PowerWater

Regulatory Proposal

for the 2024-29 regulatory period

@powerwatercorp

About this report

Who is Power and Water?

We are the essential service provider in the Northern Territory (NT), connecting thousands of homes and businesses with electricity, gas, water and sewerage. We are owned by the NT Government, and operate some of Australia's most isolated utility networks, supplying power and water to people in some of the most rugged, remote, yet spectacular places imaginable.

As a multi-utility we recognise the enormous responsibility we have in helping sustain the NT way of life. Territorians rely on our networks and place their trust in us to make sure power and water is always there when they need it, at a price they can afford. We're extremely proud of this responsibility and recognise the importance of being able to keep on providing these services over the long term.

It is this long-term commitment to supporting customers that lies at the heart of our power and water operations. The NT continues to grow, the Government is seeking to attract more new industries to the region, and the way people use our services is constantly evolving. This means we too must evolve and make sure our business, our services and our capabilities are fit to support a growing NT.

The good news is that we've already started this evolution. Over the past few years we have reviewed our whole operating model and begun making changes to the way we work. It's a long journey, and the next five years will see us continue to improve our systems, our data, and our ability to make a difference to the lives of Territorians.

What is this Regulatory Proposal about?

This Regulatory Proposal focuses on the electricity networks part of our businesses, specifically our three largest networks in Darwin-Katherine, Alice Springs and Tennant Creek. These networks are subject to economic regulation, which is all about making sure the electricity services we provide, the investments we make, and the prices we charge are fair and reasonable.

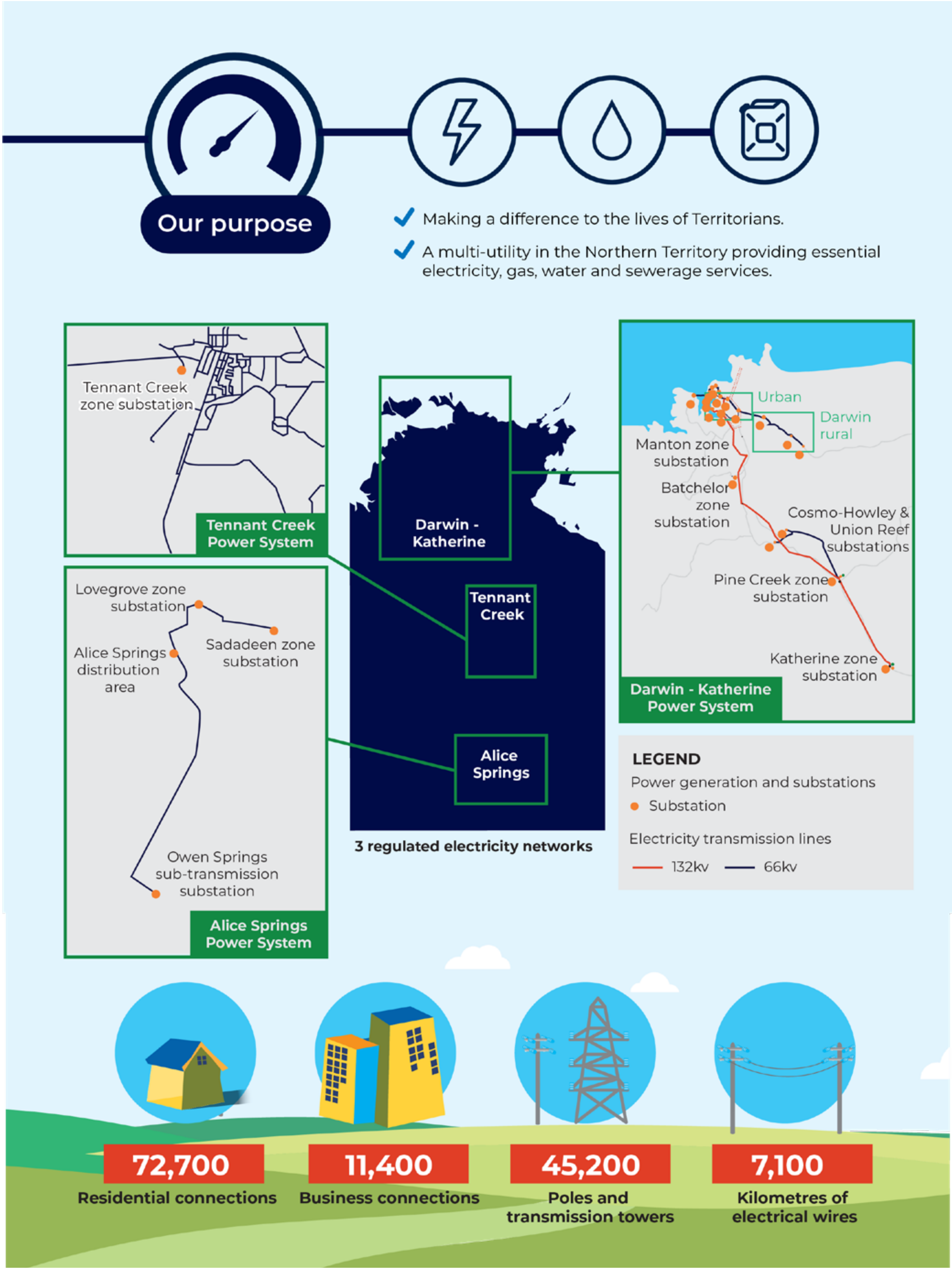
Every five years, we develop a proposal that details the costs of operating and investing in all three of our regulated networks. The proposal also covers the type of network tariffs we charge, the services we will provide, and a number of other financial components necessary to run the business (tax, financing costs, etc.). These factors are all combined to calculate how much revenue we think we will need over the next five years to pay for all this.

This Regulatory Proposal is then issued to the Australian Energy Regulator (AER). The AER reviews the information we provide, challenges us via an extensive question and answer process, and ultimately determines how much revenue we should collect via network tariffs. This AER review process takes about 18 months.

The AER's revenue determination is then used to calculate the prices (tariffs) we can charge customers for using our networks. These network tariffs are charged to the electricity retailer. The retailer then passes all or some of these costs through to end users' through their electricity bill, subject to NT Government policy settings.[1]

[1] Electricity retail prices charged to residential and commercial customers (those consuming less than 750 megawatt hours of electricity per year) are regulated by the NT Government through a pricing order made by the Treasurer under the Electricity Reform Act 2000. The Pricing Order sets the retail prices that customers may be charged for electricity and related services. Compliance with the Electricity Pricing Order is enforced by the Commission.

Figure 1 – Snapshot of our network



When is the next regulatory period?

We propose the next regulatory period will run from 1 July 2024 to 30 June 2029 (referred to as the 2024-29 regulatory period). The 2024-29 regulatory period is the focus of this document. This is only our second regulatory proposal under the AER framework.

We are currently mid-way through our first five-year regulatory period (1 July 2019 to 30 June 2024), and as such are still in the process of delivering many of the projects and initiatives we outlined in our 2018 Regulatory Proposal. We are also still in the process of applying lessons learnt during the previous regulatory review process. This includes adopting many of the recommendations the AER made last time around, such as aligning our accounting standards with other networks, improving how we engage with our customers, and improving the quality of our data and systems.

This Regulatory Proposal document sets out our plans for the 2024-29 regulatory period, and is designed to be an easy to understand summary of our comprehensive plans and strategies for the next five years (as required by the National Electricty Rule). It is essentially a snapshot of our network and business strategies over the coming decades, and provides information on our proposed services, expenditure, revenue and network tariffs for the next five years. The finer detail of our plans and estimated costs for 2024-29 is contained in the suite of appendices and models provided as part of the submission.

A document register for the Regulatory Proposal is provided at Attachment 0.05.

How does this Regulatory Proposal relate to the Draft Plan?

In August 2022, we issued a Draft Plan for the 2024-29 regulatory period. The Draft Plan was an overview of our provisional expenditure plans, designed to give customers and interested stakeholders an early look at what we believe we need to invest in, what that may cost, and how those costs should be recovered. More importantly, the Draft Plan and the customer engagement process associated with it allowed us to capture what is important to our electricity network customers and build some of their preferences into our final Regulatory Proposal.

This Regulatory Proposal builds on the Draft Plan and represents a more fully developed and informed view of our activities and revenue requirement for the 2024-29 regulatory period. We have taken on board customer and stakeholder views on the Draft Plan and have sought to amend our plans to better meet customers' expectations, where practicable.

Key customer-driven changes include revising our expenditure program to help lessen the impact of rising inflation and financing costs across Australia, placing greater emphasis on investing in systems and data rather than costly asset replacement, and making sure we can continue to connect renewable generation (both large and small scale). Further detail on changes since the Draft Plan and how we have built customer feedback into our plans is provided in the Executive Summary and Chapter 1.

What happens from here?

The AER's review will be exhaustive, testing our proposal against the requirements of the NT National Electricity Rules to make certain our plans are prudent, efficient, and in the best interest of customers. The AER will provide a draft determination on our Regulatory Proposal by 30 September 2023, and we will have opportunity to submit a revised regulatory proposal prior to the final determination. The AER will provide a final determination by April 2024.

During this review process, we will continue to engage with our customers and stakeholders on key issues. The AER will also adjust our forecasts to reflect the very latest information, including inflation, Government/climate policy, and the economic conditions at the time. This means the revenue and expenditure numbers we put forward in January 2023 will likely change, and can go either up or down.

It also means some of the projects and investments we put forward may need to change or get scaled back. If there are any specific programs customers strongly support, or any new requirements stakeholders feel should be factored into the AER's determination (and our proposal), it is important to get in touch and provide us with your feedback.

How can you provide feedback?

Over the last year, we have met with our customers, energy sector partners and government representatives to hear what is important to them. This included engaging with everyday residential customers in Darwin-Katherine and Alice Springs via our People's Panels, and holding forums with large users and retailers. We will continue to engage during the AER's review process, and welcome further feedback.

The AER will call for public submissions via its own consultation process. You can follow the AER's consultation process via the AER website.

During the AER's review process, you can also provide feedback directly to us via our 'Have Your Say' website. We look forward to hearing your thoughts.

Information used in this document

All financial figures in this Regulatory Proposal are presented in $ real 2024, unless otherwise stated.

Demand forecasts are prepared as at 17 November 2022.

Numbers may not sum due to rounding.

NT customers sharing their thoughts at one of several forums

Power and Water operations personnel

PowerWater

Contents

A message from the our Chief Executive Officer	9
A message from the our Reset Advisory Committee	10
Customer engagement	13
Highlights	14
Executive summary	17
Part A - Delivering for our customers	**32**
1. Our customers and their feedback	33
2. Our business and network	42
3. Moving to a clean energy future	51
4. Managing our network for the long term	61
5. Uplifting our capabilities	63
6. What we will deliver	66
Part B - Regulatory proposal	**70**
7. Response to the AER's Framework and Approach	71
8. Capital expenditure	75
9. Operating expenditure	91
10. Revenue	97
11. Tariffs and indicative pricing	102
12. Incentives and pass through events	112
13. Alternative control services	116

Power and Water staff with
our People's Panel

A message from our Chief Executive Officer

I'm pleased to present our regulatory proposal for the 2024-29 regulatory period.

With so much change happening across the energy sector – in the Territory and worldwide – the next decade is full of opportunity to improve the service we provide to our customers, and to make a difference to the lives of Territorians. That's why when developing this proposal, we've made a concerted effort to share our thinking with customers, and use their input to shape and then re-shape our investments and priorities for the coming decades.

Over the past 18 months, we've met more than 450 people, held over 35 workshops and spent more than 150 hours talking with and listening to our customers and stakeholders. At stakeholder workshops on our future network, I saw first-hand how Territorians are passionate about making our power system greener, and giving everyone access to renewable energy and technologies. Customers have told us they want us to look to the long term, ensure our services keep pace with change, and make sure vulnerable people don't get left behind. Retailers and regulators have told us to look at how we can use data and technology to make better investment decisions – and everyone is united in the need to keep energy prices affordable over the long term.

We have listened and we have done what we can to address this feedback. I can't promise we have found answers to all the questions facing our network as we look to decarbonise and respond to economic conditions, but we have modified our thinking since our August 2022 draft plan.

We have shifted our investment focus towards improving our data, our culture, our service and our systems. We are placing less onus on expensive network asset replacement and traditional network investments. We are moving away from 'just doing what we've always done'. Instead, we are investing to become a smarter, more efficient business over the long term, uplifting our capabilities and thereby improving the service we offer customers.

We are bringing in technologies that will allow people to continue to install rooftop solar, and allow large scale renewables to enter the NT's power system. We are turning our minds towards electric vehicles and how we can accommodate them and other emerging technologies in the future network.

Our aim is to build on the progress made over recent years, particularly since joining the rigours of the national regulatory framework. In the three years of our regulatory journey so far, we have taken on board lessons learnt and built them into our proposal. As a business we have improved, and we still have some way to go. But most importantly, we are listening.

Throughout this regulatory process, and during the regulatory period itself we are committed to keeping the conversation going with customers and our stakeholders. The regulatory proposal provides a good framework for discussion, and the review process from here will be vital in testing that our plans are prudent, flexible, and will deliver good outcomes for Territorians.

We welcome your continued feedback.

Djuna Pollard

A message from our Reset Advisory Committee

Electricity is complicated so, to draw an analogy with something Territorians understand well – transport: Power and Water don't make electricity, they deliver it. They are in the electricity transport business.

They are responsible for building and maintaining the electrical "roads" that transport electricity from generators to customers. This includes the electrical 'highways' from the large generators, the substations where the transport routes divide into the electrical 'streets' that connect directly to customers.

Power and Water's revenue proposal for the 2024-29 "regulatory period" – a five year window where Territorians will rely on electricity even more than they do now – effectively sets a budget for developing and maintaining the three major electricity 'road' networks: Darwin-Katherine, Tennant Creek and Alice Springs. To put a sense of scale to what's up for grabs, in the current five year window, Power and Water has been approved to collect over $800 million dollars from customers via their electricity retailers.

For the 2024-29 period, the AER requires Power and Water to clearly demonstrate how they have captured and understood what their customers want and how this is reflected in the expenditure proposed.

We have acted as co-chairs of Power and Water's Reset Advisory Committee. We are not Territorians but have brought our experiences from similar roles with numerous other networks in other states over many years.

We observed Power and Water's interactions with customers and their representatives on the Reset Advisory Committee and, overall, it is our view that Power and Water should be commended for the way they have presented the complexities of the regulatory process in a range of ways and sought to understand and incorporate consumer views.

However, it is important to acknowledge the complications and limitations that arise as a result of the NT Pricing Order. Engaging customers on their preferences for Power and Water's price vs service mix and tariff structures is challenged by a key unknown: How the NT Pricing Order will impact on what the vast majority of customers see in their electricity bills.

It is clear from our observations – and the feedback from customers – that Power and Water will need to take a leadership role in 'joining the dots' between government policies, retailers and other industry stakeholders. This will be a key theme for customers as they consider this proposal and provide feedback.

We encourage customers to engage further with Power and Water on this proposal. Does it reflect the feedback already given? Now that we can see some overall costs, does this change what customers think are the priorities? Have new issues emerged?

Dr. Andrew Nance

Gavin Dufty

Dr. Andrew Nance - Independent consultant and advisor

Gavin Dufty - Co-Chair of the Reset Advisory Council and advocate for St. Vincent de Paul Society

The 24 29 Reset Advisory Committee is made up of our broader customer base, with representation from everyday residential customers, advocacy bodies for socially and economically disadvantaged customers, youth and young people and small, medium and large-scale business. The committee has been working hard over the last few months, providing input to our regulatory proposals, assessing and reviewing customer engagement activities and ensuring our materials reflect what matters to them and the broader customer base.

Dr Andrew Nance is an independent consultant appointed by us to support the Reset Advisory Committee. His role is to work with our Co Chair, Gavin Dufty and Committee members to gather input and feedback on our regulatory proposal from a customer perspective.

Residential customer at People s Panel

Customer engagement

Engagement with our customers and other stakeholders is a critical and ongoing element of Power and Water's preparation for the 2024-29 regulatory period. Over the past 18 months, we have met with our customers, energy partners and government representatives to hear what is important to them, to test our forward plans, and ensure our proposal considers what Territorians believe is important to the future of the network and the NT. Where practicable, we have built their feedback into our expenditure plans, and taken on board actions to improve our customers' experience with us, and the way we engage with them. A summary of key themes is below.

Theme	What we heard	What we are doing
Support vulnerable customers 	Low income and vulnerable customers should not be left behind. Better information and incentives should be made available to help customers manage their costs and access renewable energy.	• We will continue to partner with energy providers and other stakeholders, particularly retailers, to improve the accessibility and affordability of renewable technologies. • We are developing a customer experience strategy, which will look at our customers' journey with us and set out a roadmap for improvement. An important focus of the strategy will be low income customers and how they interact with us and our services. • We are investigating options to support vulnerable customers through initiatives such as tariff trials and using our website to provide more information about energy affordability and efficiency.
Affordability 	Customers have told us to keep prices affordable and do what we can to avoid price shocks in the future.	• We have changed our investment focus. Instead of focusing purely on high cost network asset replacement, we will invest in our ICT systems, processes, and our people to improve our asset management capabilities and find alternatives to traditional network solutions. • We are improving the quality of our asset data. By producing better data, we can make better-informed decisions on asset condition, expected life, and the optimal time for replacement. We can then extend asset lives – where safe to do so – and defer costly asset replacement programs. • As advised by the Reset Advisory Committee, we have revised our demand forecast based on the latest information, which has brought costs down.
Enabling renewables 	Customers told us they want to be able to connect more renewables, both large and small scale. They expect us to pursue technologies such as battery storage where this can help alleviate network costs.	• We will invest in a 'dynamic operating envelope' system that will allow households to continue to connect rooftop solar without the need for costly network investment. • We will make the necessary network augmentations to connect more large-scale renewables. • We are improving our data, network analysis and planning capabilities so we can best identify how, when and where to connect renewables, energy storage solutions and other future network technology, without compromising system security or power quality • We will continue discussions with our energy partners on how we can pursue low cost solutions that ensure reliability and affordability of renewables for our customers, optimising outcomes across the NT.

Highlights

- Forecast revenue for the 2024-29 regulatory period is $996.2 million. This is $128.2 million or 14.8 per cent more than the current regulatory period (2019-24). Financing and depreciation costs account for 58.3 per cent of the revenue requirement, which are driven by economic conditions. We estimate the changes in the market contributes $80.7 million to the forecast revenue increase.
- Over the 2024-29 regulatory period we will spend $986.8 million (total expenditure) to operate, build and replace assets across the NT's three largest electricity networks.
- Despite ongoing customer growth and the increasing complexity of network operations, we have been able to keep our operating expenditure down, and expect to spend around $8.0 million, or 1.9 per cent less than during the current period. This reflects improvements in our operating model and cost allocation.
- Our capital expenditure forecast is around $132.1 million higher (or 29.8 per cent) than the current period. Our expenditure program is designed to deliver against our four strategic priorities, which we outlined in our Draft Plan, and have tested with our customers and stakeholders.
- Customers told us they want to be able to connect more renewables, both large and small scale. They expect us to pursue technologies such as battery storage where this can help alleviate network costs.
- Customers have told us to keep prices affordable and do what we can to avoid price shocks in the future. They also told us they expect us to provide better data and more information about their services, our performance, and what they can do to improve energy efficiency.
- We have listened to this customer feedback and plan to:
  - Invest in a 'dynamic operating envelope' system that will allow households to continue to connect rooftop solar without the need for costly network investment.
  - Connect more than 200 MW of new, large scale generation, establishing renewable energy hubs in the Territory using the contingent project provisions under the regulatory framework. This will support the NT Government's 2030 vision for renewables to supply 50 per cent of energy consumed.
  - Improve the quality of our asset data, which will allow us to better plan our asset replacement program and avoid costly 'spikes' in network replacement.
  - Use risk analysis and innovative tariff structures to find alternatives to costly network investment, making better use of the networks we already have.
  - Develop a digital customer experience strategy, which will see improvements to our website, the way we communicate with customers, and the quality of information we provide.
  - Upgrade our antiquated ICT systems with newer, fit for purpose programs and applications.
  - Install a further 24,600 smart meters, to help customers manage their power use.
  - Trial new tariffs for electric vehicles, and use the incentive mechanisms under the regulatory framework to further investigate community battery storage.
  - Reduce our leasing costs and property footprint, establishing a single site for our power and water operations and support functions.
- Our overall proposal increases smoothed revenue by 7.0 per cent per annum. For typical residential and small use customers, the total retail impact on customers' bills will be determined by the NT Government's Electricity Pricing Order, which has historically seen prices set below the actual cost of supplying electricity.

Strategic priorities and forecast costs

Managing the health of our network

What this means

Continuing the shift to more proactive, risk-based asset management, with the aim of smoothing replacement volumes and avoiding price shock for customers.

What we are doing

- Upgrade asset management systems
- New risk quantification method
- Extending asset life where safe and prudent to do so

Benefit to customers

- Network reliability
- Avoid price shock

Improving utilisation

What this means

Supporting load growth and attracting more large users to the NT. Using demand management, tariff structures, and making best use of the assets we already have.

What we are doing

- Time of use tariffs and export tariff trials
- New super user tariff
- Support industrial hubs at Holtze and Middle Arm (contingent project)

Benefit to customers

- Customer choice
- Lower costs

Capital expenditure
$575m*
*Excludes contingent projects
30%

Uplifting our systems and people

What this means

Continuing our regulatory maturity journey. Investing in outdated ICT systems and processes, enhancing our operating model and culture, and adapting to change for the long-term benefit of customers.

What we are doing

- Operating Model Program
- Multi-site consolidation
- Operating technology uplift
- Customer experience strategy
- Review customer engagement model

Benefit to customers

- Improved service
- Lower long term costs

Facilitating renewables

What this means

Supporting NT Gov target of 50% renewables by 2030. Finding ways to continue to connect solar without impacting system security, and allowing more large scale renewables to connect

What we are doing

- Dynamic operating envelope for solar photovoltaic systems
- Distributed energy resources (DER) system studies
- Renewable energy hubs (contingent project)
- Darwin-Katherine transmission line augmentation

Benefit to customers

- System security
- A greener NT

Closing RAB
$1,707m
33%

Rate of return
5.67%
16%

Financing costs
$579m
31%

Operating expenditure
$412m
2%

Revenue
$996m
15%

Tax and other
$0.43m
94%

15

Power and Water staff, Alice Springs

Executive summary

The next decade is critical for the Territory's energy future. Globally, energy systems are decarbonising. The NT is making the transition to a cleaner, lower emission power system, connecting more solar energy and looking at how batteries and electric vehicles can help change the way we use, generate, and transport electricity. It's an exciting time, and as the Territory's main provider of essential services, Power and Water will play a vital role.

We must invest in our electricity networks, technology, and people to ensure we have the right capabilities in place to support the NT's clean energy transition, and provide customers the services they want.

Customers are central to our plans. This Regulatory Proposal details the proposed expenditure, revenue and tariffs for the regulated electricity networks in Darwin-Katherine, Alice Springs and Tennant Creek over the 2024-29 regulatory period. When developing this proposal, we have sought to engage with customers from each of these network areas and capture their views on what they expect from us as their network service provider.

Customers have told us they want to be able to continue connecting renewables to the grid, and that we should be more innovative in how we manage our networks. They expect us to support emerging technologies such as electric vehicles and battery storage, while making certain vulnerable customers are not disadvantaged. Most importantly, they expect us to do our part to keep energy costs affordable, and provide better information on how they can manage their electricity bills.

We have listened to this feedback and have built a range of initiatives into our expenditure program to help give customers and our other stakeholders what they need. Some of these initiatives require major investments, such as installing ICT systems that will improve the quality of our network data and allow large scale renewables to connect. Other initiatives are more subtle, such as amending our tariff structures to help influence the way our networks are used, and working with retailers to produce information on energy efficiency.

Wherever practicable, we have designed our expenditure program to address specific issues raised by stakeholders, including the AER.

We remain committed to continuing the dialogue with our customers throughout the regulatory review process – and during the next regulatory period itself – to test that our plans remain consistent with their expectations.

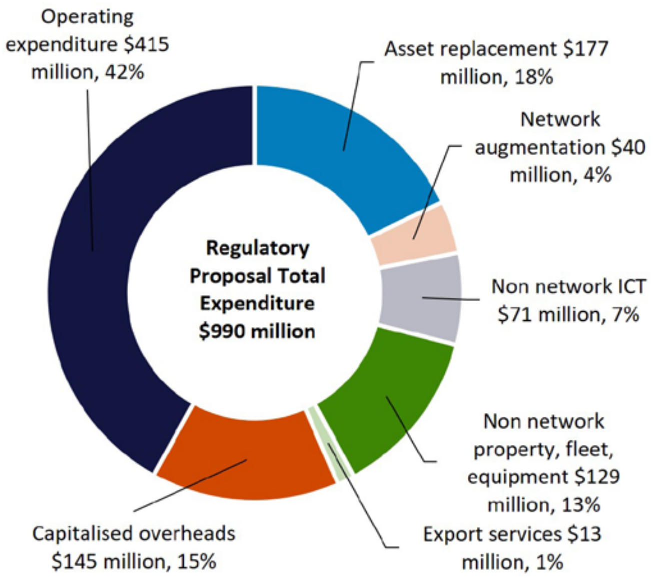
Changes since the Draft Plan

Since we released our Draft Plan in August 2022, we've undertaken a thorough review of our strategy and expenditure program, taking on board feedback on that plan, and adjusting our thinking to reflect the latest demand forecasts and market conditions.

Over the 2024-29 regulatory period we propose to spend $990 million (total capital and operating expenditure) to operate, build and replace assets across the NT's three largest electricity networks. This is $41.3 million, or 4.4 per cent higher than our Draft Plan, and a 14.8 per cent increase compared with the current period.

We improved our overhead cost allocations and delivered a targeted efficiency program to reduce our operating expenditure. The resulting reduction in our base year will allow us to accommodate the required uplift in capacity and capability in the next period, while keeping our operating costs flat on average.

Figure 2 – Strategic priorities and forecast costs



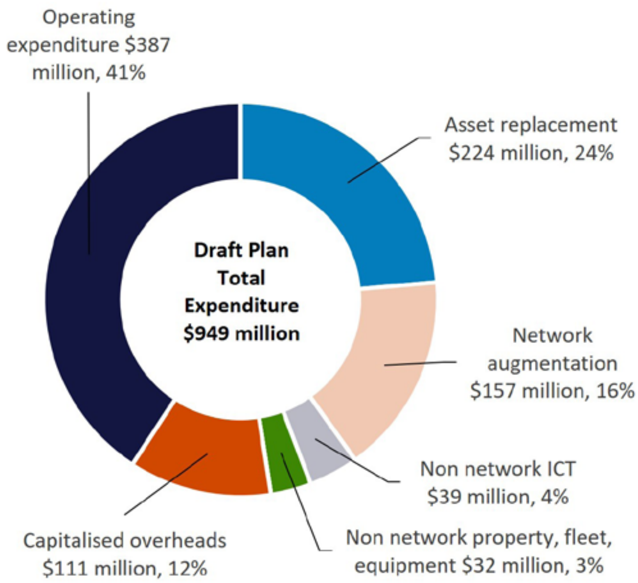


Figure 2 shows the difference between our overall expenditure plan included in this Regulatory Proposal, and what was included in our Draft Plan.

While we still expect our operating costs to be lower than what we have incurred in the current period, our operating expenditure forecast has increased since the Draft Plan, by $28.6 million. This is largely due to inclusion of a number of new, largely externally-driven step changes. These step changes reflect the expected cost of insurance, the need to establish a small technology cloud footprint, new legislative requirements, and a capability uplift to manage more dynamic and variable network use. We also moved from an adjusted 2020/21 base year to adopt the audited 2021/22 expenditures as our base year.

These increases have been partially offset by reductions in our output, price and productivity trend factors. Through the current period we reviewed our operating expenditures to improve our overhead cost allocations and delivered a targeted efficiency program to reduce our operating expenditures. These initiatives will allow us to accommodate the required uplift in capacity and capability in the next period, while keeping our operating costs flat on average.

Key changes in our operating expenditure forecasts since the Draft Plan are shown in Figure 3.

Forecast capital expenditure is $12.6 million higher than the Draft Plan, however, the mix of expenditure has changed. We have listened to customers' desire to avoid future price shocks caused by widespread asset replacement, and stakeholders' concerns about the quality of our data. This has led us to re-examine and consequently to reduce our forecast need for spending on asset replacement, and instead look to invest in systems and analytical capability to help us improve the quality of our asset data and management practices.

By having better data we can make better informed, risk-based decisions on when best to replace the network assets, and defer – or potentially eliminate – some of these costly network replacement projects where safe to do so. As shown in Figure 4, changing our focus in this way has allowed us to reduce our asset replacement forecast since the Draft Plan by $47.3 million, partially offset by an increase of $31.8 million in our ICT program. We have also been able to revise our growth capex forecast by $53.4 million as a result of moderating small use customer connections and consumption forecasts.

The single biggest change in capital expenditure since the Draft Plan, relates to a non-network project. We propose to upgrade our Ben Hammond complex in Darwin in the final two years of the period. This project will cost $89.8 million, and see us exit contracts on some of our leased properties and co-locate Darwin staff at one Power and Water owned location. The single-site consolidation project is critical to allow us to continue our operating model improvements, reduce our long-term costs, increase opportunities for collaboration, improve culture, and uplift the quality of service we provide customers. Investing in our own accommodation will offset commercial leases and mitigate increasing property costs over the medium term.

We have changed the mix of capital expenditure, reducing our reliance on age as a proxy for condition, and instead looking at systems and analytics to support an uplift in asset data, risk quantification and replacement options.

Figure 3 – Changes in operating expenditure, Regulatory Proposal vs Draft Plan ($ million real 2024)

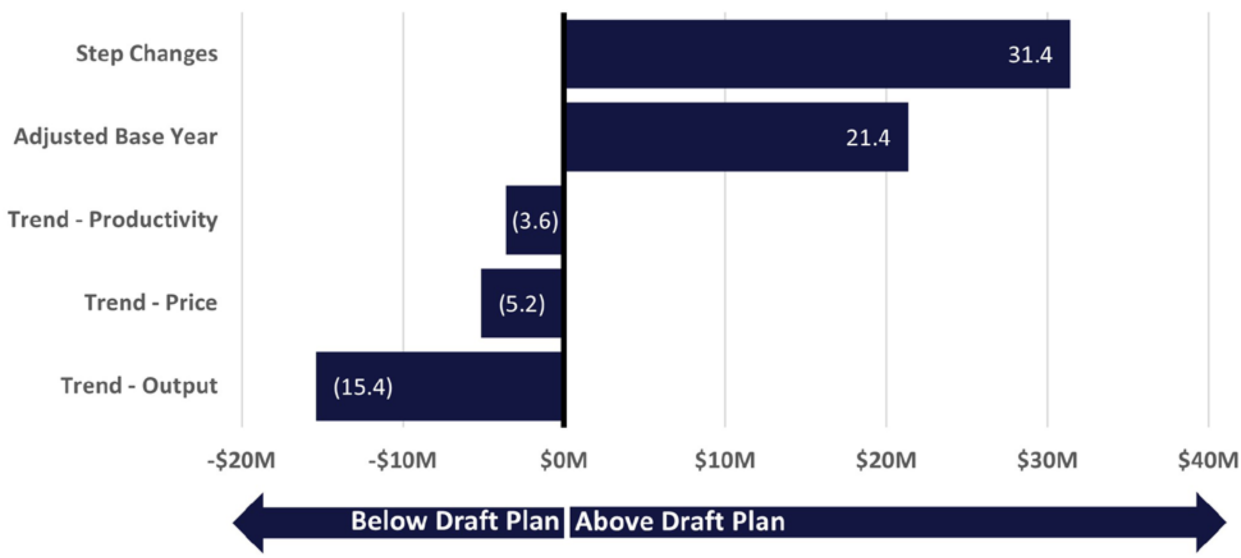
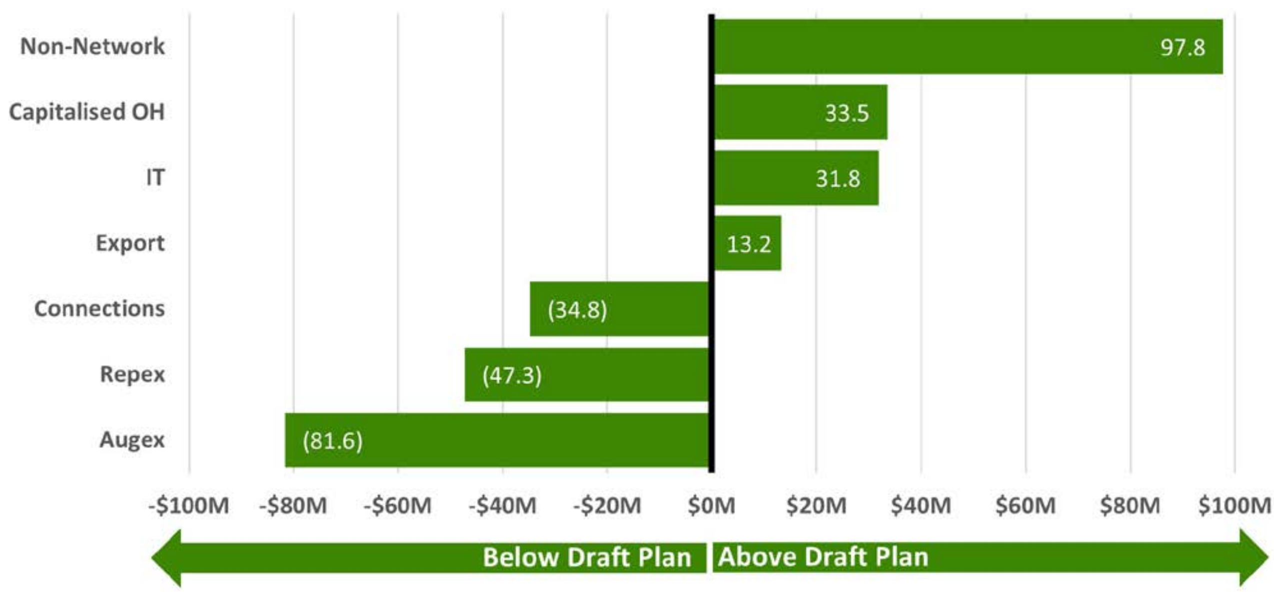
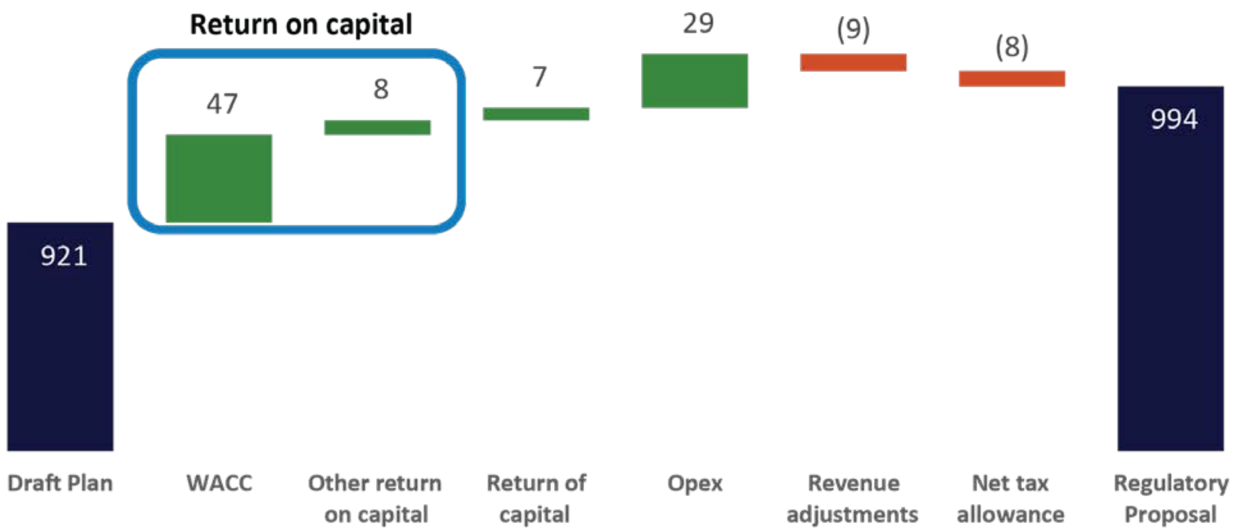


Figure 4 – Changes in capital expenditure, Regulatory Proposal vs Draft Plan ($ million real 2024)



Our overall revenue requirement has increased by $73.0 million from $921.4 million in the Draft Plan to $994.4 million in this proposal. As shown in Figure 5, almost two thirds of this increase is driven by the effect of the economic environment on our financing costs (e.g. rising interest rates). The other $28.6 million is the direct, in-period impact of the increase in forecast opex.

Figure 5 – Changes in revenue, Regulatory Proposal vs Draft Plan ($ million real 2024)




Solar panel inspection

Our strategic priorities

Change is happening right across the energy sector. Around the world, businesses are looking to decarbonise, moving away from dependence on fossil fuels and electrifying their operations using renewable resources wherever possible. At the same time, there is uncertainty in the post-pandemic market as economies recover and normalise following the impact of COVID-19. Given all this activity, the ability to innovate and respond to customer preferences is more important than ever.

In the NT, we are adapting to this global change as well as managing a number of local challenges. Over the coming years large tranches of our Darwin-Katherine network will reach the end of its design life and will need replacing. Similarly, many of our ICT systems are already past their useful life and are no longer supported or fit-for-purpose. While these are common asset management issues for any business, the context of this occurring during a nationwide energy transition heightens the need for forward thinking and urgent investment

Put simply, there is a lot going on. We need to set ourselves up to be able to deliver efficiently, and continue to provide Territorians the services they want, at an affordable price.

We remain early in our regulatory journey. The recent move to the national regulatory framework has highlighted where we can become more efficient, and has set us on our course to improve our operating model and uplift our planning, forecasting, delivery and data. We have made good progress, but we still have a way to go. A focus of the next regulatory period is about building on lessons learnt from the first regulatory period and continuing to uplift our systems and capabilities.

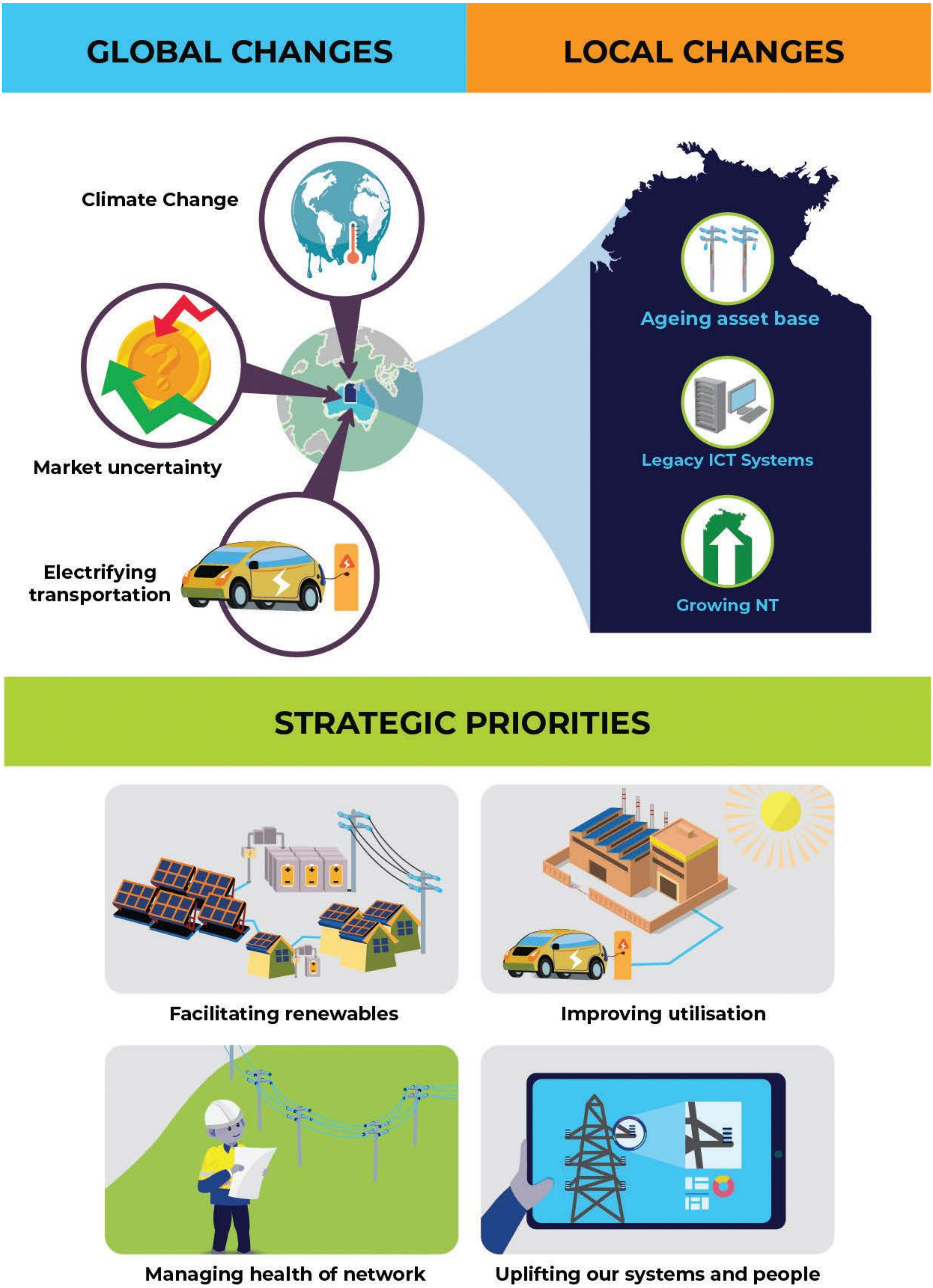
We are building on lessons learnt from the first regulatory period, continuing to uplift our systems and capabilities.

Growth is also a factor in the Territory. The NT Government is working to attract new industries and drive economic and population growth, creating greater demand for energy network services. To enable us to better navigate key challenges and respond to changes in our external environment, we have developed our expenditure plans for the 2024-29 regulatory period around four strategic priorities:

1. Facilitating renewables
2. Improving utilisation
3. Managing the health of our network
4. Uplifting our systems and people

By focusing on these priorities, we aim to adapt to change in a way that can maintain both affordability and quality of services. This is discussed in the following sections, and is illustrated in Figure 6.

Figure 6 – Strategic priorities and drivers of change



Facilitating renewables

Renewable energy is where our future lies. Our network is central to decarbonising the NT economy and achieving the NT Government's target of 50 per cent renewable energy by 2030. Customers have told us they value decarbonisation and want us to think long term about energy sustainability and affordability. Customers have also made it clear they want to continue to connect small and large scale renewable generation, particularly solar.

We are therefore seeking to significantly uplift our network planning capability, with unlocking solar and considering non-network solutions a key focus both at the transmission and distribution level. In our distribution networks, we are already well down the road to decarbonisation. The ~20,000 rooftop solar systems connected to our networks produce up to 150 MW of electricity, which is around 50 per cent of our peak demand. Territorians have embraced rooftop solar, and we want them to be able to continue to lead the decarbonisation of NT homes and businesses. That's why during the next regulatory period we will invest to improve network visibility and establish systems (dynamic operating envelopes) that will allow us to continue to connect solar without having to build expensive new infrastructure or compromise system security.

The real game-changer is at the transmission network level. Like most Australian power systems, we rely on carbon-producing generators for the bulk of our energy needs (particularly natural gas). Unlike most other Australian power systems, we are not interconnected with other jurisdictions. The networks in other states and territories are interconnected through the National Electricity Market (NEM), and are the focus of a large scale decarbonisation effort under way across the country. We don't have the luxury of relying on others. If the NT wants to decarbonise, we have to do it ourselves.

The NT Government and our customers have expressed a desire to develop renewable energy hubs, which will complement and ultimately replace carbon-producing generation. As the operator of three regional, isolated systems, we have to carefully plan and control how, when, and where best to connect large scale renewables or major loads. Connecting a new 150 MW load or generator to a network designed to serve a peak demand of 285 MW (or less than 50 MW in Alice Springs) has huge implications for the stability and reliability of the power system. It is vital we get this right.

That's why throughout the next period, as part of our future network strategy, we will conduct a series of system studies to better understand the capacity and constraints of our transmission system, and the optimal locations for connecting new generation and large loads. Our aim is to get a longer term view of the timing and scope of network investment and replacement, and use that to inform our forward-looking work program.

We are also making use of the contingent project provisions available under the NT National Electricity Rules to manage uncertainty around the timing of major renewable energy projects and commercial developments likely to occur during the regulatory period. This will allow us to move quickly to deliver these works when they do materialise, while avoiding the need for customers to pay for investments earlier than necessary.

We are getting our network and ICT systems ready for the significant change in the way customers want to use our network. This includes renewable energy hubs, electric vehicles and battery technology.

Improving utilisation

We expect electricity demand to increase significantly over the next 20 years. The NT Government predicts our population will increase by more than 30 per cent by 2040. We will also need to connect any new major industrial customers locating in the Territory.

Our customers' drive towards decarbonisation means they are seeking to electrify a lot more of their daily energy use. For example, over the coming decades we expect the uptake of electric vehicles (EVs) to increase, both for residential and fleet use. Each car can result in approximately 30 per cent more electricity consumption for a typical household. Industrial customers too are seeking to electrify more of their operations, which will dramatically increase energy demand and network stresses during peak periods.

This growth in demand provides incentive for us to improve utilisation of the network, increasing scale and passing on lower costs to customers. Rather than solely building more network, we also want to make best use of what we already have.

To do this, we are improving network tariff structures so they provide customers with price signals that reflect our future costs. This includes lower prices in off-peak periods during the day when low-cost solar is available and when there is significant capacity in our networks. Our priority is to provide customers with the right information to be able to shift energy to cheaper off-peak periods, and understand the true cost of peak energy use.

As identified in our Draft Plan, we considered introducing more complex tariffs, but have since received feedback from retailers and large users that certainty and simplicity is valued. We have therefore scaled back some of our changes, and will test complex charging mechanisms such as energy export tariffs or electric vehicle tariffs as part of a limited trial only. We have, however, retained our plans to establish clearer customer segmentation, introducing defined tariffs for medium-to-large business customers consuming between 160 MWh and 750 MWh per year.

Introducing greater segmentation will make no difference to the prices customers pay in the short term. However, it will ensure our tariff structure can accommodate future developments, including for example changes to the NT Government Pricing Order, and/or inclusion of other connection types.

During the period we will also continue to investigate how battery storage can be used to improve network utilisation. We intend to use the Demand Management Innovation Allowance available under the NT National Electricity Rules, along with potential ARENA[2] funding to research, trial and study two battery storage solutions in our Alice Springs and Darwin-Katherine networks.

A key enabler of better network utilisation is smart metering. We recently commenced installing smart meters in place of mechanical meters at customers' premises, and will continue the program over the course of the next two regulatory periods.

We are aiming to make better use of our network by introducing tariff structures that encourage people to shift energy use to cheaper off-peak periods.

[2] Australian Renewable Energy Agency

By 2034, our entire customer base will be on smart meters, unlocking a range of opportunities to improve service and lower costs.

By the start of the next regulatory period (July 2024), around half our customers will already have a smart meter installed. Our plan for the remaining ~45,400 non-smart meters is to replace around half of them during the 2024-29 regulatory period, with the remainder completed in the following period. By 2034 we will have moved our entire customer base on to smart meters, which will open up greater opportunity for efficient tariff setting and improved network utilisation, and will unlock the significant whole of supply-chain benefits of distributed energy resources.

Managing the health of our network

When Cyclone Tracy hit the NT in 1974, much of the Darwin-Katherine electricity system was decimated. A huge network rebuilding program commenced shortly after, which means a large number of assets in the Darwin-Katherine network are of a similar vintage. By the end of 2030, these assets will be approaching 55 years of age, and will be due for replacement in the years that follow.

We need to commence planning for this replacement program now – looking beyond the next regulatory period – and take steps to avoid a large spike in network investment that may cause price shock for our customers. During our customer engagement process, we tested this issue with our People's Panels. Our customers told us they wanted us to invest for the long term, and manage our ageing network proactively. They voiced concerns about the potential price uplift caused by the spike in asset replacement post 2030, and were keen for us to pursue initiatives to help flatten the cost curve.

As discussed in the Draft Plan, an option tested with customers was to bring forward replacement of some assets to the 2024-29 regulatory period to help offset expenditure increases in future periods. We also discussed the potential to bring forward collection of some revenues to help smooth the tariff revenue profile over time. The People's Panel expressed their comfort with these approaches, even if it resulted in a small increase in revenue for the 2024-29 regulatory period compared to 2019-24.

Since then, we have considered the changing economic environment, and taken on board further customer and stakeholder feedback on the need to find alternative solutions to costly network asset replacement. That's why we have changed our investment focus, reducing our preliminary network asset replacement forecasts and instead investing in ICT, processes, and our people, to improve our asset management capabilities. Our strategy is to invest in our asset data systems, risk tools, and asset management practices to extend the life of the Cyclone Tracy assets and deliver a smoother, phased replacement program. At the same time, we will identify opportunities to use new technology to retire outdated assets, rather than simply replacing like-for-like.

Over recent years, we have continued to provide reliable services to customers. During 2021/22, on average, our reliability has improved from the previous year with customers enduring 115 minutes of outages (29 minutes less than the previous year) and slightly fewer outage events. Our aim for the next regulatory period is to maintain the ongoing trend of overall reliability improvement, focusing on improving localised performance for customers in pockets of the network that experience more frequent outages and interruptions. Detail of performance in each network is provided in the Transmission and Distribution Annual Planning Report provided at Attachment 8.85.

We are accelerating our shift to proactive, risk-based asset management.

Uplifting our systems and people

To manage our business efficiently, comply with the NT National Electricity Rules, and to deliver the services and price outcomes customers want, it is essential we have the necessary people, tools, systems and operating model. During the current regulatory period we commenced the Operating Model Program (OMP). The OMP is an enterprise wide initiative that seeks to improve the quality and consistency of our systems and data, as well as the capabilities and culture of our workforce.

One of the objectives of the OMP is to upgrade our current suite of outdated ICT to fit-for-purpose systems that will improve productivity and enable our staff to work smarter and in a more customer-focused way. We have already commenced implementing new billing, call centre, and metering systems. Over the course of the next regulatory period, we will upgrade core asset and financial management systems such as Maximo and Oracle, which will provide better data and enable deeper analysis, which we can use to plan and manage our networks more efficiently. We will also uplift our operational technology (OT) systems and cyber security arrangements, which will allow us to better manage our distribution network and keep our customers' data secure.

Forecast expenditure on ICT systems during 2024-29 is approximately $70.7 million. Investment in our systems will be complemented with investment in our people. Our workforce is currently split across several leased and owned sites. To improve our working culture and our ability to attract, train and retain people, we are undertaking a project to consolidate our Darwin workforce to a single site. Our plan is to base our workforce primarily at the Ben Hammond complex, which we own and operate. The complex upgrade will cost around $89.8 million.

An advantage of being a multi-utility is our ability to procure new systems and premises for use right across the organisation, improving productivity and allowing us to share costs across the business units. This means our regulated electricity business can acquire systems and property at a substantially lower cost than if it purchased them as a smaller, standalone business.

Costs for the OMP are allocated fairly across the businesses using our AER-approved Cost Allocation Method (CAM)[3]. This ensures network tariff customers only pay for the portion of these systems that are actually used by our electricity business.

We are continuing our operating model improvements, focusing on uplifting our data, systems and culture.

[3] Note the current CAM remains unchanged from that approved by the AER in its last regulatory determination.

Residential solar PV system

What this will cost

Figure 7 shows our forecast revenue requirement for 2024-2029, and how this has changed since the current and previous periods. Our forecast revenue is 14.8 per cent higher than 2019-24, but still significantly below the $1,259.2 million allowance set by the jurisdictional regulator – The NT Utilities Commission – in 2014-19 . Following the Utilities Commission's determination, we received a Ministerial Direction to reduce our revenue allowance to $1,030.6 million (the light blue line in Figure 7).

The forecast revenue increase through 2024-29 is being driven in part by the rising cost of capital, which is largely outside our control. Current market conditions are leading to a 16.2 per cent increase in the regulated rate of return compared to the AER's 2019-24 determination. The regulated return on and return of investment (financing and depreciation costs) account for 58.2 per cent of the revenue requirement. These costs driven by the size of the regulatory asset base (RAB), and economic conditions affecting the weighted average cost of capital (WACC), such as inflation and rising interest rates. We expect the changes in the market will increase our revenue requirement by $80.7 million over the next period (see Figure 8).

Figure 7 – Forecast building block revenue for 2024-29 compared to current and previous periods ($ million real 2024)

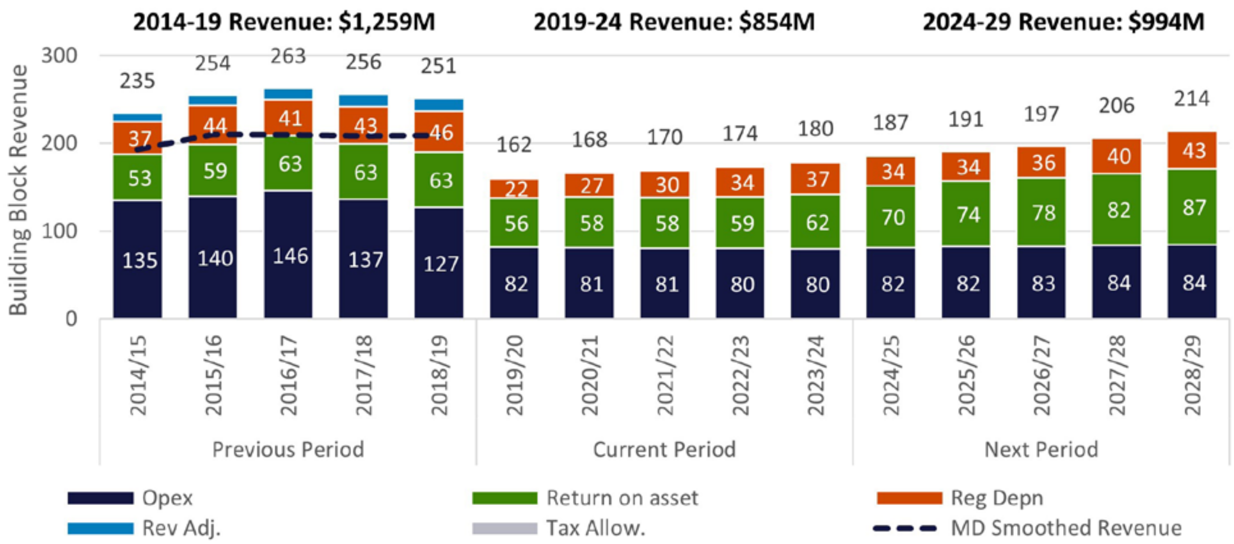
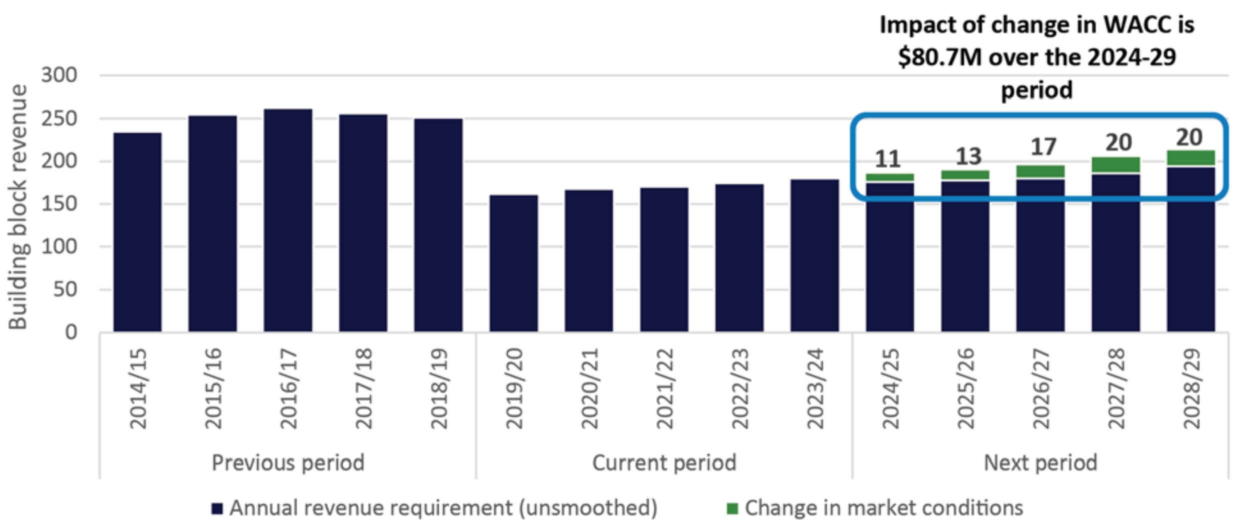


Figure 8 – Impact of market conditions on revenue requirement ($ million real 2024)



Capital expenditure

We forecast $574.8 million in capital expenditure (capex) in the 2024-29 regulatory period. This is a 29.8 per cent increase compared with the $442.7 million estimated to be spent in the current regulatory period (see Figure 9).

The increase in capital expenditure over the course of this period and into the next is driven by the need to uplift our asset management capabilities, with a focus on investing in our ICT systems and operating model.

Historically, investment in network and ICT asset replacement has been low. Our asset management strategy has been largely reactive, only replacing assets upon failure or where asset condition has deteriorated such that there is safety or reliability (or data integrity) risk. While this approach has minimised the impact on network tariffs historically, it has led us to a position where many of our assets – particularly our ICT systems – are well beyond their design life.

Replacement of network assets accounts for $176.6 million or 30.7 per cent of forecast capex, a $26.7 million uplift from the current period. The key driver of higher expenditure is an expected decline in asset condition due to age and environment.

Network augmentation capex, which includes new connections and distributed energy resources (DER) capex, accounts for $53.4 million, or 9.3 per cent of forecast capex in the 2024-29 period. DER includes rooftop solar, energy storage devices, electric vehicles (EVs) and other consumer appliances that can flow back into our network. Over the past decade, customers have installed rooftop solar at an increasing rate. Small scale solar now accounts for 10 per cent of total generation in our regulated regions, and is projected to increase to over 20 per cent by 2030. We highlight that DER capex is a new regulatory category for the next period, and is composed entirely of $13.2 million for our dynamic operating envelope solution designed to facilitate ongoing connection of rooftop solar.

However, the bulk of the overall capex increase is driven by investment in non-network capex (ICT, property, fleet and plant), which comprises 34.8 per cent of expenditure. ICT investment features heavily over the course of the next regulatory period. Our ICT systems are not currently equipped to manage the expected increase in workload and programs over the next 20 years.

We have identified an optimal sequencing of ICT projects as part of the 2024-29 regulatory period that will help us uplift our capabilities. We forecast $70.7 million for ICT capex in the 2024-29 period, compared to $50.3 million in 2019-24.

The high proportion of non-network investment during the next period reflects our plans to co-locate some of our Darwin staff into one Power and Water owned location (Ben Hammond complex). The single site consolidation project is expected to cost around $89.9 million.

Capitalised overheads account for $144.7 million or 25.2 per cent of forecast capex in 2024-29. During the current period, we improved our allocation of network and corporate overhead costs to maintenance activities and capital projects. This has increased the proportion of overhead costs capitalised against projects in the next period, when compared to the current period.

Operating expenditure

We forecast $412.0 million of operating expenditure (opex) in the 2024-29 regulatory period. Figure 10 shows the build up of our 2024-29 opex forecast

We have developed this forecast using the AER's preferred base-step-trend method. In line with the AER's method, we have used our most recent year of audited actual operating expenditure (or the revealed cost) as our base year. At the time of developing our forecast, this was $73.3 million incurred in 2021/22. This base year includes better allocation of overhead costs to opex activities and capex projects, and incorporates a targeted efficiency program to reduce our operating expenditures.

We have escalated our base year costs to account for the rate of change (or trend) in network scale, prices, and productivity. Together, these movements will decrease our opex by around 0.2 per cent per annum, resulting in a reduction of $7.0 million over the period.

In developing our forecasts, we have considered the changing environment and regulatory framework in which we operate. Customer expectations for the network to accommodate more renewables, batteries and EVs, coupled with obligations stemming from our recent move to the national regulatory framework, are imposing new costs on our business. These costs are not included in our base year.

Solely escalating and rolling forward our base year costs would not be sufficient to meet these customer expectations or our compliance requirements. We have therefore included a number of recurrent opex increases in our forecast:

- We estimate an average annual uplift of $2.9 million per annum is necessary to cover new technology and regulatory requirements relating to cyber security, the NT NER and digital cloud.
- We have included a $3.8 million annual uplift in opex to bring our network operations capability up to the standard expected of a modern distribution network service provider.
- As customers drive for more individual choice and we move away from centralised generation, network use is becoming more dynamic and the network itself is becoming more complex. While investing in better ICT systems is one part of the solution, we must also invest in our people to be able to manage that complexity, plan our future grid, and make sure we can continue to accommodate more rooftop solar and large scale renewables. To do this, we estimate we will need, on average, an additional $2.8 million per annum reflecting an increase the number of operations and planning resources.
- Finally, an uplift of around $1 million per year is necessary to cover insurance costs.

Detail on these opex step increases is provided in Attachment 9.02.

Figure 9 – Forecast and historical capital expenditure ($ million real 2024)

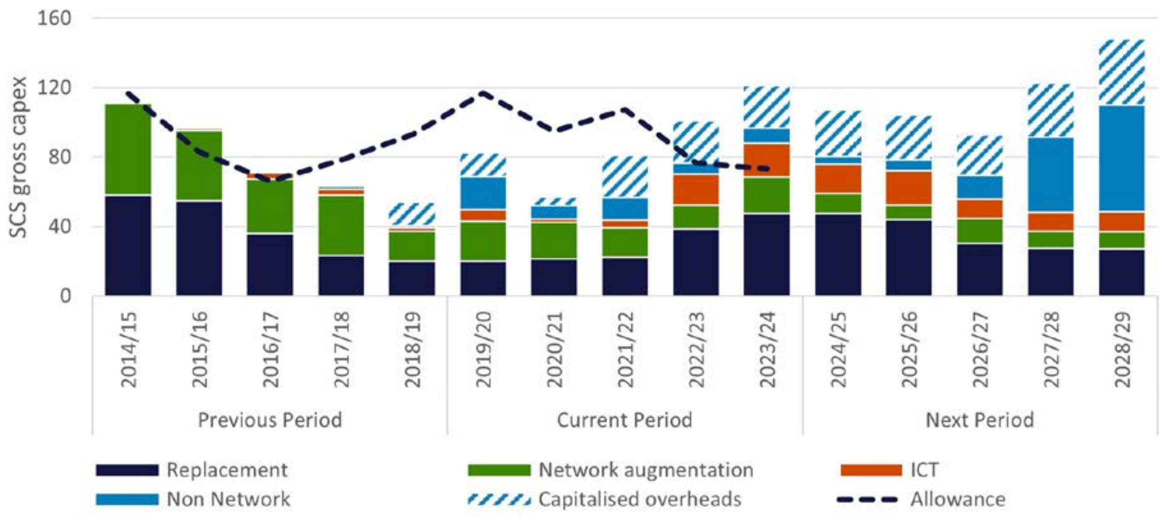
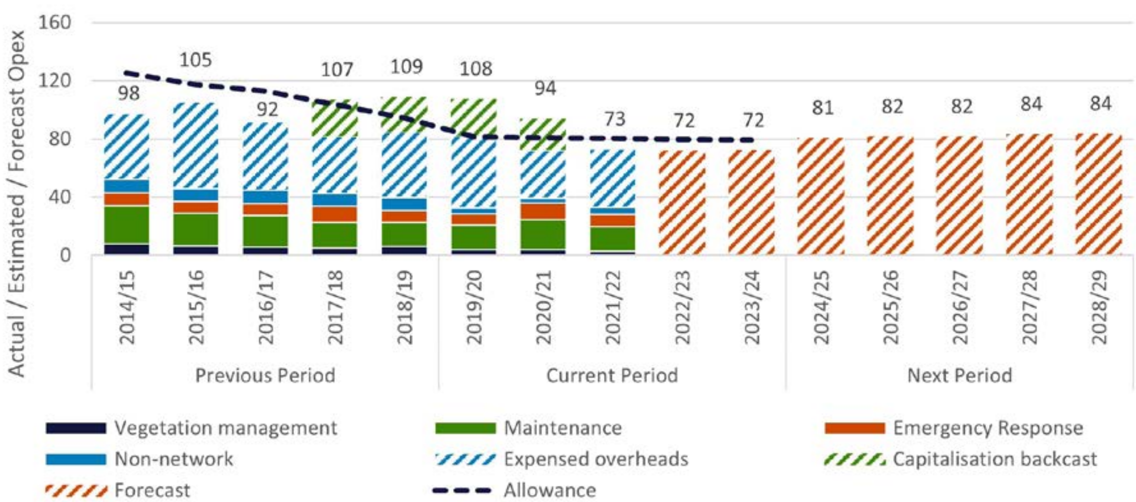


Figure 10 – Forecast and historical operating expenditure ($ million real 2024)



Customers want to keep prices down, but only to the extent this is sustainable over the long term.

Pricing and tariffs

Our overall proposal increases smoothed revenue by 7.0 per cent per annum. Using the AER's default revenue path, prices would increase by 18.4 per cent in 2024/25 and 3.2 per cent increases each year thereafter for the remainder of the period. Conscious of the impact on our customers and cost of living pressures, we have sought to develop a price path that balances the impact on customers' bills and the AER's target of being within 3.0 per cent of the building block revenues in the final year of the period. We therefore propose to adopt a smoothed x-factor price path which will see 8.4 per cent per annum price increases in the first four years, moderating to 1.2 per cent in the last year. Figure 11 shows the comparison of each price path option.

It should be highlighted that the majority of our customers[4] are covered by the NT Government's Electricity Pricing Order. This caps the amount that customers pay, with the Government subsidising retailers to cover the actual cost of service.

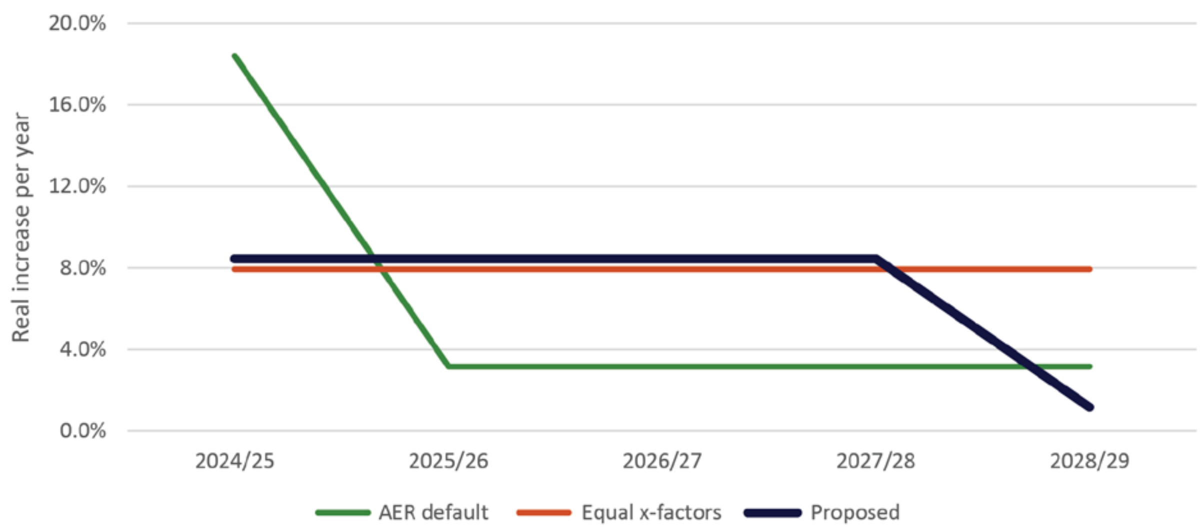
We have sought to moderate the price impact on those large customers exposed to cost-reflective tariffs by:

- Capping bill increases for the majority of our exposed customers at the average network tariff rate.
- Modifying the peak demand periods for those tariffs we propose to retain a peak demand charge for.
- Providing opportunities for cost savings through the introduction of opt-in tariff innovation trials.

In response to feedback from large users on our Draft Plan, we have better segmented our customer base with a view to continue to tailor our services to meet certain customer requirements, and provide opportunities to improve cost reflectivity. Specifically, we have:

- Introduced a new 'super user' tariff for those customers using more than 10,000 MWh per annum, reflecting feedback on the Draft Plan that simplicity, stability and certainty of energy costs were important.
- Split the existing smart meter tariff into three based on the type of connection (residential or business) and size, allowing us to facilitate any future variation to the Pricing Order.

Figure 11 – Price path options, per cent increase of average network prices



[4] Currently customers who use less than 750 MWh per annum are protected by the Electricity Pricing Order.

Retailers are supportive of the direction of our new tariff structure, and have told us they are keen to collaborate on tariff trials.

Alternative control services

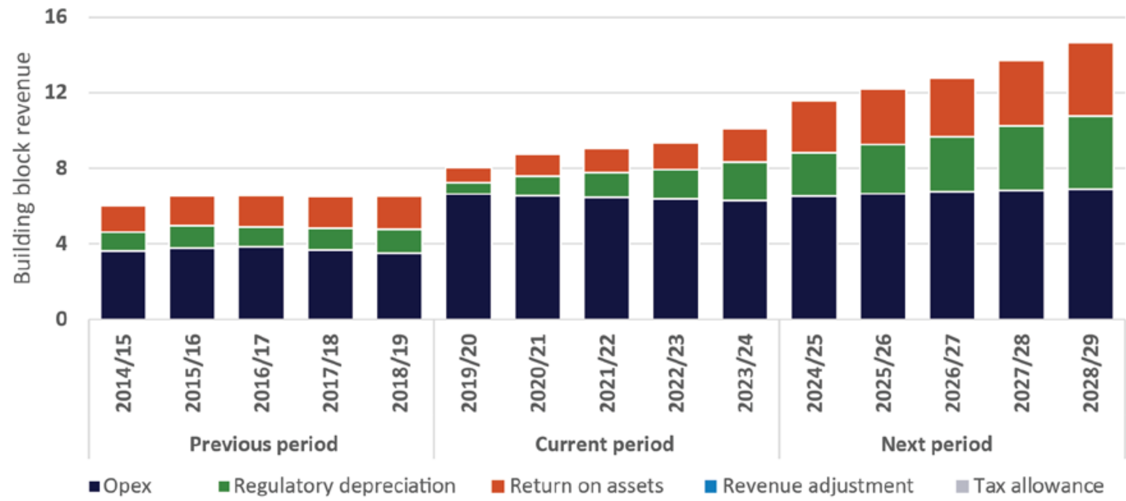
We propose to include three alternative control services (ACS) in the next regulatory period: metering services, fee-based services and quoted services. For each of these services, we identify an individual charge for the service separate to the standard network services. This means metering revenue, capex and opex are determined separately to other network services, with meters forming their own asset base.

The ACS metering revenue requirement is $64.9 million. This is entirely driven by metering services as fee-based and quoted services are charged based on the costs incurred according to the nature and scope of the service requested. The building blocks that make up the metering revenue requirement are shown in Figure 12.

The installation of smart meters and associated communications in the Territory is fundamental to making better use of our assets and increasing affordability. Smart metering technology will allow us to continue connecting rooftop solar and develop new tariff structures, and is therefore central to our future network strategy. That is why we will spend $41.5 million in capex to replace a further 24,600 old or faulty meters with smart meters and connect 2,810 new customers. We will spend $33.5 million to operate and maintain our meter population. We have included a negative step change of 0.9 per cent in our opex forecast, reflecting the efficiencies expected from remote meter reading.

Metering services are forecast to increase in cost around $133.30 per annum for a typical residential customer. This is about one and a half times the $82.30 per annum charged in the current period. Prices charged in the current period are artificially low resulting from the overestimation[5] of the number of billing meters when we developed the forecast. We market-tested our cost of providing metering services and found our forecast prices comparative.

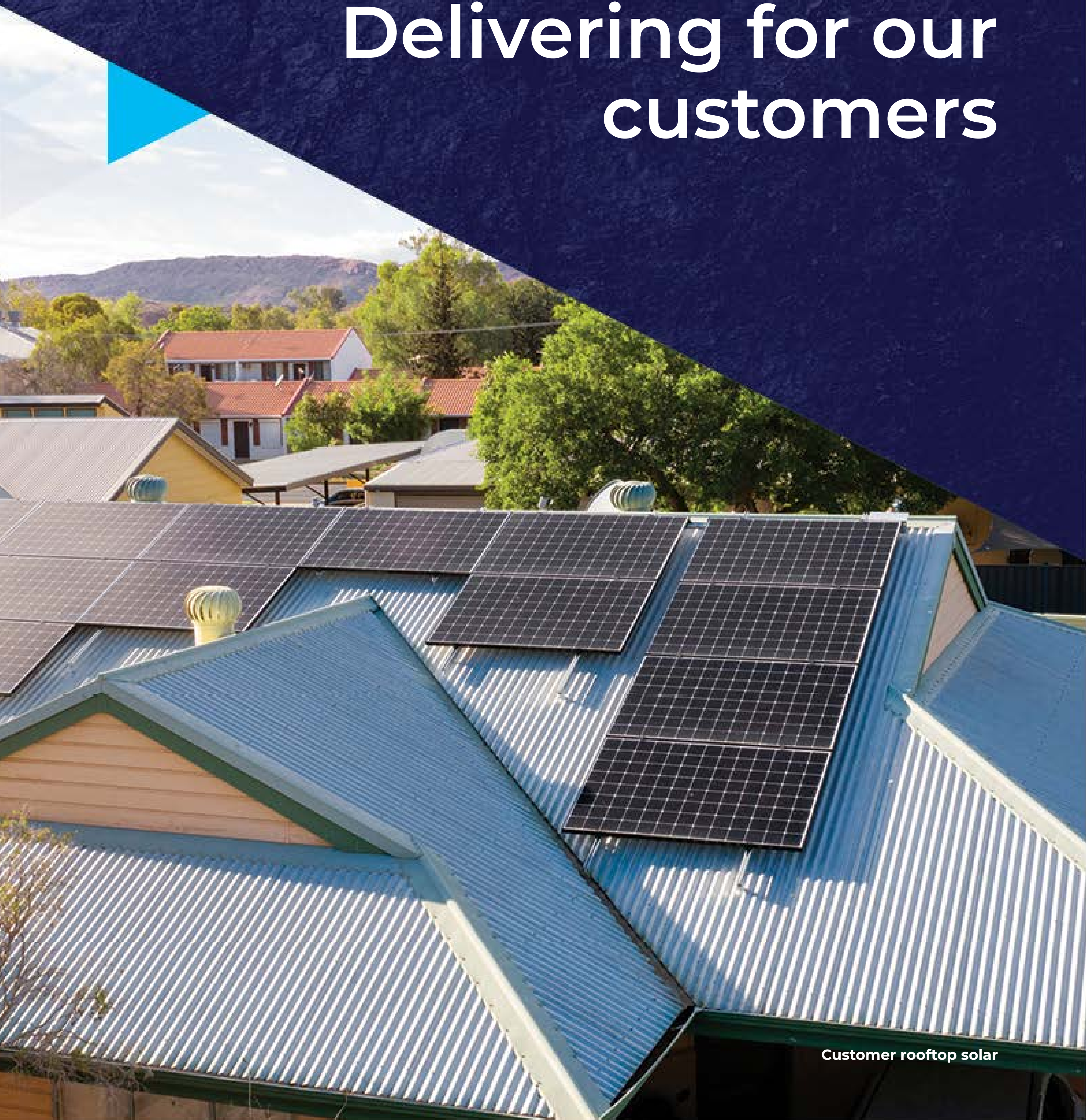
Figure 12 – Metering revenue requirement ($ million real 2024)



[5] A number of customers with three phase supply have a single phase meter for each (i.e. three meters). When developing our current period forecast, we treated each of these as an individual connection, rather than a single connection for billing purposes. This resulted in us allocating our forecast costs over a significantly higher number of customers than we actually had, which in turn under-estimated the cost of providing metering services. We have since assessed our meter population and have a more accurate estimate of the number of 'billing meters'.

Part A

Delivering for our customers



Customer rooftop solar

1. Our customers and their feedback

Our customers are central to everything we do. Thousands of homes and businesses across the Territory rely on us to provide a secure and reliable electricity supply. It is vital our customers get a say on how we deliver that service and how we invest in their energy future. This 2024-29 Regulatory Proposal has been informed by our customers and other key stakeholders, and includes a range of actions designed to address the issues that matter most to them.

By involving customers in our high level planning processes, we can help steer our business towards outcomes most valued by our customers. Territorians have become more active and engaged in the energy market, as indicated by the high levels of investment in rooftop solar panels. Clean energy is also a household topic, as electricity systems transition from fossil fuels to lower-carbon sources of energy.

1.1 How we have engaged

Customer engagement has been one of the most significant areas of improvement for us as a business. Taking on board lessons from our first regulatory review process, we have sought to engage more broadly with our stakeholders and sought their views on the initiatives we should be pursuing, and what is important to them. Our engagement has focused on understanding what our customers value, and what they expect us to prioritise.

Where practicable, rather than solely seeking the feedback of informed advocates, we have talked directly to customers about their experiences with our services. Figure 13 illustrates that we have involved customers, energy partners, and governments and regulators through a series of forums and panels. We also established a Reset Advisory Committee (RAC) consisting of major users and residential customers.

A feature of our engagement has been trying to understand how our business impacts the lives of customers. Figure 14 represents the 'Customer Lifecycle' – an overview of what customers expect and want from us. This includes when they connect, when the power is on, when power is interrupted and when power is disconnected.

Figure 13 – Stakeholder engagement segments and forums

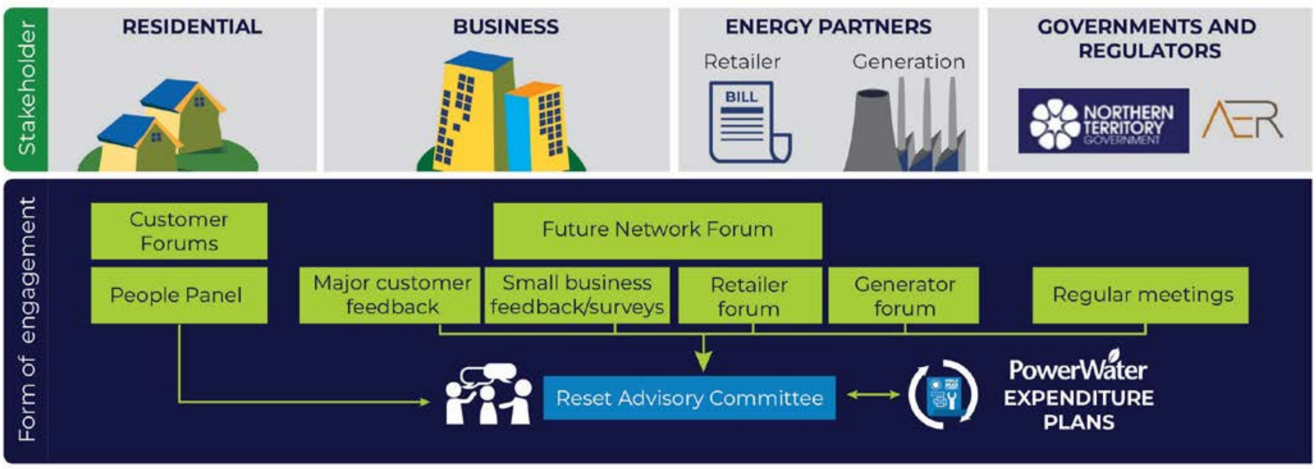


Figure 14 – The customer lifecycle

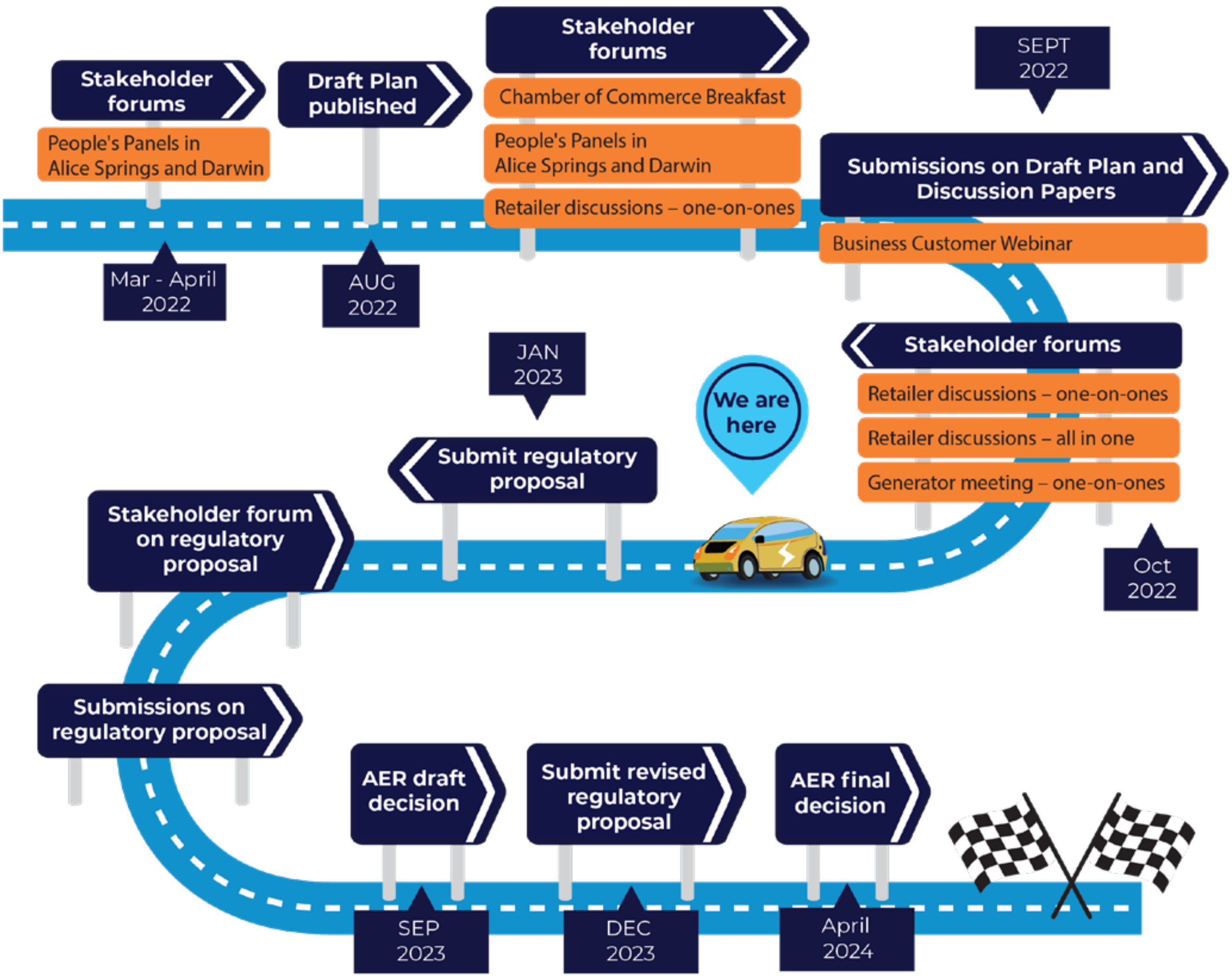
Our stakeholder engagement journey for this Regulatory Proposal commenced in July 2021, with early testing and conversations with major customers, the NT Government, residential customers, and the AER. Engagement has ramped up over the past 18 months, with particular focus on developing and then seeking feedback on our August 2022 Draft Plan. Feedback on that Draft Plan has been vital in informing this Regulatory Proposal. Figure 15 summarises the engagement conducted with regard to our Draft Plan, with the full engagement timeline in Attachment 1.01.

The engagement process has been extremely informative for us and the stakeholders who participated. However, it has not been without its challenges. Customer engagement has required a substantial cultural shift for our business, as well as for customers themselves. Our customer base is dispersed over a large area, and the appetite for engaging on energy issues – while growing – is less profuse than in other jurisdictions.

The engagement process to date has been a journey of discovery for Power and Water and for customers. We are extremely grateful to our RAC members and everyone who has participated in our engagement so far. As part of our strategy to uplift our systems and people, we are exploring ways to embed a more sustainable engagement model for our business, and to keep the conversation going in-period.

Attachments 1.01, 1.02 and 1.03 provide a more detailed overview of our engagement process, and what we have heard. The following sections summarise how we have incorporated stakeholder feedback in our proposal.

Figure 15 – Process of stakeholder engagement for the Draft Plan and Regulatory Proposal



Residential customer at People's Panel

1.2 Engagement findings and how we have responded

We captured a range of extremely valuable feedback. We have built this feedback into our plans for the 2024-29 regulatory period where practicable, as well as feeding it into our broader strategies for our business. Detailed reporting on customer and stakeholder feedback is provided in Attachments 1.01, 1.02 and 1.03. For the purpose of this Regulatory Proposal, our customer engagement findings can be distilled into two themes:

1. Our customers' vision for Power and Water
2. Customer feedback on key issues raised in the Draft Plan

1.2.1 Our customers' vision for Power and Water

In our stakeholder consultations, we unpacked what our customers thought about the future, and the role our network should play in it. A key theme has been about decarbonisation. Our customers wanted us to facilitate and actively support the shift to renewables. Our Darwin People's Panel thought we should even go further by leading change on renewables. This was consistent with the views of broader stakeholders. There was a view that Power and Water needed to have a future network strategy that sets the business up to facilitate renewables well beyond 2030.

A further theme was about helping customers make broader decisions on energy – from how to use power efficiently, to decisions on solar, batteries and electric vehicles. In particular, customers felt our active involvement in the energy industry was vital in a changing market where customers had to make decisions without a trusted advisor.

Our panels also talked about improving our communications, including developing platforms that are more active and responsive. There was a view we had to improve the diversity of our communications so that we are more accessible – from face to face, to telephone to social media. Inherent in these discussions was a view that Power and Water should keep pace with modern technology, but also accommodate traditional forms of communication so as not to leave anyone behind.

In our discussions with stakeholders, there was emphasis on not letting the network run down, with the memory of the Casuarina zone substation failure in 2008 front of mind. Our customers wanted us to think ahead on these issues and try to prevent similar failures.

Figure 16 – Vision of customers in our Darwin and Alice Springs People's Panels

1.3 Customer feedback on the Draft Plan

Customer engagement throughout the early part of 2022 was fed into our August 2022 Draft Plan. We have since tested that Draft Plan with stakeholder and customer groups, as well as via written submissions received in response to the plan.

The feedback received on the Draft Plan has heavily influenced our Regulatory Proposal. Our customers' views, along with the changing economic environment since August has helped sharpen our focus on some of the material issues for the next regulatory period.

For example, we have listened to stakeholders' concerns around the potential for being hit with unreasonably high prices in the future as we replace large tranches of critical assets, and we have taken on board their preferences for us to use better data and technology to find alternative solutions.

That's why we have changed our investment focus, reducing our network asset replacement forecasts and instead investing in our ICT systems, processes, and our people, to improve our asset management capabilities and find alternatives to traditional network solutions.

Conscious of the cost of living pressures on Territorians, we have revisited our Draft Plan and identified what we can do to improve affordability over the short and long term. This includes deferring some projects where safe to do so, but also pushing ahead with our Operating Model Program and consolidating our Darwin staff and operations into a single site, with the view to reducing lease costs and achieving long term efficiencies.

We are also making use of the contingent project provisions available under the NT National Electricity Rules to manage uncertainty around the timing of major renewable energy projects and commercial developments likely to occur during the regulatory period. This will allow us to move quickly to deliver these works when they do materialise, while avoiding the need for customers to pay for investments earlier than necessary.

More detailed information on Draft Plan feedback, and how we have incorporated this in our Draft Plan is available in Attachment 1.03. A summary of the how we have responded to the major issues raised by stakeholders is provided in Table 1.

Table 1 – How we are responding to issues raised by customers in response to the Draft Plan

Issue	What we heard	What we are doing
Affordability for low-income customers	Low income and vulnerable customers should not be left behind. Better information and incentives should be made available to help customers manage their costs and access renewable energy.	• We will continue to partner with energy providers and other stakeholders, particularly retailers, to improve the accessibility and affordability of renewable technologies. • We are currently developing a customer experience strategy, which will look at our customers' journey with us and set out a roadmap for improvement. An important focus of the strategy will be low income customers, and how they interact with us and our services. The strategy will cover the digital experience and will include a project to improve the functionality of our website and smartphone app, making it easier for customers to find information on outages and energy efficiency. • We have included costs to upgrade meter panels on older homes that contain asbestos. Low income customers are more likely to live in these older unrenovated homes. • We are also investigating options to support vulnerable customers through specific initiatives such as tariff trials and using our website to disseminate information about energy affordability and efficiency.

Issue	What we heard	What we are doing
Short term affordability vs long term sustainability	Customers have told us to keep prices affordable and do what we can to avoid price shocks in the future. Concern was raised about the impact of replacing large tranches of ageing assets.	• We have changed our investment focus. Instead of focusing purely on network asset replacement, we will invest in our ICT systems, processes, and our people, to improve our asset management capabilities find alternatives to traditional network solutions. • We are upgrading our asset management system and improving the quality of our asset data. By having better data we can make better-informed decisions on asset condition, expected life, and the optimal time for replacement. We can then extend asset lives – where safe to do so – and defer costly asset replacement programs. • We have developed a new risk quantification framework, which we are currently rolling out across our business. We will use the risk framework to continue the move away from age-based asset replacement, identify opportunities to defer timing and reduce volume of programs • Since the Draft Plan we have refreshed our demand forecast based on the latest information and project timing assumptions. This work has identified that a number of spot loads that were expected to connect in the next five years are likely to be pushed back. This will allow us to defer some of our network augmentation expenditure. We will continue to monitor and revise our demand forecasts during the next regulatory period, and will only undertake augmentation works where the timing of the new loads is more certain. • We will reduce our leasing costs and property footprint, establishing a single site for our power and water operations and support functions. • In Alice Springs, we have found a lower cost solution to alleviate corrosion issues on steel power poles. Rather than replace the entire pole, we have developed a new method whereby the base of the pole is replaced (known as rebutting). Changing from replacement to rebutting has almost halved the cost of addressing each corroded pole.
Enabling renewables	Customers told us they want to be able to connect more renewables, both large and small scale. They expect us to pursue technologies such as battery storage where this can help alleviate network costs.	• We will invest in a 'dynamic operating envelope' system that will allow households to continue to connect rooftop solar without the need for costly network investment. • We will make the necessary network augmentations to establish renewable energy hubs, should the trigger for investment arise during the period. • We will investigate the feasibility of battery storage, and intend to use the allowances under the Demand Management Innovation Allowance regulatory incentive to research, trial and study community batteries on parts of our network. Data from the studies will help inform our investment programs in the future. • We will continue discussions with our energy partners on how we can pursue low cost solutions that ensure reliability and affordability of renewables for our customers, optimising outcomes across the NT.

<table>
<tr><th>Issue</th><th>What we heard</th><th>What we are doing</th></tr>
<tr><td>Smart metering</td><td>Retailers support smart metering and want us to accelerate the program, particularly to residential customers</td><td>We recently commenced installing smart meters at customers' premises, and will continue the program over the course of the next two regulatory periods, ramping up the program over the second half of this regulatory period to reach a sustainable rate.
By the start of the next regulatory period (July 2024), around half our customers will already have a smart meter installed. Our plan for the remaining non-smart meters is to replace about half of them during 2024-29, with the remainder completed in the following period. By 2034 we will have moved our entire customer base on to smart meters, which will open up greater opportunity for efficient tariff setting, improving network utilisation, and unlocking the benefits of distributed energy resources.</td></tr>
<tr><td>Tariffs</td><td>Customers understood that while small customers do not see the network component of tariffs on their electricity bill, they still saw a need to drive more efficient tariffs.

Retailers and large users favour simplicity and certainty. All customers support incremental change rather than sweeping tariff amendments.</td><td>We propose a suite of incremental changes to our suite of network tariffs. In summary, we propose to:
Increase customer segmentation to distinguish between residential and business customers, and better align with retail competition thresholds.
Introduce a new 'Super User' customer segment for major industrials using more than 10,000 MWh pa.
Introduce new time of use charging periods and rates for smart meter customers.
Remove peak demand charging (kVA charge) for small use customers (<750 MWh pa).
Narrow the peak demand charging window for those customers with a demand charge.
Trial two new export tariffs and rebates to help manage solar PV export levels.
More detail on our proposed tariff changes is provided in Chapter 11.</td></tr>
</table>


Power lines in Katherine

2. Our business and network

We provide electricity services to more than 90 communities in the NT over a landmass of 1.3 million square kilometres. Our regulated networks in Darwin-Katherine, Alice Springs, and Tennant Creek transport electricity to more than 190,000 people. The NT's power system stands alone from other network jurisdictions, which means we are responsible for shaping our own energy future and system security.

We provide electricity, gas, water and sewerage services to townships and small communities across the NT. We have the smallest population among all Australian states and territories, and our population is dispersed over a large area. Our multi-utility structure is an advantage in addressing the diseconomies of scale in providing essential services to a relatively small population.

2.1 Our role in the NT regulated electricity systems

We are responsible for the regulated transmission and distribution networks in Darwin-Katherine, Alice Springs, and Tennant Creek. Our role is to transport electricity from generators to residential and business customers using our poles, cables, conductors, and transformer assets. We also undertake metering services to measure how much energy our customers have used, and pass that information on to retailers so they can issue electricity bills.

Until quite recently, all electricity was generated at large scale power plants. Over the last decade, we have seen more and more of our customers install rooftop solar photovoltaic (PV) generators, using our network to export their excess power to other customers. We have also seen large scale solar farms connect to our network, a trend that will accelerate as we push towards meeting the NT Government's target to have 50 per cent of electricity supplied by renewables, by 2030.

The retailer has the primary relationship with customers, managing the electricity bill and organising connection. However, as the network service provider we also have a direct relationship with customers. For example, we provide information on outages, check billing data, and provide design advice when customers (large or small) want to connect to our networks. Figure 17 illustrates our role in the electricity sector in the NT.

2.2 Our networks

We own and operate three regulated electricity networks:

- The Darwin–Katherine network supplies the city, suburbs and surrounding areas of Darwin and Palmerston, the township of Katherine and its surrounding rural areas.
- The Tennant Creek network supplies the township of Tennant Creek and surrounding rural areas.
- The Alice Springs network supplies the township and surrounding rural areas.

These three networks deliver electricity to the bulk of Territorians, are subject to economic regulation by the AER and are the subject of this Regulatory Proposal. Our regulated networks are not connected to each other, or the interconnected networks that comprise the NEM.

We also manage and maintain a significant number of smaller electricity networks that service small towns and communities, including indigenous communities under the Indigenous Essential Services program. These areas are not connected to Power and Water's three regulated electricity networks. They are classified as unregulated and are not subject to economic regulation by the AER. As such, expenditure on these networks is not covered by this Regulatory Proposal.

Figure 17 – Our role in the electricity system

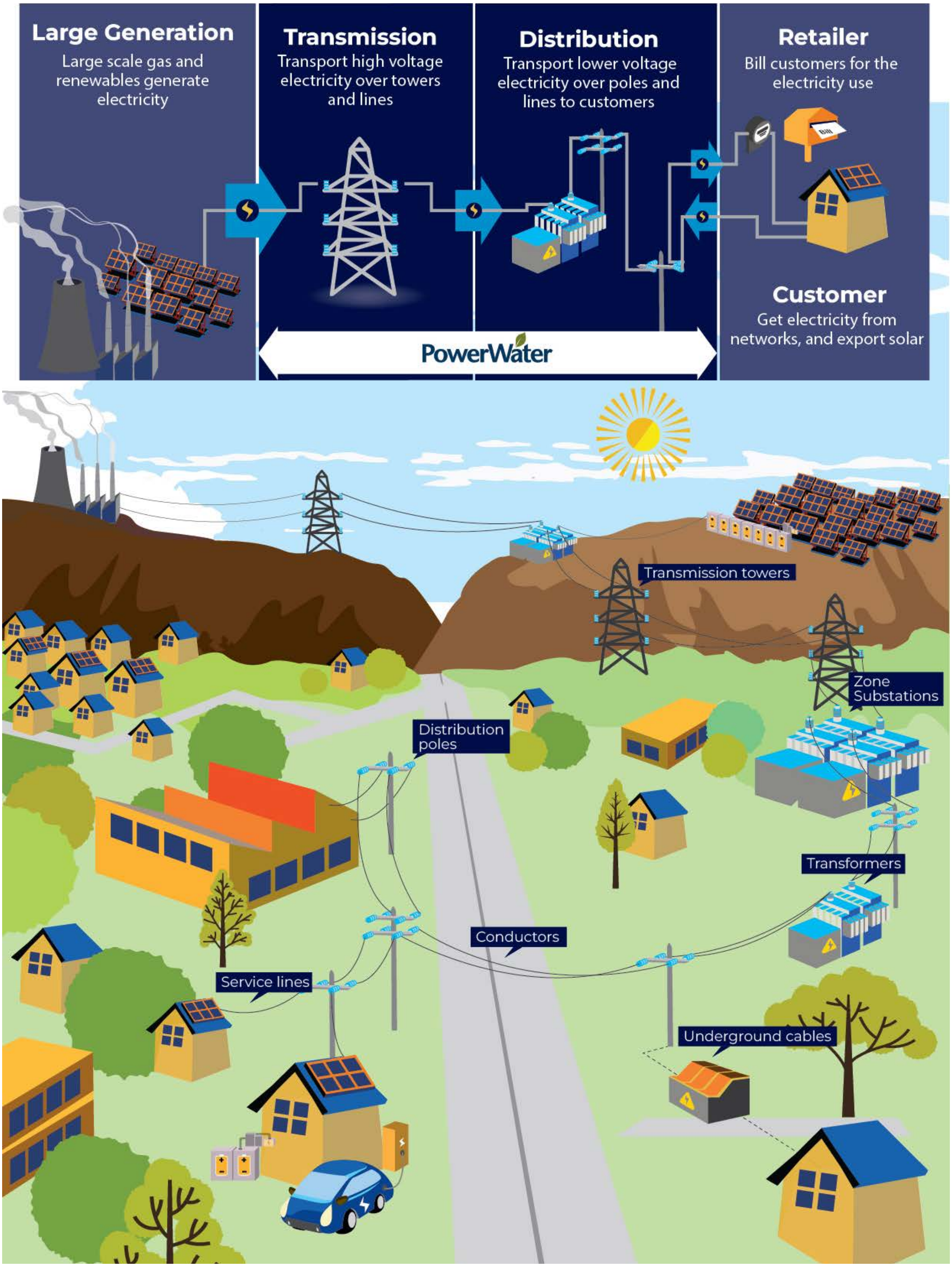
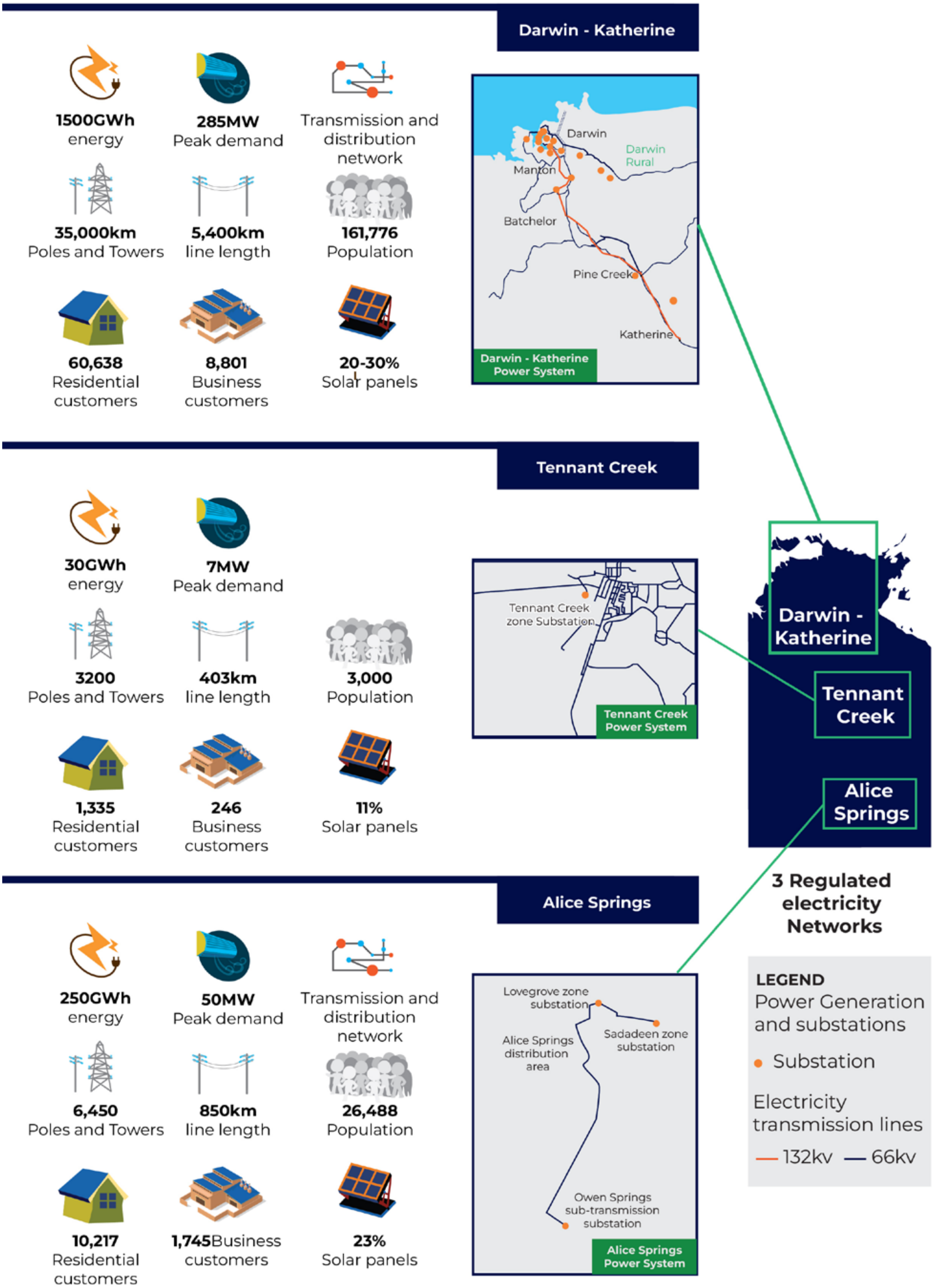


Figure 18 – Regulated areas of Power and Water's electricity network



2.3 Our operating environment

Each of our regulated networks has a different configuration, load profile, and customer base. Each network is exposed to different weather conditions and environmental factors. These differences influence how we design, manage and invest in each network. For example, the assets in Darwin are prone to cyclone and extreme events, while assets in Alice Springs face high salinity issues due to the water table.

The main differentiator between our networks and those in the NEM is size. All three of our networks are small by comparison, especially Alice Springs and Tennant Creek. Our largest network, Darwin-Katherine, has a network peak of 285 MW, and serves just over 160,000 people through 69,000 connections. However, the size and remoteness of the Territory means our powerlines cross vast distances, meaning we have to build more network to provide electricity to each of our customers.

The small scale also means we need to plan very carefully when introducing major loads or generators. For example, if a large (100 MW) mining resource wants to connect, it can more than double the load in parts of our network, potentially constraining our network and requiring huge transmission investment – akin to building a new interconnector. Our isolation also means we don't have the insurance of interconnection with other networks to help us ride through system issues when large loads trip off. This means it is vital we have sufficient data and visibility of how our network is performing, so we can continue to connect large loads and generators, and support the NT's renewable energy transition.

2.4 Our activities and services

Activities

We conduct a range of activities, from network connection and disconnection, to tree trimming and outage planning. Our network activities can be summarised into four parts of the customer lifecycle:

- **Connecting** – In the connection phase, we build new assets to meet demand from residential and commercial developments, working with our retailers to connect new customers to the grid. This includes installing new meters when a new customer connects to the network.
- **Connected** – We keep customers connected by maintaining our network assets through regular inspections and scheduled activities. We aim to replace assets before they fail and cause an outage or pose a safety risk to our workers or the public. During the connected phase, we also trim trees and shrubbery to make sure they do not contact our powerlines and electrical assets, which could lead to outages. Finally, we also read meters to ensure customers receive an accurate bill for the energy they have consumed.
- **Outages** – Sometimes, our customers may experience no electricity supply. This can be due to scheduled maintenance requiring power to be switched off temporarily, or due to an unplanned outage caused by extreme weather or asset failure. When there is an unplanned outage, we undertake emergency repairs such as during Cyclone Marcus in 2018. We also rely on our customer service team and ICT systems to notify customers of restoration times.
- **Disconnection** – When customers request disconnection, our customer service team works with the customer's retailer on ensuring a prompt service, and accurate final meter read for the last bill.

There are also many non-network activities we perform across the asset lifecycle. For example, our network planning team monitors the health of our assets to identify emerging needs. This activity is important for maintaining the reliability, safety and security of the network. Our non-network activities are directed at ensuring we have the necessary ICT, property and fleet support to perform our network activities. Like any business, we also need to perform corporate activities such as finance, legal, procurement and human resources support.

Services

The AER classifies our activities into services. This is to ensure the regulatory process does not unnecessarily regulate a market where there is sufficient competition. In its 2024-2029 Framework and Approach determination, the AER classifies our services into three broad categories:

- **Standard control services** – Services are classified as standard control if there is no prospect of competition. The AER sets a revenue cap for these services based on financing and operating costs. The transportation of energy through our network to our customers is a standard service. We discuss our plans for standard control services in Chapters 8 to 12.
- **Alternative control services** – Alternative control services relate to one-off services for an individual customer, or services where there is the prospect of competition. This includes our metering services, which are discussed in Chapter 13.
- **Unregulated services** – Unregulated services relate to areas of the business where there is sufficient competition in the market, and as such are not subject to economic regulation and are not included in this proposal.

The nature of services provided by electricity networks is constantly evolving as the sector transitions to renewables and new technologies emerge. The AER acknowledges this in its Framework and Approach determination. We will continue to monitor customers' preferences and the potential for new services during the regulatory period.

Our response to the AER's Framework and Approach determination is provided in Chapter 7, and our proposed list of regulated services for the 2024-29 period is provided at Attachment 7.01.

2.5 The type of costs we incur

Figure 19 shows the relative contribution of activities to total network costs over the last eight years, and the type of costs we incur.

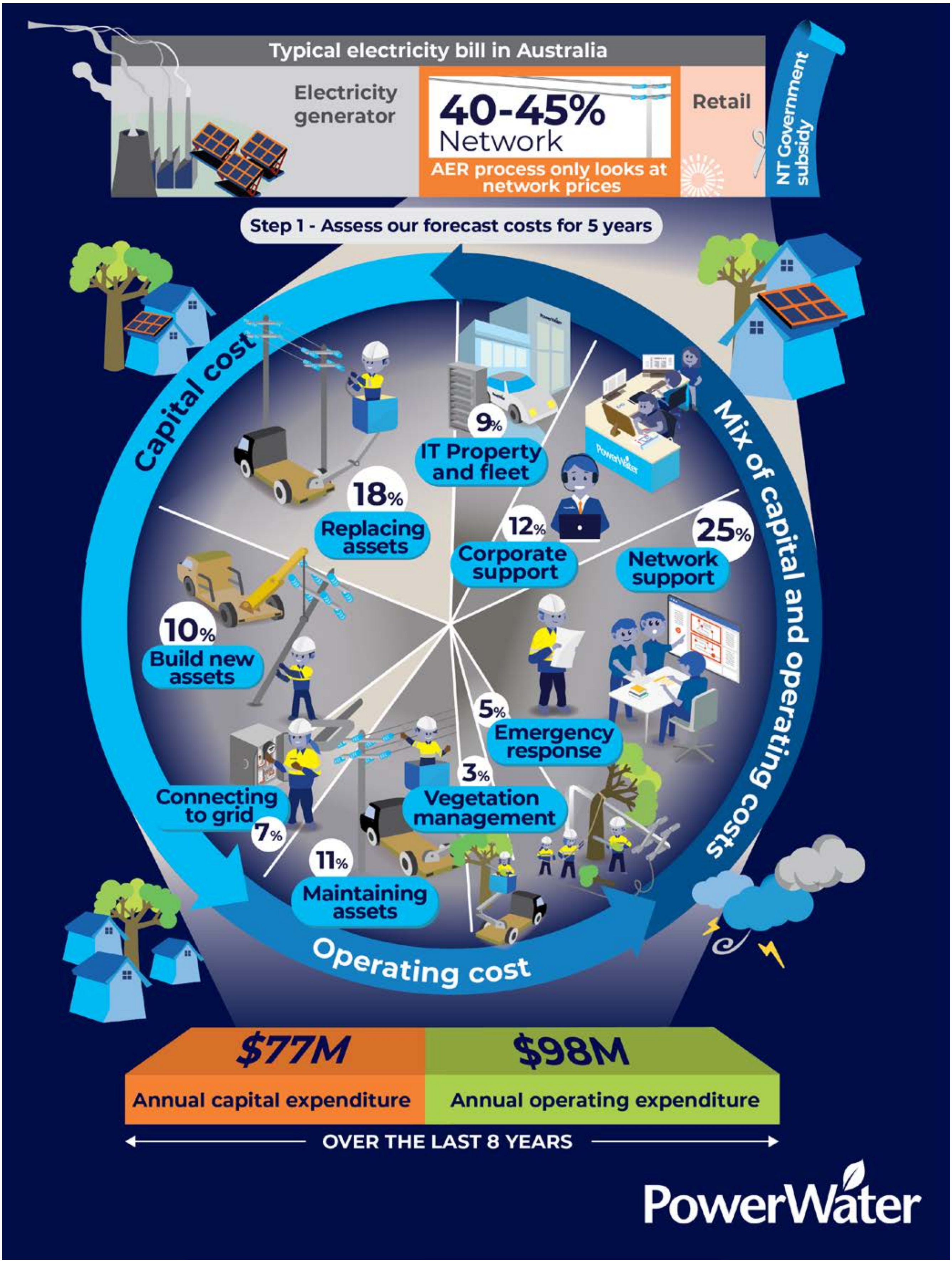
- Capital expenditure (capex) relates to building or replacing assets that provide services over a longer period. This includes replacing network assets, building new network assets, and connecting customers to the network. Capital expenditure is recovered over the expected life of an asset.
- Operating expenditure (opex) relates to regular annual expenses such as maintaining assets, vegetation management and emergency response to outages. These costs are recovered on a yearly basis.

Some activities have a mix of opex and capex. Like other businesses, we have ICT, property and fleet assets to support our network activities. Some of these costs are capex, for example the purchase of new property, vehicles or ICT equipment, while others would be opex, such as ICT support or equipment rentals. We also invest in new meters and incur opex to manage our metering functions.

We also incur overhead costs to support our network services. Overheads are essentially the day-to-day costs of running the business, and cover 'back office' activities such as planning, human resources and accounting. Network overheads cover the asset management activities we undertake to plan, control and manage the network. Corporate overheads cover finance, legal, procurement and human resources activities. We allocate overheads to each activity of business in accordance with our AER-approved Cost Allocation Methodology[6]. We allocate these costs to capital and operating expenditure depending on the nature of the activity.

[6] Note the current CAM remains unchanged from that approved by the AER in its last regulatory determination.

Figure 19 – Types of costs incurred by Power and Water over the past eight years



2.6 Factors that impact our costs

While we are facing many of the same challenges as other network operators in Australia (decarbonisation, distributed energy resources uptake, transmission investment), our business has some unique characteristics that means the way we work and the cost of providing services are subtly different to many other Australian distributions networks. These characteristics are discussed in the following sections.

2.6.1 Small scale

We have the smallest electricity network compared to other networks in the NEM on measures such as customers, energy volumes and peak demand (see Figure 20 and Figure 21). At the same time, our network is relatively spread out, meaning we need to build more network to meet the demands of each customer. As a result, when we invest in our network, the costs are spread across fewer customers. This means we are particularly sensitive to the impact of our activities on customers' prices.

It is also worth noting that despite our smaller scale, some costs – such as specific ICT systems – are fairly standard across the industry and are no lower for us than they are for larger networks.

Figure 20 – Customer numbers by distribution network ('000s)

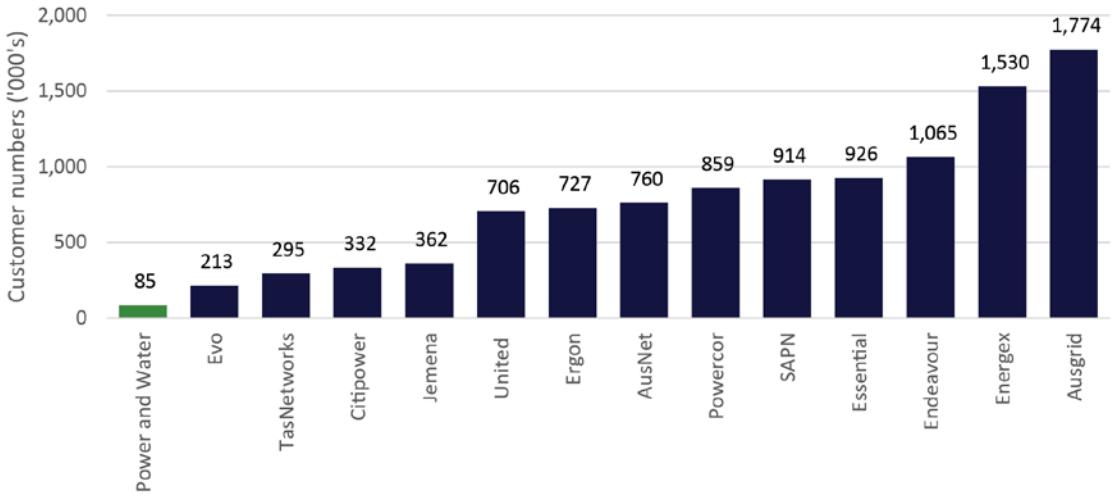
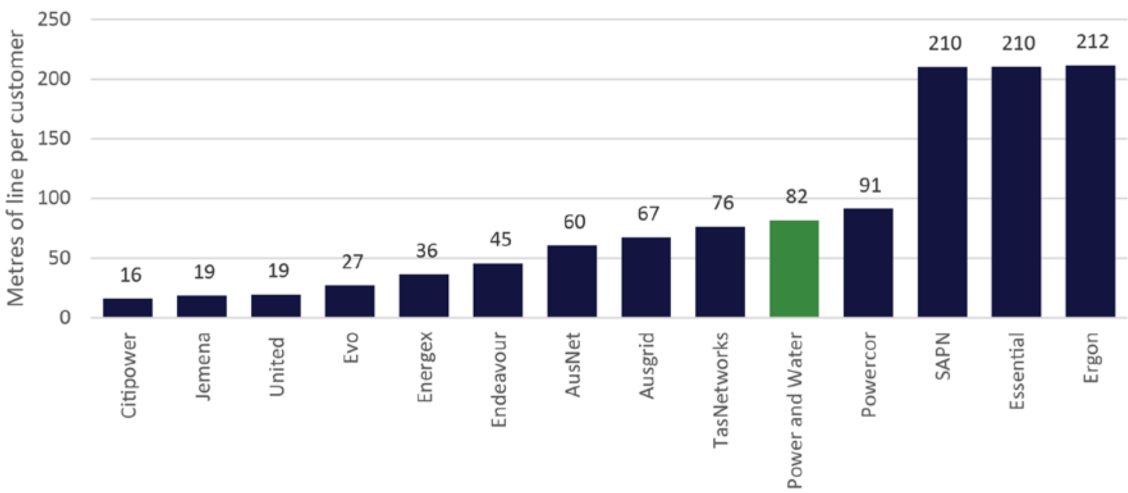


Figure 21 – Total metres of line per customer by distribution network (metres per customer)



2.6.2 Transmission network

Together with TasNetworks, we are the only businesses covered by the National Electricity Rules (NER) that has complete carriage of transmission and distribution functions. Our transmission network in Darwin-Katherine and Alice Springs is extensive, with about 400 kilometres of transmission line, 3,000 towers and four sub-transmission substations. The transmission network is the backbone of the power system, and is high value and high cost.

Being a transmission operator means we need to ensure we have sufficient capacity to allow large scale generators and large loads to connect safely to our network. Transmission works are expensive, and the costs of regulated transmission network investment is typically recovered across our entire regulated customer base, not solely the transmission-connected customers. The 'lumpiness' of transmission network investment means large tranches of transmission asset expenditure can be required at a time, which drives up revenue requirements and prices for all.

We are therefore extremely cognisant of the need to smooth our expenditure, and have historically taken a conservative approach to transmission investment in order to mitigate price shock for customers.

2.6.3 Regulatory maturity

As an organisation we are still early in our regulatory journey. We are currently mid-way through our first regulatory control period under the NT NER. Joining the national framework has helped us assess where we are as a business, and identify where we can improve. We have made good progress to date, but we still have some way to travel before we reach a level of regulatory maturity comparable with our peers in the NEM.

We are in the process of uplifting our planning capabilities, moving to longer planning horizons and more proactive asset management. Customer engagement has been a big step forward in recent years, and we will continue to refine and improve our engagement methods. The move to the AER framework has highlighted the need to improve our data quality and our ICT capabilities, which are some way behind our peers.

Making these changes takes time, money and significant cultural change. However, we are using the additional rigour and opportunity afforded by the regulatory process to make the necessary improvements and investments to get us to a level our customers need us to be at.

2.6.4 Extreme weather

We operate in extreme environments. Darwin and significant portions of the NT have high humidity in the wet season and are prone to destructive cyclones and tropical storms. We also have extreme heat compared to other places in Australia. These conditions tend to increase our emergency management costs compared to other networks and can lead to more wear and tear of our network assets. Extreme weather can also impact our field crew's productivity, especially during periods of high humidity.

2.6.5 Unique regulations

Like all other networks, we have licence and reporting obligations, and must comply with environmental regulations. We also have unique obligations that impact our costs including traversing sensitive environmental areas. This requires mitigation practices, which increases time and cost to undertake network activities. Further, the NT has many sites of cultural significance and all programs of work need to assess and mitigate against adverse cultural heritage impacts. This leads to additional costs.

Large scale solar generation

3. Moving to a clean energy future

The NT Government's vision is for renewable generation to supply 50 per cent of energy consumed in the Territory by 2030. It is an ambitious target, and one Power and Water is committed to helping make happen. We expect 30 per cent will come from large scale renewables that connect to our grid, with about 15-20 per cent coming from residential rooftop solar. To achieve this vision, we must invest in our network and systems now.

Strategic priorities

Facilitating renewables

Improving utilisation

The Darwin-Katherine Electricity System Plan sets out the NT Government's pathway to decarbonising the Territory's energy sector. The Plan sets out a range of initiatives the Government intends to pursue over the coming decade, including connecting a renewable energy hub, battery storage, and 'high spec' batteries that can provide essential system services to keep the power system secure. All these new technologies will require a reliable network connection, and we have factored these network requirements into our plans.

However, the Government-driven vision for the Territory's power system is only part of the equation. There is a drive from our customers, both large and small, to decarbonise and take advantage of the lower energy costs offered by renewables. Over the past decade, residential customers have installed around 20,000 rooftop solar systems and have told us that they want to keep on installing. Battery storage, electric vehicles, and other forms of distributed energy resources are also likely to be adopted widely over the next 10-20 years.

Major customers have their own decarbonisation targets, and are looking to electrify their operations. They want clean energy to power their businesses, and value a reliable network connection, ideally to an electricity supply predominantly generated from low cost renewables.

More significantly, these major customers are taking the lead. Many have already installed renewable generation behind the meter, and more will likely follow.

Businesses won't wait for us to make the first move. As we have seen in the residential market, where major customers see value in installing solar or batteries behind the meter, they will do so.

These changes in the way customers want to use, generate, and store electricity, will shape the way we build and invest in our network over the coming decade. That is why we have developed a future network strategy, which seeks to address these challenges and best position our network to support the NT's lower cost, cleaner energy future.

3.1 The future of our networks

The move to a clean energy future presents a fantastic opportunity. Renewable generation is low cost, low emission, and in combination with storage, has the potential to improve system security and utilisation.

By taking prudent action now to allow more renewables – both large and small scale – to connect, and to unlock the value of that already connected, we can facilitate:

- Lower bills for customers.
- A green and prosperous NT.
- A reliable and secure electricity supply.
- Customer choice and equity.

Our future network strategy sets out the high level actions we must take and the initiatives we will pursue through to 2040 to make the most of this opportunity.

We're taking a smooth and steady approach to transforming our network over the coming decades, building on the work we've already commenced. Right now, we are in the planning phase of our strategy, undertaking the necessary system studies, pilot programs and asset management planning to prepare our future works program.

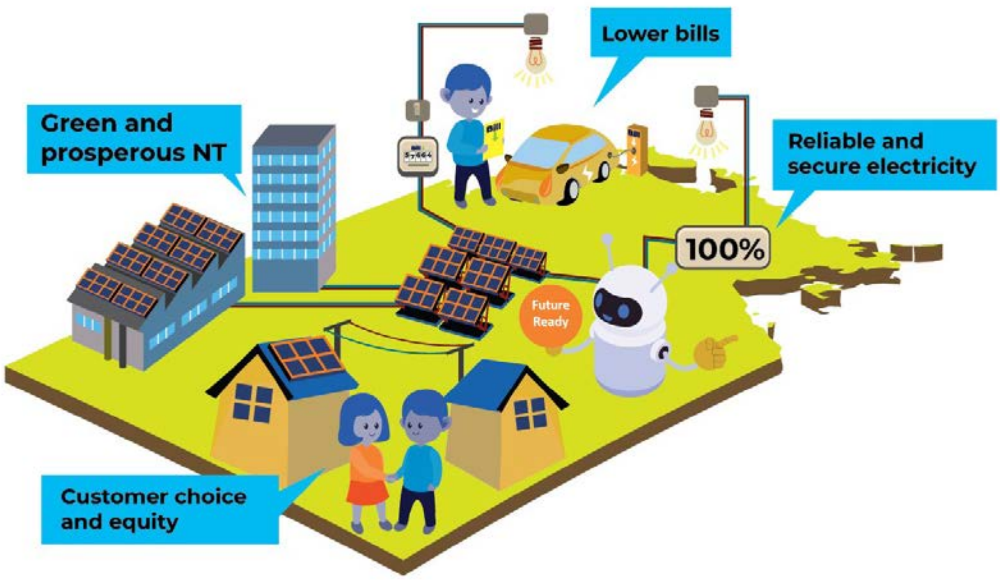
Over the next regulatory period we will enter the execution phase of our strategy, whereby we will commence implementing technical solutions and start making the network and ICT investments to facilitate renewables and set our network up to support new technologies and decarbonisation for the decades that follow. During the 2024-29 regulatory period we estimate we will spend $13.2 million of capex, and $14.1 million of opex on future network initiatives. We are also proposing $2.0 million under the Demand Management Innovation Allowance, and around $166.5 million of contingent projects that would contribute to our future networks vision.

The following sections provide an overview of the future network challenges and our proposed actions.

3.1.1 Lower bills for customers

The move to renewables isn't just about decarbonisation. It's about lowering energy costs, and cheaper bills for NT customers. Renewable generation is generally accepted as the lowest cost form of new power generation, even when accounting for firming and system integration costs.[7] While there remains a role for gas-fired generation in the NT, it makes economic sense to complement it and over time substitute it with cheaper, cost effective renewables. Having the ability to dispatch more low cost, large scale solar PV generation into the NT power system will bring the wholesale electricity cost down, resulting in lower bills for customers.

Figure 22 – Objectives of our future network strategy



[7] CSIRO GenCost Report 2021-22.

To make the most of the opportunity presented by large scale solar, as the network operator we need to address two fundamental questions:

- Where should new large scale renewables seek to connect on our network?
- How do we maximise use of the large scale renewables already connected?

Historically, the general rule is that a generator locates near to its fuel source; a coal fired generator would be located near a coal mine, a gas-fired generator near a gas pipeline. The same applies to renewables; you place solar where it is sunny and wind turbines where it is windy.

As a result, any new low emission generation will not necessarily be located in the same place as the existing thermal generation it is replacing. Any new large scale renewables will likely need an entirely new transmission network connection with sufficient capacity for the generator to be able to export electricity securely and efficiently.

It's a similar story for existing generation. Where large scale generation already has a connection, it is in customers' interests for as much as possible of the low cost, clean electricity it produces to be dispatched into the system. Our challenge is to enable this without compromising system security.

Transmission lines are expensive and can take a long time to build. It is important the short term increase in network costs that are necessary to facilitate new generation, does not inhibit us from accessing the lower energy generation costs renewables can deliver. That's why a focus of our future network strategy is to maximise large scale generation at the lowest transmission cost, and re-think the way we design and build the grid.

Our plan for the 2024-29 regulatory period therefore includes the following activities:

- **Uplift our transmission network planning capabilities** – During the next period we will conduct a series of system studies to better understand the capacity and constraints of our transmission system, and the optimal locations for connecting new generation and large loads. We will set out the timing and scope of network investment and replacement, including planning hydrogen and renewable energy hubs. This will include contingency planning.

  As part of this exercise, we will also seek to uplift our information sharing, connection processes and engagement, making it easier for generators and large loads to connect to the grid.
- **Contingent project for a Darwin Renewable Energy Hub** – The Darwin-Katherine Electricity System Plan specifies a requirement for a renewable energy hub in or near Darwin, accommodating almost 200 MW of new generation. The hub will feature large scale solar and battery storage, and will connect to the existing Darwin-Katherine transmission network.

  At the time of developing this Regulatory Proposal, the Darwin Renewable Energy Hub remained in planning and investigation phase, and therefore was not firm enough to include in the 2024-29 revenue forecast under the NER. However, given the reasonably high likelihood of the hub proceeding during the period, we have included it as a contingent project under section 6.6A of the NT NER, at an estimated cost of $120.8 million. Subject to Government direction on the Darwin Hub progressing and the firming up of costs and specifications, we will apply for an in-period revenue adjustment, providing detailed plans and analysis to the AER for approval.
- **Contingent project to maximise dispatch of current generation** – using the system studies information mentioned above, we will identify network solutions to help optimise the potential for existing large scale solar generation connected to the constrained Darwin-Katherine transmission line to export more electricity into the grid. This may include looking at non-traditional network solutions such as storage. The necessary system studies have not yet been concluded, however, given the high likelihood of investment being required in the next regulatory period, we have included this as a contingent project at an estimated cost of $45.7 million.

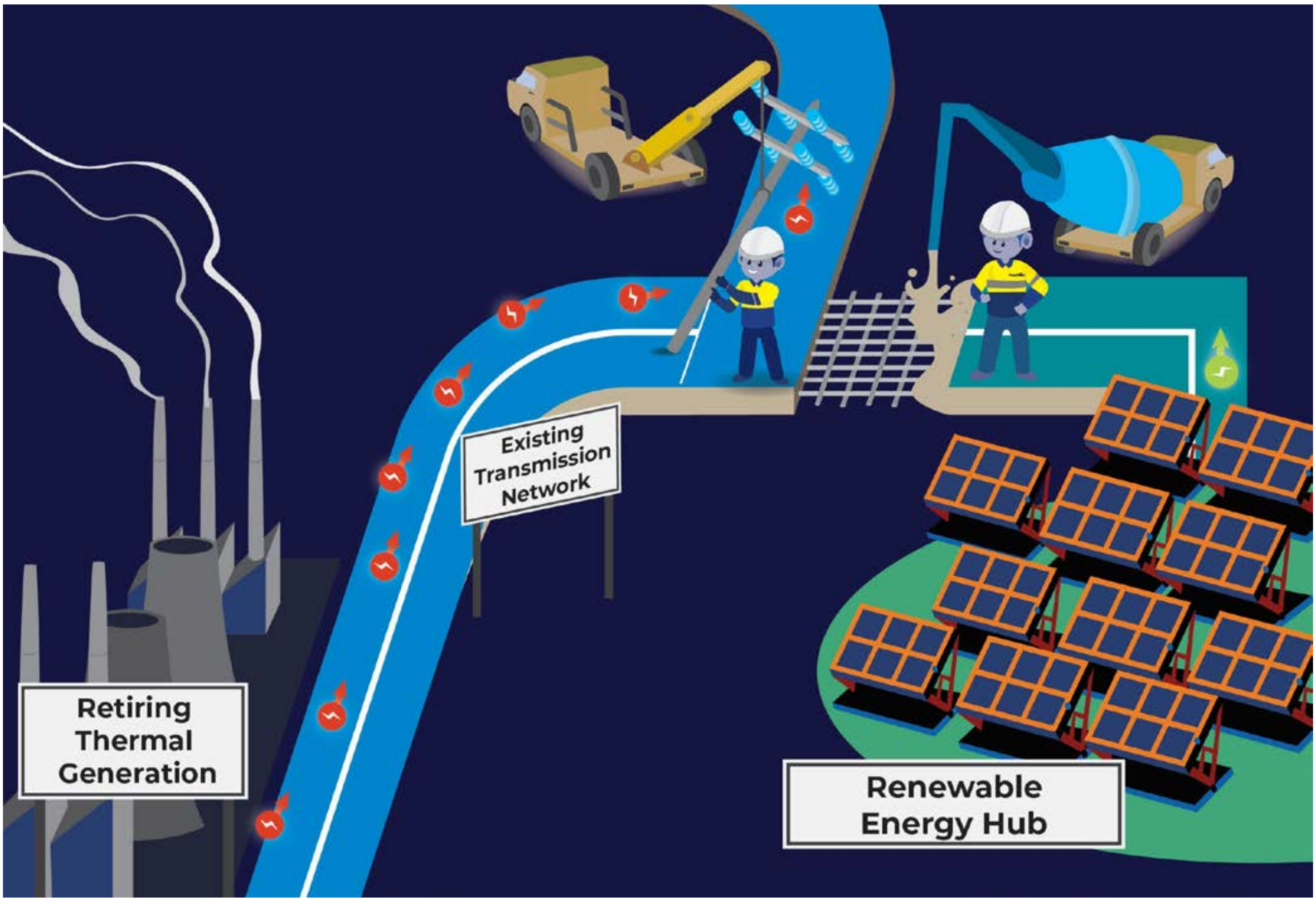
3.1.2 A green and prosperous NT

Decarbonisation is front of mind in almost all public and private sector planning. Every Australian jurisdiction has a decarbonisation target, with the Federal Government announcing the national target of achieving net zero emissions by 2050. Similarly, many large industrial customers have their own decarbonisation targets, expressing a desire to reduce dependence on carbon-emitting technology.

One of the ways Power and Water can help Government and private industry achieve decarbonisation targets is to help major businesses and industrial customers electrify their operations. Electrification can range from switching away from natural gas for heat and power, to transitioning commercial vehicle fleets to EVs.

Greater electrification will result in greater electricity demand. Under revenue cap regulation, greater demand is generally a benefit to all users, particularly if more large users are connecting. However, as a network operator we need to manage the impact of underlying demand on peak demand, which can drive the need for expensive network augmentation and affect energy affordability. Wherever practicable – and safe to do so – we should try to accommodate peak demand by making better use of the network assets already in place, rather than simply building more network.

Figure 23 – Upgrading the network to facilitate renewable energy hubs



As part of our future network strategy, we are pursuing a number of initiatives to help facilitate electrification of industries, as well as to attract more large users on to our network.
Key initiatives are:

- **Use tariff design to improve utilisation** – To offset the need for investment in network peak capacity, a key strategic priority is to encourage new and existing customers to use electricity in off peak periods that coincide with low cost solar. One of the ways to do this is via tariff design, creating specific network tariffs that provide incentives for users to consume electricity at a certain time of the day, maximising asset utilisation. During the 2024-29 regulatory period we will therefore refine our tariff structures and trial a number of innovative new tariffs (including solar PV export tariffs) to identify how we can best support electrification with a minimal increase in transmission expenditure.
- **Contingent projects for industrial hubs** – As more large customers seek to electrify and connect to our grid, it is vital they connect close to our network and in areas where there is sufficient capacity. We have the opportunity to influence when and where these loads connect, so as to minimise new infrastructure costs. We therefore propose transmission augmentation works to support two new urban districts/ industrial hubs in Holtze-Kowandi and Middle Arm, with a view to encouraging industries to connect and electrify as a contingent project with an estimated cost of $129.9 million.

Discussion with Government and prospective industries remain ongoing, therefore no costs have been included in the 2024-29 revenue requirement at this time. However, we have identified both developments as contingent projects, subject to an investment trigger in-period.

We also highlight that the uplift in transmission planning (flagged in section 3.1.1 and included in our opex in Chapter 9) will aid our ability to help customers electrify and maximise benefits to all networks users. Part of this planning uplift will include consideration of investment timing and the potential for large loads to export as well as consume electricity.

It is important to note the potential for large customers to focus on behind the meter solutions if their decarbonisation targets cannot be met through network connection. Behind the meter solutions such as large scale solar and batteries are likely to become more affordable and commercially viable for major customers. Where this occurs, it is feasible the customer may wish to export their excess behind the meter generation into the grid, necessitating a firm network connection. It is vital we factor this into our transmission planning.

3.1.3 Reliable and secure electricity

Territorians have embraced solar. Around 20,000 rooftop solar PV systems have been installed on homes and businesses throughout our networks. The combined maximum output of these systems is around 150 MW, which is almost half of the capacity of the largest generator connected to our network, the Channel Island Power Station.

The volume of rooftop solar connected to our networks is expected to continue to grow. Small scale solar is estimated to contribute around 15 per cent of energy consumed in the NT by 2030[8], and throughout our engagement sessions, customers have told us they want to keep on connecting solar. To make certain people can continue to install solar, we need to make some adjustments to how we connect and manage small scale renewable generation in our network.

[8] NT Government, Darwin-Katherine System Plan, 2021.

The system security challenge

While rooftop solar is a fantastic source of clean, inexpensive energy, without the appropriate checks and balances in place, too much of it can cause system security issues. There are three key components of electricity system security: frequency, voltage, and system strength. These three combined must be controlled to balance electricity supply and demand, allow appliances to operate safely, and make sure the system has sufficient resilience to cope with electrical disturbances.

Frequency control, voltage control and system strength are currently provided by traditional thermal generation. The gas-fired thermal generators connected to our network are synchronous machines with a spinning mass, which provide a constant, steady supply of electricity that can be controlled (turned up or down) quickly and easily. These forms of synchronous generators are ideal for managing the flow of electricity through the network and allow the system to ride out disturbances without causing power outages. They are a vital part of the NT's power system security mix.

Rooftop solar generation does not currently offer this same level of control. The rooftop PV systems in our network are passive. This means they cannot be turned up or down to help modulate frequency and voltage. The amount of electricity that rooftop solar systems produce is directly related to the amount of sunshine available. As long as the sun is shining, these passive systems keep producing electricity, and whatever is not consumed by the household or business is exported out into the network.

As more rooftop solar has been installed, the amount of electricity exported during the daytime has increased. The network can only distribute a finite amount of electricity, and because we are not interconnected with other NEM systems, this excess electricity has nowhere else go. When these passive solar systems are exporting high volumes of electricity into the grid, the thermal generators are turned down accordingly, to help balance supply and demand.

Of course, the less thermal (synchronous) generation you have operating, then the less ability you have to control system security.

The Darwin-Katherine power system requires about 60 MW of thermal generation to provide sufficient frequency and voltage control services to allow system disturbances to be managed. Falling below this 60 MW threshold places the system at risk of widespread outages if an electrical disturbance was to occur.

On most days, this is not a problem. In the NT there is usually enough demand for network-connected energy to allow sufficient thermal generation to run. However, on some days, demand met by thermal generation can fall to perilously low levels. These are known as 'minimum demand days.'

Minimum demand days

Minimum demand days can occur during the NT's dry season, when the sun is intense but humidity and air temperatures are relatively low. On such days, rooftop solar PV produces high volumes of electricity but fewer people are using air conditioning and other high consumption appliances. Put simply, the rooftop solar is producing far more energy than we need.

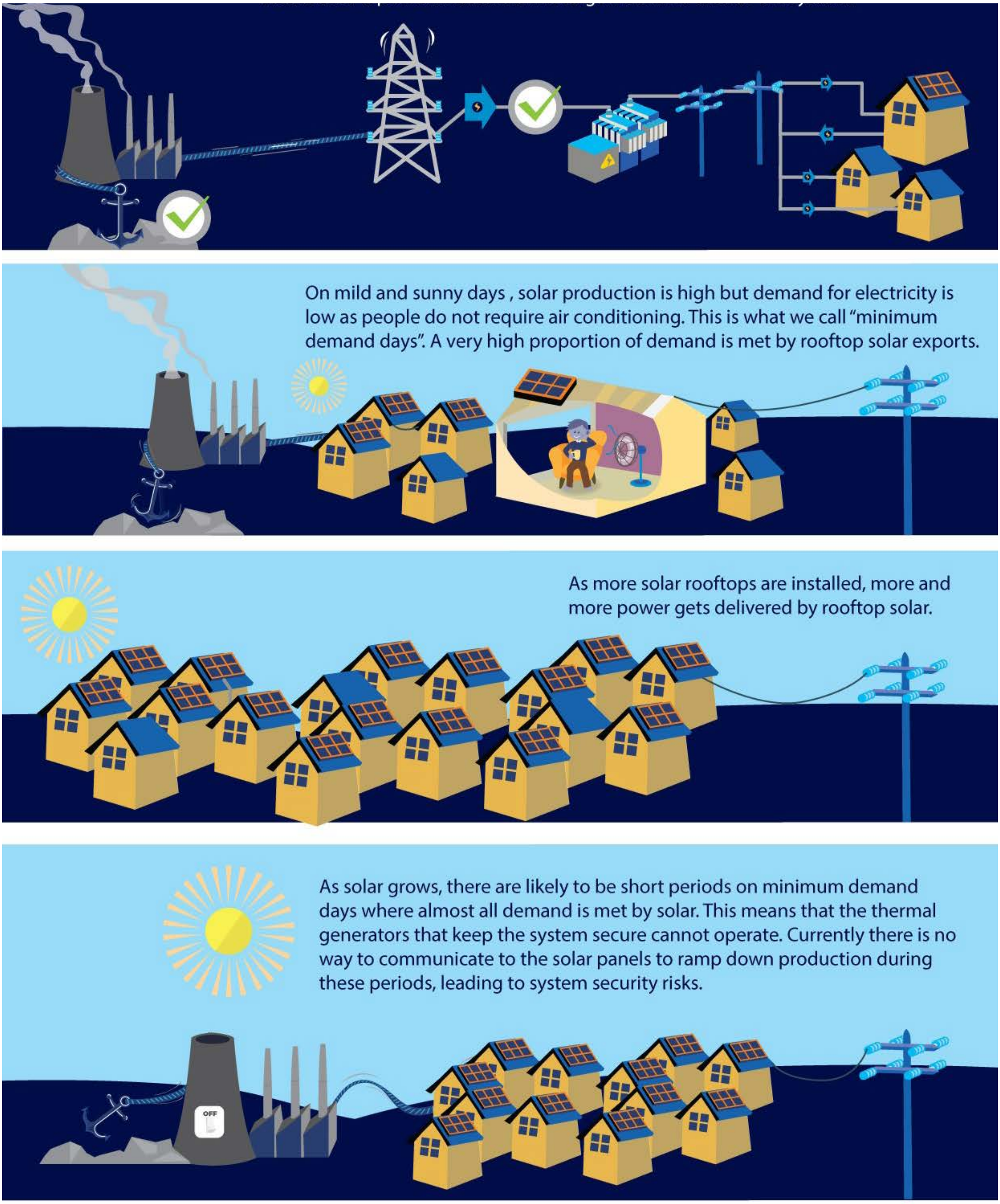
Large amounts of excess electricity are exported into the network. We can't turn down the rooftop solar PV systems, so the thermal generation has to be turned down instead. Analysis conducted for the recent Darwin-Katherine Electricity System Plan suggests that by 2030, estimated growth in rooftop solar means demand for grid-connected synchronous generation may drop as low as 28 MW. Based on the current mix of generation and storage technologies connected to our network, this would place the Darwin-Katherine system at serious risk of widespread blackouts.

What are we doing about it?

There are a range of potential solutions to the minimum demand issue. Batteries may be able to help store some of the excess electricity produced by passive solar systems, while developments in technology may lead to new forms of renewable generation and batteries that can provide the same system security services as thermal synchronous generators.

However, the most effective solution is to increase the ability to monitor and manage the output of the rooftop solar PV systems. This is something we are actively pursuing.

Figure 24 – The minimum demand day challenge



During 2024-29, we propose to undertake the following programs of work:

- **Dynamic Operating Envelope** – Operating envelopes are the limits that a customer can import and export to the electricity network. Operating envelopes are usually put in place with major loads (customers) and generators when they connect, and are designed to make sure these large customers/generators don't adversely impact network security by exporting too much or too little at any one time. These limits tend to be static and conservative, setting limits for a worst case scenario.

  However, advances in network technology means operating envelopes can now be dynamic. Dynamic operating envelopes (DOEs) are limits that can vary over time and location. Rather than being static and only catering for 'worst' case, import and export limits can be changed depending on the needs of the network at any one time. They work using algorithms (represented by robots in Figure 25) to identify when the operating envelope may change, and send signals to system controllers to limit customers' export in times of system stress or maximising it during peak demand periods. There is also scope to automate the DOEs, allowing PV system exports to be turned on or off remotely using smart communications.

  During the next regulatory period we will investigate whether DOEs can work for rooftop solar and EVs, to help address the minimum demand issue. The work will include developing a network constraints engine, uplifting the necessary ICT systems, designing standards and forecasts, and ultimately conducting a DOE trial on congested feeders.

Figure 25 – Unlocking the value of solar through dynamic operating envelopes

- **Distribution battery storage pilots** – The ability to store the energy produced by solar PV and other renewables will play a big part in addressing the minimum demand issue. Large batteries can be used to soak up the excess electricity produced during the daytime, and export it later in the evening when PV output falls away. We have therefore sought approximately $2 million of ARENA funding to trial two battery storage solutions in our Alice Springs and Darwin-Katherine networks. We will also use the funding provisions under the Demand Management Innovation Allowance to research battery storage.
- **Export tariff trial** – During the next regulatory period we will trial new export tariffs, designed to encourage customers to use more of their PV-generated electricity during the daytime, and export more during times of evening peak demand.
- **Continue smart meter installation** – To facilitate DOEs, tariff trials, and a suite of other potential innovative solutions, it is vital customers have smart meters at their properties. We will therefore continue to replace approximately 24,600 smart meters, and connect 2,810 new customers with smart meters over the next regulatory period. The balance of around 20,000 non-smart meters will be replaced with smart meters by 2034.

3.1.4 Customer choice and equity

A recurring theme throughout our customer engagement was the desire for choice and fairness. Customers told us that they want to have the option of connecting new technologies such as batteries and electric vehicles, and expect Power and Water to facilitate this. Customers were conscious however, that not everyone can afford EVs and PV systems, and that steps should be taken to give everyone the opportunity to benefit from renewables.

One of the benefits of having a small power system is the ability to scale up and improve the utility of the network for all customers. By attracting more large users and renewables to the network, we can help lower the average cost of electricity per customers and help keep prices affordable. Further, our small scale means we have more opportunity to reach out to specific customer groups and tailor suitable tariffs and services to help them manage their energy usage.

With this in mind, we are building the following initiatives into our future network strategy:

- **Optimise EV and appliance charging** – Our plan is to make the network 'EV ready'. We want to make it easy for customers to own and operate an EV by having the right connection processes, standards and pricing in place. This includes trialling EV tariffs that encourage customers to charge (or discharge) their EVs at certain times of day, as well as setting standards for smart charging and identifying optimal locations for charging stations. We will also use the DOE project (discussed above) to optimise network usage with respect to EVs.
- **Energy efficiency support and access to solar for low income households** – As discussed in Chapter 1, we are working on a suite of customer service improvements. Our aim is for incremental change, targeting areas where we can have the greatest impact for a relatively low cost. One of the initiatives already under way is to provide more information to customers who are experiencing hardship on how they can manage their energy consumption and bills. At the most basic level, this involves developing clear and consistent energy information to disseminate via our website and smartphone app. However, we are also commencing work on a customer experience strategy, under which we will develop bespoke schemes in consultation with customers (and retailers) to make sure the services and tariffs we offer are fair. We are also considering broad-based demand management schemes to help control network costs and keep electricity bills affordable.
- **Encourage large customers to connect** – As a small network, we have scope to grow. Under a revenue cap regime, connecting more large customers to the network benefits all consumers, as network demand (and costs) are shared across the customers base. We have therefore developed a 'super user' tariff, designed to attract more large industries to the Territory.

Transmission lines, Darwin

4. Managing our network for the long term

Our priority is to maintain the safety and reliability of network assets, while minimising cost impact and potential price shock for customers. This has been a key theme in our stakeholder engagement. Our strategy is to uplift our asset management processes and systems, as well as our overall operating model, to make sure our network investment decisions are efficient and in the best interest of customers.

Strategic priority

Managing health of network

A large portion of our Darwin-Katherine network assets were built shortly after Cyclone Tracy tore through the NT in 1974. As a result, many of our network assets are relatively new (compared with other Australian networks) and have not yet reached the end of their technical lives.

Since the Cyclone Tracy rebuild, Power and Water's asset management strategy has been largely reactive. This means assets have generally only been replaced when:

- The asset reaches its retirement age.
- The asset fails in service.
- The condition of the asset has deteriorated such that is poses a risk to safety, reliability and the environment.

This reactive approach has kept asset replacement costs low, while managing safety and security of supply risks within reasonable bounds. However, this approach does not address the emerging risk associated with age-based replacement.

The Cyclone Tracy assets will fall due for replacement during the coming decade, with a large tranche of assets reaching the end of their technical lives at or around the same time. Replacing all these assets will drive a substantial uplift in capex, which in turn will impact our revenue requirement and network tariffs.

If we retained the reactive asset management approach, while asset replacement costs would remain relatively low in the short term, customers would be exposed to potential price shock when we reach the Cyclone Tracy replacement wave. Therefore, over the course of this regulatory period, and throughout the next, we are moving to a more quantified and risk-based asset replacement program.

The key strategies we have developed include:

- **New asset management systems to help extend asset life** – The key to addressing the replacement wall is to lengthen the lives of assets so investment can be spread out over a longer period. Over the last decade, we have vastly improved our monitoring and decision-making on maintaining and replacing assets. This has helped us to keep some of our assets in service longer than the technical life despite the inclement conditions on our network that result in greater wear and tear. We recognise that continual improvement in our asset management process such as our new risk quantification method will help us better prioritise assets so that we are replacing assets in order of highest risk.

  To that end, during the 2024-29 regulatory period, as part of our Operating Model Project we are updating our core asset management system, Maximo. Our current instance of Maximo (2012) does not provide the asset management functionality offered by the contemporary version of Maximo. A lack of asset data is a significant impediment to risk-based investment; therefore our aim is to use Maximo to construct a coherent repository of asset condition and performance data, and use that to inform a smoother replacement profile for our replacement wall assets (and others).

- **New risk quantification method** – As part of our operating model and asset management uplift, we are introducing an enterprise-wide Risk Quantification Procedure for Investment Decision Making (see Attachment 8.09). The procedure sets out a common approach for quantifying and valuing risks, opportunities, and benefits to help inform the way we invest in our assets. Adopting this risk-based approach brings us into line with most other Australian distribution network service providers. Using this method in conjunction with improved asset information and functionality offered by the Maximo upgrade, will allow us to manage the replacement wall using a more probabilistic and data-driven approach.

- **New technology and design to retire assets or identify new solutions** – New technology may provide some of the tools to help us retire rather than replace assets, or identify new solutions, keeping a lid on the replacement wall investments. For example, we are currently looking at the feasibility of microgrid solutions for some parts of our remote areas rather than re-building existing infrastructure. As our network develops to meet the needs of the energy transition and incorporate new technology, we expect to identify further opportunities to optimise asset management practices.

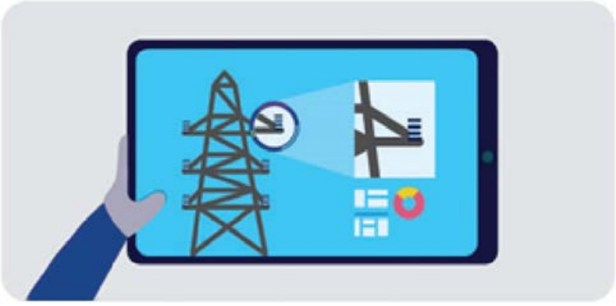

Fallen tree in distribution network

5. Uplifting our capabilities

The role of the electricity network service provider is changing. Network users are looking to decarbonise, connect more renewables, and have greater control in how and when they produce or consume electricity. Customers expect us to be part of the energy conversation, and communicate with them in a smarter and more timely way. At the same time, the regulatory framework challenges us to work more efficiently and explore newer, more cost-effective ways to deliver network services.

We need to be more than a ‘poles and wires’ business. That’s why an important part of our strategy is to uplift our systems, culture and capabilities.

Strategic priority



Uplifting our systems and people

In 2018, shortly after submitting our first regulatory reset proposal to the AER, we commenced an enterprise-wide review of our operating model, our systems and our capabilities. The review is known as the Operating Model Program, or OMP.

The origins of our operating model evolution reaches as far back as 2008, when the Casuarina outages caused widespread system blackouts and major customer disruption. Ever since then we’ve been on a journey of incremental improvement, revising our asset management practices, and making modest changes to the way we work.

The move to the national economic regulation framework helped sharpen our focus, providing a catalyst for uplifting our capabilities and initiating the OMP. The rigor of the regulatory framework has provided incentive to compare our capabilities with those of the more mature electricity distribution businesses in the NEM. The Territory is facing many of the same energy challenges as the eastern states (decarbonisation, impact of distributed energy resources), so it makes sense to look outward to what others are doing and identify how we can become more efficient.

As part of the review, it became clear that many of our ICT systems and data management capabilities were significantly below the industry standard, and in some cases would not be able to sustain the ongoing transition to renewables.

For example, while smart metering is fundamental to future network design and operation, it was clear our billing system was not suitable to manage the uplift in data necessary to support them.

As part of the OMP we therefore designed the Capability Uplift project, which identified a range of systems and processes that need to be replaced, upgraded or improved.

5.1 Capability Uplift project

The Capability Uplift project commenced during the current period. The 'Meter to Cash' project is currently in its core build phase, with go-live scheduled for 2023. This piece of work will see us install a new metering and billing system, which will bring this critical function up to the standards expected by our customers and required by the NT NER. The new metering and billing system will support our smart meters as well as enabling more accurate tariff management and billing.

Our plan is to continue the Capability Uplift project over the next regulatory period, delivering the following essential ICT upgrades:

- **Physical to Financials** – This is an upgrade to our 20-year old legacy financial management system, Oracle. By bringing Oracle up to contemporary standards, we can improve the efficiency of financial processes across the Power and Water business, and enhance our investment decision making.
- **Standardise Asset Management** – As discussed in Chapter 4, our core asset management system, Maximo, is functionally obsolete. We will therefore upgrade Maximo and standardise our asset management practices across the business. This will allow us to move more smoothly to proactive, data-driven asset management, which will help us optimise our asset management expenditure.
- **Optimise Service Delivery** – This program is dependent on the Maximo upgrade, and will drive improvements to our work planning, scheduling and close out processes. This is particularly important given the increase in program delivery required over the coming decade as we replace and refurbish our aging asset base.

The Capability Uplift project is an enterprise-wide initiative. An advantage of being a multi-utility is our ability to procure and develop new systems that can be deployed right across the organisation, improving productivity and allowing us to share costs across the business units. This means our regulated electricity business benefits from accessing systems and applications at a substantially lower cost than if it purchased them as a smaller, standalone business.

Costs for the program are allocated fairly using our AER-approved Cost Allocation Method (CAM) . This ensures network tariff customers only pay for the portion of these systems that are actually used by our electricity business.

Power and Water engineers


Power and Water operations staff

5.2 Culture and regulatory maturity

As an organisation we are still early in our regulatory journey. We are currently mid-way through our first regulatory control period under the NT National Electricity Rules. Joining the national framework has helped us assess where we are as a business, and identify where we can improve. We have made good progress to date, but we still have some way to travel before we reach a level of regulatory maturity comparable with our peers in the NEM.

We are in the process of uplifting our business planning and forecasting capabilities, moving to longer planning horizons, with a greater focus on delivery and customer service. Customer engagement is one area that has taken a big leap forward in recent years. The stakeholder engagement that has informed this Regulatory Proposal is substantially greater and more inclusive than during the first regulatory review process, and reflects our growing maturity under the regulatory framework.

Despite the incremental improvements in our regulatory maturity, we still have lots of work to do if we are to successfully adapt to the change happening to our business and right across the energy sector. One of the keys to success is cultural change. To help shift culture, it is important we can bring our people together, and share information and resources efficiently. That's why one of the most important initiatives we propose to commence during the next regulatory period is our single site consolidation project.

Single site consolidation

Currently our Darwin-Katherine staff are located across multiple sites including Ben Hammond complex, Mitchell Centre, Woods Street, Hudson Creek and 19 Mile Depot facilities. This includes a mix of properties that we own and lease.

While we are still at the early stages of business planning, initial analysis suggests there may be a net benefit in consolidating our staff in one site by developing the Ben Hammond complex. The project comprises the construction of a multi-level office, together with associated project management costs. Total project cost is estimated at $159.1 million. The portion allocated to standard control services is forecast at $89.8 million.

We recognise this is a material investment and requires deeper analysis of benefits and costs. Initial analysis suggests the benefits include reduction in lease costs across all sites, improved efficiency of staff from collaboration, improved response to faults and outages, and improved emergency response.

6. What we will deliver

Our three regulated networks each have different characteristics, face different challenges, and support a range of different residents and businesses. Many of our services are common to all parts of our networks, such as ongoing maintenance, our customer service initiatives, and our work to connect more renewables. Other programs are more bespoke, such as working with energy partners in Tennant Creek to help reduce the frequency of load shedding, and reconfiguring the Alice Spring transmission network to help prevent future system outages.

Over the 2024-29 regulatory period we will invest $986.8 million across our three networks. The regulatory framework ensures tariffs are set equitably, and customers in Alice Springs or Tennant Creek get the same value as customers in Darwin or Katherine.

In terms of network performance, our aim for the next regulatory period is to maintain the ongoing trend of overall reliability improvement, focusing on improving localised performance for customers in pockets of the network that experience more frequent outages and interruptions. Detail of performance in each network is provided in the Transmission and Distribution Annual Planning Report provided at Attachment 8.85.

We also aim to deliver a suite of broader benefits to customers, balanced against potential risks. These risks and benefits, along with a summary of network performance is provided in the following sections.

6.1 Network performance

Over recent years, we have continued to provide reliable services to customers. During 2021/22, on average, our reliability has improved from the previous year with customers enduring 115 minutes of outages (29 minutes less than the previous year) and slightly fewer outage events. While weather can impact year to year performance, this continues our positive performance over the last eight years as seen in Figure 26.

Reliability performance varies considerably across our customer base, with outage length and frequency much higher for customers in rural networks. Our reliability improvement program focuses on areas of the network where customers consistently receive poor service, and where there are cost-effective ways to materially improve performance.

Improving reliability performance on worst performing feeders requires specific solutions to address the unique causes of outages. We will continue to monitor feeder performance and implement solutions as needed.

Many of our projects will help ensure the ongoing reliability performance of our network. In addition, we have a dedicated reliability performance improvement program to ensure we are able to make prudent and efficient investment to improve reliability where required.

Quality of supply relates to voltage disturbances that can impact a customer's energy supply and appliances. We investigate cost-effective options to resolve identified quality of supply issues. Options include distribution transformer tap adjustments, upgrading or installing additional distribution transformers, segmenting the local low voltage network between transformers, upgrading the capacity of conductors, and phase balancing.

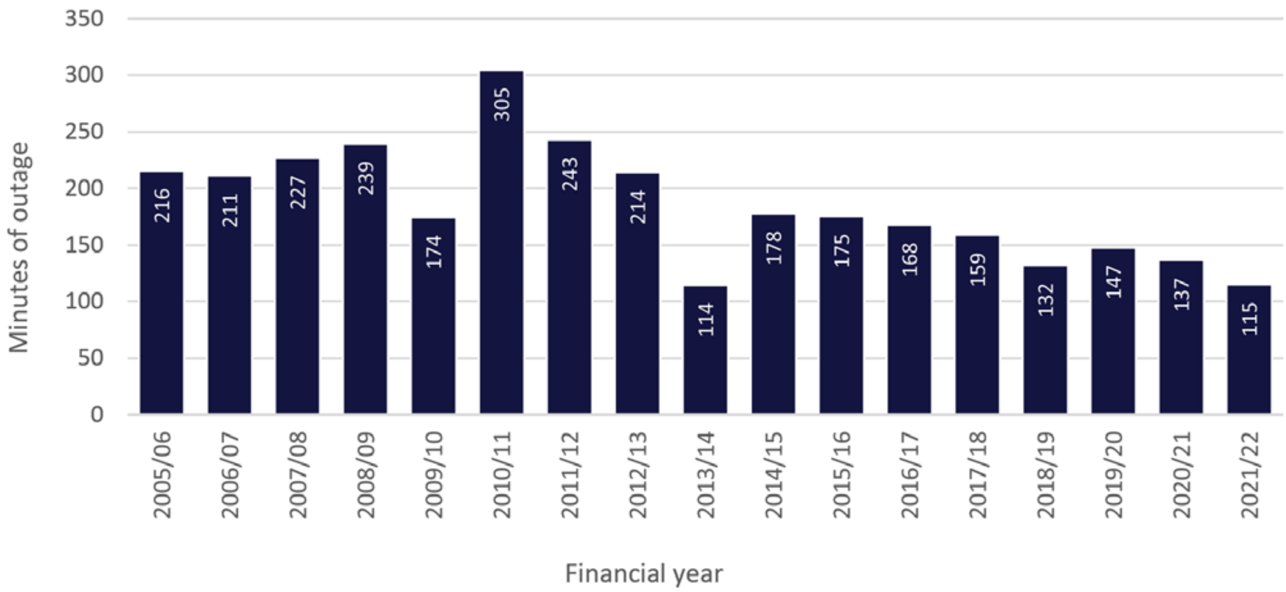
Our investment plan aims to maintain voltages within reasonable levels. This is increasingly challenging as more rooftop solar is being exported back into a grid that was designed for one-way flow. Our planned DOE solution will enable us to control residential solar PV and other energy resources to more efficiently manage voltage incursions and transient constraints that would otherwise require significant capital investment to resolve.

DOEs are being trialled in Alice Springs until the end of the 2023 - 2024 financial year. Results from this trial will be used to help inform how DOEs can be implemented across our different networks and incorporated into our standard business practices.

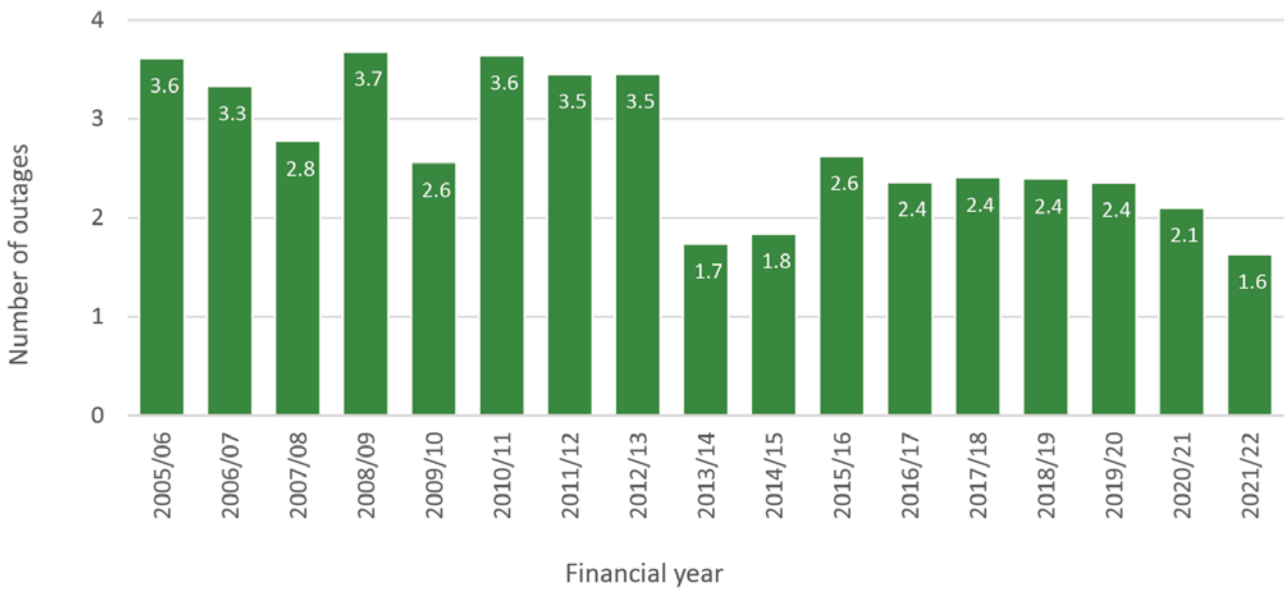
Further information on our reliability-driven capex program is provided in Attachment 8.01.

Figure 26 – Overall performance across our networks, customer interruptions to 2022

Average duration of interruption per customer



Number of interruptions per customer



6.2 Benefits and risks to customers

Our Regulatory Proposal aims to deliver a suite of benefits to our customers. Figure 27 provides a snapshot of the work we will deliver in each of our three networks.

Benefits

Key benefits we expect to deliver are as follows:

- Improved choice and ability to manage bills through tariff improvements and trials.
- Customers can continue to connect rooftop solar.
- Unlock up to 200 MW of large scale renewable generation.
- An improved customer experience.
- Better reliability for customers currently experiencing frequent interruptions.
- Improved power quality.
- Technology trials to help facilitate batteries, electric vehicles and other distributed energy resources.
- More accurate metering and improved data for customers (via smart meter installations).
- A smoother and optimised asset replacement program, helping smooth network costs over a longer period.
- Improved data quality and security.
- Support for Government energy policy, including renewable energy hubs and industrial zones, helping bring new industries and jobs to the NT.

Risks

While our proposal is designed to mitigate a range of potential risks that may occur, there remains an inherent level of risk that may arise from unforeseen events or external factors. Key risks customers should be aware of that relate to our proposal are summarised below:

- **Sensitivity to market conditions** - The changing economic environment has potential to increase financing costs, which may in turn impact network tariffs. There is a risk that we would have to reprioritise or change our plans in order to mitigate price impact for customers.
- **Potential for higher asset management costs** - We plan to mitigate large spikes in investment by extending the lives of assets through using better asset data and asset management systems. However, there remains potential for some our network assets to require replacement earlier than we have assumed.
- **Pace of change** - There is a risk of decrease in network performance and or service quality if electrification of industries and transport (for example EV uptake) occurs faster than we expect. Similarly, there is a power system security risk if minimum demand falls rapidly before we can install our dynamic operating envelope solution.
- **Cyber security** - Even when we get to security protocal 2 (SP2), the threat of cyber attack for all businesses remains real and increasingly sophisticated.
- **Resource risk** - Though we have ramped up our delivery capabilities and are investing to improve our culture, the challenge of attracting and retaining expertise in the NT remains.
- **Unforseen events** - We may need to reprioritise programs or materially change our expenditure profile as a result of unforeseen events, such as a major cyclone, pandemic, or a Government direction that impacts our structure or accountabilities.

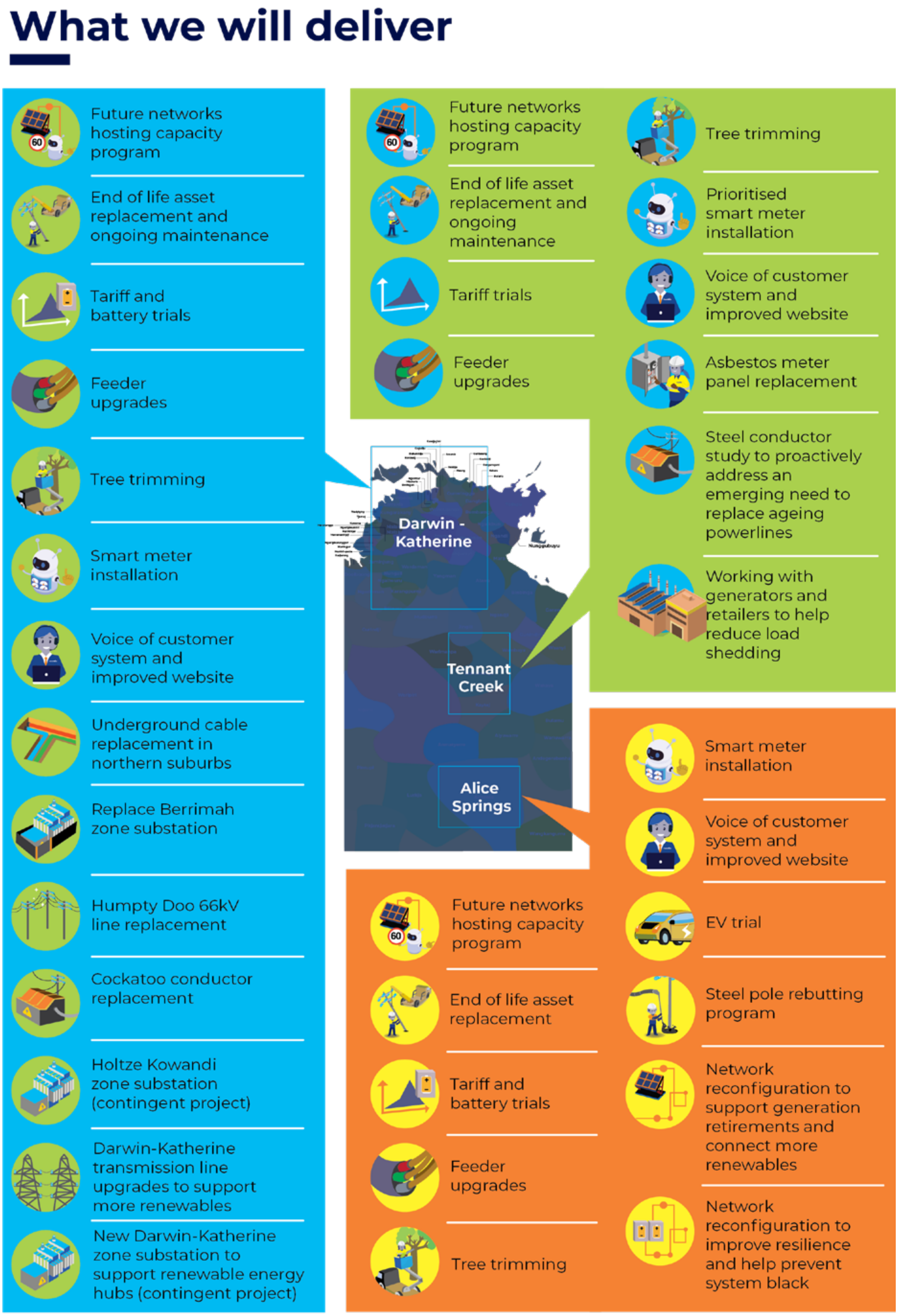
Nothwithstanding these risks, we are confident our proposal, if approved in full, will allow us to mitigate these risks and manage any price of service impact to customers.

Our Regulatory Proposal is our best estimate of revenue and expenditure requirements at this time. Customers should be aware that the AER's determination and our actual expenditure will inevitably vary from forecast, however, the regulatory framework provides appropriate mechanisms and opportunity to manage these variations.

Most importantly, we will continue our dialogue with customers to test that the plans we put forward today remain appropriate throughout the period, and will change our projects and service offerings only where prudent to do so. As such, our investment program will evolve during the period to make certain we are providing maximum benefit.

We have already begun ramping up our delivery capabilities over the current period, and believe we have the resources and expertise to be able to service customers in all three of our regulated networks, as well as continue to serve our unregulated and Indigenous Essential Services customers.

Figure 27 – Snapshot of our works program and key projects across the three networks 2024-29



Part B Regulatory proposal

Transmission towers, Wishart

7. Response to the AER's Framework and Approach

Several key components of our revenue proposal are pre-determined by the AER through its Framework and Approach process. The AER sets out items such as how our services are classified, the form of price control, how depreciation costs are calculated, and what incentive mechanisms may apply during the regulatory period. We support the AER's Final Framework and Approach for our business, and have implemented the requirements in full.

7.1 The AER's determination

The AER's Final Framework and Approach for Power and Water for the 2024-29 revenue determination process was released on 29 July 2022. The AER's decision is to:

- Retain the current standard control classification for common distribution services.
- Add provision of stand alone power systems to the list of common distribution services.
- Include energy exports as part of the common distribution services, but do not list them separately.
- Continue to apply a revenue cap form of price control for standard control services.
- Continue to apply a price cap form of price control for alternative control services (e.g. metering).
- Apply the same suite of incentive schemes as were approved for the current period, namely:
  - Efficiency benefit sharing scheme (EBSS).
  - Capital expenditure sharing scheme (CESS).
  - Demand management incentive scheme (DMIS).
  - Demand management innovation allowance mechanism (DMIA).
  - Do not apply the following incentive schemes:
  - Service target performance incentive scheme (STIPIS).
  - Customer service incentive scheme (CSIS).
  - Use the Expenditure Assessment Guideline to assess Power and Water's expenditure proposal
  - Apply forecast depreciation to calculate the value of the regulated asset base (RAB).

As signalled in our response to the AER's Preliminary Framework and Approach, we support the AER's approach for 2024-29. We welcome the subtle changes the AER made to its preliminary position, to better reflect the NT's jurisdictional requirements and to include sufficient flexibility to accommodate new services such as standalone power systems. We have adopted the AER's final Framework and Approach and submit that our Regulatory Proposal meets the requirements the NT NER. Our response to the key Framework and Approach elements is summarised in the following sections.

7.2 Applying the Framework and Approach

7.2.1 Classification of services

Our regulated services are classified into two categories: standard control services and alternative control services.

- **Standard control services** are common services undertaken by a network service provider, such as basic connection, disconnection, network maintenance and asset management. These common services benefit all customers, therefore the costs to provide them are shared across all customers and recovered via a suite of standard network tariffs.
- **Alternative control services** are those only used by a subset of customers, or only provide benefits to specific customer groups. Examples are enhanced connection services and most metering services. The costs for these services are recovered from individual or certain groups of customers and are charged via specific tariffs. Prices for some alternative control services are negotiated directly with the customer. Alternative control services are not subject to competition (i.e. only Power and Water can be expected to provide them), therefore they are regulated by the AER, who determines whether the prices we charge for them are reasonable.

Forecast revenue requirements for standard control services and alternative control services are calculated separately.

We are comfortable with the AER's approach to classifying our network services for the 2024-29 period. The classification is broadly unchanged from the current period, and we have maintained the same approach to service and price listings.

We welcome the AER's decision to accommodate stand alone power systems in the list of standard control services. The potential for stand alone power systems in the NT is currently under consideration, and it is possible we will play an active role in providing these services.

We also welcome the AER's clarification that energy export services are already provided for under the current suite of common distribution services, and support the inclusion of essential system services in the common distribution services description.

Table 2 summarises our standard and alternative control services for the 2024-29 regulatory period. The detailed listing of service classifications for 2024-29, including service descriptions, is provided in Attachment 7.01.

Pricing for standard control services is detailed in the Tariff Structure Statement and explanatory statement provided at Attachments 11.01 and 11.02.

7.2.2 Negotiated distribution services

Negotiated distribution services are those services where prices and terms and conditions can be negotiated between Power and Water and the relevant party or parties, and do not require any direct control under the regulatory framework. These are typically transmission connection services, whereby a transmission network user seeks connection or upgrade to its transmission network connection.

We have a responsibility to negotiate prices for these services in good faith, and provide assurance to the AER and customers that negotiations will be reasonable and effective. As per the requirements of the NT NER we have established a negotiating framework, which sets out the principles under which we will negotiate with parties.

Table 2 – List of services for 2024-29

Standard control services	Alternative control services
Common distribution services (including export services)	Network ancillary service
Work related to a regulated stand alone power system deployment	Public lighting service
Type 7 metering service	Standard, negotiated and enhanced connection service
Basic connection services	Type 1 to 6 metering services

72

Our negotiation framework for 2024-29 remains largely unchanged from that approved by the AER during the 2019-24 regulatory review. We have made minor modifications to improve clarity and make explicit that the negotiating framework applies to our transmission network, however, the principles for negotiation remain unchanged. A copy of the negotiating framework for 2024-29 is provided at Attachment 12.03.

7.2.3 Form of price control

The AER proposes to maintain a revenue cap for standard control services and a price cap for alternative control services. We support this approach and have adopted the necessary forms of price control for each.

Under a revenue cap, the AER determines the total amount of revenue we can recover across the period. Prices are then set so as to recover that exact amount of revenue. Where fluctuations in demand for services result in an over or under-recovery of revenue in any one year, prices are adjusted in the following year to 'true-up' revenue and allow Power and Water to collect the target revenue via the network tariffs.

A revenue cap is a conservative and predictable form of price control, which will allow us to deliver revenue certainty and stability in the next regulatory period. All other things being equal, the revenue cap will reduce network prices if demand increases.

Under a price cap, the AER determines the maximum price we can charge for each of our alternative control services. The amount of revenue we recover then depends on the level of demand that arises for those services. While there is an opportunity for Power and Water to recover more revenue than estimated, there is also a risk of under-recovery if the expected demand for these services does not materialise.

We have applied the price control formulae as specified by the AER in its Framework and Approach. Further detail on the revenue and price cap calculations is provided in Attachments 10.01 and 11.02.

7.2.4 Incentive schemes

The AER has maintained the current suite of incentive mechanisms for the 2024-29 regulatory period. We support this approach, particularly retention of the DMIA, which provides us opportunity to test and pilot new technologies and investments.

The EBSS and CESS are well-established schemes that provide network business an incentive to outperform its opex and capex forecasts. Under each scheme, we are penalised if we spend more than our forecast expenditure allowance, or rewarded if we spend less, subject to some exclusions. Rewards and penalties are shared with customers in the form of revenue adjustments in subsequent regulatory periods.

The DMIS and DMIA are also well established schemes, which provide network businesses an incentive to apply innovation and look for efficient alternatives to simply building more network assets. This helps keep network costs lower than they otherwise would be, and sends a strong signal to electricity businesses (and users) to seek technological alternatives to traditional electricity network services. The DMIA is essentially a research and development fund, that helps businesses pursue innovative projects that have the potential to deliver ongoing reductions in demand or peak demand.

Further detail on these incentive schemes is provided in Chapter 12 and in Attachment 12.01.

We note the AER has opted not to apply the STIPIS and CSIS in the 2024-29 regulatory period. These two schemes provide rewards and penalties to encourage network businesses to maintain or improve service levels, such as network reliability and call centre performance. The STIPIS and CSIS are in effect at most other electricity businesses, however, their effectiveness relies on having sufficient historical data to allow service performance measures to be set.

While we are on a pathway to being able to report against the STIPIS and CSIS in the future, Power and Water is still in the early stages of national economic regulation and does not yet have sufficient data collection systems or maturity to be able to implement these schemes. The AER acknowledges this in its Framework and Approach.

During the course of the 2024-29 period, we will aim to uplift our data collection capabilities and maturity, with a view to being able to apply the STIPIS and CSIS in future regulatory periods.

7.2.5 Expenditure assessment guideline

We note the AER's intention to apply its expenditure forecast assessment guideline to assess our capex and opex forecasts for the next regulatory period. We have had regard to this guideline in preparing our capex and opex forecasts.

7.2.6 Forecast depreciation

At the end of a regulatory period, the total value of the regulated asset base (RAB) – our stock of regulated network and non-network assets – is calculated and then rolled-forward as the starting point for the next regulatory period. Calculating and rolling forward the RAB is a vital component of the revenue determination.

The RAB is not static. Over the course of a regulatory period, new assets are built and existing assets are depreciated and ultimately retired. As part of the roll forward method, when the RAB is updated from forecast capex to actual capex at the end of the regulatory period, it must also be adjusted for depreciation.

As outlined in the AER's Framework and Approach, the depreciation approach can be based on one of two methods:

1. Actual capex incurred during the regulatory control period (actual depreciation). We roll forward the RAB based on actual capex less the depreciation on the actual capex.
2. The capex allowance forecast at the start of the regulatory control period (forecast depreciation). We roll forward the RAB based on actual capex less the depreciation on the forecast capex approved for the regulatory control period.

As per in the current period, the AER has selected option 2, the forecast depreciation method. We support this approach. Our estimate of the regulatory depreciation revenue building block for the next regulatory period is set out in section 10.3.2 of this document and in Attachment 10.01.

Power and Water staff, Alice Springs

8. Capital expenditure

Over the next five years, our aim is to continue the uplift in capital works established during the current period. We will invest $574.8 million over 2024-29 to bring the network and our supporting ICT systems up to a standard that allow us to provide a safe, reliable and affordable electricity supply to our customers, while managing the ongoing transition to renewables.

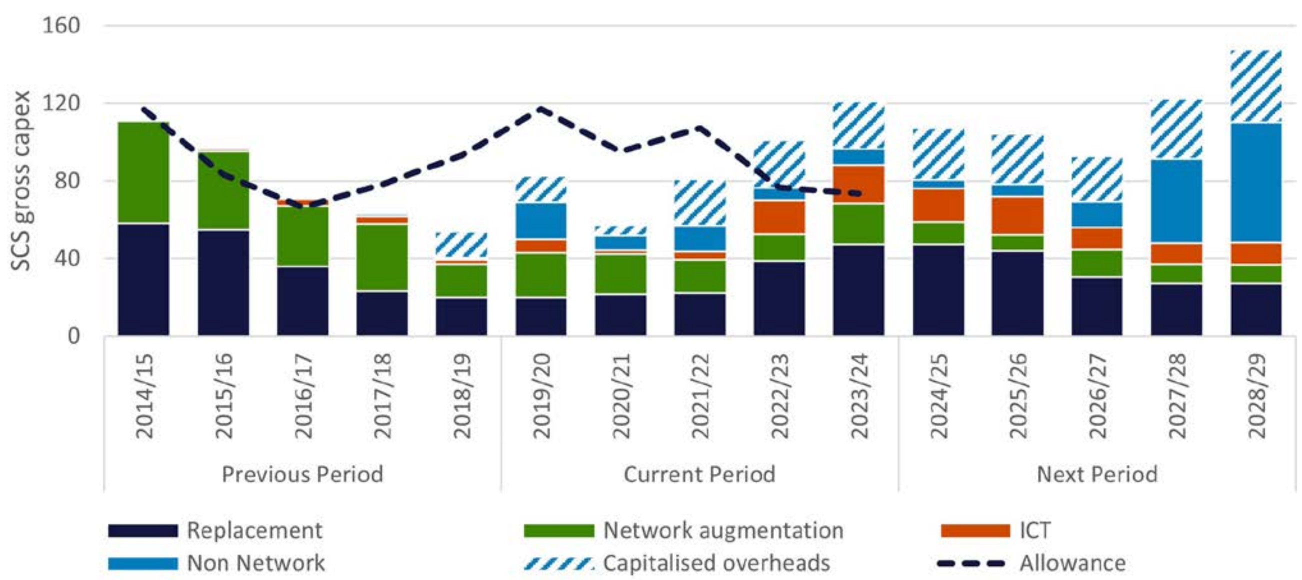
This capex forecast is $132.1 million or 29.8 per cent more than what we will spend over the current regulatory period. Figure 28 shows this uplift will build on the delivery of our program of works through to the end of the current regulatory period.

The increase in capital expenditure over the course of this period and into the next is driven by the need to uplift our asset management capabilities, with a focus on investing in our ICT systems and operating model.

Historically, investment in network and ICT asset replacement has been low. Our asset management strategy has been largely reactive, only replacing assets upon failure or where asset condition has deteriorated such that there is safety or reliability (or data integrity) risk. While this approach has minimised the impact on network tariffs historically, it has led us to a position where many of our assets – particularly our ICT systems – are well beyond their design life.

The need to uplift the quality of our asset data and our asset management capabilities is being put into sharp focus by an emerging issue relating to a large number of network assets that will all fall due for replacement at the same time. A substantial portion of our Darwin-Katherine network was constructed following the devastation of Cyclone Tracy in 1974.

Figure 28 – Forecast capex 2024-29 v 2019-24 actuals/estimated ($ million real 2024)



If we were to maintain broadly reactive, age-based asset replacement, there is a significant risk of a sharp increase in replacement expenditure as these critical network assets (poles and wires) reach end-of-life. It is therefore vital we raise our game and secure better data and analysis on these assets, so we can develop a smoother replacement program and potentially find alternatives to traditional asset replacement. This will put us in the best position to help avoid customers being hit with sudden price increases as we hit the Cyclone Tracy replacement wave.

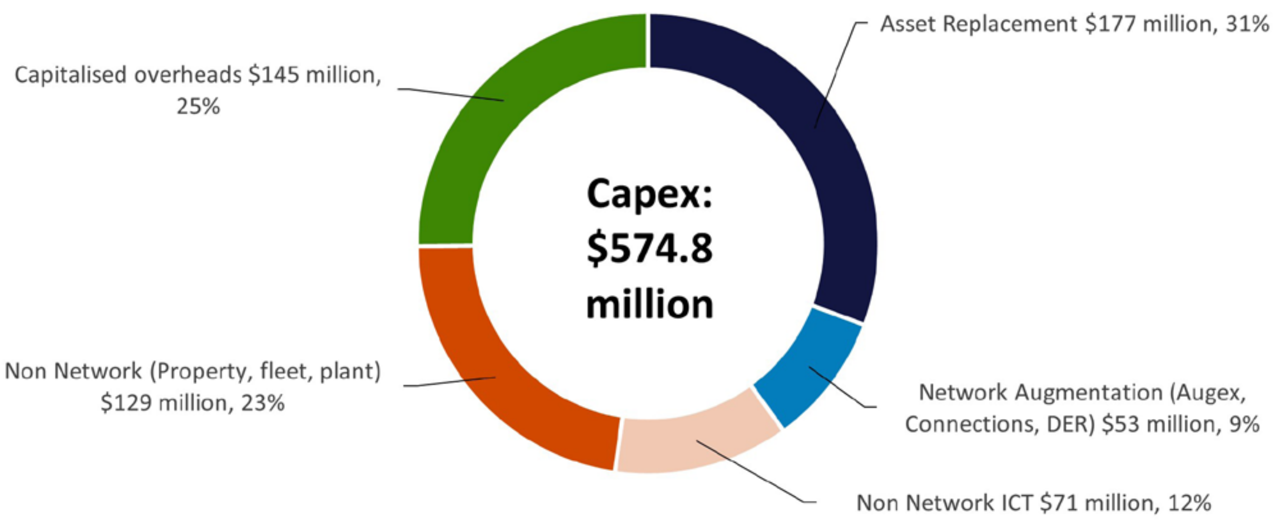
The good news is that this uplift in our asset management practices has already begun. In 2018 we commenced an organisation-wide review of Power and Water's operating model and capabilities. As part of that review, we identified a need to ramp up our delivery capability and standardise our asset management systems and processes. Work has commenced, as shown by the increasing investment in ICT and replacement capex from 2022 onwards.

Though we are not proposing a sharp increase in network asset replacement, it still comprises the biggest portion of our capex program at $176.6 million. This is a $26.7 million uplift from the current period. Our strategy is to prioritise the highest risk network assets for replacement during the first years of the next period with a view to using improved asset data and risk-based asset management practices to establish a lower and smoother level of network replacement capex in the outer years and into the next regulatory period – helping avoid price shock in the future.

To do this, we need to invest in our systems and our people, hence the bulk of our proposed capex increase over 2024-29 is driven by non-network costs (ICT, property, fleet and plant), which comprises 34.8 per cent of expenditure.

Figure 29 shows the split of capex by category.

Figure 29 – Forecast capex 2024-29, by category ($ million real 2024)



ICT investment features heavily over the course of the next regulatory period. Our ICT systems are not currently equipped to manage the expected increase in workload and programs over the next 20 years. We have identified an optimal sequencing of ICT projects as part of the 2024-29 regulatory period that will help us uplift our capabilities.

The high proportion of non-network (property and fleet) investment reflects our plans to co-locate our Darwin staff in the one Power and Water owned location. The single site consolidation project is expected to cost around $89.8 million. It will see the Ben Hammond complex upgraded to provide shared business and operational functions, before the staged conclusion of two commercial property leases.

The project is fundamental to improving efficiency of our operations. It will provide more opportunity for collaboration between teams, and coordination of projects, addressing some of our logistical and organisational challenges. Investment to develop our own accommodation will offset commercial lease, and periodic refurbishment costs and mitigate potential increasing property costs over the medium term.

8.1 Forecasting method

We submitted our Forecast Expenditure Methodology document to the AER in June 2022. The document describes the methodology we have used to prepare the capex forecasts in this Regulatory Proposal.

At a high level, there are three steps to our capex forecasting approach:

1. **Investment strategy** – The starting point for our expenditure forecasts is to understand our changing environment over a longer-term horizon. Our strategy is informed by the feedback provided by our customers on values, vision, and priorities for investment.
2. **Bottom-up plans** – We identify key drivers of investment such as asset condition, growth in network usage, support from non-network assets, and overhead requirements. We then undertake needs and options assessment to develop a bottom-up list of projects and plans over a 10 year horizon.
3. **Checks of the program** – A portfolio view helps identify the optimal mix of projects and programs that provide best value, align with longer term investment priorities, and deliver customer preferences.

Our overall approach has considered the AER's Expenditure Forecast Assessment Guidelines and the Capital Expenditure Assessment Outline for Electricity Distribution. Our forecast method seeks to align to the guidelines by:

- Presenting capital expenditure in the sub-categories nominated by the AER.
- Ensuring our project assessment provides economic justification.
- Undertaking checks such as benchmarking with peers, and comparisons to past expenditure.
- Prioritising our programs through top-down analysis of priorities and capabilities.
- Using AER models to challenge our forecasts.

We have considered the AER's Industry Practice Note on Asset Replacement Planning by applying its risk-cost assessment methods. We have applied a new risk quantification framework as part of our business case assessment. This was a key element of AER feedback in our last regulatory proposal.

We will also be presenting our ICT forecast to align with the approaches identified in the AER's guidelines including presenting our programs in recurrent and non-recurrent categories.

Figure 30 – Overview of the capex forecasting method

8.2 Forecast by category

The following sections provide a breakdown of our forecast capex for 2024-29 by category, and how it compares with 2019-24. Detailed explanation of the capex forecasts is provided in Attachment 8.01.

8.2.1 Replacement capex

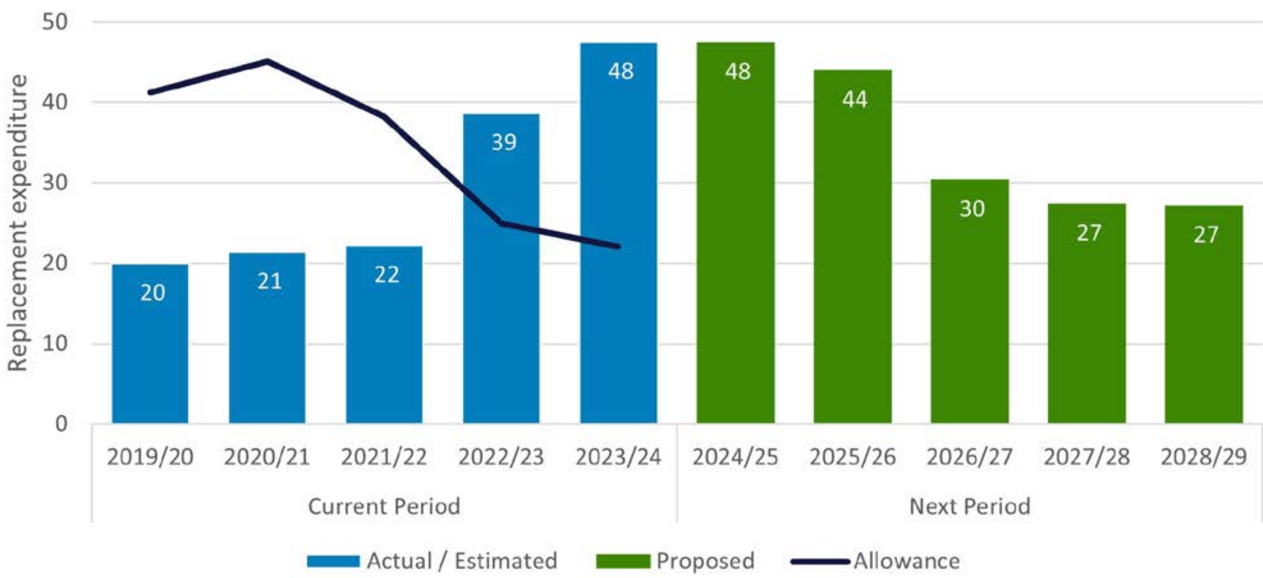
Replacement capex is to replace or extend the lives (refurbish) of our existing network assets. The primary reasons for replacing assets are degradation in condition, failure to comply with our regulations, or technical obsolescence. We only replace network assets where we demonstrate that safety, reliability, environmental and other risks outweigh the costs.

We will invest $176.6 million to replace and refresh our network assets over the next regulatory period. This is an increase of $26.7 million or 17.8 per cent (see Figure 31). As discussed, this is driven by the declining condition of our assets.

The higher replacement capex between 2023 and 2026 reflects the inclusion of major projects including Berrimah zone substation, Darwin-Katherine Transmission secondary systems, and the Alice Springs network configuration project. The latter two projects are forecast to be complete by the last year of the current regulatory period, but the Berrimah project will incur about $24.7 million in the first two years of the 2024-29 regulatory period.

Our aim is to reduce and then smooth our replacement capex program over the period, using improved asset data and risk-based asset management practices to establish a more efficient and sustainable long term replacement rate. Consistent with customer feedback, the work we do now will set us up to manage the ageing network more effectively in the long term, and help avoid unnecessary spikes in network asset replacement costs. As discussed in Chapter 4 and 5, investing in our ICT and our people is critical to us achieving this.

Figure 31 – Forecast replacement capex 2024-29 vs actual/estimated in 2019-24 ($ million real 2024)



Major network asset replacement projects and programs for 2024-29 are summarised below. The full replacement capex program, including volumetric replacement programs are described in Attachment 8.01:

- **Darwin Northern Suburbs high voltage cable program** ($28.6 million) – In the 2019-24 period, we have been progressively replacing high voltage cable in the Darwin northern suburbs with about 27 km undertaken by the end of the period. We are forecasting to replace an additional 37.5 km in the 2024-29 period. The original XLPE cables have degraded such that water ingress is leading to accelerated corrosion of the neutral/earthing wires when exposed to moisture and electrical stress. The corroded screens will increase the risk of electric shock and adversely affect our protection systems. This exposes our workers and the public to safety risks.
- **Darwin Cullen Bay to Bayview** ($5.3 million) – We currently have a program to replace low voltage cables in the Cullen Bay and Bayview areas of Darwin. By the end of the 2019-24 period, we will have undertaken 4 kilometres of replacement. We are forecasting a further 8.8 kilometres of cable replacement in the 2024-29 period.

  The cables were initially installed in the 1990s when the suburbs were first developed. Poor insulation techniques have led to water ingress in the cables. In addition, the neutral earthing system in Cullen Bay is inadequate and elevates risk to field crews through potential rises when disconnecting neutral cables to work on the assets. This is compounded by the high soil resistivity that results in poor earthing.
- **Cockatoo conductor replacement program** ($5.6 million) – We are currently undertaking a program to replace a 22 kV feeder in Lake Bennett, a rural area to the south of Darwin consistent with our 2019-24 regulatory proposal. The need for replacement arises from three issues. Firstly, the Lake Bennett feeder fails to meet compliance standards for clearance to ground. Secondly, the type of conductor is an imperial gauge 'Cockatoo' type, which gives rise to complex challenges. The conductor is showing condition issues such as broken strands and conductor damage due to burning and are difficult to repair due to the weight, gauge, high stringing tension and equipment required. This has led to deteriorating and relatively poor reliability outcomes for customers in the area. Given the radial nature of the line, there is no alternative source of supply when the conductor fails in service. Thirdly, the bat protection we use on the conductor is deteriorating due to extreme weather, leading to corrosion and risk of the conductor coming into contact with the ground.
- **Strangways to Mary River 66 kV line replacement** ($4.3 million) – This is a major committed project that will commence in 2022/23 and complete in the first year of the 2024-29 regulatory period. The project seeks to increase clearance of the 66 kV transmission line between Strangways and Humpty Doo to the east of Darwin.
- **Protection relay replacement program** ($12.1 million) – Protection relays monitor network voltages and currents and protect assets against damage when operating conditions are outside of safe bounds. We currently have over 1,350 protection relays on the network, of which about a third are already over 20 years old and operating well beyond their expected design lives.

  The drivers of the program relate primarily to the obsolescence and compliance risks of the early generation of electronic relays, referred to as static relays, on the network. The program will address a small population of remaining electromechanical relays on the network. In addition, there is an increasing need for improved recording capability at these locations to support investigations, compliance and incident response, and effectively facilitate and manage protection settings in the context of increasing renewables on our transmission network.
- **Alice Springs corroded poles ($10.3 million)** – The major targeted program for pole replacement and refurbishment is in Alice Springs. The poles are corroded from high salinity and moisture levels in the soil. This causes structural integrity issues leading to safety risks to the public and our field crews if the pole falls. We plan to replace and refurbish about 180 poles each year during the 2024-29 period. We will be targeting replacement and refurbishment of the poles that are in the worst condition and pose highest risk to the community. The project will be ongoing for the next decade due to the high volume of degraded poles.

- **Switchgear replacement** ($17.4 million) – We are forecasting $17.4 million on replacing switchgear in the 2024-29 period. This includes a program to replace high risk distribution switchgear ($5.3 million). Our volumetric model predicts that we will need to incur an additional $12.1 million on replacing distribution switchgear.

8.2.2 Augmentation capex

This is expenditure for augmenting the network due to reliability issues, compliance, and to meet increasing or changing electricity demand. In this Regulatory Proposal, we have separated augmentation capex from distributed energy resources (DER) capex and connections capex, noting they were combined into growth capex in our Draft Plan.

We expect to invest $33.2 million to augment our network during 2024-29. This is a $29.4 million or 47.0 per cent decrease compared with the current period (see Figure 32).

The decrease in augmentation works over the next period reflects that our large substations and transmission lines should be able to accommodate forecast growth in peak demand.

Demand drivers

Our demand forecasts are prepared on a locational basis, which are often termed 'spatial' forecasts. We prepare spatial forecasts for individual network elements including our transmission and sub transmission lines, zone substations, modular substations, and distribution feeders. The information is used to determine whether there are capacity constraints emerging on the network.

In summary, we have found that:

- Maximum demand in Darwin-Katherine increased in 2021/22, and is forecast to grow by close to 25 per cent over the next decade.
- Maximum demand in Alice Springs slightly decreased in 2021-22 but is forecast to increase by approximately 15 per cent over the next decade.
- Maximum demand in Tennant Creek is expected to decrease compared to last year but is projected to increase across the next decade by approximately 7 per cent.

As shown in Figure 33 to Figure 35 (on the next page), though peak demand is expected to increase in the Darwin-Katherine, Alice Springs, and Tennant Creek networks, the impact of spot loads on our system suggests much slower demand growth at each of our substations. As a result, only limited demand-driven augmentation is required at the transmission network level. We note, however, that we will still need to upgrade our 11 kV feeders leading to a small program in the 2024-29 period.

The demand forecast report is provided at Attachment 11.06.

Figure 32 – Forecast augmentation capex 2024-29 vs actual/estimated in 2019-24 ($ million real 2024)

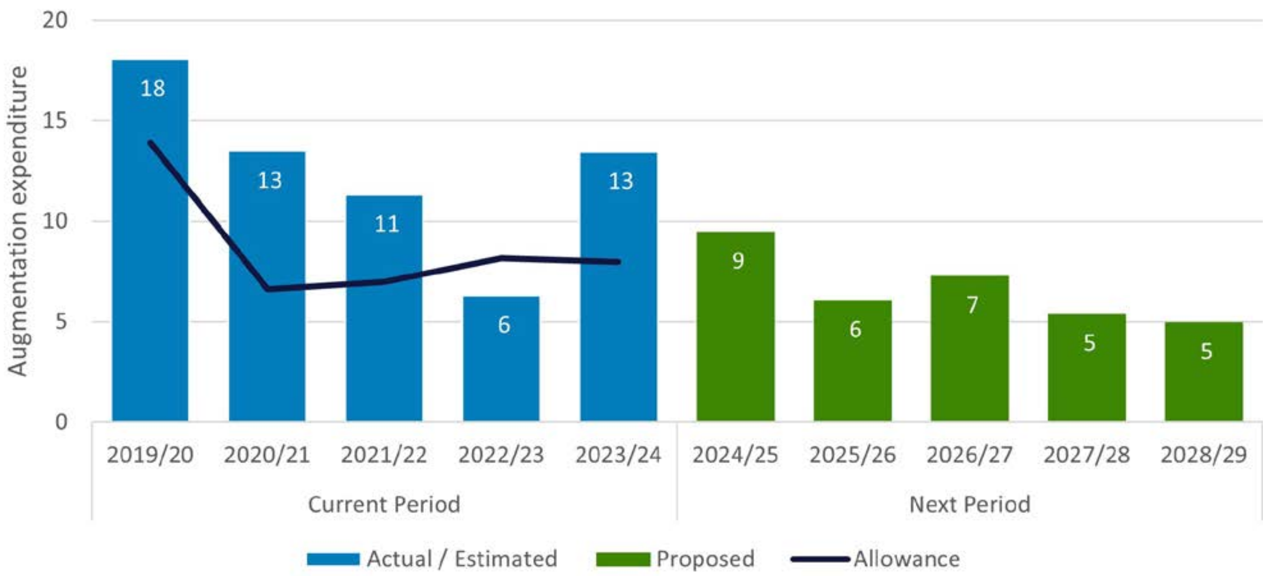


Figure 33 – Darwin-Katherine maximum demand forecasts

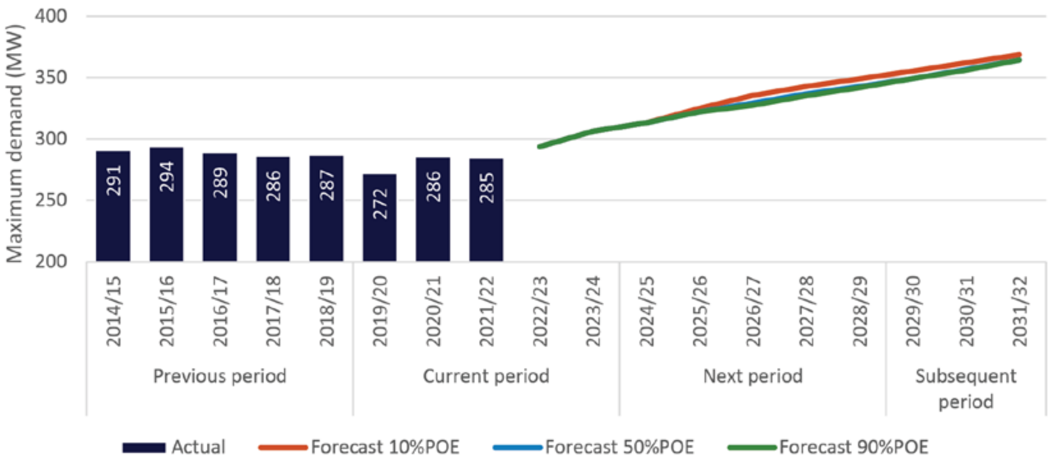


Figure 34 – Alice Springs maximum demand forecast

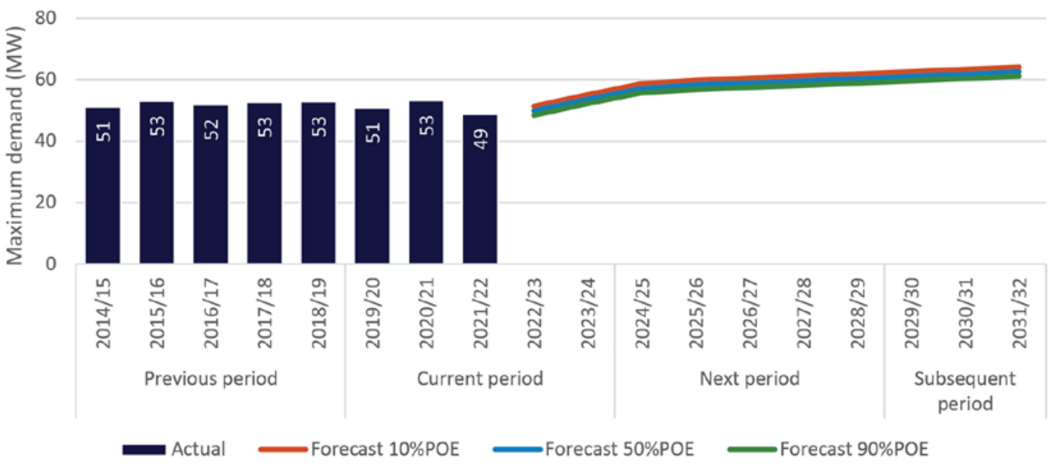
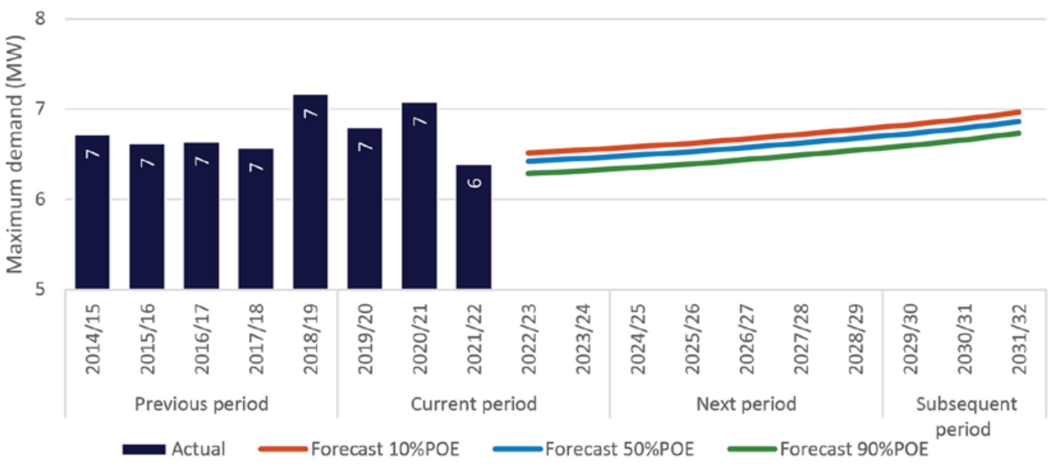


Figure 35 – Tennant Creek maximum demand forecasts



Other augmentation drivers

In respect of other augmentation capex drivers, we expect to incur similar levels of expenditure as the current 2019-24 period on maintaining our jurisdictional reliability standards, ensuring compliance with our voltage performance standards, and ensuring we comply with conductor clearance standards.

Major network augmentation for 2024-29 are summarised below. The full augmentation capex program, including DER and connections capex are described in Attachment 8.01.

- **Overloaded feeder program** ($4.1 million) – Under our Planning Criteria, we have an obligation to adhere to time limits for power restoration. This varies by type of feeder. We have identified seven feeders in the Darwin-Katherine network that are currently overloaded and have potential to inhibit our ability to restore power in a timely manner. We have identified specific works for each feeder including intra-feeder interconnectivity and improved switching capability to transfer loads within a feeder system.
- **Worst performing feeder program** ($4.8 million) – Customers in remote areas of the network, on long, radial lines are prone to service interruptions. This program targets the worst performing feeders and seeks to address reliability issues by installing automatic reclosers to clear faults quickly, installing remote controlled switches to isolate faults leading to quicker restoration for some customers, undergrounding some lines, installing covered conductors, and animal protection.
- **Uprating transmission lines in Darwin** ($5.4 million) – We have undertaken contingency analysis of our transmission lines to identify if any lines would exceed capacity. Under a critical contingency (N-1) on the line from Hudson Creek to Palmerston zone substation, the 66 kV line is expected to exceed capacity by the end of the decade. Similarly, under a critical contingency on the line from Hudson Creek to Archer zone substation, the 66 kV overhead line from Hudson Creek to Palmerston line is expected to exceed capacity by 2029-30. Options to address the overloads under N-1 include procuring additional generation at Weddell power station and uplifting the line ratings from 64 MVA to 90 MVA for each of the lines.
- **Power quality compliance program** ($4.1 million) – We must comply with quality of supply (voltage) requirements as defined in the Network Technical Code and Network Planning Criteria. This is to ensure our customers' electrical equipment is not damaged or wears out prematurely. The need for the program arises from specific voltage issues we forecast to experience in the coming years. Firstly, increased embedded generation and rooftop solar causes higher voltages on the network. In parts of our network such as Katherine, this has led to higher voltage than the prescribed standards. A second driver is under-voltage issues in some new residential and commercial developments, which we expect will heighten with electric vehicle charging.

More information on our augmentation capex forecasts is provided in Attachment 8.01.

8.2.3 DER capex

DER includes rooftop solar, energy storage devices, electric vehicles (EVs) and other consumer appliances that can flow back into our network. Over the past decade, our customers have been installing rooftop solar at an increasing rate. The network has been able to host the capacity of solar exports to date, but we have identified that by 2028, the network will face issues with minimum demand (refer to Chapter 3 for an overview of the minimum demand issue).

To address the minimum demand issue, we intend to invest $13.2 million on a major project called Dynamic Operating Envelopes, or DOEs. DOEs allow us to manage solar exports at times of minimum demand but allow customers to export at all other times in the year. The advantage of DOEs is that they allow for maximum use of low cost renewable energy, and will allow customers to continue to install rooftop solar without compromising system security. They also provide the capability for our network to better manage electric vehicle charging in the future, which is consistent with our strategic priority to better utilise the network and electricity system.

More information on our DER capex forecasts is provided in Attachment 8.01.

8.2.4 Connections capex

We are forecasting only $7.0 million of connections capex in the 2024-29 period, compared to $33.4 million in 2019-24. This reflects our moderating connections forecast (see Attachment 8.64). While we expect continued growth in larger, high voltage connections at 4.9 per cent per annum, low voltage connections will only increase by a modest 0.7 per cent per annum.

The decrease in connection capex also reflects two important regulatory changes:

1. Gifted assets are now excluded from the revenue model.
2. Reclassification of some connection services to be alternative control services.

These changes are discussed below.

Gifted assets

Over the 2019–24 period, the AER accepted our proposal to include gifted assets in our connection capex and capital contribution forecasts. This was because – at that time – the AER accepted that gifted assets were ordinarily treated as taxable revenue by the Australian Tax Office (ATO). Including the value of those assets in both gross capex and capital contributions meant that, although there was no effect on the regulated asset base as the two netted out, there was an allowance for the tax cost associated with those assets in corporate income tax building block.

However, following a 2020 Federal Court decision that effectively overturned the ATO's treatment of gifted assets,[9] the AER has revised its preferred approach. Starting with its 2021 decisions for the Victorian electricity distribution businesses, the AER no longer allows regulated energy networks to include the value of gifted assets in either the gross capex or capital contribution forecasts included in the post-tax revenue model. We have given effect to this in our Regulatory Proposal.

Reclassification of some connection services

A further driver of the lower capex relates to a change in the classification of negotiated connection services, specified in the AER's Framework and Approach determination, whereby some connecting customers will pay a separate charge as part of our alternative control services.

Under the changes, connection services other than basic connection services have been reclassified as alternative control services or ACS. Under an ACS classification, customers pay directly for the connection service rather than the works being included as part of the common distribution service funded by customers more generally through tariffs. In this respect, it is important to note that our connection costs are still at a similar level to the previous period, but that we will be recovering amounts from some customers through a different mechanism.

We have also made minor amendments to our connection policy to apply in 2024-29 to ensure alignment with the changes in classification and to incorporate changes in our regulatory obligations.

[9] Federal Court of Australia, Victoria Power Networks Pty Ltd v Commissioner of Taxation [2020] FCAFC 169, 21 October 2020.

8.2.5 Non-network ICT capex

Non-network ICT capex is investment in our hardware and software systems used to support our asset management, network operations and financial processes. We forecast $70.7 million for ICT capex in the 2024-29 period, compared to $50.3 million in 2019-24 (see Figure 36).

The majority of capex relates to non-recurrent ICT systems, which will improve our financial, asset management and service delivery capabilities. This reflects that the current systems we have in place are legacy ICT systems and do not enable us to perform as efficiently as we would like. We also are proposing recurrent capex to ensure our ICT systems remain reliable, contemporary, and cyber-secure.

The key driver of ICT capex is a sequence of investments to uplift our system capabilities. This is a key foundation of our Operating Model Program. Our core systems have not kept pace with the growing complexity of our business, new compliance requirements, and the service expectations of customers in a digital age. We have also not kept pace with other utilities in Australia, with a significant proportion of our ICT assets built about 15 to 20 years ago.

The replacement of legacy systems with upgraded capabilities is premised on delivering the following benefits:

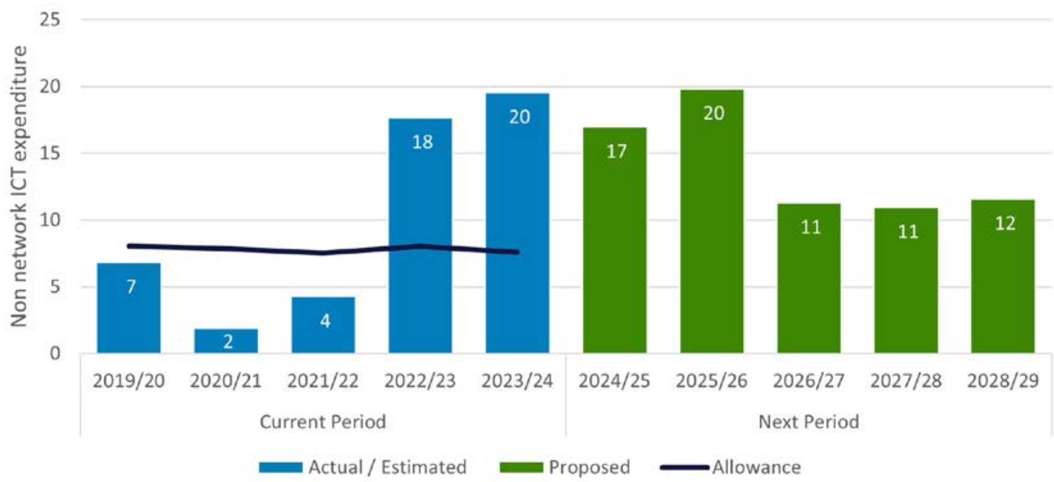
- Automate manually intensive work practices.
- Streamline and simplify our processes.
- Will support efficient business operations.
- Comply with our regulatory obligations.
- Adapt to rapid changes in our business environment.
- Meet growing digital expectations of our customers for service delivery.
- Improve our cyber security capabilities and the security of our customers' data.

Key ICT projects for 2024-29 include:

- **Operational Technology (OT) Uplift** ($21.6 million) – Our OT systems are outdated and not fit for purpose to support an increasingly complex power system. For example, our outage management system is obsolete as are components of our SCADA system. The main driver for the uplift in OT capability is to enable Power and Water to effectively manage the expected growth and demand of renewables connecting to the grid (i.e. given the NT's very high solar uptake) and the impact of this on the network.

  The OT Capability Uplift project will provide a single, integrated solution with tools to remotely monitor and control the network, better manage planned and emergency outages, and to optimise power-flow management, fault location analysis, fault isolation and fault restoration capabilities.

Figure 36 – Forecast ICT capex 2024-29 vs actual/estimated in 2019-24 ($ million real 2024)



- **IT Capability Uplift** ($20.8 million) – This expenditure is to uplift core IT systems across multiple business workstreams including financial, metering, asset management, capital delivery and customer service. Note this IT uplift is distinct from the OT uplift, focusing on corporate/administrative systems rather than network operations.

  We currently operate under disparate IT solutions. Several solutions are end-of-life and significant customisation has impacted the ability to maintain IT currency, support business practices, and align to regulatory obligations. The capability uplift project replaces legacy IT systems with new capabilities.
- **Cyber security** ($11.5 million) – In response to heightened cyber security and critical infrastructure concerns the Federal Government passed the SOCI Act, which introduced obligations in the electricity, gas, water and ports sectors to ensure the physical and electronic security of Australia's critical infrastructure. Since the passage of the SOCI Act, the Department of Home Affairs is progressing the need for tighter cyber security for critical assets through the Security Legislation Amendment (Critical Infrastructure) Bill 2020 (SLACI Bill).

  Power and Water's cyber security maturity is not adequate to comply with the obligations under the amended Act nor robust enough in the face of the worsening cyber-attack landscape. We aim to achieve of Security Profile level 2 or SP-2 (per the Australian Energy Sector Cyber Security Framework, AESCSF) by the end of the 2024-29 regulatory period.
- **Hardware and software replacement** ($13.5 million) – The operational lifespan of ICT infrastructure is generally four to five years. This is generally due to lack of spare parts for replacement and sourcing becomes more challenging, and increased risk of cyber security vulnerabilities. Further, there is a need for infrastructure to remain agile and current. During the period we will replace end-of-life servers and server infrastructure, and decommission and dispose of retired infrastructure.

  We upgrade software applications when they become incompatible with contemporary operating systems and infrastructure. This needs to be done to mitigate the risk of failure, which would adversely impact the availability of business systems. We have identified a range of software applications that will need to be updated due to lack of vendor support or because they are vital to our transformation program. Our hardware and software cost estimates are based on historical costs.

8.2.6 Other non-network capex

This expenditure is on 'supporting assets' that we need to be able to do our work. It comprises our leases and investments in corporate property, fleet and plant. Leases are amortised consistent with the approach applied in the previous AER determination.

We forecast $129.4 million of capex in the 2024-29 period compared to $54.8 million in 2019-24 (see Figure 37). This increase is driven by a 'one-off' new project of $89.8 million to consolidate staff into one central location.

Figure 37 – Forecast non-network other capex 2024-29 vs actual/estimated in 2019-24 ($ million real 2024)

Key expenditures are:

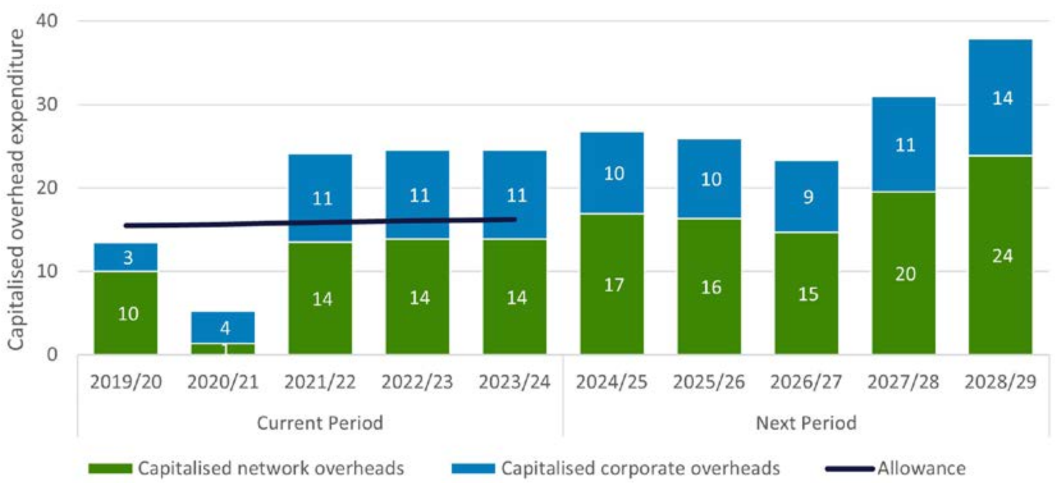
- **Single site consolidation** ($89.8 million) – Currently our Darwin-Katherine staff are located across multiple sites including Ben Hammond complex, Mitchell Centre, Woods Street, Hudson Creek and 19 Mile Depot facilities. This includes a mix of properties that we own and lease. While we are still at the early stages of business planning, initial analysis suggests there may be a net benefit in consolidating staff at our currently-leased Mitchell Centre and Wood Street sites staff into Ben Hammond complex. Expected benefits include reduction in lease costs, improved efficiency of staff from collaboration, improved response to faults and outages, and improved emergency response.
- **Property leases** ($6.4 million) – We propose $6.4 million capex for property leases for the next regulatory period, compared to approximately $21.2 million expected to be spent in the current period. This difference is due to the timing of capitalisation of leases. Our capex forecast includes renewal of two leases during 2024-29; Mitchell Street and Mitchell Street switching station.
- **Property remediation costs** ($10.5 million) – We have identified ten sites (that we own) where upgrades to facilities are required. Remediation costs include rectifying non-compliant structures, installation of physical and electronic security infrastructure, and minor capital works.
- **Fleet leases** ($14 million) – These are costs for the range of vehicles required by Power and Water staff to conduct works and support the business (cars, utes, trucks, elevated work platforms, etc). Fleet costs are driven by the size of the work program and number of employees, as well as the age/condition of the existing fleet. Our networks extend across harsh and remote terrain, in demanding conditions. These conditions are taken into consideration when managing and maintaining the fleet, hence the need to maintain a suite of good-condition vehicles.
- **Plants tools and equipment** ($8.7 million) – Plant includes non-road registered motor vehicles (e.g. forklifts, boats etc.), mobile plant and equipment, tools, trailers, elevating work platforms not permanently mounted on motor vehicles, mobile generators, furniture, and fittings. Failure to properly maintain plant, tools and equipment can lead to damage to network assets, and compromise workforce safety.

8.2.7 Capitalised overheads

This relates to the share of network and corporate overheads allocated to network and non-network capital assets in accordance with accounting standards.

Capitalised overheads accounts for $144.7 million or 25.2 per cent of forecast capex in the next regulatory period (see Figure 38). This increase of $52.9 million results from the change in our treatment of overheads to align with accounting standards, and improve consistency with other regulated network businesses. This change has not increased overall costs, it has merely resulted in a greater proportion of overheads being capitalised rather than expensed.

Figure 38 – Forecast network and corporate overheads ($ million real 2024)



8.3 Deliverability

In the current period, our capex delivery has been impacted by a range of exogenous factors. This has resulted in a change to the composition and profile of our capex program compared with historical spend, which has required us to adopt new procurement and delivery methods.

We consider the changes we have made represent a responsible and measured approach to strengthen our delivery capability for the remainder of the current regulatory period. The delivery rates being achieved now and over the next couple of years reflect a sustainable level.

We have a demonstrated capability to deliver significant capital work programs despite our relatively small workforce and limited supporting local industry. This capability is underpinned by our Project Investment Delivery Framework, which focuses on prudent advanced planning and development, efficient delivery, with sound management oversight. Within this framework, delivery strategies are developed, including novel contracting methods, to augment local internal and external capacity and deliver across the capital investment portfolio.

Our works delivery framework and supporting initiatives will provide a higher degree of scalability and flexibility allowing the business to pivot, if and as required, to meet the needs of a rapidly evolving energy landscape. During the next regulatory period, our works will help facilitate a major transition to renewables in the NT electricity system.

Further detail on our works delivery framework and the recent improvements we have implemented, are detailed in our Capital Delivery Plan included as Attachment 8.06.

8.4 Contingent projects

We have identified five large projects, all expected to cost more than $15 million, which may be required during the 2024-29 regulatory period but are uncertain in terms of timing, scope or funding arrangements. The regulatory framework requires that these projects be excluded from the forecast capital allowance, and separately identified as a contingent project.

Contingent projects are assessed by the AER individually once the trigger for investment has occured (or is sufficiently certain to occur). They are subject to a formal regulatory test and expenditure must be demonstrated to be prudent and efficient before costs are incurred.

By using the contingent project mechanism we can move quickly to deliver these works when they do materialise, while avoiding the need for customers to pay for investments earlier than necessary.

The contingent projects are:

- **Renewable Energy Hub** – The NT Government's Darwin-Katherine Electricity System Plan includes a Renewable Energy Hub where large scale solar and battery will connect to available capacity on our transmission network. This will require the construction of new transmission infrastructure and a substation to inject generation to the existing transmission network.
- **Unlocking existing large scale renewable generation on DKTL** – Many large solar generators have located south of Darwin. There are transmission constraints on the Darwin-Katherine transmission line (DKTL) due to power security issues that result in curtailment of generation. The Darwin-Katherine System Plan noted mechanisms to improve the dispatchability of this existing generation, including procuring services of grid scale batteries. However, there is considerable uncertainty around technologies available, and the level of market benefit. We therefore propose this be treated as a contingent project and use the AER's regulatory investment test process to fully assess the most appropriate solution.

- **Holtze-Kowandi land release** – The NT Government has announced the release of land in Darwin, near Palmerston, called Holtze-Kowandi. This is a significant land release that would require a new zone substation if housing and commercial demand occurs in the 2024-29 period. However, there is uncertainty on exact timing of when the load would materialise.
- **Commercial development in Middle Arm** – A new commercial zone being proposed for Middle Arm will likely attract large industrial/commerical customers. There is uncertainty on how many customers may seek connection and the resultant demand for grid services. It is likely that a significant load would require a new zone substation.
- **Development in East Arm** – An industrial precinct at East Arm may require significant investment in a new zone substation. Due to uncertainty around timing, the new zone substation is being treated as a contingent project.

Table 3 provides shows the current cost estimates for these projects.

Table 3 – Estimated contingent project capex ($ million real 2024)

Project	Cost estimate ($ million)
Renewable Energy Hub	120.8
Unlocking existing large scale renewable generation on DKTL	45.7
Holtze-Kowandi land release	60.8
Commercial development in Middle Arm	69.1
Development in East Arm	45.6
Total	**342.1**

Channel Island to Hudson Creek 132 kV transmission towers, Middle arm

9. Operating expenditure

Our forecast operating expenditure is designed to allow us to meet the service expectations of our customers, and conduct day-to-day operations and maintenance of our three regulated networks. In recent years we have managed to reduce our base operating costs, establishing an efficient level of expenditure.

Our forecast for the next regulatory period includes new costs that will allow us to design and manage our networks more effectively, supporting the Territory's transition to low cost, low emissions energy.

We estimate we will spend $412.0 million of operating expenditure (opex) in the 2024-29 regulatory period. This is $8.0 million lower than our actual opex in the current period.

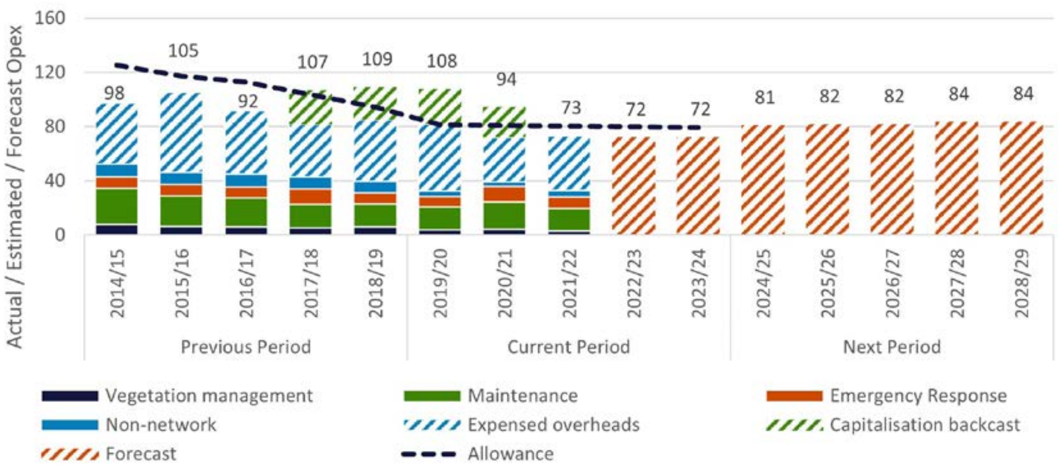
Figure 39 shows our recent pathway to reduce opex to its current level. Over the first three years of the current period (2019-2024), we have reduced our opex by 32.0 per cent, from $107.8 million to $73.3 million. We expect to continue along this path to reduce our costs further over the remaining two years, and use the incentive under the Efficiency Benefit Sharing Scheme (EBSS) to continue to drive efficiencies throughout the next period.

We have forecast our opex requirement using the AER's preferred method; the base-step-trend approach. This means we look at the overall amounts we spend on operating and maintaining the network, and project those costs forward in the context of our future operating environment and any significant, new or changed requirements.

In line with the AER's method, we have used our most recent year of audited actual operating expenditure (the revealed cost) as our base year. At the time of developing our forecasts, this was the $73.3 million incurred in 2021/22.[10]

A summary of our forecasting approach is provided in the following sections.

Figure 39 – Historical and forecast opex ($ million real 2024)



[10] It should be noted that we have changed our treatment of allocated overheads, accounting for them as capex rather than opex. This allows us (and the AER) to compare our performance against peers more easily. The accounting change results in a lower opex forecast, and is more consistent with the efficient level of expenditure substituted by the AER in the last regulatory determination. Importantly though, this change was undertaken prior to 2021/22 and therefore is expressly built into the base year, and our forward forecasts. Throughout this plan, we present expenditures for the current and next regulatory period in comparable terms.

9.1 Forecasting method

We applied the AER's preferred base-step-trend method[11] to forecast operating expenditure. This involves:

1. **Establishing an efficient opex base year from which to forecast ongoing costs** – Opex tends to be recurrent from year to year. This means that the most recent year of actual expenditure generally provides a good indication of future levels. As such, we have used our audited Financial Year 2022 as the base year.
2. **Applying trend adjustments to account for growth** – Consistent with the AER's approach we will apply a rate of change to the base year to account for changes in input prices, work activity from increasing network size, and productivity.
3. **Determining and adjusting for step changes** – We have identified and costed changes impacting our business environment that will affect our costs.

The resulting opex forecast is shown in Figure 40. Figure 41 shows our overall approach to forecasting opex. The following sections describe each step in more detail.

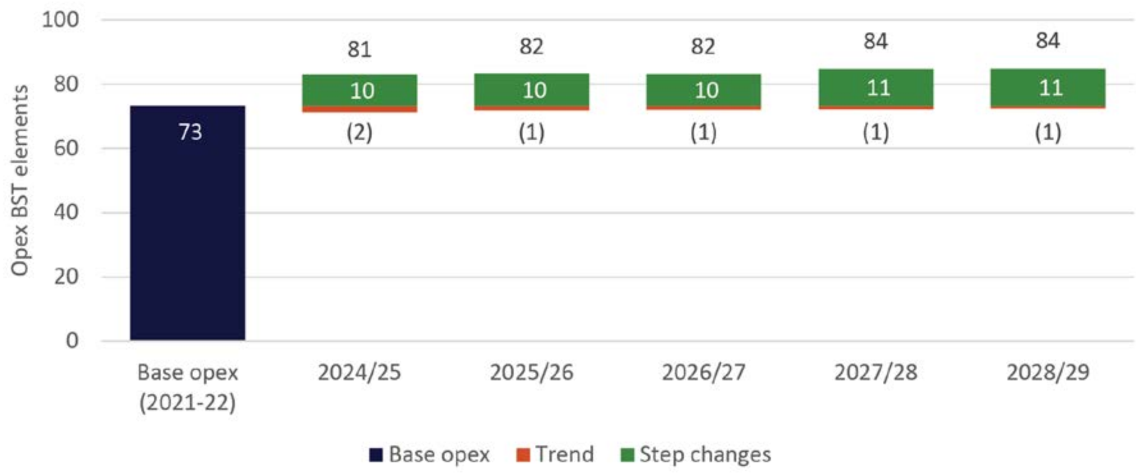
9.2 Establishing our base year opex

Under the base-step-trend method, the actual costs incurred in the latest year of audited financial statements are used as the basis for forecasting costs for the next regulatory period. This year represents the most up to date actual cost information available at the time the AER will make its decision. At the time of developing our forecasts, this was the $73.3 million incurred in 2021/22.[12]

We consider this an efficient base year, as:

- Our controllable opex[13] has continued to trend downward since 2017/18 and is below our current period forecast.
- Our 2021/22 audited, revealed costs are below the AER's opex allowance, which included adjustments to the base year, an overall productivity factor of 0.5 per cent, and a 9.6 per cent reduction in network and corporate overhead costs over the period.
- In 2021/22 we changed our treatment of shared resources (overhead costs) to better allocate the costs to the activities they perform.[14] This resulted in more of these costs being allocated to direct maintenance activities and projects in line with the AER's expectations – these changes are therefore already accounted for in the base year.[15]

Figure 40 – Forecast operating costs – base, step, trend ($ million real 2024)



[11] As outlined in the AER's Expenditure Forecast Assessment Guidelines.
[12] We expect to be able to update this to reflect the penultimate year of the regulatory period prior to the AER making its final decision. The penultimate year of actual expenditure is preferred as there will have been more time for efficiencies to be realised.
[13] (i.e. not emergency management, which is externally driven)
[14] It should be highlighted that our Cost Allocation Method (i.e. allocation between business units) has not changed, only the allocation of overhead costs between services within our regulated electricity network business.
[15] This has included making structural changes to align with standard accounting practices, good industry practice and cost-reflective pricing. More information on this change is provided in Attachment 9.01.

Figure 41 – Opex forecasting method

- With the exception of overhead costs, our split of controllable opex has been relatively consistent since 2017/18, and therefore reasonably representative of our business as usual requirements.
- We have continued to progress targeted, long term efficiency programs across the business, including for example moving to proactive asset management programs to reduce reactive maintenance over time, and increasing our IT capability to make better use of our resources.
- We have improved our internal and external controls in relation to asset management, procurement and financial governance. Together these processes ensure we undertake our opex works program in an efficient manner, in accordance with good industry practice.
- We have done some high-level opex benchmarking which has shown significant improvement in our position since the last regulatory period.[16]

9.3 Applying trend adjustments

We have considered the extent to which our costs are expected to change over the forthcoming regulatory period as a result of change in:

1. Network scale
2. Prices
3. Productivity

These three factors are accounted for by applying a trend rate of change to the base year opex, where the rate of change reflects the network scale escalation + price escalation – productivity improvement.

Each is discussed in the following sections, with more information provided in Attachment 9.01.

9.3.1 Network scale escalation

The network scale escalation factor accounts for the additional opex we will incur as a result of the forecast growth in output. Our proposed network scale escalation factor is consistent with the AER's method, as it uses the forecast growth in kilometres of network and customer numbers over the next regulatory period.

The application of these assumptions results in an annual average output growth rate of 0.2 per cent over the 2024-29 regulatory period.

9.3.2 Price escalation

The price escalation factor accounts for input costs that are expected to increase at a different rate to inflation (real cost escalation).

The growth rate assumed for labour costs is based on an independent forecast of the Wage Price Index for Electricity, Gas and Wastewater Services developed by BIS Oxford (see Attachment 2.02).

The application of these assumptions results in a real annual average price escalation of 0.1 per cent over the 2024-29 regulatory period.

9.3.3 Productivity improvement

In applying the roll forward method, the AER considers whether there should be an adjustment to capture expected changes in the productivity of the business. We propose a 0.5 per cent productivity factor, largely based on the expected benefits from the Operating Model Program.

The overall effect of the trend adjustments is an annual average decrease of 0.2 per cent, which results in a cumulative reduction of 1.3 per cent or $7.0 million of opex over the regulatory period.

[16] Noting it is difficult to compare our costs to those of larger networks that can achieve more economies of scale and scope, have been subject to regulation for a longer period, and are less affected by geographically-driven factors such as prices and weather.

9.4 Determining step changes

In developing our forecasts, we have considered the changing environment and regulatory framework in which we operate. Customers have told us they expect the network to continue to accommodate solar generation, as well as batteries and EVs. The recent move to the national regulatory framework places new obligations on our business, and the threat of cyber attack is a growing issues across many industries.

All of these issues are imposing new costs on our business, including new resources, fees, and licences. These costs are not included in our base year.

We have therefore included the following opex step changes in our 2024-29 forecast:

- An annual average increase of $0.9 million to meet minimum compliance requirements to move to SP-2 cyber security milestone as expected for all distribution network service providers under the Security of Critical Infrastructure Act.
- An annual average increase of $1.2 million to ensure we can meet our obligations under the NT NER, including obligations that commence in the next regulatory period. For example, the maintenance of the Network Technical Code, and management and coordination of regulatory investment tests.
- An annual average increase of $0.8 million to establish a small cloud presence to allow the continued use of software where vendors no longer provide our preferred, on-premise option – this applies to five of our critical software programs.
- An annual average increase of $3.8 million to resource, embed and make effective use of new operational and control systems. Our current suite of OT systems are disparate and obsolete, and considerably short of where a modern distribution network service provider should be. An OT uplift project is being delivered to bring our systems up to industry standard and give us the ability to better manage existing levels of DER and renewables. This $3.8 million is the ongoing cost associated with resourcing and operating these new systems.
- An annual average increase of $2.8 million to increase the number of operations and planning resources to enable development of the future network, including continuing to accommodate rooftop solar and new large scale renewable sources. This additional capability is essential to allow us to keep pace with the increasingly dynamic use of our network.
- An annual average increase of $1.0 million in insurance costs, reflecting changed market conditions and associated premiums experienced by other network service providers.

More information on each of these step changes is provided in Attachments 9.01 and 9.02.

Power and Water call centre staff

10. Revenue

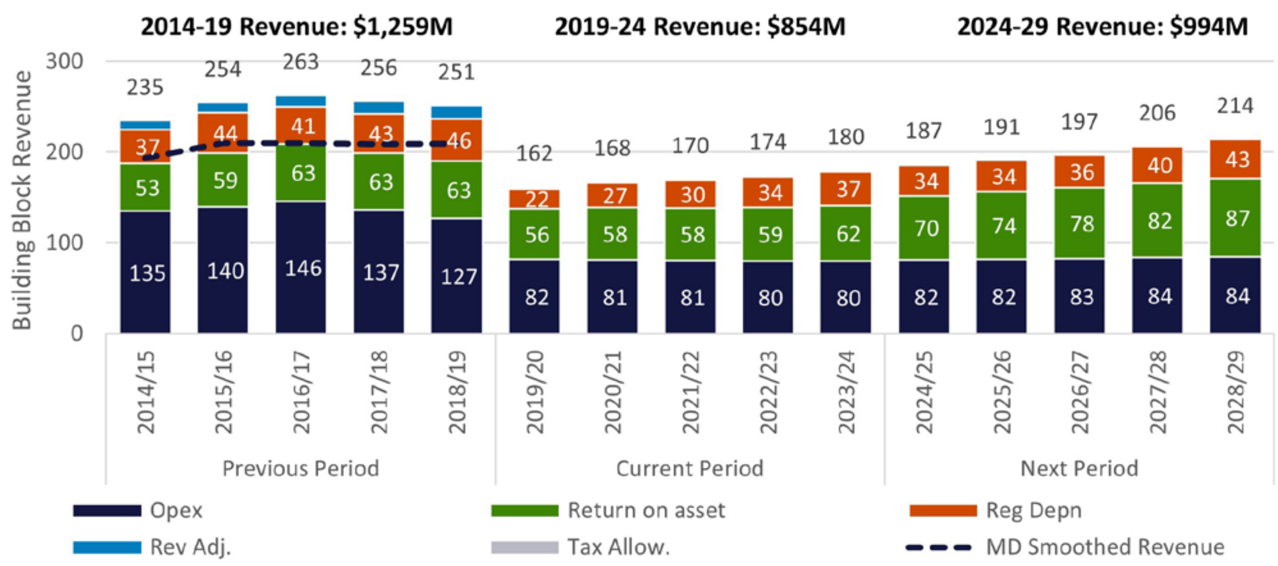
Our forecast (smoothed) revenue for 2024-29 is $996.2 million, which is a 14.8 per cent, or $128.1 million (real) increase compared to the current regulatory period estimate. Approximately 84.8 per cent, or $80.7 million of the revenue uplift is the direct result of rapidly increasing financing costs, which are driven by inflation and the current uncertainty in financial markets. These return of and return on investment costs have been calculated using the AER's approved methodology.

In its determination, the AER sets a cap on the annual revenue we can recover from customers through our network tariffs. The annual revenue is calculated using the AER's post tax revenue model, and incorporates following elements:

- Investment costs associated with our regulatory asset base (RAB), which is the value of our regulated assets at a point in time. The RAB comprises the depreciated value of our regulated assets, together with the forecast capital expenditure discussed in Chapter 8. Financing costs include a return on the RAB based on the current estimate of the rate of return, and depreciation of the RAB (often termed 'return of' investment).
- Forecast operating expenditure for the upcoming regulatory period, as discussed in Chapter 9, together with an estimate of taxation costs.
- Adjustments to revenue depending on our performance under the AER's incentive schemes, and amounts to fund new innovation.

Revenue related to alternative control services is recovered directly from customers incurring the costs and is charged via a discrete suite of tariffs subject to a separate form of price control from standard control services. The revenue requirement for alternative control services is discussed in Chapter 13 of this Regulatory Proposal.

Figure 42 – Revenue building blocks and historical trend ($ million real 2024)



10.1 Revenue forecast and trends

Figure 42 (previous page) shows our forecast revenue for 2024-29 compared to the 2019-24 and 2014-19 regulatory periods.

Our 2024-29 revenue is 14.8 per cent higher than 2019-24, but still significantly below the $1,249.0 million allowance set by the jurisdictional regulator[17] in 2014-19. We highlight that a Ministerial Direction later required us to reduce our maximum revenue for the 2014-19 period to $1,030.6 million.

Network revenue fell significantly in the first year of the 2019-24 period. The primary drivers were the AER's decision to reduce our operating expenditure, and a low rate of return due to prevailing market conditions. Further, the opening RAB was re-visited under the national economic regulatory framework, which led to a reduction in the return on assets (depreciation).

The higher revenue in the 2024-29 period is primarily explained by higher rates of return on and return of investment due to a recent change in market conditions. Other drivers include increasing capital expenditure, which has led to higher financing costs including depreciation. However, the reduction in forecast operating expenditure has helped keep revenue from rising further.

The return on and return of the RAB comprise our investment costs, and together drive 58.2 per cent of revenue. Operating expenditure and tax comprise about 41.9 per cent of revenue. Revenue adjustments account for a very small portion of our revenue.

10.2 Revenue forecasting approach

During our April 2022 People's Panel engagement sessions with customers, we flagged that our expenditure plans at the time were resulting in materially higher revenue forecasts for 2024-29 compared to the 2019-24 period. We talked through how our network tariff revenue contributes to overall energy costs, and discussed the levers available to us to control our revenue requirement, and what aspects of network revenue are less controllable (i.e. rate of return and other formulaic calculations).

When discussing our expenditure plans, customers expressed a preference for investment in projects that support decarbonisation, facilitation of renewable and new technology, and improved customer service. Our customers signalled they were comfortable with a small increase in revenue above 2019-24 levels if projects such as these can be delivered. At the time of the People's Panel sessions, we were looking at a 3.7 per cent revenue increase, which customers indicated they were comfortable with.

Since the April 2022 engagement sessions, our expected financing costs for the 2024-29 period increased markedly due to inflation, higher interest rates, and global events. When preparing this Regulatory Proposal, we have looked at the levers available to keep the revenue requirement closer to historical levels. These levers include reducing our growth and network asset replacement forecasts, changing the capex profile based on risk prioritisation and delivery capabilities, aligning our overhead allocation to other networks resulting in more capitalisation of overheads (and therefore spreading recovery of costs over a longer time frame), and implementing efficiency stretch targets for operating expenditure.

A limitation is that a significant proportion of our revenue is fixed. For example, about 50.0 per cent of our forecast revenue for the 2024-29 period relates to the costs of financing previous investments in network and non-network assets, tax liabilities relating to past investment, and incentives for performance in this period.

Only 50.0 per cent of forecast revenue is impacted by our forecast expenditure in the 2024-29 period. This can be seen in Figure 43.

The current financial market is highly volatile. Under the AER's calculations, the risk free rate is set in a period closer to the AER's determination based on market observations. Our financing costs are highly sensitive to this parameter, and it is beyond our control to influence the rate. Figure 44 shows the recent volatility in the risk free rate with a significant increase since April 2022.

[17] Utilities Commission of the Northern Territory

Figure 43 – Fixed vs conrollable revenue

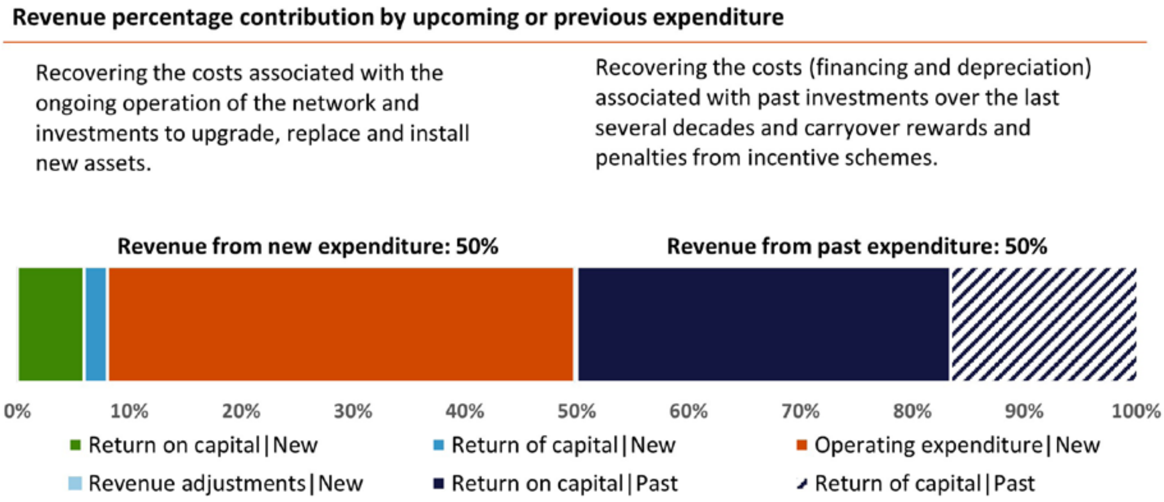


Figure 44 – Changes in risk free rate since January 2019

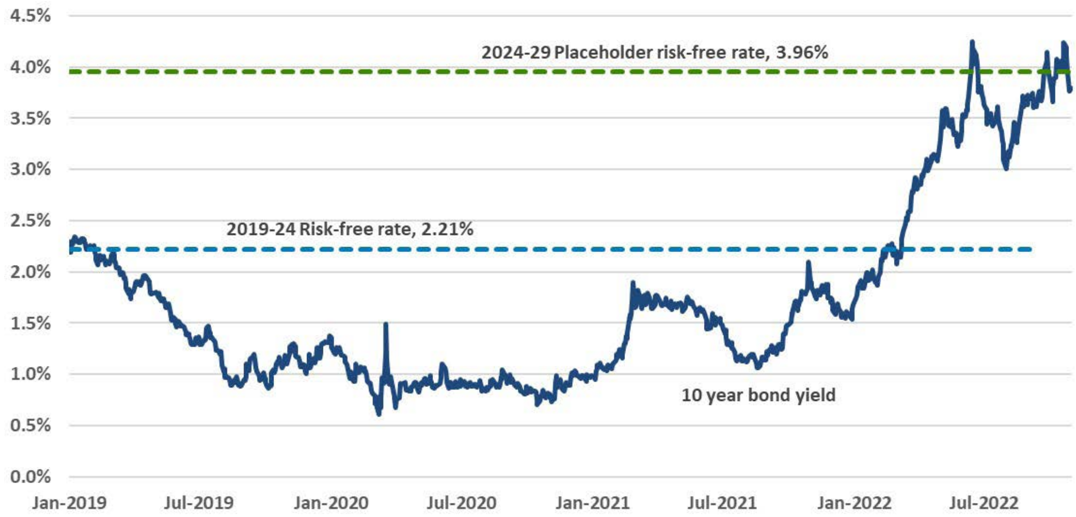
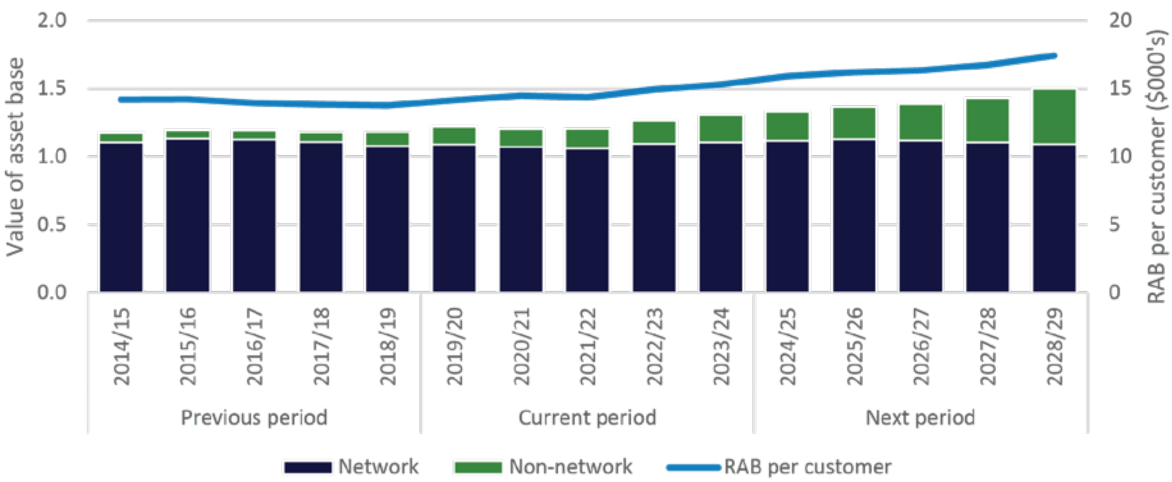


Figure 45 – Movement in RAB over time ($ billion real 2024)



10.3 Return on investment

About 58.2 per cent of our forecast revenue for the 2024-29 period relates to funding our past and future investments.

The calculation of financing costs is based on the value of the RAB and the remaining life of assets. The RAB is the sum of the depreciated value of past capital expenditure and forecast new capital expenditure. We make adjustments to the RAB to exclude capital contributions and asset disposals. Figure 45 shows the movement in our RAB over the previous, current and forecast period for our network and non-network assets. The blue line shows that the RAB per customer will increase in the forecast period.

The movement in our RAB per customer largely reflects the increase in capital expenditure over the period being higher than depreciation on past capital expenditure. We expect this trend to continue as we invest in new assets replacing assets that are highly depreciated in the RAB.

10.3.1 Return on assets

The AER determines a return on investment allowance for each year of the regulatory period. The allowance is calculated by multiplying the nominal rate of return by the nominal value of the RAB. The rate of return represents the expected rate of financing required to finance a benchmark efficient business with similar operating characteristics. The nominal vanilla weighted average cost of capital is the proportion of the return on equity and return on debt based on a defined gearing ratio.

Rate of return parameters and values are largely pre-determined through the application of the AER's Rate of Return Instrument, but in some cases are based on market data either at the time of the determination or through updated data in the regulatory period.

A key contributor to the rising rate of return has been the sudden increase in the risk free rate, which has a consequential impact on the return of equity. The risk free rate has increased significantly since our consultations with customers in April 2022 due to higher interest rates and other global factors. The risk free rate will be calculated closer to the time of our determination over an averaging period, and is then locked in for the duration of the 2024-29 period.

10.3.2 Return of assets (depreciation)

We recover a revenue allowance equal to the depreciation returns calculated in the AER's revenue models. The depreciation included in the revenue allowance is net of assumed indexation. Straight line depreciation of existing assets as at 30 June 2024 is calculated using the AER's depreciation model, which applies the year-on-year tracking method. Straight line depreciation on new assets forecast for the 2024–29 period is calculated within the AER's post-tax revenue model using the same method. In both cases, we have retained the asset classes and standard lives adopted by the AER for the 2019–24 period. Figure 46 shows the returns on and of assets.

Figure 46 – Return on and return of assets ($ million real 2024)

10.3.3 Other revenue items

About 41.8 per cent of the forecast revenue relates to operating expenditure forecasts. These forecasts account for $415.3 million of forecast revenue in the 2024-29 period. As operating expenditure is an annual cost that is unrelated to an asset, the cost is passed through directly as a revenue item.

Like other businesses, we must pay income tax to the government. The allowance for tax costs in our building block proposal reflects our expected tax liabilities over the next regulatory period. We have forecast this allowance using the AER's revenue model.

As well as shared asset revenue, our building blocks revenue is also adjusted for any incentive allowances. These can be positive or negative and are intended to give effect to schemes applied by the AER to ensure equal sharing of benefits from efficiency improvements over the period.

For the 2024–29 period, our proposed revenue includes two incentive allowances:

- CESS carryover amounts – these result from applying the AER's capital expenditure sharing scheme to our actual capex incurred over the 2019–24 period
- DMIA – this is an ex ante allowance for demand management innovation.

Adjustments to revenues for these additional allowances are shown in Table 5.

The AER may adjust revenues for benefits we and our customers receive from shared assets over the current regulatory period. The small number of assets we currently use to provide both regulated services and unregulated services do not generate sufficient revenue at this stage for the AER to make any adjustment.

Table 4 – Corporate income tax ($ million real 2024)

Corporate income tax	2024/25	2025/26	2026/27	2027/28	2028/29	Total
Estimated cost of corporate income tax	1.1	-	-	-	-	1.1

Table 5 – Other revenue adjustments ($ million real 2024)

Revenue adjustments	2024/25	2025/26	2026/27	2027/28	2028/29	Total
CESS carryover amounts	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(2.7)
DMIA	0.4	0.4	0.4	0.4	0.4	2.0
Total adjustments	**(0.1)**	**(0.1)**	**(0.1)**	**(0.1)**	**(0.1)**	**(0.7)**

11. Tariffs and indicative prices

We set network tariffs each year to collect the revenue allowance set by the AER. In the current period, we started a journey to improve the fairness of our tariffs to better reflect each customer's share of network costs. For the 2024-29 period, we are continuing this journey by improving customer segmentation across tariffs and trialling new tariffs that improve network utilisation.

11.1 Tariff setting

Under revenue cap regulation, the AER places a ceiling on the revenue we can collect for our network services based on expenditure plans and previous investments. To collect revenue, we set network tariffs based on a customer's connection, energy and demand for our network services. Importantly, the network tariff is charged to the electricity retailer rather than the end customer.

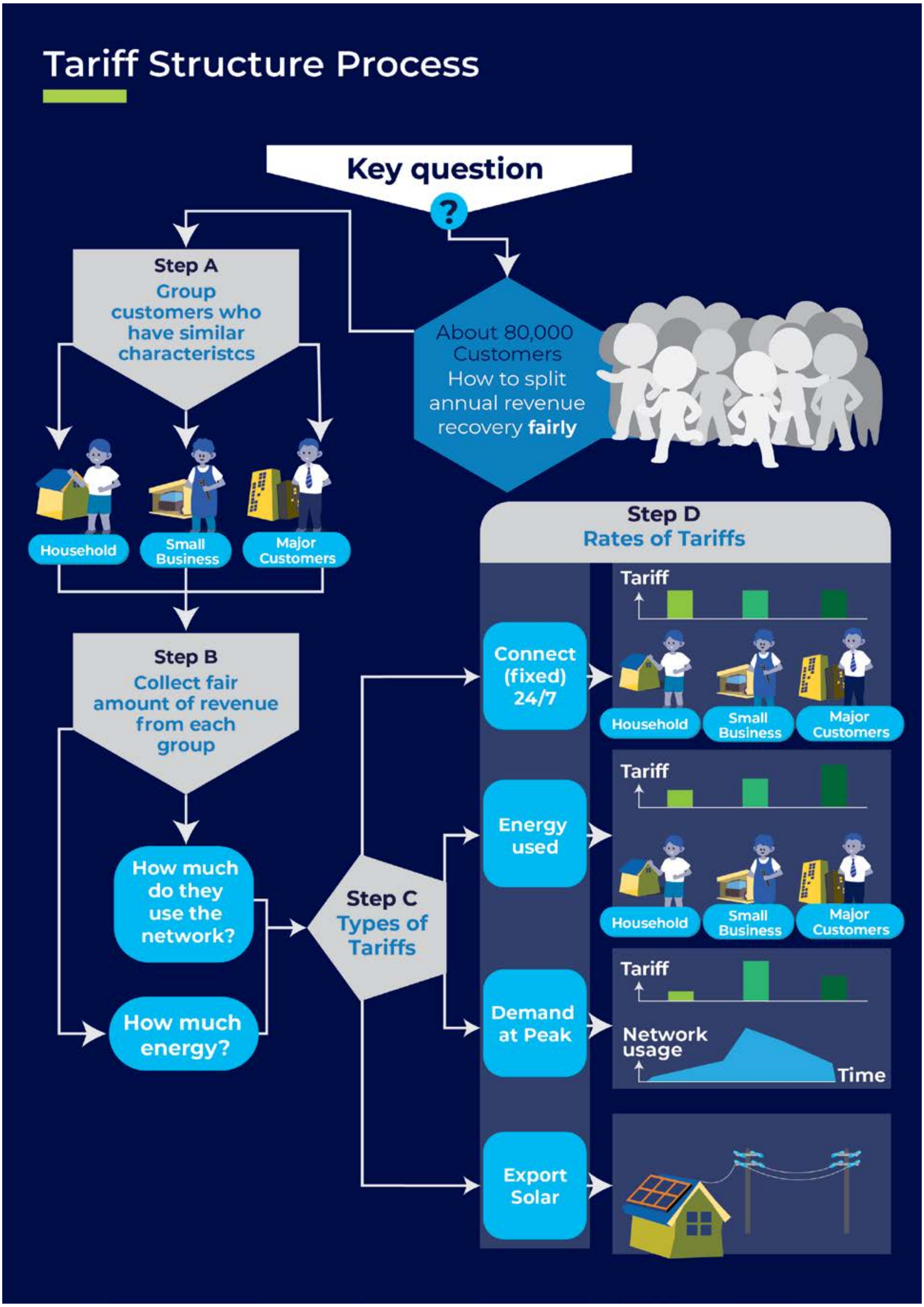
We design network tariffs to collect revenue from customers in an equitable way. Our aim is to make sure customers are paying their fair share for the costs of network services.

The NT NER require we develop network tariffs that align with pricing principles that relate to economic efficiency. Under the pricing principles, we must set tariffs to recover the expected future costs of building new networks. This involves setting a charge that reflects the long run marginal cost (LRMC) of our network services. Any residual costs should be recovered by tariffs that collect revenue from customers in the least distortionary way.

Our Tariff Structure Statement must set out how we structure our tariffs (i.e. the charging parameters for each tariff and time window), as well as the policies and procedures for assigning customers to tariffs and a description of the approach taken in setting tariffs in the annual pricing process. The key steps in setting network tariffs are described below, and shown in Figure 47.

- Step A is to develop tariff classes based on grouping customers into tariff classes and segments. This recognises that it would be administratively difficult to establish a price for each individual customer. The process instead seeks to group customers based on similar characteristics, usage of the network, and meters. For example, we group our customers based on whether they are residential, non-residential or a major energy user. We also develop our groupings based on consumption, and whether the customer connects to our high or low voltage network. Finally, we have separate tariff groupings for smart meter customers.
- Step B is to collect revenue from these customer groupings in a way that reflects the fair share of their use of the network. This is based on factors such as where customers connect to our network, and how much energy and peak demand is dedicated to the customer group.
- Step C is to identify the mix of tariff types that should be used to set tariffs. The process is based on developing a mix of efficient price signals that result in customers paying a fair share based on how they use the network. This includes fixed charges, energy consumption, and peak demand charges that may vary based on the time of day or season.
- Step D is to develop rates for each of these tariff components that result in collecting our annual revenue, based on the optimal allocation of revenue among each of the tariff components.

Figure 47 – Process for setting network tariffs



11.1.1 NT network tariffs limitations

In our discussions with customers, we highlighted that our network tariffs are not passed through to the customer by the retailer, and this limits the ability of our network tariffs to provide a direct price signal to customers. For small customers, the retailer must use the tariffs in the NT Government's Electricity Pricing Order. These tariffs do not have a specific network component, nor are the charging parameters the same. For larger customers, the retailer has the option of directly passing through our network tariff.

When considering the network tariff structures for 2024-29, we have given regard to whether there will be any changes to the Pricing Order in the future, and designed our tariff structures to enable direct price signals should the NT Government choose to amend the Order.

11.1.2 The case for more efficient tariffs

As discussed in Chapter 3, our network is facing global and local changes that will influence our costs. A focus for us is to improve utilisation of the network by delivering move energy and solar export capacity, while minimising new network investment. Network tariffs play an important role in this by providing customers price incentives to use the network during off-peak periods.

Managing peak demand in the evening

Peak demand growth across our network has been relatively flat over the last decade. Due to the extreme heat, demand for electricity is highest in the middle of the day in the October to April period.

Over the last five years, we have seen less demand for electricity from our network in these peak periods. This has largely been a result of customers using their own solar panels to energise their homes and businesses. Demand for electricity from our network has shifted to early evening when the sun is no longer shining. Figure 48 shows the underlying energy demand compared to demand delivered by the network on the maximum day in the Darwin Katherine electricity system in 2020/21. Increasing solar will not help curb peak demand over the next 20 years now that peak demand has shifted to the evening.

Further, we are seeing an uplift in customer numbers in the 2024-29 period including major residential and industrial developments. This will accelerate demand for our network services, adding to demand at peak times. Post 2030, we expect the uptake of EVs to increase in the Northern Territory. EVs will lead to significant increases in energy required from our network in all areas and will drive an increase in peak demand if customers charge in the evening peak period.

While the network has some capacity to meet growth in peak demand, we anticipate significant and systematic growth will create a need for new infrastructure at high cost. In this context, tariffs play a key role in providing signals for customers to use energy outside of peak times. While our current tariffs include a peak charge, there is an opportunity to provide more targeted signals on the cost of network electricity in peak periods relative to times of spare capacity.

Managing solar during the day

Figure 49 shows the minimum demand day on the Darwin-Katherine electricity system. There was a significant decline in demand for our network electricity between 2019 and 2021 in the middle of the day.

Network tariffs could incentivise customers to use more of their own solar, rather than exporting into the grid during these periods of high export demand. Additional demand in the middle of the day would also help increase load on minimum demand days. Both measures would help us lift constraints on solar exports

Currently our demand charge in summer is set from midday onwards, which does not provide the right signal to use more power during the midday to 2pm window when solar production is highest. We also do not have any signal for customers to export less of their energy when there is over-production of solar.

11.2 Tariff changes for 2024-2029

11.2.1 Principles underpinning tariff changes

Our proposed network tariff changes seek to support a considered and actionable tariff reform pathway for the NT Government. The revised tariff structure is based on three key principles:

- **Simplify** – pricing signals must be clear and understandable. Retailers have told us more complex tariffs such as demand charges and export charges are difficult to implement, and prefer incremental change to sweeping reform.
- **Trial** – taking on board stakeholders' preference for incremental change, we propose to run tariff trials for things such as export charging and EVs, to build an evidence case for future tariff reform
- **Segment** – we aim to provide options for the Government to revise the Pricing Order in the future, specifically by improving the segmentation of customers across our tariff classes.

These principles are discussed further below, with the Tariff Structure Statement and associated explanatory statement provided at Attachments 11.01 and 11.02 respectively.

Figure 48 – Maximum demand day profile (MW)

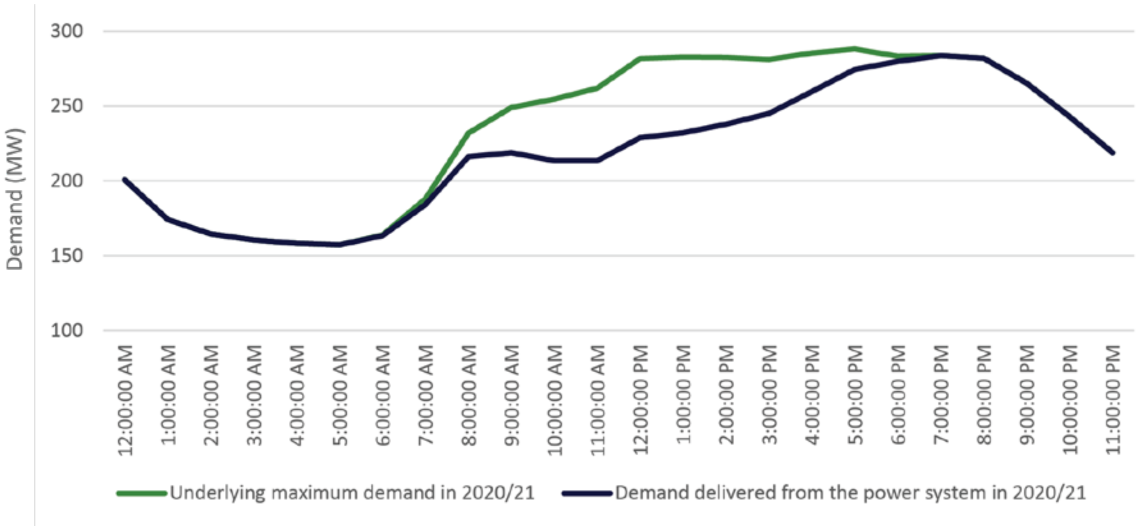
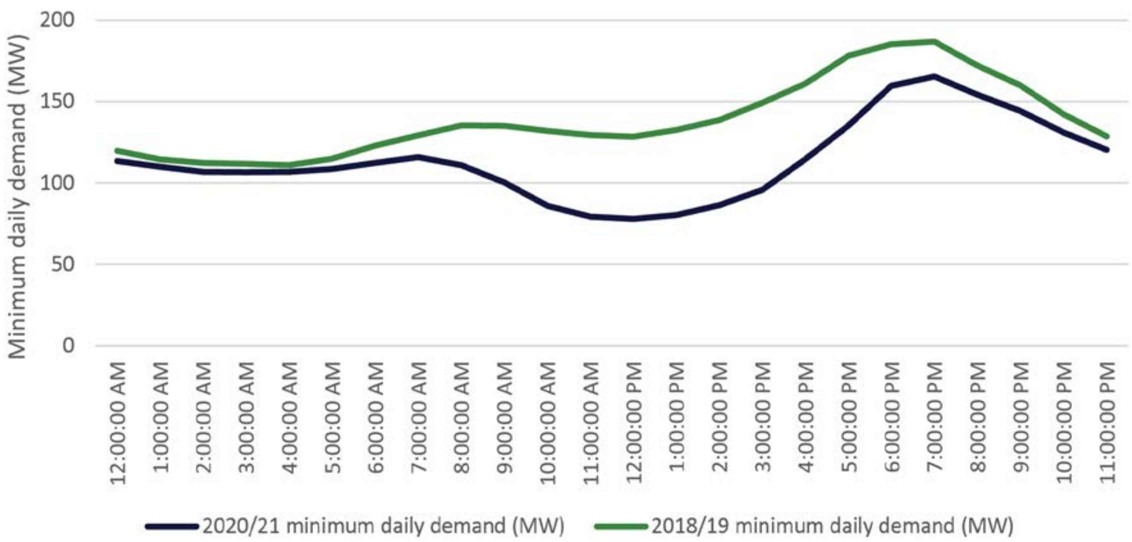


Figure 49 – Change in the minimum demand day profile in the Darwin-Katherine system in 2021 (MW)



Simplify

Our starting point was to only consider changes to our existing network tariffs where there was a clear need to change. This recognises that wholesale change is difficult to communicate to our stakeholders, and may not be compatible with existing billing systems.

Simplicity was a key factor in our thinking, particularly after speaking with retailers. Following publication of the Draft Plan in August 2022, we tested our initial thinking with the NT's electricity retailers. They shared a preference to make only incremental changes, and advised against introducing complex reforms that may require changes to billing systems or that would be difficult to communicate to customers. As a result, we will continue to apply demand charges based on maximum demand rather than something more complex such as average rolling demand.

End users and retailers also expressed a desire for a slower pace of tariff change. While the tariff changes made in the current period were a step forward, retailers are mindful of the impact on vulnerable customers who cannot change their energy usage patterns easily. Though technological advancements will almost certainly require further tariff reform over the next decade, retailers advised that it takes time to implement changes to back-end systems and embed behavioural changes.

Trial

In our tariff change proposal for 2024-29 we have thought about the optimal pace for reform based on the proportionality and immediacy of the issue. As a result, we have stepped back from our position in the Draft Plan to implement new energy export charges and rebates as fully-fledged tariffs. Instead, we plan to trial export tariffs with smart-meter enabled customers during the period, with a view to refining them for the following regulatory period.

Segment

We consider that the current tariff classes and segments are simple and effective at grouping customers with similar characteristics and use of network services. We have therefore only made minor changes to further segment customers, with a view to assisting with retail competition in the future.

We consider that our tariff components of the fixed daily charge, energy charge and demand charge are relevant and required at this point in time. We also want to place greater emphasis on demand rather than energy charges, particularly for larger customers. This includes adjusting the rates to more reflect the long run marginal cost.

A key strategic change is the need for more time of day pricing. This includes tightening the peak period to align with the time and season when our network experiences the highest demand. We also see the need to provide the right signals for customers to use more energy in the middle of the day to manage the congestion issues from high solar. This is achieved by having time of day pricing for both our energy and demand tariff components where the customer has a smart meter in place.

Our proposed tariff changes for 2024-29 are discussed further in the following section, and in detail in our Tariff Structure Statement and associated explanatory statement, provided at Attachments 11.01 and 11.02.

11.2.2 Network tariffs in the current period

Current tariff classes and charges are set out in Table 6.

11.2.3 Proposed changes to tariffs

Taking customer and retailer feedback into consideration, we propose a suite of incremental changes to our suite of network tariffs. In summary, we propose to:

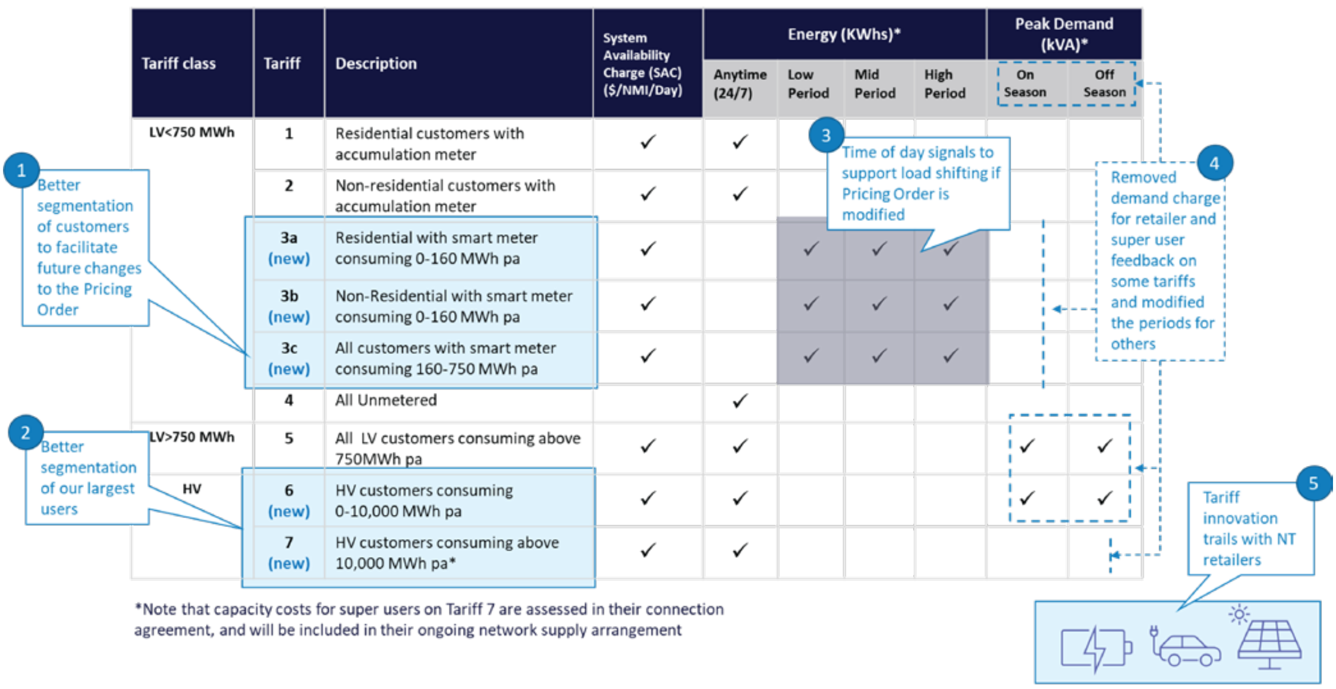
- Increase customer segmentation to distinguish between residential and business customers, and better align with retail competition thresholds.
- Introduce a new 'Super User' customer segment for major industrials using more than 10,000 MWh per annum
- Introduce new time of use charging periods and rates for smart meter customers.
- Remove peak demand charging (kVA charge) for small use customers (<750 MWh per annum).
- Narrow the peak demand charging window for those customers with a demand charge.
- Trial two new export tariffs and rebates to help manage solar PV export levels.

Our proposed tariff structure changes for 2024-29 are summarised in Figure 50.

Table 6 – Current tariff parameters

Tariff	System access charge (SAC)	Anytime kWh (c/kWh)	Peak demand ($/kVA)	
			Seasonal peak	Annual peak
Tariff 1 Residential customers consuming <750 MWh with standard accumulation meters	✓	✓	X	X
Tariff 2 Non-residential customers consuming <750 MWh with standard accumulation meters	✓	✓	X	X
Tariff 3 LV Smart Meter consuming <750 MWh with smart meters	✓	✓	✓	X
Tariff 4 Unmetered Supply (for connections without metering such as traffic lights and streetlights)	✓	✓	X	X
Tariff 5 LV >750 MWh Customers connected to the LV network consuming >750 MWh	✓	✓	X	✓
Tariff 6 HV <750 MWh Customers connected to the HV network consuming <750 MWh	✓	✓	X	✓
Tariff 7 HV >750 MWh Customers connected to the HV network consuming >750 MWh	✓	✓	X	✓

Figure 50 – Summary of changes to network tariff structures 2024-29



Changes to customer segmentation

We have made relatively minor changes to the way customers are segmented across our tariff structure. First of all, we propose Tariff 3 customers (residents and small businesses with smart meters) be further segmented into three groups, as follows:

1. Residential customers consuming 0-160 MWh per annum.
2. Non-residential customers consuming 0-160 MWh per annum.
3. All customers consuming 160-750 MWh per annum.

We have made this change in response to feedback from retailers on how better to prepare for expanded retail competition in the future. Currently, customers who consume 750 MWh per annum or less are subject to the NT Government's Pricing Order, with only those consuming more than 750 MWh per annum subject to cost reflective tariffs. Should further cost reflectivity be introduced in the NT, it is likely to be expanded to this next 160-750 MWh band of customers (as segmented by retailers). By aligning our network tariff segmentation with the retailers, we are better prepared for any changes to the Pricing Order coverage. Further, by splitting the smart meter customers into residential and non-residential allows us to provide a more targeted price signal based on the characteristics of the customers class.

The second change is to introduce a tariff segment for our largest customers. This is the new 'super users' tariff. It applies to major commercial and industrial customers connected to our transmission network, who consume more than 10,000 MWh of electricity per annum. This customer group is very small (<10 customers), each with different usage characteristics. This group of customers have expressed a preference for costing certainty over complexity. Given this feedback, coupled with the NT Government's desire to attract more major industry to the Territory, a peak demand charge is not being applied to super users.

Allocation of revenue

We are not planning any changes in the allocation of costs among customer groups. We have undertaken further analysis since our last tariff structure statement and found that there is limited evidence to suggest an unequal allocation of revenue among the customer classes.

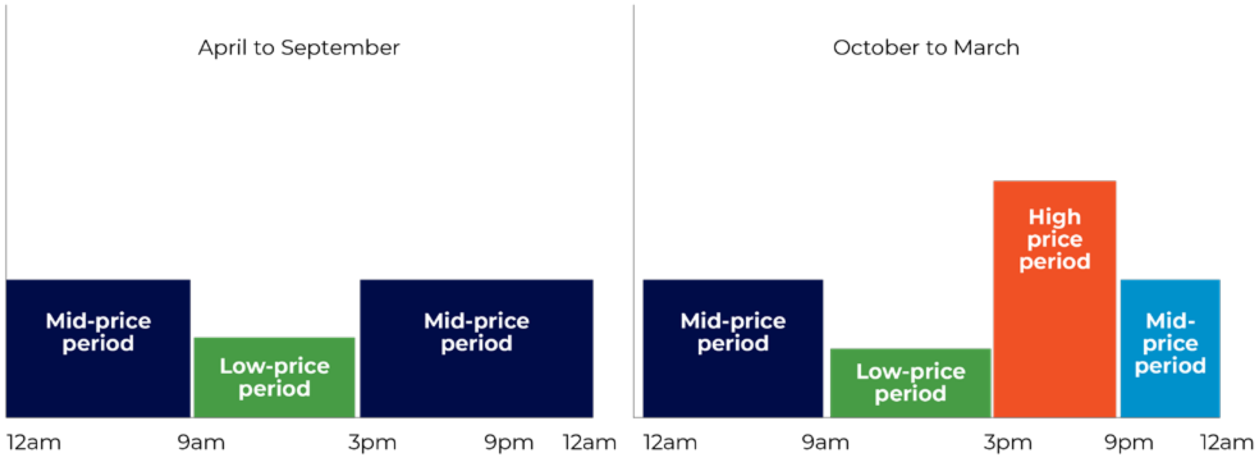
Time of day – energy consumption charge

Currently, we have a single 'anytime' charging parameter for the energy consumption component of tariffs, even if the customer had a smart meter. We are proposing to apply an energy consumption charge based on the period and time of day when energy is consumed. This would only apply to customers with smart meters as accumulation meters do not provide this level of data.

Currently, we have a peak period of 12pm to 9pm on weekdays, during which a demand charge is applied. For larger customers this is all through the year, and for smaller customers it is from October through to the end of March.

For Tariff 3 we are proposing to narrow the hours of the peak period, and move to a time of use (TOU) consumption charge rather than a demand charge. The move away from a demand charge reflects customers' and retailers' preference for simplicity.

Figure 51 – Time of use pricing for consumption of electricity (Tariff 3)



The change in the charging windows is based on the analysis presented in section 11.1.2, which shows our peak demand is shifting to the evening when the network cannot rely on solar to help meet underlying demand. The revised peak periods provide a sharper signal on the drivers of future costs for the network. We have decided not to overly narrow the time period due to the variability of when the peak demand occurs at different locations of our network. Figure 51 shows the proposed TOU charging periods.

The low price period during the day (9am to 3pm) is designed to encourage customers to use more electricity during the day, when there is ample network capacity to meet demand. It is proposed that little or no charges will accrue to customers in this period to encourage consumption to soak up excess rooftop PV. This low price period will apply throughout both the dry season (Apr to Sep) and wet season (Oct-Mar).

The key change is the introduction of a high price period during the wet season. The high price period is designed to set a price signal to encourage customers to move energy consumption away from the 3pm to 9pm window during the wet season. This window is typically when the network experiences peak demand, as solar output falls away, but temperatures and humidity remain high. The long run marginal cost will be allocated to these periods.

Prices overnight and in the early evening during the dry season will be set a mid-price point, and is again designed to send a price signal to customers to smooth their electricity consumption, shifting some to the middle of the day where practicable. Residual costs will be allocated to this period (in addition to the standard access (daily fixed) charge.

We submit that these TOU periods will help manage network impact and avoid the need to incur expensive network augmentation to meet the system peak. Our TOU proposal is consistent with that in other Australian jurisdictions and better reflects how network costs are incurred.

11.2.4 Peak demand charging

Given the desire for simplicity and incremental changes to tariffs, we have removed demand charging for all customers other than those in Tariff 5 (LV major customers) and Tariff 6 (HV smart meter customers).

For Tariff 5 and Tariff 6 customers we will apply a demand charge. However, we propose to change the peak periods to align with the new peak period used in the TOU tariffs, 3pm to 9pm. As discussed in the previous section, this change aligns more closely with the network peak and associated costs. The revised demand charging periods are:

- Wet season - Peak – 3pm to 9pm Monday to Friday (including public Holidays) from 01 October to 31 March.
- Dry season - Peak – 3pm to 9pm Monday to Friday (including public Holidays) from 01 April to 30 September.

Customers are charged for the highest recorded demand during the peak period, regardless of season, each month. As signalled in our Draft Plan, we considered introducing a charge reflecting the average of kVA demand in the peak period, applied as a daily rate. However, electricity retailers have since told us that the average charge would be too difficult to explain to customers and would likely not be able to be implemented within current billing systems.

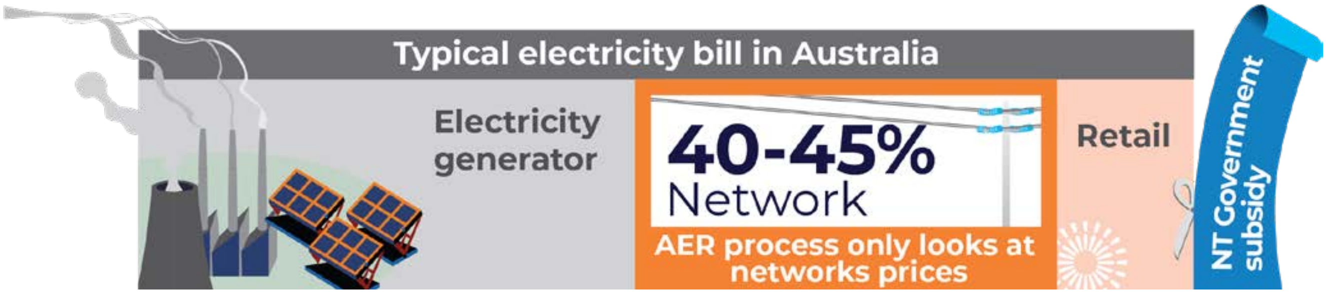
11.2.5 Tariff trials

Our unique NT settings under the Pricing Order, mean that we cannot assume any behavioural response from tariff designs for most customers. Indeed, our largest NT retailer recommended we adopt more simplistic network tariff structures that mirror the Retail Pricing Order.

We therefore propose to collaborate with NT retailers and NT Government to design targeted trials that can:

- Inform our future network tariff design.
- Provide evidence to support the NT Government considering reform to the Pricing Order for either customer thresholds or tariff structures.
- Test specific pricing innovations – we are currently thinking about potentially running trials for:
  - Export pricing.
  - EV charging.
  - Grid-scale batteries.

Figure 52 – Components of a typical electricity bill



11.3 Indicative price impact

In our conversations with customers, we have been discussing the complexity of translating the impact of a change in network revenue in 2024-29 to a customer's electricity bill.

Similar to other states and territories in Australia, a customer's electricity bill is issued by their retailer. The bill reflects the customer's share of the total cost of supplying energy including generation of electricity, the use of our transmission and distribution network, the retailer margin, and the costs of managing the power system and market operating costs.

In the NT, the Government provides a subsidy for smaller customers through the Pricing Order that reduces their electricity bill. This means that the tariffs in a customer's bill do not relate to the relative costs of each sector, making it complex to specify the relative contribution of our costs. In our conversations with customers, we have noted that in Australia, network costs account for 40 to 45 per cent of the electricity bill as shown in Figure 52.

The extent to which network costs are passed on to customers depends on how the NT Government Pricing Order will change in the 2024-29 period. However, for discussions on affordability with customers we have assumed that an increase in our network revenue would be fully reflected in a customer's bill. For larger customers, it is more probable that an increase in our network revenue would be passed through by the retailer, although this will depend on the specific tariffs of the retailer.

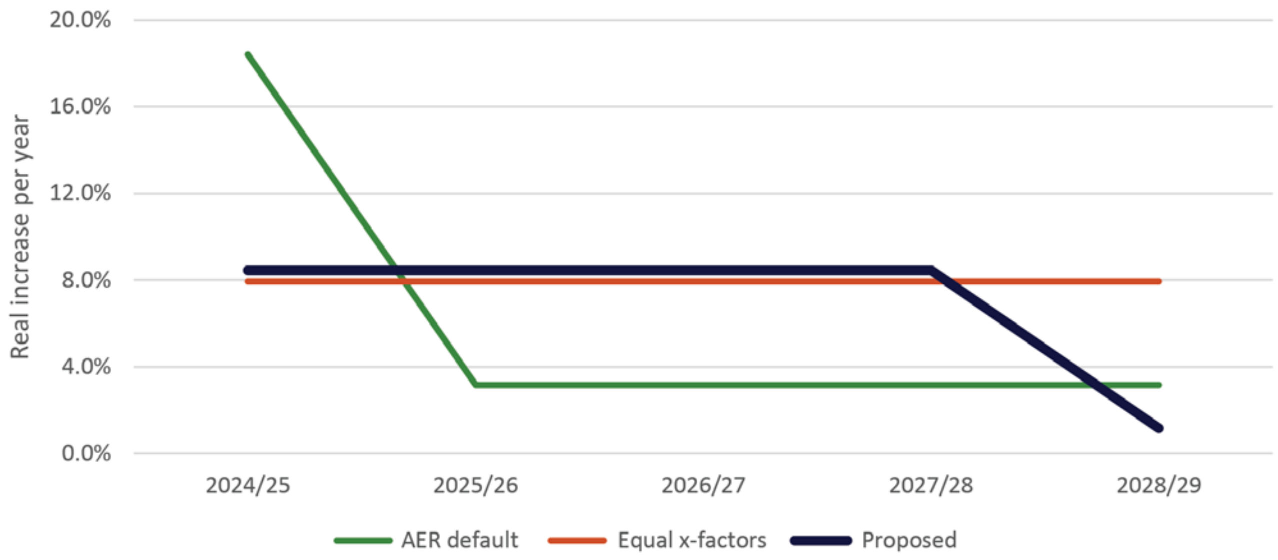
For the purposes of this Regulatory Proposal, we have assumed the annual change in smoothed revenue will have a direct impact on typical customers in each tariff class, using the updated tariff classes discussed above. Note our analysis also does not take into account changes in customer numbers, energy and demand, which also impact electricity bills.

Our overall proposal increases smoothed revenue by 7.0 per cent per annum. Using the AER's default revenue path, smoothed would increase by 18.4 per cent in 2024/25 and 3.2 per cent increases each year thereafter for the remainder of the period. Conscious of the impact on our customers and cost of living pressures, we have sought to develop a revenue path that balances the impact on customers' bills and the AER's target of being within 3.0 per cent of the building block revenues in the final year of the period. We therefore propose to adopt a smoothed x-factor price path, which will see 8.4 per cent per annum price increases in the first four years, moderating to 1.2 per cent in the last year. Figure 53 shows the comparison of each price path option.

We have sought to moderate the price impact on those large customers exposed to cost-reflective tariffs by:

- Capping bill increases for the majority of our exposed customers at the average network tariff rate.
- Nodifying the peak demand periods for those tariffs we propose to retain a peak demand charge for.
- Providing opportunities for cost savings through the introduction of opt-in tariff innovation trials.

Figure 53 – Price path options, per cent increase of average network prices



12. Incentives and pass through events

We support the use of effective, outcome-based incentive schemes that promote the long term interests of our customers. We will seek to make more use of existing incentive mechanisms to drive efficiencies and overall performance improvements throughout the business. This includes introducing an efficiency benefit sharing scheme, focusing on achieving lower operating costs.

We will also continue to use the innovation allowances available under the NT NER to support the technologies customers have told us they value, such as battery storage, electric vehicles, and rooftop solar.

12.1 Incentives

Incentive schemes are used to:

- Strengthen a service provider's incentive to continuously seek out efficiency and performance improvements and share the benefits with customers.
- Balance incentives between opex and capex so that the most efficient expenditure mix is chosen.
- Pursue efficiencies while improving or maintaining service quality.
- Encourage investment in innovation in areas that can provide longer-term benefits to our customers.

In the current regulatory period, the AER's Capital Expenditure Sharing Scheme (CESS) and demand management mechanisms (DMIA and DMIS) applied. We outperformed our capex allowance providing access to a small CESS reward, and used the DMIA to progress planning for the transition to more dynamic, two-way network flows.

In the next regulatory period, we will retain our current incentives and add the Efficiency Benefit Sharing Scheme (EBSS) to seek further efficiencies in our operating and maintenance costs.

12.1.1 Current performance

Over the current regulatory period, we estimate we will have spent $6.9 million more than our capex allowance (net of capital contributions and asset disposals). The operation of the CESS would have seen 70 per cent, or $4.9 million of this being funded by customers in future regulatory periods, with us covering the remaining $2.1 million. This overspend leads to a CESS penalty of $2.7 million

We have worked hard to ensure the forecast program for the next regulatory period is prudent and efficient, and also deliverable. We are also continuously improving our asset management and investment governance, and therefore expect to be able to leverage the CESS to outperform our allowance in the next period.

We have not yet sought to apply the DMIS to any projects in the current period. However, we have used funding available under the DMIA to deliver a number of projects associated with our future network strategy. This included commencing development of a grid visibility tool that will determine hosting capacity across the network using real time metering data. The work conducted under the DMIA will allow us to design and implement a dynamic operating envelope across our distribution system, to enable rooftop solar, electric vehicles and batteries to connect to our networks without compromising system security.

Table 7 – Proposed incentive framework

Incentive mechanism	2019 24 period	2024 29 period
CESS	✓	✓
EBSS	X	✓
STIPIS	X	X
DMIA / DMIS	✓	✓
CSIS	X	X

12.1.2 Proposed incentive framework

As discussed in Chapter 7, our incentive framework for 2024-29 is aligned with the AER's Framework and Approach determination.

We strongly believe incentive schemes play an important role in encouraging network businesses to continually look for improvements to the way they deliver services. By retaining the demand management mechanisms (DMIA and DMIS) we can continue our future network projects and set ourselves up to tackle the impact of solar and electrification of industries over the coming decades.

The DMIA in particular provides opportunity for us to pursue innovative solutions that can keep costs down in the future, while allowing us to deliver services customers want. For example, during 2024-29 we will use the DMIA to investigate how battery storage can be used to improve network utilisation. This includes researching, trialling and studying two battery storage solutions in our Alice Springs and Darwin-Katherine networks.

The AER's Framework and Approach paper requires us to implement an EBSS to support the use of the revealed cost opex forecasting method. We consider the introduction of the EBSS will not only drive further efficiencies in our opex, but it will also provide a better balance of capex and opex incentives. Without an opex incentive, there may be a bias towards opex solutions in place of spending capex. We consider this should be avoided, and see the EBSS as one mitigation.

We do not propose to apply other incentive mechanisms such as the Service Target Performance Incentive Scheme (STPIS) or customer service incentive scheme (CSIS) at this stage. This is largely because we do not have the information to report on the performance measures required under the scheme. Moreover, we expect a greater focus on delivering efficiencies under the capex and opex incentives will deliver better affordability outcomes for our customers.

Table 7 compares the current incentives applicable to those we are proposing for the next regulatory period.

More information on our incentive schemes is available in Attachment 12.01.

12.2 Pass through events

We have nominated a number of specific, pre-defined events that are unpredictable in nature, beyond our control, and if they occur, would involve us incurring significant costs. The pass through mechanism allows us to recover the efficient cost of these events from customers, that we would otherwise not be able to. These apply to both standard control services and alternative control services.

For the 2024-29 period, we have defined five pass through events. Four of these are retained from the current period, with one new event proposed.

12.2.1 Retained nominated pass through events

In the next period we propose to retain the following nominated pass through events:

- **Insurance coverage event** - To address the risk of Power and Water incurring costs beyond the limit of a relevant insurance policy due to changes in the insurance market.
- **Insurer's credit risk event** - To address the risk of one of Power and Water's insurers becoming insolvent and PWC incurring costs associated with high or lower claims limits or deductibles.
- **Natural disaster event** - To address the risk of a natural disaster such as a cyclone, fire, flood or earthquake that increases the cost to Power and Water of providing direct control services.
- **Terrorism event** - To address the risk of a terrorism event increasing Power and Waters costs.

These four events remain unchanged from those previously accepted by the AER, with the exception of a minor change to the terrorism event to include cyber-attack in the definition of terrorism. Given the recent high profile data breaches across Australia, we consider it prudent to explicitly call out cyber terrorism in the pass through mechanism.

12.2.2 New pass through event

We propose one new pass through event for 2024-29, relating to the potential for energy sector reform that may impact Power and Water's structure or accountabilities.

Further detail regarding our proposed nominated pass through events is provided at Attachment 12.02.

Operational staff working on distribution lines

13. Alternative control services

During the 2024-29 regulatory period, we will continue replacing end-of-life mechanical meters with smart meters, as well as installing smart meters for all new connections. Developing an expansive smart meter fleet will allow our customers to continue to install distributed energy resources such as rooftop solar and batteries, while enabling innovative tariff setting and better asset management. It will also address the condition, accuracy and reliability issues with our current metering fleet.

We will continue to provide cost reflective fee-based and quoted services.

13.1 Metering

Metering for type one to six meters is an alternative control service[18] whereby we identify an individual charge for the service separate to the standard control services. This means metering revenue, capex and opex are determined separately to all other network services, and meters form their own asset base.

Our forecast revenue and costs assume we will retain responsibility for metering in the Territory for the next regulatory period. Our proposal is consistent with the AER's decision to retain a price cap for metering services.

Over the next period we plan to recover $64.9 million of revenue from metering customers. This will allow us to invest $41.5 million of capital in metering assets, and $33.5 million to operate and maintain our meter population, read the meters, and provide metering coordination and data management services.

While there is a step increase in tariffs of 33.9 per cent in the first year of the period, this is primarily driven by the fact incorrect volumes were used to set prices in the current period (see section 13.1.1). We have developed tariffs such that the main increase is in the first year of the next regulatory period, with increases of only 4.9 per cent per year across the remainder of the period.

There are approximately 87,500 'billing meters' in our network, 24.9 per cent of these are now over 30 years old, and well beyond their 15-year technical design life (see Figure 54).

Though a range of factors contribute to meter accuracy and performance (for example location and meter type), age is a good indicator. Generally speaking, the further a meter gets beyond its technical design life, the more it becomes prone to measurement errors, which results in inaccurate billing and non-compliance with national measurement requirements. It is therefore important to periodically test our meter and replace non-compliant meters.

[18] Metering for type seven meters are covered as a standard control service.

Figure 54 – Existing meter population by age, at June 2024

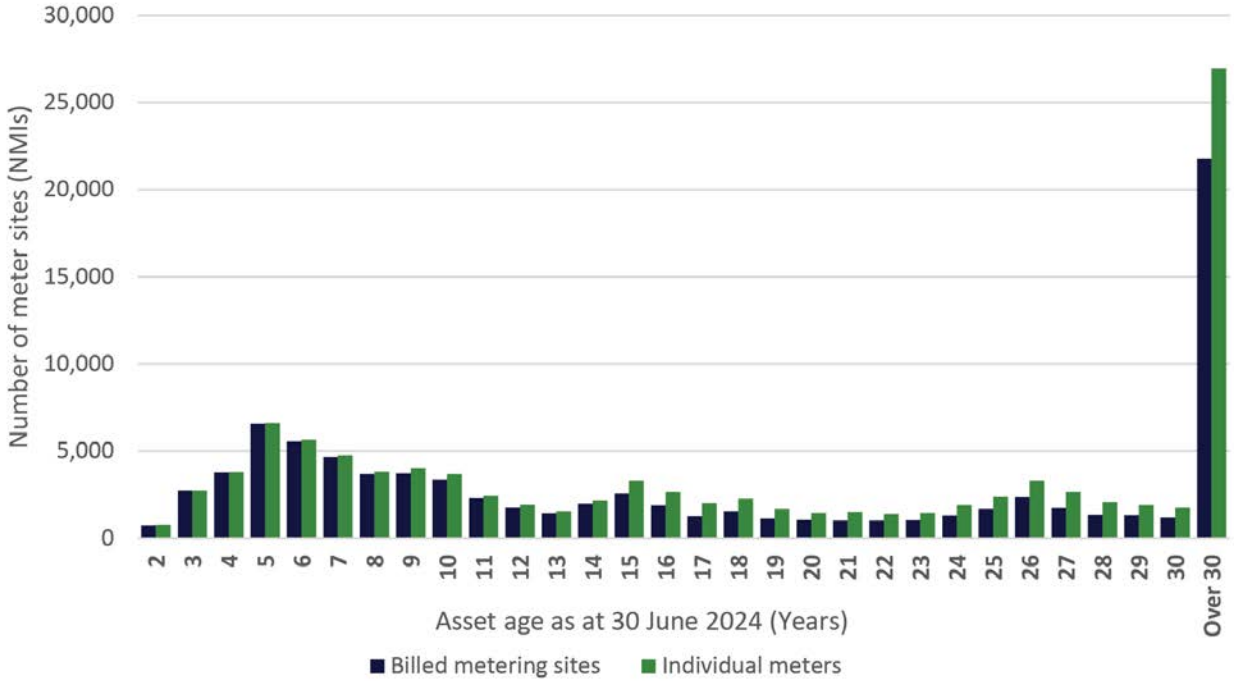
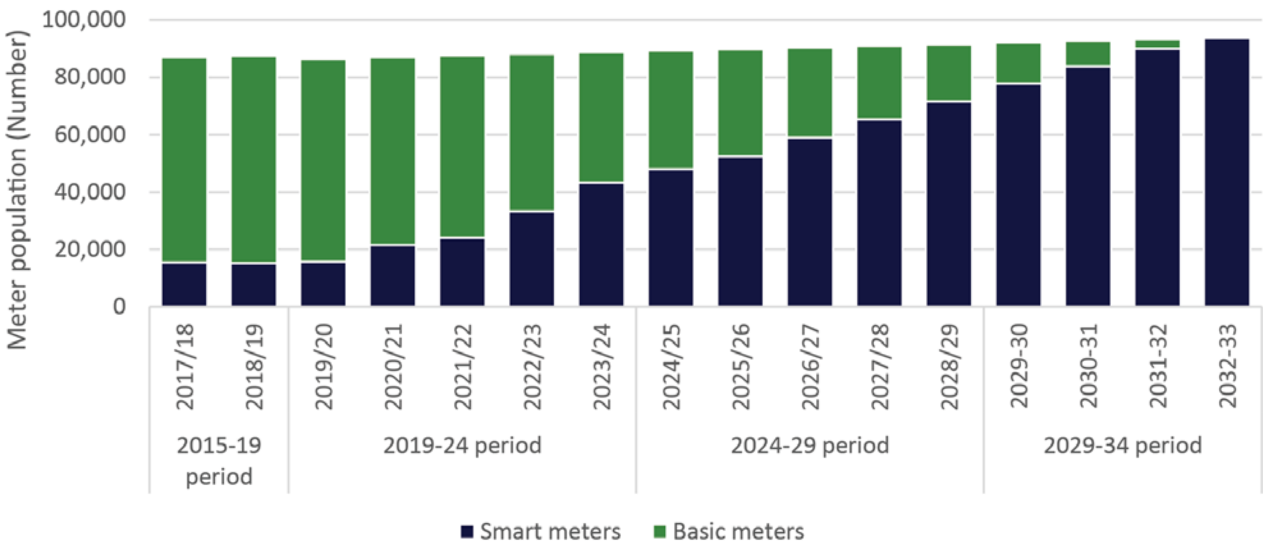


Figure 55 – Meter replacement volumes over time



During the current regulatory period we continued to install smart meters for new connections and replacement meters. Smart meters have become the standard across the industry[19], and offer a range of potential benefits including better data, better outage management, and billing equity. The cost of smart meters has fallen dramatically over the past decade, and are generally easier to source than traditional mechanical meters. It therefore made sense to start making the progressive age-based switch to smart metering.

In its 2019-24 determination, the AER approved our smart meter program, and we intend to continue this activity over the course of 2024-29 and the following period (2029-34).

By the end of the current period (June 2024), we expect around half of our meter population (43,300 meters) will be smart meters. In the next regulatory period, we estimate we will install a further 24,600 smart meters by replacing end-of-life, faulty or failed meters, as well as another 2,810 smart meters for new connections. The balance of around 20,000 non-smart meters will be replaced with smart meters during the following regulatory period (2029-34).

We considered both a faster and a slower replacement program for our aged meter population prior to putting this proposal forward. We believe what we have proposed represents the best balance between the benefits and costs of the program. By continuing the current replacement rates we have a program that is deliverable, minimises the need to ramp-up our workforce, and most importantly, smooths the impact on tariffs over time.

The metering strategy included with this Regulatory Proposal is consistent with that presented to customers in our August 2022 Draft Plan, and the People's Panels, which received broad support from customer groups (see Attachments 1.01 and 1.02 and 1.03).

13.1.1 Current performance

Despite a later than forecast start to the metering program, we expect to deliver it in full by the end of the current period. For the current regulatory period, the capex allowance was $31.2 million. This was to:

- Replace end of life mechanical meters with smart meters, increasing our smart meter population by around 21,200.
- Connect 2,784 new customers with smart meters.
- Replace the 3G modems on existing smart meters before the 3G network scheduled decommissioning in 2024.
- Install communications on a number of smart capable, but not yet enabled meters.
- Remediate around 2,800 asbestos meter panels.

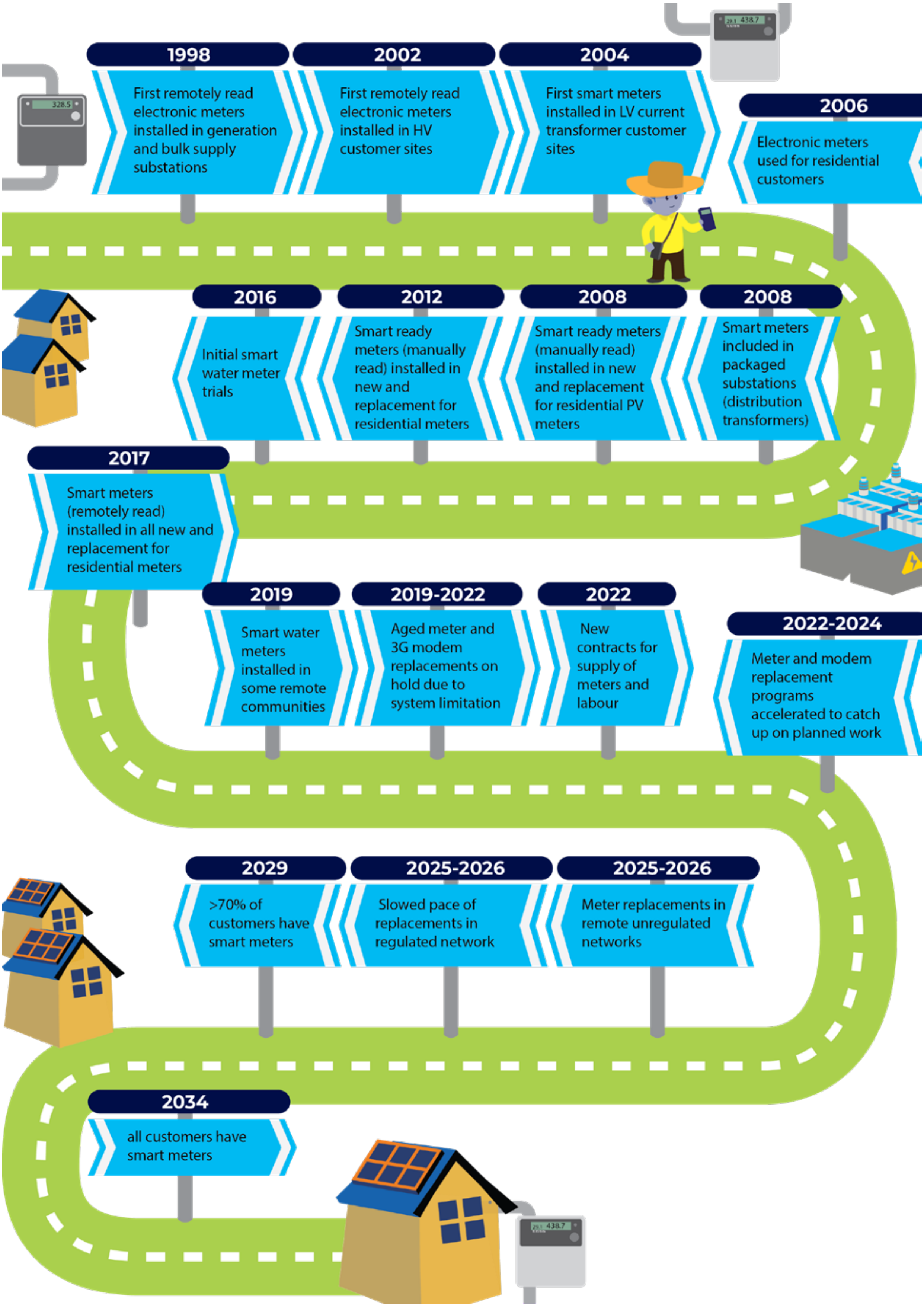
We have spent $9.3 million of capex in the first three years, and estimate we will spend another $25.6 million in the next two years. This will deliver the proposed program in its entirety, at a slightly higher cost than the $31.2 million allowance.[20]

Our planned smart meter installation program was paused at the beginning of the current period, as we identified our existing ICT systems were not able to process and store the huge uplift of data volumes produced by smart meters. We are in the process of installing the necessary back-end metering, billing and market systems to cope with the increased scale of data. With these constraints now being addressed, we have started to ramp up our delivery capacity to achieve the planned volumes.

Our metering opex is expected to be $35.3 million over the current period, or $7.1 million per annum, on average. This is $3.1 million or 9.6 per cent higher than the current period forecast. This increase in cost is largely driven by an increase in actual labour rates compared to forecast.[21]

[19] In November 2022, the Australian Energy Market Commission (AEMC) put forward a recommendation for a 100 per cent uptake of smart meters by 2030 as part of a suite of reforms putting customers at the heart of the transition to net zero (see: https://www.aemc.gov.au/news-centre/media-releases/metering-review-smarter-energy-future).
[20] In 2021/22, we improved our overhead cost allocation approach, which resulted in more costs being directly charged to opex activities and capex projects. This affected ACS categories as well as SCS categories. More information on this change is provided in see section 9.2 and Attachment 9.01.
[21] We completed a labour rate review in 2021. As part of this we escalated our costs which were established four years prior and had not been indexed. We also improved our overhead cost allocation approach, as discussed previously.

Figure 56 – Our metering journey



13.1.2 Capital expenditure

We plan to spend $41.5 million of capex over the next five years to provide our customers accurate and reliable metering services. Our forecast capex program is $6.7 million or 19.2 per cent higher than the current regulatory period, and $10.3 million or 32.9 per cent higher than the AER's allowance.

Our proposed capex program for meters includes:

- $17.5 million to replace a further 21,000 end of life mechanical meters with smart meters.
- $2.7 million to replace failed in-service meters.
- $7.2 million to manage asbestos meter panels in order to replace end of life meters.
- $2.3 million on other replacement programs.
- $9.2 million related to non-network metering costs, including for example fleet, property and equipment.
- $2.6 million to connect a further 2,810 customers to the network.

During the current period, we have identified a number of environmental impacts that could shorten the lives of our smart meter population. For example, we found that the LCD displays on meters fail more frequently in the tropics. We have not proposed to reduce the life of metering assets as part of this plan, but will monitor these issues and the impact on the health of our meter population over the next five years.

13.1.3 Operating expenditure

We plan to spend $33.5 million over the next five years to operate and maintain our meters and manage meter data. This is a decrease of 5.1 per cent when compared to the $35.3 million we expect to spend in the current period, but $1.3 million, or 4.0 per cent higher than the current period allowance.

Our forecast opex remains in line with our actual spend in the current period. Increases driven by the allocation of various step changes from our overall opex program to metering services (see section 9.4) are wholly offset by:

- Establishment of a contracting panel to supplement internal labour for metering work, which is providing efficiencies and reducing overall costs.
- Improved allocation of overhead costs from overall opex directly to activities and projects (see section 9.2 and Attachment 9.01).

We have used the same base-step-trend forecasting method as we used for standard control services, including the use of 2021/22 revealed costs as the base year (see section 9.1).

The base step trend method has resulted in:

- Output growth of 0.3 per cent, directly related to the number of new customers connecting to the network, and therefore requiring new meters, resulting in an additional $0.3 million over the period.
- A number of step changes totalling $1.2 million, such as savings for increased remote, rather than manual meter reads and reductions in special meter reads, as well as an allocation of the step changes that apply across our opex program as a whole, such as the cyber security uplift.
- An additional $0.1 million of debt raising costs, forecast using the same method as our standard control services (more information about the calculation of debt raising costs is provided in section 10.3).

13.1.4 Revenue

We plan to recover $64.9 million in revenue for metering services during the next period. This is $29.8 million or 84.8 per cent higher than the $35.1 million we expect to recover during the current period (see Figure 57).

Forecast metering revenue comprises:

- $33.6 million in opex.
- $15.1 million return of capital (depreciation).
- $16.2 million return on capital.

Over the next period, the asset base will grow by $19.2 million or 38.5 per cent, from $49.9 million to $69.1 million.

The key drivers of the increased revenue requirement are:

- The $19.2 million or 38.5 per cent increase in the metering asset base resulting from our concerted efforts to replace end of life meter assets.
- Decreasing but still significant metering opex of around $6.7 million per annum, which we expect to last until we can deliver significant portions of our network more robust and remote metering solutions.
- Current economic conditions and associated increases in financing costs estimated to be worth $3.3 million.

13.1.5 Tariffs and indicative prices

We have made a number of changes to the way our metering services are categorised to better allocate costs between customers. Specifically, we have separated low voltage current transformer and high voltage metering each into their own categories. This will ensure these higher cost services are not incorrectly allocated to customers with lower cost service provision.

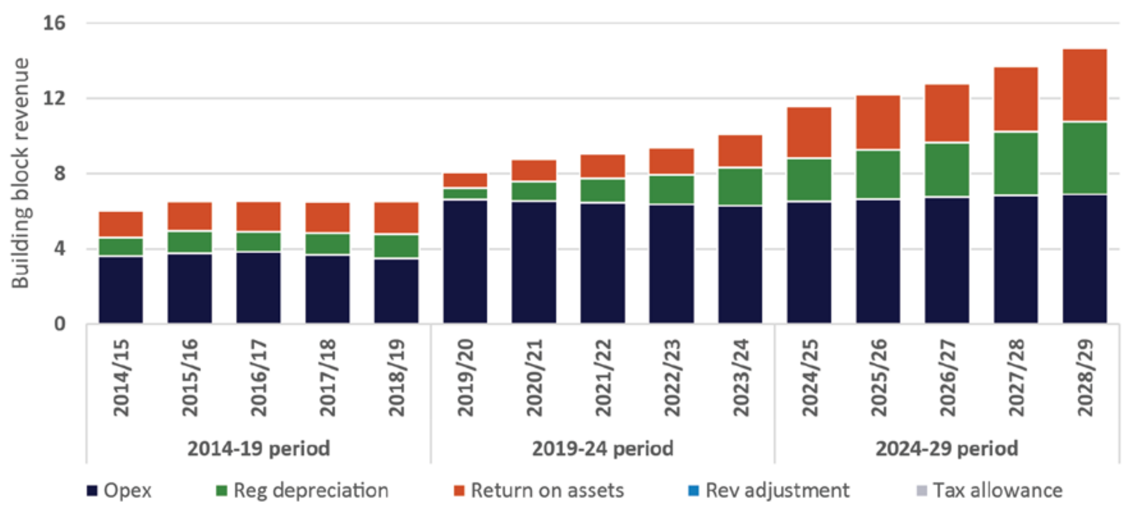
Not all generators were charged for metering services in the 2019-24 regulatory period due to an historical anomaly where NMIs were not allocated to these meters and as there was no mechanism to charge the generators through our billing system. These issues will be corrected prior to the commencement of the 2024-29 regulatory period.

More information on the proposed changes to our metering tariffs is provided in Attachment 13.01.

We have allocated the forecast revenue to each of the proposed updated tariffs and annualised the costs[22]. The resulting tariffs are provided in Table 8.

While there is a step increase in tariffs of 33.9 per cent in the first year of the next regulatory period, this is primarily driven by incorrect volumes being used to set prices in the current period, as well as the impact of upgrading the meter fleet for meters beyond their technical design life and the change to capitalisation policy. We have developed tariffs such that the main impact is in the first year of the next regulatory period, with increases of only 4.9 per cent per year across the remainder of the period.

Figure 57 – Metering revenue ($ million real 2024)



[22] These annual charges will be converted into a daily charge for billing purposes.

Table 8 – Metering tariffs ($ per meter per annum excluding GST real 2024)

Metering tariffs	2023/24 [e]	2024/25	2025/26	2026/27	2027/28	2028/29
Single phase meters (including prepayment)	82.25	110.16	115.53	121.16	127.07	133.27
Three phase direct connected meters (including 3 single phase meters on a single NMI)	108.98	145.95	153.06	160.53	168.36	176.57
Low voltage current transformer metering	434.89	582.42	610.82	640.61	671.85	704.62
High voltage metering	1,500.45	2,009.45	2,107.45	2,210.22	2,318.00	2,431.05

13.2 Fee-based services

Fee-based services are usually standard in nature and there is little to no difference between a customer or retailer's request. In these cases, we provide a price list. The list of fee-based services is consistent with the current regulatory period, and the AER's Framework and Approach determination.

We have developed each of our proposed prices using a bottom-up, input cost model to determine the efficient, cost reflective charge for each service. The cost build-up comprises historical labour rates and materials costs, the incremental cost of contractor services and a tax allowance where each is applicable and available. We have also applied real cost escalation using the escalators applied to our opex forecasts (see section 9.3 and Attachment 9.02).

The resulting tariffs are provided in Attachment 13.01.

13.3 Quoted services

Quoted services are those which are unique depending on the scope of a customer or retailer's request. It is not practical to establish individual fees for these services as they vary from project to project.

Consistent with the AER's Framework and Approach paper, we have re-classified standard and negotiated connection services from standard control services to alternative control services. We have classified them as quoted services and applied a price cap form of control. We have used the AER's method of determining prices for these services.

We will apply the AER's price cap formula for quoted services set out in the Framework and Approach determination.

Our quoted services are based on labour costs, materials, the incremental cost of contractor services, a margin on costs and a tax allowance where applicable. We have also applied real cost escalation using the escalators applied to our opex forecasts (see section 9.03 and Attachment 9.02).

The resulting indicative rates are provided in Attachment 13.01.

66 kV isolator at entry to Owen Springs transmission substation

PowerWater

Power and Water Corporation

Level 2, Mitchell Centre
55 Mitchell Street, Darwin
Phone 1800 245 092

powerwater.com.au

@powerwatercorp