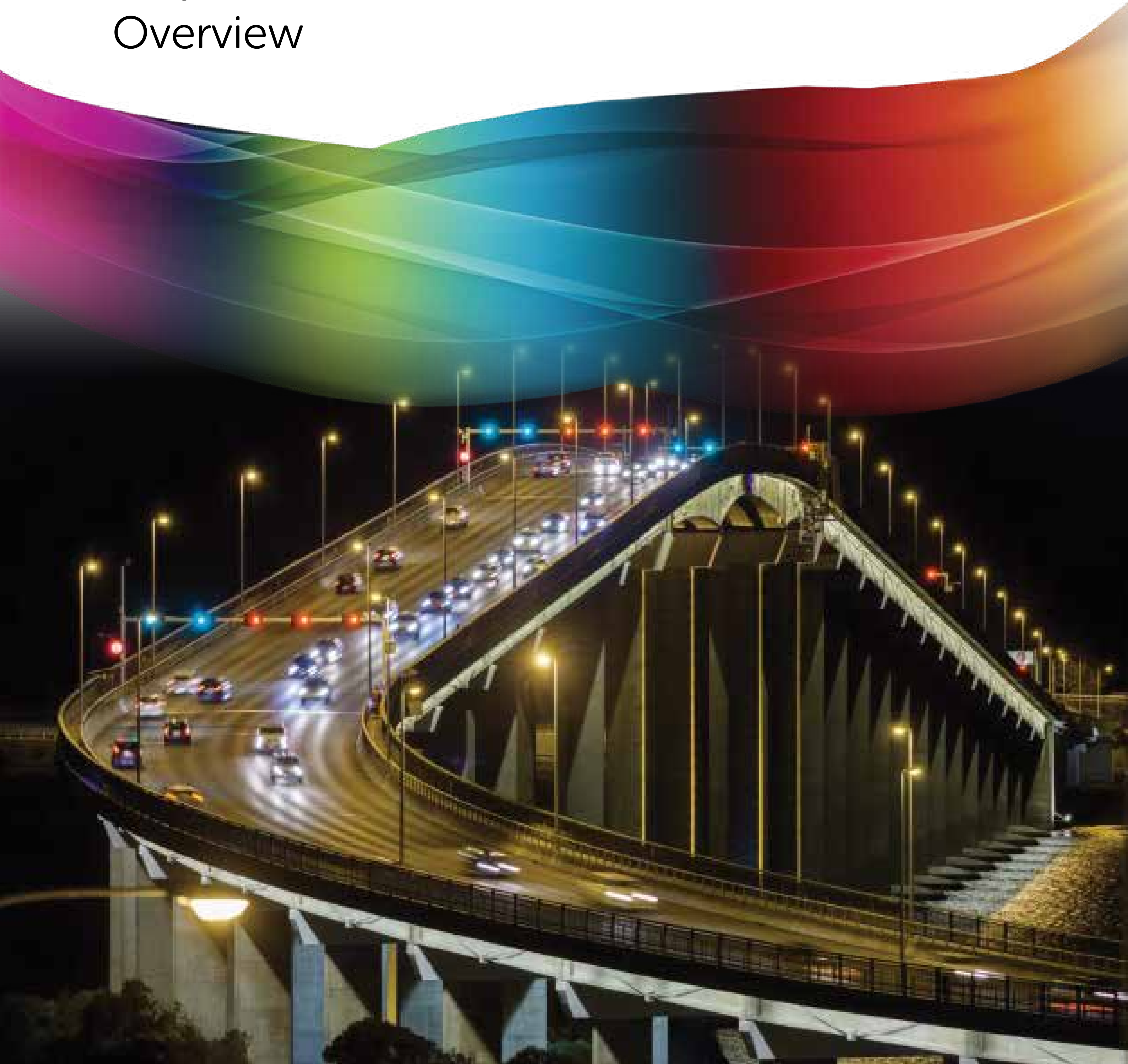
TasNetworks
Delivering your power

January 2018

Tasmanian Transmission and Distribution Regulatory and Revenue Proposals

Regulatory Control Period
1 July 2019 to 30 June 2024

Overview



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Message from the CEO

This paper provides an overview of our plans for the five year regulatory period from 1 July 2019 to 30 June 2024, which TasNetworks will submit to the Australian Energy Regulator (AER) in January 2018. In developing these plans, we have consulted with a wide range of customers, listened to their feedback and responded. We believe the resulting plans place the business in a sound position to manage the network services of the future, while delivering the lowest sustainable prices for our customers.

In our short history as a combined transmission and distribution service provider, we are proud of our achievements to date. We have worked hard to drive cost savings, while maintaining our track record in providing sustainable, safe and reliable services for customers today and in the future.

Our customers understand that the electricity system supporting Australia's economy and lifestyle is experiencing change on an unprecedented scale. This transformation is being driven by changes in Australia's generation mix and by our customers, who are embracing new technologies, taking control of their energy use and supporting action on climate change. Our role is to facilitate these developments by making sure that the Tasmanian network is capable of accommodating our customers' changing needs, and that we care for our customers and make their experience easier.

We are working with customers on large and small renewable generation projects, ranging from new hydro and wind capacity, to increasing numbers of solar connections on homes and businesses. There are a number of significant projects in the early concept stage that may harness Tasmania's renewable energy resources to support the National Electricity Market. Our proposal includes the transmission works associated with these initiatives as contingent projects, and we will continue to engage as our planning progresses.

We are also starting to see the emergence of battery storage, electric vehicles and customers who are thinking about different ways of managing their electricity supply. To accommodate these changes, our network pricing strategy includes new pricing arrangements to encourage efficient use of our network and fair pricing outcomes.

Our plans for the next regulatory period require a careful balance to be struck between the everyday task of ensuring that our services remain safe and reliable and investing to address the new challenges ahead. In developing our plans we have considered the condition of our network assets and supporting technology systems that underpin an increasingly data-intensive and transaction-based energy market. We have consulted extensively with our transmission and distribution customers to ensure that we understand their expectations and we have the systems to meet those expectations.

A consistent and clear message from our customers is that service and reliability are generally acceptable and affordability is the primary concern. In response to this feedback, we revisited the plans that we published in our Direction and Priorities Paper in August 2017. We have made further reductions to our expenditure plans compared to our preliminary proposal enabling modest movements in our network charges to provide the lowest sustainable cost. To do this – in a sector with a range of new obligations, changing technology, and increasing customer interactions – we need to deliver additional future efficiency gains and prioritise our activities. We must do this without compromising network safety or reliability.

Our proposal includes a reduction in the rate of return on our transmission assets to match the distribution rate of return. This benefits all our customers, easing price pressures in an era of unprecedented reform.

We are confident that we have struck the right balance by keeping prices low, maintaining reliability and safety, while continuing to innovate to provide a better, sustainable future. We are confident this proposal is one the Regulator and our customers can accept.

Lance Balcombe

Chief Executive Officer

1. Snapshot of our five-year forecasts compared to the previous five years (June 2019 $)

Revenue	% Change	$ Change million
Revenue Allowance - Transmission	-19%	-$172
Revenue Allowance - Distribution	-7%	-$108
Combined Revenue	-12%	-$280
Combined Capex	+20%	$157
Combined Opex	-6%	-$44

There are a number of factors contributing to our lower revenue allowance forecasts compared to our allowance over the previous five year period (from 2014 to 2019).

In particular, lower forecasts of the weighted average cost of capital (WACC) – including the alignment of the transmission WACC to the distribution WACC – contribute to lower forecast revenues. In simple terms, WACC refers to the returns we require on our investments and compensates us for the cost of funds we borrow.

Our capital program is increasing as we renew assets in poor condition, replace technology platforms at end of life, manage increased bushfire related risk and connect new customers. However, we are forecasting a reduction in our operating expenses for both our networks as we consolidate merger efficiencies and drive efficiencies from our business transformation. These savings targets are ambitious and when coupled with our approach to WACC and reductions to our capital expenditure by over $42 million by optimising the capital program will ensure modest increases for our distribution customers in the form of network charges over the forthcoming regulatory period. For our transmission customers, our proposed lower revenue and expenditure plans, place downward pressure on charges.

2. Background

TasNetworks provides both distribution network services (via the poles and wires) and transmission network services (via the large towers and lines) to customers in Tasmania. The business was created through the merging of Transend Networks and Aurora Energy Distribution in mid 2014, a process that has delivered a more optimised and efficient business and allowed us to focus on managing 'one' Tasmanian network.

We are submitting our first combined transmission and distribution proposal to the AER, covering the 2019-24 regulatory period. As required by the National Electricity Rules (the Rules), this overview paper provides:

- a summary of our proposals, to provide our customers with an overview of our plans;
- an outline of our engagement approach and how we have sought to address concerns identified as a result of that engagement;
- a description of the key risks and benefits of the regulatory and revenue proposals (regulatory proposal) for our consumers; and
- a comparison of our proposed total revenue requirement with allowances in the current periods and an explanation of any material differences.

Our 2019-24 regulatory proposal sets out our expenditure plans, incentive arrangements, revenue requirements and prices. Our proposal has been developed so that it delivers the best possible outcome for our transmission and distribution customers today and into the future. We have listened to our customers and modified our plans accordingly during the development of our proposal. In particular, we have made further reductions in our proposed expenditure and rate of return on our transmission assets following feedback on our provisional plans.

We have a strong track record in putting forward proposals that set challenging targets for our business – this proposal is no different.

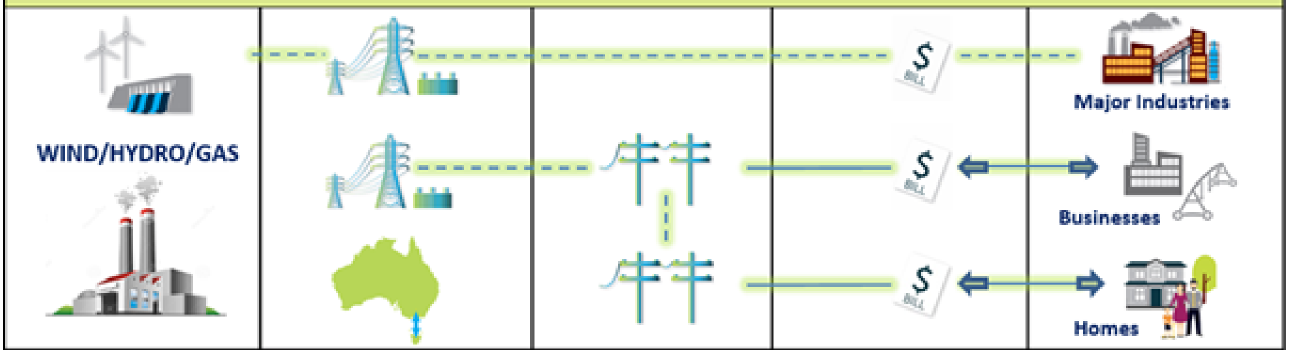
3. Who we are and what we do

3.1 Our role as Tasmania's network service provider

As the owner and operator of Tasmania's electricity transmission and distribution networks, our role is to deliver electricity safely and reliably to more than 285,000 households, businesses and organisations across Tasmania. Our role in the electricity supply chain and our customer service relationships is summarised below.

Figure 1: How your electricity gets to you and TasNetworks' role

How your electricity gets to you



BIG GENERATION	TRANSMISSION	DISTRIBUTION	RETAIL	CONSUMERS
In Tasmania, the majority of electricity is currently generated by large generators at hydro dams, a gas-fired plant or via a number of wind farms in the NW and NE of the State.	Electricity is sent around the state using TasNetworks' high voltage transmission network. The Basslink undersea cable is also used to transmit electricity to and from Tasmania. Major industrial customers can connect directly to the transmission network.	When your electricity arrives at towns and cities it is converted to a lower voltage as it enters TasNetworks' distribution network to be sent to homes and businesses.	Retailers service homes and businesses by managing bills, connection requests and passing on TasNetworks' network charges.	The energy market place is also changing. Customers can now produce their own electricity by installing small scale renewable generation such as solar panels. The excess can be exported back into the network or stored in batteries for later use.

What it takes to deliver your power

TasNetworks is responsible for the design, construction, operation and maintenance of the network that supplies power from the generation source to Tasmanian homes and businesses.

The network is made up of:

Transmission

3,540
circut kilometres of transmission lines

7,742
transmission line support structures

11,183
hectares of easements

Distribution

16,566
kilometres of high voltage powerlines

4,973
kilometres of low voltage powerlines

2,524
kilometres of high and low voltage underground cables

230,129
poles

3.2 Our strategy in a changing environment

The electricity system supporting Australia's modern economy and lifestyle is experiencing change on an unprecedented scale. The transformation is driven by customers as they embrace new technologies, take control of their energy use and support action on climate change.

In such a dynamic context, Tasmania's and indeed Australia's energy future may unfold in many different ways. No-one has perfect foresight on what may occur. That's why we've worked with Energy Networks Australia (ENA) and CSIRO to develop the Electricity Networks Transformation Roadmap[1], which sets out a pathway for the transformation of electricity networks over the next decade and beyond. The Roadmap accommodates the rapid uptake of new technologies and supports better customer outcomes. This pathway has been reinforced by Dr Alan Finkel's review into the future security of the National Electricity Market[2], where many of the recommendations were incorporated and subsequently adopted by the Federal Government.

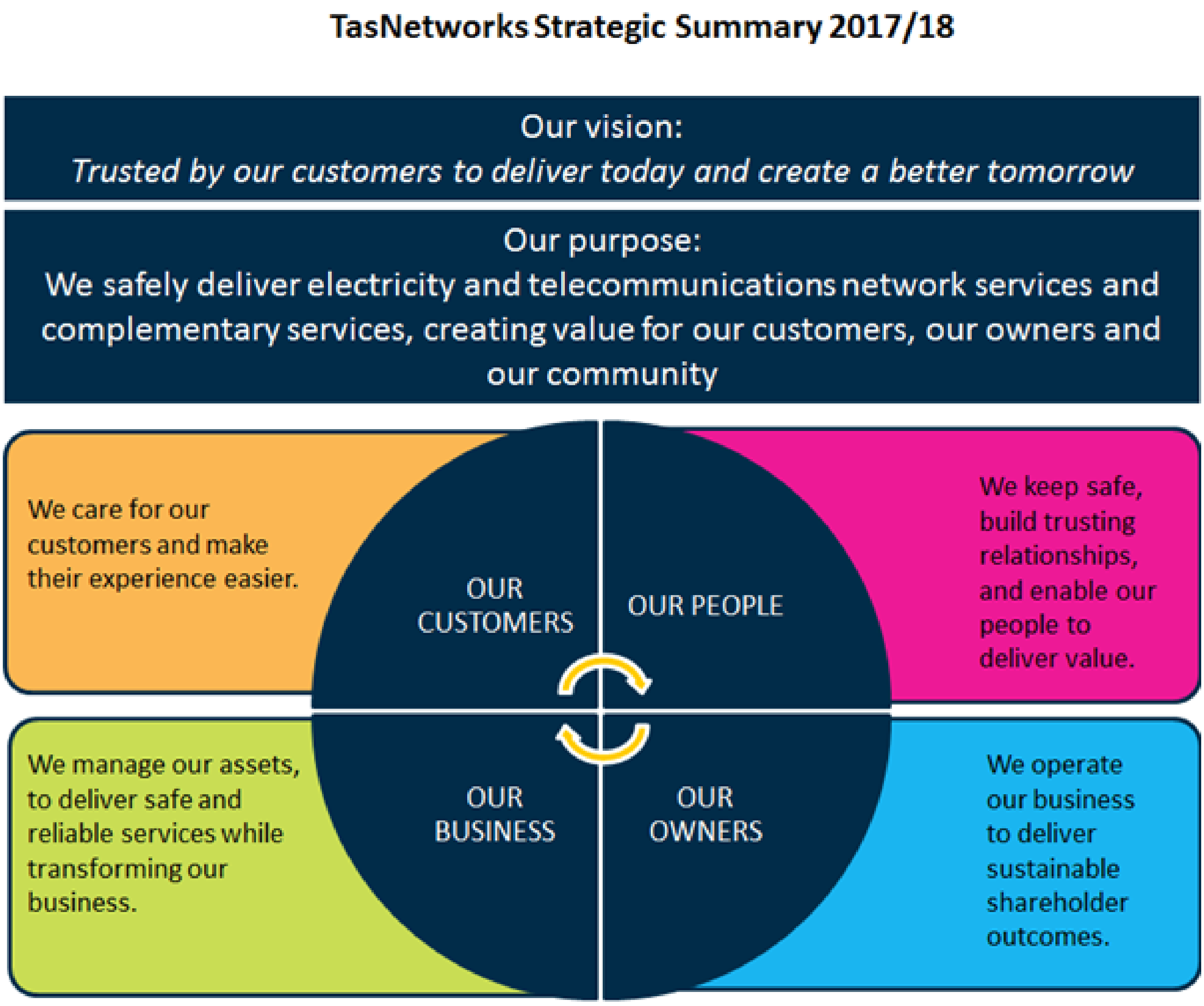
[1] For further information please refer to the following link: http://www.energynetworks.com.au/electricity-network-transformation-roadmap
[2] For further information please refer to the following link: https://www.environment.gov.au/system/files/resources/1d6b0464-6162-4223-ac08-3395a6b1c7fa/files/electricity- market-review-final-report.pdf

Building on the national Electricity Networks Transformation Roadmap we have carefully considered the particular features of the Tasmanian electricity sector to develop a transformation roadmap for TasNetworks to 2025. Our roadmap outlines some of the key changes we expect to see that will affect how we provide services, and the areas in which we will continue to transform our business. Further details on our TasNetworks Transformation Roadmap 2025 are provided on our website or can be obtained by contacting us directly.

https://www.tasnetworks.com.au/TasNetworks/media/pdf/our-network/TasNetworks-Transformation-Roadmap-2025-22-June-2017_1.pdf

With this longer term vision in mind, we have set our strategy to guide our plans for the next regulatory period. As shown in the figure below, our overarching vision is to be trusted by our customers to deliver today and create a better tomorrow.

Figure 2: Overview of TasNetworks' strategy



In accordance with this strategy, we are implementing a demanding agenda and working hard to achieve efficiency gains across Tasmania's transmission and distribution services with the package of measures set out in our proposal, ensuring these savings immediately flow through to customers' network charges.

4. Customer engagement

4.1 Our customers

We conducted an extensive customer engagement process in developing our regulatory proposals for our 2014 transmission review and more recently in our 2017 distribution review. In this combined transmission and distribution review, we are consolidating our understanding of the price-service offering our diverse customer base wants us to provide.

An important part of developing a deeper understanding of customers' views is the need for on-going engagement outside the revenue and pricing review process. Accordingly, there are strong engagement linkages between our revenue reset and other foundation activities, as shown in the figure below.

Figure 3: On-going customer engagement

To support our business, our customers and our engagement activities, we developed an engagement framework using international best practice models. This framework assists in determining the right level of engagement for the various customer segments. We have applied this engagement framework when consulting with customers for this combined transmission and distribution review.

Our transmission are large generators and large industrial customers that have a material impact on the Tasmanian economy. These customers receive their transmission network charges directly from us. We engaged with the majority of these customers through one-on-one discussions and small workshops.

Under the National Electricity Market arrangements we also provide transmission services to Victorian customers, just as Tasmanian customers receive services from the Victorian transmission network.

We engage with the Australian Energy Market Operator (AEMO) on our forward plans and work with AEMO annually to consider national planning requirements and to adjust transmission prices to reflect inter-regional charges.

Our distribution customers receive our transmission and distribution network charges via their retailer. We deliver electricity to a diverse range of business and residential distribution customers, and increasingly these customers use our network to deliver energy they have generated. We have undertaken a range of activities to gather feedback and understand the priorities and concerns of these customers, as summarised in the figure below.

Figure 4: Our Revenue Reset Engagement activities

Copies of research reports and other information on the results of our customer engagement are available at www.tasnetworks.com.au.

4.2 What our customers have told us

Customers' of both our transmission and distribution networks expect us to be the technical experts in managing our network and developing the revenue and expenditure proposals which deliver the services and outcomes our customers want and need.

Our transmission customers provided us with a range of feedback on the current and future operation of our business. The key themes were:

- 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 and although reliability is good, this is still a key focus;
- keen to see TasNetworks demonstrate benefits and efficiencies resulting from our investment in technology; and
- engaging with customers before making investment decisions which may impact their price has been appreciated.

Key messages from our residential and distribution customer engagement activities are summarised below:

- We are meeting most customers' needs from an overall reliability perspective, but for some their needs and expectations are changing.
- Overall satisfaction with current reliability levels is quite high. The majority of customers support our proposed strategy to maintain reliability rather than investing more to improve it.
- While improvements in reliability and outage response could strengthen satisfaction, customers are not willing to pay higher prices for these improvements.
- Continual improvement in how we communicate with customers is critical. This includes use of social media platforms, such as Facebook.
- Customers recognise that technology is changing the electricity industry, particularly in relation to solar panels, battery storage and electric vehicles.
- Customers recognise that the nature of the grid is changing and are interested in distributed energy resources and the capacity to use the network to trade energy.

The majority of our customers are concerned about affordability, but some want new technologies and/or better outcomes and are prepared to pay for these improvements within reasonable bounds.

The following customer quotes summarise the type of feedback received.

"Keep the lights on; don't care how it's done"

"You need to manage the pace of change as best as possible"

"We are already changing the way we use energy at home and being rewarded with lower bills"

"We'd like to know more about solar and renewable energy"

"Thank you for providing updates on Facebook! This is very helpful"

4.3 Feedback from electricity Retailers

Our customer base isn't restricted to end-users of the electricity we deliver over our distribution network; it includes electricity retailers. Currently, TasNetworks services the customers of a few retailers in Tasmania. However, despite the residential and lower end of the small business electricity market being opened to full retail competition in 2014, Aurora Energy remains the only retailer competing in those markets.

TasNetworks has sought to engage with all retailers on the subject of pricing reform, and throughout this process Aurora Energy has been the main contributor. Aurora Energy has remained supportive of a slow transition to cost reflective pricing, highlighting the importance of information provision to support customers through the transition to more cost reflective pricing.

We recognise that the process of pricing reform is challenging and, to be successful, we will need to gain customers' understanding and acceptance of any new or modified pricing arrangements. Through our emPOWERing You trial we are gathering data about customers' electricity use and their responses to the type of demand based time of use network tariffs we are proposing. This will help us gauge customers' willingness to embrace change and allow us to help customers understand what a change may mean for them.

We will continue to work with all electricity retailers, to progress our pricing strategy and ensure that our new network charges are incorporated into the retail tariffs offered to customers in the future.

4.4 Feedback from the Consumer Challenge Panel

The development of our expenditure and revenue plans has been assisted by feedback from the Consumer Challenge Panel (CCP). The objective of the CCP is to advise the regulator on:

- whether our proposals are in the long-term interests of consumers;
- the effectiveness of our customer engagement activities; and
- whether customer feedback has been reflected in our proposals.

While the CCP's role is to advise the regulator, their input has been invaluable to us as we finalised our proposals. We are pleased that the CCP commended us on our approach to consumer engagement[3], noting that we have presented many of the key issues in an accessible and informative fashion. Equally, however, the CCP also provided helpful advice on areas where issues could be explained better or where further information is required to assist customers. We have endeavoured to address the CCP's feedback in our regulatory proposal.

The CCP also emphasised that our customers have not expressed a willingness to accept the rising price path described in our Direction and Priorities paper. We recognise this point. Our challenge is to balance price pressures against reliability and safety considerations, having regard to the long term interests of customers.

On reflection, we agree with the CCP that more emphasis should be given to price considerations. For this reason, we revisited our provisional expenditure and revenue forecasts to minimise the price impact on our customers. Further details of these changes are provided in the next section.

[3] Consumer Challenge Panel, Submission to TasNetworks' Directions and Priorities Consultation Paper, September 2017, page 1.

We believe that our updated regulatory proposal now achieves the lowest price outcome for our customers while maintaining network reliability and safety now and into the future.

The CCP also highlighted the following risks for us and our customers:

- **Demand risk**. The Tasmanian electricity network has a small number of users reliant on international prices for their products who consume over 50 per cent of electricity load in Tasmania. The closure of a major customer would have implications for network charges to the remaining customers, as the fixed costs of providing network services would have to be spread over a smaller customer base.

- **Large, uncertain capital projects.** Our Direction and Priorities paper identified four major projects ('contingent projects') that may be required in the forthcoming regulatory period. Although these projects would deliver substantial benefits in terms of energy security or lower generation costs, they would lead to higher network charges.

We agree with the CCP that the above points are downside risks for customers in relation to network price outcomes. We note, however, that the contingent projects will only go ahead if they deliver an overall benefit to our customers. In relation to demand risk, we are working hard to maintain the sustainability of our major industrial customers in the medium term – and our broader customer base – by ensuring that our prices are as low as we can sustain.

5. How we have addressed customers' feedback

Our November 2017 "Directions and Priorities Paper: Summary of Submissions and Key Themes[4]" summarised the feedback we received on our preliminary plans, as follows:

- More detailed information is required before customers or stakeholders can make informed decisions on our future plans and associated revenue and price outcomes – including more detailed information explaining customer benefits.
- We heard loud and clear that customers value lower prices – and that we must make a clear case for any cost increases that will increase customer prices.
- General support for maintaining existing levels of reliability.
- Concern with the proposed increases in capital expenditure, particularly areas with higher than trend expenditure, specifically on new IT and communication systems and on transmission development expenditure.
- Further information and detailed modelling is required in relation to the contingent projects and the potential impact on revenue and pricing forecasts.
- Concern about our tariff strategy and the price implications for particular groups of customers.

We provided initial feedback on these areas as part of that document, noting that more information would be available as we finalised our plans and regulatory proposal.

The feedback reinforced six proposed direction and priority areas for our proposal:

1. ensuring the safety of our customers, employees, contractors, and the community;
2. keeping the power on, maintaining service reliability, network resilience and system security;
3. delivering services for the lowest sustainable cost;
4. improving how we communicate with, and listen to, our customers;
5. innovating in a changing wworld; and
6. bringing the community on the journey of pricing reform.

The table below summarises the feedback we received on each of these themes and how we have taken this into account in our proposals for the 2019-24 regulatory period.

[4] https://www.tasnetworks.com.au/TasNetworks/media/pdf/customer-engagement/Direction-and-Priorities-Feedback-Paper.pdf

Table 1: How have we addressed customers' feedback?

Issue or Theme	Customer feedback	Our Proposal
Ensuring the safety of our customers, employees, contractors, and the community	Customers continue to call out safety as a critical priority and focal area for TasNetworks. Many customers consider safety to be a 'hygiene' factor: it's taken for granted that we will operate safely. Aurora Energy and TasCOSS, along with major business customers, reinforced this as a key priority.	Safety is our top priority. Our operating expenditure includes the costs of safety measures and activities expected in our industry. It includes promoting safety awareness to our customers, people, contractors and the broader community. The majority of our Renewal and Enhancement capital expenditure is to support the safety of our customers, employees, contractors and the community. We will continue to inform and educate our customers of safety hazards and safe behaviours through a range of targeted activities and information campaigns, including through our Community Zero Harm initiative.
Keeping the power on, maintaining service reliability, network resilience and system security	Our customers continue to reinforce the importance of a reliable supply and there is a growing recognition following the South Australian 'system black' incident that network resilience and system security are also critical. Most customers are not willing to pay any more for improved reliability, and would prefer we prioritised reducing costs ahead of improving reliability. However, some customers value reliability highly and would be prepared to pay more at a reasonable and stable price.	The majority of our planned network investment is focused on replacing unreliable and aged assets that are in poor condition, to ensure they do not present unacceptable safety or bushfire risks, or increased rates of power outages. This expenditure is critical in helping us to continue to deliver safe and reliable network services. We are continuing to ensure we make the most prudent and efficient investment decisions given the generally long life of our assets and the level of industry disruption.

Issue or Theme	Customer feedback	Our Proposal
Delivering services for the lowest sustainable cost	Customers continue to reinforce the expectation that we continue to operate our business as efficiently as possible, to drive good outcomes for customers today and into the future. This is consistent with the feedback we regularly receive, including in many of the submissions we received as part of this consultation.	We have heard the feedback from our customers that delivering our services for the lowest sustainable cost is very important. We have taken a number of additional measures compared to our provisional Revenue Proposal to meet this expectation including: • the re-phasing of technology investments relating to market data management systems; • a 5.0 per cent optimisation of the distribution network capital expenditure forecasts; • a 0.5 per cent optimisation of the transmission network capital expenditure forecasts; • a 5.0 per cent optimisation of the shared business services capital expenditure forecasts; • bringing transmission into alignment with our distribution rate of return, resulting in a reduction to our transmission rate of return of 25 basis points; • a reduced claim for the costs of additional obligations or 'step changes' that we expect to incur; • efficiency savings to absorb cost increases from labour and customer growth; • an additional one per cent annual reduction in our transmission and distribution operating expenditure forecasts for the final three years of the regulatory control period, following on from a 0.5 per cent reduction in the second year; and • a rebalancing of our transmission revenue profile to provide a flatter price path over the period This package of measures will reduce transmission and distribution revenues, in nominal terms, by $29.8 million and $28.4 million respectively compared to our provisional plans; or a total of $58.2 million over the forthcoming regulatory control period. In addition to the above measures, our contingent project proposals ensure that customers do not pay for projects that are not certain to proceed.

Issue or Theme	Customer feedback	Our Proposal
Improving how we communicate with, and listen to, our customers	Customers want us to continue to look into ways in which we can better communicate with them. This includes better communication in real time to customers across different regions and with different demographics, particularly during outages, and improving our approach to customer engagement on strategic issues.	We continue to pursue our goal of caring for our customers and making their experience easier – using a range of tools and strategies, including continued investment in developing our people to provide good customer service. We will also maintain and improve customer facing platforms to make our customers' experience easier. We are also planning to invest in systems that support complaint handling, connection applications and customer interaction tracking, which are currently unsupported.
Innovating in a changing world	Customers are keen to see TasNetworks continue to demonstrate and drive innovation to deliver better customer outcomes. However, there are different views on the pace of change. Some customers believe we are moving too quickly, while others believe we are not moving fast enough.	Building on the Network Transformation Roadmap, our 2025 vision recognises the network challenges as the technological advances and changes in the generation mix place new demands on the Tasmanian network. We have developed an Innovation Framework to ensure that we pursue opportunities for cost-effective innovations. We will leverage the learnings from the CONSORT Bruny Island Battery and emPOWERing You trials we are currently undertaking, coupled with increased data analytics to better understand our customers and tailor our service provision.
Bringing the community on the journey of pricing reform	Feedback from customers and stakeholders, including our owners and retailers, has reinforced the importance of helping the community to transition to more cost-reflective pricing for distribution-connected customers.	Over the next five years we aim to improve the quality of information available to support future pricing strategy refinement and customers' understanding of how to benefit from new types of tariffs. This information will reflect learnings from the emPOWERing You and CONSORT Bruny Island trials.

6. Our capital expenditure proposals

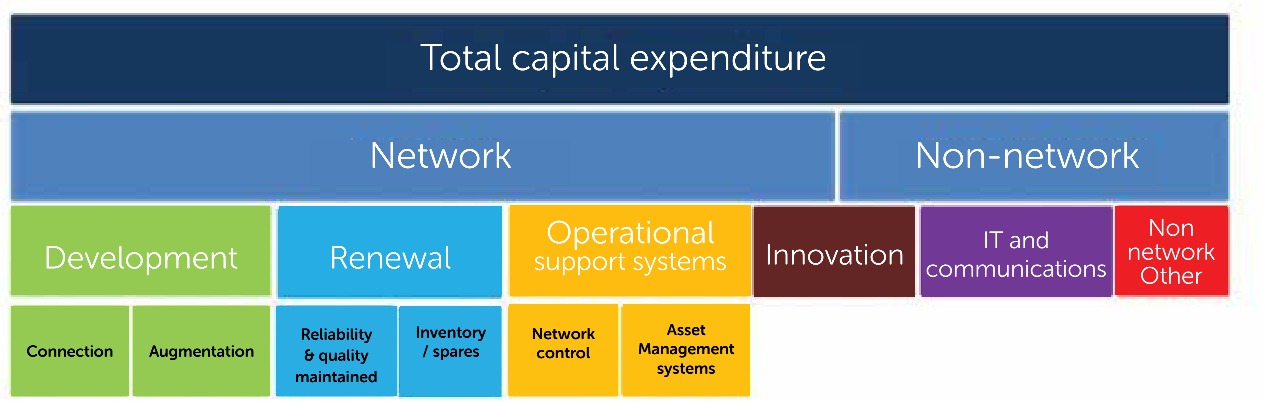
The AER determines the amount of transmission and distribution revenue we can earn each year, using a 'building block' methodology. This allowed revenue is adjusted from year to year, to reflect the outcome of incentive schemes and any over- or under-recoveries from previous years.

Most of our revenue allowance is to fund the assets that provide services to our customers. Network services involve many assets – ranging from field assets such as poles and wires and transmission towers, to the supporting operating platforms, such as asset, customer, market and financial information systems.

When considering the costs of providing services each year, the majority are for recovering the costs associated with existing assets that provide our services (depreciation and the cost of capital returns). The remainder is for future capital expenditure requirements, for forecast new assets that we need to deliver our services into the future.

Consistent with our Forecasting Method, our capital expenditure forecasts are typically determined at an expenditure category level and aggregated, and then subject to a 'top down' review. We apply a common set of capital expenditure categories across distribution and transmission activities, as shown in Figure 5.

Figure 5: Capital expenditure categories



The above breakdown of capital expenditure includes an 'innovation' category that spans network and non-network activities. In this proposal, however, we have not directly attributed expenditure to the 'innovation' category – as innovation is an activity that affects investment decisions across the entire business, rather than being a standalone activity. Our network innovation strategy is provided as a supporting document.

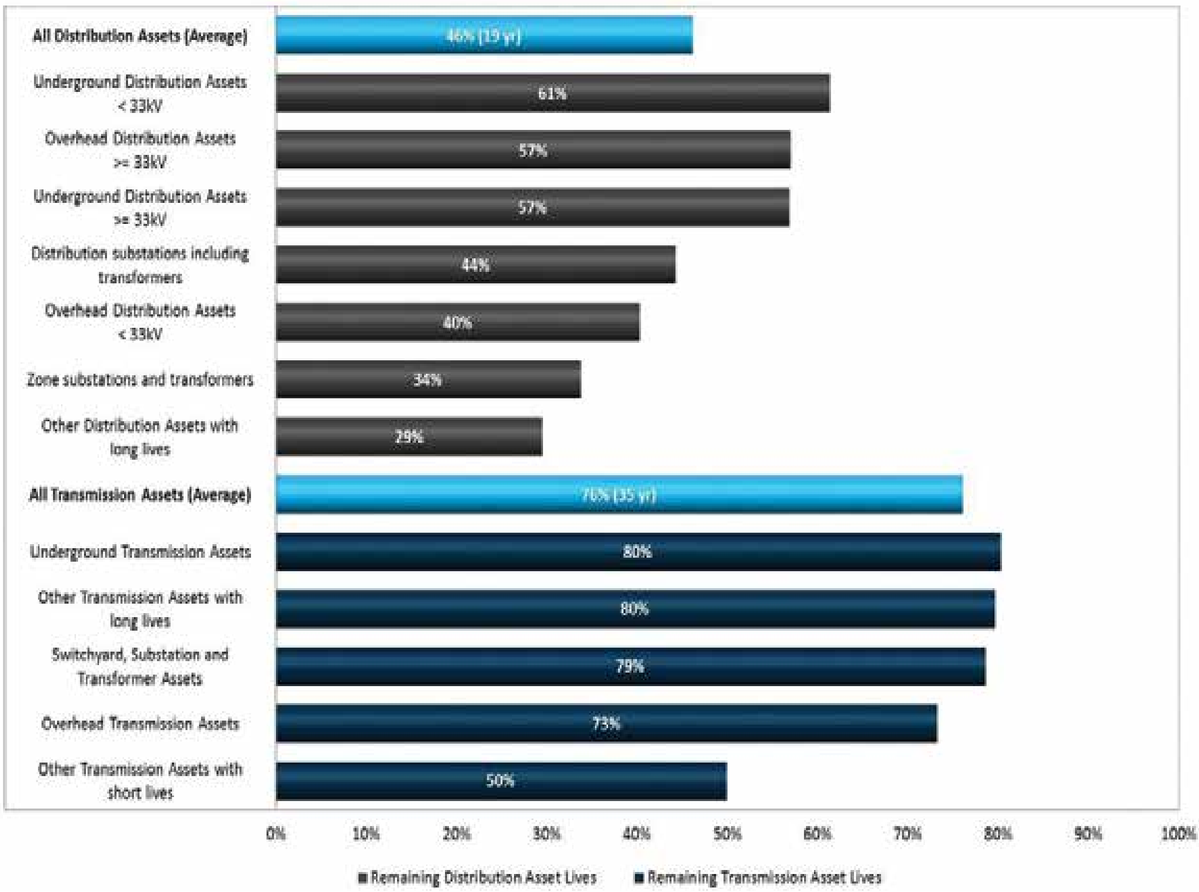
As noted above, we have applied a top down discipline to our preliminary capital expenditure forecasts to address our customers' feedback that affordability is of primary concern. As a result, we have reduced our total capital expenditure forecasts by over $42 million, with the majority of this reduction applying to distribution. The optimisation of the distribution program reflects the benefits that are expected to flow from our planned investments in business transformation. We will therefore deliver the same programs for less cost.

While we seek to minimise our capital expenditure, we must also ensure that the safety and reliability of our network services is not compromised. To achieve this objective, our analysis shows that capital expenditure must increase in the forthcoming regulatory period, as we renew assets in poor condition, replace technology platforms at end of life, manage increased bushfire related risk and connect new customers.

Our asset management approach is to replace assets on the basis of condition and risk, rather than age. Nevertheless, the remaining life of our transmission and distribution assets provides a useful indication of the relative pressures on our transmission and distribution networks in relation to asset renewal.

The figure below shows the average remaining asset lives by asset class for our transmission and distribution networks. On average, it shows that our distribution assets are substantially older with less remaining life compared to transmission. For each asset category, there will be a range of asset lives with a number approaching their end of life. In broad terms, the risk to safety and reliability increases as the number of aged assets grows.

Figure 6: Remaining life by asset category



In developing our capital expenditure forecasts, we have considered the risks associated with our ageing assets together with the future demands on our network, particularly in response to changing customer use and the growth of renewable generation. Overviews of our capital expenditure forecasts for transmission and distribution are set out below.

6.1 Transmission capital expenditure

Our key focus for the transmission network will continue to be bulk energy transfer:

- to large users and large customer communities – with more than half of Tasmania's energy being transported to large customers at transmission voltages and never entering the distribution system; and
- transferring Tasmania's clean hydro and wind energy resource – including to the rest of the National Electricity Market.

We will continue to maximise network utilisation through innovation. In terms of system load, forecast growth is relatively modest. This outlook is reflected in low development capital expenditure over the forecast period – with development expenditure focused on system security investment. We have assumed that there will be no new large transmission loads that require material regulated investment.

Our transmission investment in the 2019-24 period will be focussed on:

- Renewing assets in poor condition - Our expenditure requirements are primarily driven by asset condition and risk in our aging protection and control systems, circuit breakers and power transformers.
- Security of the system, supporting the clean energy transition - This work is driven by voltage and ancillary services support – including an investment in excess of $15 million for a new static var compensator at the George Town Substation The compensator will support more stable and efficient operation of our transmission network with changing generation and interconnector flows, and allow dispatch of lower cost generation. This project alone will increase our level of development capital expenditure when compared to the current period, in which little development capital expenditure was required.

The composition of our actual transmission capital expenditure for the current regulatory period, and our forecast for the 2019-24 regulatory period is shown in the figure and table below. This forecast reflects a top-down optimisation adjustment of $5.7 million compared to our provisional Revenue Proposal across the program.

Figure 7: Historic and forecast transmission capital expenditure by category (June 2019 $m)

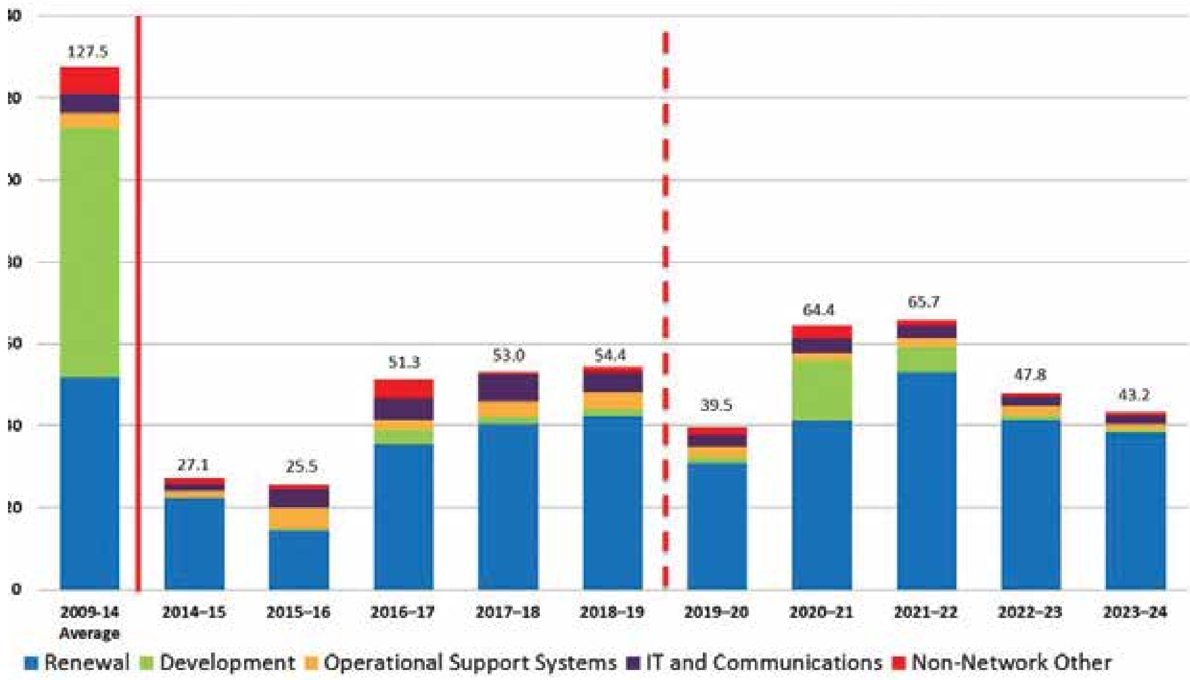


Table 2: Historic and forecast transmission capital expenditure by category (June 2019 $m)

Category	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24
Development	0.2	0.3	3.5	1.8	1.8	1.5	14.8	6.3	1.0	0.6
Connection	0.0	0.0	0.2	0.1	0.1	-	1.1	1.9	-	-
Augmentation	0.2	0.3	3.3	1.7	1.8	1.5	13.7	4.4	1.0	0.6
Renewal	22.3	14.4	35.4	40.3	42.1	30.7	41.1	52.9	41.5	38.3
Reliability & Quality Maintained	22.3	14.4	30.9	40.3	42.1	30.7	41.1	52.9	41.5	38.3
Inventory and Spares	-	-	4.5	-	-	-	-	-	-	-
Operational Support Systems	1.5	5.0	2.4	3.9	4.1	2.6	1.9	2.1	2.2	1.4
Network Control	0.5	3.4	0.8	1.9	2.4	0.9	0.5	0.7	0.7	0.4
Asset Management Systems	1.1	1.6	1.6	2.0	1.7	1.8	1.5	1.4	1.5	1.0
IT and Communications	1.7	4.6	5.4	6.5	4.8	3.0	3.5	3.0	2.7	2.2
Non-Network Other	1.4	1.1	4.6	0.4	1.5	1.5	3.1	1.4	0.5	0.8
Total transmission capital expenditure	27.1	25.5	51.3	53.0	54.4	39.5	64.4	65.7	47.8	43.2

The figure and table above show an increase in our development capital expenditure compared to recent levels. This increase is not driven by demand growth, which remains flat. Instead, it relates principally to a single $15 million project to install a new static var compensator at the George Town Substation. In addition, we have identified the following five major projects (called 'contingent' projects) that may be required if particular 'trigger events' occur:

- significant new connection of renewable generation – including potential wind generation and pumped storage hydro – in Tasmania's northwest;
- a second HVDC interconnector between Tasmania's northwest region and Victoria;
- constraints in transmitting energy from Sheffield into the rest of the network, depending on the location of new wind generation and a potential second interconnector;
- rationalisation of our ageing 110 kV transmission network in the Upper Derwent region to address asset condition issues and support connection requirements for Hydro Tasmania's Tarraleah power station; and
- augmentation of the 220 kV transmission system between Sheffield and Burnie, which includes he establishment of new double circuit transmission line operating at 220 kV between Sheffield and Burnie substations; and reconfiguration and rationalisation of the 110 kV transmission line between these substations to facilitate the new 220 kV transmission line within the existing corridor.

In each case, the investment will only proceed if it delivers an overall customer benefit in accordance with the Rules. If one or more of the projects is required as a regulated investment, we are likely to ask the AER to approve additional funding which will flow through to network charges.

We initially indicated in our Directions and Priorities Consultation Paper that we had identified four contingent projects. However, as our planning has progressed and more information has become available about potential investments in renewable energy on Tasmania's northwest and west coasts. We have subsequently refined these activities and categorised them into five discrete projects.

6.2 Distribution capital expenditure

Our key focus for the distribution network will be to maintain and renew the 'poles and wires' network that delivers energy to our 285,000 business and residential distribution customers, including increasing numbers of customers with their own generation sources.

Our distribution investment plans recognise the following:

- increased investment to manage safety risks (that may not be fully offset by efficiencies elsewhere):
    - increase in pole renewal as early staked poles reach end of useful life and staking over the next ten years as poles reach the end of their useful life;
    - targeted bushfire mitigation programs;
    - vegetation management – to manage outage and fire risk;
    - service connection inspection and renewal due to safety issues associated with failure; and
    - improved network resilience in response to changing environmental factors.
- we expect the number of new distribution customer connections will increase consistent with recent trends, with new connection standards to support network security and two way flows;
- supporting two way flows in the distribution network will require an increase in technology-related expenditure, including for:
    - increased visibility / situational awareness of the distribution network;
    - efficient asset management investment and operation, including in relation to new technology integration;
    - timely customer information and network management; and
    - new services – including potentially facilitating customer payment for use of their distributed energy resources such as batteries or generators,
- we will continue to manage network voltage levels which may be impacted due to growth in embedded generation, noting that this has the potential to drive more reactive projects to address these emerging issues; and
- increased expectations for technology investments to support improved customer relationship management, SMS notifications, planned outage information, website portals, and network pricing reform.

The composition of our actual distribution capital expenditure to 2018-19 and our forecast for the 2019-24 regulatory period is shown in the figure and table below. Our forecast capital expenditure includes a top-down optimisation adjustment of $36.4 million compared to our provisional Regulatory Proposal.

Figure 8: Historic and forecast distribution capital expenditure by category (June 2019 $m)

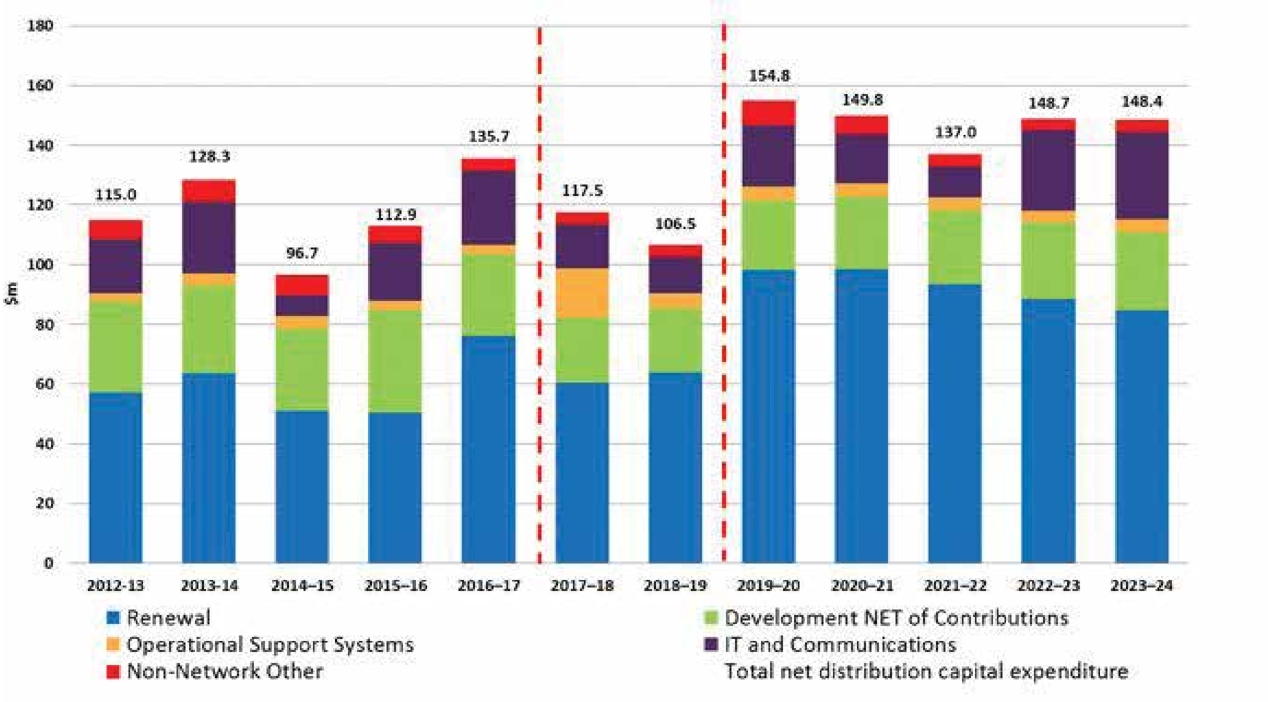


Table 3: Actual and forecast gross and net distribution capital expenditure for the current and forthcoming regulatory period (June 2019 $m)

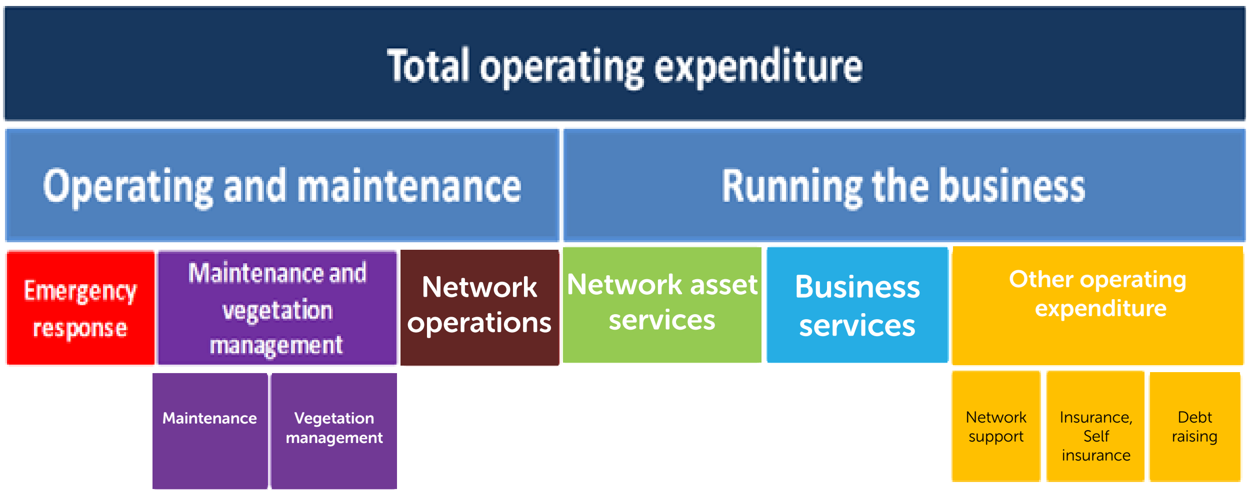
Category	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24
Development	39.1	40.5	40.9	45.1	38.9	33.5	33.0	29.3	30.5	31.0	32.2	32.4
Connection	29.9	27.6	31.4	31.8	32.5	26.7	26.5	22.4	24.1	24.6	25.7	26.2
Augmentation	9.2	12.9	9.5	13.4	6.4	6.9	6.5	6.9	6.4	6.4	6.5	6.2
Renewal	57.2	63.5	51.0	50.4	76.1	60.6	64.0	98.1	98.4	93.4	88.3	84.8
Reliability & Quality Maintained	57.2	63.5	51.0	50.4	76.1	60.6	64.0	98.1	98.4	93.4	88.3	84.8
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	16.3	5.0	4.6	4.3	4.3	4.1	4.6
Network Control	1.2	2.5	3.8	2.0	0.8	3.3	2.0	0.8	0.8	0.8	0.5	2.4
Asset Management Systems	1.6	1.7	0.7	1.3	2.3	12.9	2.9	3.9	3.5	3.6	3.6	2.2
IT and Communications	18.1	23.9	7.0	19.4	24.8	15.0	12.3	20.7	16.4	10.4	27.0	29.3
Non-Network Other	6.5	7.3	6.8	5.5	4.3	3.9	3.8	8.0	6.2	4.2	3.6	3.9
Total gross distribution capital expenditure	**123.7**	**139.4**	**110.2**	**123.7**	**147.3**	**129.2**	**118.1**	**160.8**	**155.9**	**143.3**	**155.1**	**155.0**
Customer capital contributions	**8.7**	**11.2**	**13.5**	**10.8**	**11.6**	**11.7**	**11.6**	**6.0**	**6.0**	**6.3**	**6.5**	**6.6**
Total net distribution capital expenditure	**115.0**	**128.3**	**96.7**	**112.9**	**135.7**	**117.5**	**106.5**	**154.8**	**149.8**	**137.0**	**148.7**	**148.4**

7. Our operating expenditure proposals

As is the case for capital expenditure, our operating expenditure categories are common across transmission and distribution. However, our forecasting approach for operating expenditure is somewhat different: it focuses on movements in aggregate and/or expenditure trends (using the AER's base-step-trend methodology), rather than a detailed 'bottom up build' for each of the expenditure categories.

We have categorised operating expenditure as either 'Operating and Maintenance' of the physical electricity network and or 'Running the business' (which consists of the essential service and support functions of an efficient network business). Our cost categories for operating expenditure are illustrated in the figure below.

Figure 9: TasNetworks' operating expenditure categories



7.1 Transmission operating expenditure

The figure and table below show our transmission operating expenditure proposal alongside our actual and expected operating expenditure from 2012-13 to 2018-19. The total/actual forecast operating expenditure (pre-efficiencies) reflects TasNetworks' forecast costs using the AER's base-step-trend approach. Our proposed transmission operating expenditure allowance for the next regulatory period is below the level obtained by applying the AER's base-step-trend approach.

Figure 10: Historic and forecast transmission operating expenditure by category (June 2019 $m)

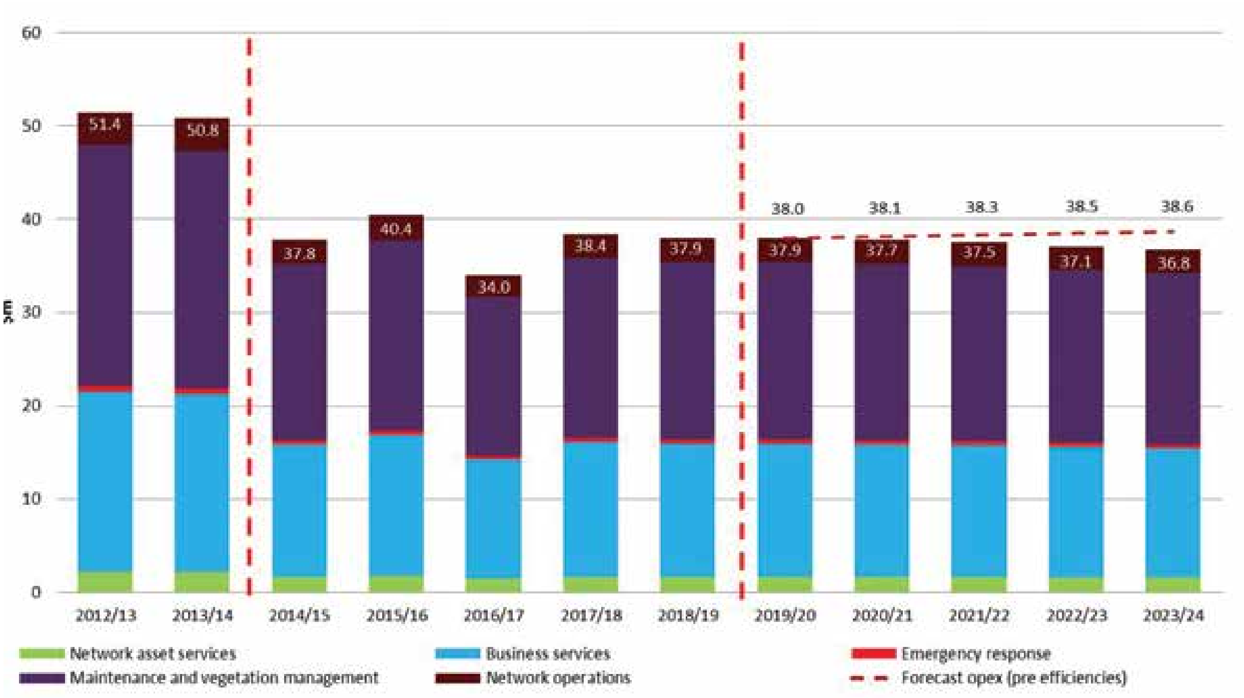


Table 4: Actual and forecast transmission operating expenditure by category (June 2019 $m)

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	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Maintenance and Vegetation Management	25.8	25.5	19.0	20.3	17.1	19.3	19.0	19.0	18.9	18.8	18.7	18.5
Business Services	19.4	19.1	14.2	15.2	12.8	14.5	14.3	14.3	14.2	14.1	14.0	13.8
'Other' Operating Expenditure	5.7	5.6	4.2	4.5	3.7	4.2	4.2	4.2	4.2	4.1	4.1	4.0
Total transmission operating expenditure	**51.4**	**50.8**	**37.8**	**40.4**	**34.0**	**38.4**	**37.9**	**37.9**	**37.7**	**37.5**	**37.1**	**36.8**

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

As already noted, our proposed operating expenditure is below the forecast obtained using the base-step-trend method. This outcome reflects our adoption of target cost efficiency improvements on the operating expenditure allowance that results from applying the AER's forecasting methodology. We have done this in response to customer concerns regarding affordability.

We are continuing to drive efficiency improvements over the forthcoming regulatory period, so that over the period we constrain our operating expenditure increases to around the rate of inflation. In effect, this means that we are aiming to absorb the cost pressures associated with factors such as increasing labour rates and the additional costs associated with serving a growing load and generator customer base, factors that the AER typically accepts in its regulatory determinations as legitimate drivers of higher operating expenditure.

Even though our costs already benchmark well against our peers, we are continuing to seek efficiency savings in the forthcoming regulatory period. Our proposed operating expenditure levels are therefore ambitious – and reflect a continued focus on prioritising our activities and driving our business to achieve the lowest sustainable prices for our customers.

7.2 Distribution operating expenditure

The figure and table below show our distribution operating expenditure proposal alongside our actual and expected operating expenditure from 2012-13 to 2018-19. We also show a breakdown of by expenditure category.

Figure 11: Distribution Operating expenditure Actual/ Forecast– by expenditure category (June 2019 $m)

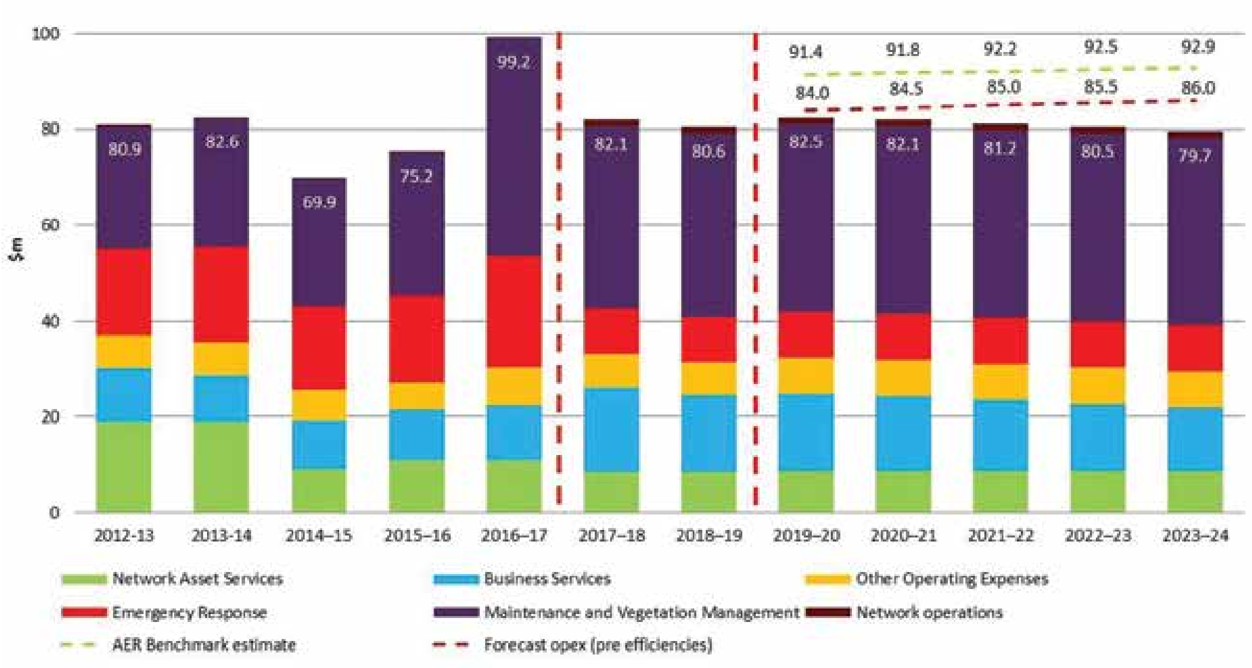


Table 5: Actual and forecast distribution operating expenditure by category (June 2019 $m)

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	9.5	9.5	9.6	9.6	9.6	9.6	9.6
Maintenance and Vegetation Management	25.5	26.7	26.7	30.0	45.6	38.2	38.2	39.2	39.2	39.2	39.2	39.2
Distribution Asset Services	19.1	19.1	9.1	11.0	10.9	8.4	8.4	8.6	8.6	8.6	8.6	8.6
Business Services	11.1	9.4	10.3	10.5	11.5	17.6	16.1	16.1	15.7	14.9	14.1	13.3
‘Other’ Operating Expenditure	7.0	7.4	6.4	5.7	7.9	8.4	8.4	8.9	8.9	8.9	8.9	8.9
Total distribution operating expenditure	**80.9**	**82.6**	**69.9**	**75.2**	**99.2**	**82.1**	**80.6**	**82.5**	**82.1**	**81.2**	**80.5**	**79.7**

The figure and table above show that our distribution operating expenditure increased in 2016-17. Our increased expenditure has been necessary to address emerging risks on our distribution network, such as the bushfire risks posed by vegetation, especially in light of experiences interstate.

As better information became available, we concluded that bushfire and asset-related risks were higher than previously thought. Therefore, we acted prudently to address these risks by increasing operating expenditure, at the expense of the return to our shareholders rather than our customers.

While we believe that distribution operating expenditure can return to lower levels, it will take time to do so without compromising network safety and performance. Our view is that this lower level of operating expenditure can only be achieved if it is supported by improved processes, practices and business platforms to offset the range of new obligations and increased complexity associated with providing distribution services to a diverse and changing customer and generation base. We are striving to deliver the required efficiency improvements over the course of the current and forthcoming regulatory period.

As shown in the figure and table above, we are projecting real cost reductions in distribution operating expenditure over the period, even though we are connecting new customers and facing additional obligations or 'step changes' that will tend to push our costs higher. Further, we have undertaking a benchmarking exercise consistent with the AER's method and this indicates that our proposed operating expenditure is below the benchmark efficient level. This reflects that we have proposed similar ambitious operating expenditure levels, with a continued focus on prioritising our activities and driving efficiency to achieve the lowest sustainable prices for our customers.

8. Incentive mechanisms

The regulatory framework includes a range of incentives to make sure we focus on keeping costs as low as we sustainably can, while also striving to deliver better service. Incentive schemes affect our revenue allowances in the following ways:

- Capital and operating incentive payments or penalties based on our performance in the previous period are factored into the revenue cap, as part of our forecast and the AER's decision.
- The AER provides annual allowances for demand management initiatives for our distribution services and for network capability improvements for our transmission services. Our performance against these schemes can also affect revenue and pricing in the next regulatory period.
- Service incentives lead to adjustments to the revenue allowance, and resulting prices, each year. We face financial penalties if performance is worse than target, or rewards for above target performance. The maximum rewards or penalties are five per cent of our allowable revenue for distribution and 1.25 per cent for transmission[5] .
- In addition to the service incentive arrangements, we must compensate individual distribution customers if they experience too many outages during the year, or outages that exceed a specified duration. This arrangement is called the Guaranteed Service Level or GSL Scheme, set out by the Tasmanian Economic Regulator.

Our transmission and distribution service performance has improved in recent years, which has delivered significant value for our customers. We are asking the regulator to make a technical change to our service targets for transmission, so that we continue to face strong incentives to maintain and improve performance.

We are also asking the regulator to allow us to report both transmission and distribution performance on a financial year basis. This change will provide a clearer link between our transmission and distribution service performance and customer pricing outcomes.

[5] Includes network capability component only

9. Indicative annual revenues and prices

Based on the expenditure forecasts outlined above, this section sets out our forecast total revenue requirement for transmission and distribution alongside the regulated revenue allowance since 2012-13, for a range of different WACC scenarios.

The WACC is the estimated rate of return on our regulated assets. It is set by the AER to provide the owners of our business with an opportunity to earn a reasonable rate of return on their investment. The figure below shows how the WACC has changed over time for the Tasmanian transmission and distribution networks. These movements, which are driven primarily by changes in financial markets, have a significant impact on the maximum allowed revenues for these networks.

Figure 12: Changes in the regulated WACC for Tasmania's transmission and distribution networks

As already noted, we have decided to align the WACCs for transmission and distribution for this review by adopting 5.89 per cent for both networks, which means that our rate of return on transmission is lower than would be allowed under the AER's Rate of Return Guideline. We are proposing to calculate the WACC for transmission based on the AER's Guideline and then apply a discount. As distribution customers benefit from our transmission network services, this decision will benefit all of our customers.

The WACC changes each year to reflect changing interest rates and the resulting cost of debt. The figures below show indicative revenue allowance outcomes for transmission and distribution depending on different WACC estimates. The revenue outcomes do not take account of any under-or-over-recoveries from previous years, or incentive allowances as a result of performance. Therefore, the information presented below is indicative only, reflecting our best view at the current time.

Figure 13: Transmission Revenue scenarios (June 2019 $m)

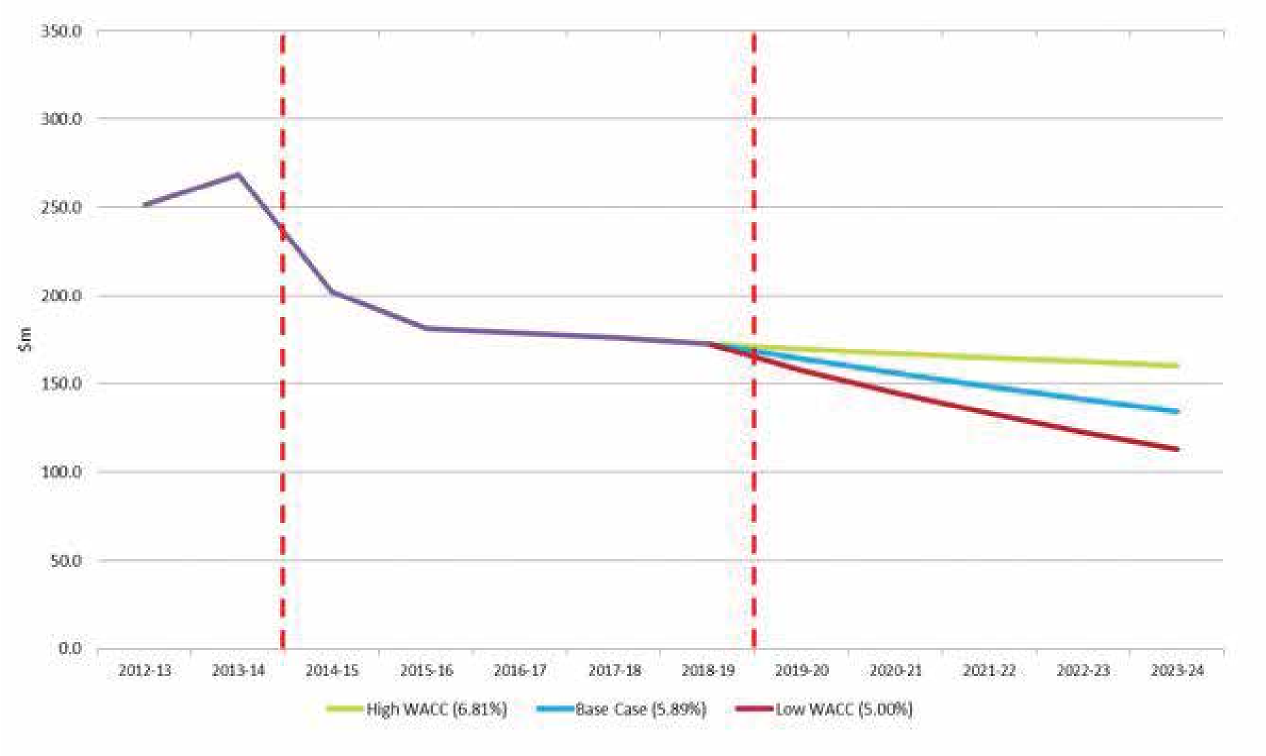
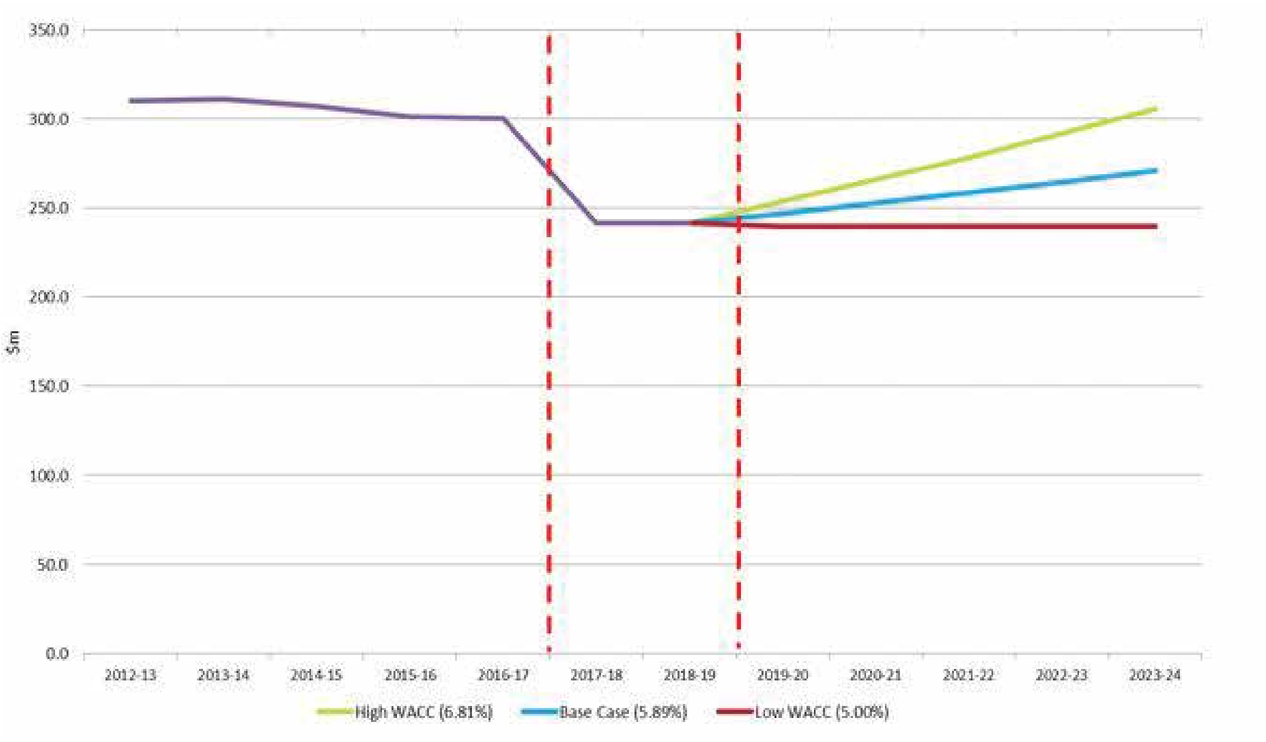


Figure 14: Distribution Revenue scenarios (June 2019 $m)



The transmission revenue profile as shown in the figure and table below means that transmission prices (in real terms) should drop at the end of the current regulatory control period and then remain relatively consistent over the 2019-24 period in nominal terms, continuing to fall in real terms.

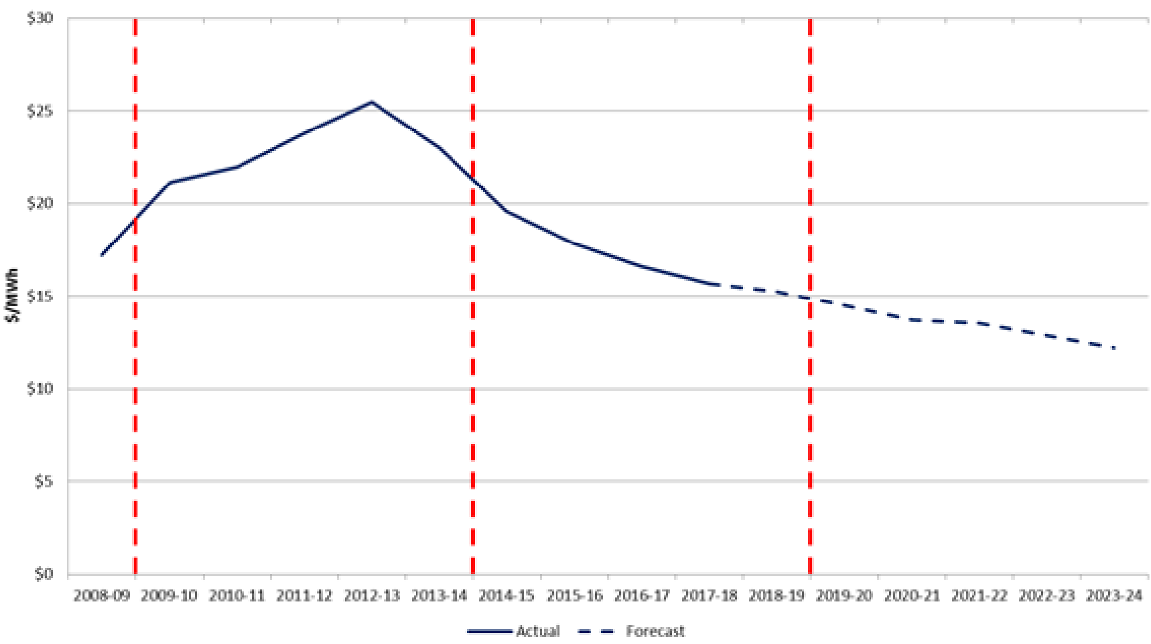
Figure 15: Revenue allowance for prescribed transmission services (June 2019 $m)[6]

Table 6: Transmission Smoothed Revenue Requirement (June 2019 $m)

	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Transmission Revenue Requirement (smoothed)	172.9	164.4	156.3	148.6	141.3	134.3

The transmission revenue profile translates to an average price of $13.69 per MWh, which is 21 per cent lower in real terms than the average price over the previous five year period as shown in the figure below.

Figure 16: Indicative average transmission charges ($/MWh) (June 2019 $)



[6] Figure compares the proposed transmission revenue profile to an application of standard transmission WACC and revenue smoothing.

The distribution revenue allowance for each year is show in the figure and table below.

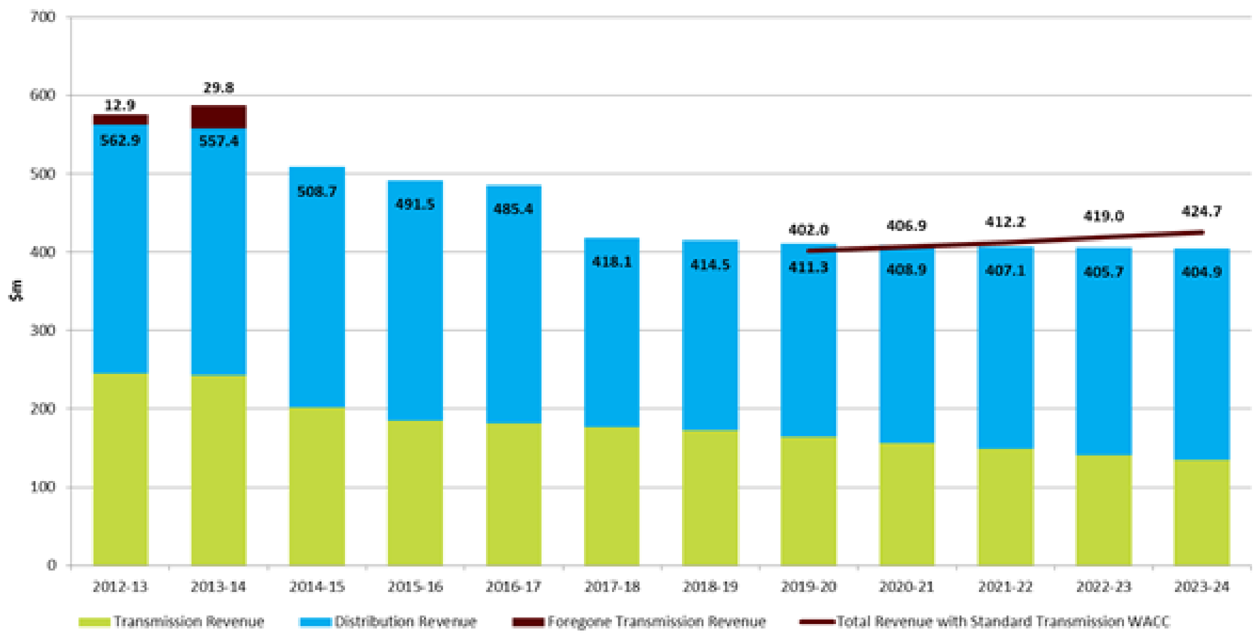
Figure 17: Revenue allowance for standard control distribution services (June 2019 $m)

Table 7: Distribution Smoothed Revenue Requirement (June 2019 $m)

	2018–19	2019–20	2020–21	2021–22	2022–23	2023–24
Distribution Revenue Requirement (smoothed)	241.6	246.9	252.6	258.5	264.4	270.6

The figure below shows our total smoothed revenue over the forthcoming regulatory period compared with historic levels. The figure also shows our combined revenue should we not have applied the expenditure optimisations and transmission WACC alignment. Our proposed combined transmission and distribution revenue is significant less than pre merger levels.

Figure 18: Total Network Smoothed Revenue Requirement (June 2019 $m)



The distribution revenue allowance for each year together with relevant share of the transmission network charges (around 55 per cent) as shown in the table below 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. The table below outlines our forecast revenue to be recovered from distribution customers.

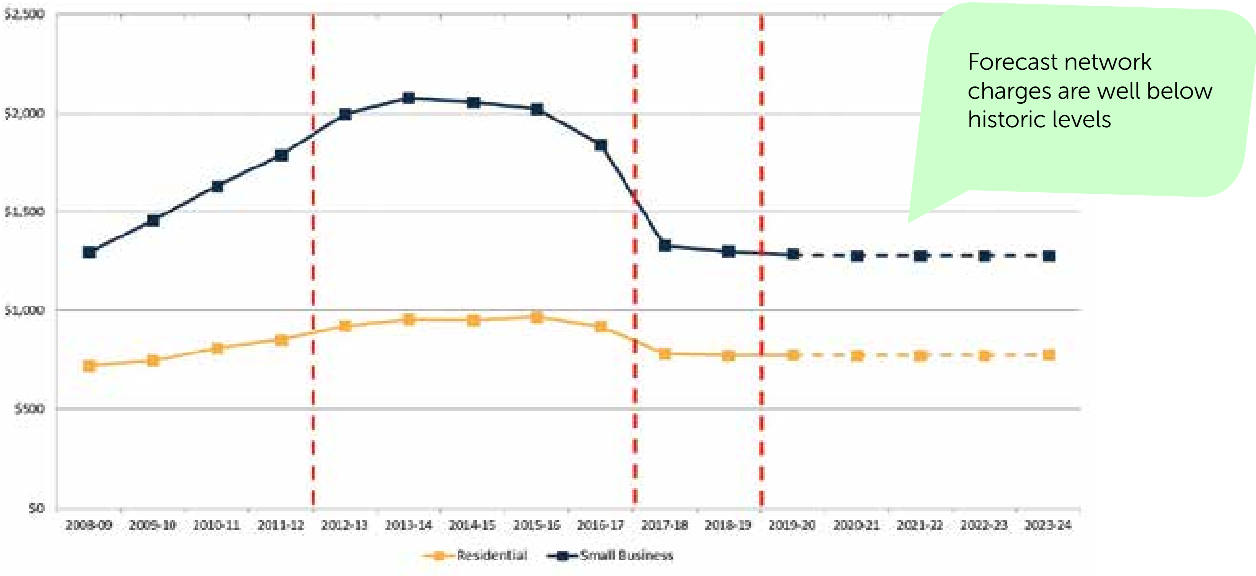
Table 8: Revenue to be recovered from distribution customers (June 2019 $m)

	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24
Transmission Revenue	90.9	89.8	85.8	82.0	78.3	74.8
Distribution Revenue	241.6	246.9	252.6	258.5	264.4	270.6
Total Revenue	**332.5**	**336.7**	**338.4**	**340.5**	**342.7**	**345.4**

TasNetworks charges each customer's retailer, based on the applicable network tariff. It is up to the retailer as to whether, and how, network tariffs are passed on to customers in the final retail bill. For many small customers, the Tasmanian Economic Regulator makes pricing decisions that affect how network charges are reflected in 'standing offer' customer bills.

Our proposed transmission and distribution revenue allowance results in the indicative average annual network charges for residential and small business customers shown below. Consistent with our strategy of sustainable and predictable pricing, our proposal results in most customers' network charge increasing only slightly above CPI and remaining well below pre-merger levels. The forecast network charge includes forecast transmission charges and distribution charges, and assumes no over- or under-recoveries or incentive adjustments.

Figure 19: Indicative average annual network charge (June 2019 $m)



10. Sending better price signals

10.1 Our transmission pricing plan

Due to the confidential nature of individually calculated transmission prices, we engage directly with our transmission customers to outline our plans for the 2019-24 period. We also provide indicative prices for the period.

Our transmission customers have indicated their support for the current transmission pricing methodology. Therefore, we do not propose any changes.

10.2 Our distribution pricing plan

Since commencing operations on 1 July 2014, we have embarked on a process of pricing reform which has seen us gradually moving towards cost reflectivity. The AER approved our first distribution Tariff Structure Statement for the 2017-19 period. This was an 'establishment' phase of our distribution customer pricing reforms that set a pathway for the future by:

- introducing the concept of reform to our stakeholders;
- introducing demand based tariffs for small customers and providing our customers with future investment and price signals; and
- progressing the slow (multi-period) process of unwinding inefficient legacy price levels and cross-subsidies.

10.3 Next phase distribution pricing reform

For the next phase of pricing reform, we are building on the ground work undertaken to date, considering other networks' experiences, AER feedback and further analysis we've undertaken.

For the 2019-24 period, we will continue 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) to provide new opportunities to control their electricity costs;

- offering 'introductory' discounts for our new demand based time of use tariffs for both residential and small business customers, to encourage customer take up of the new tariffs;
- introducing new tariffs specifically for embedded networks; and
- obtaining customer data through our emPOWERing You and Bruny Island Battery trials to inform our tariff design and pricing strategies.

Through the introduction of the new small business and residential time of use network tariffs – initially on an opt-in basis via customers' retailers – and the financial incentives on offer to encourage their take up, our aim continues to be to facilitate a customer led transition to cost reflective tariffs.

We are not proposing to change the design of existing tariffs for customers supplied at high voltages. These tariffs already feature combinations of cost reflective elements such as time of use and demand based charges.

We believe that more cost reflective pricing will provide fairer and better outcomes for all our customers.

Further information on tariff reform is available on our website:
https://www.tasnetworks.com.au/customer-engagement/tariff-reform/

11. Benefit and risks to customers

The Rules require us to explain the benefits and risks to customers arising from our regulatory proposal and tariff proposals.

11.1. Benefit

The following points summarise the principal benefits to customers from our proposal:

- Affordability – We have reduced our expenditure and returns compared to our initial plans in response to customers' concerns regarding affordability. Our forecast costs and revenue requirements reflect the lowest sustainable prices for our customers.

- Safety – Our capital and operating plans aim to deliver programs that are safe and sustainable for the electricity network, our people and contractors, our customers and the communities we serve.

- Reliability – We propose to maintain reliability in accordance with our customers' preferences.

- Efficiency – We are working hard to deliver cost efficiencies without compromising safety or reliability. Our continuing investment in new systems and processes will help drive these savings.

- Innovation – Our customers want us to embrace new technology where it is cost effective to do so. In response, we are putting greater emphasis on seeking opportunities to improve how we respond to new opportunities through our innovation framework.

- Equity – Our new network tariffs are continuing to improve fairness in our charging and deliver savings to customers that use the network more efficiently.

- Sustainability – We are working hard to ensure we only build, maintain and operate the network customers are prepared to use and pay for.

11.2. Risks

We have identified the following risks that customers should consider in reviewing our proposal:

- Pace of customer and technology-driven change – there is a risk of fundamental disruption in our sector, beyond the pace we anticipate. Our plans therefore reflect our present assessment of the services that will be required of our network over the years to 2024, and an efficient way to deliver these services.

- New obligations – given the unprecedented changes in the electricity sector, it is possible that new obligations are imposed on us in the forthcoming regulatory period. If these obligations increase our costs materially, we may seek to increase our network charges accordingly. We will work hard to avoid any such increase, but it remains a possibility given the current level of uncertainty.

- The potential financial impacts of Australian Energy Market Commission (AEMC) reviews concluded after September 2017 and before we submit our proposal, including the System Security Market Frameworks Review and the Inertia Rule change, have not been included in this regulatory proposal. We will revisit our expenditure forecasts following the AER's draft decision, as the outcomes and expenditure implications arising from these reviews are better understood.

- Contingent projects – We have identified a number of large capital projects, such as a second Bass Strait interconnector, that may be required if particular 'trigger events' occur. We have not included the costs of these projects in our expenditure and revenue plans. However, we may seek additional funding, which could feed through to higher network charges, if one or more of these contingent projects is required.

- Service performance risks – Our plans have been designed to connect new customers, maintain reliability and safety, and provide customer services, at a sustainable cost. There is always a risk that the forecast expenditure proves to be inadequate to maintain reliability across all our communities, or to meet other customer service expectations. If our capital or operating expenditure is higher than forecast, it may feed through to higher prices in future regulatory periods.

- Price impact from performance – We are subject to incentive schemes which adjust our annual network charges (up or down) depending on whether our service performance is better or worse than expected. The operation of the incentive schemes could therefore expose customers to unexpected price volatility – meaning that prices could be higher or lower than presented in our proposal. Our proposal to modify an aspect of the transmission incentive scheme helps to mitigate this risk.

- Price impact from lower consumption – As we are subject to a revenue cap, our network charges could increase if energy 'sales' are lower than expected, even if the peak demand for our service remains the same or increases. Much of our distribution revenue is still recovered from energy consumption charges, and until we transition away from this model this risk will remain. As noted by the CCP, we also have a small number of users who consume over 50 per cent of electricity load in Tasmania. The closure of a major customer would have implications for network charges to the remaining customers, as the fixed costs of providing network services are spread over a smaller customer base – including customers in Victoria.

- Bushfire risks – Tasmanians know that we live in a state that is prone to bushfire. We have committed ongoing expenditure to manage this risk. We balance the cost of additional investment and safety measures against the benefit of reduced risk. It is important to get the balance right and we recognise the risk of bushfire cannot be eliminated entirely.

- Extreme weather events and climate change – The effects of extreme weather events including floods, storms and fires are increasing. These events have historically had a significant impact and cost on both TasNetworks and the Tasmanian community. TasNetworks may need to respond to these types of events more in the future and this would have implications for network charges if these additional unforeseen costs are passed through to customers.

12. Next steps - have your say

The AER will shortly commence its review of our Regulatory Proposal. Under its review process, the AER will publish an issues paper on our proposal in March 2018. The AER's issues paper is intended to help consumers and other stakeholders understand our proposal, and to assist interested parties in framing their submissions to the AER. The AER will also hold a public forum, and invite submissions on our proposal.

After considering our proposal and submissions from interested parties, the AER will publish a draft decision in September 2018. It will then invite further submissions, including a revised proposal from us, before making its final decision in April 2019.

In addition to responding to the AER, you can provide feedback to us, and we encourage you to raise any matter that is of interest or concern to you.

You can:

Email your submission to: revenue.reset@tasnetworks.com.au
Go on line at http://www.tasnetworks.com.au/customer-engagement
Post your submission to:
Program Leader Revenue Resets
Po Box 606
Moonah Tasmania 7009

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