feedback received since the publication of our original Regulatory Proposal reinforces the key themes from our earlier engagement program, as described in the previous section.

In addition, however, the most recent feedback we received also identified a number of specific challenges that need to be addressed in this revised Regulatory Proposal. We have also considered the feedback received by the AER through its consultation process following the release of its Issues Paper. Our responses to these streams of feedback are discussed in Chapters 3 and 4 below.

3 Feedback on the AER's Issues Paper

Following the submission of our original Regulatory Proposal in January 2018, the AER published its Issues Paper[17]. The purpose of the AER's Issues Paper was to highlight some of the key elements of our original Regulatory Proposal, and explain how stakeholders can assist in the AER's review. As part of this process, the AER invited interested parties to a public forum in Hobart on 10 April 2018. The AER invited written submissions on our original Regulatory Proposal by 16 May 2018. The AER has taken account of the submissions it received in developing its draft decision.

We welcome the written submissions in response to the AER's Issues Paper and our original Regulatory Proposal[18]. These submissions, together with the direct feedback received from our customers and stakeholders (which we discussed in the previous chapter), have been taken into account in preparing this revised Regulatory Proposal.

The table below summarises the feedback received in submissions to the AER's Issues Paper, and our responses.

Table 3-1: Issues Paper – matters raised by customers and stakeholders

Topic	Feedback received	Our response
Network Capital Expenditure	A number of submissions expressed concern regarding our proposed increases in replacement capital expenditure, and queried the supporting analysis. One submission suggested that existing assets should be 'worked harder.' The proposed increase in capitalised overheads was also queried. One submission commented that a greater emphasis should be given to non-network solutions.	We have revisited our capital expenditure forecasts in light of the comments received and the AER's draft decision. We have provided further justification for our proposed expenditure, including an examination of non-network options. We have made downward adjustments to our forecast expenditure where it is possible to do so. We have also revisited our overheads and explained the reasons for the proposed increases.
Contingent projects	Several submissions raised concerns regarding our proposed contingent projects, particularly in relation to their potential impact on customers. The justification for a second interconnector was also queried in a number of submissions.	Following further detailed modelling and analysis, and discussions with Hydro Tasmania, we have reduced the number of contingent projects from five to three. A lower cost alternative has been identified in relation to one project. For the remaining three contingent projects, we have provided further information to explain the rationale for each project and its probable timing.

17 Australian Energy Regulator, Issues Paper - TasNetworks Distribution and Transmission Determination 2019 to 2024, March 2018.

18 The submissions are available at https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/tasnetworks-determination-2019-24-0/proposal#step-57113

Topic	Feedback received	Our response
Non-network capital expenditure	A number of submissions raised concerns regarding our proposed increase in information technology and communications expenditure, and queried the benefits it will provide in terms of improved customer service outcomes or future efficiency savings.	We acknowledge the concerns regarding our proposed IT and communications capital expenditure. We have reviewed our plans with a view to making reductions where it is appropriate to do so. We have also provided more detailed information on the benefits that our proposed IT and communications expenditure will deliver.
Risk assessment and mitigation	Submissions raised concerns regarding the robustness of our approach to risk assessment and mitigation, and queried whether our approach is overly cautious given the proposed increase in expenditure to manage safety and bushfire risk.	We acknowledge the importance of a robust risk assessment framework that appropriately balances costs and risk, and have developed a methodology by which we have quantified risk and improved our investment evaluation. We have revisited our capital expenditure to identify savings where these can be achieved without compromising safety or exposing customers to unacceptable service performance risks.
Demand forecasts	The Consumer Challenge Panel's submission[19] commented that we have not provided a detailed analysis of our demand forecasts, which makes it difficult to assess the impact of demand forecasts on our proposed expenditure.	Our original Regulatory Proposal explained that we use AEMO's regional forecast for Tasmania as an input to our connection point forecasts. We also explained that the demand-related capital expenditure is low compared to historical levels, because of the forecast modest demand growth.
Operating expenditure	One submission commended us for proposing productivity improvements, instead of adopting the AER's assumption of zero productivity improvement. Other submissions queried the choice of base year and argued that the 2017-18 year included vegetation management costs that are unlikely to be recurrent.	We submitted operating expenditure forecasts that set challenging targets for the forthcoming regulatory period. The 2017-18 year reflects the latest available actual data and therefore provides the best indication of our future operating expenditure requirements. Our forecasts remove any expenditure from the base year which is considered to be non-recurrent.
Pass through events	One submission commented that only costs over and above the level of insurance that an efficient and prudent NSP would obtain should be able to be passed through.	Our approach is to obtain insurance where it is cost effective to do so. The pass through arrangements facilitate an efficient outcome by providing network companies with an alternative cost recovery mechanism, where commercial insurance is either prohibitively expensive or not available.

19 Consumer Challenge Panel, Re: Issues Paper – TasNetworks electricity network revenue proposal 2019-24, 16 May 2018, page 7. As noted above, the submissions to the Issues Paper are available on the AER's website.

Topic	Feedback received	Our response
Regulatory asset base	A number of submissions raised concerns regarding the value of the RAB. One submission commented that the long-term interests of consumers would be better served by lower RAB values over time. Another submission commented that our RAB was overvalued as a result of demand forecasting errors during 2006-2014, and should be written down.	Investors will only commit funds to long lived assets if they can expect to earn a reasonable rate of return. In this context, it is essential that the rules for recognising historical investment decisions remain stable. Our future capital expenditure allowances should be driven by the expenditure objectives in the Rules, rather than targeting a particular RAB outcome.
Rate of return	One submission argued that the rate of return should be lower than we proposed. Another submission commented that TasNetworks should retain its commitment to align the transmission and distribution rate of return to the lower distribution rate.	Our revised approach is consistent with the AER's draft decision, which implements its draft 2018 Rate of Return Guidelines.
Metering	A number of submissions did not support our proposed accelerated metering depreciation, with one submission commenting that it did not consider there to be any economic justification for such an approach.	We recognise our customers' concerns regarding the price impact of accelerated depreciation of metering assets. While we maintain our view that the economic life of the asset should determine the depreciation profile, we have addressed customers' concerns by withdrawing our proposal to apply an accelerated depreciation allowance for the 2019-24 regulatory period. We will revisit this matter during the 2019-24 period.
Public lighting	Two submissions, including one from the Local Government Association of Tasmania, did not support our proposed increase in public lighting charges, on the basis that the price increases are being driven by an increased allocation of overheads to public lighting services which has not been justified.	We are conscious of the pricing issues raised. We have also revisited our allocation of overheads to public lighting in response to the specific concerns raised by the Local Government Association of Tasmania. Our actual overhead costs for 2017-18 are lower than our estimated overheads for 2017-18.
Tariff reform	Mixed views were expressed in submissions, with some pressing for a faster pace of reform. Other submissions, however, preferred a more gradual transitional approach and queried the appropriateness of some of the proposed tariff reforms. The Tasmanian Small Business Council (TSBC) said that the reduction in distribution price cross-subsidies will stall over the next five years, which is a matter of major concern to the TSBC.	We recognise the challenge of getting the balance right between driving effective change and managing the impact on customers. In this revised Regulatory Proposal, we have also considered the AER's draft decision and the views of the TSBC, which supports a quicker path to more cost reflective charges. We have developed a revised proposal that balances the interests of all our customers.

Topic	Feedback received	Our response
Revenue and pricing outcomes	Submissions expressed concern that our proposed distribution prices would increase above the rate of inflation. One submission suggested that the reduction in transmission charges did not provide much benefit to distribution customers.	In this revised Regulatory Proposal, we have responded to customers' concerns regarding affordability. The updated pricing proposal reflects the lowest prices for our transmission and distribution customers, consistent with maintenance of a secure, reliable and safe electricity network.

4 How are we taking customers' further feedback into account?

We recognise the importance of ensuring that our revised Regulatory Proposal reflects the updated feedback from our customers, including the matters raised in response to the AER's Issues Paper. The table below shows how and where customers' and stakeholders' views have been taken into account in this revised Regulatory Proposal.

Table 4-1: Feedback received and taken into account

What we heard	How we have addressed the feedback received
Our capital expenditure plans require further justification, as reliability performance is now better than ever.	Chapter 5 sets out our revised capital expenditure plans. We have provided further justification for our investment plans and made reductions where this can be achieved without exposing customers to unacceptable safety or performance risks.
The proposed contingent projects expose customers to large potential increases in capital expenditure.	Section 5.2.8 explains that we have reduced the number of contingent projects and provided detailed support for the remaining three contingent projects. The projects will only proceed if they provide a demonstrable net benefit.
Our operating expenditure plans need to be consistent with our lowest sustainable costs.	Chapter 6 set out our revised operating expenditure. The AER's draft decision accepted our original forecasts. We have updated our forecasts to reflect the latest available information, but maintained our overall approach, which is focused on delivering the lowest sustainable level of operating expenditure.
Our proposed IT expenditure needs to be fully justified.	We provide supporting documents to accompany this revised Regulatory Proposal that provide further information to explain our proposed IT expenditure.
Our metering charges should not include accelerated depreciation.	Chapter 14 presents our revised proposed metering charges, which no longer includes an allowance for accelerated depreciation.
The proposed increase in public lighting charges is too high.	Chapter 15 explains why our revised public lighting charges are reasonable.
There should be an increased focus on 'innovative projects', which demonstrate how we are moving towards our 2025 strategy.	We have explicitly identified our distribution innovation capital expenditure, as explained in section 5.3.7 and updated our plans to include additional specific initiatives linked to our 2025 strategy.

Part Two:

Revenue Capped Services

Part Two of this revised Regulatory Proposal sets out information relating to our revenue capped services, in response to the AER's draft decision. The services addressed in this part comprise Prescribed Transmission Services and Standard Control Distribution Services.

This part sets out updated information on our capital and operating expenditure proposals to address the issues raised by the AER's draft decision. We have also updated the information on each of the revenue 'building blocks' (return on capital, regulatory depreciation, operating expenditure, corporate tax allowance and efficiency payments).

Part Two concludes by setting out our revised transmission and distribution revenue paths and indicative outcomes for customers in terms of average annual network charges. We also respond to the AER's concerns regarding our Tariff Structure Statement by proposing new 'opt out' arrangements to provide a faster path to more cost reflective pricing arrangements.

5 Revised capital expenditure forecasts

5.1 Introduction

This chapter presents our revised capital expenditure plans for the forthcoming regulatory period, for both our transmission and distribution networks, in light of the AER's draft decision. We have responded to the specific issues raised by the AER and, where appropriate, revised our capital expenditure forecasts. In addition, our forecasts have also been updated for the latest available information, noting that our original proposal was finalised in late 2017.

As explained in our original Regulatory Proposal, we applied a top down discipline to our preliminary capital expenditure forecasts to address our customers' feedback that affordability is of primary concern. As a result, we reduced our total capital expenditure forecasts over the 5 year period by more than $42 million

At the time of lodging our original Regulatory Proposal, we believed that the optimisation of our expenditure plans provided the right balance between affordability and ensuring that the safety and reliability of our network services is not compromised. Specifically, our analysis identified a need for increased capital expenditure in order to renew assets in poor condition, replace technology platforms at end of life, manage increased bushfire related risk and connect new customers.

The AER's draft decision concluded that we can go much further in driving down our expenditure than we indicated in our proposal. Specifically, the AER found that our governance and risk management processes identified risk, but lacked a robust quantification in the cost-benefit analysis that supported our capital expenditure forecast. As a consequence, the AER concluded that a number of capital expenditure programs or projects could be deferred. In addition, the AER commented that our proposed optimisation, which reduced our transmission and distribution capital expenditure by 0.5 per cent and 5 per cent respectively, were arbitrary amounts.

As a first step in preparing this revised Regulatory Proposal, we accepted the AER's feedback on our cost-benefit assessment. To address the AER's concerns, we undertook a comprehensive review of our approach to ensure that risk is properly understood and incorporated in our cost-benefit analysis. We participated in the AER's forum on its draft industry practice application note, which provides guidance to network businesses on the application of cost–benefit analysis when making asset replacement investment decisions.

In accordance with the AER's draft application note, we analysed our asset information to develop the 'probability of asset failure', 'likelihood of consequence' and 'cost of consequence', which enabled us to quantify risk. We have updated investment evaluation summaries for over 75% of our proposed expenditure and amended our forecast capital expenditure accordingly. This review of our capital expenditure plans has been reflected in our updated forecasts in this revised Regulatory Proposal.

In this chapter, we explain our response to the issues raised in the draft decision. For each capital expenditure category, we have revisited our forecasts to ensure we address the important feedback provided by the AER and its consultant, Arup, in the draft decision. We have also revisited our proposed optimisation, which imposes a 'top down' reduction to our total forecast capital expenditure, and highlighted the initiatives that we expect to achieve these savings.

The chapter is structured as follows:

- Sections 5.2 and Section 5.3 present our revised transmission and distribution capital expenditure forecasts.
- Section 5.4 addresses the AER's comments in relation to our proposed 'top down' optimisation of our transmission and distribution capital expenditure forecasts.
- Section 5.5 explains why our revised capital expenditure forecasts should be accepted.

Our revised capital expenditure forecasts are supported by additional information and analysis, provided as appendices to this revised Regulatory Proposal, which provide further detailed information in response to the AER's draft decision. We are confident that our revised capital expenditure forecasts comply with the Rules requirements and can now be accepted by the AER.

5.2 Revised transmission capital expenditure forecasts

5.2.1 Overview

Our original Regulatory Proposal explained that:

- Our transmission capital expenditure in the current five year regulatory period was expected to be approximately 22 per cent below the AER's total allowance of $271.8 million.
- Our proposed transmission investment in the forthcoming period is below the AER's allowance for the current period, but represents an increase compared to our actual expenditure.
- Our primary focus is on increased renewal capital expenditure to ensure that our assets are safe, fit for purpose, and reliable.
- We explained that we will continue to maximise asset life, increase utilisation, and defer investment, all within the bounds of managing risk appropriately and employing improved asset management techniques and practices.

In its draft decision, the AER imposed a reduction in our forecast capital expenditure of 14 per cent to $222.6 million[20]. In reducing our proposed transmission capital expenditure, the AER commented that:

- our forecasts reflect overly conservative assumptions about the risks and consequences of asset failures; and
- there is a lack of risk quantification in the underlying cost-benefit analysis supporting our capital expenditure forecasts.

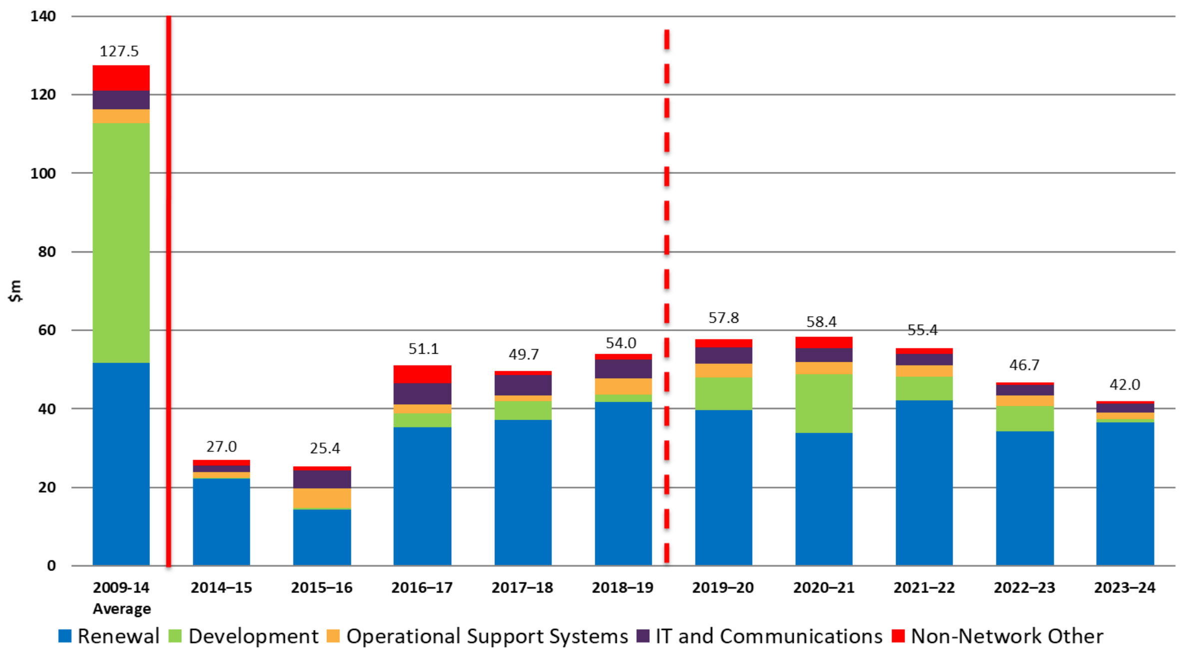
As explained in the sub-sections below, we have addressed the issues raised by the AER in its draft decision. Our detailed review has resulted in a total transmission capital expenditure of $260.4 million over the 5 year period, which is very closely aligned to our original proposal of $260.6 million. Our actual and revised forecast transmission capital expenditure is summarised in the table and figure below.

[20] AER, draft decision, TasNetworks Transmission and Distribution Determination 2019 to 2024, Overview, page 37.

Table 5-1: Transmission capital expenditure by category (June 2019 $m)

Category	2017–18	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Development	4.8	1.9	8.2	14.9	6.1	6.4	1.0
Connection	0.9	0.1	0.1	1.5	2.2	6.4	1.0
Augmentation	4.0	1.8	8.2	13.3	3.9	-	-
Renewal	37.1	41.8	39.8	33.9	42.1	34.2	36.5
Reliability & Quality Maintained	35.1	41.8	39.8	33.9	42.1	34.2	36.5
Inventory and Spares	2.0	-	-	-	-	-	-
Operational Support Systems	1.5	4.1	3.6	3.2	2.9	2.8	1.6
Network Control	0.5	2.4	0.8	0.6	0.6	0.4	0.4
Asset Management Systems	0.9	1.7	2.8	2.6	2.3	2.4	1.2
IT and Communications	5.2	4.8	4.1	3.5	3.0	2.7	2.2
Non-Network Other	1.0	1.5	2.1	3.0	1.3	0.5	0.8
Total transmission capital expenditure	**49.7**	**54.0**	**57.8**	**58.4**	**55.4**	**46.7**	**42.0**

Figure 5-1: Overview of actual and revised forecast transmission capital expenditure (June 2019 $m)



As previously indicated, our position is that renewal capital expenditure must increase in the forthcoming regulatory period in order to maintain the safety and reliability of our assets. In light of the issues raised by the AER's draft decision, however, we have revisited our plans and updated our expenditure forecasts accordingly.

5.2.2 Key assumptions for our revised forecast transmission capital expenditure

In preparing our revised transmission capital expenditure forecasts, our assumptions are unchanged from our initial proposal, with the exception of the updated global assumptions presented in section 1.3.

5.2.3 Transmission development capital expenditure

The AER's draft decision accepted our forecast total transmission development capital expenditure over the 5 year period, which comprised augmentation expenditure of $21.2 million and customer connection expenditure of $3 million ($2018-19, including overheads), which relates to a single project to establish an additional 22kV connection point at Sheffield substation[21].

Our proposed augmentation expenditure relates to the planned installation of a ±50 MVAr 110 kV STATCOM at George Town Substation. The AER's draft decision explained that this project will address existing and forecast voltage unbalance and instability issues, as well as providing market benefits by reducing Basslink export constraints.

The AER's draft decision also explained that the cost of this project meets the threshold for the requirement to undertake a RIT-T process in accordance with the Rules. The AER noted that the RIT-T process will provide further transparency to stakeholders regarding the potential net benefits of this project[22]. We agree with the AER's observations and we intend to progress the RIT-T process in the coming months.

Our most recent analysis of the business case for the STATCOM installation at George Town indicates that the project is unlikely to be economic if Marinus Link proceeds before 2030. As explained in section 5.2.8, we propose that Marinus Link is treated as a contingent project for the 2019-24 regulatory period. In accordance with the Rules provisions[23], the AER is required to determine the amount of capital expenditure that is reasonably required for the purpose of undertaking the contingent project. Therefore, if the Marinus Link contingent project triggers are met, the AER may take account of any savings in relation to the deferral or avoidance of the STATCOM project in determining the allowed capital expenditure for Marinus Link. On that basis, we consider it appropriate to include the STATCOM project in this revised Regulatory Proposal, consistent with our original Regulatory Proposal and the AER's draft decision.

The AER's draft decision rejected two projects from our NCIPAP proposal on the grounds that these projects deliver reliability benefits rather than increasing capacity. In this revised Regulatory Proposal, we have therefore transferred these projects to development capital expenditure – the projects are:

- Waratah Tee remote control of a disconnector; and
- Second Farrell bus coupler, the costs of which have been updated to reflect the latest available information.

21 AER, draft decision, TasNetworks Transmission Determination 2019 to 2024, Attachment 5, Capital Expenditure, page 9.

22 AER, draft decision, TasNetworks Transmission Determination 2019 to 2024, Attachment 5, Capital Expenditure, page 22.

23 National Electricity Rules 6A.8.2(e)(1)(i).

The table below shows our annual actual and updated transmission development forecasts.

Table 5-2: Transmission development capital expenditure (June 2019 $m)

Category	2009-14 Average	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Connection	13.2	0.0	0.0	0.2	0.9	0.1	0.1	1.5	2.2	6.4	1.0
Augmentation	47.9	0.2	0.3	3.3	4.0	1.8	8.2	13.3	3.9	-	-
Transmission Development	61.1	0.2	0.3	3.5	4.8	1.9	8.2	14.9	6.1	6.4	1.0

These figures do not include our revised contingent projects, which are described in further detail in section 5.2.8.

5.2.4 Transmission renewal capital expenditure

The AER's draft decision proposed reductions in our forecast total transmission renewal capital expenditure by 18 per cent from $204.5 million to $167.0 million (including overheads)[24] over the 5 year period. The AER's substitute estimate was derived by adjusting input assumptions in the underlying cost-benefit analysis for the 13 programs and projects listed in the table below.

Table 5-3: AER's Program and project list[25]

Project	Asset Group	Draft decision
Boyer T13 & T14 supply transformers	Transformer	Deferral
Burnie supply transformers	Transformer	Partial Deferral
Burnie – Waratah H Pole replacement program	Poles	Partial Deferral
Chapel St 11 kV HV switchgear replacement	Switchgear	Deferral
George Town – TEMCO 110 kV transmission line replacement	Transmission Lines	Partial Deferral
Knights Rd 11 kV HV switchgear replacement	Switchgear	Deferral
Port Latta supply transformers	Transformer	Partial Deferral
Railton 22 kV HV switchgear replacement	Switchgear	Partial Deferral
Replace 110 kV ASEA HLD live tank breakers	Switchgear	Partial Deferral
Replace 220 kV Sprechur and Schuh HPF live tank circuit breakers	Switchgear	Partial Deferral
Sorell 22 kV HV switchgear replacement	Switchgear	Deferral
St Marys supply transformers	Transformer	Deferral
Ulverstone 22 kV HV switchgear replacement	Switchgear	Deferral

24 AER, draft decision, TasNetworks Transmission and Distribution Determination 2019 to 2024, Overview, page 38.

25 AER, draft decision, TasNetworks Transmission Determination 2019 to 2024, Attachment 5, Capital Expenditure, Table B.4.2, page 35.

The AER's analysis indicated that partial or full deferral of the 13 programs and projects was required, as the optimal asset replacement timing moves from the 2019–24 regulatory control period to the 2024–29 period or later[26].

The AER's consultant, Arup concurred with the AER that the projects could be deferred partially or entirely, observing that[27]:

> *"NPV analysis key assumptions have not been appropriately justified – these include failure rates, recovery times, VCR, and failure modes. Justification of the values used would make TasNetworks' analysis more robust and transparent."*

In preparing this revised Regulatory Proposal, we have addressed the concerns raised by the AER and its consultant, Arup. The table below summarises our response in relation to each of the transmission renewal projects and programs.

Table 5-4: TasNetworks' responses to draft decision findings on transmission renewal projects and programs

Project	Draft decision findings	Revised proposal
Boyer T13 & T14 supply transformers	The AER noted that TasNetworks' Transformer Asset Management Plan, dated October 2017 identified the assets as being in acceptable condition. Arup also noted that the plan indicated a suitable spare would be purchased by June 2018. Proposed capex: $3.92 million Draft decision: $0	Our revised NPV analysis with quantified risk assessment confirms that replacement of both transformers in the forthcoming (2019 to 2024) regulatory period is the most economic option. We have therefore maintained the forecast we originally submitted and will provide the AER with the updated supporting analysis (TN049). Revised proposed capex: $3.92 million
Burnie supply transformers	The AER referred to the Transformer Asset Management Plan, which indicated that the transformers are in acceptable electrical condition and marginal physical condition, but fit for service for at least another 7 years. The AER made an allowance for one replacement transformer. Arup commented that there is a spare transformer available and it questioned whether any expenditure should be allowed for the 2019-24 period. Proposed capex: $3.59 million Draft decision: $1.79 million	While our revised NPV analysis supports our original Regulatory Proposal, we have decided to manage the increased risk in this instance. We have given strong weight to customers' affordability concerns and the need to reduce capital expenditure to the lowest sustainable level. Revised proposed capex: $0

[26] AER, draft decision, TasNetworks Transmission Determination 2019 to 2024, Attachment 5, Capital Expenditure, page 35.

[27] Arup, Addendum A TasNetworks transmission repex addendum to Arup's Final Draft Report, 24 September 2018, page A12.

Project	Draft decision findings	Revised proposal
Burnie – Waratah H Pole replacement program	The AER considered the pole failure assumption to be unreasonable assumption. Arup regarded the options considered as too restricted. An allowance for replacing half the number of poles was considered reasonable. Proposed capex: $4.57 million Draft decision: $2.28 million	Our revised NPV analysis with quantified risk assessment confirms that the replacement program can be partially deferred into the 2024 to 2029 regulatory period. We therefore accept the AER's draft decision. Revised proposed capex: $2.58 million
Chapel St 11kV HV switchgear replacement	The AER concluded that the optimal timing for replacement was 2029-34. Arup suggested that 2035 was optimal, using a lower VCR of $21,400 per MWh. Arup also noted that TasNetworks' unserved energy calculations need further justification. Proposed capex: $3.81 million Draft decision: $0	Our revised NPV analysis indicates that replacement of switchgear in the forthcoming period is the preferred option, with commencement of the project deferred until 2022 and completion in 2025. Unserved energy calculations have been revised in response to AER and ARUP feedback and reflected in the Investment Evaluation Summary. Revised proposed capex: $2.70 million
George Town – TEMCO 110kV transmission line replacement	The AER and Arup concluded that refurbishment and maintenance would provide the most economically efficient solution. Proposed capex: $5.57 million Draft decision: $2.23 million	Our revised NPV analysis shows that the transmission line should be replaced in the 2019-24 regulatory period. We have, however, reduced our original cost estimate to reflect the latest available information. Revised proposed capex: $4.00 million
Knights Rd 11kV HV switchgear replacement	The AER concluded that the optimal timing for replacement was 2029-34. Arup suggested that 2031 was optimal, using a lower VCR of $21,400 per MWh. Arup also noted that TasNetworks' unserved energy calculations need further justification. Proposed capex: $2.03 million Draft decision: $0 million	Although our revised NPV analysis confirms that the switchgear should be replaced in the forthcoming regulatory period, we have decided to accept the increased risk by deferring the replacement until the next regulatory period. Revised proposed capex: $0
Port Latta supply transformers	The AER referred to the Transformer Asset Management Plan, which indicated that the transformers are in acceptable electrical condition and marginal physical condition, but fit for service for at least another 5 years. The AER made an allowance for 1 replacement transformer. Arup agreed with the AER's assessment. Proposed capex: $3.82 million Draft decision: $1.91 million	Our revised NPV analysis indicates that replacement of both transformers in R19 remains the preferred option. We are therefore resubmitting our original capital expenditure forecast for this project, together with the supporting analysis for the AER's review (TN050). Revised proposed capex: $3.82 million

Project	Draft decision findings	Revised proposal
Railton 22kV HV switchgear replacement	The AER concluded that the optimal timing for replacement was 2024-29. Arup suggested that 2028 was optimal, using a lower VCR of $21,400 per MWh. Arup noted that the AER's approach reduces expenditure to a lesser extent than Arup would recommend, which should allow TasNetworks to prioritise switchgear replacements. Proposed capex: $1.99 million Draft decision: $0.70 million	Our revised NPV analysis indicates that the project commencement should be deferred until 2022 and completed in 2025. We have revised our unserved energy calculations in response to feedback from the AER and Arup. However, we do not accept Arup's VCR estimate and instead we have applied AEMO's values for VCR, which we consider to be more appropriate. Revised proposed capex: $0.67 million
Replace 110kV ASEA HLD live tank breakers	The AER noted that no unserved energy costs were provided. The AER considered that half the replacements would provide spares to extend the life of the remaining assets. Arup noted that TasNetworks' analysis showed deferral would be the most cost effective option, but the risk of doing so had not been costed. Proposed capex: $5.72 million Draft decision: $2.86 million	Our revised NPV analysis confirms that our originally preferred project is optimal. We are therefore resubmitting our original capital expenditure forecast for this project, together with the supporting analysis for the AER's review (TN045). Revised proposed capex: $5.72 million
Replace 220kV Sprechur and Schuh HPF live tank circuit breakers	The AER noted that no unserved energy costs were provided. The AER considered that half the replacements would provide spares to extend the life of the remaining assets. Arup noted that TasNetworks' analysis showed deferral would be the most cost effective option, but the risk of doing so had not been costed. Proposed capex: $6.81 million Draft decision: $3.40 million	Contrary to the AER's findings in its draft decision, our revised NPV analysis confirms that our originally preferred project is optimal. We are therefore resubmitting our original capital expenditure forecast for this project, together with the supporting analysis for the AER's review (TN044). Revised proposed capex: $6.81 million
Sorell 22kV HV switchgear replacement	The AER concluded that the optimal timing for replacement was 2024-29. Arup suggested that 2029 was optimal, using a lower VCR of $21,400 per MWh. Arup also noted that TasNetworks' unserved energy calculations need further justification. Proposed capex: $1.91 million Draft decision: $0	Although our revised NPV analysis confirms that our original replacement plans are optimal, we have decided to accept the increased risk by deferring the replacement until the next regulatory period. Revised proposed capex: $0 million

Project	Draft decision findings	Revised proposal
St Marys supply transformers	The AER noted that TasNetworks' Transformer Asset Management Plan, dated October 2017 identified the assets as being in acceptable condition. Arup also noted that the plan indicated that the T1 transformer may potentially be relocated, thereby indicating that it is in an acceptable condition. Proposed capex: $4.15 million Draft decision: $0	Although our revised NPV analysis confirms that our original replacement plans are optimal, we have decided to accept the increased risk by deferring the replacement until the next regulatory period. Revised proposed capex: $0 million
Ulverstone 22kV HV switchgear replacement	The AER concluded that the optimal timing for replacement was 2029-34. Arup suggested that 2031 was optimal, using a lower VCR of $21,400 per MWh. Arup also noted that TasNetworks' unserved energy calculations need further justification. Proposed capex: $2.03 million Draft decision: $0	As noted in relation to the switchgear replacements at Knights Rd and Sorell, we have decided to defer the proposed capital expenditure, although our revised NPV analysis supports our original forecast capital expenditure. Revised proposed capex: $0 million

As detailed in the table above, we have addressed the issues raised by the AER and Arup, and revisited our forecast transmission renewal capital expenditure accordingly. The table below shows our annual actual and revised renewal forecasts. Our revised forecast maintains our earlier forecast that no expenditure will be required for inventory and spares, as we currently have adequate stock for the forthcoming regulatory period.

Table 5-5: Transmission renewal capital expenditure (June 2019 $m)

Category	2009-14 Average	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Reliability and quality maintained	51.7	22.2	14.4	30.8	35.1	41.8	39.8	33.9	42.1	34.2	36.5
Inventory / spares	-	-	-	4.5	2.0	-	-	-	-	-	-
Total transmission renewal	51.7	22.2	14.4	35.3	37.1	41.8	39.8	33.9	42.1	34.2	36.5

Our revised forecast transmission renewal capital expenditure for the five years commencing 1 July 2019 is $186.4 million compared to expenditure of $150.8 million for the preceding five year regulatory period. Our revised forecast total renewal capital expenditure over the 2019-24 period is $18.1 million or approximately 9 per cent lower than our original Proposal of $204.5 million. Our reassessment demonstrates that this increase is necessary in order to maintain current performance and to manage network safety and reliability risk prudently and efficiently.

5.2.5 Transmission Operational Support Systems

The AER's draft decision accepted our proposed transmission operational support systems capital expenditure[28]. The AER correctly noted our asset management information system is comprised of multiple systems that require further development or renewal within the 2019–2014 regulatory control period. For example, the geographic information system is approaching end of life and requires modernisation, and other operational support systems such as the condition based risk management system, are also scheduled for upgrade.

Our most recent assessment is that our total expenditure in relation to our Asset Management Information System (AMIS) should increase by $15.2 million across our transmission and distribution activities for the 2019-24 regulatory period. The increased capital expenditure is required to lift our asset management maturity to a level commensurate with our industry peers and good industry practice. In our view, the AER's draft decision has highlighted important weaknesses in our asset management systems and practices that warrant this additional expenditure.

The increase in AMIS capex will see the application of condition-based risk management systems and practices extended to an additional 30 asset classes. Quantification of risk across these classes will greatly assist in ensuring that our capital expenditure is prudent and efficient, to the benefit of our customers. The transmission component of the proposed AMIS capital expenditure will increase by $4.1 million over the 5 year period.

The table below shows our annual actual and revised forecast capital expenditure.

Table 5-6: Transmission operational support systems capital expenditure (June 2019 $m)

Category	2009-14 Average	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Transmission Network Control	1.8	0.5	3.4	0.8	0.5	2.4	0.8	0.6	0.6	0.4	0.4
Transmission Asset Management Systems	1.8	1.1	1.6	1.6	0.9	1.7	2.8	2.6	2.3	2.4	1.2
Total transmission Operational Support Systems	**3.6**	**1.5**	**5.0**	**2.4**	**1.5**	**4.1**	**3.6**	**3.2**	**2.9**	**2.8**	**1.6**

As indicated above, our operational support systems requirements are considered across the transmission and distribution networks as a whole. The distribution component of this capital expenditure is presented in section 5.3.5.

5.2.6 Transmission IT and communications capital expenditure

This expenditure category is concerned with the provision of information technology (**IT**) and communication services, including:

- information management systems to manage large amounts of structured and unstructured information across the business;

[28] AER, draft decision, TasNetworks Transmission Determination 2019 to 2024, Attachment 5, Capital Expenditure, page 38.

- IT management, which refers to IT capabilities enabling operations and supporting planning and management of the business, including managing applications, IT portfolio, infrastructure, architecture, security and IT services;
- Stakeholder and Customers – systems that support and improve the provision of information and services to our customers and stakeholders and enhance the customer experience; and
- Measures to address cyber security, which is becoming an increasing exposure for electricity networks around the world.

Our approach to developing the proposed IT program of work encompasses both transmission and distribution IT requirements. Our original Regulatory Proposal explained our expenditure plans for each of the following functional areas:

- Business Systems Upgrades;
- Data Warehouses, Business Intelligence and Analytics;
- Digital Customer Engagement;
- Enterprise Architecture Evolution;
- Enterprise Information Management;
- IT Infrastructure, Security and Support; and
- Mobility.

The AER's draft decision accepted our proposed IT capital expenditure for transmission[29]. In particular, the AER noted that this expenditure category is forecast to decline and remain low compared to longer term historical levels of investment.

The table below provides details of our actual and revised forecast transmission IT & Communications capital expenditure. Our forecasts are unchanged from our original Regulatory Proposal and the AER's draft decision.

Table 5-7: Transmission IT & Communications capital expenditure (June 2019 $m)

Category	2009-14 Average	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Total	**4.6**	**1.7**	**4.6**	**5.4**	**5.2**	**4.8**	**4.1**	**3.5**	**3.0**	**2.7**	**2.2**

Our revised proposed distribution IT & Communications capital expenditure is presented in section 5.3.6.

5.2.7 Transmission Non-network Other capital expenditure

As explained in our original Regulatory Proposal, Non-network Other capital expenditure includes capital expenditure on our vehicle fleet and facilities (land and buildings). Our vehicle fleet and facilities are managed as shared services, with costs allocated directly to the transmission and

29 AER, draft decision, TasNetworks Transmission Determination 2019 to 2024, Attachment 5, Capital Expenditure, page 39.

distribution functions where appropriate, following which they are allocated in accordance with our approved Cost Allocation Methodology (**CAM**).

The AER's draft decision accepted our transmission Non-network Other capital expenditure, noting that it is 19 per cent lower than our actual and estimated expenditure in the current period[30]. The table below provides details of our actual and forecast transmission Non-network Other capital expenditure. Our forecasts are unchanged from our original Regulatory Proposal and the AER's draft decision.

Table 5-8: Transmission Non-network other capital expenditure forecast (June 2019 $m

Category	2009-14 Average	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Transmission Fleet	3.3	1.3	1.0	3.6	1.0	1.5	0.8	1.4	0.9	0.4	0.7
Transmission Land & Buildings	3.3	0.1	0.1	1.0	-	-	1.3	1.6	0.4	0.2	0.1
Total Transmission Non-network Other	**6.5**	**1.4**	**1.1**	**4.6**	**1.0**	**1.5**	**2.1**	**3.0**	**1.3**	**0.5**	**0.8**

The distribution non-network other capital expenditure is presented in section 5.3.7.

5.2.8 Transmission contingent projects

Contingent projects are significant network augmentation projects that are reasonably required to be undertaken in order to achieve the capital expenditure objectives as defined in the Rules. However, unlike other proposed capital expenditure projects, the need for the project within the regulatory control period and the associated costs are relatively uncertain.

We originally proposed 5 contingent projects:

- Second Bass Strait Interconnector (Project Marinus);
- Sheffield to Palmerston 220 kV Augmentation;
- Rationalisation of Upper Derwent 110 kV Network;
- North West 110 kV Network Development; and
- North West 220 kV Network Development.

The AER rejected our contingent project proposal on the basis that we had not demonstrated that the proposed contingent project triggers are:

- reasonably specific and capable of objective verification
- probable to occur during the regulatory control period[31].

As already noted, in this revised Regulatory Proposal we are no longer including the Rationalisation of the Upper Derwent 110 kV Network and North West 110 kV Network Redevelopment as

[30] AER, draft decision, TasNetworks Transmission Determination 2019 to 2024, Attachment 5, Capital Expenditure, page 40 and 42.

[31] AER, draft decision, TasNetworks Transmission Determination 2019 to 2024, Attachment 5, Capital Expenditure, page 50.

contingent projects, as the projects are not expected to proceed in the forthcoming regulatory period, for the following reasons:

- In relation to the Upper Derwent project, we have determined in collaboration with Hydro Tasmania that the timing of the development of the new station is such that it is unlikely to impact on any transmission arrangements within the 2019-24 period.
- In relation to the North West 110 kV project, we have concluded that minor reinforcements of the existing 110 kV lines between Burnie and Smithton substations will accommodate the development of new wind farm projects over the next regulatory period.

In relation to Project Marinus, following the submission of our original Regulatory Proposal, we have published a Project Specification Consultation Report (PSCR) in accordance with the RIT-T requirements[32]. The PSCR (TN006) provides further detailed information on the project, which should address the matters raised by the AER. We also provide an additional supporting document (TN007) which responds to AER's feedback in relation to our proposal to treat Project Marinus as a contingent project.

In relation to the remaining two contingent projects, the Sheffield to Palmerston 220 kV Augmentation and the North West 220 kV Network Redevelopment, the conditions have not changed since submitting our original Regulatory Proposal in January 2018. Specifically, we confirm that:

- The Palmerston to Sheffield 220 kV corridor will need to be reinforced to facilitate significant generation developments in the North West Renewable Energy Zone or to facilitate power flows from central Tasmania to the second interconnector.
- The Sheffield to Burnie 220 kV corridor will need to be reinforced to facilitate significant generation developments in the North West or to facilitate a connection of a second Bass Strait interconnector into Burnie.

We are therefore resubmitting these contingent projects in this revised Regulatory Proposal. For each project, we have addressed the issues raised by the AER in its draft decision by preparing a 'Project Needs Analysis' for each project. These reports are provided as supporting documents to this revised Regulatory Proposal (TN061 and TN062). The Project Needs Analysis sets out the following information:

- background on the existing network capacity and configuration;
- the issues or 'identified need' that would arise if particular 'triggers' eventuate;
- high level options for addressing the identified need;
- preliminary analysis of the net benefits that would arise from the proposed contingent project; and
- specific trigger events that are consistent with the analysis presented.

32 https://www.tasnetworks.com.au/TasNetworks/media/pdf/our-network/Project-Marinus-Project-Specification-Consultation-Report.pdf

In summary, the Project Needs Analysis address the matters raised by the AER in relation to the Sheffield to Palmerston 220 kV Augmentation and the North West 220 kV Network Redevelopment contingent projects. As noted above, we have separately addressed the AER's issues in relation to Project Marinus.

It is important to reiterate that the inclusion of the three contingent projects in our revised Regulatory Proposal ensures that provisions are made to allow significant infrastructure projects to proceed if they deliver a net economic benefit. Furthermore, the contingent project approach also ensures that customers are not paying for capital projects unless they actually proceed in the forthcoming regulatory period. As such, the AER's acceptance of the three contingent projects in this revised Regulatory Proposal is unequivocally in our customers' interests.

5.3 Distribution capital expenditure forecasts

5.3.1 Overview

In our original Regulatory Proposal, we proposed a total distribution capital expenditure allowance of $738.8 million over the 5 year period, which reflects an increase of 22.5 per cent compared to the expenditure we expect to incur in the previous five years. The figure below provides a breakdown of forecast distribution capital expenditure by category and a comparison with past expenditure. The amounts shown are net of capital contributions from customers.

At a high level, our distribution investment plans in our original Regulatory Proposal reflected the following considerations and drivers:

- increased investment to manage safety risks (that may not be fully offset by efficiencies elsewhere), including expenditure on:
  - increased pole renewal and staking. as early staked poles reach end of useful life over the next ten years;
  - targeted bushfire mitigation programs to reduce the risk of fire starts from our network;
  - low voltage cable replacement;
  - service connection renewal; and
  - improving network resilience in response to changing environmental factors.
- new connection standards will be required to support network security and two way flows;
- an increase in technology-related spending to support two way flows in the distribution network, by delivering:
  - increased visibility / situational awareness of the distribution network;
  - efficient asset management investment and operation, including in relation to new technology integration; and
  - timely customer information and network management.
- the continuing need to manage network voltage levels which may be impacted by the growth in embedded generation; and
- increased expectations for technology investments to support improved customer relationship management, including SMS notifications, planned outage information, website portals, and network pricing reform.

In its draft decision, the AER proposed a reduction of 25 per cent in our forecast total distribution capital expenditure from $734.4 million[33] to $550.9 million over the 5 year period. In its draft decision, the AER commented that[34]:

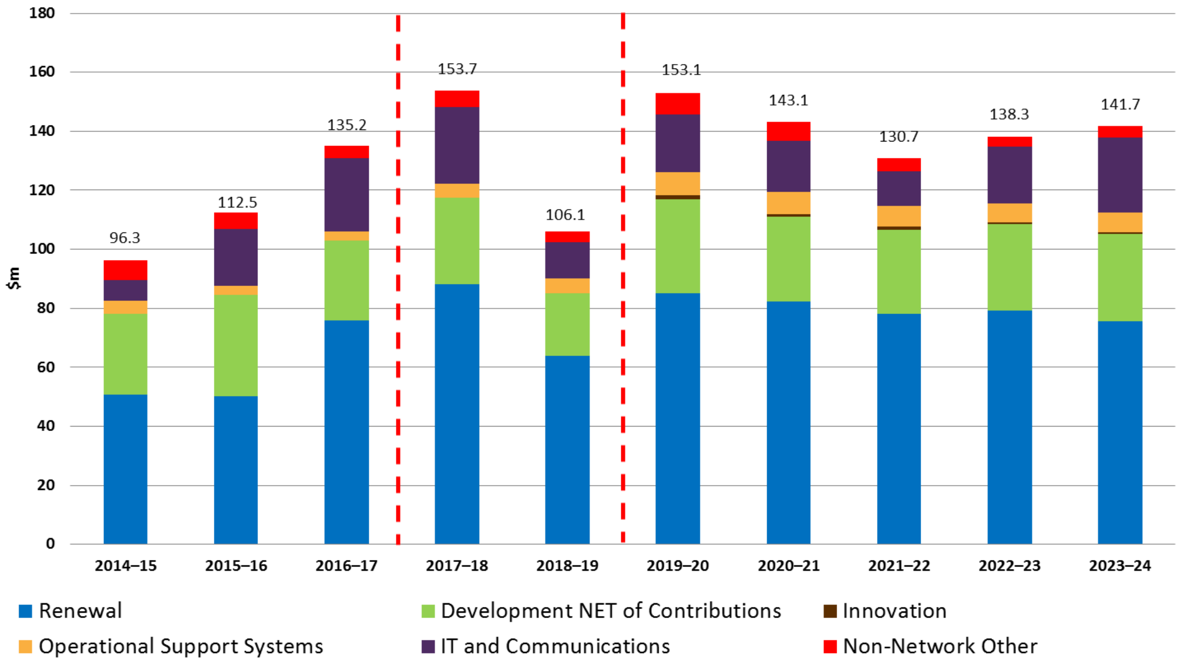
[33] The draft decision stated that our forecast distribution capital expenditure was $734.4 million, which is our original expenditure forecast of $738.8 million minus forecast disposals (of $4.4 million).

[34] AER, draft decision, TasNetworks Distribution Determination 2019 to 2024, Attachment 5, Capital Expenditure, page 9.

- it is satisfied that some aspects of our proposal, such as our proposed augmentation and connections expenditure, reasonably reflects the capex criteria.
- our proposed replacement and non-network expenditure are likely to be higher than an efficient level.

In the following sections of our revised Regulatory Proposal, we provide a detailed response to the issues raised by the AER. The figure and table below show our updated actual and forecast distribution capital expenditure, net of capital contributions.

Figure 5-2: Overview of actual and forecast net distribution capital expenditure (June 2019 $m)



In contrast to our original Regulatory Proposal, we have explicitly identified our distribution innovation capital expenditure to address customer feedback that there should be an increased focus on 'innovative projects' that are linked to our 2025 strategy. As explained in section 5.3.7, we have included four innovation projects which have been identified through the application of our innovation strategy, which was submitted as a supporting document to our original Regulatory Proposal (TN008).

The following table presents our forecast gross distribution capital expenditure by category and a comparison with recent regulatory periods, and also presents this information net of capital contributions.

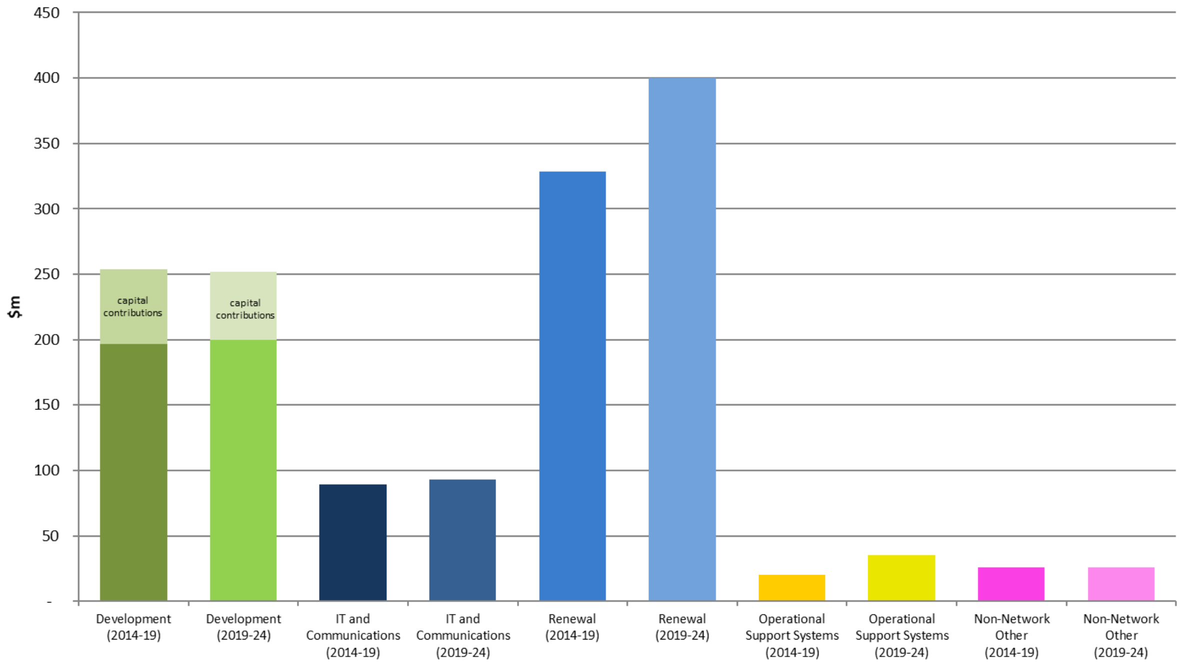
Table 5-9: Actual and forecast gross and net distribution capital expenditure for the current and forthcoming regulatory period (June 2019 $m)

Category	2012-13	2013-14	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Development	38.9	40.4	40.8	45.0	38.7	39.2	32.9	41.2	39.2	38.9	40.1	40.4
Connection	29.8	27.5	31.3	31.6	32.4	32.3	26.4	28.9	32.2	32.4	33.6	34.2
Augmentation	9.1	12.9	9.4	13.3	6.4	6.9	6.5	12.3	7.1	6.5	6.4	6.2
Renewal	57.0	63.2	50.9	50.2	75.8	88.1	63.7	85.2	82.2	78.1	79.2	75.6
Reliability & Quality Maintained	57.0	63.2	50.9	50.2	75.8	88.1	63.7	85.2	82.2	78.1	79.2	75.6
Inventory and Spares	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operational Support Systems	2.8	4.2	4.4	3.2	3.1	4.7	4.9	7.8	7.3	7.0	6.4	6.8
Network Control	1.2	2.5	3.8	2.0	0.8	1.0	2.0	0.8	0.9	0.8	0.5	2.4
Asset Management Systems	1.6	1.7	0.7	1.3	2.3	3.7	2.9	7.0	6.5	6.2	5.8	4.4
Innovation			0.0	0.0	0.0	0.0	0.0	1.3	0.9	1.1	0.7	0.7
IT and Communications	18.0	23.8	7.0	19.3	24.7	26.0	12.2	19.6	17.4	11.7	19.2	25.2
Non-Network Other	6.4	7.3	6.7	5.5	4.3	5.4	3.8	7.4	6.3	4.4	3.6	3.9
Total gross distribution capital expenditure	**123.2**	**138.9**	**109.8**	**123.3**	**146.7**	**163.4**	**117.6**	**162.5**	**153.4**	**141.2**	**149.0**	**152.6**
Customer capital contributions	8.6	11.1	13.5	10.8	11.5	9.7	11.6	9.4	10.4	10.4	10.8	11.0
Total net distribution capital expenditure	**114.6**	**127.8**	**96.3**	**112.5**	**135.2**	**153.7**	**106.1**	**153.1**	**143.1**	**130.7**	**138.3**	**141.7**

The following figure shows our revised forecast net distribution capital expenditure for the next five years by category, compared to our updated actual expenditure incurred and estimated for the 2014-19 period.

The analysis shows that our capital expenditure forecasts for each category are generally closely aligned with our historical expenditure. The only exception is distribution renewal capital expenditure, which is forecast to increase in the forthcoming regulatory period in response to ageing assets and increased risk.

Figure 5-3: Comparison of historical and forecast net distribution capital expenditure by major category (June 2019 $m)



For the reasons set out in the sub-sections below, we are confident that our revised distribution capital expenditure addresses the issues raised by the AER in its draft decision and complies with the Rules requirements. As explained in chapter 2, we have continued to have regard to customer feedback and survey information in updating our distribution capital expenditure plans. We are confident that our revised distribution capital expenditure forecast provides the best price-service offering to our customers.

5.3.2 Key assumptions for distribution capital expenditure forecasts

In preparing our revised distribution capital expenditure forecasts, our assumptions are unchanged from our initial proposal, with the exception of the updated global assumptions presented in section 1.3.

5.3.3 Distribution development capital expenditure

In our original Regulatory Proposal, we forecast a reduction of approximately 19 per cent in our gross distribution development capital expenditure compared to the previous 5 years. We explained that our expenditure forecasts reflected an expected continuation of low demand growth on the distribution system, with localised agricultural growth in regional areas and commercial development in Hobart's central business district (**CBD**). We also identified a change in the mix of development works at the sub-category level, most notably:

- a reduction in expenditure for the establishment of new zone substations; and
- an increase in the expenditure needed to reinforce our regional overhead networks and to underground CBD networks.

In its draft decision, the AER accepted our proposed distribution development capital expenditure, noting that it is consistent with flat or declining maximum demand in the forecast period[35].

During the course of the AER’s review, we advised that we expected to revise our forecast capital contributions upwards in our revised Regulatory Proposal. In its draft decision, the AER noted that increasing the share of connections costs contributed by new customers would reduce TasNetworks' forecast net connections capex, which is to be included in the RAB[36].

In this revised Regulatory Proposal, our forecast distribution development capital expenditure is unchanged from our original Regulatory Proposal, with the following exceptions:

- Our customer initiated capital expenditure forecast has been updated, as the original forecast inadvertently excluded overheads.
- As indicated in the AER’s draft decision, we have amended our forecast capital contributions upwards in light of our latest information from 2017-18.
- We have included an allowance of $1.3 million for the cost of an additional project to provide supply to Crotty Dam. The need for this additional project has been identified following the submission of our original Regulatory Proposal.

In relation to the Crotty Dam supply project, we note the following points:

- There are two locations at Crotty Dam which have been supplied by a Remote Area Power Supply (RAPS) system since 2014, being the dewatering site and the intake gate site.
- The primary sources of power at both sites are diesel generators. These mainly charge a lead acid battery bank, but they are sized for the maximum load. Since the installation of the RAPS in 2014, the baseload at both sites has increased. The change in load has caused the RAPS system at the intake site to start failing.
- The original intake site diesel generator failed in March 2018. A generator was hired to maintain supply and a replacement generator has now been installed, however a permanent sustainable solution is needed. We have investigated four long term solutions, being two RAPS alternatives and two overhead power line options. Our investigations concluded that the optimal solution is the installation of an overhead 22 kV powerline between John Butters Power Station and the Crotty Dam site, and the decommissioning of the existing RAPS system.

Our updated actual and revised forecast gross development capital expenditure proposed for our distribution network is presented in the table below.

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35 AER, draft decision, TasNetworks Distribution Determination 2019 to 2024, Attachment 5, Capital Expenditure, page 10.

36 AER, draft decision, TasNetworks Distribution Determination 2019 to 2024, Attachment 5, Capital Expenditure, page 29.

Table 5-10: Gross distribution development capital expenditure (June 2019 $m)

Category	2012-13	2013-14	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Connection	29.8	27.5	31.3	31.6	32.4	32.3	26.4	28.9	32.2	32.4	33.6	34.2
Augmentation	9.2	12.9	9.4	13.3	6.4	6.9	6.5	12.3	7.1	6.5	6.4	6.2
Total Distribution Development	**39.0**	**40.4**	**40.8**	**45.0**	**38.7**	**39.2**	**32.9**	**41.2**	**39.2**	**38.9**	**40.1**	**40.4**

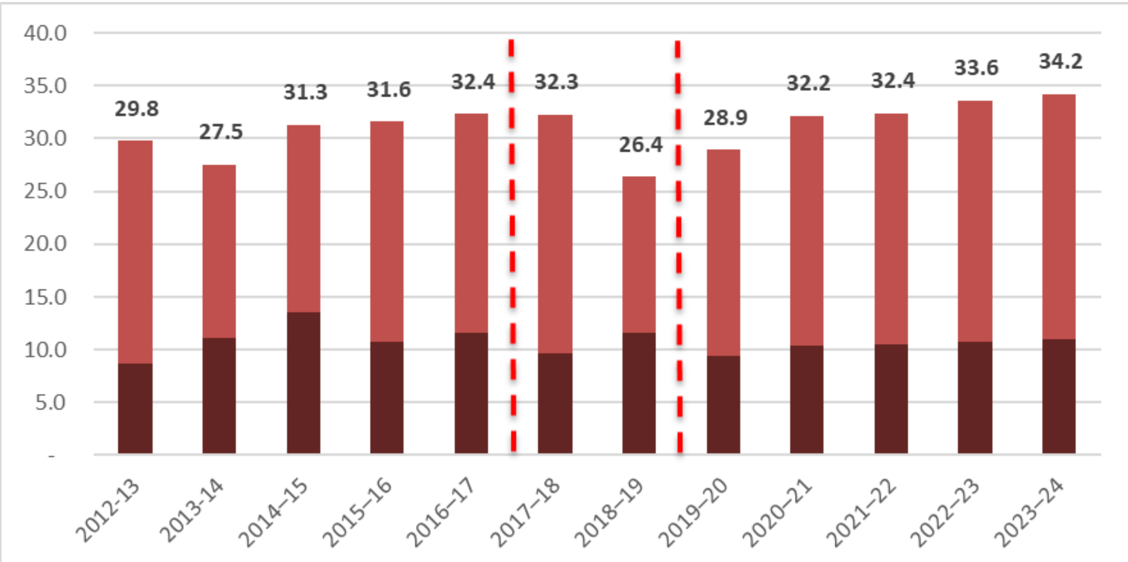
The table below shows our updated actual and revised forecast distribution connection capital expenditure and distribution customer capital contributions.

Table 5-11: Connection capital expenditure and capital contributions (June 2019 $m)

Category	2012-13	2013-14	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Customer Initiated Connection Assets	3.6	4.3	4.7	0.0	0.0	0.2	0.7	0.0	0.0	0.0	0.0	0.0
Customer Initiated Major Works	1.7	1.9	1.2	0.1	0.7	0.1	2.5	1.4	1.4	1.4	1.4	1.4
Customer Initiated Non-Major Works	16.1	13.4	15.3	22.4	24.4	22.5	16.5	15.3	17.6	17.7	18.7	19.1
Customer Initiated Subdivisions	5.2	4.7	5.9	7.0	5.8	8.0	5.2	10.5	11.4	11.5	11.8	12.0
Customer Initiated Substations	3.3	3.2	4.2	2.1	1.4	1.5	1.5	1.7	1.8	1.8	1.8	1.8
Total Connection - Gross	**29.8**	**27.5**	**31.3**	**31.6**	**32.4**	**32.3**	**26.4**	**28.9**	**32.2**	**32.4**	**33.6**	**34.2**
Customer capital contributions	8.6	11.1	13.5	10.8	11.5	9.7	11.6	9.4	10.4	10.4	10.8	11.0
Total Connection - Net	**21.2**	**16.4**	**17.8**	**20.8**	**20.8**	**22.6**	**14.8**	**19.5**	**21.8**	**22.0**	**22.9**	**23.3**

The figure below presents the same information in bar chart format.

Figure 5-4: Total gross distribution connection capital expenditure (June 2019 $m)



Our revised forecast net distribution connection capital expenditure for the five years commencing 1 July 2019 is $109.4 million compared to expenditure of $96.9 million which we expect to incur for the preceding five years. Our forecast gross distribution connection capital expenditure is in line with our capital expenditure in the current regulatory period, as well as our historical expenditure.

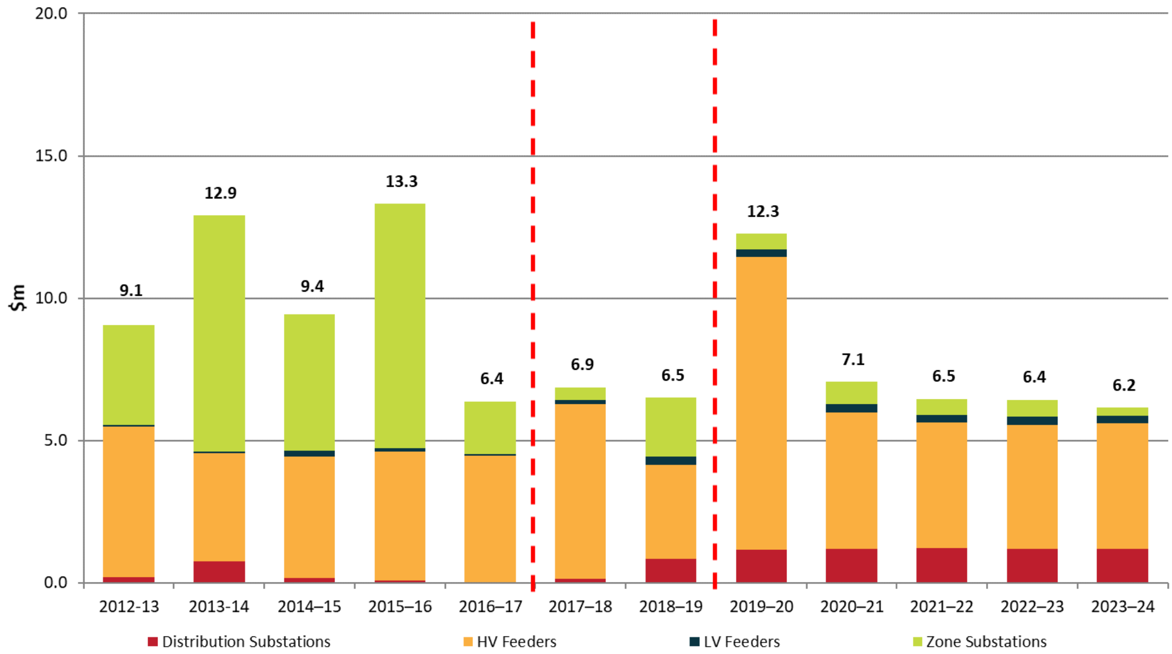
The table below shows our updated actual and revised forecast distribution augmentation capital expenditure.

Table 5-12: Distribution augmentation capital expenditure (June 2019 $m)

Category	2012-13	2013-14	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Distribution Substations	0.2	0.8	0.2	0.1	0.0	0.2	0.9	1.2	1.2	1.2	1.2	1.2
HV Feeders	5.3	3.8	4.3	4.5	4.5	6.1	3.3	10.3	4.8	4.4	4.4	4.4
LV Feeders	0.1	0.0	0.2	0.1	0.1	0.1	0.3	0.3	0.3	0.3	0.3	0.3
Zone Substations	3.5	8.3	4.8	8.6	1.9	0.5	2.1	0.5	0.8	0.6	0.6	0.3
Distribution augmentation	**9.1**	**12.9**	**9.4**	**13.3**	**6.4**	**6.9**	**6.5**	**12.3**	**7.1**	**6.5**	**6.4**	**6.2**

The figure below presents the same information in bar chart format.

Figure 5-5: Distribution augmentation capital expenditure (June 2019 $m)



Our revised forecast distribution augmentation capital expenditure is $38.4 million, which is approximately 9 per cent lower than our distribution augmentation expenditure over the previous 5 years. The increased expenditure in 2019-20 is influenced by a number of large development projects associated with the distribution high voltage network. Our forecast annual distribution augmentation expenditure declines gradually over the remainder of the forthcoming regulatory period.

5.3.4 Distribution renewal capital expenditure

As explained in our original Regulatory Proposal, distribution renewal capital expenditure is driven by two primary objectives:

- satisfying our regulatory obligations, including the requirement to maintain the safety of the distribution system; and
- maintaining network reliability in accordance with our customers' expectations.

We explained that our distribution renewal plans are developed through a careful 'bottom up' evaluation of investment requirements for each asset class, combined with a top down discipline to optimise program synergies. The forecasts are derived and verified through:

- asset specific condition assessment;
- asset life and failure rate modelling;
- trending of historical volumes;
- an analysis of risk, which adopts a systematic approach to assessing consequences and likelihood of asset failures or events; and
- benchmarking/validation, including through the application of the AER's repex model.

In its draft decision, the AER did not accept our proposed distribution renewal capital expenditure for the following reasons[37]:

- The AER's repex model did not support the level of expenditure proposed by TasNetworks
- Although TasNetworks has governance and risk management processes in place to identify risk, there is a lack of risk quantification in the underlying cost-benefit analysis supporting its repex forecast
- The forecast repex in relation to Bushfire Mitigation Programs has not been justified with reference to quantitative risk-based analysis or changed obligations
- TasNetworks did not quantify the safety risks associated with CONSAC cable failures in its NPV analysis
- TasNetworks' past asset management and replacement practices have been sufficient to maintain network reliability
- TasNetworks has applied an arbitrary 'optimisation' of 5 per cent to its capex forecast.

The AER's draft decision forecast an amount of $306.4 million for our total distribution renewal capital expenditure over the 5 year period, which equates to a 34 per cent reduction[38] from our original forecast of $463.1 million.

In light of the AER's concerns, we have undertaken a comprehensive review of our distribution renewal capital expenditure plans. This review has included further detailed risk assessments, which apply a more rigorous approach to quantifying risk in a cost-benefit analysis. We have also applied a

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37 AER, draft decision, TasNetworks Distribution Determination 2019 to 2024, Attachment 5, Capital Expenditure, page 37.

38 AER, draft decision, TasNetworks Distribution Determination 2019 to 2024, Attachment 5, Capital Expenditure, page 37.

consistent approach in examining alternative options, including the ‘do nothing’ option. Our updated actual and revised forecast distribution renewal capital expenditure is set out in the table below.

Table 5-13: Distribution renewal capital expenditure (June 2019 $m)

Category	2012-13	2013-14	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Reliability and quality maintained	57.0	63.2	50.9	50.2	75.8	88.1	63.7	85.2	82.2	78.1	79.2	75.6
Inventory / spares	0	0	-	-	-	-	-	-	-	-	-	-
Total distribution renewal	**57.0**	**63.2**	**50.9**	**50.2**	**75.8**	**88.1**	**63.7**	**85.2**	**82.2**	**78.1**	**79.2**	**75.6**

Our revised forecast distribution renewal capital expenditure for the five-years commencing 1 July 2019 is $400.3 million compared to our original forecast of $463.1 million, and our actual expenditure of $328.8 million for the previous five year period. We currently have an adequate stock of inventory and spares, so we do not forecast any additional requirements for the forthcoming regulatory period.

In the following paragraphs, we draw out and respond to a number of the issues raised in the AER’s draft decision on our major reliability and quality maintained capital expenditure programs and projects for the forthcoming regulatory period.

- **Pole replacements**

  Our original Regulatory Proposal explained that we own and manage approximately 230,000 poles, the majority of which are treated wood pole structures. We have an ageing pole population, with many of our poles approaching the end of their useful life. As a result, our original Regulatory Proposal forecast an increase in our pole condemnation rates and, therefore, an increase in pole replacement expenditure in the forthcoming period.

  The AER’s consultant, Arup, made the following observations in relation to our forecast capital expenditure for pole replacements[39]:

  - Arup has not seen adequate evidence for a need to replace such a substantial number of poles given the number of pole failures is not increasing at the same rate as the level of investment.
  - TasNetworks has stated that there has been no material reduction in the performance of poles, therefore this level of investment to prevent the potential of failures appears to lack justification.
  - TasNetworks has not provided evidence of a thorough and robust options analysis. Arup recommends that TasNetworks undertakes a more sophisticated options and economic analysis that takes into account a wide variety of feasible options.

  In response to the issues raised by Arup, it is important to recognise that unassisted pole failures represent a potentially serious safety issue. As such, we plan our replacement program to maintain current levels of performance, based on predictive modelling. Arup’s

39 Arup, Final report, Review of TasNetworks' proposed capital expenditure for the 2019-24 regulatory control period, 10 August 2018, page 121.

comments imply that we should only increase pole replacements in response to a worsening failure rate. In our view, Arup's suggested approach would be contrary to a prudent asset management strategy because it would fail to maintain safety. We therefore do not accept the basis of Arup's criticism of our proposed increase in pole replacement volumes.

We have revisited our forecast volumes for pole replacements, using a quantitative risk assessment (TN033). This updated analysis confirms that our replacement volumes should increase in response to the ageing asset population. We also note that benchmarking pole replacements with mainland Australia must allow for the different classes of timber. TasNetworks does not have access to high class 1 timber for poles at cost-effective rates, which means that our average life for poles is shorter than for other distributors.

Our revised capital expenditure for pole replacements is supported by updated NPV analysis, which addresses the AER's comments regarding our methodology.

- **Pole staking**

  Our original Regulatory Proposal explained that our pole staking program enables the deferral of pole replacement. In addition to forecasting an increase in the number of pole replacements, our original forecasts also reflected a projected increase in pole staking rates.

  While the AER's draft decision did not comment specifically on our pole staking program, it is important to note that any reduction imposed by the AER in our proposed volume of pole replacements should be offset by an increase in the allowance for pole staking. For the reasons outline above, however, we do not envisage that the AER's final decision will impose reductions in our forecast replacement volumes.

  It should also be noted that we are working with University of Tasmania to develop a test for soft rot to improve the identification of poles that are suitable for staking. Potentially, this initiative may also identify treatments to inhibit the growth in soft rot and thereby extend pole life. We are therefore working hard to drive efficiencies in this area, which will be passed on to customers if further optimisation of the replacement/staking decision is achieved.

- **Low voltage wooden cross-arms**

  Our original Regulatory Proposal explained that we have approximately 210,000 sawn timber low voltage cross-arms installed across the distribution network, which have relatively short asset lives (15 to 20 years). As a result of improved inspection techniques, such as aerial helicopter inspections and infrared thermography, we explained that we have identified an increased number of cross-arms that require replacement. Our original plans noted that we would prioritise replacements of cross-arms in High Bushfire Loss Consequence Areas (**HBLCA**).

  In light of the AER's draft decision and the general issues it raised in relation to our assessment approach, we have reviewed our planned replacement program for wooden cross-arms. Our updated analysis, which includes a monetised risk assessment, concluded that a proactive replacement program for cross-arms outside HBLCA is not warranted. Instead, the optimal approach is to replace these cross-arms in conjunction with pole replacements and pole staking outside HBLCA, so that all pole top hardware is replaced at the same time as a pole is replaced or reinstated.

We have therefore updated our capital expenditure forecasts in relation to wooden cross replacements to reflect our revised asset management strategy. A proactive replacement approach remains appropriate for wooden cross-arms in HBLCA.

- **Overhead pole mounted transformers**

  Our original Regulatory Proposal explained that we adopt a 'run-to-failure' approach in relation to our approximately 30,000 overhead distribution pole mounted transformers. As these assets approach 50 years of service life, the probability of failure significantly increases. Due to an ageing transformer population, our original Regulatory Proposal forecast an increase in replacement capital expenditure in the forthcoming regulatory period.

  In light of the AER's draft decision and its general observations regarding our approach, we have reviewed our proposed program in relation to overhead distribution pole mounted transformers and our forecast renewal capital expenditure. We have confirmed that 'run to failure' remains the appropriate strategy.

- **Distribution network fuses**

  Our original Regulatory Proposal explained that we have approximately 28,000 expulsion drop out (**EDO**) fuses currently in use across our distribution network. These fuses have a high failure rate and the potential to contribute to increased bushfire risk. To reduce this risk, our capital expenditure plans included an allowance to systematically replace EDO fuses with an appropriate modern equivalent. In the first instance, we are prioritising replacements in HBLCA.

  The AER's consultant, Arup, observed that we had not sufficiently quantified risk in our justification of this expenditure program.[40]

  In light of Arup's comments and the AER's draft decision, we have reviewed our approach to managing EDO fuses and our forecast renewal capital expenditure (TN042). Our updated options analysis, which now includes a monetised risk assessment, confirms that the proactive replacement of EDO fuses is justified. Furthermore, we are obliged to manage risk in accordance with ALARP principles, noting that bushfire risk is associated with electricity assets and known failure modes for specific equipment types. EDOs are well documented as a potential cause of fire starts and a prudent network operator is obligated to take appropriate remediation action in accordance with ALARP principles. We therefore maintain our earlier plans for the replacement of EDO fuses.

[40] Arup, Final report, Review of TasNetworks' proposed capital expenditure for the 2019-24 regulatory control period, 10 August 2018, page 92.

- **Substandard overhead conductors**

  Our original Regulatory Proposal included an allowance to replace substandard overhead conductors in HBLCA. In the absence of the proposed capital expenditure, we considered that the risks to network reliability and safety would be unacceptable.

  The AER's consultant, Arup, provided feedback that we should provide more quantitative analysis in support of our proposed expenditure.[41]

  In light of this feedback and the AER's draft decision, we have reviewed our proposed renewal capital expenditure for overhead conductors by including a monetised risk assessment in our options analysis. Our updated analysis indicates that copper conductor replacement within the HBLCA is justified, albeit at a reduced volume compared to our original Regulatory Proposal. We have therefore updated our forecast capital expenditure accordingly.

- **Conductor clearances**

  Our original Regulatory Proposal explained that an increased number of defects have been detected following the introduction of Light Detection and Ranging (**LIDAR**) technology to assess conductor clearances. As we are obliged to ensure adequate conductor ground clearance, this improved information led to an increase in our forecast capital expenditure.

  The AER's consultant, Arup, suggested that we use the increased visibility from the LIDAR program to target high risk conductors in our next regulatory period.[42]

  In light of the AER's draft decision, we have updated our NPV analysis and considered the comments made by Arup. Our updated analysis confirms our original forecast plans in relation to conductor clearances.

- **Overhead low voltage services**

  Our original Regulatory Proposal explained that more than half of the low voltage service wire failures can be attributed to 10 mm copper service wires, which provide supply in approximately 45,000 installations. Our plans included a program to replace substandard overhead service wires over a seven year period.

  The AER's consultant, Arup, suggested that we provide additional analysis in relation to this proposed expenditure.[43]

  In light of this feedback and the AER's draft decision, we have updated our NPV analysis for low voltage services to include a monetised risk assessment (TN041). The updated analysis confirms that our originally proposed plans are optimal. Contrary to Arup's comments, there is significant evidence that 10mm services are in poor condition and higher risk of failure

41 Arup, Final report, Review of TasNetworks' proposed capital expenditure for the 2019-24 regulatory control period, 10 August 2018, page 100.

42 Arup, Final report, Review of TasNetworks' proposed capital expenditure for the 2019-24 regulatory control period, 10 August 2018, page 112.

43 Arup, Final report, Review of TasNetworks' proposed capital expenditure for the 2019-24 regulatory control period, 10 August 2018, page 86.

than other LV service conductors. We therefore remain of the view that our proposed replacement program is warranted.

- **Low voltage cables**

  Our original Regulatory Proposal explained that we experience an average of 31 low voltage cable failures per annum, of which around 60 per cent can be attributed to Concentric Neutral Solid Aluminium Conductors (**CONSAC**) low voltage cables, which is a disproportionally high failure rate. We explained that CONSAC failures present a serious public safety risk due to the potential for electric shock and therefore we consider that the current replacement program should be accelerated.

  In light of feedback from Arup[44] and the AER, we have reviewed our proposed capital expenditure to address the risks associated with CONSAC low voltage cables (TN040). Our updated NPV analysis indicates that a reduced replacement volume is warranted, consistent with a 'business as usual' replacement strategy. We will monitor failure rates and reappraise the replacement volumes if the failure rates increase. At this stage, however, we consider it appropriate to adopt a lower replacement volume than originally forecast and we have revised our capital expenditure forecasts accordingly.

- **Ground mounted substations**

  Our original Regulatory Proposal included targeted replacement of high voltage ground mounted distribution substations that have reached their end of life, or that present a significant safety or reliability risk. Currently, we own, maintain and operate approximately 2,000 high voltage ground mounted distribution substations. Many older substations were installed in the early 1960s with approximately 10 per cent of substations, installed prior to 1990, utilising oil as the insulating medium; an obsolete technology which presents a safety risk due to the potential for catastrophic failure.

  In light of the AER's draft decision and the general issues it raised in relation to our assessment approach, we have reviewed our proposed capital expenditure for the replacement of ground mounted substations (TN037). We have concluded that our original plans remain appropriate.

Given the above findings, we have updated our forecast for distribution reliability and quality maintained capital expenditure in the forthcoming regulatory period. Our actual and revised forecast distribution reliability and quality maintained capital expenditure is presented in the table below.

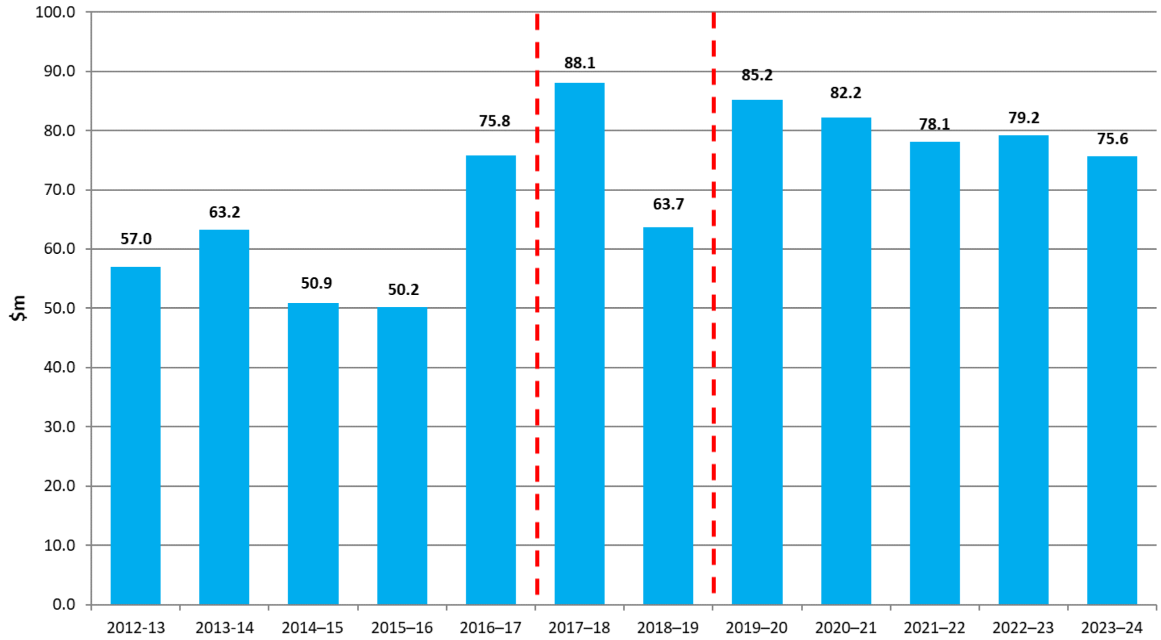
Table 5-14: Distribution reliability and quality maintained capital expenditure (June 2019 $m)

Category	2012-13	2013-14	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Total	57.0	63.2	50.9	50.2	75.8	88.1	63.7	85.2	82.2	78.1	79.2	75.6

The figure below presents the same information in bar chart format.

44 Arup, Final report, Review of TasNetworks' proposed capital expenditure for the 2019-24 regulatory control period, 10 August 2018, page 80.

Figure 5-6: Distribution reliability and quality maintained capital expenditure (June 2019 $m)



5.3.5 Distribution Operational Support Systems

The AER's draft decision accepted our proposed capital expenditure in relation to distribution Operational Support Systems as being prudent and efficient. As explained in relation to the transmission component of this expenditure, however, our updated forecast expenditure includes an additional $15.2 million in relation to our Asset Management Information System (**AMIS**) for the 2019-24 regulatory period.

As already explained, the increased capital expenditure is required to lift our asset management maturity to a level commensurate with our industry peers and good industry practice. Our proposed additional expenditure responds to the AER's concerns in its draft decision regarding our asset management systems and practices. The proposed expenditure will enable us to apply condition-based risk management systems and practices to an additional 30 asset classes.

The distribution component of the proposed increase in AMIS capital expenditure is $11.1 million over the 5 year period. It is expected that this expenditure will enable us to ensure that our asset-related capital expenditure is prudent and efficient, which will benefit our customers. Our revised distribution Operational Support Systems capital expenditure is set out in the table below alongside our actual capital expenditure in recent years.

Table 5-15: Distribution Operational Support Systems capital expenditure (June 2019 $m)

Category	2012-13	2013-14	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Distribution Network Control	1.2	2.5	3.8	2.0	0.8	1.0	2.0	0.8	0.9	0.8	0.5	2.4
Distribution Asset Management Systems	1.6	1.7	0.7	1.3	2.3	3.7	2.9	7.0	6.5	6.2	5.8	4.4
Total distribution Operational Support Systems	**2.8**	**4.2**	**4.4**	**3.2**	**3.1**	**4.7**	**4.9**	**7.8**	**7.3**	**7.0**	**6.4**	**6.8**

5.3.6 Distribution IT and communications capital expenditure

As discussed in section 5.2.6 above, the IT program of works has been designed to respond to the business' requirements for maintaining operability and to address both expected market changes and changes in regulatory requirements. A large component of our proposed IT and communications capital expenditure for the forthcoming regulatory period relates to market systems that are specific to the provision of distribution services.

The AER's draft decision concluded that we had not demonstrated that our proposed distribution ICT capital expenditure of $103.8 million over the 5 year period is efficient and prudent. Instead, the AER's draft decision proposed an alternative estimate of $79.4 million, which is 24 per cent below our original forecast. The AER's proposed reduction comprises[45]:

- a reduction of approximately $23 million ($2018-19) relating to the meter data management system (**MDMS**) replacement project.
- a small reduction of approximately $1 million ($2018-19) relating to the meter data management system upgrades program, which is to ensure that the forecast reflects the expected average level of costs in each year.

Our original Regulatory Proposal explained that the MDMS is the primary repository of installation, customer, and metering data. We explained that the existing MDMS will be 20 years old and at end-of-life in 2025, when this initiative is planned to be completed. The replacement of the MDMS is programmed to follow on from the replacement of the customer connection works management tool. MDMS replacement involves a total cost of $63 million, with $30 million expected in the forthcoming regulatory period and the remainder in the subsequent period commencing in 2024.

The AER's draft decision raised a number of concerns with our proposed MDMS expenditure[46] that we have addressed, assisted by refinement of the scope and cost of the project since submission of our original Proposal (TN034). We have also revisited the issue of IT security, which is discussed below (TN054).

45 AER, draft decision, TasNetworks Distribution Determination 2019 to 2024, Attachment 5, Capital Expenditure, page 54.

46 AER, draft decision, TasNetworks Distribution Determination 2019 to 2024, Attachment 5, Capital Expenditure, pages 58 and 59.

MDMS replacement cost-benefit assessment

As can be seen in the table below, the imperative for replacing the MDMS and the preferred solution have changed since it was first proposed in 2016 for the 2017-19 regulatory period.

Table 5-16: Chronology of MDMS replacement analysis

Date	Regulatory Period	Imperative/proposal
2016	RP 2017-19	No immediate – proposal to maintain compliance of existing system. Estimate for upgrade to Gentrack v4 post 2019
2017	RP 2019-24 (original Regulatory Proposal)	Anticipated end-of-life of mData21. Replace through integration with existing ERP, estimates for external costs due to limited engagement with potential vendors.
2018	RP 2019-24 (revised Regulatory Proposal)	Confirmed end-of-life of mData21. Replace through integration with existing ERP, firm estimates for external costs obtained following detailed engagement with potential vendors.

Our strategy and cost estimates have changed compared to those in our original Regulatory Proposal because although the technical end-of-life of the Gentrack system was expected, notification of the end-of-life date had not yet been received. Moreover, at the time of preparing our original Regulatory Proposal, detailed engagement with potential vendors also proved difficult. Without an agreed scope, only one vendor was able to provide a broad 'order of magnitude' estimate range, while the other vendor declined. This was due to the lack of availability of vendors as, at the time, they were otherwise fully engaged implementing systems changes resulting from the Power of Choice metering reforms.

Since submitting our original Regulatory Proposal, a full re-evaluation of the options has been conducted based on a refined scope and timelines following detailed engagement with vendors. The key issues raised by the AER in the draft determination have now been addressed below:

- We can confirm that replacement of the MDMS is justified, given the risks posed if we continued with the current platform.
- Through refinement of the project scope and prudent planning of the timescale for the project, the proposed capex for 2019-24 has fallen significantly from our original Regulatory Proposal.
- The level of accuracy of the estimates has been significantly enhanced through vendor engagement and detailed internal resource planning such that no contingency amount is included in the estimated costs.
- The chosen solution provides the potential for further process cost efficiencies at virtually no additional extra cost compared to the next best option.
- The project that provides the highest net benefit in NPV terms has been selected (TN034).

It is TasNetworks' firm position that the risks to the business and to the quality of service we provide to Tasmanian customers makes replacement of the current MDMS a non-discretionary need. The longer term costs and potential impacts of system failure far outweigh the costs of replacement, which can also be expected to provide significant efficiencies in operations going forward.

IT Security

The Finkel Review identified cyber security of the National Electricity Network as a key issue, which has led to the development of the Australian Energy Sector Cyber Security Framework (**AESCSF**). TasNetworks recently completed a facilitated self-assessment in accordance with this framework. As a provider of critical infrastructure, we have defined a baseline and a target future state against the AESCSF. Subsequently, we scoped a program of capital work designed to lift our IT security to the anticipated AEMO targets over the 2019-24 regulatory period, and to ensure secure energy supply is maintained (TN054). The identified initiatives in this work program are:

- Significantly improved implementation of the Australian Signals Directorate Essential 8 mitigation strategies across the organisation
- Improved asset and configuration management processes and controls
- Significant development of governance arrangements, policies and procedures
- Deliver improved threat and vulnerability management capabilities across the operational technology landscape
- Improve physical access controls across assets and sites
- Substation Upgrade Security implementation
- Improved identity and access management systems, process and controls.

Our capital expenditure forecasts have been updated to include the required additional expenditure to address cyber security risks.

Our revised forecast distribution ICT capital expenditure is set out in the table below, which reflects the updated MDMS cost information and the additional expenditure in relation to IT security. We are confident that the revised forecast addresses the concerns raised by the AER's draft decision and the issues raised by our customers and stakeholders.

Table 5-17: Distribution ICT capital expenditure (June 2019 $m)

Sub-category	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Distribution	7.0	19.3	24.7	26.0	12.2	19.6	17.4	11.7	19.2	25.2

5.3.7 Innovation capital expenditure

As explained in section 5.3.1, in this revised Regulatory Proposal we have now explicitly identified our distribution innovation capital expenditure in response to customer feedback. Through the application of our innovation framework, we have identified four projects totalling $4.7 million over the 5 year regulatory period, covering the following topics:

- Asset management and bushfire mitigation (2 projects)
- Stand-alone power supplies
- Network adaptation to manage distributed energy resources.

Further information on these projects and the benefits they are expected to deliver is provided in supporting documents that accompany this revised Regulatory Proposal (TN055-TN058).

5.3.8 Distribution Non-network Other capital expenditure

As noted in section 5.2.7, our vehicle fleet and facilities (land and buildings) are managed as shared services, with costs allocated to the transmission and distribution functions in accordance with our approved CAM. This expenditure enables us to manage safety risks efficiently, meet operational requirements, and to minimise the total life cycle costs of providing regulated network services.

In its draft decision, the AER accepted our proposed distribution Non-network capital expenditure. The table below shows our forecast Non-network Other capital expenditure for the distribution network, which is unchanged from our original Regulatory Proposal, alongside our actual capital expenditure.

Table 5-18: Distribution Non-network Other capital expenditure forecast (June 2019 $m

Category	2012-13	2013-14	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Distribution Fleet	5.1	5.7	5.6	2.7	1.8	3.6	2.6	2.8	2.9	3.0	2.5	3.3
Distribution Land & Buildings	1.3	1.6	1.2	2.9	2.5	1.8	1.3	4.6	3.5	1.4	1.1	0.5
Distribution Non-network Other	**6.4**	**7.3**	**6.7**	**5.5**	**4.3**	**5.4**	**3.8**	**7.4**	**6.3**	**4.4**	**3.6**	**3.9**

5.4 Top down optimisation

The AER's draft decision noted that we applied the following 'top down' reductions to our total transmission and distribution capital expenditure in response to our customers' concerns regarding affordability:

- a 5 per cent ($36.4 million) optimisation to our total forecast distribution capital expenditure over the 5 year period.
- a 0.5 per cent ($5.7 million) optimisation to our total forecast transmission capital expenditure over the 5 year period.

During its review of our original Regulatory Proposal, the AER asked us to provide details on how this efficiency was identified and how it will be achieved. We explained that our distribution capital expenditure program mainly consists of a large number of low-cost projects and programs, and therefore there will be opportunities to find efficiencies in program execution. In contrast, our transmission capital expenditure program mainly consists of a small number of high-cost projects and therefore the opportunity to find efficiencies in program execution is limited.

The AER and its consultant, Arup, concluded that we were unable to identify efficiencies specific to a project or program. On that basis, the AER's draft decision rejected our proposed optimisation, although it commented that it is commendable that we applied some form of 'optimisation' to its capital expenditure forecast[47].

[47] AER, draft decision, TasNetworks Distribution Determination 2019 to 2024, Attachment 5, Capital Expenditure, page 50.

We accept the AER’s comments in its draft decision that our proposed cost savings have not been explicitly calculated. Nevertheless, we have identified a number of initiatives that support future improvements in our program delivery. These initiatives combined with the expected benefits from SAP implementation, will realise cost savings from improved process efficiencies. For example, we have identified specific improvement opportunities in relation to:

- **Pole asset management** by adopting more proactive, predictive maintenance methods
- **Wood pole rectification timeframes** using statistical analysis, real test and modelling methods to predict pole lives
- **Program planning and execution** through the developments of a Rolling Works Program, improvements in program optimisation and efficiencies in work delivery
- **Bushfire mitigation program** using TasNetworks NetMaps and SAP to allow easier identification for packaging work, improved resource utilisation and reduced mobilisation and demobilisation costs.

As these initiatives are currently being progressed, it is difficult to estimate precisely the magnitude and timing of the resulting cost efficiencies. Nevertheless, we continue to recognise our customers’ affordability concerns and the importance of committing to future cost efficiencies and sharing these savings with customers as soon as practicable. In these circumstances, we resubmit the transmission and distribution optimisation amounts that we included in our original Regulatory Proposal. These savings have been included in our total transmission and distribution capital expenditure forecasts, as set out in sections 5.2.1 and 5.3.1.

5.5 Why our revised capital expenditure should be approved

Our revised transmission and distribution capital expenditure forecasts address the objectives in the Rules, which require us to deliver the following outcomes efficiently:

- meet or manage the expected demand for prescribed transmission services and standard control distribution services over that period;
- comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services and standard control distribution services;
- maintain the quality, reliability and security of supply of prescribed transmission services and standard control distribution services;
- maintain the reliability and security of the transmission and distribution systems through the supply of prescribed transmission services and standard control distribution services; and
- maintain the safety of the distribution system through the supply of prescribed transmission services and standard control distribution services.

The feedback we received from our customers has been important in guiding our expenditure plans, particularly where we are able to exercise discretion in our expenditure decisions. In developing our original Regulatory Proposal, we tailored our capital expenditure plans to deliver affordable, safe, reliable and efficient transmission and distribution services.

In this revised Regulatory Proposal, the majority of our planned network investment continues to be focused on replacing unreliable and aged assets that are in poor condition, to ensure they do not present unacceptable safety or bushfire risks, or adversely impact our strategy of maintaining current levels of network reliability. This expenditure is critical in helping us maintain safe and reliable network services. Our revised capital expenditure plans look beyond the current period to consider the implications for cost, performance and risk in subsequent periods.

In this revised Regulatory Proposal, we have addressed the issues raised by the AER in its draft decision. As explained in this chapter, we have revisited our capital expenditure forecasts and, in a number of instances, amended our forecasts downwards to address the points raised by the AER. It is important to note that we are accepting more service performance risk as a result of the lower capital expenditure proposed in this revised Regulatory Proposal. Our revised forecasts represent the minimum efficient investment we need to meet our compliance obligations and to maintain an efficient balance between cost, safety and reliability. We have also factored in 'top down' optimisations to our transmission and distribution capital expenditure forecasts in anticipation of future cost efficiencies and in recognition of our customers' affordability concerns.

We consider that the information presented in this revised Regulatory Proposal and the supporting documents demonstrates that our capital expenditure forecasts comply with the Rules requirements and should be accepted by the AER.

6 Operating expenditure forecasts

6.1 Introduction

This chapter presents our revised operating expenditure forecasts for the forthcoming regulatory period for the provision of transmission and distribution services. In its draft decision, the AER accepted our proposed transmission and distribution operating expenditure.

While the AER made a number of different assumptions in applying its base-step-trend forecasting methodology (which we also adopted), the AER's assessment resulted in a higher alternative operating expenditure allowance than our original Regulatory Proposal.

In this revised Regulatory Proposal, we have updated a number of our input assumptions and our base year operating expenditure, as audited actual information is now available. Given the AER accepted our operating expenditure in our original Regulatory Proposal, we are confident that our updated forecasts will also be accepted.

The remainder of this chapter is structured as follows:

- Section 6.2 recaps on our operating expenditure forecasting methodology.
- Sections 6.3 and 6.4 apply the forecasting methodology to derive our forecast transmission and distribution operating expenditure, respectively.
- Section 6.5 explains why our forecast operating expenditure is prudent and efficient, having regard to the operating expenditure factors in the Rules.

6.2 Forecasting methodology

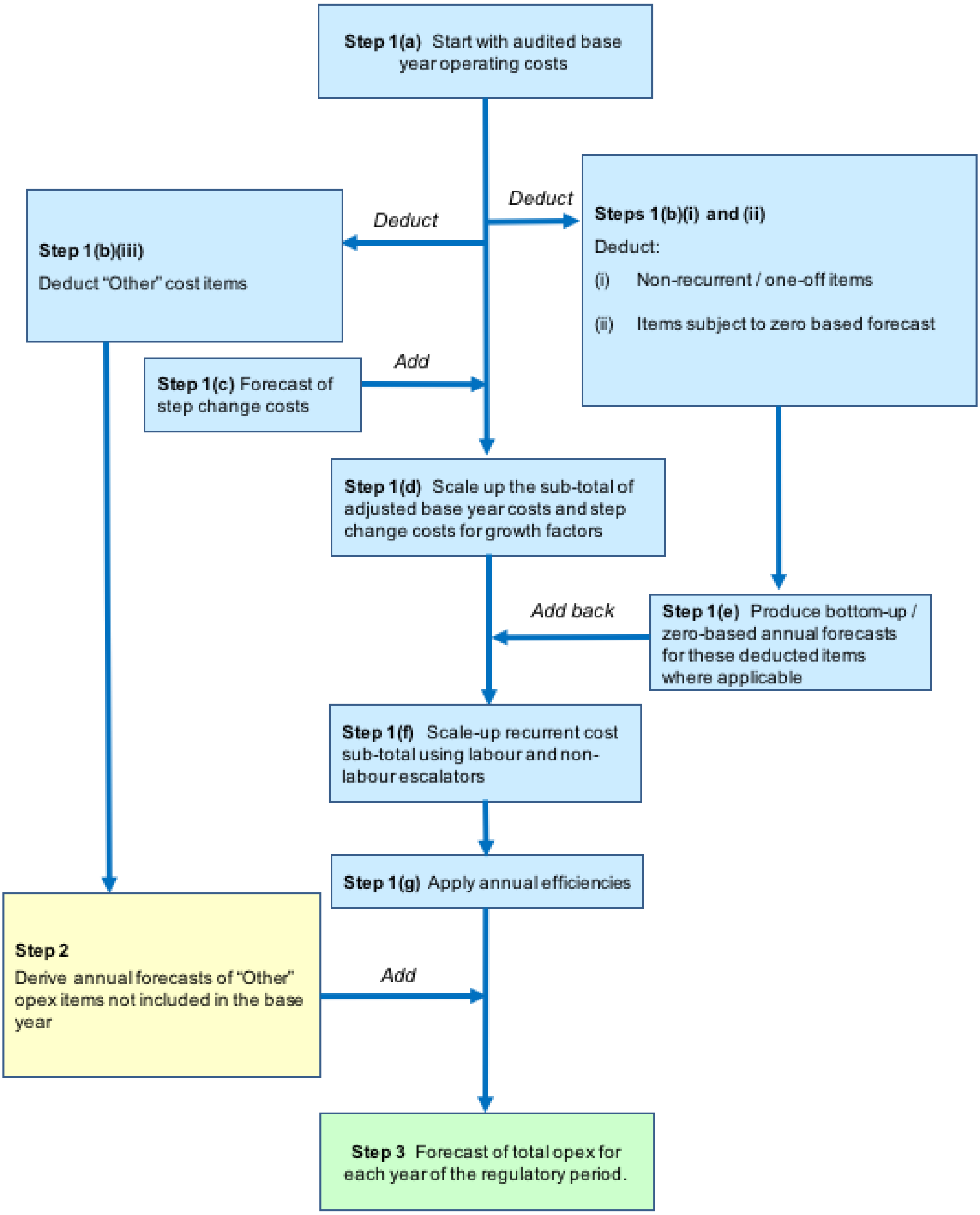
As explained in our original Regulatory Proposal, we have adopted the AER's 'base-step-trend' approach to develop our transmission and distribution operating expenditure forecasts. This methodology projects future expenditure by building from an efficient base year, being 2017–18 for the forthcoming regulatory period. It is a simple method that is effective in identifying the operating expenditure drivers for the forecast period.

Our methodology comprises the following three steps.

- **Step 1 -** Derive and verify the recurrent operating expenditure forecast as follows:
- **Step 2 -** Include the forecast for 'Other' operating expenditure elements. A forecasting methodology which reflects the relevant drivers is adopted for each element.
- **Step 3 -** Derive the total operating expenditure forecast by summing the recurrent operating expenditure and 'Other' operating expenditure annual forecasts, to provide the total operating cost forecast for each year of the regulatory period.

Our operating expenditure forecasting methodology is illustrated in the figure below.

Figure 6-1: Our operating expenditure forecasting methodology

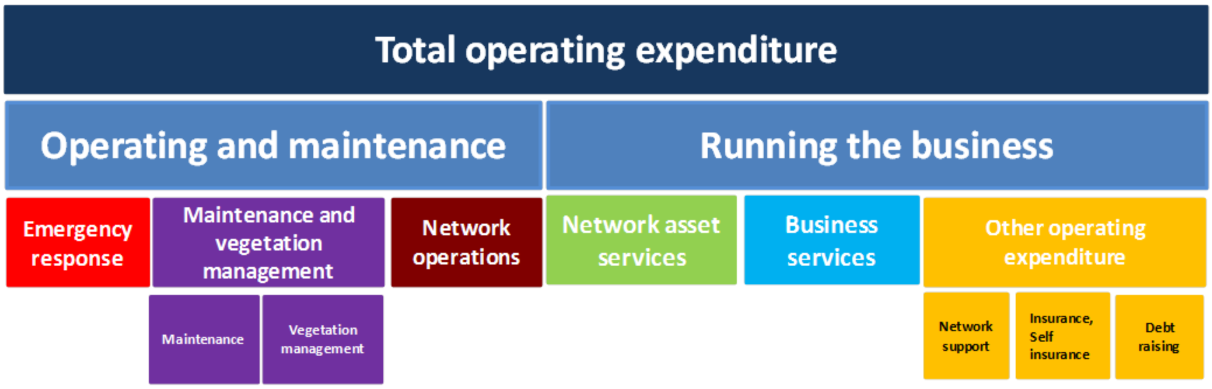


6.3 Transmission operating expenditure

6.3.1 Overview

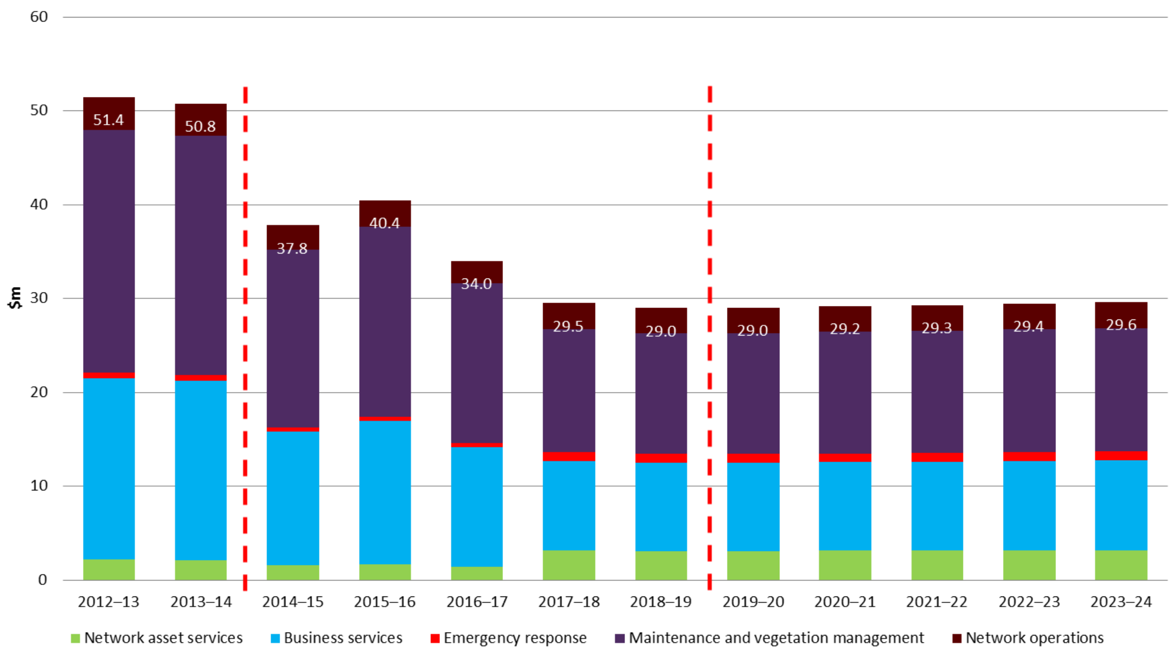
The figure below shows the expenditure categories for transmission operating expenditure for the forthcoming regulatory period.

Figure 6-2: Forecasting methodology categories for transmission operating expenditure categories



The figure below shows our revised forecast transmission operating expenditure for the forthcoming regulatory period with historical actual and estimated expenditure. As previously explained, this revised Regulatory Proposal presents an amended operating expenditure forecast that reflects updates to a number of our input assumptions and our base year operating expenditure, as audited actual information for the 2017-18 base year is now available.

Figure 6-3: Overview of forecast and actual transmission operating expenditure (June 2019 $m)



As shown in the above figure, we have reduced our transmission operating expenditure significantly from the levels in 2012-13 and 2013-14. The lower transmission operating expenditure benefits all our customers, as both distribution and transmission customers use our transmission network.

The table below shows our actual and revised forecast annual transmission operating expenditure by category. The total revised forecast transmission operating expenditure for the forthcoming regulatory period is $146.6 million compared to $170.7 million for the current period, which is a reduction of approximately 14 per cent.

Table 6-1: Actual and forecast transmission operating expenditure by category (June 2019 $m)

Category	2012-13	2013-14	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Emergency Field Operations	0.6	0.6	0.4	0.5	0.4	0.9	0.9	0.9	0.9	0.9	0.9	1.0
Maintenance and Vegetation Management	25.8	25.5	19.0	20.3	17.1	13.1	12.8	12.9	12.9	13.0	13.1	13.1
Business Services	19.4	19.1	14.2	15.2	12.8	9.6	9.4	9.4	9.4	9.5	9.5	9.6
'Other' Operating Expenditure	5.7	5.6	4.2	4.5	3.7	5.9	5.8	5.8	5.8	5.9	5.9	5.9
Total transmission operating expenditure	**51.4**	**50.8**	**37.8**	**40.4**	**34.0**	**29.5**	**29.0**	**29.0**	**29.2**	**29.3**	**29.4**	**29.6**

6.3.2 Key assumptions for transmission operating expenditure

In preparing our revised transmission operating expenditure forecasts, our assumptions are unchanged from our initial proposal, with the exception of the updated global assumptions presented in section 1.3.

Further information on the efficient base year, asset growth scaling factors and labour and non-labour escalation rates for transmission services is provided below.

6.3.3 Transmission recurrent base year costs - Steps 1(a) and 1(b)

As explained in our original Regulatory Proposal, the 2017–18 regulatory year is the base year for determining the recurrent component of the transmission operating expenditure forecast. We have chosen 2017-18 as our base year for transmission operating expenditure forecasting because:

- it provides the most recent audited operating expenditure data that will be available at the time of the AER's final decision;
- it is representative of our underlying operating conditions for the current and forthcoming regulatory periods; and
- its selection is consistent with the design of the incentive mechanisms, which provides a constant incentive to deliver efficiency savings.

The AER's draft decision accepted that 2017-18 should be adopted as our base year for the purpose of forecasting transmission operating expenditure[48]. The AER's draft decision adopted our estimated operating expenditure for 2017-18, as our actual expenditure was not known at the time we submitted our original Regulatory Proposal.

Our actual transmission operating expenditure for 2017-18 has turned out to be $29.5 million compared to the $38.4 million estimated in our original Regulatory Proposal. This significantly lower

48 AER, draft decision, TasNetworks Transmission Determination 2019 to 2024, Attachment 6, Operating Expenditure, page 6.

transmission operating expenditure reflects our increased focus on distribution activities in 2017-18, which means that there is an offsetting increase in distribution operating expenditure.

While any increase in distribution operating expenditure is unwelcome, it is appropriate to use the latest available actual information in preparing our forecasts. Furthermore, as noted above, the increase in distribution operating expenditure is offset by lower transmission operating expenditure. Distribution customers benefit from lower transmission costs, and therefore the rebalancing between transmission and distribution operating expenditure will only have a limited overall impact on network costs for distribution customers.

Our adjustments to the base year are consistent with the approach described in our original Regulatory Proposal, as set out below:

- In relation to step 1(b)(i) we have not identified any non-recurrent costs in our actual operating expenditure for 2017-18. Therefore, we are not proposing any adjustment to our base year operating expenditure to remove non-recurrent operating expenditure.
- In relation to step 1(b)(ii) we are not proposing any zero-based forecasts for the forthcoming regulatory period.
- In relation to step 1(b)(iii) we are not proposing any adjustments.

The AER's draft decision accepted our approach in relation to each of these steps, and we have therefore retained this approach in preparing our revised operating expenditure forecasts. The table below shows the derivation of the efficient base year operating expenditure for transmission.

Table 6-2: Efficient base year transmission operating expenditure (June 2019 $m)

Transmission operating expenditure for 2017–18	29.5
Deduct non-recurrent / one-off items:	0.0
Deduct items subject to zero based forecast	0.0
Deduct other cost items	0.0
Base year efficient transmission operating expenditure	**29.5**

The base year expenditure for 2017-18 is then converted to an equivalent dollar amount for 2018-19 being the final year of the current regulatory control period.

6.3.4 Transmission step changes – Step 1(c)

In our original Regulatory Proposal, we explained that we are not proposing to include any 'step changes' in our forecast transmission operating expenditure, even though additional costs may arise. However, we noted that it may be appropriate to revisit this approach in our revised proposal as our planning progresses or as new information becomes available. In addition, we also noted that we may seek to pass through costs associated with additional obligations[49] that arise in the forthcoming regulatory period, when the details and/or cost implications become known.

[49] Such as the System Security Market Frameworks Review. As already noted, the costs associated with the Inertia Rule change, "Managing the rate of change of power system frequency", are recoverable as a network support cost.

In this revised Regulatory Proposal, we confirm that we are not proposing any step changes in relation to transmission operating expenditure.

6.3.5 Transmission output growth - Step 1(d)

In broad terms, our operating expenditure requirements increase as the size of the transmission network grows, both in terms of assets, generation and demand served. However, as a result of economies of scale there is not a one-for-one relationship between business growth and its operating costs.

It has become common practice for the AER to take into account the impact of business growth and economies of scale on future operating expenditure requirements. However, the AER's method for making this adjustment has evolved in recent determinations. In our original Regulatory Proposal, we calculated a growth factor based on the weighted average of the output measures as determined by the AER's consultant, Economic Insights, comprising:

- Energy throughput. The forecast growth in energy delivered for the Tasmanian network plus net imports.
- Ratcheted maximum demand. Non-coincident historical maximum demand for each individual connection point measured in megawatts (**MW**).
- Weighted entry and exit connections. The summation of the number of connection points weighted by the voltage of each connection point measured in kiloVolts (**kV**).
- Circuit length. Total transmission line circuit length measured in kilometres (**km**).

The AER's draft decision adopted the same methodology, but adopted the following weights using an updated specification of electricity transmission outputs based on its 2017 annual benchmarking report[50]:

- energy throughput, 23.1 per cent
- ratcheted maximum demand, 19.4 per cent
- customer numbers, 19.9 per cent
- circuit line length, 37.6 per cent.

In addition, the AER used our forecasts of distribution customer numbers as a proxy for connection points[51]. The AER explained that this approach is consistent with its 2017 Annual benchmarking report and the associated Economic Insights report.

In this revised Regulatory Proposal, we have adopted the AER's amended transmission growth factors as set out in the table below.

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50 AER, draft decision, TasNetworks Transmission Determination 2019 to 2024, Attachment 6, Operating Expenditure, pages 17 and 18.

51 AER, draft decision, TasNetworks Transmission Determination 2019 to 2024, Attachment 6, Operating Expenditure, page 17.

Table 6-3: Cost impact of transmission network growth (June 2019 $m)

	2019–20	2020–21	2021–22	2022–23	2023–24	Total
Transmission growth factor	0.23%	0.22%	0.24%	0.20%	0.22%	-
Total $m	**0.07**	**0.13**	**0.20**	**0.26**	**0.33**	**1.00**

6.3.6 Transmission zero based expenditure items – Step 1(e)

As explained in section 6.3.3 (in relation to step 1(b)), any zero based expenditure items are subject to a separate forecast on the grounds that the base year expenditure does not reflect the recurrent costs. In this revised Regulatory Proposal, there are no such items.

6.3.7 Transmission real price escalation – Step 1(f)

Our original Regulatory Proposal explained that this component of the rate of change calculation captures the impact of the increases in the prices of our inputs, which flows through to higher operating expenditure. There are different types of inputs:

- labour costs (internal and contractor); and
- non-labour costs, which include materials, motor vehicle expenses and tools.

The AER's draft decision forecast real average annual price growth of 0.22 per cent, which is slightly lower than our proposed average annual price growth of 0.24 per cent. In this revised Regulatory Proposal, we have adopted the AER's forecast real average annual price growth of 0.22 per cent.

6.3.8 Transmission productivity growth – Step 1(g)

Our original Regulatory Proposal explained that the productivity growth factor in the rate of change formula is intended to capture future productivity improvements. We proposed a stretch target for our transmission activities, which would deliver cumulative savings of $4.2 million over the forthcoming regulatory period.

In its draft decision, the AER adopted a forecast productivity improvement of zero, noting that:

- over the period from 2006 to 2016, operating expenditure productivity for the industry has been negative, but very close to zero; and
- Economic Insights has previously recommended that a forecast opex productivity growth rate of zero should be used when measured productivity growth is negative[52].

In this revised Regulatory Proposal, we have adopted a forecast of zero for transmission productivity. In adopting this revised productivity factor, we note that it is consistent with the AER's draft decision. More importantly, our actual transmission operating expenditure in 2017 - 18 is $8.9 million or 23 per cent lower than our estimate that the AER accepted as efficient. On this basis, there is no case for applying a further productivity factor to this much reduced base year operating expenditure.

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52 AER, draft decision, TasNetworks Transmission Determination 2019 to 2024, Attachment 6, Operating Expenditure, page 19.

6.3.9 Transmission 'Other' expenditure items - Step 2

Our actual transmission debt raising costs are reported as finance charges, rather than operating expenditure, and therefore a separate debt raising allowance must be included to align with this regulatory treatment. In our original Regulatory Proposal, we proposed a total benchmark debt raising cost allowance of $5.05 million over the regulatory period.

In its draft decision, the AER allowed our proposed debt raising cost allowance[53] and this amount is included in this revised Regulatory Proposal.

Table 6-4: 'Other' transmission operating expenditure (June 2019 $m)

Expenditure item	2019–20	2020–21	2021–22	2022–23	2023–24
Transmission debt raising costs	1.01	1.00	1.01	1.02	1.01
Total transmission 'Other'	**1.01**	**1.00**	**1.01**	**1.02**	**1.01**

6.3.10 Total transmission operating expenditure forecast - Step 3

Our total revised transmission operating expenditure forecasts are summarised in the table below. Please note that numbers may not sum exactly due to rounding.

53 AER, draft decision, TasNetworks Transmission Determination 2019 to 2024, Attachment 3, Rate of Return, page 24.

Table 6-5: Transmission operating expenditure forecasts (June 2019 $m)

Element / Driver	Details in	2019–20	2020–21	2021–22	2022–23	2023–24
Actual transmission base year expenditure	Section 6.3.3	29.50	29.50	29.50	29.50	29.50
Base year (2017-18) allowance		46.90	46.90	46.90	46.90	46.90
Difference forecast to allowance (2017-18 base year)		**-17.40**	**-17.40**	**-17.40**	**-17.40**	**-17.40**
Final year (2018-19) equivalent allowance		46.38	46.38	46.38	46.38	46.38
Estimated final year expenditure (2018-19)		**28.97**	**28.97**	**28.97**	**28.97**	**28.97**
Base year adjustments	Section 6.3.3	0.0	0.0	0.0	0.0	0.0
Transmission step changes	Section 6.3.4	0.0	0.0	0.0	0.0	0.0
Transmission output growth	Section 6.3.5	0.07	0.13	0.20	0.26	0.33
Transmission zero based forecasts	Section 6.3.6	0.0	0.0	0.0	0.0	0.0
Transmission labour and non-labour escalation	Section 6.3.7	0.1	0.05	0.13	0.21	0.31
Sub-total before productivity savings		**29.04**	**29.16**	**29.30**	**29.45**	**29.62**
Transmission productivity savings	Section 6.3.8	0.00	0.00	0.00	0.00	0.00
Total transmission (excluding 'Other')[54] [55]		**29.04**	**29.16**	**29.30**	**29.45**	**29.62**

54 Excludes debt raising costs to provide a like-for-like comparison with historical data.

55 The NER, S6A.1.2, requires that TasNetworks identifies the extent to which forecast expenditure is on costs that are fixed and to what extent it is on costs that are variable. In the short term, operating expenditure can be regarded as variable, however, in the medium to long term, the cost of sustainably managing high value, long life assets are more appropriately regarded as fixed, relative to a particular asset base.

6.4 Distribution operating expenditure forecasts

6.4.1 Overview

The figure below shows our distribution operating expenditure categories.

Figure 6-4: Distribution operating expenditure categories

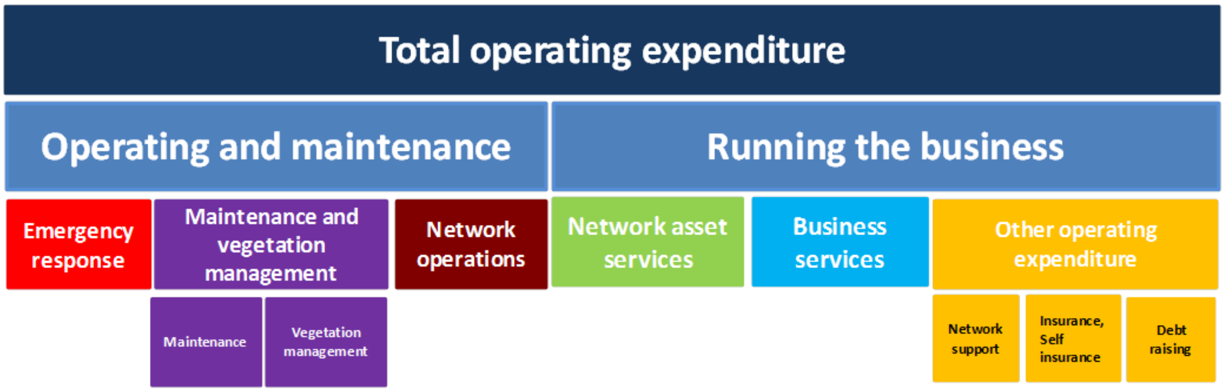
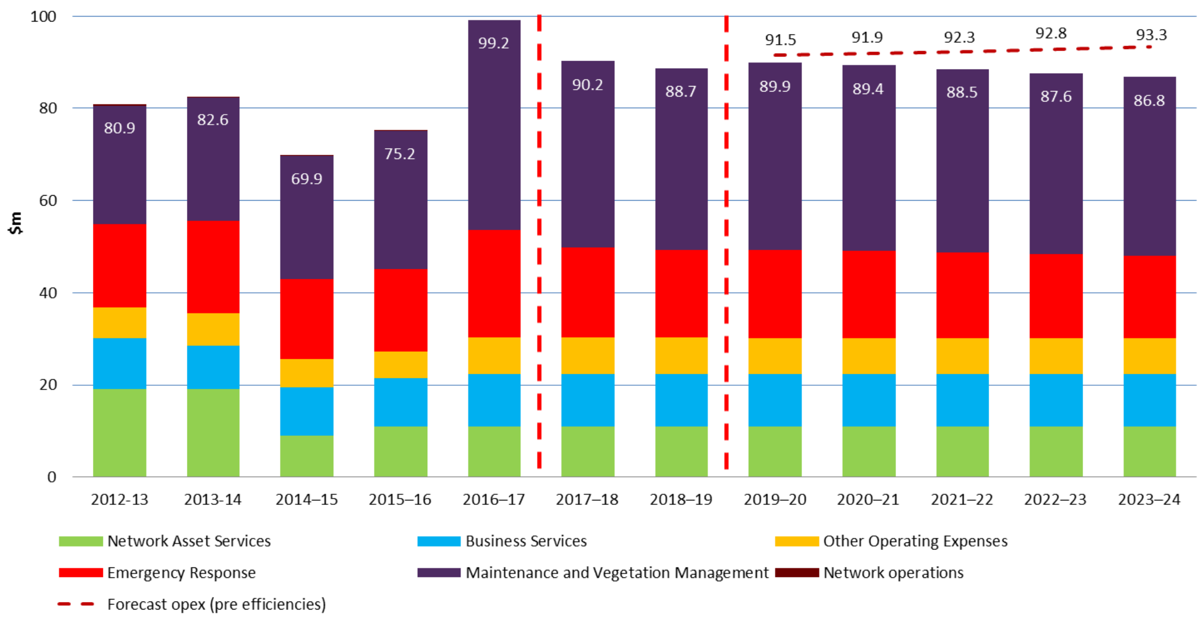


Figure 6-5 shows our revised forecast distribution operating expenditure for the forthcoming regulatory period alongside our pre-efficiency forecast together with historic actual and estimated expenditure. As previously noted, our operating expenditure forecasts have been updated to reflect the latest input information and our audited 2017-18 operating expenditure, which is our base year for forecasting purposes.

Figure 6-5: Overview of forecast and actual distribution operating expenditure (June 2019 $m)



The table below presents our actual and revised forecast annual distribution operating expenditure by category, which totals $442.2 million over the forthcoming regulatory period compared to $423.3 million for the previous five year period.

Table 6-6: Actual and forecast distribution operating expenditure by category (June 2019 $m)

Category	2012-13	2013-14	2014–15	2015–16	2016–17	2017–18	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Emergency Field Operations	18.1	20.0	17.4	18.0	23.4	19.5	19.0	19.2	19.0	18.6	18.2	17.8
Maintenance and Vegetation Management	25.5	26.7	26.7	30.0	45.6	40.4	39.4	40.5	40.3	39.8	39.3	38.8
Distribution Asset Services	19.1	19.1	9.1	11.0	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9
Business Services	11.1	9.4	10.3	10.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5
'Other' Operating Expenditure	7.0	7.4	6.4	5.7	7.9	7.9	7.9	7.8	7.8	7.8	7.8	7.8
Total distribution operating expenditure	**80.9**	**82.6**	**69.9**	**75.2**	**99.2**	**90.2**	**88.7**	**89.9**	**89.4**	**88.5**	**87.6**	**86.8**

6.4.2 Key assumptions for distribution operating expenditure

As noted in relation to transmission operating expenditure, our assumptions are unchanged from our initial proposal, with the exception of the updated global assumptions presented in section 1.3.

Further information on the efficient base year, asset growth scaling factors and labour and non-labour escalation rates for distribution services is provided below.

6.4.3 Distribution recurrent base year costs - Steps 1(a) and 1(b)

Our original Regulatory Proposal adopted 2017–18 as the base year for determining the recurrent component of the operating expenditure forecast. We explained that our estimated operating expenditure was adjusted in accordance with step 1(b)(ii), by deducting expenditure relating to.

- Guaranteed Service Level payments;
- the National Energy Market (**NEM**) levy; and
- the Electrical Safety Inspection (**ESI**) levy.

The AER's draft decision accepted our proposed base year distribution operating expenditure. In accepting our expenditure as efficient, the AER noted that its benchmarking results indicate that we are operating relatively efficiently when compared to other distributors in the NEM[56].

As noted in relation to transmission operating expenditure, our actual 2017–18 operating expenditure was not available at the time of our original Regulatory Proposal. Our actual distribution operating expenditure is higher than the estimate in our original proposal. This increase in distribution operating expenditure has been offset by lower transmission operating expenditure, which reflects the increased focus of the business on distribution matters.

We recognise that our actual distribution operating expenditure for 2017-18 has exceeded our earlier estimate, but it is appropriate to use the latest available actual expenditure information as this most accurately captures the recurrent costs of providing distribution services. As already noted,

56 AER, draft decision, TasNetworks Distribution Determination 2019 to 2024, Attachment 6, Operating Expenditure, page 15.

the EBBS incentive mechanism ensures that we obtain no financial benefit from increased operating expenditure in the base year. Furthermore, the higher distribution operating expenditure has been offset by lower transmission operating expenditure, which means that our overall performance exceeds the estimates provided in our original Regulatory Proposal. We also note that our distribution customers will benefit from our lower transmission operating expenditure, as our network tariffs recover both transmission and distribution costs.

The tables below show the derivation of our updated efficient base year operating expenditure for the distribution network.

Table 6-7: Efficient base year distribution operating expenditure (June 2019 $m)

Distribution operating expenditure for 2017–18	90.2
Deduct non-recurrent / one-off items:	0.0
Deduct items subject to zero based forecast	-7.9
Base year efficient distribution operating expenditure	**82.3**

The adjusted base year for 2017-18 is converted to an equivalent dollar amount for 2018-19, being the final year of the current period, as shown in Table 6-14.

6.4.4 Distribution step changes – Step 1(c)

The base year operating expenditure derived in step 1(b) reflects the scope of our distribution activities (including self-insured expenses and recoverable asset damage costs) in 2017-18. As already noted, however, this scope may change in the forthcoming regulatory period. Such changes may result in increases or decreases in our forecast of recurrent operating expenditure, relative to the 2017-18 base year. These changes in costs are termed 'step changes'.

Our original Regulatory Proposal included the following step changes for the distribution network.

Table 6-8: Distribution Step changes

Activity	Details
Damage to assets	In the forthcoming regulatory period, the recovery of the costs of damage to assets from a third party will be treated as part of standard control services. This is a change from the current approach and therefore a step change to our operating expenditure forecasts is required. This step change reflects the AER's new regulatory approach to the revenue obtained from third parties and will not lead to higher prices to our customers.
Ring-fencing	The implementation of the AER's ring-fencing guidelines will impose additional operating expenditure on our distribution business. These costs are an unavoidable consequence of a regulatory change. Only costs incremental to ring-fencing costs incurred in the 2017-18 base year are included in the step change.
Voltage management	We are forecasting increased expenditure to meet compliance obligations relating to voltage on our network, largely resulting from increased distributed generation.
Capex-opex trade off	We identified a demand management project that will enable us to defer the replacement of an aging transformer. While this step change will increase our operating expenditure, the net effect of this demand management initiative is to deliver savings to customers.

Our original Regulatory Proposal also noted that we were not seeking step changes that we are entitled to claim, such as inspecting private infrastructure which will be paid for by our shareholder. Where we did seek step changes, we only sought 50 per cent of the costs in recognition of our customers' concerns regarding affordability.

In its draft decision, the AER explained that it had not examined our proposed step changes because our forecast operating expenditure allowance was assessed as efficient, without having to make any allowance for step changes[57]:

> *"We have not included any of the step changes TasNetworks proposed in our alternative estimate. TasNetworks' proposed total opex is lower than our alternative estimate of total opex even when we do not include these step changes in our alternative estimate. Consequently we have not formed, and did not need to form, a view on whether these step changes are required since it would not affect our decision to accept TasNetworks' total opex forecast. Accordingly, we did not seek further information and evidence from TasNetworks to further substantiate the qualitative and quantitative elements of its proposed step changes."*

We recognise that the AER did not include an allowance for our proposed step changes in its alternative operating expenditure forecast. However, we acknowledge the AER's reasoning that it was not necessary to include an allowance because our proposed operating expenditure had already satisfied the AER's efficiency assessment.

In this revised Regulatory Proposal, we have maintained our original approach which included an allowance of 50 per cent of the forecast cost of the four step changes, as set out in the table below. As already noted, the decision to not recover the full costs of the step changes effectively means that we must deliver productivity improvements in other aspects of our operating activities.

Table 6-9: Forecast distribution step changes to include in base costs (June 2019 $m)

Category	2019–20	2020–21	2021–22	2022–23	2023–24
Damage to assets	0.2	0.2	0.2	0.2	0.2
Ring-fencing	1.2	1.2	1.2	1.2	1.2
Voltage management	1.0	1.0	1.0	1.0	1.0
Capex-opex trade off	0.2	0.2	0.2	0.2	0.2
Distribution step changes base year	**2.6**	**2.6**	**2.6**	**2.6**	**2.6**

57 AER, draft decision, TasNetworks Distribution Determination 2019 to 2024, Attachment 6, Operating Expenditure, page 22.

6.4.5 Distribution output growth - Step 1(d)

As already noted, this step recognises the impact of growth, both in terms of assets and customer numbers, on our future operating expenditure. In our original Regulatory Proposal, we calculated a growth factor based on ratcheted maximum demand; customer numbers and circuit length. This approach is consistent with previous AER determinations.

In the AER's draft decision, the AER explained that it has refined its earlier approach by using an average of the output weights from four models. The AER noted that this approach helps to address concerns raised by the Australian Competition Tribunal (the **Tribunal**) in its merits review of the AER's 2015 decision for NSW electricity determinations. The Tribunal raised concerns regarding the AER's reliance on a single model and in remitting the NSW decisions directed the AER to use a broader range of modelling and benchmarking[58].

The AER also noted that it is currently updating its economic benchmarking analysis to incorporate data for 2016–17. Furthermore, the AER explained that it intends to update its forecast output growth to reflect the 2018 economic benchmarking results[59].

We note the AER's draft decision and the refinements to its approach to estimating the distribution output growth factor. We agree that the AER's new approach has merit, and we note that the AER intends to further update its calculations in its final decision. In light of the draft decision, we have adopted the AER's updated distribution growth factors, which are set out in the table below.

Table 6-10: Cost impact of distribution network growth (June 2019 $m)

	2019–20	2020–21	2021–22	2022–23	2023–24
Distribution growth factor	0.36%	0.35%	0.32%	0.32%	0.36%
Total	**0.0**	**0.1**	**0.3**	**0.5**	**0.7**

6.4.6 Distribution zero based expenditure items - Step 1(e)

As already noted, any zero based expenditure items are subject to a separate forecast on the grounds that the base year expenditure does not reflect the recurrent costs. In relation to distribution services, consistent with our original Regulatory Proposal, we are including zero-based forecasts of GSL, NEM levy, ESI levy and distribution debt raising costs. Details of our expenditure forecasts for these items are provided in section 6.4.9 below.

58 AER, draft decision, TasNetworks Distribution Determination 2019 to 2024, Attachment 6, Operating Expenditure, page 21.

59 AER, draft decision, TasNetworks Distribution Determination 2019 to 2024, Attachment 6, Operating Expenditure, page 21.

6.4.7 Distribution real price escalation – Step 1(f)

As noted in relation to transmission operating expenditure, there are different types of inputs:

- labour costs (internal and contractor); and
- non-labour costs, which include materials, motor vehicle expenses and tools.

In its draft decision, to forecast labour price growth the AER used the average growth in the wage price index (WPI) for the Tasmanian utilities industry forecast by Deloitte Access Economics (DAE) and our consultant, Jacobs. In contrast, we only applied the forecast by Jacobs. In relation to forecast non-labour price growth, the AER also adopted our assumption that these costs would increase in line with CPI[60]. In this revised Regulatory Proposal, we have adopted the AER's forecast real average annual price growth.

6.4.8 Distribution productivity growth – Step 1(g)

In our original Regulatory Proposal, we proposed very significant cumulative distribution operating expenditure savings of $19.2 million over the forthcoming regulatory period. We noted that this level of saving represents a significant commitment by TasNetworks, and highlights our ongoing focus on business productivity improvement and the pursuit of efficiencies.

The table below shows the savings we proposed in our original Regulatory Proposal.

Table 6-11: Distribution productivity improvements per cent (real) and annual savings (June 2019 $m)

Input	2019–20	2020–21	2021–22	2022–23	2023–24
Annual distribution cost savings (%)	-1.88%	-2.93%	-4.43%	-5.90%	-7.39%
Annual distribution cost savings ($m)	-1.6	-2.5	-3.8	-5.0	-6.4
Cumulative distribution cost savings for the period (%)	-1.88%	-2.41%	-3.09%	-3.79%	-4.52%
Cumulative distribution cost savings for period ($m)	-1.6	-4.1	-7.8	-12.9	-19.2

In its draft decision, the AER made the following observations regarding forecast productivity growth[61]:

> *"For this draft decision, we have not included any forecast productivity growth. This is consistent with TasNetworks' proposal and our standard approach to forecasting productivity, which results in a zero productivity growth forecast"*

We note that the AER is incorrect in commenting that we did not include a productivity growth factor in our forecast distribution operating expenditure. In addition to applying a productivity factor, we also committed to further productivity savings by claiming only 50 per cent of the forecast costs of the 'step changes' and we also proposed to absorb the cost impact arising from projected growth over the 5 year period. As set out in the table above, the cumulative effect of these

60 AER, draft decision, TasNetworks Distribution Determination 2019 to 2024, Attachment 6, Operating Expenditure, page 18.

61 AER, draft decision, TasNetworks Distribution Determination 2019 to 2024, Attachment 6, Operating Expenditure, page 21.

measures was to reduce our forecast distribution operating expenditure by $19.2 million over the 5 year period.

In this revised Regulatory Proposal, we have maintained the approach we adopted in our original Regulatory Proposal, noting that our operating expenditure base is higher than originally estimated. The resulting productivity savings are now slightly higher than our original Regulatory Proposal, being $19.5 million over the 5 years rather than $19.2 million.

Table 6-12: Revised distribution productivity improvements per cent (real) and annual savings (June 2019 $m)

Input	2019–20	2020–21	2021–22	2022–23	2023–24
Distribution productivity savings in this year relative to the base year (2017-18)	-1.75%	-2.66%	-4.08%	-5.52%	-7.01%
Annual distribution cost savings ($m)	-1.6	-2.4	-3.8	-5.1	-6.5
Cumulative distribution cost savings for the period (%)	-1.75%	-2.21%	-2.84%	-3.51%	-4.22%
Cumulative distribution cost savings since 2017-18 ($m)	-1.6	-4.0	-7.8	-12.9	-19.5

We note that the AER has recently published a draft decision paper on its future approach to productivity growth for distributors[62]. In this draft paper, the AER explains that it intends to adopt a productivity growth forecast of 1.0 per cent per annum for its next regulatory determination for each electricity distributor.

Our view is the productivity growth should reflect the particular circumstances for each distributor, rather than adopting a ‘one size fits all’ approach. In our case, we have proposed productivity savings, in addition to a reduced claim for the costs of ‘step changes’ and absorbing the costs associated with projected growth.

The combined effect of these commitments exceed the 1 per cent per annum savings indicated in the AER’s draft decision paper. More importantly, however, the resulting operating expenditure forecasts reflect a challenging target for our business, consistent with the Rules requirements and our focus on addressing the affordability issues raised by our customers.

62 AER, draft decision paper, Forecasting productivity growth for electricity distributors, November 2018.

6.4.9 Distribution 'Other' expenditure items - Step 2

In our original Regulatory Proposal, we proposed 'Other' distribution operating expenditure comprising the following line items:

- GSLs
- ESI Levy
- NEM Levy
- Distribution debt raising costs.

The AER's draft decision accepted each of our cost forecasts. In relation to debt raising costs, the AER explained that it accepted our total operating expenditure in its entirety and therefore accepted our debt raising costs[63]. In response of the AER's draft decision, we have therefore maintained our original forecasts for 'Other' operating expenditure, as shown in the following table.

Table 6-13: 'Other' distribution operating expenditure (June 2019 $m)

Expenditure item	2019–20	2020–21	2021–22	2022–23	2023–24
GSL	3.1	3.1	3.1	3.1	3.1
ESI levy	4.0	4.0	4.0	4.0	4.0
NEM levy	0.7	0.7	0.7	0.7	0.7
Distribution debt raising costs	0.9	0.9	0.9	0.9	1.0
Total distribution 'Other'	**8.7**	**8.7**	**8.7**	**8.7**	**8.8**

63 AER, draft decision, TasNetworks Distribution Determination 2019 to 2024, Attachment 3, Rate of Return, page 19.

6.4.10 Total distribution operating expenditure forecast - Step 3

Our revised distribution operating expenditure forecasts are summarised in the table below.

Table 6-14: Total distribution operating expenditure forecasts (June 2019 $m)

Element / Driver	Details in	2019–20	2020–21	2021–22	2022–23	2023–24
Actual distribution base year expenditure	Section 6.4.3	90.24	90.24	90.24	90.24	90.24
Deduct items subject to zero based forecasts	Section 6.4.3	-7.93	-7.93	-7.93	-7.93	-7.93
Base year efficient distribution operating expenditure	Section 6.4.3	**82.31**	**82.31**	**82.31**	**82.31**	**82.31**
Base year (2017-18) allowance		69.69	69.69	69.69	69.69	69.69
Difference forecast to allowance (2017-18 base year)		12.62	20.55	20.55	20.55	20.55
Final year (2018-19) equivalent allowance		68.17	68.17	68.17	68.17	68.17
Estimated final year expenditure (excl. zero based forecasts)		**80.77**	**80.77**	**80.77**	**80.77**	**80.77**
Base year adjustments to derive efficient base year expenditure	Section 6.4.3	0.0	0.0	0.0	0.0	0.0
Distribution step changes	Section 6.4.4	2.6	2.6	2.6	2.6	2.6
Distribution output growth	Section 6.4.5	0.01	0.12	0.29	0.50	0.74
Distribution zero based forecasts (excluding debt raising costs)	Sections 6.4.6 and 6.4.9	7.80	7.80	7.80	7.80	7.80
Distribution labour and non-labour escalation	Section 6.4.7	0.29	0.57	0.84	1.10	1.41
Sub-total before productivity savings		**91.47**	**91.86**	**92.29**	**92.77**	**93.31**
Distribution productivity savings	Section 6.4.8					
Annual distribution cost savings ($m)		-1.60	-2.44	-3.77	-5.12	-6.54
Total distribution (excluding 'Other')[64]		**89.86**	**89.42**	**88.53**	**87.64**	**86.77**

64 Excludes debt raising costs to provide life-for-like comparisons with historical data.

6.5 Why our revised operating expenditure should be approved

In developing our revised operating expenditure forecast for the forthcoming regulatory period, we have continued to apply the AER's preferred base-step-trend methodology. As part of this methodology, we have imposed tough efficiency targets to deliver an overall outcome that we believe our customers will find acceptable.

In this revised Regulatory Proposal, we have addressed all of the issues raised by the AER in its draft decision. We are pleased that the AER accepted the operating expenditure forecasts presented in original Regulatory Proposal, and there is no reason why the AER should not accept our updated forecasts. In relation to the 'expenditure factors' that must be considered by the AER, we note that:

- Our costs benchmark well against our peers.
- We have taken account of customers' concerns regarding affordability in preparing our operating expenditure forecasts.
- We routinely consider capital and operating substitution possibilities and non-network options in our expenditure decisions.
- Our forecasts are not affected by related party arrangements.

As explained in our original Regulatory Proposal, we consider that our revised operating expenditure forecasts achieve an appropriate balance between the pressure to reduce expenditure and the importance of safety and maintaining service performance and managing network risks, both now and into the future.

7 Regulatory Asset Base

7.1 Introduction

This chapter presents information on our Regulatory Asset Base (**RAB**), which has been calculated in accordance with the Rules, specifically:

- clauses 6A.6.1, 6A.6.3, and Schedule 6A.2 in relation to transmission assets; and
- clauses 6.5.1, 6.5.5, and Schedule 6.2 in relation to distribution assets.

The AER's draft decision accepted our approach to calculating the transmission and distribution RABs, but updated the calculations for the latest information.

This chapter is structured as follows:

- Section 7.2 presents information on the roll forward of the transmission and distribution asset base values to 1 July 2019.
- Section 7.3 explains the derivation of the forecast opening and closing RAB values for transmission and distribution for each year of the forthcoming regulatory control period.

7.2 Opening Regulatory Asset Base as at 1 July 2019

7.2.1 Opening Transmission RAB

The AER's draft decision largely accepted our proposed transmission opening RAB, while updating the following inputs[65]:

- Actual CPI for 2017–18 was used in the indexation calculations.
- The WACC input for 2018–19 was adjusted to reflect the return on debt update for that year in the 2014–19 PTRM.
- Forecast straight-line depreciation for 2018–19 was applied following the return on debt update for that year in the 2014–19 PTRM.

The AER determined an opening transmission RAB value of $1,459.4 million ($ nominal) as at 1 July 2019. This value is $8.0 million (or 0.5 per cent) lower than our proposed opening RAB of $1467.4 million ($ nominal) as at 1 July 2019.

The table below shows our revised derivation of the transmission RAB value as at 1 July 2019 (that is, the closing RAB as at 30 June 2019), using the updated information in the draft decision and our actual capital expenditure for 2017-18.

65 AER, draft decision, TasNetworks Transmission Determination 2019 to 2024, Attachment 2: Regulatory asset base, page 6.

Table 7-1: Roll forward of transmission regulatory asset base from 1 July 2015 to 30 June 2019 ($m nominal)

	2014-15	2015-16	2016-17	2017-18	2018-19
Opening RAB	1,410.30	1,407.24	1,399.26	1,410.91	1,430.11
Net capital expenditure	25.97	25.46	52.31	53.67	62.13
Inflation on opening RAB	24.22	23.76	20.65	26.94	35.04
Forecast straight-line depreciation	-53.25	-57.21	-61.31	-61.40	-62.80
Closing RAB	1,407.24	1,399.26	1,410.91	1,430.11	1,464.49
Add difference between actual and forecast 2013-14 net capital expenditure					-
Add return on difference in 2013-14 net capital expenditure					-
Closing RAB					**1,464.49**
Opening RAB (Adjusted)[66]					**1,455.00**

As shown in the table above, the transmission RAB value as at 1 July 2019 (in nominal dollars) is $1,455.0 million. The capital expenditure amount for 2018-19 is an estimate.

7.2.2 Opening Distribution RAB

The AER's draft decision largely accepted our proposed opening distribution RAB, but made the following updates to our proposed inputs to the RFM[67]:

- The actual 2017–18 CPI was used in the indexation of the RAB.
- The WACC input for 2018–19 was adjusted to reflect the return on debt update for that year in the 2017–19 PTRM.
- The forecast straight-line depreciation for 2018–19 was adjusted following the return on debt update for that year in the 2017–19 PTRM.

The AER determined an opening RAB value of $1,747.0 million ($ nominal) as at 1 July 2019. This value is $8.8 million (or 0.5 per cent) lower than our proposed opening RAB of $1,755.8 million ($ nominal) as at 1 July 2019.

The table below shows our revised calculation of the distribution RAB value as at 1 July 2019 (that is, the closing RAB as at 30 June 2019), using the updated information in the draft decision and our actual capital expenditure for 2017-18.

66 The opening transmission RAB is adjusted for the removal of asset value for connection assets that will convert from prescribed to negotiated.

67 AER, draft decision, TasNetworks Distribution Determination 2019 to 2024, Attachment 2: Regulatory asset base, page 6.

Table 7-2: Roll forward of distribution regulatory asset base from 1 July 2017 to 30 June 2019 ($m nominal)

	2017-18	2018-19
Opening RAB	1,615.15	1,724.96
Net capital expenditure	156.46	123.56
Inflation on opening RAB	30.83	42.26
Forecast straight-line depreciation	-77.50	-98.29
Closing RAB	1,724.96	1,792.49
Add difference between actual and forecast 2016-17 net capital expenditure		8.34
Add return on difference in 2016-17 net capital expenditure		0.98
Closing RAB		**1,801.81**

As shown in the table above, the distribution RAB value as at 1 July 2019 (in nominal dollars) is $1,801.8 million. The capital expenditure amount for 2018-19 is an estimate.

7.3 Forecast of Regulatory Asset Base for the forthcoming period

7.3.1 Forecast Transmission RAB

The AER's draft decision determined a forecast closing RAB value at 30 June 2024 of $1,578.6 million ($ nominal), which is $48.2 million (or 3.0 per cent) lower than our proposed amount of $1,626.8 million. The draft decision reflects the AER's amended opening RAB as at 1 July 2019, and its draft decisions on forecast depreciation and forecast capex.

Table 7-3 presents a summary of the amounts, values and inputs we used in our revised calculations of the forecast transmission RAB value for each year of the forthcoming regulatory period.

Table 7-3: Transmission regulatory asset base roll forward 1 July 2019 to 30 June 2024 ($m)

	2019-20	2020-21	2021-22	2022-23	2023-24
RAB (start period) - nominal	1455.0	1498.9	1538.7	1573.7	1598.6
Nominal capital expenditure	60.2	62.3	60.6	52.2	48.2
Inflation on opening nominal RAB	35.6	36.7	37.7	38.6	39.2
Nominal straight-line depreciation	-52.0	-59.2	-63.3	-65.8	-71.7
RAB (end period) - nominal	1498.9	1538.7	1573.7	1598.6	1614.3
RAB (end period) - $ June 2019	**1463.0**	**1466.0**	**1463.4**	**1451.1**	**1430.3**

In accordance with S6A.2.1(f)(4) of the Rules, only actual and estimated capital expenditure properly allocated to the provision of prescribed transmission services in accordance with our approved CAM has been included in the RAB. The information presented above reflects our revised forecast transmission capital expenditure for the forthcoming regulatory period.

7.3.2 Forecast Distribution RAB

The draft decision determined a forecast closing RAB value at 30 June 2024 of $2,006.5 million ($ nominal), which is $208.2 million (or 9.4 per cent) lower than our proposed amount of $2,214.7 million. The draft decision on the forecast RAB reflects the AER's updated opening RAB as at 1 July 2019, and its draft decisions on forecast depreciation and forecast capex.

The table below presents a summary of the amounts, values and inputs we used in our revised calculation of our forecast distribution RAB value for each year of the forthcoming regulatory control period. The information reflects our revised forecast distribution capital expenditure for the forthcoming regulatory period.

Table 7-4: Distribution regulatory asset base roll forward 1 July 2019 to 30 June 2024 ($m)

	2019-20	2020-21	2021-22	2022-23	2023-24
RAB (start period) - nominal	1,801.81	1,905.58	1,994.24	2,065.91	2,143.87
Nominal capital expenditure	160.57	151.58	141.83	153.71	161.37
Inflation on opening nominal RAB	44.14	46.69	48.86	50.61	52.52
Nominal straight-line depreciation	-100.94	-109.61	-119.02	-126.36	-133.72
RAB (end period) - nominal	1,905.58	1,994.24	2,065.91	2,143.87	2,224.04
RAB (end period) - $ June 2019	**1,860.01**	**1,900.00**	**1,921.21**	**1,946.04**	**1,970.54**

In accordance with clause S6.2.1(e)(4) of the Rules, only actual and estimated capital expenditure properly allocated to the provision of standard control distribution services in accordance with our approved CAM has been included in the RAB. It should be noted that the nominal capital expenditure in the table above excludes capital contributions. Customer initiated capital expenditure included in the RAB is the gross (total) expenditure minus customer capital contributions.

8 Regulatory depreciation

This chapter sets out information on our revised regulatory depreciation for the forthcoming regulatory period in accordance with the requirements of clauses 6A.6.3, S6A.1.3(7), 6.5.5 and S6.1.3(12) of the Rules.

In our original Regulatory Proposal, we explained that straight-line depreciation is applied using standard asset lives for each regulatory asset class. We noted that straight-line depreciation is a well-established method used to reflect the decline in the service potential of an asset over its economic life.

We also noted that the AER accepted our proposal to use the year-by-year tracking method for depreciating existing assets in its most recent determination. The year-by-year tracking method captures the timing of new additions for each asset class in the relevant year, which provides more granular and accurate information on the remaining asset lives. These calculations are made in a separate depreciation model, and the depreciation amounts are substituted directly into the PTRM.

We explained that we proposed to adopt the year-by-year tracking method for our transmission and distribution assets for the forthcoming regulatory period.

In its draft decision, the AER accepted our approach to depreciation, including our proposed asset classes, straight-line depreciation method, and standard asset lives. The AER also accepted our year-by-year tracking approach to calculate the straight-line depreciation of existing assets, however the draft decision made some changes in our proposed depreciation model to ensure that any small residual asset values as at 1 July 2019 calculated in the RFM are fully depreciated. The draft decision's depreciation allowances reflected the AER's draft decision on our RAB and capital expenditure, as well as updated CPI and WACC values which were not available at the time of our original Regulatory Proposal.

In this revised Regulatory Proposal, we have revised our calculation of the transmission and distribution regulatory depreciation allowances using the methods accepted by the AER in its draft decision.

Our revised regulatory depreciation for prescribed transmission services is presented in the table below. It reflects our response to the draft decision and the revised transmission capital expenditure forecasts presented in this revised Regulatory Proposal. It also reflects updated CPI data and our revised transmission WACC.

Table 8-1: Regulatory depreciation - Transmission assets

	2019-20 ($m)	2020-21 ($m)	2021-22 ($m)	2022-23 ($m)	2023-24 ($m)
Straight-line depreciation (June 2019 $)	50.7	56.4	58.9	59.7	63.5
Straight-line depreciation (nominal)	52.0	59.2	63.3	65.8	71.7
Inflation on the opening RAB (nominal)	35.6	36.7	37.7	38.6	39.2
Regulatory depreciation (nominal)	16.3	22.5	25.6	27.3	32.5
Forecast inflation on opening RAB (% per year)	2.45%	2.45%	2.45%	2.45%	2.45%

Similarly, the table below shows the revised depreciation building blocks for distribution Standard Control Services for the forthcoming regulatory period. It reflects our response to the draft decision and the revised distribution capital expenditure forecasts, along with updated CPI data and the revised distribution WACC presented in this revised Regulatory Proposal.

Table 8-2: Regulatory depreciation - Distribution assets

	2019-20 ($m)	2020-21 ($m)	2021-22 ($m)	2022-23 ($m)	2023-24 ($m)
Straight-line depreciation (June 2019 $)	98.5	104.4	110.7	114.7	118.5
Straight-line depreciation (nominal)	100.9	109.6	119.0	126.4	133.7
Inflation on the opening RAB (nominal)	44.1	46.7	48.9	50.6	52.5
Regulatory depreciation (nominal)	56.8	62.9	70.2	75.8	81.2
Forecast inflation on opening RAB (% per annum)	2.45%	2.45%	2.45%	2.45%	2.45%

Our forecast regulatory depreciation is calculated in accordance with the requirements set out in clauses 6A.6.3 and 6.5.5 of the Rules. As shown in the tables above, the regulatory depreciation is the straight line depreciation (nominal) minus inflation on the opening RAB (nominal).

9 Rate of return and financing costs

9.1 Weighted Average Cost of Capital (WACC)

As a capital intensive business, our allowed rate of return or WACC has a significant impact on our revenue requirements and, ultimately, electricity prices.

In accordance with the current Rules, our original Regulatory Proposal applied the AER's 2013 Rate of Return Guidelines in estimating the WACC for our transmission and distribution assets. In applying these Guidelines, we had regard to the decisions made by the Australian Competition Tribunal on 26 February 2016[68] and the Federal Court on 24 May 2017[69] in relation to the approach for estimating the cost of debt allowance. We also proposed to align the WACC estimates applicable to our transmission and distribution assets, which reduced our proposed transmission revenues.

The Rules require the AER to review its 2013 Rate of Return Guidelines by December 2018. In accordance with this requirement, the AER published its draft 2018 Rate of Return Guidelines in July 2018.

The AER's draft 2018 Rate of Return Guidelines proposed a number of changes to the WACC parameters. In addition, the AER also noted that the Council of Australian Governments proposes to replace the current Guidelines with a binding legislative instrument. The intention of the new legislative framework is to remove discretion in setting the rate of return, so that the Rate of Return Guidelines are applied automatically. In contrast, the current legislative framework allows both the service providers and the AER an opportunity to depart from the Guidelines if the departure would better achieve the rate of return objective, which is specified in the Rules.

At this time, the legislative amendments to introduce binding Guidelines have not been implemented. In its draft decision, however, the AER has applied its draft 2018 Rate of Return Guidelines. In deciding to apply the draft Guidelines, the AER explained that it had consulted widely in developing it and considered that it had sufficient evidence to depart from the 2013 Guidelines.

We note that the AER's 2018 Rate of Return Guidelines remain in draft form. As a member of Energy Networks Australia, we support its submissions in relation to the draft Guidelines, which raise concerns regarding a number of key parameter values. In particular, the draft Guidelines reduce the market risk premium and equity beta with the effect of understating the cost of equity. A reduction in the cost of equity is notably problematic given the challenging policy environment and transformational changes occurring in the electricity sector. Customers' long term interests are not promoted by reducing the allowance for the cost of equity as proposed in the draft Guidelines.

Notwithstanding these concerns, we propose to apply the AER's draft 2018 Guidelines in this revised Regulatory Proposal, consistent with the AER's draft decision. Our approach is intended to be a pragmatic response to the draft decision, noting that the AER's 2018 Guidelines will be finalised in December 2018 and its final decision for our transmission and distribution determination will reflect

68 *Applications by Public Interest Advocacy Centre Ltd and Ausgrid* [2016] ACompT 1 (ACT 1 of 2015, ACT 4 of 2015) (*Ausgrid*); *Applications by Public Interest Advocacy Centre Ltd and Endeavour Energy* [2016] ACompT 2 (ACT 2 of 2015, ACT 6 of 2015); *Applications by Public Interest Advocacy Service Ltd and Essential Energy* [2016] ACompT 3 (ACT 3 of 2015); *Application by ActewAGL Distribution* [2016] ACompT 4 (ACT 5 of 2015); and *Application by Jemena Gas Networks (NSW) Ltd* [2016] ACompT 5 (ACT 8 of 2015) (NSD 420 of 2016).

69 Australian Energy Regulator v Australian Competition Tribunal (No 2) [2017] FCAFC 79.

the finalised Guidelines. For ease of reference, we reproduce the AER's draft decision on the rate of return for transmission and distribution below.

Table 9-1: Rate of return parameters for transmission[70]

	TasNetworks' final decision (2014–19)	TasNetworks' proposal (2019–24)	AER draft decision (2019–24)	Allowed return over regulatory control period
Nominal risk free rate	2.55%	2.64%[a]	2.66% [b]	
Market risk premium	6.5%	6.5%	6%	
Equity beta	0.7	0.7	0.6	
Return on equity (nominal post–tax)	7.1%	7.2%	6.3%	Constant (%)
Return on debt (nominal pre–tax)	6.07%[c]	5.44%	5.42% [d]	Updated annually
Gearing	60%	60%	60%	Constant (60%)
Nominal vanilla WACC	6.37%	5.89%	5.77%	Updated annually for return on debt
Forecast inflation	2.38%	2.45%	2.45%	Constant (%)

Source: AER analysis;
[a] TasNetworks' placeholder risk free rate based on an averaging period of 4 August to 31 August 2017
[b] AER placeholder averaging period of 20 business days ending 31 July 2018
[c] AER return on debt for 2014–15 (the first year of the 2014–19 period)
[d] AER placeholder trailing average return on debt for 2019–20 (the first year of the 2019–24 period).

Table 9-2: Rate of return parameters for distribution[71]

	TasNetworks' final decision (2017–19)	TasNetworks' proposal (2019–24)	AER draft decision (2019–24)	Allowed return over regulatory control period
Nominal risk free rate	2.85%	2.64%[a]	2.66% [b]	
Market risk premium	6.5%	6.5%	6%	
Equity beta	0.7	0.7	0.6	
Return on equity (nominal post–tax)	7.4%	7.2%	6.3%	Constant (%)
Return on debt (nominal pre–tax)	5.1%[c]	5.01%	4.98%[d]	Updated annually
Gearing	60%	60%	60%	Constant (60%)
Nominal vanilla WACC	6.00%	5.89%	5.51%	Updated annually for return on debt
Forecast inflation	2.45%	2.42%	2.45%	Constant (%)

Source: AER analysis;
[a] TasNetworks' placeholder risk free rate based on an averaging period of 4 August to 31 August 2017
[b] AER placeholder averaging period of 20 business days ending 31 July 2018
[c] AER return on debt for 2017-18
[d] AER placeholder trailing average return on debt for 2019–20 (the first year of the 2019–24 period).

70 AER, draft decision, TasNetworks Transmission Determination 2019 to 2024, Attachment 3, Rate of return, Table 3-1, page 6.

71 AER, draft decision, TasNetworks Distribution Determination 2019 to 2024, Attachment 3, Rate of return, Table 3-1, page 6.

It should be noted that we accept the rate of return in the AER's draft decision on the basis that:

- it will be updated to reflect the AER's finalised 2018 Guidelines; and
- legislation is enacted requiring the Guidelines to apply for the 2019-24 regulatory period.

For the purpose of this revised Regulatory Proposal, and subject to the caveats set out above, we accept the draft decision that the rate of return for transmission is 5.77 per cent (nominal vanilla, indicative) and for distribution is 5.51 per cent (nominal vanilla, indicative), for the first year of the 2019–24 regulatory control period[72]. As explained in our original Regulatory Proposal, the rate of return will be updated annually to reflect the updated cost of debt.

9.2 Equity raising costs

Our original Regulatory Proposal explained that equity raising costs are transaction costs incurred when network service providers raise new equity from outside the business in order to fund capital investment. Equity raising costs are costs that would be incurred by a prudent service provider acting efficiently. Accordingly, the AER provides a benchmark allowance to recover an efficient amount of equity raising costs, when a network service provider's capital expenditure forecast requires an external equity injection to maintain the benchmark gearing of 60 per cent.

In its draft decision, the AER explained that it has amended its approach to equity raising costs to be consistent with its revised value for imputation credits[73]. In particular, the AER has adopted a consistent dividend distribution rate of 0.83 in estimating equity raising costs and gamma, compared to its earlier rate of 0.7.

For the purpose of this revised Regulatory Proposal, we have accepted the AER's amended benchmark and recalculated the equity raising cost allowance accordingly. An amount of $0.4 million has been included in the transmission regulatory asset base and $2.1 million in the distribution regulatory asset base, in accordance with the approach and calculations set out in our completed PTRMs.

9.3 Debt raising costs

Debt raising costs are benchmarked costs associated with raising or refinancing debt. These costs include underwriting fees, legal fees, company credit rating fees and other transaction costs. Debt raising costs are an unavoidable aspect of raising debt that would be incurred by a prudent service provider, and data exists to enable us to estimate these costs.

Our actual debt raising costs are reported as finance charges rather than operating expenditure. Therefore, a separate debt raising allowance must be included in our operating expenditure to align with the regulatory treatment.

Our financial modelling treats the debt portfolios of our transmission and distribution activities separately, so it is necessary to estimate separate debt raising costs for these two debt portfolios.

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72 AER, draft decision, TasNetworks Transmission and Distribution Determination 2019 to 2024, Overview, page 34.

73 AER, draft decision, TasNetworks Distribution Determination 2019 to 2024, Attachment 3, Rate of return, page 19.

9.3.1 Debt raising cost allowance for transmission

In its draft decision, the AER accepted our proposed debt raising cost allowance as part of our total operating expenditure forecast which the AER accepted in its entirety[74]. In this revised Regulatory Proposal, our debt raising cost allowance remains unchanged.

Table 9-3: Debt raising cost allowance for transmission

	2019-20 ($m)	2020-21 ($m)	2021-22 ($m)	2022-23 ($m)	2023-24 ($m)
Debt raising cost allowance (June 2019 $m)	1.01	1.00	1.01	1.02	1.01

9.3.2 Debt raising cost allowance for distribution

In its draft decision, the AER also accepted our proposed debt raising cost allowance for distribution as a component of our total operating expenditure[75]. Our debt raising cost allowance remains unchanged in this revised proposal.

Table 9-4: Debt raising cost allowance for distribution

	2019-20 ($m)	2020-21 ($m)	2021-22 ($m)	2022-23 ($m)	2023-24 ($m)
Debt raising cost allowance (June 2019 $m)	0.9	0.9	0.9	0.9	1.0

74 AER, draft decision, TasNetworks Transmission Determination 2019 to 2024, Attachment 3, Rate of return, page 18.

75 AER, draft decision, TasNetworks Distribution Determination 2019 to 2024, Attachment 3, Rate of return, page 19.

10 Forecast allowance for corporate tax

10.1 Introduction

This chapter sets out information on our proposed regulatory allowance for corporate tax in the forthcoming regulatory period.

In May 2018, the AER commenced a review of its approach to estimating the regulatory tax allowance following a letter from the Minister for Energy, which indicated that there was a material difference between:

- the AER's regulatory forecast of tax costs for energy networks; and
- actual tax payments made by these businesses to the Australian Tax Office.

The AER’s review is considering whether changes to its regulatory tax approach are needed to ensure that consumers pay no more than necessary. In June 2018, the AER published an Issues Paper that explored the reasons why there may be differences between the regulatory allowance and the amount of tax paid. The AER’s final report and recommendations are expected to be published in December 2018. At this stage, it is unclear whether the AER’s recommendations will require any change to the Rules or, if so, the process and timeframes for implementing change.

In its draft decision, the AER has indicated that it will consult with TasNetworks directly on specific implementation issues and possible interactions with other aspects of the revenue determination as soon as the likely direction of the tax review and any model changes are evident[76]. We welcome the AER’s commitment to consult with us.

For the purpose of this revised Regulatory Proposal, we have continued to apply the AER’s current approach to determining the regulatory tax allowance.

The remainder of this Chapter is structured as follows:

- Section 10.2 recaps on the method we have applied for calculating the corporate income tax allowance.
- Section 10.3 sets out our estimate of the value of imputation credits (gamma).
- Section 10.4 provides information on our forecast of depreciation for corporate tax purposes.
- Section 10.5 provides an overview of our calculation of the corporate tax allowance.

10.2 Method for calculating corporate income tax allowance

As explained in our original Regulatory Proposal, our calculation of the cost of corporate income tax for each year (ETC_t) of the forthcoming regulatory period is in accordance with clauses 6A.6.4 and 6.5.3 of the Rules, which requires the following formula to be applied:

$$ETC_t = (ETI_t \times r_t)\ (1 - \gamma)$$

[76] AER, draft decision, TasNetworks Transmission Determination 2019 to 2024, Attachment 7, Corporate Income Tax, page 7.

where:

ETI_t is an estimate of the taxable income for that *regulatory year* that would be earned by a benchmark efficient entity as a result of the provision of *standard control services* if such an entity, rather than the *Distribution Network Service Provider*, operated the business of the *Distribution Network Service Provider*, such estimate being determined in accordance with the *post-tax revenue model*;

r_t is the expected statutory income tax rate for that *regulatory year* as determined by the *AER*; and

γ is the value of imputation credits.

10.3 Imputation credit value (gamma)

The value of imputation credits (gamma) is an important input to the calculation of the corporate income tax allowance. Under the Australian imputation tax system, shareholders may receive imputation tax credits with dividends, which offset tax liabilities. Therefore, investors would accept a lower rate of return for an investment with imputation credits attached than if there were no imputation tax credits attached.

In effect, the assumed value of gamma has a direct bearing on the overall returns that are delivered to network business owners. Specifically, if the value ascribed to gamma is higher than the value that equity-holders place on imputation credits, the overall benchmark return to owners will be less than the level required to promote efficient investment in, and efficient operation and use of, electricity transmission and distribution services for the long term interests of consumers.

The value of gamma has been highly contentious in recent years. In our original Regulatory Proposal, we proposed a gamma value of 0.4, which reflected the AER's position in its most recent determinations and is consistent with the decision of the Federal Court on 24 May 2017[77]. Subsequently, the AER's draft 2018 Rate of Return Guidelines, which were published in July 2018, now propose a gamma of 0.5. The AER's draft decision has also adopted this higher gamma value, which has the effect of reducing our tax allowance.

As explained in Chapter 9 of this revised Regulatory Proposal, we have decided to accept the AER's draft decision in relation to the cost of capital, noting that the AER's 2018 Guidelines will be finalised in December. The AER has undertaken to consider the submissions lodged in relation to its draft Guidelines and to update its final decision for our transmission and distribution determination accordingly. On this basis, we accept the draft decision's gamma of 0.5 for the purpose of this revised Regulatory Proposal.

10.4 Forecast regulatory tax depreciation

The calculation of the corporate tax allowance requires a forecast of tax depreciation. In our original Regulatory Proposal, we calculated tax depreciation in accordance with the tax law and the methodology contained within the PTRM. We calculated tax depreciation on a straight line basis, using applicable straight line tax depreciation rates.

[77] Australian Energy Regulator v Australian Competition Tribunal (No 2) [2017] FCAFC 79.

In the its draft decision, the AER adopted the same methodology as our original Regulatory Proposal but calculated a different tax depreciation amount as a result of its proposed reduction to our forecast capital expenditure. In this revised Regulatory Proposal, we have similarly updated the calculation to reflect our revised capital expenditure forecasts. In terms of the calculation method, however, our approach is unchanged from our original Regulatory Proposal and the AER's draft decision.

10.5 Calculation of corporate income tax allowance

The calculation of the corporate income tax allowance depends on:

- pre-tax revenues
- tax expenses (including tax depreciation)
- the corporate tax rate, which is set by Government
- gamma.

The pre-tax revenues are determined by the building block revenue calculation. As our revenue requirement in this revised Regulatory Proposal differs from the AER's draft decision, it follows that our proposed corporate tax allowance also differs from the draft decision. The tables below show our revised regulatory tax allowance for transmission and distribution.

Table 10-1: Forecast tax allowance from 1 July 2019 to 30 June 2024 - Transmission ($m nominal)

	2019-20	2020-21	2021-22	2022-23	2023-24
Benchmark income tax payable	2.9	3.7	4.2	4.5	6.1
Imputation credit	-1.4	-1.9	-2.1	-2.3	-3.0
Net tax allowance	**1.4**	**1.9**	**2.1**	**2.3**	**3.0**

Table 10-2: Forecast tax allowance from 1 July 2019 to 30 June 2024 - Distribution ($m nominal)

	2019-20	2020-21	2021-22	2022-23	2023-24
Benchmark income tax payable	15.3	16.0	16.8	17.8	19.3
Imputation credit	-7.6	-8.0	-8.4	-8.9	-9.7
Net tax allowance	**7.6**	**8.0**	**8.4**	**8.9**	**9.7**

11 Incentive schemes

11.1 Scheme for the forthcoming regulatory period

In our original Regulatory Proposal, we proposed the application of the following incentive schemes in the forthcoming regulatory period:

- Efficiency Benefit Sharing Scheme (**EBSS**);
- Capital Expenditure Sharing Scheme (**CESS**);
- Service Target Performance Incentive Scheme (**STPIS**); and
- Demand management incentive scheme and innovation allowance mechanism.

In accordance with the Rules requirements, we explained the application of these schemes in the forthcoming regulatory period in relation to our transmission and distribution services. The AER's draft decision accepted our proposed application of version 2 of the EBSS[78] and version 1 of the CESS[79] in the 2019-24 regulatory period.

In relation to the STPIS for our distribution services, the AER's draft decision confirmed that the current version of the distribution STPIS (November 2009) will apply for the 2019–24 regulatory period. The AER's draft decision calculated the parameter values and incentive rates in accordance with the published scheme and our original Regulatory Proposal. The AER made a number of minor adjustments to address data issues in relation to the customer service parameter[80]. In this revised Regulatory Proposal, we accept the AER's draft decision in relation to the STPIS for our distribution services.

In relation to the STPIS for our transmission services, our original Regulatory expressed concern that the loss of supply event frequency targets did not provide appropriate incentives to improve and maintain performance. In effect, the parameters provide an 'all or nothing' incentive scheme, which presents us with limited scope to manage network service performance over time. As such, we argued that the continued application of the current thresholds would not be consistent with the objectives of the scheme, and would be contrary to the interests of our customers due to the potential for increased pricing volatility.

With these considerations in mind, and to better balance risks and rewards, we proposed a reduction in our loss of supply event frequency thresholds. In its draft decision, the AER commented that the issue raised related to the design of the scheme[81]. As such, the AER found that our proposal could not be addressed in this determination. The AER said that our proposed change will require an

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78 AER, draft decision, TasNetworks Distribution Determination 2019 to 2024, Attachment 8, Efficiency benefit sharing scheme, page 6. A similar reference applies in relation to the AER's draft decision for transmission.

79 AER, draft decision, TasNetworks Transmission Determination 2019 to 2024, Attachment 9, Capital expenditure sharing scheme, page 7. A similar reference applies in relation to the AER's draft decision for distribution.

80 AER, draft decision, TasNetworks Distribution Determination 2019 to 2024, Attachment 10, Service target performance incentive scheme, page 13.

81 AER, draft decision, TasNetworks Transmission Determination 2019 to 2024, Attachment 10, Service target performance incentive scheme, page 12.

alteration to the transmission STPIS, which will require comprehensive stakeholder consultation prior to implementation.

On this basis we have decided to accept the AER's draft decision, noting that the AER should consider amendments to the scheme design to enable a change to STPIS parameters such as we proposed in January 2018.

The AER's draft decision also made a number of changes to our proposed caps and floors in relation to the service component of the scheme, which we understand more accurately reflect the scheme requirements[82]. We accept the AER's proposed changes.

In relation to our Network Capability Incentive Parameter Action Plan (NCIPAP), the AER rejected two projects on the grounds that they will improve reliability rather than increase network capacity[83]. We accept the AER's assessment of these projects and we have removed them from our NCIPAP. As explained in section 5.2.3, these projects have been transferred to our transmission development capital expenditure, as both deliver reliability benefits.

We have identified an alternative NCIPAP project to replace the two that have been disallowed. This project is to reconfigure the Port Latta 110 kV supply from a loop in and out arrangement to a double tee. This project demonstrates market benefit through avoided wind spill. The project cost allowance under NCIPAP is $0.845 million. This project is supported by AEMO and we seek AER approval for its inclusion in the NCIPAP in the AER's final decision (TN063 and TN064).

11.2 Payments in relation to the current regulatory period

In our original Regulatory Proposal, our revenue requirement for the forthcoming regulatory period included payments principally relating to the EBSS, but also included allowances under the Demand Management and Embedded Generation Connection Incentive Scheme (formally the Demand Management Incentive Scheme, or DMIS).

In its Issues Paper[84], the AER commented that payments in relation to the distribution CESS for the current period, being 2017-19, will not apply in the 2019-24 period because the actual expenditure will not be known. The AER has subsequently clarified that the CESS payments will apply, using our actual distribution capital expenditure for 2017-18, which is now available, and our estimated capital expenditure for 2018-19. We concur with the AER's proposed application of the CESS in relation to our distribution capital expenditure for the current regulatory period.

In its draft decision, the AER calculated different amounts for the EBSS and CESS, as follows:

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82 AER, draft decision, TasNetworks Transmission Determination 2019 to 2024, Attachment 10, Service target performance incentive scheme, page 11 and 12.

83 AER, draft decision, TasNetworks Transmission Determination 2019 to 2024, Attachment 10, Service target performance incentive scheme, page 15.

84 AER, Issues Paper, TasNetworks Distribution and Transmission Determination 2019 to 2024, March 2018, section 4.3.2.

- In relation to the CESS, the differences arose from the AER's application of an updated model and inputs[85].
- In relation to the EBSS, the AER identified and corrected some input errors used to calculate its carryover amounts[86].

In this revised Regulatory Proposal, we have re-applied the EBSS and CESS calculations for our transmission and distribution services in accordance with the AER's approved schemes and draft decision. As already noted, our higher capital expenditure in 2017-18 has contributed to penalty payments in relation to the CESS. In contrast, the EBSS provides for an increased bonus for transmission (as operating expenditure in 2017-18 was lower than expected) and a significant penalty for distribution (as operating expenditure in 2017-18 was higher than expected).

The net impact of these incentive payments is presented in the next section. The completed EBSS and CESS spreadsheet models are provided as supporting documents.

[85] AER, draft decision, TasNetworks Transmission Determination 2019 to 2024, Attachment 9, Capital expenditure sharing scheme, page 10. A similar reference applies in relation to the AER's draft decision for distribution.

[86] AER, draft decision, TasNetworks Distribution Determination 2019 to 2024, Attachment 8, Efficiency benefit sharing scheme, page 6. A similar reference applies in relation to the AER's draft decision for transmission.

12 Annual revenue requirements, X-factors and control mechanism

12.1 Introduction

This chapter provides information on the revenue and pricing outcomes from our revised Regulatory Proposal, as follows:

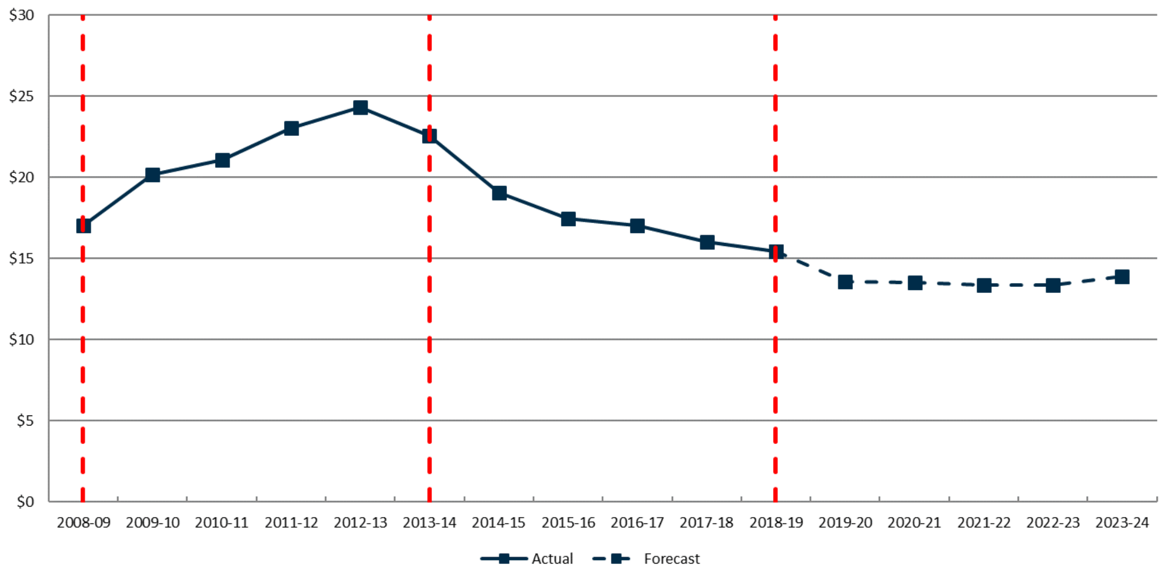
- Section 12.2 summarises the price outcomes for our transmission and distribution customers.
- Section 12.3 sets out the transmission and distribution revenue calculations and the proposed X factors to apply in the forthcoming regulatory period.

12.2 Price outcomes

For transmission customers, our prices are set in accordance with our pricing methodology, which is unchanged from our current approach. Transmission charges for our Tasmanian customers are affected annually by intra-regional settlements residue payments from AEMO and inter-regional charging between Tasmania and Victoria.

The price impact of our proposal will vary for particular customers, depending on their particular circumstances and the annual adjustments described above. As such, the figure below provides a broad indication of the implications of our revised Regulatory Proposal for average transmission prices over the forthcoming regulatory period, which we expect to be 20 per cent lower in real terms than the previous five year period.

Figure 12-1: Average price impact of transmission proposal ($/MWh) (June 2019 $)



Transmission and distribution network costs presently make up around 43 per cent of the average Tasmanian residential and small business customer electricity retail bill[87].

[87] Based on 2017-18 Aurora Energy retail standing offer prices.

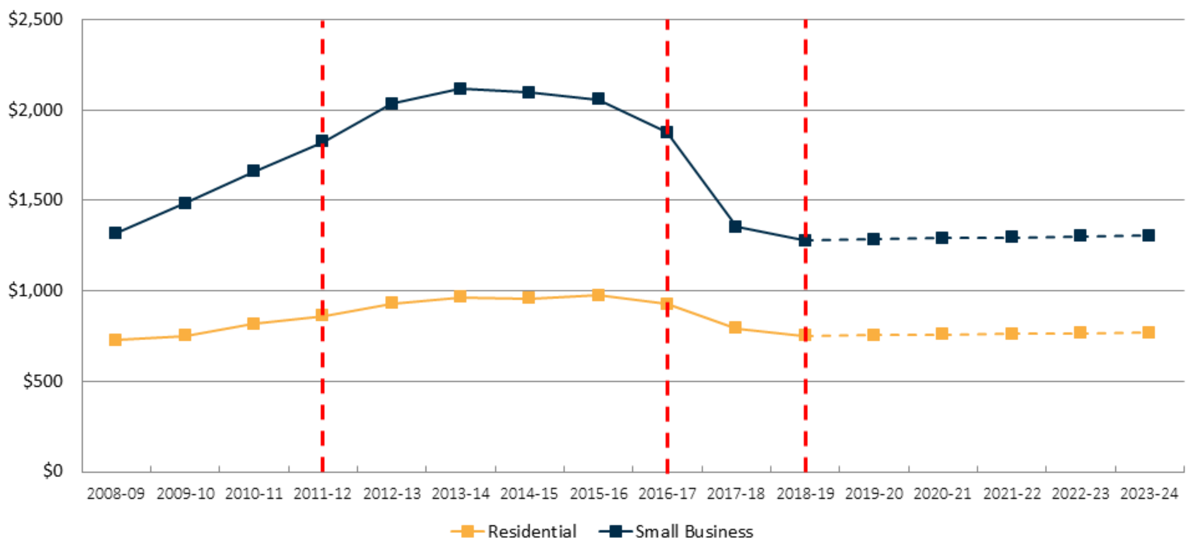
The distribution revenue allowance for each year, together with a share[88] of the transmission network charges (around 55 per cent), is recovered from our distribution customers. This revenue recovery is achieved through a framework of distribution network pricing “tariffs” which are applied to each customer and charged to retailers. The table below outlines the forecast revenue to be recovered from distribution customers.

Table 12-1: Revenue to be recovered from distribution customers (June 2019 $m)

	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24
Transmission Revenue	79.5	78.6	78.1	77.7	77.3	76.8
Distribution Revenue	241.0	244.0	247.1	250.1	253.2	256.4
Total Revenue	**320.5**	**322.6**	**325.2**	**327.8**	**330.5**	**333.2**

Our proposed transmission and distribution revenue allowance results in the indicative average annual network charges for residential and small business customers as shown below. Consistent with our strategy of sustainable and predictable pricing, our revised Regulatory Proposal results in most customers’ network charges increasing only slightly above CPI and remaining well below pre-merger levels.

Figure 12-2: Average annual total network charges for distribution customers (June 2019 $)



At the start of the next regulatory period, our proposed network charges for a typical residential customer will be 22 per cent lower in real terms compared to our charges in 2013-14. The reduction for a typical small business customer over the same period will be even greater at 39.6 per cent in real terms.

12.3 Transmission and distribution building blocks and X factors

The tables below show our revised proposed total revenue requirements, broken down by transmission and distribution.

88 Determined via the application of our Transmission Pricing methodology.

Table 12-2: Our Total Smoothed Revenue Requirements ($m nominal)

	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Total Smoothed Revenue requirement	409.1	401.1	413.4	426.1	439.2	452.7
Transmission revenue requirement	168.1	151.1	154.1	157.1	160.2	163.4
Distribution revenue requirement	241.0	250.0	259.3	269.0	279.0	289.3
Transmission revenue as a % of total	41.09%	37.67%	37.27%	36.87%	36.48%	36.09%
Distribution revenue as a % of total	**58.91%**	**62.33%**	**62.73%**	**63.13%**	**63.52%**	**63.91%**

The table below shows our revised proposed transmission building block calculation for the forthcoming regulatory period alongside the final year of the current period, which is 2018-19.

Table 12-3: Summary of Transmission Building Block Revenue Requirements and X Factors ($m nominal)

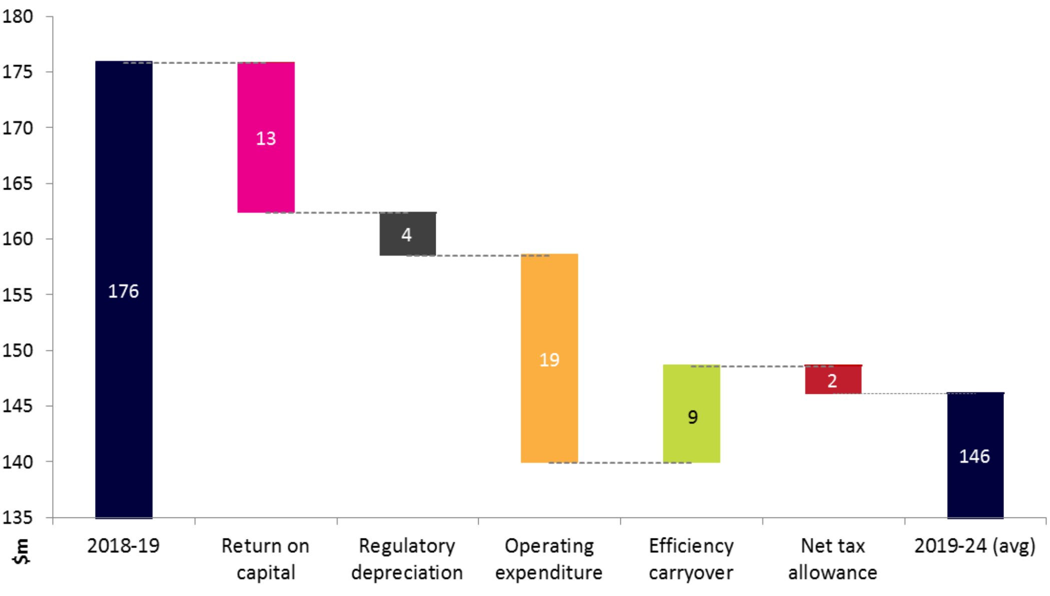
	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Return on Capital	95.70	84.0	86.5	88.8	90.8	92.2
Regulatory Depreciation	26.78	16.3	22.5	25.6	27.3	32.5
Operating expenditure (incl. Debt Raising)	48.90	30.8	31.7	32.6	33.6	34.6
Efficiency carry over[89]	-	18.6	9.9	10.9	5.1	0.9
Net tax allowance	4.44	1.4	1.9	2.1	2.3	3.0
Transmission Revenue Requirement (unsmoothed)	175.83	**151.1**	**152.4**	**160.0**	**159.0**	**163.3**
Transmission Revenue Requirement (smoothed)	168.13	**151.1**	**154.1**	**157.1**	**160.2**	**163.4**
X factors[90]		**12.28%**	**0.47%**	**0.47%**	**0.47%**	**0.47%**

The figure below shows the key drivers of the change in transmission revenue compared to the current period, expressed in real terms.

89 This mainly relates to Efficiency Benefit Sharing Scheme payments.

90 The X factor applies in the revenue cap CPI-X formula, which means that the percentage shown is the proposed annual reduction in revenue expressed in real terms.

Figure 12-3: Transmission revenue requirements from 2018-19 to 2019-24 (average) (June 2019 $m)



The table below presents our revised proposed distribution revenue requirements.

Table 12-4: Summary of Distribution Building Block Revenue Requirements and X Factors ($m nominal)

	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Return on Capital	101.33	99.26	104.98	109.86	113.81	118.11
Regulatory Depreciation	57.64	56.80	62.92	70.16	75.75	81.20
Operating expenditure (incl. Debt Raising)	68.42	92.96	94.80	96.19	97.59	99.02
Efficiency carry over[91]	12.83	-21.19	-21.70	-22.23	2.86	-2.23
Net tax allowance	12.16	7.64	7.98	8.38	8.90	9.67
Distribution Revenue Requirement (unsmoothed)	252.39	**235.48**	**248.98**	**262.37**	**298.91**	**305.77**
Distribution Revenue Requirement (smoothed)	241.01	249.99	259.31	268.96	278.97	289.34
X factors[92]		**-1.25%**	**-1.25%**	**-1.24%**	**-1.24%**	**-1.24%**

Clause 6.5.9(b)(2) of the Rules governs the setting of the X factors for distribution. It requires that the expected maximum allowed revenue for the final year of a regulatory period is as close as reasonably possible to the annual building block revenue requirement for that year.

91 This mainly relates to Efficiency Benefit Sharing Scheme payments and also includes allowances provided under the Demand Management and Embedded Generation Connection Incentive Scheme (formally the Demand Management Incentive Scheme, or DMIS).

92 The X factor applies in the revenue cap CPI-X formula, which means that the percentage shown is the proposed annual reduction in revenue expressed in real terms.

While the proposed difference between our costs and revenues in the final year of the 2019-24 period is somewhat higher than recommended by the AER's PTRM handbook[93], it results in an annual real price reduction throughout the regulatory period. Given our customers' concerns regarding affordability, we consider the proposed X factors to be appropriate.

The figure below shows the key differences in our revised proposed distribution revenue compared to the final year of the current regulatory period, expressed in real terms.

Figure 12-4: Distribution revenue requirements from 2018-19 to 2019-24 (average) (June 2019 $m)

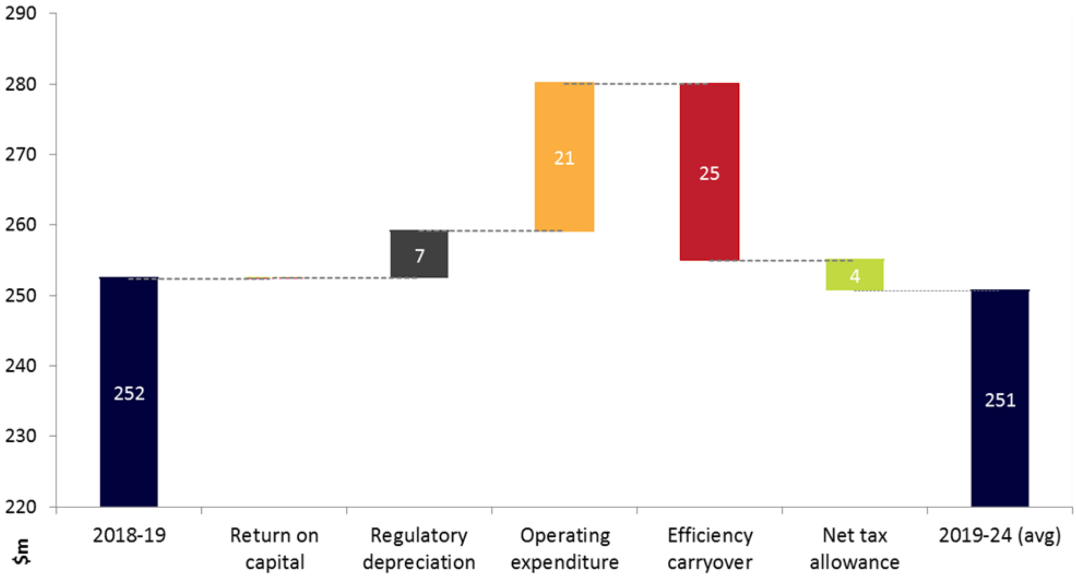
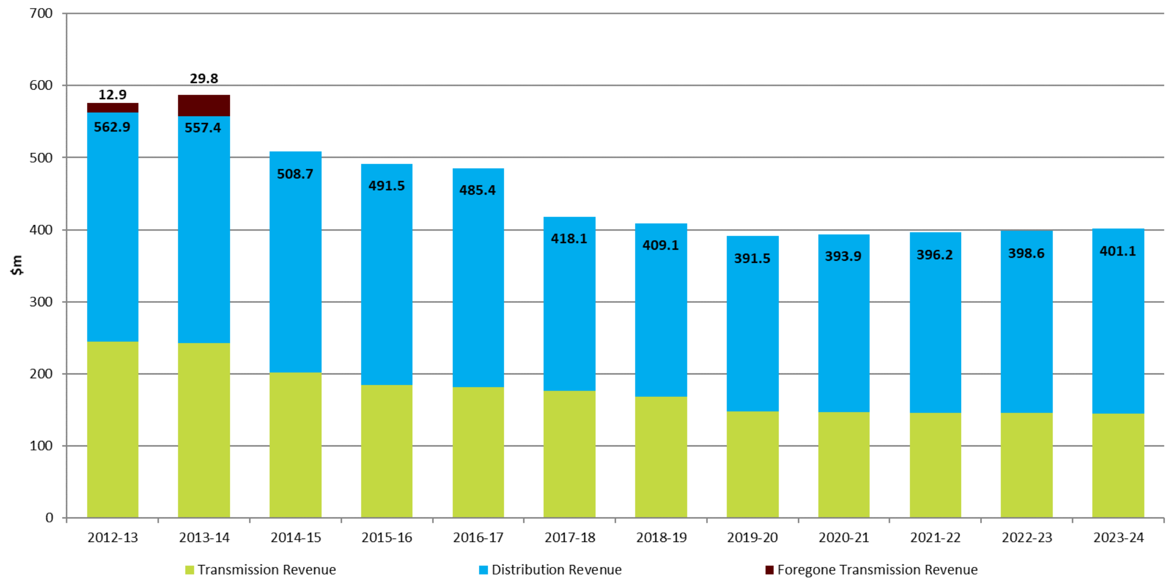


Figure 12-5 shows our total smoothed revenue requirement over the forthcoming regulatory period compared with historical levels. Our revised proposed combined transmission and distribution revenue is significantly less than pre-merger levels.

Figure 12-5: Total Network Smoothed Revenue Requirement (June 2019 $m)



93 AER, Electricity transmission network service providers, Post-tax revenue model handbook, 29 January 2015, page 25.

13 Network pricing

13.1 Transmission pricing methodology

Our original Regulatory Proposal explained that our transmission pricing methodology complies with the pricing principles in part J of the Rules and the AER's Pricing Methodology Guidelines. We explained that:

- The Rules provide limited scope for discretion in relation to transmission pricing; and
- Our transmission customers have no desire to change the current arrangements.

The AER's draft decision accepted our proposed transmission pricing methodology, which is unchanged from our current approach.

13.2 Network pricing for distribution customers

Our original Regulatory Proposal explained that we have embarked on a process of pricing reform which has seen us gradually moving towards cost reflectivity. For the 2019-24 period, we proposed a continuation of this gradual pricing reform through the following measures:

- Ongoing gradual tariff rebalancing to unwind legacy cross-subsidies between different customer types.
- Introducing two new demand based network tariffs as an option for customers with distributed energy resources (**DER**), with discounted off-peak prices for the 2019-24 regulatory period.
- Offering introductory discounts for our new demand based time of use tariffs, including discounted off-peak demand charges.
- Introducing new network tariffs for embedded networks – one for embedded networks connecting to our distribution network at low voltage and another for embedded networks connecting at high voltage.
- Obtaining data from customers participating in our emPOWERing You and Bruny Island Battery trials to inform our future tariff design and pricing strategies.

In its draft decision, the AER did not accept certain aspects of our proposed tariff structure statement and therefore decided not to approve our tariff structure statement[94]. The AER made the following comments in relation to our proposed tariff reform program and our tariff structure statement:

- The AER require us to adopt an 'opt out' arrangement, as opposed to 'opt in', whereby retailers face a cost reflective network tariff by default when a customer meets the trigger for tariff assignment or reassignment[95].

94 AER, draft decision, TasNetworks Distribution Determination 2019 to 2024, Attachment 18, Tariff Structure Statement, page 14.

95 AER, draft decision, TasNetworks Distribution Determination 2019 to 2024, Attachment 18, Tariff Structure Statement, page 14.

- The AER has requested that our revised tariff structure statement describes more comprehensively how the long run marginal cost estimates translate into our indicative price schedule[96].
- The AER supported our proposal to continue the removal of discounts between legacy tariffs, but requires improved transparency and additional options to be considered to accelerate the unwinding of the discounts[97].
- The AER did not accept our embedded network tariffs, noting that such tariffs should demonstrably lead to a more equitable contribution towards the cost of the distribution network[98].
- The AER requires us to provide further information on how we derive individually calculated tariffs, which are part of our suite of network tariffs[99].
- The AER requires further information to be provided in our tariff structure statement to explain the tariff assignment procedures[100].
- The AER did not accept our LRMC estimates because they included replacement projects or programs which increase the capacity of the network, rather than being responsive to changes in demand. The AER's draft decision therefore requires us to amend our LRMC estimates as part of our revised Regulatory Proposal[101].
- The AER prefers a two document approach to the tariff structure statement. The AER explained that the first document should only include the elements of the tariff structure statement listed in the Rules as the constituent elements. A further separate document should contain TasNetworks' reasons for each of these proposed elements (i.e. an explanatory document)[102].

In response to the draft decision, we have amended our Tariff Structure Statement to address all of the matters raised in the AER's draft decision. In accordance with the draft decision, our Tariff Structure Statement is set out in two documents which are submitted alongside this revised Regulatory Proposal (TN011 and TN012).

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96 AER, draft decision, TasNetworks Distribution Determination 2019 to 2024, Attachment 18, Tariff Structure Statement, page 16.

97 AER, draft decision, TasNetworks Distribution Determination 2019 to 2024, Attachment 18, Tariff Structure Statement, pages 18 and 19.

98 AER, draft decision, TasNetworks Distribution Determination 2019 to 2024, Attachment 18, Tariff Structure Statement, page 28.

99 AER, draft decision, TasNetworks Distribution Determination 2019 to 2024, Attachment 18, Tariff Structure Statement, page 29.

100 AER, draft decision, TasNetworks Distribution Determination 2019 to 2024, Attachment 18, Tariff Structure Statement, page 30 and 34.

101 AER, draft decision, TasNetworks Distribution Determination 2019 to 2024, Attachment 18, Tariff Structure Statement, pages 32 and 33.

102 AER, draft decision, TasNetworks Distribution Determination 2019 to 2024, Attachment 18, Tariff Structure Statement, page 36.

Part Three:

Distribution Alternative Control Services

Part Three of the revised Regulatory Proposal sets out information relating to Alternative Control Services. This part provides information on metering services, public lighting services and ancillary services.

14 Metering services

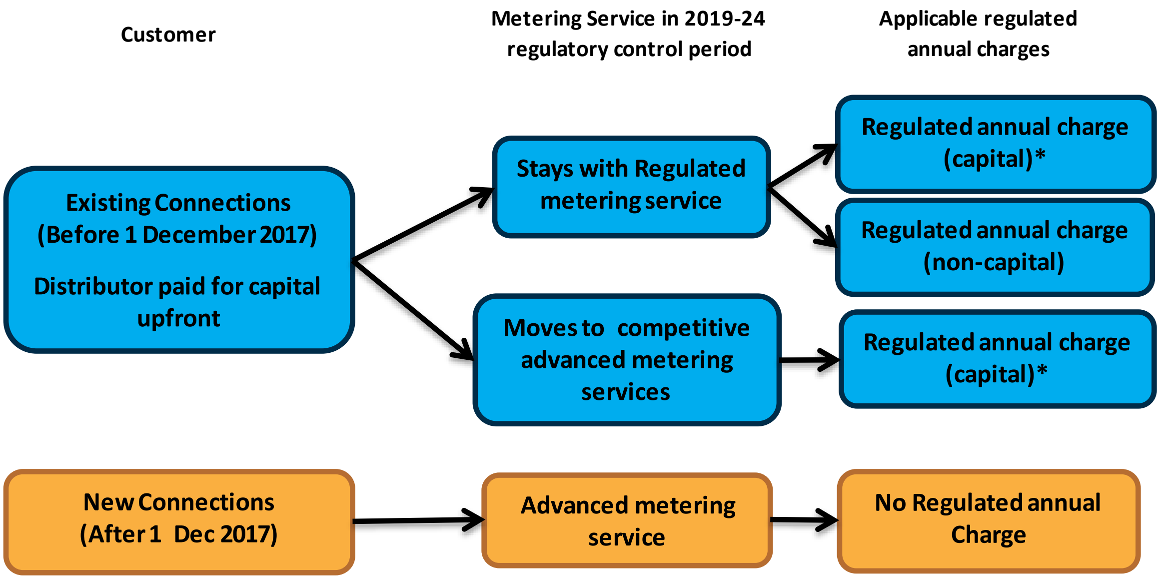
14.1 Introduction

Our original Regulatory Proposal explained that new metering arrangements commenced on 1 December 2017, following a Rule change[103]. From that date, we are not permitted to install or replace existing meters with type 6 meters. However, we are able to continue to provide services for existing type 6 metering equipment as an alternative control service. Our charging arrangements for this service distinguish between:

- the capital component, which recovers the cost of the metering Regulated Asset Base (**metering RAB**) and tax; and
- the non-capital component, which recovers the operating expenditure.

The figure below illustrates how the type 6 metering charges apply following the introduction of competition. Under this charging model, if an existing customer (as at 1 December 2017) switches to a competitive advanced metering service provider, the customer will continue to pay the capital component but will not pay the non-capital charge. This charging methodology provides a fair way of recovering the costs of our existing metering assets, without imposing a one-off exit fee on customers that move to a competitive metering provider.

Figure 14-1: Current charging structure for type 6 metering



*Except for Siemens PAYG Meters

In our original Regulatory Proposal, we proposed to continue with the above charging arrangement but to accelerate depreciation. This proposed change would allow us to fully recover the costs of the existing metering assets by June 2024, which would better reflect their economic life.

103 AEMC, National Electricity Amendment (Expanding competition in metering and related services) Rule 2015, 26 November 2015.

In its draft decision, the AER rejected our proposal to accelerate the depreciation of our metering assets. In particular, the AER commented that we have not demonstrated customer support for accelerated depreciation[104].

Given our customers' concerns regarding affordability, we have decided to withdraw our proposal to accelerate the depreciation of our metering assets and accept the AER's draft decision. However, our view remains that there is a strong case for applying a profile of depreciation charges that reflects the economic life of the assets, and so minimises the potential for some customers to pay for assets that have been withdrawn from service. We will revisit this matter during the 2019-24 regulatory control period with a view to obtaining customer support for accelerated depreciation in the 2024-29 period.

We have updated our proposed metering building block calculation to reflect our acceptance of the the AER's draft decision on accelerated depreciation. The remainder of this chapter is structured as follows:

- Section 14.2 provides updated information on our building block costs for regulated metering services.
- Section 14.3 sets out our revised X factors and indicative prices to apply to regulated metering services.

14.2 Building block costs for regulated metering services

The AER's draft decision accepted our metering RAB. In this revised Regulatory Proposal, we have updated our RAB to reflect our actual capital expenditure in 2017-18, which was estimated in our original Regulatory Proposal.

Table 14-1: Roll forward of metering RAB from 1 July 2017 to 30 June 2019 ($m nominal)

	2017-18	2018-19
Opening RAB	53.4	51.3
Capital expenditure	3.0	0.0
Inflation on opening RAB	1.0	1.3
Disposals	0.0	0.1
Straight-line depreciation	6.1	6.3
Closing RAB	51.3	46.1

As shown in the table above, the metering RAB value as at 1 July 2019 (in nominal dollars) is $46.1 million.

Our revised forecast metering RAB is presented below, which reflects the draft decision in relation to accelerated depreciation. As noted in our original Regulatory Proposal, there is no forecast capital

104 AER, draft decision, TasNetworks Distribution Determination 2019 to 2024, Attachment 15, Alternative Control Services, page 26.

expenditure because new meters have been provided on a competitive basis since 1 December 2017.

Table 14-2: Metering RAB roll forward 1 July 2019 to 30 June 2024 ($m nominal)

	2019–20	2020–21	2021–22	2022–23	2023–24
RAB (start period) - nominal	46.1	42.0	37.7	33.4	29.4
Nominal capital expenditure	0.0	0.0	0.0	0.0	0.0
Inflation on opening RAB	1.1	1.0	0.9	0.8	0.7
Nominal straight-line depreciation	-5.2	-5.4	-5.2	-4.8	-4.9
Disposals	0.0	0.0	0.0	0.0	0.0
RAB (end period) – nominal	42.0	37.7	33.4	29.4	25.2
RAB (end period) – $ June 2019	41.0	35.9	31.0	26.7	22.4

The AER's draft decision did not accept our proposed operating expenditure in relation to metering services. Specifically, the AER rejected our proposed overhead rate and instead applied a 144 per cent overhead rate in line with its consultant's recommendation[105]. In this revised Regulatory Proposal, we have accepted the AER's draft decision in relation to our metering operating expenditure allowance.

The table below summarises our updated building block calculation for type 6 metering services for the forthcoming regulatory period, showing the capital and non-capital components separately.

Table 14-3: Summary of Building Block Revenue Requirement for type 6 and 7 metering services ($ m nominal)

	2019–20	2020–21	2021–22	2022–23	2023–24
Return on Capital	2.5	2.3	2.1	1.8	1.6
Regulatory depreciation	4.1	4.3	4.3	4.0	4.2
Estimated cost of corporate income tax	0.5	0.5	0.6	0.6	0.6
Capital component	7.2	7.2	7.0	6.4	6.4
Non-capital component (operating expenditure)	5.7	5.8	5.8	6.2	6.2
Total Revenue Requirement (unsmoothed)	12.9	13.0	12.7	12.6	12.5

A detailed description of our pricing approach and proposed prices is provided in our revised Tariff Structure Statement, which is provided alongside this revised Regulatory Proposal.

105 AER, draft decision, TasNetworks Distribution Determination 2019 to 2024, Attachment 15, Alternative Control Services, page 27.

14.3 Control mechanism, X factor and indicative prices

Our revised proposed metering services prices for the forthcoming regulatory period are derived from the building block annual revenue requirements and our meter volume forecasts. The proposed X factor, which is reflected in the prices, is -1.59 per cent for each year.

The capital and non-capital charges are detailed in the Tariff Structure Statement, which is provided alongside this revised Regulatory Proposal. As already noted, the capital charge will continue to apply if an existing meter is replaced with a new advanced meter, but the non-capital charge will not.

15 Public lighting services

Our original Regulatory Proposal explained that public lighting services have generally been provided as monopoly services by us to specific customers—usually local government councils—while the emergence of new lighting technologies and providers is increasing the potential for alternative supply arrangements.

We explained that our current lighting charges are based on an annuity approach, rather than a building block model. The annuity approach is preferred because we have sufficient information on the replacement cost and expected lives of new assets, but limited historical information on our public lighting assets that can be used to calculate the regulated asset base value.

Our original Regulatory Proposal explained that we have recently conducted a detailed review of the available asset and expenditure data, and the time and resources being expended in providing public lighting services. This review revealed that the public lighting prices currently on offer fall significantly short of full cost recovery. To address this issue, we proposed a gradual glide path for public lighting prices spanning the 2019-24 and 2024-29 regulatory periods, to transition public lighting to fully cost reflective pricing, which will affect our revenue recovery.

In its draft decision, the AER did not accept our proposed lighting prices. The AER commented that it accepted our labour rates and luminaire input costs, but did not accept our proposed overheads. Instead, the AER concluded that our overheads should be capped at 25 per cent of direct costs[106].

We welcome the AER's acceptance of our labour rates and luminaire input costs, noting that a few minor changes to luminaire input costs have been made. However, we do not accept the AER's approach to benchmarking to determine a maximum overhead rate.

To assist us in relation to this issue, we engaged consulting firm Sankofa to review the benchmarking information in relation to public lighting overheads. Sankofa's report, which is provided as a supporting document to this revised Regulatory Proposal (TN060), explained that:

- TasNetworks classifies some costs as 'overheads' that the Victorian networks classify as 'direct costs'. Consequently, we appear to have higher overheads than our peers for a given level of total public lighting costs.
- Tasmania and Victoria currently use different luminaire types, which means that the average costs are not comparable. The use of new lighting technologies, as opposed to differences in the efficiencies of the distributors, is a potentially important explanation of the variance in reported costs.
- Businesses allocate overheads differently between standard control and alternative control services. For example, in Victoria, Powercor allocates 46 per cent of its overheads to standard control services, whereas TasNetworks allocates 25 per cent. As a consequence, a benchmarking analysis that only focused on ACS overheads may wrongly conclude that TasNetworks' overheads are inefficient.

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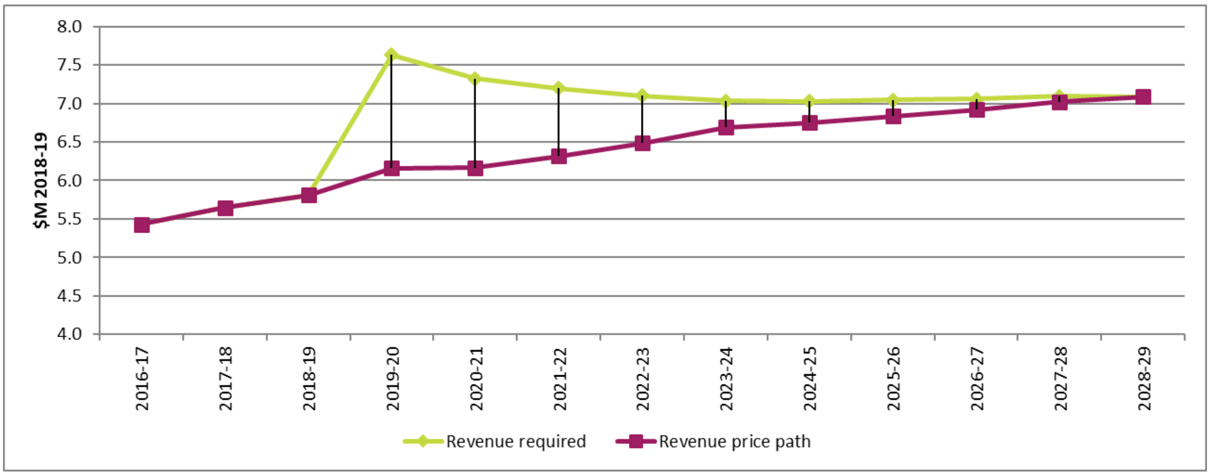
106 AER, draft decision, TasNetworks Distribution Determination 2019 to 2024, Attachment 15, Alternative Control Services, page 24.

- The AER's consultant, Marsden Jacob, recommended an overhead cap of 25 per cent on directly incurred public lighting costs. However, the Marsden Jacob report sources the benchmark of 25 per cent from an earlier AER decision. Given the specific differences noted above between Tasmania and Victoria, it would be better to take a fresh look at the underlying benchmarking data rather than relying on an earlier AER decision.

For the reasons set out above, our position is that a more comprehensive benchmarking review would not support Marsden Jacob's conclusions. Instead, it would illustrate that there are important differences between network companies that explain our higher reported overhead rates for public lighting. Our position is that our total public lighting costs are efficient and the AER's proposed reduction in our overheads is not appropriate.

Currently, our public lighting prices are not sufficient to enable us to recover our costs of providing these services. Nevertheless, we are conscious of the importance of addressing our customers' concerns regarding affordability. Therefore, consistent with our original Proposal, we are proposing to transition our public lighting prices to be fully cost reflective over a ten year period, which means implementing a gradual glide path for public lighting prices spanning the 2019-24 and 2024-29 regulatory periods, as shown in the figure below. Furthermore, reductions in our costs mean that the ten year price path is now shallower with a lower final price point than our original proposal, which provides an additional customer benefit.

Figure 15-1: Our revised proposed price path and revenue impacts (June 2019 $m)



In summary, we consider our proposed public lighting prices appropriately address our customers' concerns regarding affordability, while reasonably reflecting the efficient costs of providing these services. Specifically, our proposed transition to fully cost reflective pricing is an important aspect of our proposal. Given the different approaches to cost allocation and the inherent differences in the costs of providing public lighting services, our position is that a reduction in our public lighting overhead costs is not warranted.

16 Ancillary services

16.1 Introduction

Our original Regulatory Proposal explained that ancillary services share the common characteristic of being non-routine services provided to individual customers on an ‘as needs’ basis. The customer requesting the service is charged according to a tariff for ‘fee-based services’ or a price based on the scope of work for ‘quoted services’.

The remainder of this chapter addresses our fee-based services and quoted services.

16.2 Fee-based services

Our original Regulatory Proposal identified a need to increase the prices of our fee-based services in the forthcoming regulatory period to reflect:

- an updated allocation of our overhead costs in accordance with our CAM; and
- internal and external labour costs, which are forecast to increase slightly faster than CPI, in accordance with advice received from Jacobs[107].

We explained, however, that the reallocation of costs to Alternative Control Services would lead to an off-setting reduction in Standard Control Services costs. We noted that our proposed approach to fee-based services is intended to ensure that customers pay the appropriate prices for the services they request, and are not cross-subsidised by other customers. We also made a number of changes to the fee-based services we proposed to offer in the forthcoming regulatory period.

In its draft decision, the AER accepted our proposed changes to the fee-based services, but did not accept our proposed prices. In particular, the AER compared our proposed fees to the AER’s calculated maximums using alternative labour and overhead rates. The AER explained that it had assessed most of our proposed fees to be too high, mainly because of the overheads applied to our fee-based services[108].

In selecting its alternative labour rates, the AER explained its approach as follows[109]:

> *“In determining efficient labour rates for TasNetworks, we must base our considerations on utility labour rate information from other jurisdictions because equivalent information is not available for Tasmania. In our 2017–19 determination the labour rates we used for Tasmania were the highest of the jurisdictions assessed as we considered, at the time, this approach would provide TasNetworks to recover at least its efficient cost of labour. However, consistent with Marsden Jacob's recommendations, for this determination we allocate TasNetworks the lowest labour rate of other jurisdictions considered as Tasmania has the lowest Average Weekly Earnings of any capital city in Australia. By doing so we provide*

107 Jacobs Labour Cost Escalation Report, 25 October 2017.

108 AER, draft decision, TasNetworks Distribution Determination 2019 to 2024, Attachment 15, Alternative Control Services, page 19.

109 AER, draft decision, TasNetworks Distribution Determination 2019 to 2024, Attachment 15, Alternative Control Services, page 27.

TasNetworks with opportunity to respond with an alternative labour rate in its revised proposal."

In response to the draft decision, we have reviewed and revised our fee-based services model in light of the matters raised by the AER. The key changes made are as follows:

- we have applied in our model the efficient labour rates determined by the AER rates with the exception of administration where we applied our proposed rate;
- we have implemented the AER's suggestion that separate charges should be calculated for de-energisation and re-energisation and for special meter reads;
- we have also included an amount for premium services (same day, non-scheduled visits and afterhours) at the rates approved by the AER;
- we have applied the AER's $20 per hour vehicle allowance to the technical specialist rate for those services where a vehicle is required; and
- we have included an allowance for the additional direct costs of market support staff involved in the delivery of fee-based services.

We consider that we have applied a sound methodology for the pricing of our fee-based services.

A full description of our fee-based services is provided in the Alternative Control Services Descriptors Paper and the proposed charges are outlined in the Tariff Structure Statement, which are submitted as part of this revised Regulatory Proposal.

16.3 Quoted services

Our original Regulatory Proposal explained that we proposed to expand and amend our categories of labour to reflect our current practice, as follows:

- General Administration; Engineer and Senior Engineer are to be included as new categories;
- 'Pole Tester' is to be removed; and
- 'Electrical Inspector' is to be renamed 'Asset Inspector'.

We also proposed to apply the following formula for our quoted services, with the relevant definitions provided in our original Regulatory Proposal:

$$Price = Labour + Contractor\ Services + Materials + Margin$$

In its draft decision, the AER approved our labour rates (raw labour cost plus on-costs) with the exception of our rate for Administration, for which the AER adopted a maximum rate recommended by its consultant, Marsden Jacob. The AER also explained that to apply a price cap to overheads, which were not addressed in our quoted services model, it applied the maximum overhead rate of 61 per cent recommended by our consultant to the approved labour rates (raw labour cost plus on-costs). The AER also concluded that our proposed margin should be considered as part of the overall overhead allowance.[110]

[110] AER, draft decision, TasNetworks Distribution Determination 2019 to 2024, Attachment 15, Alternative Control Services, page 12.

We accept the AER's draft decision in relation to the margin. The price we charge for quoted services will therefore not include a margin.

In this revised Regulatory Proposal, we accept the AER's proposed capped labour rates for all skill set designations except for Administration. We note that Marsden Jacob's recommendation on the Administration labour rate assumes that:

1. all labour rates for TasNetworks will be lower than mainland distribution networks because the Average Weekly Earnings (AWE) in Tasmania are lower than mainland states, noting that AWE is influenced by industry mix; and
2. an average rate of several administrative categories included in the Hays labour benchmarking survey is a reliable benchmark of network administrative costs, noting that this data does not include Tasmania.

Marsden Jacob's approach assumes that a labour rate for Administration should be set at the lower end of the range for TasNetworks because the average Tasmanian wage is lower than mainland states. This approach ignores industry-based competitive labour market forces. Specialist skills, such as those required to work at a network service provider, are in demand across State borders. Although TasNetworks may be able to pay a *generally* lower rate for some skills than mainland states due to overall lower average wages and cost of living, there will be a limit to this course due to the willingness of some staff to relocate for higher wages. The Hays survey data also includes many disciplines in administration which are irrelevant to electricity network administration.

Given these issues, we engaged the consulting firm Sankofa to analyse RIN labour cost data. Sankofa's report, which is provided as a supporting document (TN060), found that:

1. TasNetworks' corporate and network overhead support staff (as a proxy for administration) *actual* hourly rate is already amongst the lowest in the NEM; and
2. TasNetworks' proposed labour rate for administration is very close to the actual labour rate realised for support staff.

These points illustrate that our proposed labour rate for Administration is efficient and should be approved by the AER. In view of these findings, our revised Regulatory Proposal continues to apply the Administration labour rate we originally proposed.

In this revised Regulatory Proposal, we have also included three new rates for skill sets where a vehicle is required. These skill set designations are:

- Distribution electrical technician – including vehicle
- Distribution operator – including vehicle
- Asset inspector – including vehicle.

The hourly rate for each of these three skill sets is the labour rate approved by the AER in the draft decision plus the AER's $20 per hour vehicle allowance.

Part Four:

Pass through events, Connection, Negotiating Framework and other matters

Part Four of this revised Regulatory Proposal sets out information that is applicable to our revenue capped services (namely, prescribed transmission services and distribution Standard Control Services). It provides information on our connection policy, confidentiality and certification.

As the AER's draft decision accepted our proposed pass through events and negotiating framework, no further information is provided in relation to these matters. As already noted, TasNetworks may incur costs in relation to the Inertia Rule change, "Managing the rate of change of power system frequency". These costs fall within the definition of "network support payment", which means the costs are treated as a pass through under clause 6A.7.2 of the Rules.

17 Connection pricing policy

Our original Regulatory Proposal noted that the Rules require us to prepare a connection pricing policy for the AER's approval. The policy sets out the charging arrangements for providing connection services to retail customers or real estate developers. The connection policy must be consistent with the charging principles specified in the Rules[111] and the AER's guidelines[112], which were published in June 2012.

A connection policy sets out the nature of connection services offered by a distributor, when connection charges may be payable by retail customers and how those charges are calculated. A connection policy must detail:

- the categories of persons that may be required to pay a connection charge and the circumstances in which such a requirement may be imposed;
- the aspects of a connection service for which a connection charge may be made and the basis on which connection charges are determined;
- the manner in which connection charges are to be paid (or equivalent consideration is to be given); and
- a threshold (based on capacity or any other measure identified in the connection charge guidelines) below which a retail customer (not being a nonregistered embedded generator or a real estate developer) will not be liable for a connection charge for an augmentation other than an extension.

In our original Regulatory Proposal, we indicated that our proposed connection policy was largely unchanged from the current connection policy, which the AER approved in its 2017-19 distribution determination. However, we acknowledge that a number of drafting changes were proposed in the policy, which should have been identified in our main submission.

In its draft decision the AER did not accept our proposed Connection Policy in two respects:

- Attachment 10 of the policy proposed charges for developers in relation to existing assets, contrary to the AER's guidelines; and
- The proposed charge rates for upstream augmentation costs need refinement to address an anomaly in the original calculation.

We accept the AER's draft decision in relation to our connection policy, which has been amended accordingly. Our revised Connection Policy is provided as a supporting document to this revised Regulatory Proposal (TN005).

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111 NER, clause 5A.E.1.

112 Connection charge guidelines for electricity retail customers, under chapter 5A of the National Electricity Rules, Version 1.0, June 2012.

18 Confidentiality

In accordance with the Rules and the AER's Confidentiality Guideline, we have completed a confidentiality template that we have provided to the AER. This template details the matters in our revised Regulatory Proposal and supporting documents for which we are claiming confidentiality.

19 Certification

19.1 Certification statements

Clauses S6.1.1(5), S6.1.2(6), S6A.1.1(5) and S6A.1.2(6) of the Rules require us to provide a certification by TasNetworks' Board for the underlying key assumptions for our transmission and distribution capital expenditure and operating expenditure forecasts. The certification statement is provided as a supporting document to this revised Regulatory Proposal (TN004).

20 Table of supporting documents

Key Summary Documents

Document ID	Document Title	Confidential
TN001	Transmission and Distribution Revised Revenue and Regulatory Proposal 2019-2024 Overview Paper	N

Key Strategies and Policies

Document ID	Document Title	Confidential
TN002	Annual Planning Report 2018	N
TN003	Corporate Plan 2018-2019	N
TN004	Directors Certification of Key Assumptions for the Revised Revenue and Regulatory Proposal	N
TN005	Distribution Connections Pricing Policy	N
TN006	Marinus Project Specification Consultation Report	N
TN007	Marinus Link Contingent Project Explanatory Paper	Y
TN008	Network Innovation Strategy	N

Asset Management Plans

Document ID	Document Title	Confidential
TN009	Asset Management Information Systems Asset Management Plan	N
TN010	Bushfire Risk Mitigation Plan	N

Models and Pricing Tariffs

Document ID	Document Title	Confidential
TN011	Tariff Structure Statement 2019-2024	Y
TN012	Tariff Structure Statement 2019-2024 - Explanatory Statement	N
TN013	Capex Forecast Model	N
TN014	Distribution Operating Expenditure Model	N

Document ID	Document Title	Confidential
TN015	Transmission Operating Expenditure Model	N
TN016	Quoted Services Labour Rates Model	N
TN017	Public Lighting Annuity Model	N
TN018	Metering Post Tax Revenue Model Distribution (PTRM)	N
TN019	Metering Roll Forward Model (RFM)	N
TN020	Fee Based Services Model Distribution	N
TN021	Roll Forward Model Transmission	N
TN022	Roll Forward Model Standard Control Distribution	N
TN023	Transmission Regulated Asset Base and Tax Depreciation Model	N
TN024	Distribution Regulated Asset Base and Tax Depreciation Model Standard Control	N
TN025	Post Tax Revenue Model (PTRM) Transmission	N
TN026	Post Tax Revenue Model (PTRM) Standard Control Distribution	N
TN027	Transmission EBSS Model	N
TN028	Transmission CESS Model	N
TN029	Distribution EBSS Model	N
TN030	Distribution CESS Model	N

Incentive Schemes

Document ID	Document Title	Confidential
TN031	STPIS Model Customer Service	N
TN032	STPIS Model Reliability of Supply	N

Investment Evaluation Summaries

Document ID	Document Title	Confidential
TN033	Pole Replacements	N
TN034	Market Systems MDMS Replacement	Y
TN035	BFM Project – Replace Aged/Deteriorated CU Conductor	N
TN036	Replacement of HV Switchgear in Ground Mounted Substations	N
TN037	Replacement of Ground Mounted Substations	N
TN038	Asset Management Information System (AMIS) Improvement Program Dx	N
TN039	Asset Management Information System (AMIS) Improvement Program Tx	N
TN040	Replace Low Voltage CONSAC Cable	N
TN041	Replace Overhead LV Services	N
TN042	BFM – Replace EDOs with Alternative Device	N
TN043	Transmission Line Protection Renewal Program	N
TN044	Replace 220 kV Sprechure and Schuh HPF Live Tank Circuit Breakers	N
TN045	Replace 110 kV ASEA HLD Live Tank Breakers	N
TN046	GT-TE Transmission Line Replacement	N
TN047	Burnie-Waratah H Pole Replacement Program	N
TN048	Transformer Protection Renewal Program	N
TN049	Boyer T13 and T14 Supply Transformers Replacement	N
TN050	Port Latta Supply Transformers Replacement	N
TN051	Chapel St 11kV HV Switchgear	N
TN052	Railton 22kV HV Switchgear	N
TN053	SIWES – Endangered Species	N

Document ID	Document Title	Confidential
TN054	IT Security	Y
TN055	Automated Asset Condition Identification	N
TN056	Stand Alone Power Systems	N
TN057	DSO Framework Early Stage Implementation	N
TN058	Preemptive Asset Failure Detection Pilot Implementation	N

Reports

Document ID	Document Title	Confidential
TN059	Nature Research – TasNetworks Customer Engagement Report May 2018	N
TN060	Sankofa – Review for TN on the AER’s draft decision for ACS	N

Other supporting analysis and plans

Document ID	Document Title	Confidential
TN061	Project Needs Analysis Palmerston to Sheffield 220 kV Augmentation	N
TN062	Project Needs Analysis Sheffield to Burnie 220 kV Augmentation	N
TN063	AEMO Endorsement Letter for Revised NCIPAP Proposal	N
TN064	Revised NCIPAP Project Plan	N