Attachment 8.01

Capital expenditure

31 January 2023

PowerWater

Contents

PowerWater

Abbreviations

The following table provides a list of abbreviations and acronyms used throughout this document. Defined terms are identified in this document by capitals.

Term	Definition
ACS	Alternative Control Services
AER	Australian Energy Regulator
AESCSF	Australian Energy Sector Cyber Security Framework
Augex	Augmentation Capex
BAU	Business As Usual
BESS	Battery Energy Storage System
Capex	Capital Expenditure
CECV	Customer Export Curtailment Value Note
Connex	Connections Capex
DCDD	Department of Corporate and Digital Development
DER	Distributed Energy Resources
DKESP	Darwin-Katherine Electricity System Plan
DKTL	Darwin-Katherine Transmission Line
DKS	Darwin-Katherine System
DMIA	Demand Management Innovation Allowance
DOE	Dynamic Operating Envelope
DTC	Distribution Transfer Capacity
DWDM	Dense Wavelength Division Multiplex
EMS	Energy Management System
EPMC	Enterprise Portfolio Management Committee
EPMO	Enterprise Portfolio Management Office
EVs	Electric Vehicles
ICT	Information and Communications Technology
ISDN	Integrated Services Digital Network
ISP	Integrated System Plan

Term	Definition
LDC	Land Development Commission
MSS	Modular Substation
NBN	National Broadband Network
NEM	National Electricity Market
NER	National Electricity Rules
NT	Northern Territory
NTEM	Northern Territory Electricity Market
NTEMS	Northern Territory Electricity Market Settlement
OT	Operational Technology
PSTN	Public Switched Telephone Network
PV	Photovoltaic
Repex	Replacement Capex
RIN	Regulatory Information Notice
SAMP	Strategic Asset Management Plan
SCADA	Supervisory Control and Data Acquisition
SCS	Standard Control Services
SOCI	Security of Critical Infrastructure
SP-2	Security Profile 2
TDAPR	Transmission and Distribution Annual Planning Report
ZSS	Zone Substation

Overview

We are proposing a 29.8 per cent increase in capital expenditure (**capex**) in the 2024-29 regulatory period compared to 2019-24. Our proposed expenditure responds to strategic priorities including efficiently managing our ageing network assets, improving network utilisation, facilitating acceleration of renewables in our power systems, and incrementally refreshing our aged ICT systems. Our forecast capex also includes a 'one-off' investment of $89.8 million to centralise more of our Darwin staff in one location.

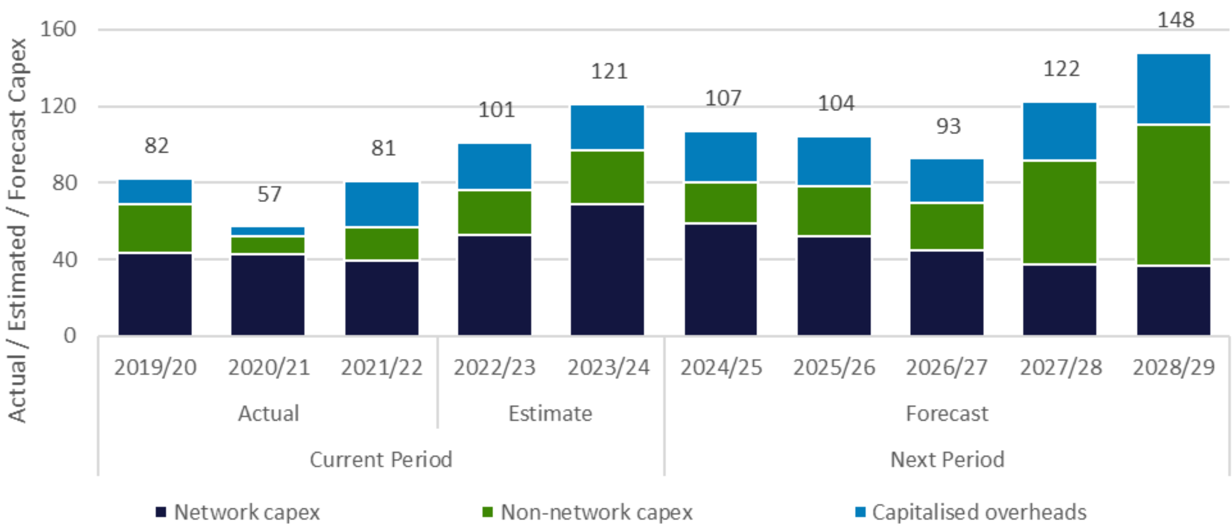
We incur capital expenditure to replace network assets, build new network assets, connect customers to the network, and invest in information and communication technology (**ICT**) systems, corporate property and fleet investment and leases. We also incur indirect costs relating to undertaking capital expenditure, termed capitalised overheads.

Our forecast

We forecast capex of $574.8 million for the 2024-29 regulatory period, compared to $442.7 million in the 2019-24 regulatory period. The 2024-29 forecast is $132.1 million higher or about 29.8 per cent more than our actuals and estimates of capex in the current 2019-24 period. The forecast capex is 22.5 per cent higher than the Australian Energy Regulator's (**AER**) regulatory allowance for the current 2019-24 period of $469.4 million.

Figure OV.1 compares the forecast capex to the current period network capex, non-network capex and capitalised overheads.

Figure OV.1: 2024-29 Forecast capital expenditure compared to 2019-24 actuals/estimates ($ million, real 2024)



The network capex forecast is at similar levels to the actual/estimates for 2019-24. The 2024-29 forecast reflects a moderate increase in replacement capex to maintain network performance as network assets age and condition issues emerge. The forecast also reflects a decline in augmentation capex, driven by much slower demand growth than in previous periods.

Non-network capex is increasing significantly due to a one-off property project in the last two years of the regulatory period, and an increase in our ICT capex as we bring our ageing ICT systems up to contemporary standards. The forecast of capitalised overheads is increasing as a result of a change in our approach to overhead allocations.

Alignment with strategic priorities

Power and Water is facing complex global and local challenges, requiring a strategic re-think of our priorities. The key long-term challenges influencing our capital expenditure include maintaining the reliability of the network as our network assets age beyond their manufacturing life, security of the network as renewables increase, and ensuring our systems and people can efficiently meet increasing complexity.

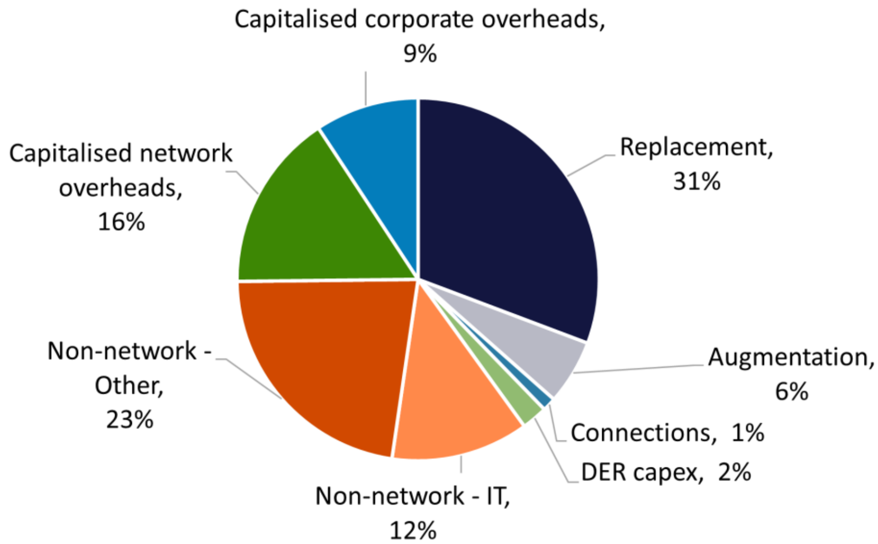
Our capex forecast is designed to help achieve our strategic priorities: facilitating renewables, improving utilisation, managing the health of our network, and uplifting our systems and people. To do this, our capex program has investment focus areas:

- Uplift in asset management capabilities and asset replacement – Historically, with the exception of a short spike in works following the 2008 Casuarina failures, our asset replacement rates have been low. This is due largely to the fact many of our assets are younger than their expected technical life. However, over the next 20 years, a significant proportion of assets built after Cyclone Tracy in 1974 will exceed their expected life. Our program for 2024-29 seeks a moderate uplift to replacement capex as we respond to emerging condition issues associated with the ageing of these assets to 2030.
- To keep the increase in replacement capex to a minimum, and manage potential price impacts on customers, we are complementing this network asset replacement program with investment in our asset management systems and data quality. This uplift in our data and asset management capabilities will allow us to extend the lives of these assets where safe to do so, and manage costs more prudently over the long term.
- Managing growing rooftop solar – The Northern Territory (**NT**) Government's announcement of a 50 per cent renewable target for electricity in Darwin-Katherine and Alice Springs has driven a marked acceleration in small and large scale renewables in the next regulatory period. We have included programs to facilitate the increased amount of small scale solar on the network while maintaining system security. We have also proposed contingent projects to facilitate large scale renewables through our transmission network, consistent with the NT Government's Darwin-Katherine Electricity System Plan (**DKESP**).
- Investing in transformative ICT systems – 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 period that will help us uplift our capabilities.
- Investing in corporate property - We have proposed a corporate property project to consolidate more of our Darwin staff in one location. This project is at a very early stage of planning, but we consider there is a strong likelihood that we can demonstrate a net benefit to our customers in the long term.

Description of capex forecast by capex category

Figure OV.2 provides a breakdown of the capital forecast by AER category. At a high level, about 40.0 per cent of capital expenditure relates to network investment, 34.8 per cent relates to non-network investment, and 25.2 per cent relates to capitalised overheads. The significant impact of non-network investment relates to a one-off property investment (about 15.6 per cent of forecast capex) where we intend to co-locate our Darwin staff into one Power and Water owned location (Ben Hammond complex).

Figure OV.2: Breakdown of program by capex category (per cent)



We incur replacement expenditure (**repex**) to replace or extend the lives of our existing network assets. Repex accounts for 30.7 per cent of forecast capex in the 2024-29 period. In total, we are forecasting $176.6 million in the 2024-29 period compared to $149.9 million actuals/estimates in the current 2019-24 period, an increase of 17.8 per cent. The uplift in replacement reflects emerging condition issues with our assets as our Cyclone Tracy assets reach and exceed their expected life. Our replacement strategy has sought to use techniques such as risk quantification to defer replacement programs where the risk can be managed. The key programs relate to replacing a zone substation at Berrimah, and ongoing programs to replace high voltage cables in the Northern Suburbs of Darwin and to replace corroded poles in Alice Springs. We are also investing in new programs including a planned replacement of overhead service lines and protection relays.

Augmentation capex (**augex**) relates to expenditure on new network assets to address capacity issues with growing peak demand, comply with prescribed reliability and voltage standards set by our jurisdictional regulator, and address condition and risk issues. Augex accounts for only 5.8 per cent of forecast capex in the 2024-29 period. In total, we are forecasting $33.2 million in the 2024-29 period compared to $62.6 million actuals/estimates in the current 2019-24 period, a decrease of 47 per cent. We are proposing minimal expenditure to meet growing peak demand across our three regulated systems, reflecting the existing capacity on the network and a more cautious approach to forecasting spot loads. Other programs include maintaining reliability of poor performing feeders and maintaining compliance with voltage standards.

Distributed energy resources (**DER**) capex is a new category of expenditure related to facilitating growing small-scale renewables on the network, primarily rooftop solar photovoltaic (**PV**) systems. We will be investing in a new dynamic operating envelope (**DOE**) solution to help manage exports of solar to ensure the network and power system remain reliable and secure, while maximising the level of low-cost renewable generation. The capital expenditure portion of the project is $13.2 million, or about 2.3 per cent of the forecast capex for the 2019-24 period.

Connections capex (**connex**) is required to service new, altered or upgraded connections for residential, commercial and industrial customers. Connex accounts for only 1.2 per cent of forecast capex in the 2024-29 period. In total, we are forecasting $7.0 million in the 2024-29 period compared to $33.4 million actuals/estimates in the current 2019-24 period, a decrease of 79.0 per cent. This is driven by a change in service classification where negotiated connections have changed from SCS to alternative control services (ACS) consistent with the AER's Framework and Approach paper. It is also driven by a change in the way gifted assets are treated under the regulatory framework, where they are no longer captured as a standard control service. We have also proposed minor amendments to the connection policy to apply in the 2024-29 period.

ICT systems and staff support our network and corporate functions. Non-network ICT accounts for 12.3 per cent of the forecast capex in the 2024-29 period. In total, we are forecasting $70.7 million in the 2024-29 period, compared to $50.3 million actuals/estimates in the current 2019-24 period, an increase of 40.6 per cent. 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.

Non-network other comprises our leases and investments in corporate property, fleet and plant. Non-network other accounts for 22.5 per cent of the forecast capex in the 2024-29 period. In total, we are forecasting $129.4 million in the 2024-29 period, compared to $54.8 million actuals/estimates in the current 2019-24 period, an increase of 136.3 per cent. This largely relates to developing the Ben Hammond complex so that all Power and Water staff across four facilities can be housed in the one premise, rather than leasing out separate properties. This project accounts for $89.8 million of non-network other capex.

Overheads are network and corporate costs that are shared costs across the business that we cannot directly allocate to a particular business activity. A portion of these costs are allocated as capitalised overheads based on our accounting practices and in accordance with our cost allocation method. Capitalised overheads account for 25.2 per cent of forecast capex in the 2024-29 regulatory period. In total, we are forecasting $144.7 million in the 2024-29 period compared to $93.8 million actuals/estimates in the current 2019-24 period, an increase of 54.3 per cent. While this represents an increase to the capex forecast, it is offset by a commensurate reduction in forecast operating expenditure (opex). We have made this simple accounting change to reflect guidance from the AER to better align Power and Water more closely with other Australian networks. This change is consistent with our AER-approved cost allocation method, which we have not revised.

We are also proposing five contingent projects relating to:

- Transmission works to connect a large renewable energy hub in the south of Darwin.
- Transmission works to alleviate constraints on our transmission network on the Darwin-Katherine transmission lines.
- Works to connect new land development in Holtze-Kowandi.
- A new commercial development in Middle Arm.
- A new commercial development in East Arm (Wishart).

Feedback from stakeholder engagement

We have sought to incorporate the key elements of feedback from our customers when developing our expenditure forecasts.

The key theme we heard from our residential and business customers was that we need to prudently invest for the long-term including managing our ageing assets and facilitating the transition to a renewable energy system. At the same time, customers wanted us to consider how we manage short term affordability in the context of rising revenue requirements in the 2024-29 period. Customers considered that we should apply levers to reduce expenditure where sensible and ensure that we roll out new and innovative technology at a prudent and incremental pace.

Table OV.1 shows the key themes of feedback that relate to capex, and how we incorporated the feedback.

Table OV.1: Feedback from stakeholders relevant to our forecast capex for 2024-29

Theme	Customer feedback	Incorporating feedback into network capex forecasts
Levers to improve short term affordability	In our engagement sessions, our People's Panels and major customers considered we should look at opportunities to reduce capex, but to ensure this was not at the expense of long-term sustainability. Customers 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 to improve safety outcomes and place downward pressure on our costs. • This includes 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 and/or reduce the volume of replacement programs and focus on the highest risks to public safety. • 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 has allowed 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.

Theme	Customer feedback	Incorporating feedback into network capex forecasts
Facilitate renewables	Our People's Panels, major customers, and submissions on the Draft Plan were generally supportive of our strategic priorities including our plans to facilitate growing renewables on the network but wanted us to scale up prudently. Stakeholder submissions also wanted us to think carefully about large scale generation.	• Our business case analysis found that a Dynamic Operating Envelope (DOE) solution would help us manage imminent security issues from minimum demand, while maximising low cost solar on the energy system. We have sought to incrementally roll-out the DOE solution in the 2024-29 period rather than wholescale operation of DOEs. • In addition to the renewable hub contingent project, we have included a new contingent project related to alleviating transmission constraints for existing large scale generators. This includes an emphasis on procuring services rather than investing in new assets, and the investment would be premised on a RIT-T.
Alternatives to network investment	Some of our major customers and generators suggested that there may be non-network alternatives to address programs identified in the Draft Plan.	• We have been actively discussing opportunities for a non-network solution in place of reactors in Katherine, however our analysis suggests the need may not arise in the 2024-29 period. • We have been discussing how services from new technology such as grid-scale batteries could be used to alleviate network constraints.

Changes since our Draft Plan

The feedback we have received from stakeholders has caused a fundamental change in the composition and focus of our capex forecasts. In particular, we have undertaken a rigorous check of our capex programs and assumptions since the Draft Plan.

This has resulted in material reductions in our network capex. This has been underscored by a thorough review of alternative options guided by our new risk quantification framework, and a review of each element of our demand forecasts including the timing and magnitude of large new customer loads. In total, our network capital expenditure programs have reduced by 39.6 per cent since the Draft Plan.

Non-network capex elements have increased materially since our Draft Plan. This reflects a shift in focus in our asset management approach to prudently manage risk and deliver improved safety outcomes to our customers. In response to customer concerns on the potential price shock caused by replacing large tranches of ageing of assets, we consider the optimal approach is to use better data and analysis to ensure we can extend the life of our ageing assets as long as possible, and which also allows for the introduction of new and alternative solutions to meet the needs of the energy transition. This requires investment in both our systems and our people, with a focus on uplifting our operational technology (**OT**) systems and our foundational ICT systems such as investing in our capability uplift program.

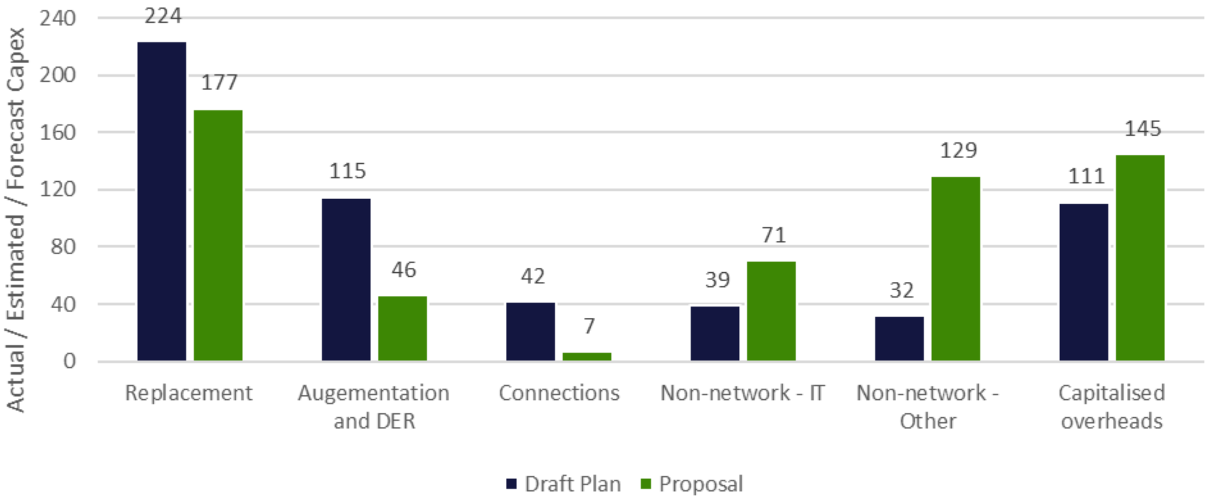
A further change is a proposed new investment in consolidating our Darwin-based staff in one central location, referred to as our single site consolidation project. Our early planning has indicated that consolidating our staff in one location should be prioritised, and will significantly improve our culture, information sharing capabilities, and productivity.

Capitalised overheads have increased since the Draft Plan. This is largely a reflection of including actual data from 2021/22 into the calculation of the base overheads, and the application of the AER's approved method to calculate ongoing capitalised overheads.

As a result of our response to customer feedback provided following release of the Draft plan and ongoing internal challenge of our planning and forecasting practices, we have made a net reduction of $20.9 million to the capex forecast (excluding overheads).

In total, we are proposing a similar amount of capex to the Draft Plan, within 2.2% but the composition has changed markedly from network capex to non-network capex. Figure OV.3 shows the changes since our Draft Plan by capex category.

Figure OV.3: Comparison of Regulatory Proposal to Draft Plan ($ million, real 2024)



We provide a summary of some of the larger movements in the capex forecast since our Draft Plan in Table OV.2. This is not intended to be an exhaustive list or to show a full variance analysis.

Table OV.2: Summary of major changes in forecast capex since Draft plan ($ million, real 2024)

Category	Description of major changes to forecast since Draft Plan estimates	Overall capex change[1]
Replacement expenditure	There are three primary sources of reductions to the forecast: • Removal of the replacement wall as a result of customer preferences ($27.8 million), which has been substituted with a lesser amount of investment to uplift our people and our systems to improve asset replacement decisions. • Deferral of a range of replacement projects to beyond the next regulatory period, largely due to improved risk modelling including: – Lovegrove zone substation ($16.6 million) – Humpty Doo zone substation ($9.9 million) – Palmerston zone substation ($3.3 million). • Removal of IT related projects to avoid duplication with OT capability uplift project ($5.9 million). These reductions were offset by increases associated with updated scoping, unit cost information, and reprofiling of work reflecting delivery capabilities	Reduction of $47.3 million
Augmentation expenditure	There are two primary sources of reductions to the forecast: • Removal of future network strategy initiatives of hosting capacity and community batteries ($41.0 million), and which was re-introduced as DER capex with a more focussed scope. • Deferral of augmentation projects planned for the following sites, to beyond the next regulatory period, largely due to moderated demand growth assumptions including: – Katherine zone substation ($22.2 million) – Wishart zone substation ($4.9 million) – Archer zone substation ($1.4 million) – Substation reactors (reduced from $7.8 to $1.9 million). These reductions were offset by minor increases associated with updated scoping of remaining projects.	Reduction of $68.4 million
DER capex (export services)	Inclusion of the Dynamic Operating Envelope project ($13.2 million) as part of our response to the increasing uptake of DER.	Increase of $13.2 million
Connections	Connection forecast has reduced by $34.8 million as a result of two drivers: • Removal of gifted assets. • Reclassification of some connection services to Alternative Control Services.	Reduction of $34.8 million

Category	Description of major changes to forecast since Draft Plan estimates	Overall capex change[1]
Non-network ICT	Increases to recurrent capex as a result of incorrect scope, unit costs and application of the CAM at the time of the Draft plan for core IT projects and program including: • Software replacement increased from $1.0 to $5.8 million. • Hardware replacement increased from $1.6 to $7.7 million. Increases to non-recurrent capex following further analysis of the requirements and options to uplift our asset management and operational capabilities to manage the future network: • Increase in scope of cyber security following further analysis of the requirements (increase from $1.5 to $11.5 million). • Increase in scope of Operational Technology uplift project replacing previous scope of ADMS and EMS projects (increase from $16.7 to $21.6 million).[2] • Increase in the scope of the Operating Model Program's Capability Uplift project following resequencing of the project and updated estimates from vendors (increase from $16.3 to $20.8 million).	Increase of $31.8 million
Non-network other	The primary source of increase is the inclusion of the single site consolidation project ($89.8 million). Other minor updates reflect updated unit costs and application of the CAM.	Increase of $97.8 million

Notes:

(1) This table summarises major adjustments only, not all adjustments. As such, column 2 is not necessarily designed to sum to Colum 3.

(2) When the EMS project previously included in the repex forecast at the time of the Draft plan, the revised capex forecast for the OT capability uplift project has reduced relative to the Draft Plan.

About this report

The purpose of this document is to provide relevant information to support our proposed capex forecast for the 2024-29 period as detailed in Chapter 8 of our Regulatory Proposal. This capex attachment is complemented by a suite of supporting documents, which contain technical and detailed information such as strategies, business cases and reports.

The structure of the document reflects the AER's Forecast Expenditure Assessment Guidelines and the AER's assessment of capex in recent regulatory determinations, and is as follows:

- Sections 1 to 5 provide information to demonstrate the efficiency and prudence of overall forecast capex for the 2024-29 period. We provide background and context on our network and support assets (section 1), compare our forecast capex to previous expenditure and explain our performance in the current 2019-24 period (section 2), identify key drivers of capex (section 3), our forecast methods and governance (section 4) and provide information to substantiate the deliverability of the forecast capex (section 5).
- Sections 6 to 12 provide relevant information for each category of capex including changes from the previous period, method and approach, relevant benchmarks, and a description of programs. The categories include replacement capex (section 6), augmentation capex (section 7) distributed energy resources capex (section 8) connections capex (section 9), non-network ICT capex (section 10), non-network other capex (section 11), and capitalised overheads (section 12).
- Section 13 provides an overview of proposed contingent projects.

The information we have provided aligns to the requirements of the AER's reset Regulatory Information Notice (**RIN**). How our proposed capex for 2024-29 addresses the capex objectives, criteria and factors in the NT National Electricity Rules (**NER**) is provided at Attachment 0.06. Material assumptions underlying both our capital and operating expenditure is provided in Attachment 0.04.

Other key points to note include:

- All financial figures in this Attachment are presented in $ real 2024, unless otherwise stated.
- Demand forecasts are prepared as at 17 November 2022.
- Number may not sum due to rounding.

1. Our assets

We operate in a unique environment that influences the need, scope and magnitude of capital expenditure. We build, operate and maintain three stand-alone electricity networks in Darwin-Katherine, Alice Springs and Tennant Creek which are regulated by the Australian Energy Regulator. These networks transport about 1,700 GWh of energy to over 84,000 customers across the regions.

Power and Water is a NT Government owned corporation that provides electricity, water, sewerage and gas to our customers. The Power Services division of Power and Water provides electricity network services to more than 90 communities in the Northern Territory over a landmass of 1.3 million square kilometres. Our networks in Darwin-Katherine, Alice Springs and Tennant Creek are subject to economic regulation by the AER.

Our role in the electricity supply chain is shown in Figure 1.1. Unlike most states and territories in Australia, we operate transmission and distribution networks that deliver energy from generators to our 73,000 residential and 11,000 business customers. With the increased penetration of solar exports, our network also now plays a role in exporting our customers' solar energy to other customers.

1.1 Our assets

Capital expenditure 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 by Power and Water from customers over the expected life of an asset. In this section, we provide information on our current assets in service.

Figure 1.1 also provides a high-level visualisation of how electricity is transported through our network. Our transmission network transports large scale generation including new renewable energy at high voltage. Our zone substations are the connection point between our transmission and distribution networks. The zone substations transform the electricity from 66 kV into 22 kV and 11 kV voltages, which are then transported through high voltage feeders. These are then transformed to lower voltages via our distribution substations and transported through low voltage lines. The service wires are the connection to our customers' premises.

Figure 1.1 identifies the key assets on our network including transmission towers, distribution poles, zone substations and distribution transformers, and our conductors and underground lines including service lines to households.

Like other businesses, we have supporting ICT, property, fleet and plant and equipment assets to support our network activities. ICT assets include infrastructure, systems, hardware, software used to provide corporate and network support. These also include operating technology such as systems that monitor and control network performance. We also have depots and commercial offices to house our staff, which are either owned or leased. Our fleet assets include the costs of owning and leasing vehicles used to perform our network activities. Plant and equipment include ancillary assets that support our network assets.

Figure 1.1: Our role in the electricity sector and a visualisation of our network ecosystem

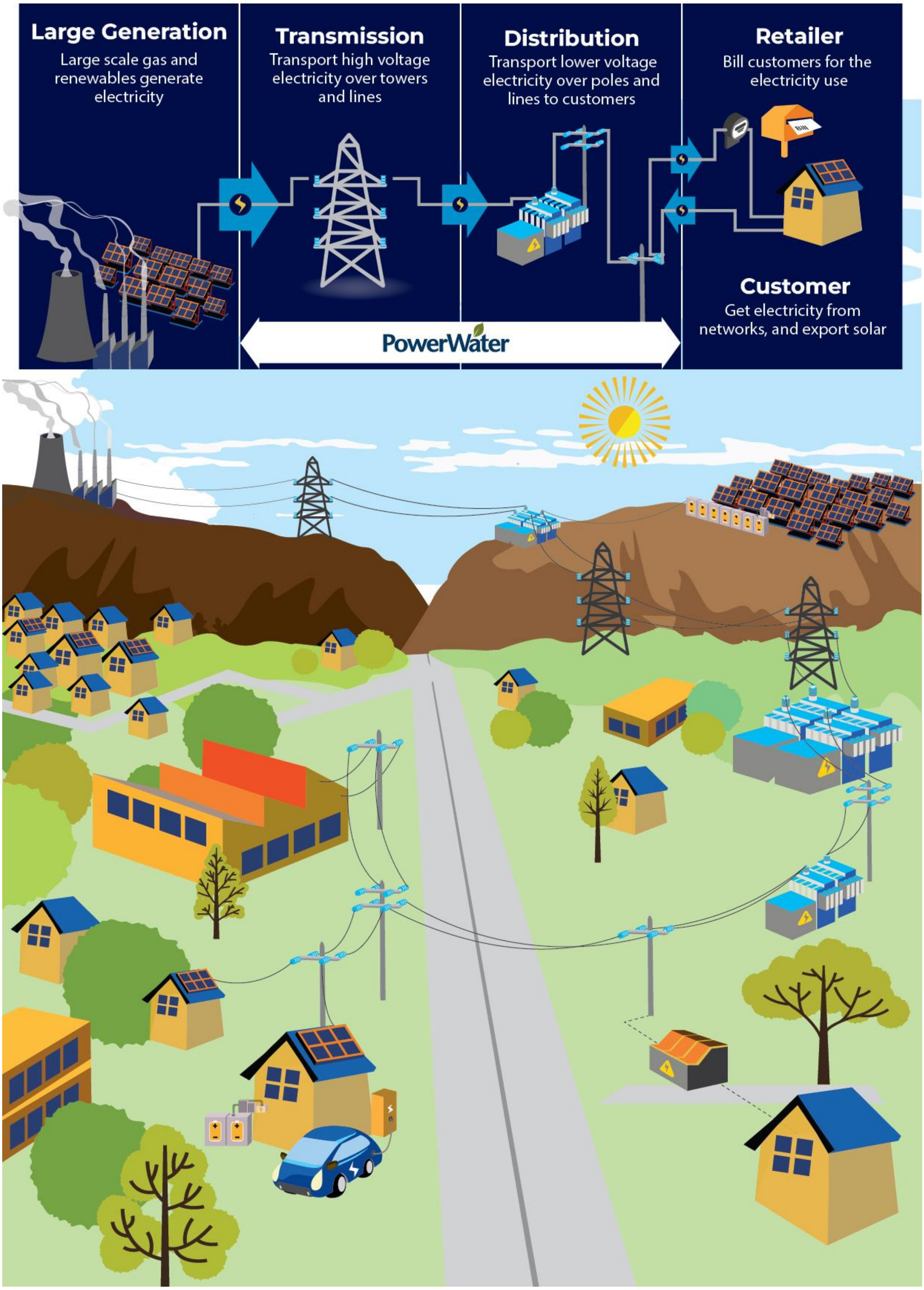
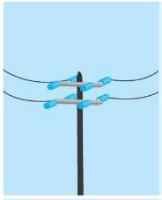
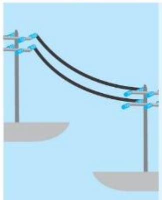
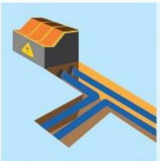


Figure 1.2: Our network assets by region

Asset Category	Asset Type		Region: Darwin-Katherine	Region: Alice Springs	Region: Tennant Creek	Total
	**Transmission towers** Support the conductors that transport electricity at 132kV from generators to transmission substations.	132kV towers	854	0	0	**854**
		66kV towers	2,127	217	0	**2,344**
	**Distribution poles** Poles support the conductors that transport electriciy at 22kV and 11kV, and other assets including transformers and switches that enable us to control the network	11kV poles	4,523	1,250	0	**5,773**
		22kV poles	17,689	2,672	2,262	**22,623**
		Low Voltage poles	10,197	2,249	880	**13,326**
	**Conductors** Overhead lines that conduct electricity throughout the network. The voltages can range from 132kV down to 400V (low voltage)	132kV overhead (km)	354	0	0	**354**
		66kV overhead (km)	339	33	0	**372**
		Distribution feeder - overhead (kms)	2,628	504	340	**3,472**
		Low voltage - overhead (kms)	1,016	124	44	**1184**
	**Service Lines** The final connection from our network to customers premises. These are normally at 240V	Service lines - residential	15,078	3,261	992	**19,331**
		Service lines - commercial	4,035	464	247	**4,746**
	**Underground cables -** Conducts electricity throughout the network and are installed underground	66kV underground (km)	25	14	0	**39**
		Distribution feeder - underground (kms)	789	98	3	**890**
		Low voltage - underground (kms)	607	98	1	**706**
	**Transformers -** Transformers convert electricity from one voltage to another. For example, at zone substations they convert 66kV to 22kV.	Transmission substations	3	2	0	**5**
		Zone substations	19	1	1	**21**
		Distribution substations	4,207	561	130	**4,898**

1.2 Our networks

We operate three stand-alone regulated networks that are physically disconnected including:

1. The Darwin–Katherine network supplies the city, suburbs and surrounding areas of Darwin and Palmerston, the township of Katherine and its surrounding rural areas.
2. The Alice Springs network supplies the township and surrounding rural areas from the Ron Goodin Power Station and the Owen Springs Power Station.
3. The Tennant Creek network supplies the township of Tennant Creek and surrounding rural areas from a centrally located power station.

1.3 Unique characteristics impacting our capex forecasts

In preparing our capex forecasts, we have considered our unique operating characteristics including:

- **Transmission assets** – Unlike most other distribution networks in the National Electricity Market (**NEM**), we design and operate a transmission network in Darwin-Katherine and Alice Springs. This requires renewal of existing transmission assets, investments to meet transmission capacity and power system constraints, and connection and integration of renewable energy hubs and new generators.
- **Scale of network** – While we have the smallest number of customers, our customer base is dispersed across a large land size. This means we have a relatively higher number of assets to serve each customer. For example, while we have less than five per cent of Ausgrid's customers, we operate ten per cent of the number of Ausgrid's poles.
- **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.
- **Environment** – The extreme climate in Darwin-Katherine impacts the durability of our assets, requires designs that can withstand the climate, and impacts the productivity and availability of labour.
- **Stand-alone networks** – Our regulated networks operate within stand-alone energy systems that cannot rely on the benefits of inter-connection, and which require specific power system requirements to keep the system secure. For example, the power systems require thermal generators to feed a minimum level of demand, and this creates a constraint on the amount of renewables that can be dispatched through our transmission network unless we invest in DER hosting capacity.
- **Remoteness** – Working in a remote area of Australia with a relatively low customer scale impacts our cost structures including availability of materials, access to labour, and contractors.
- **ICT diseconomies** – Our small size does not allow us the scale efficiencies of ICT available in other networks. While we manage these diseconomies through shared investment with our water, sewerage and gas lines of business, we still lack the scale of other networks.
- **Large cohort of Cyclone Tracy assets** – Unlike anywhere in Australia, a large part of our network was built in a short period of time following Cyclone Tracy in 1974. This means that a significant proportion of our network will exceed their manufacturing life at the same time.

These unique characteristics limit the ability to benchmark our capex with peers on metrics such as capex per customer. Having said that, our top-level checks have considered relevant category benchmarks such as the AER's repex model.

1.4 Changes impacting our network

Over the last year, we have spoken to our People's Panels, business customers and our broader stakeholders about the future of our network, and key changes we need to make to adapt.

The most pressing change is a shift to renewable energy. The NT Government have planned for 50 per cent of underlying demand being met by renewable energy by 2030, with further ambitions to move toward net zero by 2050. This impacts both the way we expand and optimise our transmission networks to connect new large scale renewables, and the way we manage exports from rooftop solar on our distribution network. This provides the opportunity to deliver our customers low cost and clean generation, but also poses challenges on how we facilitate renewables through our networks.

We also expect increased demand for electricity over the next 20 years, as significant population growth occurs and new businesses to locate in the NT. Further, we expect the uptake of electric vehicles will grow significantly over the next 20 years. This increase in demand provides opportunity to improve network utilisation and achieve economies of scale. However, we will need to manage demand at peak times of energy use to minimise investments in new assets.

In addition, we face internal drivers of change including the ageing of our Cyclone Tracy assets which will require careful planning in terms of maintenance and replacement programs. Further, many of our existing ICT systems have not been refreshed for a generation, the exception being our metering and billing systems. This impedes our ability to adapt and respond to change and limits our ability to provide modern services expected by our customers.

We have developed strategic priorities to guide our strategies and expenditure plans. This includes facilitating renewables, improving utilisation, managing the health of our network and uplifting our systems and people.

Our Operating Model Program (provided at Attachment 2.01) and our Future Network Strategy (provided at Attachment 8.08) provide a framework to give effect to our strategic priorities. Further information on our strategies and how these have influenced our capital expenditure forecast is provided in section 4.

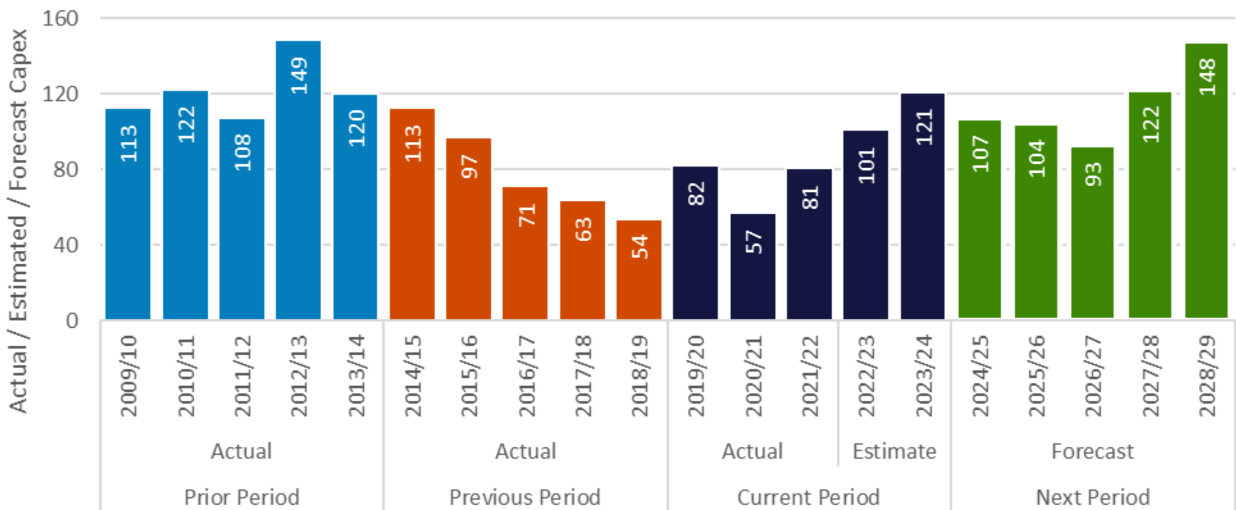
2. Comparisons to past trends

Our forecast capex is higher than the current and previous regulatory periods but lower than the peak of our investment in 2009-14. By the end of the 2019-24 period, we will have delivered projects that have effectively mitigated safety and reliability risks associated with condition issues with the network. We have also delivered a major new ICT project that significantly improves our metering and billing systems.

In this section we compare our forecast capex in the 2024-29 period to previous regulatory periods, noting the significant volatility in our capex levels over time. We also identify how our actual and estimated 2019-24 regulatory period capex has delivered sound outcomes for customers, and identify variances to the AER's capex allowance.

Figure 2.1 compares the forecast capex to the 2019-24 current period, and the previous 2014-19 and 2009-14 periods.

Figure 2.1: Comparison of historical and forecast capex trend ($ million, real 2024)



The comparison shows that the 2024-29 forecast is above the actual and estimated capex in 2014-19 and 2019-24 regulatory periods, but at similar levels to the 2009-14 period.

In 2008, the network suffered a major outage in Casuarina, which led to an external review of our network activities. The review showed that the network was in poor condition after sustained under-investment and maintenance. Reliability deteriorated significantly for customers over this period and as a result, we invested significantly in the 2009-14 period focusing on zone substations. The high capital spend in the 2009-14 regulatory period reflected a degree of catch up for under-investment in the previous years. During these years, minimal investment was undertaken on non-network capex.

Capital investment fell in the 2014-19 period as the network stabilised. At the same time, peak demand started to flatten relative to historical levels as customers used their solar panels to meet energy needs.

The combination of these factors meant our network capex fell significantly during this period. During this period we continued to use our legacy ICT systems.

During 2019-24 we increased our expenditure. This was due to delivery of major replacement projects, where asset data showed condition issues and high risks from asset failure. We also commenced investments in refreshing our ICT assets as part of our transformation program.

The higher capex forecast in 2024-29 is a combination of emerging condition issues on the network, the need to continue to modernise our ICT systems, and a one-off project to invest in consolidating more of our Darwin staff in one central location.

2.1 What we have delivered

Our network capital program has been directed at minimising risks related to the condition of our existing assets, meeting higher demand for electricity in pockets of our network, maintaining reliability and compliance, connecting new customers to our network, and providing our customers with an export service for their solar.

2.1.1 Network investments

In the 2019-24 determination, the AER accepted our proposal to increase replacement capex to manage emerging risks on the network and replace assets that fail in service. By the end of the period we will have delivered or progressed several key projects, including:

- **Replacement of Berrimah zone substation** – We have commenced a major project to replace Berrimah zone substation in Darwin. The existing substation has multiple condition issues that has high consequences in terms of reliability to customers in the area, and safety for our workers and the public given the explosive nature of the assets in the existing zone substation.
- **Alice Springs corroded pole program** – We have commenced a program to refurbish corroded poles in Alice Springs, with an expectation of completing 900 by the end of the 2019-24 period. This is reducing the safety risks to the public associated with pole failure. Our program has targeted the poles with the highest risk. An innovative aspect of the program has been the implementation of a new method to rebut the existing pole, rather than replacing the pole at a much higher cost.
- **Underground cable programs** – By the end of the 2019-24 period, we will have replaced 30 kilometres of underground cable in the Darwin northern suburbs and the Cullen Bay/ Bayview area. These cables have failure modes that give rise to safety risks to the public and which cause outages to customers in the area.
- **Overhead conductor replacement** – By the end of 2019-24 we will have replaced about 10 kilometres of overhead conductor and 60 distribution poles at Lake Bennett, a rural area south of Darwin. The existing line does not meet mandated clearance standards, a particular risk on road crossings. The conductor type (Cockatoo) also has condition issues including broken strands and high stringing tension. The replacement program will provide improved reliability to customers in this area.

Our augmentation program in 2019-24 has been materially lower than previous periods due to a dampening in peak demand growth. However, we have undertaken minor augmentation works on our high voltage feeder network to ensure there is sufficient capacity to meet demand at peak times.

We have also continued to invest in maintaining reliability of customers in rural areas of our regulated networks. By the end of the 2019-24 period we will have undertaken measures to improve reliability on short and long rural lines including animal protection, automatic re-opening of the line for transient faults and segmenting the line to provide quicker restoration to some customers connected upstream from the fault.

We have delivered the Sadadeen 11kV system upgrade to facilitate the Ron Goodin power station retirement in Alice Springs, and undertaken the first utility scale solar connections in Darwin.

Consistent with our regulatory obligations, we have also undertaken corrective works to improve voltage on our distribution network, particularly in response to customer complaints. This has addressed issues with equipment damage at our customers' premises due to voltage imbalance.

2.1.2 Non-network investment

Our ICT program has focused on hardware and software upgrades, and cyber security initiatives. These initiatives have ensured that the underlying currency of our ageing ICT systems are secure.

By the end of the 2019-24 period we will have completed the first major project from our capability uplift program. The meter to cash project aimed to replace our legacy metering and billing system. The current metering system resulted in a large number of manual processes to extract data, and was not capable of meeting our new compliance obligations under Chapter 7A of the NT NER to validate and estimate data. The billing system had limited functionality and integration. This was not only manually intensive but led to poor customer experience in terms of billing accuracy. The new meter to cash system will improve our meter capabilities and our billing processes.

We have also ensured our vehicles and property sites are functional to provide corporate and network services. This includes remediation of our depots and commercial buildings. We consider that co-locating our Darwin staff in a central location will improve our efficiency in the long term.

2.2 Current performance

The capital programs have helped us maintain reliability and quality of services over the first three years of the regulatory period. While reliability performance is greatly impacted by weather events, Figure 2.2 shows that our average outage duration times per customer in the first three years of the period have been consistent with the previous period. Figure 2.3 shows a similar trend for average frequency of outages per customer. In 2021/22 we also met all our reliability performance targets set by our jurisdictional regulator as shown in Table 2.1.

Figure 2.2: *SAIDI 2005/06 to 2021/22*

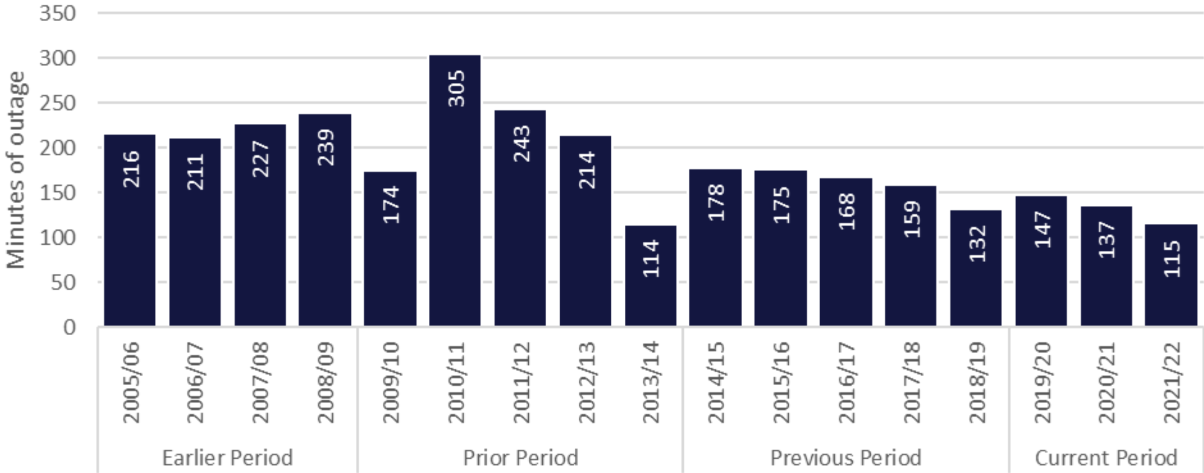


Figure 2.3: *SAIFI 2005/06 to 2021/22*

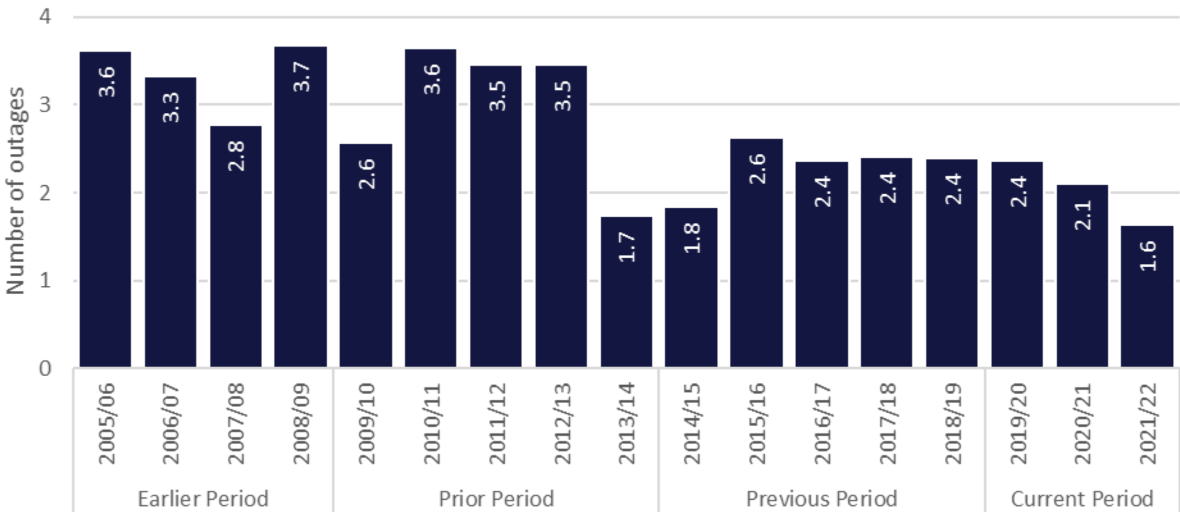


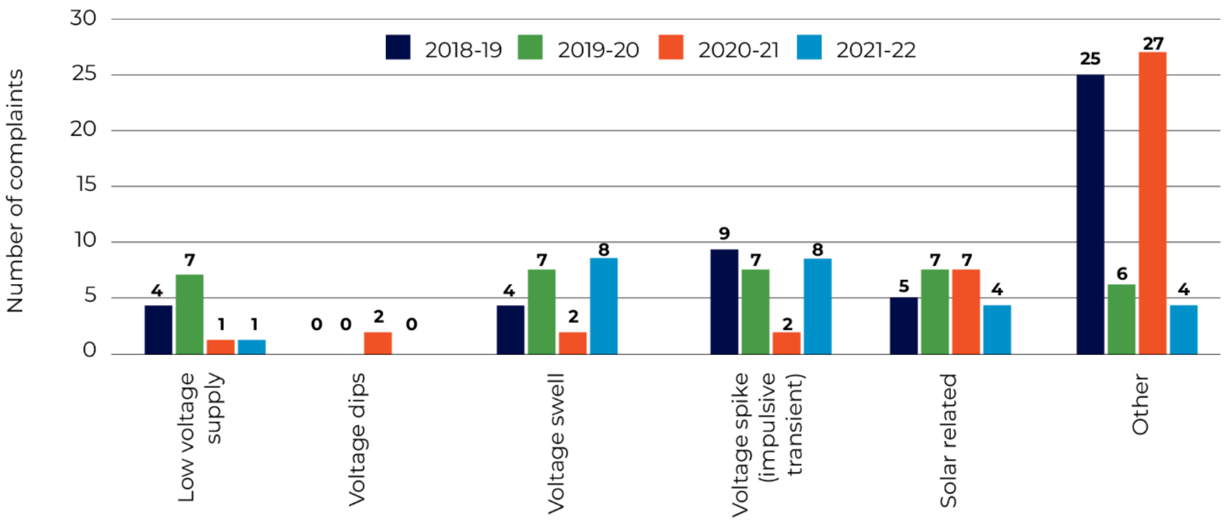
Table 2.1 2021-22 Reliability performance compared to approved target in EIP Code

Feeder Category	Adjusted SAIDI[1]			Adjusted SAIFI[1]		
	Performance Target	Actual Performance	Performance	Performance Target	Actual Performance	Performance
CBD	4	0.223	Target met	0.1	0.003	Target met
Urban	140	70.815	Target met	2	1.258	Target met
Rural short	190	133.232	Target met	3	1.823	Target met
Rural long	1500	831.082	Target met	19	8.745	Target met
Whole of network[2]	175.8	114.524	Target met	2.6	1.627	Target met

[1] The recorded data is 'adjusted' to remove excluded events consistent with the reporting requirements in the EIP Code.
[2] The EIP does not specify 'whole of network' targets. We derive a 'whole of network' target based on our feeder category targets.

We have also maintained a reasonable level of quality of supply, while facilitating a significant increase in solar on the network. Figure 2.4 shows that customer complaints in respect of voltage issues are declining as we correct issues in our quality of supply program.

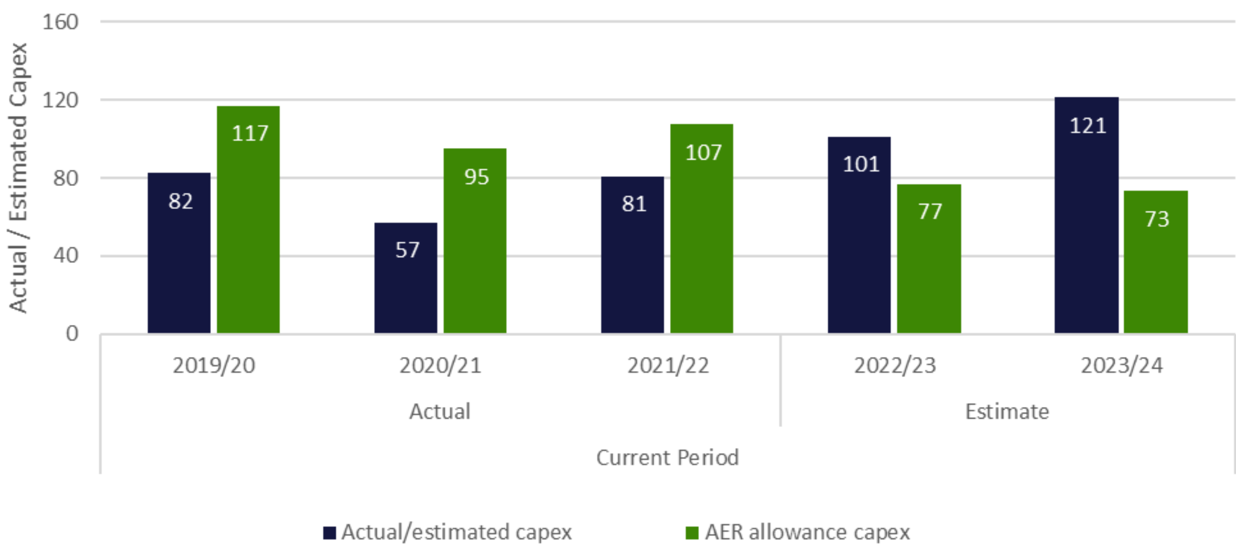
Figure 2.4: Customer complaints on voltage



2.3 Variances to our capex allowance

Our actual/estimate SCS capex in the current 2019-24 regulatory period is $26.6 million lower (5.7 per cent) than the AER capex allowance. Figure 2.5 shows actual capex in the first three years of the regulatory period has been lower than the AER allowance, but that we expect to increase capex significantly in the last two years of the 2019-24 period.

Figure 2.5: Comparison of actual/estimated capex in 2019-24 to AER capex allowance ($ million, real 2024)



Our lower-than-expected delivery of network capex in the first three years of the period has primarily been driven by exogenous factors that have constrained our existing resources. This includes a need to connect more large scale renewable generation to our transmission network, management churn and vacancies. These issues are being addressed through our network capital delivery strategy as detailed in Attachment 8.06, which is improving our delivery in the current financial year. The strategies we are adopting will help us to uplift our delivery capability in the last two years of the regulatory period. By the end of the period, we expect to be 13.0 per cent lower than the capex allowance.

The key reason for under-delivery of the non-network investment in the first three years of the period relates to a re-prioritisation of the core capabilities program in our ICT program. Our regulatory allowance included a significant program of ICT projects that were aimed at renewing and refreshing our aged ICT systems. Further analysis within the regulatory period showed issues with the technology solutions in terms of affordability and overly complex requirements. This led to a re-prioritisation of the program with a focus on delivering the new metering system required to meet new compliance obligations. By the end of the period, we expect to have delivered higher levels of capex than the AER's capex allowance as we implement our new metering and billing system, which is the first tranche in our re-prioritised core capability program.

The additional work we have undertaken on re-prioritising and sequencing our core capability program has provided assurance that the program can be delivered. This is discussed further in section 5.

3. Drivers of forecast capex

The key driver of network capex relates to a moderate uplift in replacement to maintain network performance as condition issues emerge on our network. For non-network capex the key drivers are refreshing our ICT assets to manage the expected increase in workload over the next 20 years and a one-off project to co-locate more of our Darwin staff into one Power and Water owned location.

Power and Water will need to adapt to significant change over the next 20 years. In response, we have identified four strategic priorities to meet the global and local changes impacting our network. These initiatives include managing the health of our assets (particularly the expected ageing of Cyclone Tracy assets), facilitating higher levels of renewables on the network, improving network utilisation, and uplifting our people and systems.

In this section, we identify the key drivers of capex in the long term and how this has impacted our capex forecasts for the 2024-29 period.

3.1 Managing condition issues from ageing asset base

A key strategic priority for Power and Water is safely maintaining reliability and affordability in the context of an ageing asset base. This has been a key theme in our engagement with customers, who have told us that they want us to maintain reliability in the long term.

Historically, with the exception of a short spike in works following the 2008 Casuarina failures, our asset replacement rates have been low. This is due largely to the fact many of our assets are younger than their expected technical life. While nearly all of our network assets are under 50 years today, a significant cohort will be very close to 50 years old by 2040 and potentially due for replacement. This is explained by the unique circumstance in the NT where our network was re-built in a short period of time following Cyclone Tracy in 1974. The coincident ageing of our network will increase the risk of reliability and safety events, and this in turn may create the need for a significant uplift in network asset replacement over the next 20 years.

Our stakeholders placed a high priority on managing the reliability of the network but also wanted us to think about how we can minimise investment. The key strategies we have developed include:

- **Improve asset management approach to extend asset lives** – The key to minimising replacement levels over time is to lengthen the lives of assets, where safe to do so. 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 risk quantification, will help us better prioritise assets so that we are replacing assets in order of highest risk. This has been reflected in the 2024-29 forecasts where we have identified assets that could potentially stay in service longer while minimising safety and reliability risks.
- **New technology and design to retire assets** – New technology may provide some of the tools to help us retire rather than replace assets, keeping a lid on the replacement wave ahead. For example, we are currently looking at microgrid solutions for some parts of our remote areas (including on the fringe of our regulated networks) rather than re-building existing infrastructure.
- **Smoothing mechanisms to mitigate price shocks** – Our customers suggested novel ideas to save revenue in this period to pay for replacement in later periods. We have assessed our ability to propose these programs under the NT NER and found that the AER would have no ability to approve the initiatives. We consider that the above strategies may provide us with some ability to minimise the expected uplift in replacement without the risk of a price shock.

Our forecast replacement capex for the next regulatory period is about 17.8 per cent higher than our estimate in the current period. We have used our Risk Quantification Procedure (provided at Attachment 8.09) to identify assets that can remain in service with tolerable risks for customers, effectively lengthening the lives of assets. This approach has the risk of creating a potential spike in replacement beyond 2030, but experience in other states such as South Australia suggest this type of strategy could help stretch the replacement need over a longer period. Overall, we see that the longer we keep assets in service, the greater the potential for new technology to provide solutions that do not require 'like-for-like' investment.

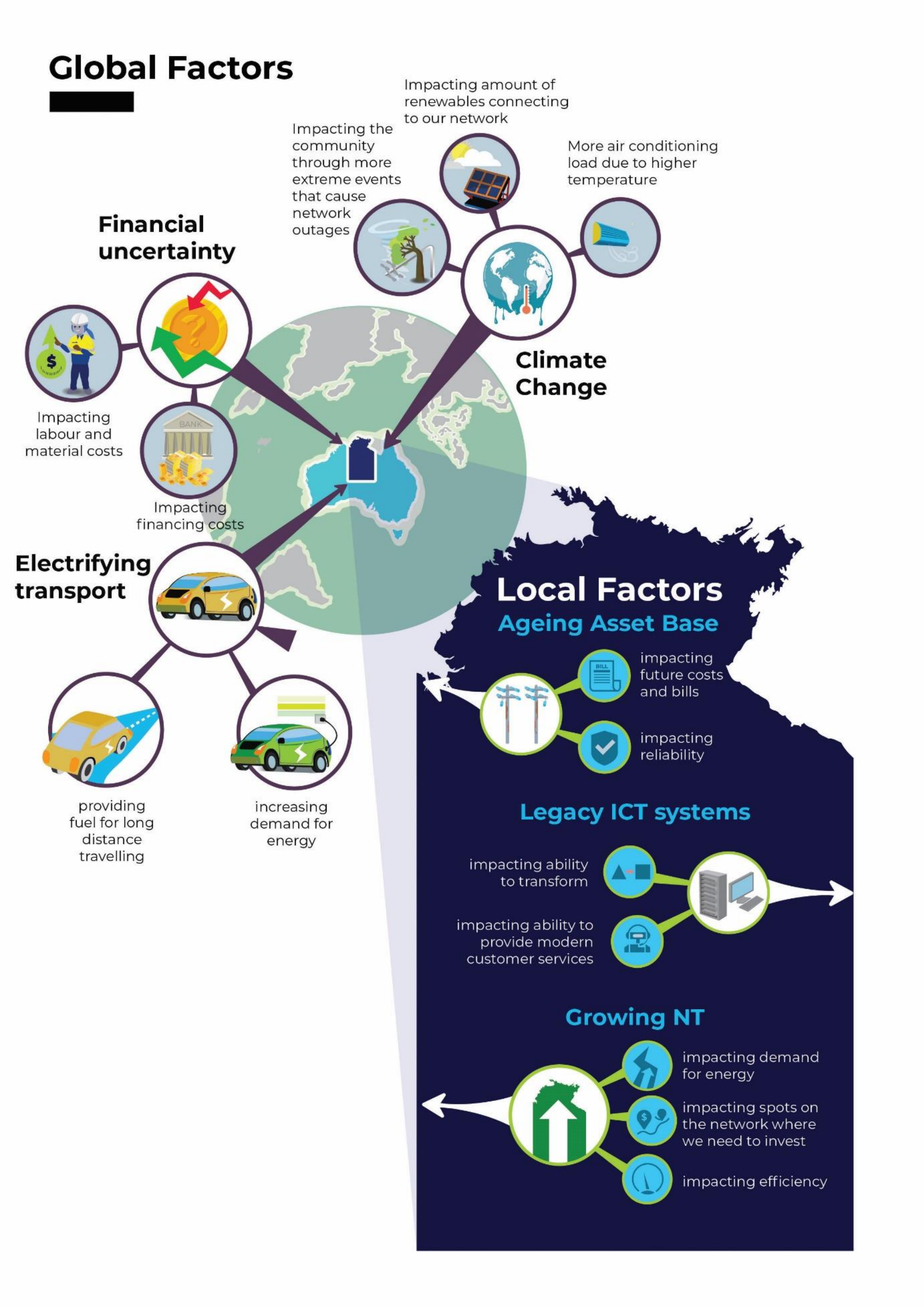
3.2 Investing to facilitate renewables

The NT Government is planning for an energy system where 50 per cent of underlying demand is met through renewable generation. This primarily relies on solar production, complemented by batteries to provide storage and grid stability. Beyond 2030, we expect that the NT will further decarbonise the energy systems as we move towards net zero emissions.

Our stakeholders want Power and Water to be an active leader in facilitating renewables in the energy system, and to make prudent investments where there are clear benefits. This follows extensive conversations with our residential customers in our People's Panels, business customers and stakeholders in our Future Network Forums.

Whilst our discussions with stakeholders have been centred on our three regulated networks, they have also involved consideration of our unregulated networks across the NT. Our discussions have focused on key changes impacting our networks. Our small network is being disrupted by global and local change factors, as identified in Figure 3.1.

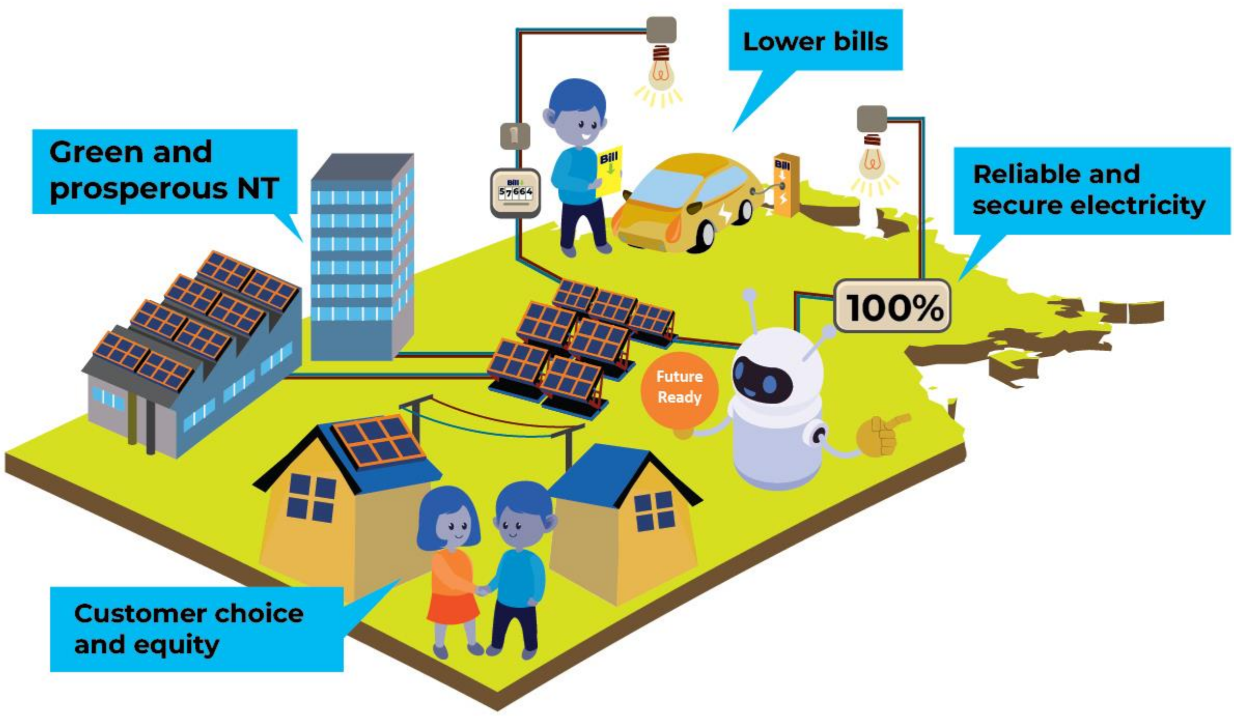
Figure 3.1: Global and local change factors impacting our network



We recently developed a Future Network Strategy (provided at Attachment 8.08) that identifies the potential benefits from unlocking renewables in the NT. Our future network strategy is directed at unlocking the following benefits:

- **Lower bills** – Analysis in the Darwin-Katherine Electricity System Plan demonstrated renewable generation is significantly cheaper than emissions generation, providing opportunities to reduce wholesale costs.
- **A greener and more productive NT** – Clean energy not only helps the environment but also has the potential to unlock economic benefits in the NT, particularly our export markets that will increasingly need to demonstrate that products have minimised emissions.
- **Reliable and secure electricity** – Enabling rooftop solar PV to continue to connect, without compromising system security and power quality.
- **Customer choice and equity** – Facilitating renewables opens up the possibility of our customers earning a return on renewable investments. Further we see that there may be opportunities for lower income households to improve their situation through improved access to solar and energy efficiency.

Figure 3.2: Objectives of the Future Network Strategy



There are significant engineering challenges for our network and power system to enable these benefits. The emerging challenge for our network is how to ensure the system remains secure on minimum demand days. Our analysis shows that rooftop solar will grow significantly by 2030 and will present a minimum demand challenge in the 2024-29 regulatory period. In the absence of investment, we would need to constrain new customers from exporting onto the network. Our options analysis shows a clear market benefit in investing in a solution (dynamic operating envelope) that can communicate to rooftop solar systems when the system is reaching a security threshold. This would enable us to allow customers to export solar at all other times, except for the limited periods when the system is facing a constraint.

A further challenge is how we utilise the existing transmission network efficiently to connect new large scale generation. Currently, many large scale generators are locating on the transmission line that connects Darwin and Katherine, and there are limitations to how much of this solar can be dispatched due to power system constraints. Consistent with the NT Government's Darwin-Katherine Electricity System Plan, we are proposing a contingent project predicated on an assessment of the market benefits of solutions that can help relieve transmission constraints to enable greater dispatch of renewable generation. This may include acquiring services off a grid-scale battery and/or synchronous generator to keep the system secure, and to allow much higher levels of generation to be dispatched at an estimated cost of $45.7 million (real 2024 including overheads).

Our future network strategy supports the NT Government's approach to developing a Renewable Energy Hub south of Darwin. The initiative would centralise large scale solar and battery storage in a location close to existing transmission infrastructure, enabling efficient dispatch of renewable generation. We have proposed a contingent project to activate the Renewable Energy Hub through a new transmission line and substation at an estimated cost of $120.8 million (real 2024 including overheads).

Each of these projects are discussed in section 13.

3.3 Uplifting our core ICT systems

The Operating Model Program is an initiative we commenced in the 2019 to uplift organisational capabilities and efficiencies across people, process, and technology. Under the initiative, we have identified the significant benefit from uplifting the technical competencies across the business.

The origins of the OMP 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.

It has become increasingly 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.

Our core ICT systems have not kept pace with the growing complexity of our business, new compliance requirements and the service expectations of our customer base in a digital age. We have not kept pace with other utilities in Australia, with a significant proportion of our ICT assets built about 15 to 20 years ago.

By upgrading our ICT systems to contemporary standards, we can automate manually intensive work practices, streamline and simplify our processes, support efficient business operations, comply with our regulatory obligations, adapt to rapid changes in our business environment, and meet growing digital expectations of our customers for service delivery.

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

During the 2019-24 period, we already delivered on a major system for metering and billing purposes as part of our core capability uplift program. Our forecast capex for 2024-29 includes system upgrades across core workstreams including customer experience, finance, asset management, and capital delivery.

3.4 Centralising staff in Darwin

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 more of 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. The portion allocated to standard control services is forecast at $89.8 million. The project would relocate our staff from the Mitchell Centre and Woods Street offices to the Ben Hammond Complex.

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, improved efficiency of staff from collaboration, improved response to faults and outages, and improved emergency response.

Despite the incremental improvements we have been making in our business, 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.

4. Forecast capex method and governance

We have made improvements to our forecast methods since the 2019-24 AER determination. This includes advances in strategic planning, demand forecast methods, and risk assessment approaches. Our method for the 2024-29 proposal is based on developing long term strategies incorporating customer feedback, undertaking bottom-up plans based on need and options, and testing whether the portfolio is prudent and efficient. Our capital governance provides assurance that the proposed program will be delivered efficiently and prudently.

In this section we outline our approach to develop the 2024-29 capex forecasts, including where our forecast method has aligned or changed from business as usual (BAU) methods. Our overall approach has carefully considered guidelines published by the AER including the 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, comparisons to past expenditure, and deliverability.
- Using AER models to challenge our forecasts.

We have also considered the AER's Industry Practice Note on Asset Replacement Planning by applying its risk-cost assessment methods.

4.1 Alignment to business-as-usual methods

Our BAU capex forecasting method relies on an annual review of capital needs based on our asset management and corporate planning processes. The processes are informed by our corporate purpose and key business strategies. The outputs of our planning process are reflected in our Transmission and Distribution Planning Report (**TADPR**) (provided at Attachment 8.85) and our Statement of Corporate Intent.

We have made significant improvements to our BAU methods to forecast capital expenditure over the course of the current regulatory period. Our methods have adapted to feedback from the AER and stakeholders on issues raised in our 2019-24 determination, which included the need to improve risk assessment, demand forecasts, and top-down checks. We also recognise that the energy landscape is rapidly changing, and we need to think more strategically about the longer term. This includes embedding customer priorities and values.

Our forecasts for the 2024-29 proposal reflect these improvements. In recent TDAPRs, we have shown how our planning has evolved to consider longer term drivers of investment over the next 20 years. This includes opportunities and challenges of moving to a renewable generation mix, managing the ageing of our network assets, and the impact of new demand such as electrical vehicles. We have also moved the planning horizon for our distribution networks to ten years to align with planning for our transmission networks.

The additional measures we have applied for the 2024-29 proposal include:

- **Incorporating customer feedback** – We have captured our customers' preferences and priorities through an extensive engagement process, and this has helped us formulate strategic priorities that underpin our expenditure decisions. This has resulted in refreshed asset management and non-network strategies, which have informed our forecast methods.
- **Improving our business case process** – We have updated our business case process to address feedback received from the AER on the level of analysis necessary to justify forecast capex. Historically, our business case development required a high-level outline of the project need in the first state, with subsequent stages requiring the detailed analysis and justification for seed funding. Typically, this second stage occurs much closer to project execution.

  - Taking on board feedback from the previous regulatory review, we have identified the need for more detailed upfront analysis (particularly given the need for five-year revenue forecasting), and as such have recently implemented an improved process. Our improved process requires consideration of the economic prudence and efficiency of proposed expenditure against the tests specified in the NT NER at the first stage of business case development, as well as consideration of network and non-network options. These enhanced first stage documents are referred to as 'regulatory business cases'.
  - Given we are only in our third year of the NT NER regulation, this added rigour to the first stage of our business case development is a recent addition to our capex governance framework. While the new process represents an improvement on past practices, we are still in the process of refining the approach and embedding it as part of BAU.
- **Re-testing already approved programs** – Material programs that were already approved in the AER's 2019-24 determination and have already commenced have been subject to re-testing, with greater focus on the requirements of the NT NER.
- **Risk quantification** – We have applied a new risk quantification framework (provided at Attachment 8.09) as part of our business case assessment. This was a key element of AER feedback in our last regulatory proposal. Accordingly, we have developed a risk quantification framework that has been applied to projects in the capex forecast.
- **Improved spot load forecasting** – We have updated our demand forecasts to produce both system and spatial (location specific) forecasts that incorporate a new approach to estimate large new loads (spot loads).
- **Revised non-network capex forecasting** – Non-network capex generally is forecast over a shorter period as part of our BAU processes. We have undertaken a one-off process to forecast projects, programs and leases to the end of the regulatory period. We have subjected our non-network capex to the same new business case process as network capex.
- **Top-down challenge** – We have incorporated top-down checks of our proposed capex portfolio including assessing deliverability, utilising AER category benchmarking tools, and prioritising projects.
- **Consistent modelling** – We have developed and maintained a series of models for network and non-network capex for SCS capex. This has been done to support the cost estimate and financial assessments undertaken at a business case level. The models categorise capital projects and programs into the AER's RIN reporting definitions such as repex, augex, connections, DER, non-network ICT and non-network other. This has been relied upon in developing the AER's prescribed model for standard control services.

We highlight that some projects in our 2024-29 regulatory proposal are in the very early planning phase and as such have not yet advanced through our capital governance framework. However, as these projects progress, they will be subject to detailed business case development, further top-down challenge and assessment of risk, prudence, efficiency, and deliverability.

4.2 Description of key steps and inputs to forecast capex

At a high level, there are three steps to our capex forecasting approach for 2024-29:

- **Strategy** (Step 1) – 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.
- **Bottom-up plans** (Step 2) – 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.
- **Checks and challenges** (Step 3) – We test elements of the program against applicable benchmarks, scrutinise key inputs, and prioritise projects with demonstrable need.

These steps are discussed in the following sections.

4.2.1 Step 1 – Developing the investment strategy

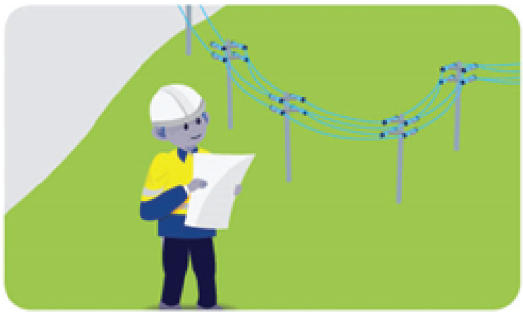
Our long-term strategic priorities have been the starting point for developing our forecast capex for the 2024-29 period. Underpinning the long term strategy is our purpose - to make a difference to the lives of Territorians. This recognises that we are more than just an essential service provider. We need to play our part in enabling the economic, environment and social aspirations of Territorians.

Over the last 18 months, we have engaged with customers and stakeholders on changes impacting our business, seeking input on the priorities and values that are most important to them. This has helped us articulate four strategic priorities for the next 20 years:

- **Facilitating renewables** – Renewable energy is where our future lies. Our network is central to 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 placing unlocking the value of solar generation at the heart of our network planning, both at the transmission and distribution level.

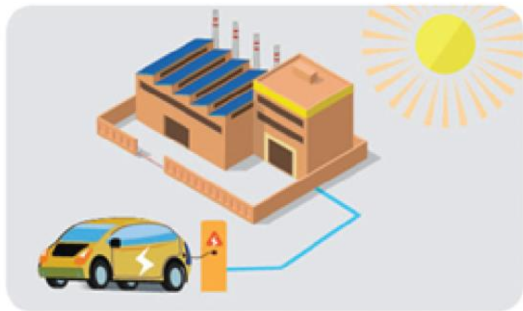
Facilitating renewables

- **Managing the health of our assets** – 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.



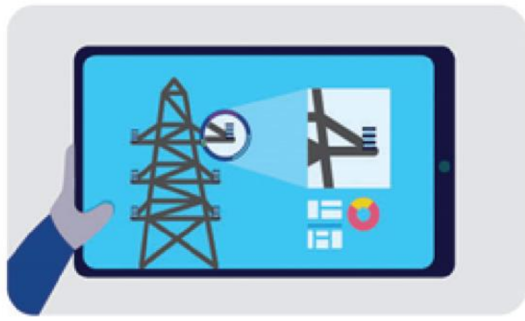
Managing health of network

- **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. 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.



Improving utilisation

- **Uplifting our people and systems** – 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 tools, systems. A key enabler of this is investment in our ICT to align with our Future Operating model.



Uplifting our systems and people

The strategic priorities have provided a catalyst for new and refreshed strategies underpinning our expenditure decisions. This includes our new Future Network Strategy, which identifies focus areas that will help lower bills, improve environmental and economic outcomes for Territorians, and which improves choice and equity for customers. The focus areas include efficiently unlocking both small and large low-cost renewables, increasing our scale and utilisation, and re-designing our network to reduce future costs. The Future Network Strategy (Attachment 8.08) has influenced our capex forecasts including a new DOE solution and the inclusion of contingent projects that maximise dispatch of large-scale renewables.

We have also refreshed our Strategic Asset Management Plan (**SAMP**) provided at Attachment 8.13. This document provides context on key changes impacting our network in the long-term, describes our current performance relative to the past, and identifies our network asset management framework. Importantly the SAMP articulates emerging challenges on the network including the need to facilitate growing renewables on our network, that is aligned with our future network strategy.

We have refreshed our network asset management plans for each of our asset classes. These are included as Attachments 8.14 to 8.24.

We have refreshed our ICT strategy (provided at Attachment 8.65) to align with our Future Operating Model program (provided at Attachment 2.01). The refreshed ICT strategy discusses opportunities to improve our business performance by uplifting our core ICT systems, while also ensuring that we are keeping pace with cyber security requirements.

We have refreshed our property and fleet strategies (provided at Attachments 8.76 and 8.75) to reflect opportunities and key challenges impacting our operations.

4.2.2 Step 2 – Develop bottom-up plans

The strategies have informed the development of bottom-up plans for categories of capex. The initial process is to clearly articulate drivers of investment with regard to our underlying strategies and to then assess investment need, options and optimal timing.

Drivers of capex

Our bottom-up plans follow the AER expenditure categories:

- **Replacement capex** – We replace or refurbish network assets (replacement capex), which are in deteriorated condition and pose material risks. In some cases, we replace an asset due to the asset not meeting compliance standards such as clearance to ground. We regularly monitor the health of our assets through our inspection and maintenance programs as well as analysis of outages. We also monitor the age of the population by technology type to identify long term replacement needs. We identify assets that may require replacement or refurbishment over a 10-year planning horizon.
- **Augmentation capex** – We undertake demand driven augex when there is insufficient capacity to meet demand at peak times. We develop ten-year forecasts of peak demand at a local level for transmission feeders, large substations and high voltage feeders. We assess if there is sufficient capacity to meet the forecast demand in electricity at peak times at each level of the network. We also invest to maintain reliability and voltage standards in accordance with our jurisdictional obligations. In some cases, we undertake new investment to ensure we comply with other elements of our regulatory obligations.
- **Renewable energy transition capex** – This relates to efficient investment to address constraints with our network in relation to transporting large scale renewables through our transmission network, and exporting rooftop solar through our low voltage distribution network.

- **Non-network ICT** – We require non-network assets such as ICT to meet our corporate obligations, operate the business efficiently and support network activities. Our ICT systems require a significant refresh to ensure we meet our regulatory obligations, ensure cyber-security, and provide services that reflect customer expectations in a digital world. Our forecast method for ICT closely followed the AER's Guidance Note on ICT expenditure assessment. We forecast recurrent expenditure such as hardware refreshes and software upgrades. Separately we forecast non-recurrent expenditure such as new or upgraded systems.
- **Non-network other** – Like any business we need commercial buildings and depots to house our staff, in addition to fleet, plant and equipment to support our operational activities. Our forecast approach seeks to identify the cost of properties we lease such as our head corporate office. The forecast ongoing lease costs are capitalised. We will also forecast refurbishment or replacement costs on buildings we own. Similar to property leases, we forecast ongoing lease costs of the vehicles that our field staff use to travel to and manage the network.
- **Capitalised overheads** – We undertake network support activities such as network forecasting and planning, procurement, works scheduling and project management. A range of corporate support activities such as finance, legal, procurement and human resources are necessary to support these activities. Similar to all networks these costs are allocated to capital and operating expenditure in accordance with accounting standards. The assessment for overheads uses the base year, step and trend method. The portion allocated to capital expenditure is dependent on the allocation method, which is turn reflects the relative level of capital and operating expenditure.

Identify project need and solutions

We undertook an assessment of need and options at an individual project or program level. This includes business case development and re-assessment of ongoing projects that had already been subject to a business case that had been approved to be delivered within the current regulatory period.

Our business cases consider risks and benefits. In most cases, we utilised our new risk quantification framework to inform our analysis of the need and timing. In many cases, the business case assessment identified that the project could be deferred or avoided with minimal risks.

As part of our capex forecasting approach we have looked at non-network options such as demand management. We have made significant improvement in our project planning approach for non-network alternatives. In 2020, Power and Water published a Demand Side Engagement Strategy, which is targeted at notifying and working with non-network providers to find credible and less costly solutions to traditional network investment.

We have also considered opex substitution for capex, including corrective maintenance, minor repairs, or patching ICT solutions. In some cases, the solution to address the problem has involved a mix of operating and capital expenditure such as our DOE solution that limits constraints on exports, and for several of our non-recurrent ICT capex projects including cyber security, OT capability uplift and our Operating Model capability uplift program.

4.2.3 Step 3 – Checks

The final step in our forecast capex process is to perform a series of checks on the capital portfolio identified by the business cases. We recognise this is a maturing aspect of our business and that we will need to develop further tools to assist in ranking projects by risk, value or strategic importance. Nevertheless, we applied tools and checks to finalise the proposed forecast capex for the 2024-29 period. This included the following elements of reviews on the business cases:

- We reviewed the evidence of need. In some cases, we found that deeper analysis of the data did not support the proposed expenditure, including an asset's deteriorated condition.
- We reviewed if feasible options had been considered. In some cases, this has led to a lower cost solution or deferral of a capital project. For instance, we have deferred investment in a zone substation at Alice Springs through network re-configuration, or use of staging solutions.
- We have also considered if extending the timing of planned replacement programs could lead to a reduction in capex within a reasonable risk tolerance. This has allowed us to extend programs for longer periods consistent with our strategic priority to prudently extend asset life and create option value.

We also undertook a high-level review of our replacement capex forecast. This included reviewing the basis of a replacement wall program that sought to bring forward replacement into the 2024-29 period to mitigate significant increases in replacement in the future. Based on a review of the NT NER, we considered that the program would not meet the capex criteria and factors. Further, we undertook analysis of other networks and found there were opportunities to extend asset life. We also used the AER's repex model to test our replacement program at an asset class level, including our unit costs.

We have undertaken a review of key inputs including our spatial demand forecasts. Our review suggested that our estimate of spot loads over-estimated of the magnitude and timing of some loads. This has led to a downward revision of our spatial forecasts and has resulted in significant reductions in demand driven capex.

We have integrated the learning from the organisation-wide review of our operating model and capabilities. From this 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 our strategic priorities, including the ongoing transition to renewables.

As a final step, we have also tested the deliverability of our needs-based capital expenditure forecasts to ensure that the network and non-network programs are capable of delivery.

As a result of the above checks, we have deferred or avoided the need for a significant number of capex projects compared to our forecasts in the August 2022 Draft Plan. We summarise the major movements in the capex forecast on page xi. In total, we are proposing a similar amount of capex to the Draft Plan, within 2% but the composition has changed markedly from network capex to non-network capex.

4.3 Key inputs

Our capex forecasting method has relied on key inputs, including our risk quantification framework, demand forecasts and our cost estimation processes. Further information on material assumptions underlying operating and capital expenditure can be found in Attachment 0.04 and Attachment 0.06.

4.3.1 Risk quantification process

We have applied risk quantification to conduct economic appraisal of the costs and benefits of investments. This is a relatively new approach for Power and Water and follows extensive feedback from the AER in our 2019-24 determination. By providing a quantitative basis for valuing risks, we can more consistently consider needs across the capital portfolio.

We identify the probability of a risk occurring, and the consequence such as safety, reliability, environment and other factors consistent with our corporate risk framework. Such an approach allows us to defer investment and improve affordability, where the risks can be managed appropriately.

The key values in our new approach including health and safety of workers and the public, compliance, direct financial costs, environmental, service delivery and customer experience. Each of these values have a dollar impact based on whether the consequence is insignificant, minor, moderate, major or severe.

The risk is measured as the probability of the event occurring, multiplied by likelihood of a consequence from the event multiplied by the value of that consequence.

Our Risk Quantification Procedure is provided at Attachment 8.09.

4.3.2 Demand and customer number forecasts

We have developed a forecast of key growth metrics including energy, demand and customer numbers. The forecast has relied on a new method that provides more granular estimation of the impacts of solar, population growth and economic growth.

The key growth parameters to develop our 2024-29 forecasts include:

- **Spatial maximum demand forecasts** – These forecasts have been used to identify potential constraints on our transmission and distribution networks that give rise to a capital or non-network solution. These forecasts are provided at Attachment 8.47.
- **Minimum demand regional forecasts** – These forecasts have been a key input to our assessment of solar hosting constraint on our low voltage network. This has influenced the development of our business case for Dynamic Operating Envelopes. These forecasts are provided at Attachment 8.48.
- **Connection number forecasts** – These forecasts have informed our analysis of required connections capex for standard control services. The connections model and associated report are provided at Attachment 8.63 and 8.64 respectively.

4.3.3 Cost Estimates

We have developed cost estimates for all projects and programs in the forecast capex for the 2024-29 regulatory period. We have applied cost estimates based on the most appropriate data. This includes a mix of contract information, market estimates, historical costs or trends, or individual cost scope for elements of major projects.

Our cost estimate methodology and approach is provided at Attachment 8.07. Each of our business cases include a description of how the costs have been estimated.

4.4 Capital governance

4.4.1 Investment Governance Framework

The investment governance framework is described in our Capital Investment and Delivery Policy provided as Attachment 8.04. This document details our commitment to achieving value for money through prudent decision making and efficient and effective expenditure delivery. It commits us to having a governance framework to achieve this purpose. This governance framework consists of approval gateways, monitoring and control mechanisms, performance metrics, authority delegations, policies, procedures, systems and audit programs.

Our Capital Investment and Delivery Framework provides a link between this policy and its implementation. The policy and framework are overseen by the Enterprise Portfolio Management Committee (**EPMC**) and supported by our Enterprise Portfolio Management Office (**EPMO**). These functions consolidate projects from across the business to provide both a 'whole of business' and business unit perspective on project investment and delivery.

4.4.2 Governance review process

The process to derive the capex forecast for the 2024-29 regulatory period has been subject to strong internal governance to ensure that the forecast reflects an efficient and prudent process. This includes:

- Establishment of a dedicated project, project director and program management office, with clear workstreams. This included:
  a. an '**accountable'** Executive General Manager who is ultimately accountable for the quality and timely delivery of the deliverable,
  b. an internal subject matter expert '**responsible'** for managing delivery of each deliverable, and
  c. for some deliverables an external consultant to '**support'** the development of the deliverable.
- Establishment of a Project Decision Committee, as a sub-committee of the Executive leadership team to provide direction and facilitate decision making.
- Oversight by the Regulation & Market Operations Steering Committee - comprising the Executive leadership team.
- Oversight by the System Control, Market Operations & Regulation Committee – a Board level sub-committee
- Final approval of Power and Water's Board.

5. Deliverability

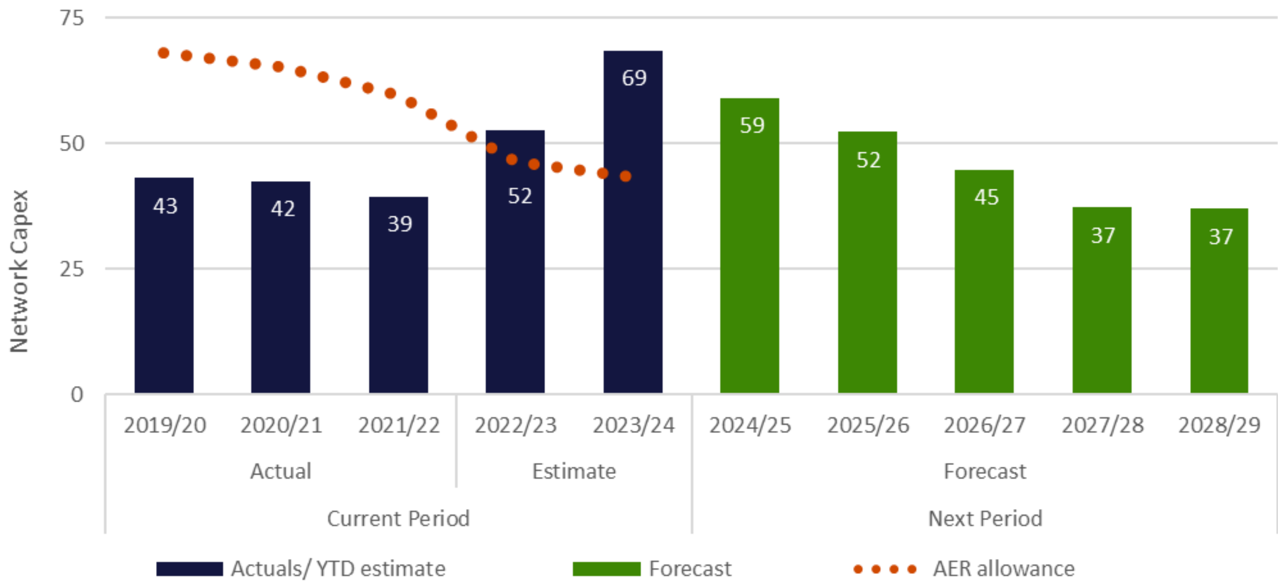
We have undertaken a check of whether we can deliver the forecast capex in the 2024-29 period. Our checks have provided assurance we can deliver the forecast level of capex, and that we have the framework in place to scale up delivery capabilities to meet our future needs. Our analysis also indicates our non-network capex can be delivered through improved project management and sequencing.

Our forecast capex represents an uplift from actual capex in the first three years of the 2024-29 regulatory period. We have already begun ramping up our delivery capabilities over the current period, and are confident 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.

5.1 Delivery of network capex

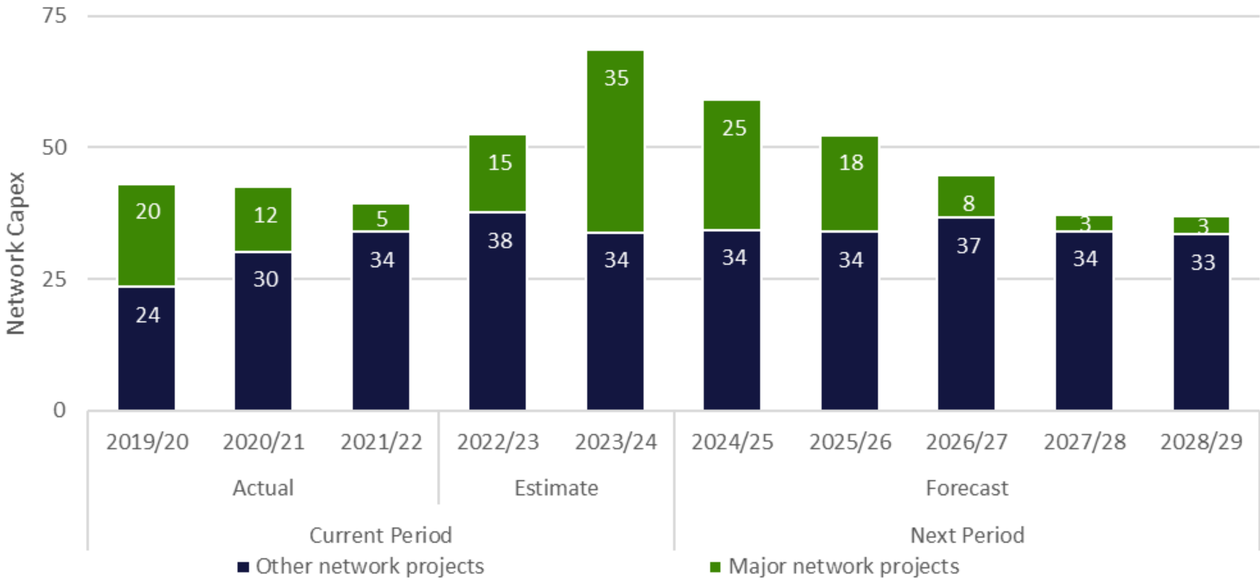
Figure 5.1 compares the forecast network capex in the 2024-29 regulatory period compared to actuals and estimates in the current 2019-24 regulatory period. It shows that the approved AER capex allowance for 2019-24 was front-ended and that actual capex in the first three years has fallen behind this level. Figure 5.1 also shows that we plan to increase capex in the last two years of the 2019-24 period, effectively re-profiling the five-year program. By the end of the period, we estimate we will be only $36.9 million (13.0 per cent) behind the approved forecast of $282.8 million. Forecast capex in each year of the 2024-29 period will be lower than the peak of capex in 2023-24.

Figure 5.1 Comparison of actual/estimated to AER allowance in current period, and forecast network capex for next period ($ million, real 2024)



The uplift in capex delivery in 2022/23 to 2024/25 relates to major projects. Other, smaller, less resource intensive programs will only see a moderate increase (see in Figure 5.2). This has been a relevant consideration in our deliverability checks, as major projects such as a new zone substation can be largely externally delivered.

Figure 5.2: Major projects compared to other network projects for current and next regulatory periods[1] ($ million, real 2024)



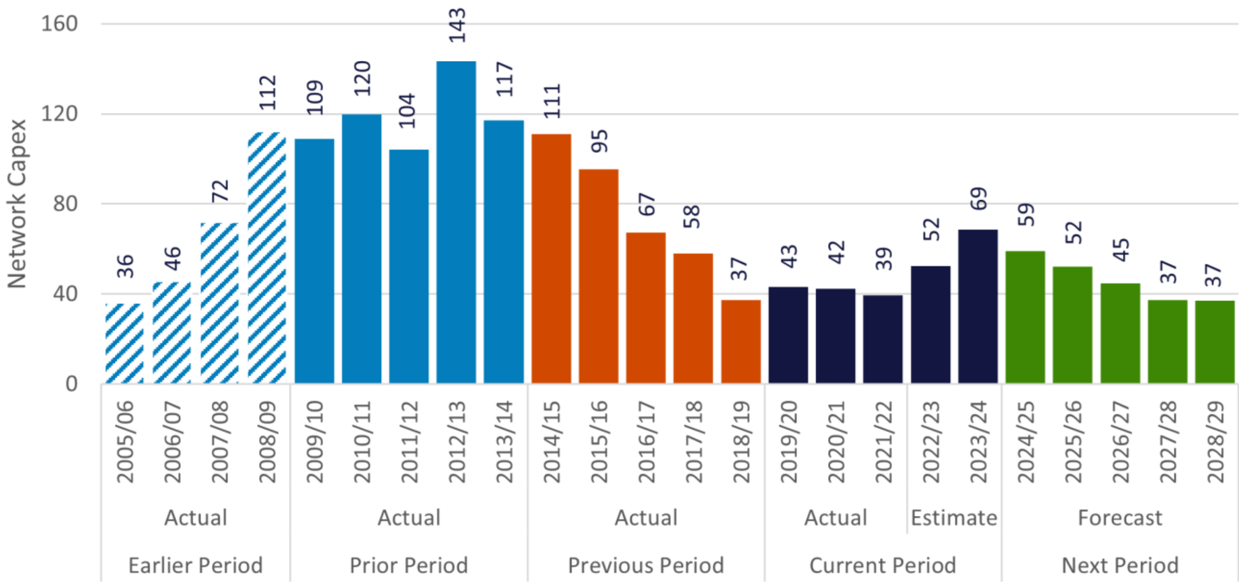
We recently developed a capital delivery plan that describes initiatives undertaken to uplift our delivery capabilities. This has drawn from experiences in the 2009-14 regulatory period, when we were required to deliver a significant uplift in capex following the Casuarina zone substation failure. Our capital delivery plan also identifies the key issues experienced in the current regulatory period, the action we have taken to address them, and evidence to show the initiatives have improved our delivery capability.

We note that contingent projects are likely to arise in the 2024-29 period. Our ability to resource these projects has also been a central consideration in our checks on delivery capability, and we are confident we will be able to scale up as necessary.

We have a proven track record of delivering significant and rapid uplifts in capex in previous regulatory periods. This is shown in Figure 14. In the 2009-14 period, we more than doubled our delivery levels, achieving annual average network capex $118.7 million. This is significantly higher than the annual average being proposed for 2024-29 of $46.0 million. This provides us confidence we have the capability to rapidly upscale for uncertain but large investments.

[1] The split between major and other (minor) network projects has been estimated for the actual capex incurred over the period FY20, FY21 and FY22

Figure 5.3: Comparison of network capex across regulatory periods ($ million, real 2024)

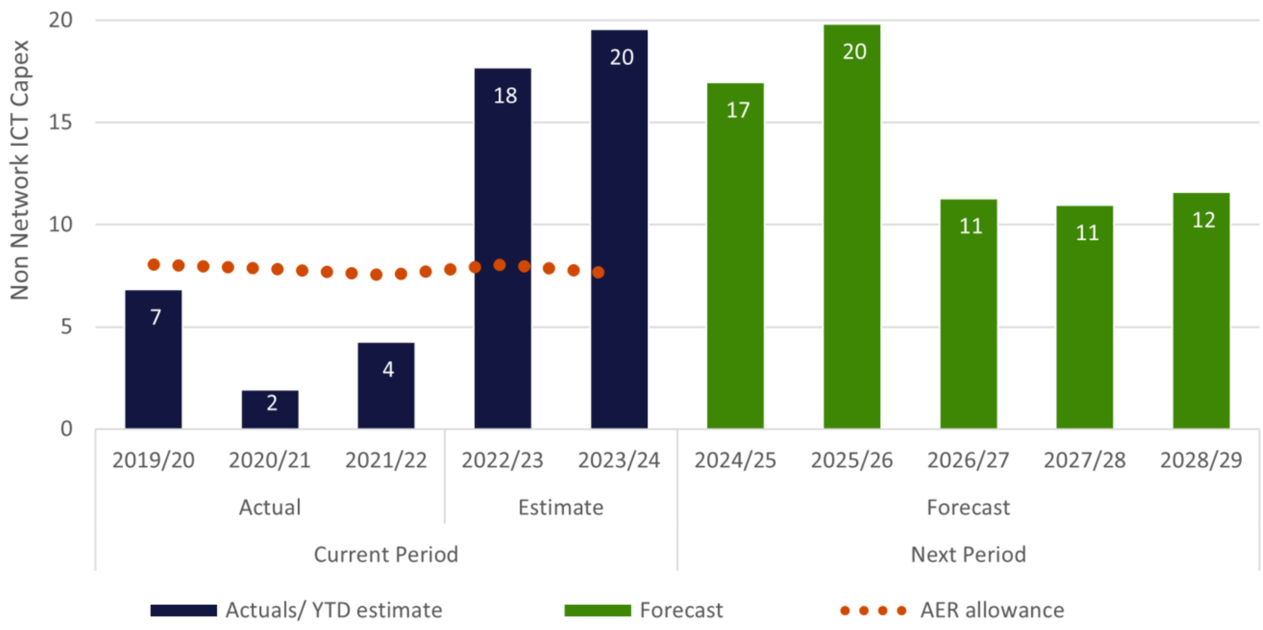


Our works delivery framework and supporting initiatives provide a high degree of scalability and flexibility, allowing the business to pivot, if and as required, to meet the needs of a rapidly evolving energy landscape. During the next regulatory period, our works will help facilitate a major transition 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 Network Capital Delivery Plan provided at Attachment 8.06.

5.2 Deliverability on non-network ICT capex

Figure 5.4 compares the forecast non-network ICT capex in the 2024-29 regulatory period compared to actuals and estimates in the current 2019-24 regulatory period. We expect to have incurred 10 per cent more capex by the end of the 2024-29 period than was included in the regulatory allowance. Forecast capex in the first two years of 2024-29 are at similar levels to the final two years of the current regulatory period, and then reduce in the final three years of the 2024-29 period.

Figure 5.4: Historical and forecast Non-network ICT capex ($ million, real 2024)



Our 2019-24 regulatory allowance included a significant program of projects aimed at renewing and refreshing our aged ICT systems. Analysis during the regulatory period highlighted issues with the estimated cost and complexity of the technology solutions, which were not foreseen at the time of making the 2019-24 forecast. Additionally, the introduction of Market Settlement Systems, and the Northern Territory Electricity Market Settlement (**NTEMS**) associated with the required market reform required Power and Water to re-sequence initiatives due to the interplay of systems in our business.

These issues led us to re-profile the ICT program, within which we prioritised the new metering and billing system in order to meet compliance obligations.

Our experience during 2019-24 has provided important lessons on delivering major ICT projects. This includes investing more time upfront to ensure the project team and partner delivery teams are fully aligned on interdependencies, ways of working, and schedule. These lessons have been built into our ICT project management and delivery processes and will help facilitate a smoother and more effective delivery model.

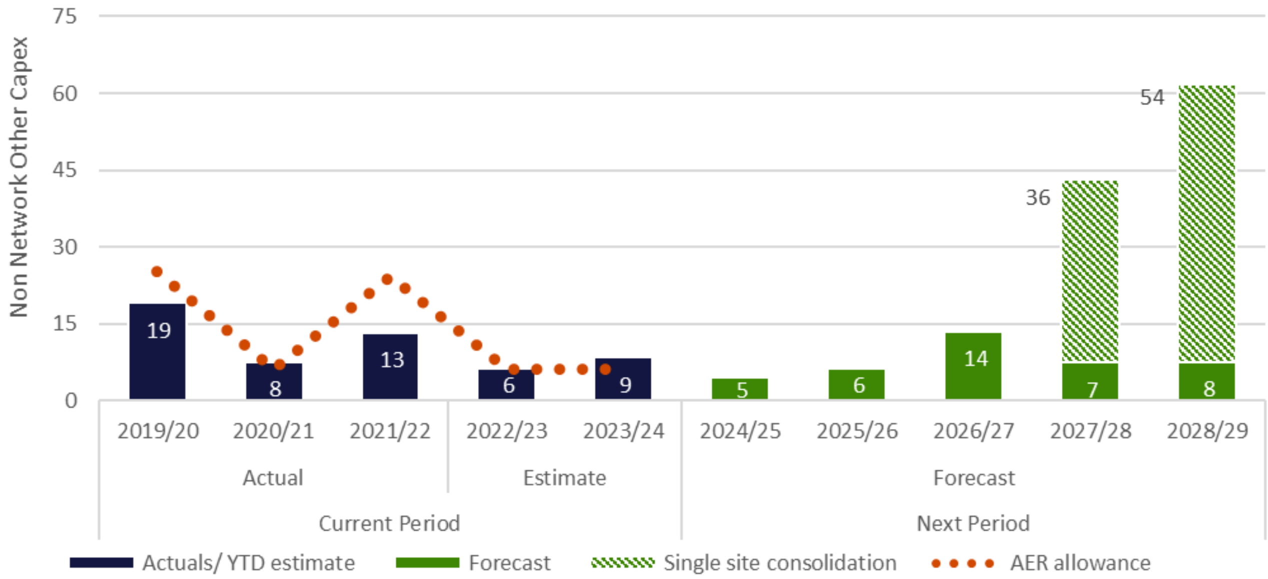
Since implementing lessons learnt, we have established a core project and delivery team for the ICT Capability Uplift program (part of the Operating Model Program). They are on track to deliver tranche 1 during the current period.

We have implemented a blended delivery model. This includes a combination of internal and external resources to deliver ICT projects. We also partner with the Department of Corporate and Digital Development (**DCDD**) for project delivery where DCDD have an established skill set or service provider. We are in the process of reviewing our delivery model for the 2024-29 ICT program of work, which will set out guiding principles on design, delivery, testing, transition, and implementation. Further information is provided in section 10 and our ICT Strategy provided at Attachment 8.65.

5.3 Deliverability of non-network other capex

Figure 5.5 compares the forecast non-network other capex in the 2024-29 regulatory period compared to actuals and estimates in the current 2019-24 regulatory period. Our non-network capex in the 2019-24 period is lower than the AER's capex allowance by $13.6 million (19.9 per cent). Forecast capex in the final two years of the 2024-29 is an outlier compared to previous years, due to the inclusion of a one-off property project that seeks to consolidate our Darwin staff in one location. We consider this project would rely on external market-based contractors and is deliverable with sufficient lead-time included for planning and delivery.

Figure 5.5: Non-network Other capex ($ million, real 2024)



PowerWater

6. Replacement capex

We are forecasting a 17.8 per cent increase in repex in the 2024-29 period compared to the current period. Our repex program fits into a longer-term strategy on efficiently managing our ageing cohort of Cyclone Tracy assets. This includes managing emerging condition issues, while including using risk quantification to identify opportunities to extend asset lives. We have tested the outcomes with the AER's repex model and explain any differences in outcomes.

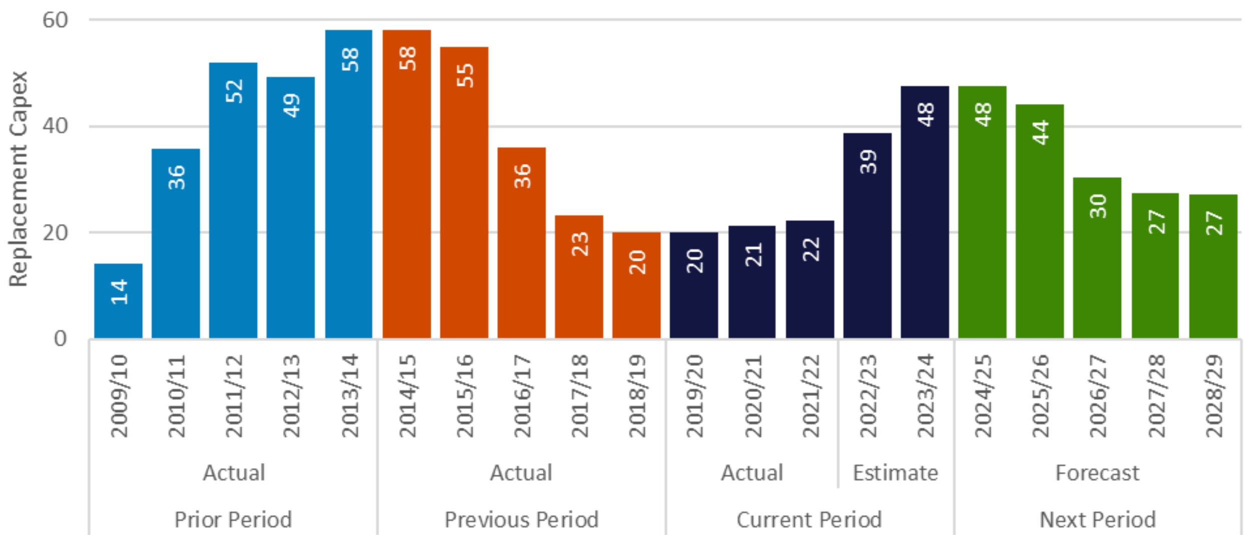
The purpose of this chapter is to set out the information and data that supports our proposed replacement capex for the 2019-24 period. This includes an overview of proposed repex, identifying drivers of repex in the 2024-29 period, explaining the overall method and key inputs, comparing the outcomes to the AER's repex model, and providing a description of the programs based on the AER's categorisation of assets.

6.1 Overview of repex

Repex is expenditure 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 undertake repex where we demonstrate that safety, reliability, environmental and other risks outweigh the costs.

We forecast replacement capex of $176.6 million in the 2024-29 period, an increase of $26.7 million compared to the 2019-24 period, an increase of 17.8 per cent. Figure 6.1 shows a material increase in estimated repex between 2022/23 and 2025/26, followed by a reduction over 2026/27 to 2028/29.

Figure 6.1: Forecast replacement capex in 2024-29 compared to actual/estimated in 2019-24 ($ million, real 2024)



The higher replacement capex between 2022/23 and 2025/26 reflects the inclusion of major projects including Berrimah zone substation, upgrade of 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 $18.6 million in the first year of the 2024-29 regulatory period.

Between 2022/23 and 2025/26 we also are forecasting an increase in volumes to our major replacement programs including replacement of high voltage cables in Darwin Northern suburbs and replacement of corroded poles in Alice Springs. Our capital acceleration program has provided a means to uplift our delivery capability of these programs to align with our needs.

The small uplift in repex also reflects our aged based volumetric modelling of reactive replacement of network assets (volumetric asset replacement) that do not relate to a planned program of works. This reflects the expected condition issues as an increasing proportion of assets installed after Cyclone Tracy reach their expected life.

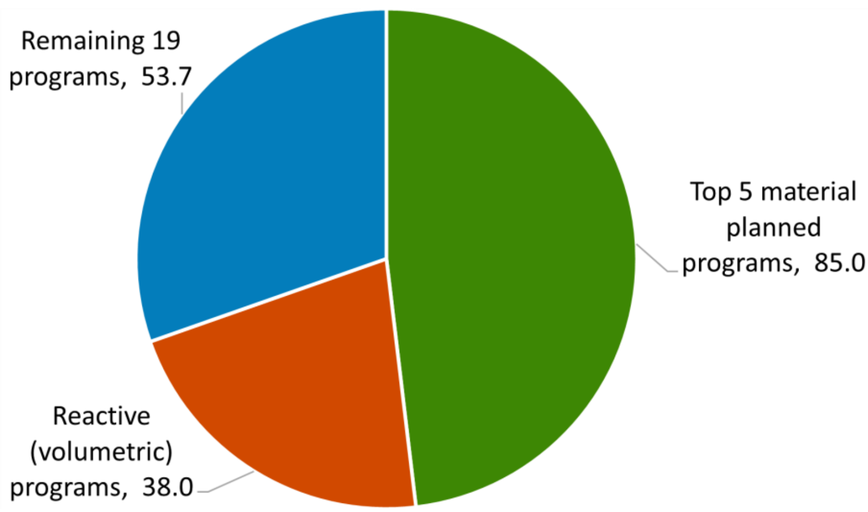
We show the total repex by year in the 2024-29 regulatory period in the table below.

Table 6.1 Forecast replacement capex in 2024-29 by year ($ million, real 2024)

Category	2024/25	2025/26	2026/27	2027/28	2028/29	Total
Repex	47.5	44.0	30.4	27.5	27.2	176.6

In terms of composition, there are 25 planned programs, together with a volumetric forecast of reactive replacements. The top five planned programs account for $85.0 million, or 48.1 per cent of the proposed repex program for the 2024-29 period. This includes Darwin high voltage cables ($28.6 million), Berrimah zone substation replacement ($24.7 million), protection relay replacement ($12.1 million), Alice Springs corroded ($10.3 million) poles, and overhead service lines ($9.3 million). Reactive replacements based on our Volumetric asset replacement accounts for $38.0 million, or about 21.5 per cent of proposed repex for the 2024-29 period. The remaining 19 planned programs or projects account for $53.7 million as shown in Figure 6.2**.**

Figure 6.2 Composition of repex program by material projects, reactive, and remaining programs (per cent)



6.2 Methods and approach

We categorise replacement activities into three types. Firstly, our planned replacement is for assets that we seek to replace or refurbish before they fail in service. These assets that have a high consequence of failure in terms of safety, customer reliability, security, compliance or environmental impact. Secondly, we have assets which are scheduled for replacement based on a known defect. Scheduled replacements aim to replace or refurbish the asset before it fails due to moderate risk of consequence. Reactive replacements occur after an asset has failed in service. This would likely occur in cases where the risk is minimal or where the event was unlikely based on our regular maintenance data.

There were three approaches to forecast our repex, depending on the asset category:

- **Major repex projects** - This relates to material projects such as major works in zone substations. Our business case assesses the need, options and costings for the replacement or refurbishment of the individual assets. The costings are based on individual elements of the assets.
- **Planned repex programs** – This relates to an ongoing program of works related to a subset of assets such as replacement of poles or cables. In this case, the assets may exhibit common condition, compliance or technical obsolescence issues that have been identified as part of our monitoring of assets. Our business case assessment seeks to identify the need, options, risk quantification, timing and costings. We generally use unit costs based on historic trends or a build-up of costs.
- **Volumetric forecasts** – For all other asset types we use volumetric modelling based on historical replacement levels and age assessment. These are generally for assets with high populations where there is some level of current replacement activity based on defects or failure in service, but no systematic issues warranting a repex program. Our approach has closely followed the AER's repex model for these categories and has excluded any asset types subject to a major project or planned repex program. Our Volumetric asset replacement is summarised in our business case.

For our major projects and planned repex programs, we have applied our Risk Quantification Procedure (Attachment 8.09) to identify the option that maximises the net present value. In all cases we have examined whether there is a credible non-network option, or if there is an alternative opex-capex substitution possibility such as preventative or corrective maintenance.

6.3 Comparison to AER's repex model

The AER's Forecast Expenditure Assessment Guidelines notes that it uses a repex model as a 'top-down' assessment of a network's forecast replacement capex. This is a predictive model that uses asset age, unit costs, and previous levels of repex expenditure to provide a top-down forecast of repex. The AER also uses benchmark data of other networks to compare the results when peer data is used.

We engaged EMCa to apply the AER's repex model and compare the results of the AER's repex model to the repex forecasts in our capex proposal for 2024-29. EMCa's report is provided at Attachment 8.11.

EMCa applied the scenarios that the AER have most recently applied in assessing regulatory proposals including:

- The Historical scenario is a type of intra-company benchmark forecast, which produces a forecast assuming the DNSP maintains the asset lives and unit costs it has been able to achieve in the recent historical period, as evidenced by the reported performance in the CA RIN.
- The Costs and Lives scenarios are two more aggressive scenarios (i.e. they will typically produce a lower forecast than the Historical scenario). These two scenarios separately consider the forecast assuming either historical unit costs or lives can be improved. In this regard, any historical unit costs or lives that are worse than the median unit cost or life move to the median. The Costs scenario also moves the unit cost to the forecast unit cost in circumstances where this is lower than both the historical and median unit cost.
- The Combined scenario is the most aggressive forecast (i.e. this scenario will typically produce the lowest forecast). This scenario assumes all unit costs and lives can move to their median (or the forecast unit cost if it is lower)

Relevantly, the repex model is only used for certain asset classes, and where there is sufficient information on similar assets used by peers. EMCa advised that its modelling was applied to the following asset groups – poles, underground cables, overhead conductors, service lines, transformers and switchgear. A number of asset categories were removed in accordance with the AER guideline following calibration of the AER's repex model. The resulting modelled categories comprise approximately 57% of the forecast repex as shown in Table 6.2 below.

Table 6.2: Composition of forecast repex by asset group ($ million, real 2022)[2]

Asset group	Forecast repex	Proportion
Modelled categories	89.2	57%
Unmodelled categories	66.8	43%
Total	156.0	100%

[2] Based on values relied upon for the repex modelling by EMCa included in Attachment 8.11

The key results are identified in Table 6.3 below. In total, our proposed modelled repex is lower than forecast under the historical scenario, but higher than the cost, lives and combined scenarios. While there are differences across each asset group, the data suggests that our unit costs are higher than peers, and our calibrated age is lower than peers.

Table 6.3: Repex model outcomes for modelled categories ($ million, real 2022)[3]

Modelled categories	Proposed repex	AER scenarios			
		Historical	Cost scenario	Lives scenario	Combined scenario
Poles	10.4	33.5	7.4	33.0	16.1
Overhead conductors	0.3	4.5	2.7	1.4	1.4
Underground cables	37.1	36.5	23.4	8.2	6.8
Service lines	8.3	4.4	0.2	4.4	2.0
Transformers	13.6	14.7	10.7	10.6	7.5
Switchgear	19.4	11.6	5.6	7.1	4.2
Total modelled repex	89.2	105.2	50.1	64.7	38.0

The threshold value is the Lives scenario, being the higher of the cost and lives scenario.

Our proposed modelled repex forecast is lower than the historical scenario of $105m, by 15%, and higher than the threshold scenario of $65m by 38%.

[3] Based on values relied upon for the repex modelling by EMCa included in Attachment 8.11

EMCa's analysis suggests that some caution should be applied in assessing the results, and that there are likely to be some unique drivers in the analysis that when normalised would result in a prediction closer to Power and Water's proposal for modelled repex. This includes:

- Recognition of non-age-based replacement or unique asset replacement projects. Whilst not the primary purpose of this assessment, we note that Power and Water has included a number of programs in its forecast that are driven by type issues and not aligned with a predictive age-based model such as the Repex model. Where this is the case, there will be heightened focus on justification of these programs for inclusion into the repex forecast. This includes the HV underground replacement program and 11 kV overhead switchgear replacement program.
- Potential allowance for higher unit costs in the Territory than for the NEM. The NEM median unit cost reflects the combination of larger programs and which include economies of scale associated with a thick resources market, none of which are present in the Territory. Given the small scale and lumpy nature of distribution repex in the Territory, Power and Water is unlikely to realise the costs experienced in the NEM. EMCa tested the influence of cost on the repex model results by applying the NEM median costs to all asset categories and then included a 10% uplift to account for operational efficiency factors present in the Territory. The results indicated an aggregate level of repex that approximates the proposed modelled repex with this adjustment. It may be argued that all other things being equal, Power and Water is subject to cost uplifts that exceed 10% compared with the NEM median.
- Other systemic factors impacting repex modelling. In its published guidance material, the AER also recognise a number of factors that impact the reliability of the repex modelling for DNSPs. This includes low volume assets, smaller networks, locking in peaks and troughs.

EMCa's view was that:

> *"We consider that Power and Water is subject to a range of factors, and which in our opinion reinforces the use of the AER Repex model as a tool to determine potential areas of further review using other assessment methods and not as a basis for a substitute estimate of repex requirements."*

EMCa provided its observations of the drivers of the material differences at an asset class level to the threshold scenario, where the main sources of difference are:

- Poles, are lower than the threshold value. Care is required in making direct comparisons on the pole design and asset replacement lives with other DNSPs. For example, Power and Water generally achieves longer lives from its pole fleet, and which we understand follow different design and has adopted mid-life refurbishment options compared with the NEM. Power and Water has also adopted a lower cost pole refurbishment option to extend the life of poles, and which results in lower overall cost.
- Underground cables, are higher than the threshold value. Power and Water has adopted a corrective replacement program to address early life failures associated with installation and design issues, and which forms part of a program that is continuing from the current period.
- Service lines, are higher than the threshold value. Power and Water is proposing a new service line replacement program consistent with other DNSPs and in response to recent failures and safety incidents.
- Switchgear, is higher than the threshold value. Power and Water has included a targeted replacement program for distribution switchgear.

6.4 Description of major projects and programs by asset groups

In the following sections we describe the major projects and programs included in the replacement forecast by AER asset groups. We show the total forecast repex by asset group in the table below and which reconciles with the RIN.

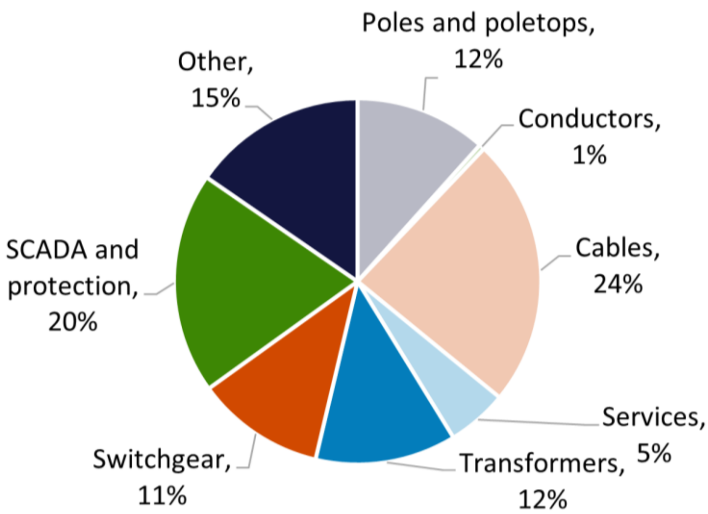
Table 6.4: Composition of forecast repex by asset group ($ million, real 2024)

Asset group	Forecast repex
Poles and poletops	20.5
Conductors	0.8
Cables	42.1
Service lines	9.4
Transformers	21.9
Switchgear	20.1
SCADA and protection	34.6
Other	27.1
Total	176.6

Approximately two-thirds of our forecast repex is made up of three asset groups as shown in Figure 6.3. These are:

- Other (15.4%), including a major pole refurbishment (re-butting) program in the Alice Springs area.
- SCADA and Protection (19.6%), including a major program to replace a portion of our protection relays.
- Cables (23.8%), including two major cable replacement programs – for HV and LV cable.

Figure 6.3: Composition of forecast repex by asset group for 2024-29 period (per cent)



In the sections below we provide the totals for context, and then discuss the major projects and programs that contribute to these totals. Importantly, we have focussed on the major projects and programs, typically exceeding a cost of $1 million. We have also included the contribution of our volumetric program, from our modelling of forecast replacement volumes (provided at Attachment 8.10). A full list of projects and programs is provided at Attachment 8.03.

Cost estimates are based on our cost estimation methodology provided at Attachment 8.07. Further information can also be found in the regulatory business cases in support of each project.

Also, projects and programs are categorised across more than one asset group. As we describe the total expenditure for each project and program, rather than the contribution to the asset group, the figures may not sum.

6.4.1 Poles and Pole-tops

Power and Water has about 3,200 transmission towers and 42,000 poles across our regulated network. These assets keep our overhead wires (conductors) at a safe height clearance from the community. Due to the harsh environment, Power and Water relies on steel as the primary material in our poles and towers. The dominant cause of failure of steel poles and towers is corrosion due to water and wind exposure.

We are forecasting $20.5 million on refurbishing and replacing poles and pole-top components in the 2024-29 period. This is comprised of the major projects and programs shown in the table below and discussed in the following sub-sections, noting that a portion of the Cockatoo conductor replacement project and Strangways to Mary River 66 kV line replacement project costs relate to the poles asset group (discussed in conductor section).

Table 6.5: Major projects and programs by asset group ($ million, real 2024)

Major projects and programs	Total
Transmission Line Pole top corrosion program	3.4
Volumetric asset replacement – poles and poletops	7.4

Transmission Line Pole top corrosion program ($3.4 million)

We currently have a program to replace insulators and cross arms on transmission towers in our Darwin-Katherine transmission network. Our transmission towers are subject to extreme tropical weather and some are located in inter-tide mangrove areas. This has resulted in corrosion on the insulators and cross arms[4] of the towers, commonly termed the 'pole-top' components. Similar to Alice Springs, this approach extends the asset life of the transmission tower by addressing the condition or functional failure of components rather than replacing the tower.

4 These are special steel structures designed to hold the power line wires on the pole.

Our analysis shows that the underlying corrosion cause for insulators relates to leakage current through the insulators where they connect with conductors (the 'hot' end), particularly when wet. The corrosion of the insulator leads to mechanical failure of the insulator strings due to compromised strength and potential for flashover (sparks that damage the asset). For cross arms, we consider that the use of an ungalvanized hollow box section steel creates a humid 'micro-environment' which exacerbates corrosion. Corroded cross arms can lead to mechanical failure with the potential for the live conductor to fall to ground.

Our analysis identified three key risks with pole-top failures. The key risk is safety of our staff who may be impacted by the structure or elements falling while inspection or maintenance is undertaken. While the towers on the Darwin-Katherine transmission line are located in more regional areas, there is also a safety risk to the public. Finally there are reliability risks from the failure of the asset given that transmission lines supply power to all the zone substations.

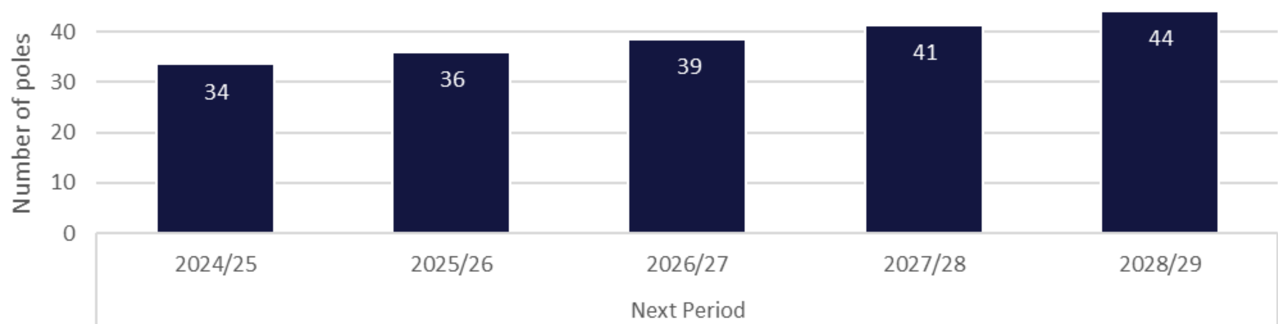
We identified three options to address the issue including run to failure, inspection and replacement of defect items, and a targeted proactive replacement.[5] The targeted program was considered the option that was least cost given the quantified risks with the 'run to failure' option, and the high operating costs entailed in inspections. This is consistent with our current approach where we identify the insulators and cross-arms at most risk based on analysis that takes into account recent inspection data, structure age, and criticality of asset for reliability. The program has a total cost of $3.4 million to replace 350 insulators and 30 cross arms.

Several learnings from the current program have been considered in our approach to undertaking replacement of pole-tops. This includes 'live line' work methods may ne be efficient for all pole-top arrangements, using polymer rather than porcelain insulators is a lower lifecycle cost, and using galvanised steel to replace bare cross arms is a better design option.

Volumetric asset replacement – poles and pole-tops ($7.4 million)

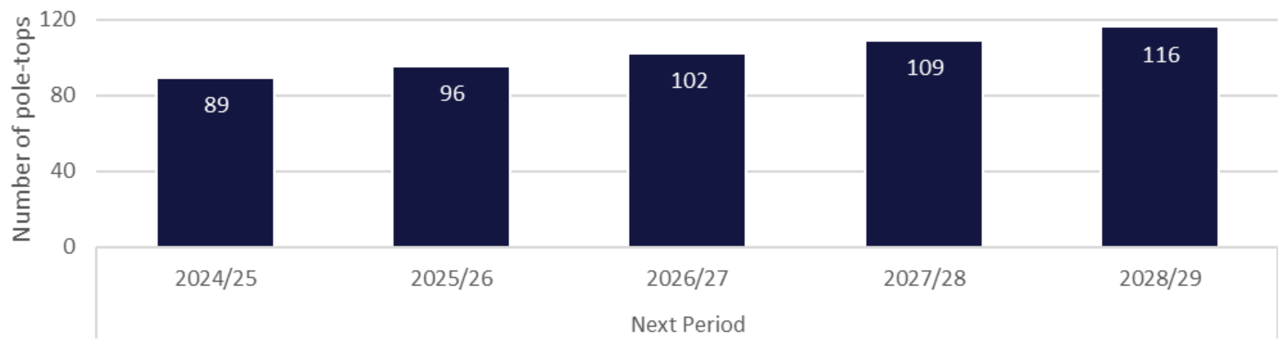
Our volumetric asset replacement forecasts excludes population of poles that are already included in the planned programs identified above. Our forecast is $3.3 million for poles and $4.1 million on pole tops. The forecast quantities for poles are set out in Figure 6.4 and pole tops in Figure 6.5**.** Due to the ageing of assets, the model predicts increasing replacement volumes for each category.

Figure 6.4: Volumetric forecast of pole volumes for the 2024-29 period (quantity)



[5] Non-network alternatives were not considered viable as we could not identify a solution that would not entail 'like for like' replacement or opportunities for a lower cost replacement technology.

Figure 6.5: Volumetric forecast of pole-top volumes for the 2024-29 period (quantity)



6.4.2 Overhead conductors

Conductors are the wiring infrastructure that transports electricity above ground through poles and transmission towers. We have about 5,400 kilometres of overhead conductors comprised of about 700 kilometres of transmission lines, and 3,500 kilometres of high voltage distribution feeders and 1,200 kilometres of low voltage conductors.

We are forecasting $0.8 million on replacing overhead conductors in the 2024-29 period. This is comprised of the major projects and programs shown in the table below. These projects and programs are described in the following sub-sections, noting that a portion of the Cockatoo conductor replacement project and Strangways to Mary River 66 kV line replacement project costs relate to the poles asset group.

Table 6.6: Major projects and programs by asset group ($ million, real 2024)

Major projects and programs	Total
Cockatoo conductor replacement	5.6
Strangways to Mary River 66 kV line replacement	4.3
Volumetric asset replacement - conductors	0.3

Darwin – 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. Due to delays in in the existing program, including scheduling of required outages with our customers, we will only complete 27 kilometres of the expected 40 kilometre section of the feeder by the end of the current 2019-24 regulatory period. Our forecast for the 2024-29 period comprise conductor replacement of 19 kilometres of the Lake Bennett feeder and a further 7 kilometres of the Acacia feeder. This includes the residual 13 kilometres from the current period.

The need for replacement arises from two primary issues. Firstly, there are a significant number of spans that do not comply with the minimum clearance requirements. Secondly, the type of conductor is an imperial gauge “Cockatoo” type, which gives rise to complex challenges. The conductor is displaying signs of having reached end of its serviceable life, including broken strands, corrosion and conductor damage due to annealing, and is difficult to repair due to the weight, gauge, high stringing tension[6] 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 where there is no alternative source of supply when the conductor fails in service.

Our analysis quantifies the risks posed by this asset. There are compliance and safety risks with not addressing the mandated clearance issues, that impacts a significant amount of the feeder. In an investigation undertaken in August 2017, 66.7% of the conductor spans over road crossings and 39.6% of conductor spans for other areas (excluding road crossings) did not meet the minimum ground clearances. Further, we expect reliability to further decline for customers connected to the feeders. Our risk quantification analysis indicates that reliability is the most material of risks, followed by non-compliance penalties.

We examined four credible options to address the risks - replace the conductor on failure, install mid-span poles and install new conductor sequentially, a complete line re-build, and install stand-alone power stations (SAP) and remove the line from service. The analysis indicated that installing mid-span poles and re-conductoring was the least cost option to address the needs. The run to failure option resulted in high risks that would continue to grow over time. The complete line re-build and SAP options had much higher costs to reduce the risks compared to mid-span poles and re-conductoring.

The scope of the least cost option is to replace 26 kilometres of cockatoo conductor in the first three years of the 2024-29 regulatory period, along with the installation of 119 new distribution poles and 171 new pole tops.

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 the Darwin.

The need for the project arises from two issues. The primary issue is that many of the 118 spans that comprise the length of the 22 kilometre conductor do not meet clearance requirements introduced retrospectively in 2010. To address the risks, we had been operating the line at lower capacity of 7 MW, which means less spans are non-compliant. Nevertheless, the radial line connects to three zone substations along the Arnhem Highway and has an ongoing heightened risk. The second issue is higher demand in the Humpty Doo area, which now requires us to operate at a higher capacity, resulting in much higher levels of non-compliance.

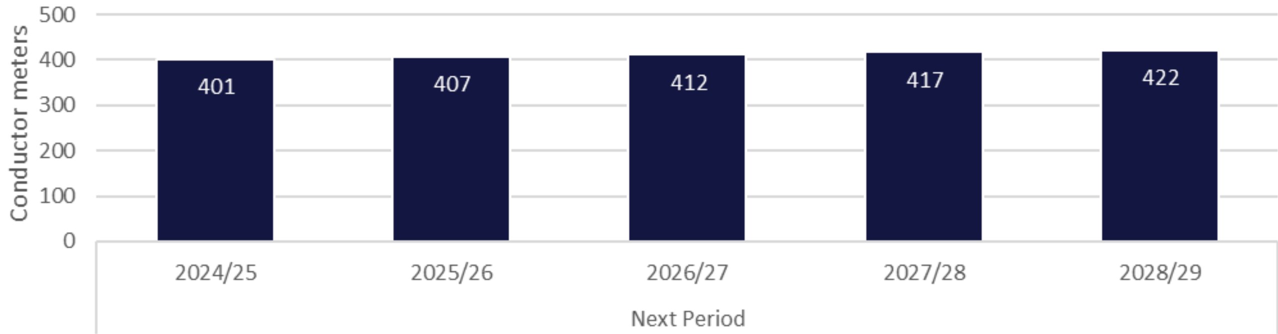
Our business case assessment considered that a prudent solution to address the two issues was to undertake immediate works on over 40 of the highest risk spans with very low clearance over the road, dirt road crossings and grounds. The total forecast capex is estimated at $4.3 million.

6 There are relatively long spans between poles, requiring the conductors to be strung with high tension. This results in higher failure rate due to mechanical tension.

Volumetric asset replacement – conductors ($0.3 million)

Our volumetric asset replacement forecasts in Figure 6.6 exclude the population of conductors related to the Lake Bennett and Manton conductor program and the Strangways to Mary River conductor replacement programs. We are forecasting a steady rate of reactive replacement of conductors, which is relatively low in value. We note that the replacement is based on the impacted span as measured in metres, rather than replacement of the whole length of conductor. This is a very small fraction of the conductor population.

Figure 6.6: Volumetric forecasts of conductor replacement (metres)



6.4.3 Underground cables

Underground cables are wiring infrastructure constructed below ground often through ducts or tunnels. We have about 1,630 kilometres of underground cable, comprising of about 40 kilometres of transmission, 890 kilometres of high voltage distribution cables, and 710 kilometres of low voltage cable.

We are forecasting $42.1 million on replacing cables in the 2024-29 period. This is comprised of the major projects and programs shown in the table below. These projects and programs are described in the following sub-sections.

Table 6.7: Major projects and programs by asset group ($ million, real 2024)

Major projects and programs	Total
Darwin Northern Suburbs High voltage cable replacement	28.6
Darwin Cullen Bay and Bayview Low Voltage Cable program	5.3
Volumetric asset replacement – cables	3.2

Darwin Northern Suburbs High voltage cable replacement ($28.6million)

In the 2019-24 period, we have been progressively replacing high voltage cable in the Darwin northern suburbs with about 26.7 kilometres undertaken by the end of the period. We are forecasting to replace an additional 37.5 kilometres in the 2024-29 period.

The underlying need for the project is the condition of cables installed in the area. About 146 kilometres of XLPE type cable was installed in the late 1970s and early 1980s. The XLPE cables installed at the time have undergone a degradation process that leads to water ingress, resulting in accelerated corrosion of the neutral/earthing wires when exposed to moisture and electrical stress. A compounding factor is that the cables installed in the northern suburbs have an aluminium screen which oxidises in the presence of water causing the screen to turn into a powder and become electrically discontinuous (open circuit). The oxidisation process also increases the volume of the aluminium, causing the cable to swell and deform, and is a likely factor in the insulation failures. Together these issues increase the risk of cable failure and impaired operation of the earthing system.

We have extensive condition data and outage data to show that a large proportion of the assets are at the end of their serviceable life. By using population sampling statistical methods, we have determined that between 54 per cent and 79 per cent of the cable is very highly likely (95 per cent confidence) to have reached the end of its serviceable life. This is likely to grow over time.

The risk analysis shows that reliability is the dominant quantified risk. While the northern suburbs cables account for only 16 per cent of the cable fleet, they contribute an average of 47 per cent of the cable outages as measured by SAIDI and SAIFI. This risk will grow over time as the probability of failures rise. We have relied on the safety consequences values suggested by Ofgem for our analysis as documented in our Risk Quantification Procedure (Attachment 8.09).

Our options analysis shows that a reactive run to failure model results in deteriorating network performance and increasing safety risk to both the public and workers. Further there is a higher cost of reactive replacement. The preferred option is consistent with our current approach to target cable replacement where we use testing results and criticality based on demand and proximity to the public to identify the highest risk cables.

As part of our options analysis, we considered the optimal timeline to replace the cables from 1 year to 20 years. The analysis demonstrates that a 16 year replacement is optimal. On that basis, we have identified that we should undertake about 7.5 kilometres of cable replacement each year. The unit rate has been derived based on recent cable projects undertaken under the new contracting arrangement in the Northern Suburbs.

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 4.0 kilometres of replacement.[7] We are forecasting a further 7.6 kilometres of cable replacement in the 2024-29 period, based on addressing the highest risk areas.

[7] We had initially estimated 7 kilometres of replacement in the 2019-24 period. However due to the limited supply of civil contractors, the project has been delayed. We note that these deliverability issues have been resolved.

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. The water is reacting with compounds in the cable insulation leading to calcium adipate that further damages the cable insulation. Calcium adipate also expands cable joints and lugs (connects the cable to the terminal) and eventually leads to failure of the cable. Calcium adipate is also conductive when wet, elevating the risk of electric shock to field crews. 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.

The key risks arising from the condition issues include worker and public safety risks particularly arising from the inadequate neutral earthing system, but also from the risk of conductivity due to calcium adipate. While reliability issues have not been material to date, the continued degradation in the condition of the cables gives rise to increasing risk of cable failure. Further, when an unplanned outage does arise it could lead to extended outage time for customers due to the difficulty in locating the fault due to inadequate earthing.

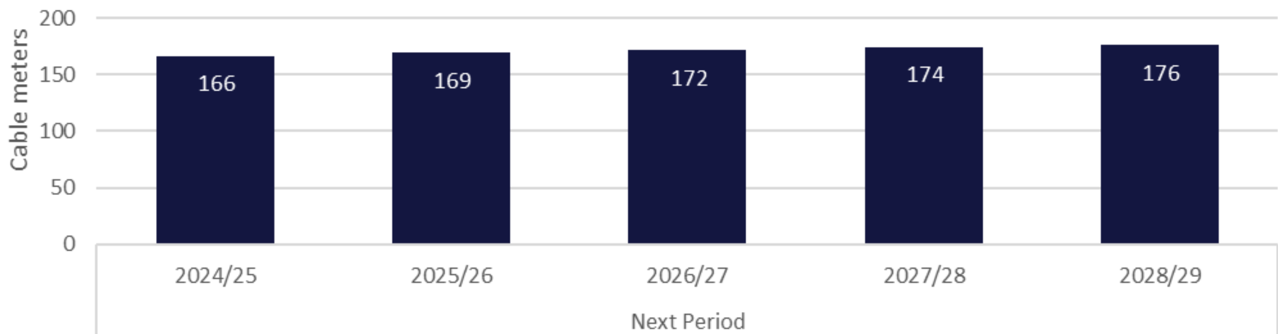
Our options assessment examined three options[8], of which only two were feasible.[9] This included run to failure, and targeted proactive replacement and refurbishment. The latter option is the current approach. Our options analysis confirmed that proactive replacement is the least cost approach to addressing the risks with the cables. The run to failure option has higher costs due to the complexity in identifying the location of the fault, the difficulty of accessing the fault due to other underground services (which have been directly buried) and footpaths, together with the high risks of keeping the assets in service.

Under the recommended proactive replacement option, we would prioritise replacement cable based on evidence of condition including data on the severity of calcium adipate. The approach also lowers the present cost of the program by performing the replacement over many years, rather than a single year. The option also presents an opportunity to outsource the works to a contractor, improving the deliverability of the capex program.

Volumetric asset replacement – underground cables ($3.2 million)

Our volumetric asset replacement forecasts exclude the population of assets related to the cable replacements in Darwin's northern suburbs and in Cullen Bay and Bayview. The results show that cable replacement will increase over the 2024-29 period, consistent with the incremental ageing of the population. Figure 6.7 identifies the quantities of replacement by metres.

Figure 6.7: Volumetric forecasts – cables (metres)



[8] We did not find any credible non-network alternatives that would allow us to provide energy to the customers in the absence of cables.
[9] We considered replacing the remaining kilometres of line in one year, but this would not have been practically deliverable.

6.4.4 Service lines

Service lines are wiring infrastructure that connect to a customer's premises. We have about 57,000 kilometres of service lines, including 24,000 conductors (above ground) and 33,000 cables (underground).

We forecast capex of $9.4 million on replacing service lines in the 2024-29 period. This is a significant uplift in capex compared to previous regulatory periods, due to the introduction of a new planned program in Darwin as shown in the table below. These projects and programs are described in the following sub-sections.

Table 6.8: Major projects and programs by asset group ($ million, real 2024)

Major project and program	Total
Service lines planned program	9.3
Volumetric asset replacement – service lines	0.1

Service lines planned program ($9.3 million)

Previously, Power and Water has only replaced service lines when they fail in service particularly after tropical storms or cyclones. Until recently, our maintenance strategies did not include inspection so there was limited data on the condition of service lines. However two recent safety incidents involving condition issues with our overhead service lines, including a fatality in our unregulated region, has prompted a change in our asset management approach for service lines.

Following the fatality in 2020, NT WorkSafe instructed Power and Water to initiate an inspection program including in our regulated networks and to undertake a review of maintenance strategies. Our initial inspection program subsequently found a significant number of defects on overhead service lines in our regulated region, which has necessitated a revision to our maintenance strategies including an ongoing cyclic inspection program.

The inspection program has identified several condition issues with overhead service lines. We found that the insulation for the service conductor has deteriorated in many of our service lines due to prolonged exposure to UV radiation (sunlight) and moisture ingress, leading to direct exposure of the wiring. We also found that a high proportion (about 25 per cent) of service lines were close to vegetation leading to a risk of live conductor falling to ground or a conductive surface. Additionally, we found instances of failure in the service clamp that attaches the wiring to the pole that could lead to apparatus becoming energised and being touched by our workforce or public.

The overriding risk from these condition issues relate to worker and public safety. The failure of a service line may result in a live conductor touching conductive surfaces of buildings or laying on the ground in residential premises. The quantified risk of reliability associated with the failure of service lines is relatively low, as the failure only impacts the individual house rather than the street or suburb.

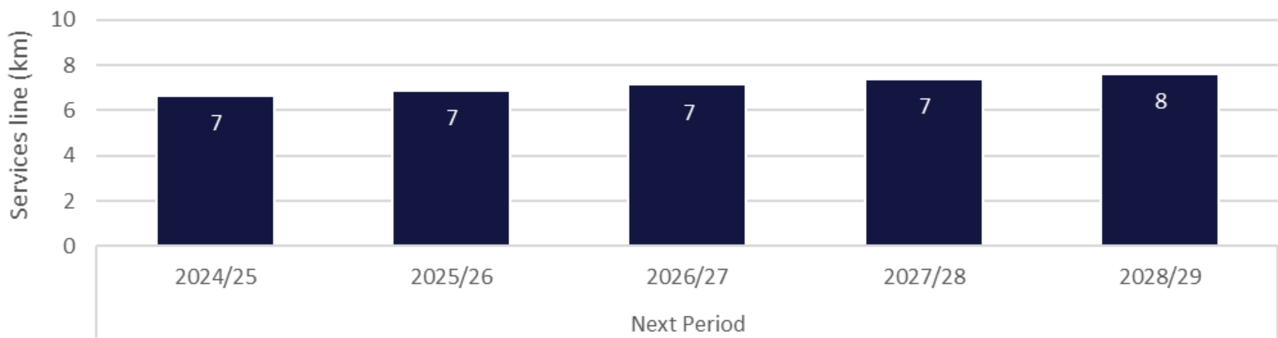
Our options analysis examined two credible options.[10] The 'run to failure' option is consistent with our historical approach to service lines where we only replace service lines on failure, which has generally been during storms and cyclones. The second option was targeted replacement where we identify defects during a cyclic inspection and proactively schedule replacement, which will occur over multiple regulatory periods. This includes addressing the backlog of defects from our current inspection program. The second option was determined to provide the highest benefit due to the higher quantified safety risks presented by the run to failure option.

The proposed scope of the project in the 2024-29 period is to replace 4,000 service lines (800 a year) at an average unit cost of $2,000 based on previous expenditure data.

Volumetric asset replacement – service lines

Our volumetric asset replacement forecasts excluded all overhead service lines. We note that the remaining 33,000 underground service lines are not subject to the same levels of risk. We have used historical failures and the asset age profile to predict a very low level of replacement of underground service lines of $0.1 million. Figure 6.8 shows the quantities of service lines forecast for the 2024-29 period.

Figure 6.8: Volume forecast of quantity of service lines (quantity)



6.4.5 Transformers

Transformers step-down voltage as energy flows from large scale generators through our network. The first voltage transformation occurs at our zone substations where energy is transformed from 132 kV or 66 kV from our transmission network to either 11 kV or 22 kV. The reason for transforming voltage relates to the technical efficiencies of conducting energy over long distances using higher voltage, but the necessity of customers receiving lower voltage to safely meet their energy needs.

In total we have four sub-transmission substations, 26 zone substations, and 4,900 distribution substations. In terms of the distribution substations we have about 340 ground substations, 1,300 kiosk substations, 2,900 pole substations, and 320 single phase substations.

[10] Non-network alternatives were not considered credible, as we could not identify an alternative technology to substitute a service line to the customer. We note that as part of our service line replacement, we would assess if there are lower capacity options that may be more suitable.

We are forecasting $21.9 million on replacing transformers in the 2024-29 period. This is comprised of the major projects and programs shown in the table below, with the majority relating to a major committed project to replace the existing Berrimah zone substation. These projects and programs are described in the following sub-sections.

Table 6.9: Major projects and programs by asset group ($ million, real 2024)

Major projects and programs	Total
Berrimah zone substation replacement	24.7
Single phase substation refurbishment and replacement program	3.5
Volumetric asset replacement - transformers	13.3

Berrimah zone substation ($24.7 million)

The Berrimah zone substation was a material project assessed by the AER in our 2019-24 proposal, with the project expected to commence early in the 2019-24 period. However the project has only substantially commenced in 2022/23 at a cost of $1.3 million, with about $5.7 million of expenditure committed for the last year of the 2019-24 period. We are forecasting that the remaining capex of $24.7 million will occur in the first two years of the 2024-29 regulatory period.

The approved business case for the project notes the underlying condition issues at Berrimah zone substation.

Five of the six 66 kV circuit breakers in the switchyard together with one of the transformers are likely to fail in the short term. Failure of these assets during operation will result in significant outages and loss of substation capacity for extended periods of time.

While the building structure itself is in relatively good health, the auxiliary systems including air conditioning, fire systems and auxiliary supplies are also expected to fail in the short term. Most of these systems were original units installed in 1981 and there are on-going issues which requires regular repair.

The majority of protection relays are over 15 years old with a significant number over 25 years old. Most of these relays are no longer supported and spares cannot be sourced from the original equipment manufacturers.

The 11 kV switchboard was installed as part of the original substation establishment. Over the years, the switchboard was extended and the original bulk oil circuit breaker trucks were replaced by vacuum equivalents, reducing the risk of fire and explosive failure. The main concern with this switchboard is that it is does not have appropriate arc-fault containment and there is inadequate protection to quickly isolate the bus in the event of a bus fault.

Frame Earth Leakage is used on similar switchboards in PWC to provide this protection, however this has been disabled at Berrimah due to the degradation of panel insulation and subsequent spurious bus trips that resulted in widespread outages.

Our options analysis considered the feedback of the AER at the time of the 2019-24 regulatory determination. The AER considered that we had demonstrated that green-field option (that is, re-building a new zone substation in an adjacent site) and which maintains the capacity of the current zone substation, reasonably reflects the efficient costs that a prudent operator would incur.

Consistent with the preferred option, we will replace the existing Berrimah substation with a new substation initially configured with two standard sized transformers with provision for a third transformer circuit. The firm transformer capacity will have a minimum of 41 MVA once the new substation is commissioned. In the future, there will be options to increase firm capacity by installing a third transformer at Berrimah or proceeding with the development of a permanent zone substation at Wishart.

Single phase substation refurbishment and replacement program ($3.5 million)

The program commenced in the 2019-24 period to resolve corrosion issues with the enclosure and tank of single phase underground distribution substations in Darwin's northern suburbs. The substations are vital to performing live works on the high voltage network. By the end of the current regulatory period we expect to have addressed 81 of these units under the current program leaving 191 SPUDS at elevated risk due to deteriorated condition. In the 2024-29 period we forecast that a further 115 substations will be refurbished and 20 replaced altogether.

The need for the project was established in our 2019-24 regulatory proposal where there was evidence of significant corrosion of the external tank leading to oil leaks and failure, as well as deterioration of the internal components required for operational switching. The deterioration of the substations are strongly related to age with most of the substations being installed in the early 1980s, and their continued exposure to tropical weather in Darwin over the life of the asset. This also relates to the design and location of the asset where the substation is mounted on concrete in residential gardens allowing the water to pool. An additional issue that has been identified during the current program is the need to upgrade earthing of the unit to align with newer standards.

The dominant risk relates to health and safety of the public. The substations are installed in the front yards of residential properties in four of the northern suburbs of Darwin. The primary mode of failure is oil loss leading to internal flash over (sparking). Since the older transformers in corroded condition are not arc-flash rated, the assets pose a risk of the substation catching on fire or exploding and not being contained by the corroded enclosure. The second risk is environmental damage from leaking oil close to residential areas. Reliability is a lower quantified risk as a failure of an individual substation will lead to outages for only a small number of customers.

We directly examined three options in our business case. It should be noted that preventative maintenance was a non-credible option as previously we found that measures such as removing debris, soil and water was ineffective in most locations as the materials build up in a short timeframe due to high vegetation growth rates and wet season conditions. The first credible option of reactive replacement leads to significantly high quantified risks. The second credible option was to continue the existing proactive replacement and refurbishment program where we target substations through normal inspection processes and address the issues through either replacement or refurbishment. This option was preferred as it has the highest net present value. We also explored a third option of accelerating replacement but considered this was not economic.

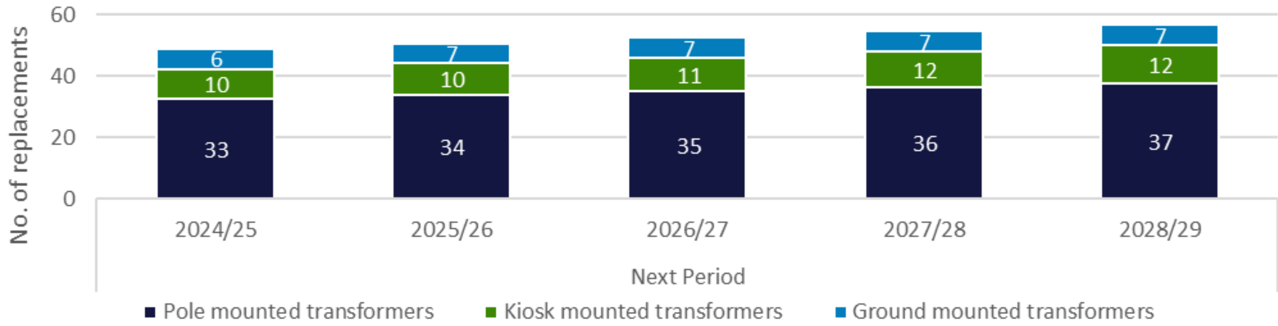
The forecast scope of the program is to replace 20 substations and refurbish 115 substations. At the time of replacement or refurbishment, we will also ensure the earthing meets new compliance standards. The unit cost estimates have considered previous costs in the 2019-24 period, and reflect the relatively low cost of refurbishment compared to replacement.

Volumetric asset replacement – transformers ($13.3 million)

Our volumetric asset replacement forecasts excludes zone substation transformers. The modelling forecasts that we will incur $3.9 million on pole mounted substations, $5.2 million on kiosk mounted substations, and $4.2 million on ground mounted substations.

The volume of replacement for each asset type is provided in Figure 6.9.

Figure 6.9: Quantities of distribution substation replacements (quantity)



6.4.6 Switchgear

Switchgear enables elements of the network to be turned off to assist with fault management and planned maintenance, and to ensure safety. We have 300 high voltage switchgear, 1,730 distribution switchgear, and 3645 distribution pillars.

We are forecasting $20.1 million on replacing switchgear in the 2024-29 period. This is comprised of the major projects and programs shown in the table below, with the majority relating to a major committed project to replace the existing Berrimah zone substation. These projects and programs are described in the following sub-sections. Forecast expenditure for distribution pillars has been included in the Other assets group, consistent with the classification included in the RIN.

Table 6.10: Major projects and programs by asset group ($ million, real 2024)

Major projects and programs	Total
Distribution switchgear condition-based replacement	5.3
Volumetric asset replacement – switchgear	12.1

Distribution switchgear condition-based replacement ($5.3 million)

This is a continuing program from the current period, that seeks to address fault issues with a type of distribution switchgear (Magnefix) that is operating above current fault levels, and poses a risk to the safety of the public and our workers.

An increasing number of the population has been failing in service. The main failure modes are deterioration of the switchgear insulation due to harsh service conditions, and termination failures which can lead to explosive failures. Development of the network over time has resulted in an increase of system three phase fault levels above 14.4kA in some areas of the distribution network. Currently the network contains 29 Magnefix switchgear installations where the system fault levels exceed or are encroaching on the equipment rating, of which 9 are planned for replacement by the end of the current regulatory period.

The key risk with failure of the substation relates to worker safety. There are no barriers present between the operator and the switchgear in the event of a switchgear failure or incorrect operation. All operations can only be performed manually with the operator standing directly in front of the switchgear. In addition to worker safety, many of these installations are in public areas and present an elevated safety risk to members of the public. We have three recorded instances of explosive failures, underscoring the risk to safety posed by the assets. There are also reliability risks when a distribution substation fails including significant outage time for a large number of customers. For example, in one incident about 600 customers experienced an outage of 5.5 hours.

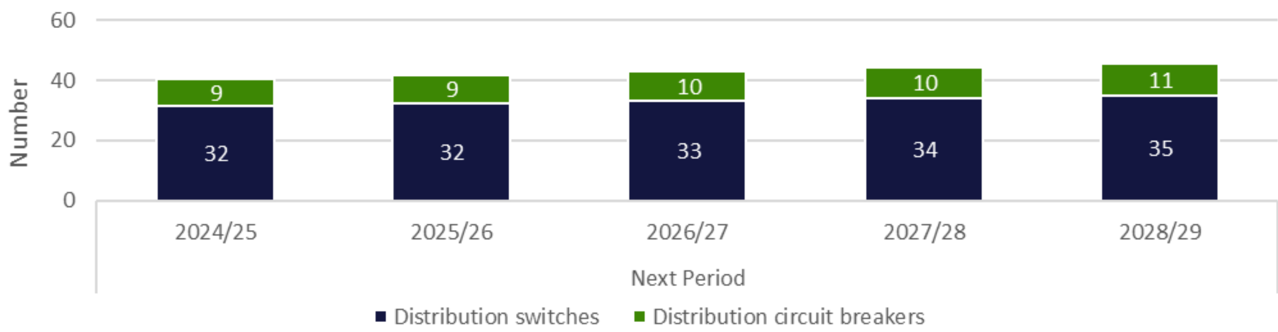
Our options analysis shows that run to failure results in high residual risks compared to other options, and would be imprudent given recent experience with explosive failures. The preferred option is to target replacement on high risk switchgear based on the fault level and the proximity of the location to the public and asset condition. A third option to alleviate fault levels through operational configuration such as a split bus configuration can lead to greater risk of outages for customers, and therefore is less economical than targeted replacement.

The scope of the project is to replace 20 of the high risk switchgear installations in the 2024-29 period. Each asset will require replacement of the padmount/package substation containing the switchgear, civil works and re-termination of the cables. The cost of the project has been based on recent replacements.

Volumetric asset replacement – switchgear ($12.1 million)

Our volumetric asset replacement forecasts excluded distribution pillars. The modelling forecasts that we will incur $8.8 on distribution switches, and $3.4 million on circuit breakers. The volume of replacement for each asset type is provided in Figure 6.10.

Figure 6.10: Forecast volumes of switchgear and circuit breakers (quantity)



6.4.7 SCADA, protection and communications

Electricity networks require an ecosystem of secondary assets to keep the network secure. This includes SCADA which gathers, processes, and display information about the status of the network and controls the network. It also includes protection relays which detect and keep the network safe in the event of a fault. Finally it includes communication assets such as data networks, microwave radio, optical fibre network and pilot cable network to signal the performance of the network with the control team.

We are forecasting $34.6 million on replacement activities for SCADA, communications and protection, with the majority relating to a major committed project to replace the existing Berrimah zone substation. The remainder of the forecast is comprised of the major projects and programs shown in the table below. These projects and programs are described in the following sub-sections.

Table 6.11: Major projects and programs by asset group ($ million, real 2024)

Major projects and programs	Total
Protection relay replacement program	12.1
MPLS migration	5.6
Energy Management System software replacement	1.6
Communication battery replacement	1.6
Code compliance and safety program	1.4
Microwave systems retirement	1.4

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 relate to older electromechanical technology. We have been progressively replacing our electromechanical relays over the past decade with digital substitutes.

The drivers of the program relate primarily to the poor functionality and obsolescence of remaining electromechanical relays on the network. The relays on our 66 kV transmission network have compliance issues with the Technical Code around redundant (X-Y) protection schemes needed for equipment operating at 66 kV and above. We have identified that 8 static protection relays operating at 66 kV are non-compliant. While the non-compliance issue has been managed over time, there is new information suggesting physical signs of degradation. Further, there is an increasing need for recording capability at these locations to support investigations, compliance and incident response in the context of increasing renewables on our transmission network.

In addition, the remaining electro-mechanical relays on our distribution network are out of vendor support, do not enable us to comply with more stringent reporting conditions, and have higher failure risks. Further, unlike digital relays, they do not leverage the network flexibility benefits of remote management, which is becoming of increasing value as our network seeks to facilitate growing renewables.[11]

We examined three options in our business case. The run to failure with spares as a mitigation was not the preferred option on the basis that it does not address the current non-compliance issues, that we expect further degradation in the condition of the assets which increases risk over time, requires strong management of our spares, and does not provide for improved network flexibility. We also considered run to failure but this had similar issues and higher costs. The preferred option was targeted selection of relays and sites to replace obsolete relays over time with modern, faster acting and more configurable relays.

Under the preferred option, we will replace a total of 69 relays representing about 15 per cent of the existing static relay population over the 2024-29 period. We consider this will need to be incrementally uplifted in future regulatory periods as at this rate of replacement we would still have electromechanical relays in operation beyond 2050.

The scope of the project involves replacing the identified eight relays on the Channel Island to Hudson Creek transmission network that are non-compliant. We would also replace 61 distribution protection relays in Darwin urban areas, Batchelor, Weddell and Alice Springs. In addition, we would install a data recorder in eight locations and install integrated protection settings management software to meet the needs of increasing renewables, DER and storage.

MPLS migration ($5.6 million)

Consistent with our regulatory obligations[12], we operate a communications network that provides information and controls the status of performance and faults. The communication devices currently rely on multiplexors, which combine or split out the signal from our population of communication devices.

The types of multiplexors currently in use on the Power Services electricity network are old technology and have been superseded by Multiprotocol Label Switching (MPLS) devices. MPLS is designed to operate in a virtual environment and therefore provides more flexibility as the switching and throughput can be made without physical changes to the network.

The underlying need to transition to MPLS in the 2024-29 period is that multiplexors are being phased out by vendors as evidenced by End of Life and End of Support notices. In addition to the primary driver of obsolescence, a critical router of the Digital Mobile Radio network is close to end of life, and new routers are only compatible with MPLS. Further there are advantages of using MPLS to overcome functionality issues with our existing substation LAN. Finally there are operational benefits of migrating to MPLS in terms of network control.

11 Modern relays are based on microprocessor (digital) control and provide multiple protection functions within each device, as well as providing diagnostic capabilities that support the required investigations into abnormal operations and timely reporting to System Control. Modern relays are also able to communicate via the SCADA system and the restricted-access engineering ICT network to provide operational information to System Control.

12 The Power Networks Technical Code and Planning Criteria (Technical Code) requires Power and Water Corporation to maintain a communications network for monitoring and control of the electricity network and provide a communications network between any Users connected to the network and System Control.

We examined two options to address the obsolescence issue with end of support multiplexors. In both options we would replace the 151 PDH and 62 SDH devices with an MPLS solution, replace the 22 digital radio switches, upgrade LAN at 10 substations, develop a testing facility, and purchase critical spares. The difference in options related to the type of MPLS used. The MPLS-IP was preferred to MPLS-TP due to its additional functionality.

Due to the change in technology and functionality of the devices, the 143 SDH and PDH assets are expected to be replaced by 104 MPLS assets, having removed those assets expected to be replaced under major projects or customer connections. However, the final number will be determined during the detailed design phase for each site.

Other projects and programs

Additional smaller projects and programs include:

1. **Energy Management System software replacement ($1.6 million)** – This SCADA project is already underway and will be largely complete by the end of the 2019-24 period, except for residual capex of $1.6 million in the first year of the 2024-29 period. The EMS allows us to perform remote switching and identify and respond to network outages. The purpose of the project is to ensure the EMS be in a fully supported state for all hardware and software, be appropriately sized, and improve cyber security.
2. **Communication battery replacement ($1.6 million)** – The communications network is reliant on battery systems to ensure that communications are not interrupted during power outages. Analysis shows that many of our communication batteries are beyond their expected life, and are subject to high temperatures which further reduce life expectancy. Further the solar panels that charge some of our communication batteries have degraded. Our options analysis showed that run to failure has high risks, and that a proactive replacement program is preferred. Under this option we would replace 43 communication batteries in the 2024-29 period focusing on batteries that are older and have been exposed to higher temperatures.
3. **Code compliance and safety program ($1.4 million**) – This project addresses the high risk of communications network installations that are not compliant with Power and Water’s legislative obligations including the Network Technical Code and Planning Criteria. Action is required to address the identified (known) gaps such as the absence of fully independent and physically separated communications paths, and other minor emergent non-compliant installations identified from business-as-usual activities during the next regulatory period.
4. **Microwave systems retirement ($1.4 million)** – The microwave communications systems clears electrical faults in remote locations where fibre is not economical to install. The key driver of this project is obsolescence. The vendor has issued ‘End of Support’ notices for 48 of our 64 microwave terminal units, meaning that technical assistance, replacement assets and software and firmware patches will no longer be available. We examined three options. Run to failure with replacement of spares was high risk due to network performance decline and cyber security risk. Proactive replacement with a modern equivalent that is compatible with MPLS was the preferred option compared to replacing with fibre. This was due to the lower cost and strategy alignment with MPLS migration (see project above).

6.4.8 Other asset group

The AER's recognises that a network is likely to have programs of works assets that do not align neatly with the definitions used for the RIN. We have identified several projects and programs that relate to 'other' network assets.

We forecast that we will incur $27.1 million of repex on 'other' network assets in the 2024-29 period. This is comprised of the major projects and programs shown in the table below. These projects and programs are described in the following sub-sections.

Table 6.12: Major projects and programs by asset group ($ million, real 2024)

Major projects and programs	Total
Alice Springs corroded poles	10.3
Zone substation minor works program	4.5
Distribution pillars	3.4
Road access to transmission network and communication hubs	1.9
Zone substations fire replacement systems	1.1
CBD tunnel refurbishment	1.0

Alice Springs corroded poles ($10.3 million)

We are currently undertaking a major planned program to rectify corroded pole issues in Alice Springs. In the 2024-29 period, we forecast to refurbish 180 poles annually (900 poles in total) at a total cost of $10.3 million.

The underlying need relates to corrosion of the pole due to exposure to high salinity and alkalinity. Corrosion causes a loss of thickness in the base of the pole, and this can lead to structural issues (termed 'tip load') with supporting the weight of conductors and transformers. The consequences of pole failure include safety to the community and workers, outages to customers, property damage, and the higher costs involved in reactive replacement of the pole.

We assessed 5 credible options using our risk quantification framework.[13] The least cost option was a targeted replacement program directed at highest risk poles in the population. This is our current approach, which relies on replacing poles within high-risk areas identified through analytics. The schedule of replacement is based on a criticality analysis that augments the risk score determined by the GIS analysis with an assessment of the tip load of each pole.

13 Non-network alternatives were not considered viable on the basis that there is no opportunity to remove the pole or use an alternative technology to provide the service.

Importantly, our approach has focused on refurbishment as the preferred method to address the issue, which is a much lower cost than replacing the pole. Previous to 2019, we replaced corroded poles but we have subsequently implemented an innovative new approach that can keep the existing pole in service. This involves pole re-butting, a process of removing the bottom section of the pole, welding on a new section and re-installing the pole in the ground.[14] Historical data shows that about 3 per cent of poles cannot be re-butted and require full replacement due to the weight on the pole or co-location of other underground utilities. Unit costs for the program are based on historical costs for refurbishment or replacement, with an additional allowance for more complex poles that we expect to encounter in the 2024-29 regulatory period.

Zone substation minor works program ($4.5 million)

Zone substations receive electricity from bulk supply substations and transform the energy to a lower voltage for distribution along powerlines to distribution substations. A zone substation includes transformers and high voltage switchgear identified in the AER's RIN categories, but also includes a range of other assets including buildings, civil and grounds, instrument transformers, outdoor disconnectors and busbars, components of power transformers, and substation auxiliary plant.

We currently have an ongoing program to maintain and replace assets within a zone substation based on a well-established and detailed maintenance strategy.[15] This comprehensive and regular monitoring and maintenance strategy allows condition, compliance and risk issues associated with zone substation minor assets to be accurately assessed in a timely manner.

We assessed two options. The first option was a run to failure approach, which showed a significant increase in risk over time predominantly relating to worker safety from operating assets that can fail in service. The second option was to continue our current practice of condition-based replacement and refurbishment. The costs were based on historical trends by type of asset, but adjusted downwards to account for the decommissioning of zone substations. Option 2 was shown to also have higher risks over time, but much less than Option 1. We considered that the higher short-term risks could be tolerated without increasing the forecast capex.

Based on the adjusted historical average, we expect to undertake 59 projects to replace or refurbish zone substation assets at a cost of $4.5 million in the 2024-29 period. The majority of forecast capex relates to the buildings, amenities, and related substation civil infrastructure.

Distribution pillar replacement ($3.4 million)

This is a new planned program that we forecast to commence in the first year of the 2024-29 period. The project will replace 280 and rectify/repair 1,000 distribution pillars over the regulatory period. These assets are part of our underground network, with each distributing power to typically 4 to 8 customers.

---

14 The solution consists of a movable frame that is placed on the ground adjacent to the pole. It is used to support the corroded poles while the base is removed and a new based installed. The poles are then re-installed in the ground with a full concrete casing that is designed to prevent water ingress and future corrosion.

15 This includes monthly visual, three-monthly detailed and annual thermographic partial discharge survey for the ZSS asset class. It also includes regular functional diagnostic, intrusive and fault maintenance inspections for HV circuit breakers, switchboards and power transformers.

The need for the program arises from the deteriorated condition of the covers, outer enclosures and foundations in the base. This is due to the operating environment of the asset, in particular prolonged exposure to heat and UV light, infestation of pests and dirt, subsidence of ground, and a humid environment accentuated by water sprinklers in garden beds. Our inspection data of about 5000 pillars over the last five years has identified about 20 per cent have a defect, of which about 25 per cent are critical to public safety. Our analysis also shows that a large proportion of pillars were built at the time of Cyclone Tracy (47 years old today) and that these assets are expected to further decline in condition as they further exceed their expected operating life of 35 years.

The predominant risk associated with deteriorated pillars are health and safety of the public, given the proximity to our customer's properties. In particular, damaged coverings expose or enable access to 'energised' elements of the asset, leading to potential for electric shocks. We have had three recent events where customers have exposed live elements, and one of the incidents led to an electric shock.

We examined four options in our business case. The option to replace on failure resulted in unacceptably high quantified risks due to the relatively high probability of a safety event. We also analysed the net present value of our current approach of replacing about 20 pillars each year and corrective repairs on about 110 pillars. We found that the expected decline in the condition of assets would mean that safety risks would significantly increase at this level of investment. The third option was to develop a targeted replacement and repair program that prioritise assets where there is high foot traffic, high population density or close to critical infrastructure such as schools. This would increase replacement volumes to 56 pillars per year and repairs to 200 per year. This was the option that maximised net present value. A fourth option to only replace assets was not economic.

The costs of undertaking 280 replacement and 1,000 repairs was estimated at $3.4 million based on historical costs.

Road access to transmission network and communication hubs ($1.9 million)

Many of our transmission lines and communications huts are located in remote locations. To access these assets, we need access to safe and reliable roads that can carry heavy machinery where network assets require rectification or accessibility by four-wheel drive for communications assets.

We have identified 24 road sections in the Darwin Katherine area that service overhead network assets, and which are in poor condition. We also have identified an additional four road sections that service communications huts which are also in poor condition. The condition of the current access routes is inadequate to enable staff to safely travel to remote areas in tropical storms and after severe wet weather. They are also not equipped to transport heavy equipment such as transmission and communication towers.

Our options analysis shows that doing nothing results in poor and declining accessibility to address faults and asset failures, undertake maintenance and will pose an increasing risk to field crew safety. We assessed the difference between undertaking a program to rectify the roads over 5 and 20 years. The analysis found that undertaking the works over a shorter 5-year timeframe maximised the net present value.

The forecast works will cost $1.9 million over the 2024-29 regulatory period. This will improve access roads from Batchelor to Adelaide River, Adelaide River to Pine Creek, Pine Creek to Katherine and Leanyer Swamp. We will also undertake works for access to communication huts including Lake Bennett, Hughes, Pine Creek Mesa, and Mount Bundy.

Other projects and programs

Additional smaller projects and programs include:

1. **Zone substations fire replacement systems ($1.1 million)** – Fire suppression systems are required to be installed at all zone substations and comprise a fire indictor panel for monitoring and control, and a gas system to suppress the fire. The run to failure option was not preferred as it increases the risk to the network and to field crews if a fire were to occur. The preferred option is to undertake planned replacement of the fire systems components as required based on condition, age, obsolescence and testing requirements for pressure vessels. The forecast capex relates to replacement of one fire indicator panel and 10 cylinders, on average, each year during the 2024-29 regulatory period.
2. **Darwin CBD cable tunnel refurbishment ($1.0 million)** – The Darwin CBD is supplied by cables which are installed in underground tunnels. The tunnels are typically more than 30 years old and made of reinforced concrete. The need for the project arises from the condition of the tunnels that is leading to workplace safety and health concerns. The issues include cracks that allow water to flow through the tunnel causing flooding, attracting snakes, rats and breeding insects. While there are sump pumps in place these are failing from blockages and over-use. The tunnel structure is also damaged from tree roots and deliberate destruction to allow more cables. Finally there is notable obstruction in the tunnels from unorthodox installation of cables in the past.

   There are risks to our workers from the current condition of the tunnels including the risk of injury due to debris that is hidden under water when field crews are working underground, danger from snakes and other animals that may be attracted to the water and shelter, and obstruction of exit routes due to poor installation practices.

   Our options assessment shows that there are material risks of doing nothing. The preferred option is to remediate and refurbish the tunnels including sealing the joints between prefab panels to prevent water ingress and tree roots entering the tunnel, replacement of sump pumps and refurbishing drainage systems, and refurbishment of cable racks. We forecast the costs of undertaking the works at $1.0 million in the 2024-29 period.

7. Augmentation capex

We are forecasting a significant 47.0 per cent decrease in augex in the 2024-29 period compared to the current 2019-24 period. We consider that there is sufficient capacity on the network to meet our forecast demand. Where there remains some uncertainty in demand, we have identified a number of contingent projects. Our proposed augex program reflects continued investment in reliability and compliance programs together with new investment to address compliance and risk issues.

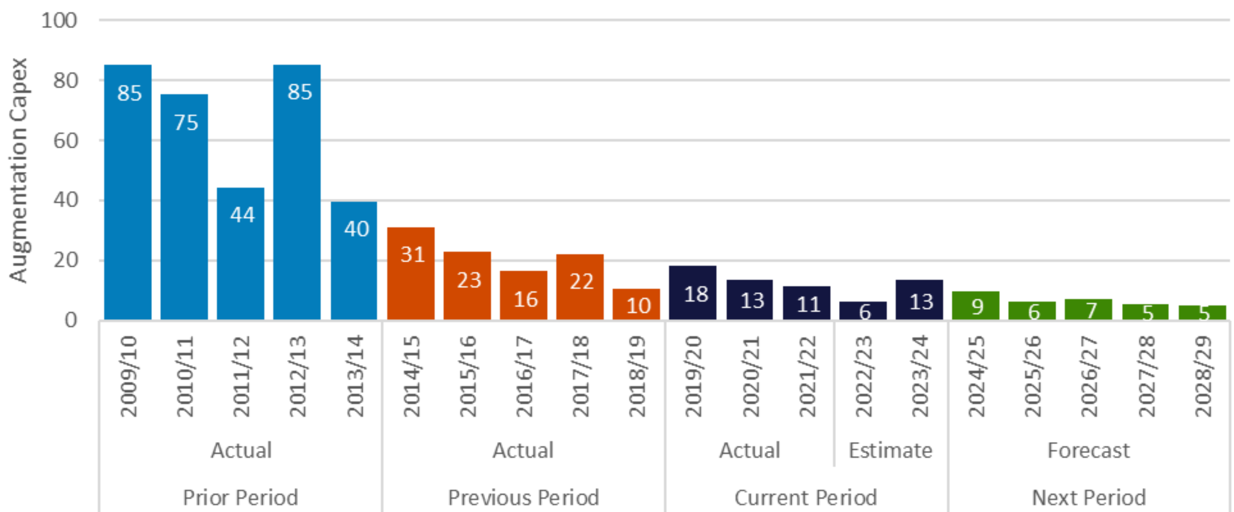
The purpose of this chapter is to set out the information and data that supports our proposed augex for the 2024-29 period. This includes an overview of proposed augex, identifying drivers of augex in the 2024-29 period, explaining the overall method and key inputs and providing a description of the projects and programs by driver.

Augmentation capex includes investment in new network assets to reliably meet growth in peak demand, ensure we meet our compliance obligations for reliability performance, voltage standards, and conductor clearance standards and condition and risk. It should be noted that DER capex is classified as a separate category of new network capex and this is discussed in section 8.

7.1 Overview of augex

We forecast augmentation capex of $33.2 million in the 2024-29 period compared to $62.6 million in the 2019-24 period, a decrease of 47.0 per cent. Figure 7.1 below shows that augex is significantly lower than previous regulatory periods. In the 2010-14 period, we incurred considerable augmentation capex to ensure the system had sufficient capacity to meet growing demand. From 2014/15 onwards, augmentation has declined as peak demand growth flattened. This was largely due to an increase in solar self-consumption during the day, which meant that our network shifted from experiencing peak demand in the day to the evening.

Figure 7.1: Forecast augex in 2024-29 compared to actual/estimated in previous periods ($ million, real 2024)



We show the total augex by year in the 2024-29 regulatory period in the following table.

Table 7.1 Forecast augmentation capex in 2024-29 by year ($ million, real 2024)

Category	2024/25	2025/26	2026/27	2027/28	2028/29	Total
Augex	9.5	6.1	7.3	5.4	5.0	33.2

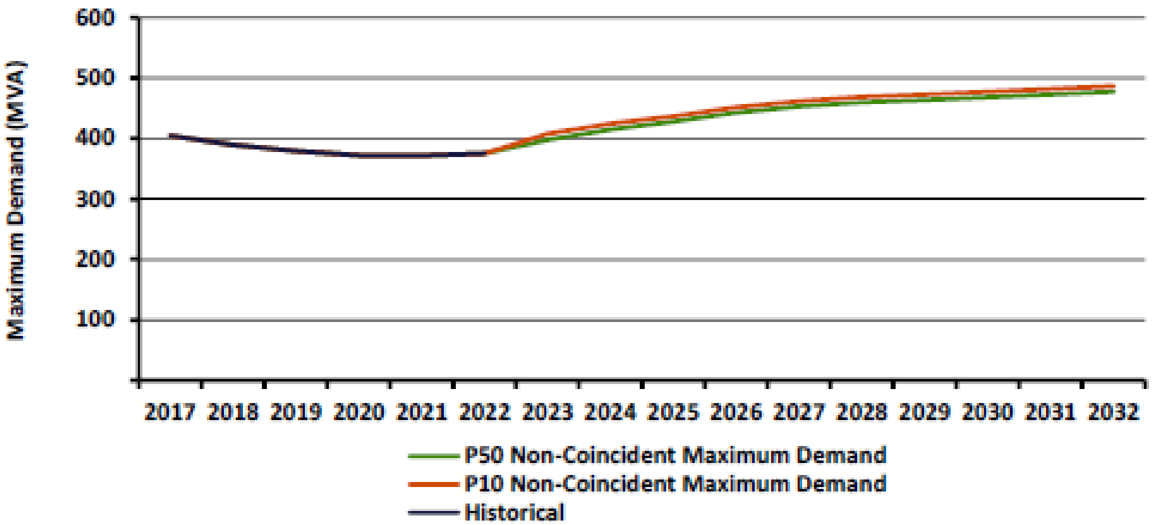
In terms of composition, there are 10 planned projects and programs for the next regulatory period.

7.2 Drivers of augex

Augex is well below historical levels of capex. This is largely attributable to our assessment of capacity on the network at a spatial (local) level compared to peak demand growth forecasts.

Our peak demand growth forecasts are increasing in most areas of our network in the 2024-29 regulatory period. While there are differences between each of our regions, Figure 7.2 shows an increase in aggregate growth in zone substation forecasts in the 2024-29 period. The growth is largely attributable to ‘spot loads’ on the network particularly in Archer, Humpty Doo and Strangways. This also reflects that solar is not having the same impact on curbing peak demand growth, as we have shifted to an evening peak.

Figure 7.2: Aggregate non-coincident zone substation maximum demand forecast POE 50and POE 10 forecasts



Source: Spatial Demand Forecasting Methodology Report and Result (provided at Attachment 8.47)

As part of our challenge process, we reviewed the methods applied for estimating ‘spot load’ timing and magnitude. A key change has been to the way we estimate spot loads, which has resulted in much slower forecast demand growth in each of our zone substations. We determined that our large substations and transmission lines were able to accommodate the forecast peak demand growth due to existing capacity and opportunities to transfer load under contingencies. We note however that we will continue to face a need to upgrade our 11 kV feeders leading to a small program in the 2024-29 period.

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

We also have two specific programs that commenced in the 2019-24 period that upgrade assets on the network to meet compliance and risk drivers. This includes a program to uprate our transmission lines and ensuring we comply with conductor clearance standards.

We have also included additional projects aimed at compliance with our jurisdictional planning standards in relation to the security of our network assets and addressing risks to power system security presented by our communications infrastructure.

We discuss each of our proposed programs in the subsequent sections.

7.3 Methods and approach

Our method to forecast augex has closely followed our BAU annual processes, but reflects the outcomes of high level checks and risk quantification in our business cases.

7.3.1 Demand driven augex

On an annual basis, we forecast projected maximum demand for distribution feeders, zone substations, and transmission lines. The demand forecasts reflect recent trends in maximum demand, forecast major connections, and forecast major embedded generation. In summary, the method involves using historical demand as a base for each network element and applying a weather normalisation technique to provide a weather-adjusted base. From here, we apply a forecast trend based on historical demand growth, projected changes in demand due to connections, solar uptake and other factors, and finally we include localised spot loads.

For the 2024-29 regulatory proposal, we updated our methods for establishing spatial demand forecasts, and also prepared system demand forecasts for each of our regulated regions. Our updated demand forecast methodology is described in Attachment 8.47 and Attachment 8.48.

Our planning process considers if there is likely to be thermal constraints on our equipment with reference to the thresholds in our Network Planning Criteria. If a constraint arises, we assess the least cost option to address the constraint including load transfers, non-network alternatives and network upgrades.

For the 2024-29 proposal, we have only identified a need in respect of our distribution feeders and minor substation works. Our approach has been to examine each of our high voltage circuits and distribution feeders compared to the forecast demand growth in the zone. We have applied the relevant contingency criteria to assess if there is sufficient capacity available on the circuit or distribution feeder. Where there is insufficient capacity, we have considered options to address the issue.

We also note that the NT has a number of prospective, but currently un-committed large projects that would result in significant spot loads if they proceed as planned. In accordance with our updated demand forecasting methodology, these projects have been excluded from our capex forecast for 2024-29 and have instead been included as contingent projects (refer to section 13).

7.3.2 Reliability driven augex

The Electricity Industry Performance Code (EIP Code) applies to our three regulated networks and is the key regulatory instrument that provides guidance on establishing a plan to achieve reliability targets and address the worst performing feeders on our network.

The EIP Code requires us to propose reliability performance targets to the Utilities Commission. The targets are based on System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) performance standards. SAIDI is an index showing the average length of time customers are without power and SAIFI is an index showing the average frequency of power interruptions to customers.

The EIP Code also requires us to provide an annual report to the Utilities Commission on the five worst performing feeders for each feeder category. This includes information on the SAIDI performance on each of the identified feeders, and a statement that explains the performance and action we intend to take to improve performance.

For our 2024-29 proposal, we assessed the three options to address existing or expected reliability issues. The analysis suggested that we should continue to invest at historic levels. On this basis we used a historical average approach to set the expenditure levels.

7.3.3 Compliance and risk driven augex

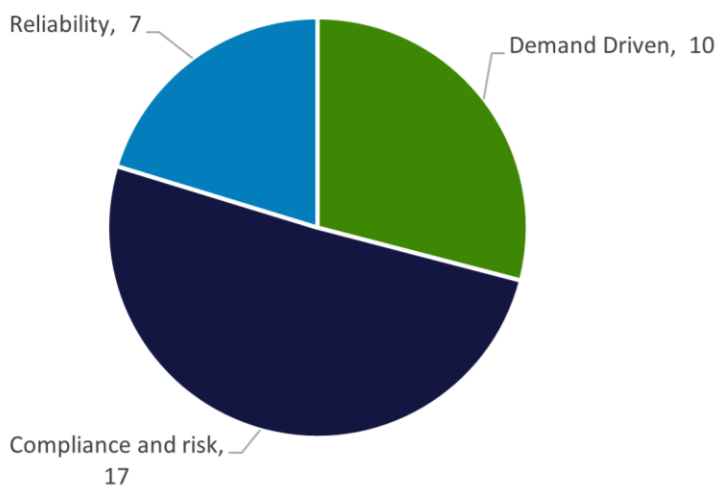
We regularly monitor the performance of our assets against our performance standards and regulatory obligations. We forecast the performance of our assets and assessed the likely level of capex that would be required to meet and maintain compliance over the 2024-29 period.

These programs have been estimated using a business case approach that identifies the optimal scope for the project.

7.4 Description of projects and programs by driver

Figure 7.3 shows that augex in 2024-29 is primarily driven by compliance and risk driven programs ($16.8 million), followed by demand driven programs ($9.7 million) and reliability driven programs ($6.7 million).

Figure 7.3 Forecast augex by category for next regulatory period ($ million, real 2024)



7.4.1 Demand driven

We forecast augex of $9.7 million on demand driven capex in the 2024-29 period. This is comprised of the major projects and programs shown in the table below and described in the following sub-sections.

Table 7.2: Major projects and programs by asset group ($ million, real 2024)

Major project and program	Total
Overloaded feeder program	4.1
Tindal Zone Substation and feeder reinforcement	3.5
Network Design Planning program (Zone substation minor augmentation)	2.1

Overloaded feeder program ($4.1 million)

Under our Planning Criteria regulations, we have an obligation to adhere to time limits for power restoration during contingency events. This varies by type of feeder. For urban areas with between 5MVA and 50MVA of demand, we must restore supply within 60 minutes and this typically is achieved by network reconfiguration (switching) to make use of available distribution transfer capacity (**DTC**) to contiguous feeders and/or substations to assist with restoration.

In the current period, we are addressing overload issues with feeders on the network through multiple solutions including activities such as improving the capacity through increasing transfer of load, increasing the size of network cables, and enabling higher transfers through operational switching.

Our business case has identified a need to undertake augmentation works to address seven cables in Darwin-Katherine network the 2024-29 regulatory period. This was based on an analysis of the capacity of each high voltage feeder in the network under N-1 contingencies and reviewing whether a capacity constraint arises due to the P50 forecast increase in peak demand growth.

We considered two options to overcome identified future capacity constraints, utilising our new risk quantification approach that provides a specific value for customer reliability. We analysed the relative risk of discontinuing our practice of addressing overloaded feeders. This increased the quantified risk of outages particularly in commercial areas. The second option is to continue our current practice of undertaking augex on feeders that present a high risk (i.e. in commercial areas). We found that the second option provides the highest net present value.

We have identified the specific works for each feeder including improved intra-feeder interconnectivity and improved switching capability to transfer loads within a feeder system during contingency conditions. The unit costs have been based on previous costs incurred on similar projects.

Tindal Zone Substation and feeder reinforcement ($3.5 million)

Tindal zone substation is located in the Katherine region of our network. It is currently supplied by two 22 kV distribution lines and has a firm capacity of 5.5 MVA. Due to forecast demand growth, we plan to increase the zone substation firm capacity to 13.5 MVA and build a third 22 kV feeder to strengthen the resilience and security of supply to this substation.

This project involves the rebuild and augmentation of the Tindal Zone Substation and construction of a new 22 kV feeder to supply Tindal from Katherine. The planning for this project commenced in 2019/20, with the bulk of expenditure estimated to be incurred in 2023/24 with completion in 2024/25. We have included $3.5 million to complete this project in the forecast.

Network Design Planning program ($2.1 million)

The Network Design Planning (NDP) program is a series of minor network augmentation projects that are required at our zone substation and sub-transmission substations to address capacity issues or operational flexibility.

This typically includes improving the cyclic ratings of power transformers to avoid overload (e.g. by adding cooling fans), modifying feeder supply arrangements to improve load transfer capacity, and increasing the ratings of substation equipment. These projects help defer major expenditure. We have used historical expenditure for similar projects as the basis for our forecast capex in 2024-29.

7.4.2 Reliability and quality of supply

We forecast $6.7 million of capex on reliability and quality of supply programs in the 2024-29 period. This is comprised of the major projects and programs shown in the table below and discussed in the following sub-sections.

Table 7.3: Major projects and programs by asset group ($ million, real 2024)

Major project and program	Total
Worst performing feeder program	4.8
Voltage rectification – Alice Springs	1.9

Worst performing feeder program ($4.8 million)

The EIP Code sets out requirements to maintain network reliability within defined targets and to report on the five worst performing feeders per feeder category and the actions being taken to manage those feeders.

The program is required to ensure that we maintain an adequate level of reliability for customers connected to parts of our network that inherently have low reliability. This is generally in more remote areas of the regulated network where customers receive energy from long, radial lines that are subject to higher frequency of outage events and lower back-up in the network. Customers in these areas are disproportionately impacted by outages. A consistent theme in our engagement with customers was the need for Power and Water to consider equity among customers, including issues such as reliability of services.

Over the current regulatory period, we have invested about $1 million a year on works directed at worst performing feeders. This includes installing automatic reclosers to clear transient faults in a short period, installing remote controlled switches to isolate the fault leading to quicker restoration for some customers, localised undergrounding, installing covered conductors and animal protection.

Our analysis shows that our investment has been effective at arresting the decline, but not improving, reliability performance in the targeted rural locations.[16] Our analysis shows that lower levels of capex will deteriorate our performance on both short and long rural feeders. We have used our risk quantification framework to develop a quantified view of the risks of declining reliability, however we note that such analysis does not consider the disproportionate impact on rural customers impacted by much higher levels of outage compared to other customers.

We examined three options. The 'do nothing' option is based on discontinuing our current approach to target investment at worst performing feeders. This option is likely to result in Power and Water not meeting its short and rural targets in the EIP Code over the 2024-29 period. The second option is to use historical expenditure as a basis to forecast annual capex in the 2024-29 period. Our analysis suggests that this option would more likely lead to Power and Water meeting its current performance on short and long rural feeders. The third option is to improve our current performance by spending more capex in the 2024-29 period compared to historical averages. We considered this option would lead to a performance in excess of the regulatory threshold and is therefore not justifiable.

The scope of works has not been costed on a bottom-up basis but is instead based on historical levels of capex. The rationale for this forecasting approach is that our annual program of works takes into account emerging issues that are difficult to forecast ahead of time.

Voltage rectification – Alice Springs ($1.9 million)

This project seeks to rectify voltage issues in our Alice Springs network through the installation of two reactor banks at Owen Springs zone substation, as part of the Install ZSS Reactors program.

The need for this project arises from over-voltage issues that arise on minimum demand days in the Alice Springs network. Minimum system demand occurs when high solar PV output coincides with periods of relatively low demand (particularly from commercial and industrial customers, and air conditioners). These events typically occur in the 'shoulder' periods of Spring and Autumn during the day when solar output is high but air conditioning load is low. Our load flow analysis demonstrates that we would not meet our voltage compliance obligations during minimum load periods from 2022/23, and consistently onwards from 2025/26.

While we are implementing operational measures[17] to manage the risk in 2022/23, we note that additional measures will be required in the 2024-29 period as solar penetration increases. Our options assessment concluded that doing nothing is not a credible option as it will lead to repeated and increasing non-compliance with the Technical Code over time. We examined a range of solutions to address the issue including (i) stricter static limits, (ii) encouraging demand management to activate higher consumption on minimum demand days, (iii) procuring load banks (to increase demand), (iv) a battery energy storage system (BESS) to act as a load by charging during period of minimum demand, (v) introducing dynamic solar export limits by implementing 'dynamic operating envelopes' (DOE), and (vi) installation of reactors (to absorb reactive power and boost voltage).

---

16 Our business case examines the performance of feeders where works have been undertaken. While year to year data is volatile, the analysis suggests that the works have stabilised a potential decline in performance in these feeders, demonstrating the need for ongoing investment to arrest a decline in performance.

17 This includes switching out zone substation and distribution capacitor banks – this is an effective step with switching undertaken manually if a system low event window is expected. We are also looking to proactively engage embedded customers and large scale customers to enable VOLT-VAR settings.

We consider that the installation of reactors to be the preferred option. It is a simple, proven and cost-effective technology, and if the reactors and associated assets were to become stranded (e.g. because of the later deployment of DOEs in Alice Springs), they can be moved to another location in Power and Water's network.

The scope of the solution is to procure and install two 2.75 MVAr air-core shunt reactor units with associated switchgear to be installed on the 66 kV bus at Owen Springs zone substation by 2025/26. The estimated cost is $2.2 million, of which $1.9 million is incurred in the next regulatory period. The balance of $0.3 million is the estimated cost of planning and development and will be incurred in 2023/24. The scope includes civil and fencing works, installing primary and secondary cables from the reactor units to the new circuit breakers and installing protection and control systems for the operation of the reactor banks.

7.4.3 Compliance and risk driven

We forecast $16.8 million of capex on compliance driven projects in the 2024-29 period. This is comprised of the major projects and programs shown in the table below and discussed in the following sub-sections.

Table 7.4: Major projects and programs by asset group ($ million, real 2024)

Major project and program	Total
Power quality compliance program	4.1
Transmission line uprating	5.4
Low clearance program	2.1
Protective security of network infrastructure	2.0
Miscellaneous communications projects	3.2

Power quality compliance program ($4.1 million)

Power and Water must comply with quality of supply (voltage) requirements as defined in the Network Technical Code and Network Planning Criteria. The purpose is to ensure that our customers' electrical equipment is not damaged nor suffers a material reduction in expected life.

The need for the program arises from specific voltage issues we forecast to experience in the 2024-29 period. 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. To some degree, new requirements for inverters to have both 'volt-var' and 'volt-watt' modes available will help mitigate over-voltage issues from rooftop solar, but the problem will continue in Katherine due to older solar installations and embedded generation. A second driver is under-voltage issues in some new residential and commercial developments, which we expect will heighten with electric vehicle charging.

We examined four options to address the likely power quality non-compliance. The 'do nothing' option would breach our compliance obligations, increase costs associated with customer claims, and heighten the risk of reputational damage. Reactive replacement involves undertaking work only in response to a customer complaint, however this option does not address the undetected issues with over voltages and may lead to higher risks in the future. The third option is consistent with our current approach where we proactively identify power quality issues through load flow studies and system modelling and initiate targeted work based on the results. The third option is the preferred option due to the ability to target works where there are identified issues that require rectification on the supply side.[18]

The volume of work in the next period for the preferred option is based on the historical trend and the forecast cost has been derived from the recent historical costs of similar work. This forecasting methodology (as opposed to a bottom-up forecast) is appropriate because it is difficult to identify the likely works more than 12 months in advance. The types of work we have historically undertaken include upgrading conductors and upgrading overloaded transformers.

Transmission line uprating ($5.4 million)

A review of line clearances on the 66 kV transmission network has shown that some lines do not maintain statutory clearances to the ground and that some have insufficient mechanical strength to meet cyclone ratings. These issues present risks to public safety and to the reliability of the network. As the lines are unable to meet design standards during foreseeable loading conditions, Power and Water is obligated to take action to mitigate the risks. The cost forecast is based on the unit costs incurred in recent similar work.

Low clearance program ($2.1 million)

This is an ongoing compliance program to address compliance issues associated with transmission conductors.

The need for capital works arises from non-compliance with statutory clearances to the ground and insufficient tower mechanical strength to meet new cyclone ratings. In our options assessment, we considered that the 'do nothing' option was not prudent as it would result in ongoing and deliberate breaches of our compliance obligations and would expose the public and our staff to safety risks. Further, it would increase the risk of outages in the event that the identified towers could not withstand a cyclone. The preferred option was to rectify all the remaining non-compliant spans by 2028/29.

The work will be undertaken on specific spans of the Hudson Creek to Palmerton line, the Hudson Creek to Archer line, and the Hudson Creek to Woolner line.

Protective security of network infrastructure ($2.0 million)

The need for this program arises from an increased number of incidents involving unauthorised access. The project involves upgrading the protective security assets such as fences at zone substations, replacing locks, and improving access control at distribution enclosures. This project is likely to cost $2.0 million.

Miscellaneous communications projects ($3.2 million)

There are four minor augmentation programs included for our communications network:

1. Sadadeen (SD) to Lovegrove (LG) fibre optic upgrade – addresses the risks to network security and functionality of the current topology of the fibre optic cables in Alice Springs.
1. Darwin to Alice Springs communications link – addresses the high risk of loss of the communications link which would result in significant safety and network operations issues in Alice Springs.
2. Antenna monitoring – addresses the condition and compliance risks associated with communication antennas.
3. Fountain Head communications site supply reliability – high supply reliability risk at the Fountain Head communications site.

---

[18] The root cause of a significant proportion of power quality issues at premises is from within the premise and rectification is therefore the responsibility of the premise's owner

8. Distributed energy resources (DER) capex

Over the past decade, our customers have been installing solar roof panels at an increasing rate. Small scale solar now accounts for 10 per cent of total energy generation in our regulated regions, and is projected to increase to over 20 per cent by 2030. The network has been able to host the capacity of solar export from the solar installations so far but we have identified that the combined effect of solar export at times of low load will cause local voltage compliance and system-wide security issues. We have identified an innovative solution to maximise solar exports whilst managing local and system-wide impacts. This will lead to a net benefit for all customers in terms of lower electricity prices. The forecast capex for the project is $13.2 million in the 2024-29 period.

The purpose of this chapter is to set out the information and data that supports our proposed DER capex for the 2019-24 period. This includes identifying the driver of capex, explaining the business case and key inputs, and providing a description of the program.

DER includes solar PV, energy storage devices, electric vehicles (**EVs**) and other consumer appliances that can lead to two-way flow of electricity within the network. The increase in DER to date and the forecast over the next 20 years creates both opportunities and challenges for our network, given that the network was designed to operate with one-way flow of electricity.

In June 2022, the AER released a DER integration expenditure guidance note. DER expenditure relates to addressing integration issues with increasing DER and could include:

- Augmenting the distribution network to physically provide greater solar PV export capacity.
- ICT capex to develop greater visibility of the low voltage network and manage changes being driven by technological developments including batteries and EVs.

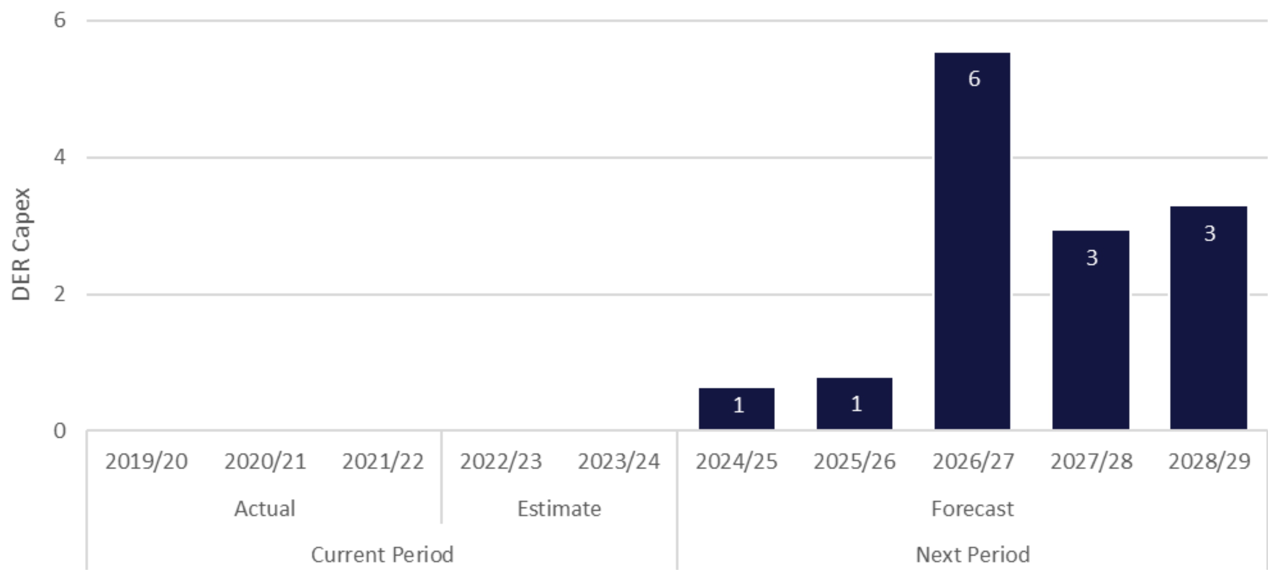
Our Future Network Strategy (Attachment 8.08) outlines a long-term roadmap to address key drivers of change impacting our network including the transition to renewable energy in the NT. This includes details of our DER integration strategy, and collectively supports the proposed DER capex, step changes in SCS operating expenditure for the next period, and potential research and studies funded under the Demand Management Innovation Allowance (**DMIA**) and external funding (such as from ARENA). It also identifies how our transmission network will need to adapt to large scale renewables coming onto the network. Finally, our strategy identifies activities that improve the utilisation and design of the network and broader energy systems through DER and large-scale renewables.

In this section, we focus primarily on proposed capex for a new solution to manage export constraints from increasing rooftop solar. We note that this project also relates to a proposed opex step change (provided at Attachment 9.02) to activate our Future Network Strategy.

8.1 Overview of DER capex

We forecast DER capex of $13.2 million in the 2024-29 period. As can be seen in Figure 8.1, this is a new investment type for Power and Water, with no capex incurred in the current regulatory period.

Figure 8.1: Forecast DER capex in 2024-29 compared to actual/estimated in 2019-24 ($ million, real 2024)



We show the total DER capex by year in the 2024-29 regulatory period in the table below.

Table 8.1 Forecast augmentation capex in 2024-29 by year ($ million, real 2024)

Category	2024/25	2025/26	2026/27	2027/28	2028/29	Total
DER capex	0.6	0.8	5.5	2.9	3.3	13.2

The DER capex solely relates to a major project termed Dynamic Operating Envelopes (**DOEs**) provided at Attachment 8.61.

8.2 Methods and approach

Our methodology has been guided by the AER's DER integration guidance note. The guidance note requires DNSPs to develop a DER integration strategy and to follow the suggested procedure for evaluating projects. This is complemented by the AER's Customer Export Curtailment Value note (**CECV**) which provides a methodology for quantifying the value of constrained solar exports.

8.3 Description of DOE project

The need for this project arises from our analysis of the network's ability to accommodate a forecast increase in the uptake of rooftop solar, and has been informed by an assessment of our network hosting capacity. As discussed below, the analysis has been limited to the impending problem of minimum demand events, the binding constraint in the 2024-29 period.

DOEs curtail solar exports at times of minimum demand but allow customers to export at all other times in the year. The prevailing advantage of DOEs is that they allow for maximum use of low cost renewable energy. 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.

In the sections below, we summarise the need, options and scope of the project. Further information can be found in the business case.

Investment Need

The projected increase in the penetration of rooftop solar across the regulated networks is increasing. The key driver of investment is managing the local voltage impacts and the system security risk that minimum demand events give rise to and which are expected to increase in frequency and duration over the next period.

At times of low system load and high solar export, excess local voltages can arise which can manifest at higher voltage levels because the normal network controls for managing excessive voltages, such as transformer tap changing, can no longer control the voltage to within statutory limits.

The voltage excursion can manifest at the transmission level and result in synchronous generators to absorb reactive power. However at times of minimum load, there is typically few synchronous generators connected to the system. 'Minimum demand events' describes occasions when the minimum demand falls below the threshold necessary to maintain system strength (i.e. because of the lack of contribution to fault level from synchronous generators) and system inertia. On these occasions, there is of risk of insufficient system strength and/or inertia to cope with a major system disturbance. According to NTESMO, a gas generator trips roughly once every six days. If tripping occurred during a period in which operational demand was below this 'minimum demand threshold', a system black event would likely occur.

To prevent system blacks from occurring during minimum demand events, NTESMO instructs Power Services to shed net generating parts of the network to lift minimum demand above the threshold. Power Services has little visibility of the LV network, making it difficult to identify these regions. Its approach to shedding is therefore necessarily crude, effected by disconnecting parts of the LV network at the feeder level, and causing involuntary outages for all customers within the feeder area, regardless of whether they are net generators.

Our analysis of scenarios shows that under a central case there remains a need to manage minimum demand from falling below the 50 MW threshold[19] to avoid undue system security risk. In the absence of any investment or intervention, the minimum demand is forecast to fall below the 50kW threshold for the first time in 2029-30. From 2030-31 onwards, minimum demand events are projected to become more frequent. Minimum demand events are projected to occur on more than 60 days of the year by 2034-35 and 100 days of the year by 2039-40 as seen in Figure 8.2.

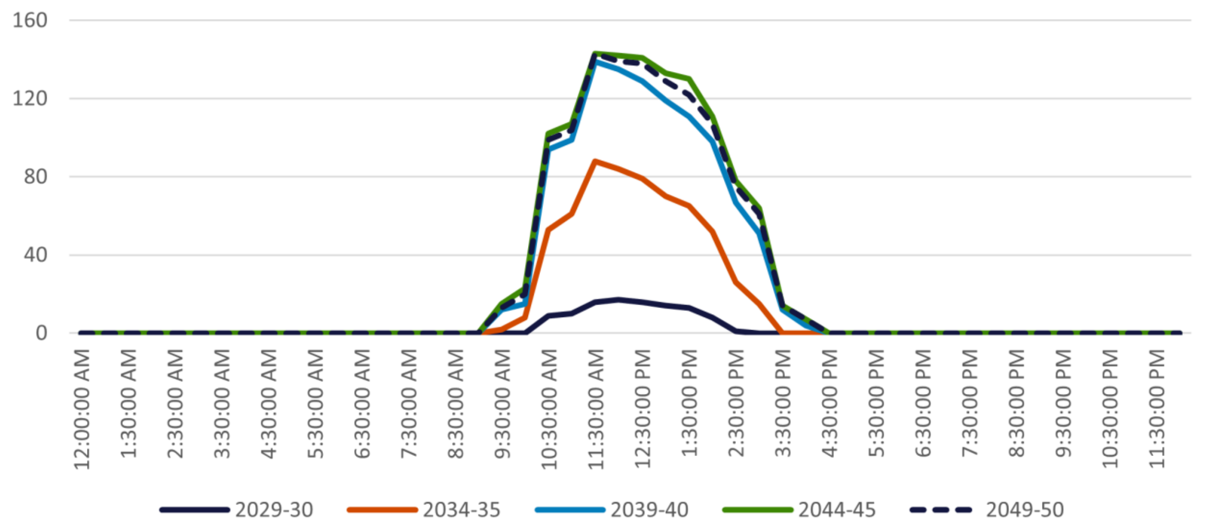
[19] Currently the threshold is 68MW but is expected to be reduced to 50MW when the proposed 35MW high specification security BESS is installed by TGEN in 2024

PowerWater

Similarly, action needs to be taken to reduce local voltage non-compliance that arise during periods of minimum demand. Voltage excursions are occurring now and are forecast to become more frequent and more widespread as the DER hosting capacity of feeders becomes increasingly inadequate.

In our counter-factual ‘base’ case we assume that rooftop generation is curbed through static export limits for new connection and modifying customers.

Figure 8.2: Projected frequency of minimum demand events in Darwin-Katherine, by half-hour internal, by year



Source: Power and Water (provided at Attachment 8.61)

Options assessment

We identified four options to address the need for the project. This included:

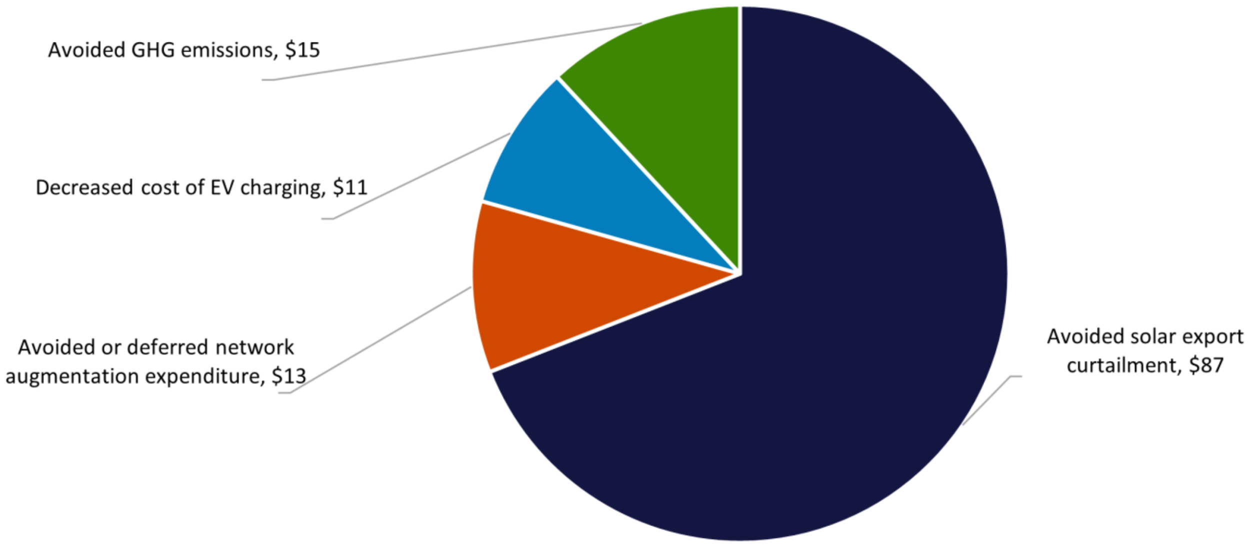
- **Stricter static exports (base case)** – Consistent with the AER’s methodology, we could mitigate minimum demand by implementing stricter static export limits. Static export limits are a blunt tool for curtailing solar during minimum demand events. They would be applicable year-round, not just during the infrequent periods in which minimum demand threatens system security. Based on analysis we considered that the static limit could be kept at 2.3 kW for new and modified connections from 2027/28.
- **Comprehensive dynamic operating envelopes** – Power Services could prevent minimum demand events through targeted curtailment of solar exports at specific times. Targeted curtailment would be made possible through an investment in DOEs, which vary the connection import and export limits to the electricity grid. This option is comprehensive because it makes dynamic export limits accessible to all customers with DER, regardless of connection type or size of installation.
- **Targeted Dynamic Operating Envelopes** – This option also involves the roll-out of DOE capability across all network feeders. However, it is more targeted than Option 2 in that it limits the implementation of DOEs to commercial customers.
- **Additional infrastructure** – We considered alternative network and non-network solutions such as network upgrades, rebalancing feeders, and transformer tap changes. We conclude that the network and non-network solutions provide limited benefits because they only respond to some of the impacts of minimum loads and do not provide the capability to future proof the network for the continued uptake of DER technologies.

Preferred option

A cost benefit analysis of the options concluded that Option 2 (investing in comprehensive DOE capability is the most prudent and efficient to meet the identified needs and therefore the 'preferred option'. This solution is also consistent with the preferences of our customers to efficiently facilitate renewables in the NT energy system.

The preferred investment is projected to result in at least $128.9 million in gross benefits over a 30-year period. This compares to a cost of $92.7 million over the same period. Nearly three quarters of the quantified benefit is attributable to avoided solar export curtailment, or increased solar exports, relative to the base case as shown in Figure 8.3.

Figure 8.3: Benefits of preferred option



Source: Power and Water (provided at Attachment 8.61)

9. Connections capex

We are forecasting only $7.0 million of SCS connex, compared to $33.4 million in the 2024-29 regulatory period compared to the 2019-24 period. The key reasons for the lower capex relates to a change in the classification of 'negotiated' connection services where the connecting customers will separately pay for connection services as part of our alternative control services. It also reflects a change in the treatment of gifted assets, which we have excluded to align with recent AER decisions.

We have also made some 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.

The purpose of this chapter is to set out the information and data that supports our proposed connex for the 2024-29 period. This includes an overview of proposed connex, identifying drivers of connex in the 2024-29 period, explaining the overall method and key inputs, and providing more detail on the forecasts.

Connex is required to service new, altered or upgraded connections for residential, commercial and industrial customers.

In this section, we provide details on connex for SCS connex only. This includes total connection capex for connection services classified as SCS, and the specific portion relating to capital contributions. Please see the ACS overview for more information on the proposed prices for connection services classified as ACS.

9.1 Overview of connex

We forecast connections capex of $7.0 million in the 2024-29 period, compared to $33.4 million in the 2019-24 period as seen in Figure 9.1.

Figure 9.1: Forecast connections capex in 2024-29 compared to actual/estimated in 2019-24 ($ million, real 2024)

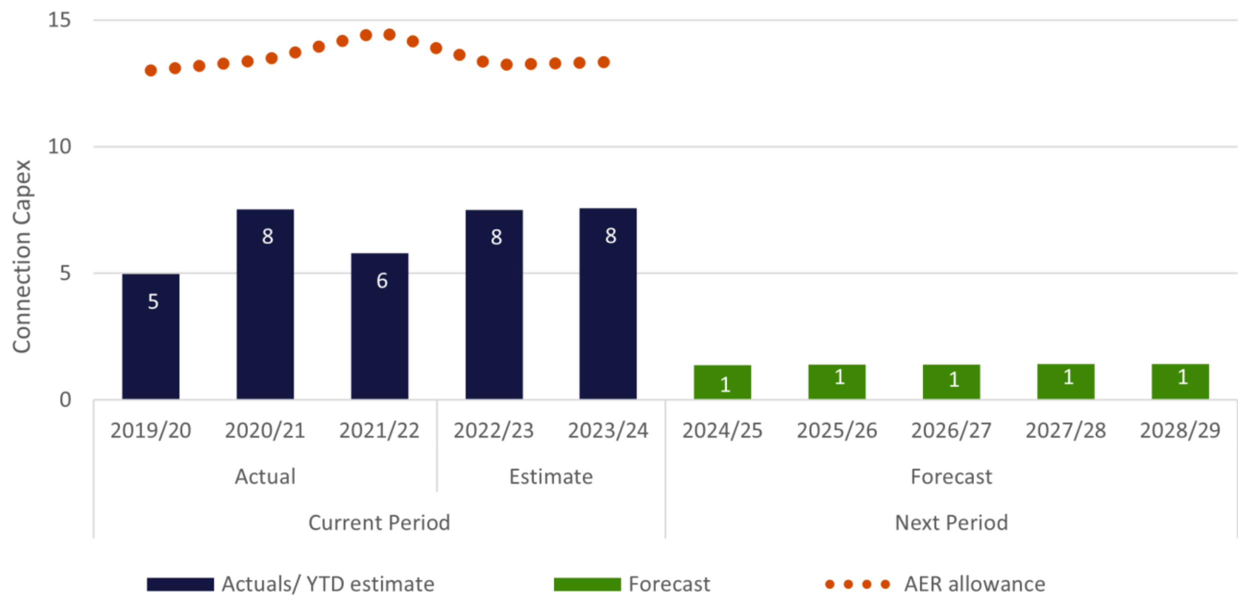


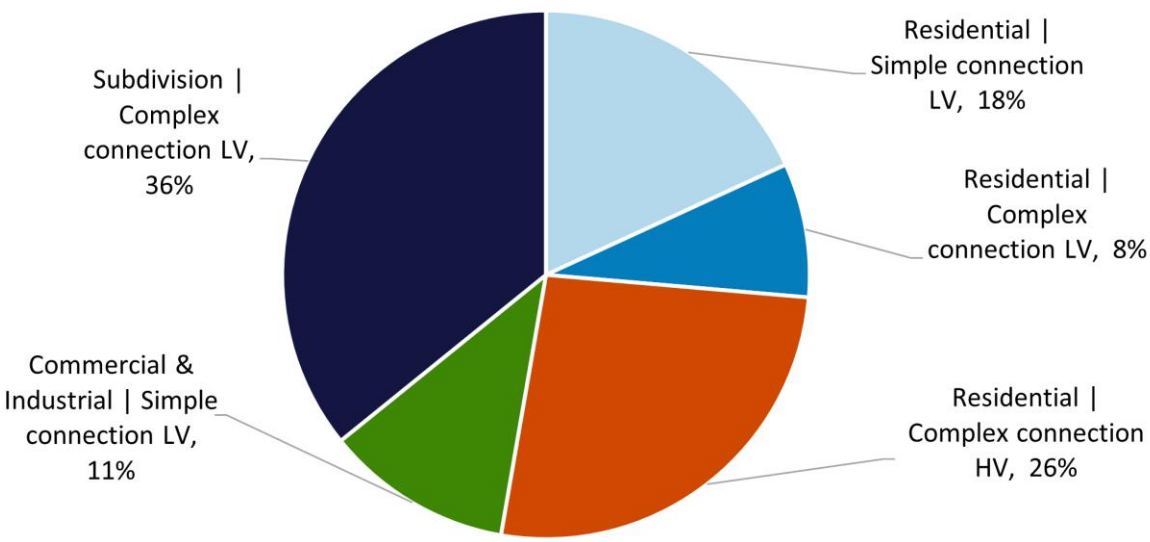
Table 9.1 sets out our gross capex for SCS, broken down into net capex and capital contributions.

Table 9.1: Gross capex, net capex and capital contributions ($ million real 2024)

	2024-25	2025-26	2026-27	2027-28	2028-29	Total
Gross capex	1.4	1.4	1.4	1.4	1.4	**7.0**
Net capex	1.2	1.2	1.2	1.2	1.2	**6.0**
Capital contributions (excluding Tindal)	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**1.0**

Figure 9.2 sets out our proposed net capex by connection type. It shows that subdivisions for complex connections low voltage are the largest category, followed by residential complex connections at high voltage.

Figure 9.2: Breakdown of gross capex by customer connection type (per cent)



9.2 Drivers of connex

9.2.1 Removal of gifted assets

The primary driver of lower connection capex is the exclusion of gifted assets. This accounts for $53.4 million, or 88.2 per cent of the reduction in connection capex from the 2019–24 allowance to the 2024–29 regulatory period forecast.

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 the corporate income tax building block.

However, following a 2020 Federal Court decision that effectively overturned the ATO's treatment of gifted assets,[20] 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.

9.2.2 Reclassification of some connection services to Alternative Control Services

The secondary driver of lower capex is the change in the classification of services as set out in the AER's 2024-29 Framework and Approach paper. Under the changes, (which are supported and accepted by Power and Water as part of our Classification Proposal) connection services other than basic connection services which were previously classified as standard control have been re-classified as Alternative Control Services (**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.

In the 2019-24 period, all of our connection services were classified as a standard control service. This included any additions or upgrades to the connection assets located on the customer's premises, excluding metering (premises connection service), an enhancement required to connect a power line or facility outside the present boundaries of the transmission (extension) and any shared network enlargement/enhancement undertaken by a distributor which is not an extension (network augmentation).

As explained above, in its final Framework and Approach paper, the AER has redefined our connection services to align with the definitions in Chapter 5A of the National Electricity Rules and re-classified some connection services which are more appropriately recovered directly from customers:[21]

- **Basic connection services** – This is to connect residential and small non-residential premises, including connection of micro-embedded generation such as rooftop solar. The services exclude real estate developers, customers with maximum demand of the electrical installation greater than 100 amps per phase and embedded generating unit operators that are not micro embedded generators. Basic connection services will be classified as SCS in 2024-29.
- **Negotiated connection services** – These are connection services that do not meet the definition of a basic connection service or where the connection applicant elects to negotiate the terms upon which the connection is provided. These services will now be classified as ACS in 2024-29.

A proportion of connection expenditure in the 2019-24 period related to services that have now been classified as negotiated for the 2024-29 period. This has had the effect of reducing SCS connections capex in the 2024-29 period.

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

[21] Standard Connection Services are not currently proposed to be offered by Power and Water in 2024–2029 period. However, Power and Water may seek the AER's approval for a standing offer to provide standard connection services in the future. Connection charges for these services will be in accordance with Power and Water's published Pricing Schedule for Connection Charges for Alternative Control Services.

9.3 Methods and approach

In the following section we discuss our approach to forecasting connections capex and capital contributions.

9.3.1 Forecast connection capex

The approach to forecast connex relies on a modelling approach that identifies historical (implied) unit costs, forecast volumes, and changes in service classification.

The first step was to use historical data to determine an average unit cost for each type of connection. We have four broad connection types including residential, commercial/ industrial, sub-division and embedded generators. These are further categorised based on whether the connection is simple or complex, and whether it relates to the low or high voltage network. We relied on four years of data to derive a unit cost for connection services, noting that all load connection services had been classified as SCS in the 2019-24 period. We used actual RIN data from 2018-19 to 2021-22 as a basis for the estimate.[22]

Our next step was to derive forecast volumes for each connection type. We engaged Energeia to develop total and new connection forecasts for each connection type (see Attachments 8.63 and 8.74). Energeia's forecasts for residential, commercial/industrial and sub-division connections were based on a regression model that considered economic, building activity and population drivers. Embedded generation forecasts were based on historical relationship between uptake of solar and the return on interest taking into account factors such as the feed in tariff rate, costs of the solar system, and the price of electricity.

We then calculated the forecast connex as the average unit price multiplied by the forecast volumes for each connection type. The final step was to allocate connection types to SCS and ACS based on the AER's change in classification in the AER's Framework and Approach paper.

As noted above, we did not include gifted assets in the connex forecasts for the 2024–29 period.

9.3.2 Forecast capital contributions

Once we have forecast connex, we then estimate forecast capital contributions. To do this, we start with the forecast connex for each connection type classified as SCS. We then multiply that forecast by an *assumed* contribution rate for that type to determine the forecast capital contributions.

Based on our experience over the 2019–24 period, we assumed a 20 per cent contribution for the more complex or larger connection types including RES complex LV, RES complex HV, Commercial simple LV and Sub division Complex LV. We assumed zero contribution for less complex or typically smaller connection types.

22 We note that the submitted RINs had mistakenly reported generator connection costs as an SCS, and this error has been corrected in our modelling.

9.4 Amendments to our Connection Policy

We are required to submit a connection policy to apply for the 2024-29 regulatory period. Our Connection Policy (Attachment 8.62) sets out the circumstances in which Power and Water requires a retail customer or real estate developer to pay a connection charge for a new or altered connection. It also sets out how the charges are calculated for basic and negotiated connection services, including the application of capital contribution and the operation of the pioneer scheme.

We have proposed changes to the Connection Policy that applied in the 2019-24 period. In particular, we have amended the definitions of connection services to align to the AER's Final Framework and Approach paper and our Classification Proposal (provided at Attachment 7.01). We have aligned our definition of basic connection service to be consistent with other networks in respect of the 100 amp per phase threshold plus we have ensured that, irrespective of their technical attributes, all residential connections will be treated as a basic connection. This means that our rural residential customers will be subject to capital contribution provisions rather than be subject to an ACS where charges are likely to have been much higher.

We have also included new provisions in relation to export services, consistent with changes to the AER's Connection Charge Guidelines. There are only three conditions upon which we will apply a zero static export limit. This includes where there is a high probability we will not meet a regulatory obligation (such as a voltage level and power quality standard) or not being able to maintain the distribution network within its technical limits. This may also be when the cost of augmenting the distribution network to allow a reasonable export capacity level by the connection applicant outweighs the benefits arising from providing the additional export capacity. The last condition is if the service is requested by the connection applicant.

10. Non-network ICT capex

We forecast $70.7 million for ICT capex in the 2024-29 period, compared to $50.3 million in the 2019-24 period. 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 efficiently. We also are proposing recurrent capex to ensure our ICT systems remain reliable, contemporary, and cyber-secure.

ICT capex relates to all devices, applications and systems that combined allow for interaction with the digital world. We note that our DER capex includes ICT capabilities, however, consistent with recent AER decisions we have separately set out our requirements.

The purpose of this section is to set out the information and data that supports our proposed non-network ICT for the 2019-24 period. This includes an overview of proposed ICT, identifying drivers of ICT in the 2024-29 period, explaining the overall method and key inputs, and providing a description of the ICT projects and programs.

We note that some of the proposed projects also relate to proposed opex step changes (provided at Attachment 9.02) for delivering our Operating Model program and ICT strategy.

10.1 Overview of non-network ICT capex

We forecast non-network ICT capex of $70.7 million in the 2024-29 period, an increase of $20.4 million compared to the 2019-24 period as seen in Figure 10.1.

Figure 10.1: Forecast non-network ICT Capex ($ million real 2024)

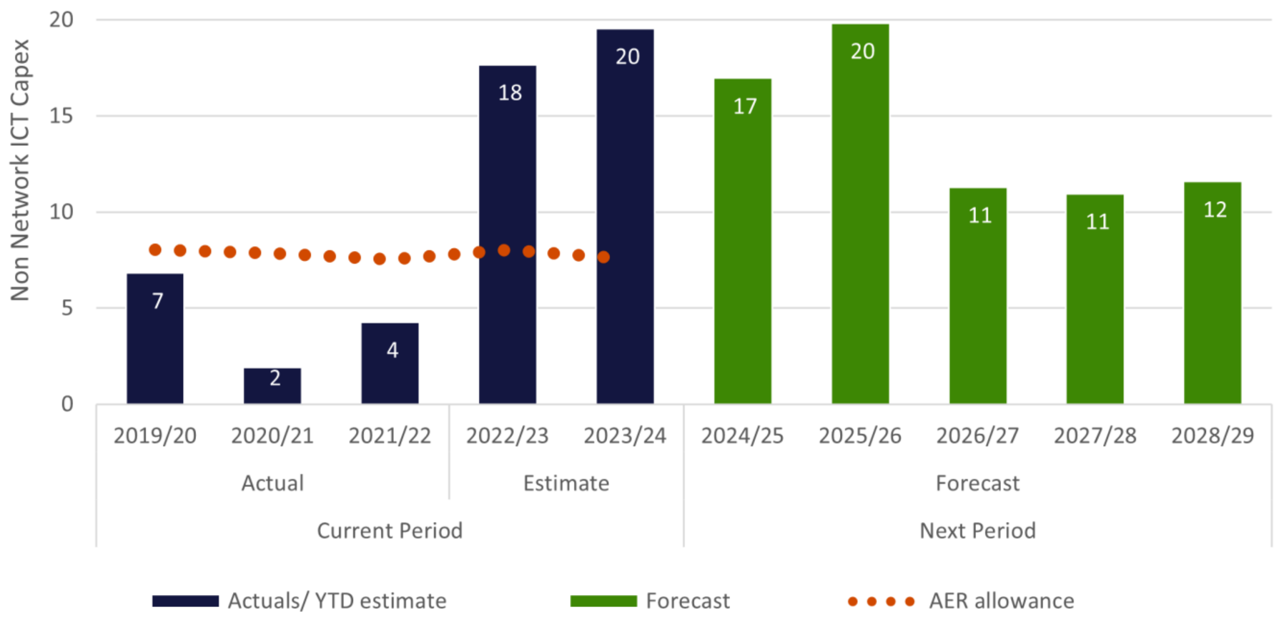


Figure 10.1 provides a summary of the program by ICT category. The material investments relate to non-recurrent capex to improve our IT and OT capability and to allow us to achieve a prudent level of cyber security maturity. The capability uplift is via two projects. The 'Operating Model Program' involves new capabilities critical to our transformation strategy including financial management, asset management, capital delivery, and service delivery. This project commenced in the 2019-24 period (and was formerly referred to as the 'Transformation Project'). We expect to have delivered the replacement of the metering and billing system with new capabilities, together with updates to our Energy Management System (**EMS**). The second capability uplift project is referred to as the Operational Technology (**OT**) Capability Uplift project and is designed primarily to provide ICT functionality to support distribution system management and outage management.

We show the recurrent, non-recurrent and total Non-network ICT capex by year in the 2024-29 regulatory period in the table below.

Table 10.1 Forecast non-network ICT capex in 2024-29 by year ($ million, real 2024)

Category	2024/25	2025/26	2026/27	2027/28	2028/29	Total
Recurrent ICT capex	2.4	4.2	2.3	3.2	5.5	17.7
Non-recurrent ICT capex	14.6	15.6	9.0	7.7	6.1	53.0
Total ICT capex	17.0	19.8	11.3	11.0	11.6	70.7

In terms of composition, there are 9 planned ICT projects, which includes the Operating Model Capability Uplift project under our Operating Model program that comprises four parts.

Table 10.1 also shows that the majority (75%) of our forecast expenditure for the 2024-29 period is non-recurrent acquisition-related expenditure.

10.2 Drivers of non-network ICT capex in 2024-29 period

At present, the business uses aged ICT systems that are losing currency and functionality. While we have made some investments in the 2019-24 period, we recognise the need to prudently manage our ICT investment to ensure we have the functionality to support the transition to a clean energy future (such as managing the system with increase renewable energy), ensure that systems are scaled to our smaller network, and minimise costs.

We commenced our ICT refresh journey in the 2019-24 period, with the expected completion of our meter and billing system and the commencement of an upgrade to our EMS by the end of the period. We have significantly re-prioritised our ICT refresh program compared to our 2019-24 regulatory proposal, taking a more cautious and prudent approach to investing in large ICT systems.

This has meant that some of the system replacements we had initially intended to commence in the 2019-24 regulatory period, will now occur in the 2024-29 period including a new asset management system, mobility and capital delivery system and the physicals-to-financials ICT systems (which are all part of the Operating Model Program, provided at Attachment 2.01).

The key drivers of ICT expenditure in the 2024-29 period relate to continued investment in our systems capability uplift and the growing need to manage cyber-security threats, as described in our ICT strategy (provided at Attachment 8.65).

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.

10.2.1 Uplifting our operational technology to meet the needs of our customers

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 NT's very high solar uptake) and the impacts of this on the network.

Our proposal includes provision for 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.

10.2.2 Uplifting technical competencies under our Operating Model Program

Our Operating Model Program is charged with delivering uplifted organisational capabilities and efficiencies across people, process, and technology. Under the initiative, we have identified the significant benefit from uplifting the technical competencies across the business.

This recognises that our core systems have not kept pace with the growing complexity of our business, new compliance requirements and the service expectations of our customer base in a digital age.

The benefits of upgraded capabilities include automating manually intensive work practices, streamlining and simplifying our processes, supporting efficient business operations, complying with our regulatory obligations, adapting to rapid changes in our business environment, and meeting growing digital expectations of our customers for service delivery.

Our proposed program has considered the optimal timing and sequence of programs, and our capability to deliver the projects on time and on budget.

10.2.3 Cyber security

We have identified a strong need to uplift our cyber security. This recognises the worsening cyber security landscape as evidenced by recent cyber-attacks on key commercial organisations.

Cyber security is critical to ensure the NT homes and businesses receive reliable energy, water and sewerage services. Further, other essential infrastructure such as communications and telephony rely on our electricity network.

In an environment of increased cyber threats,[23] the Australian Government has introduced amendments to the Security of Critical Infrastructure Act (**SOCI Act**) that introduce stronger physical and cyber security requirements. [redacted]

We have undertaken an extensive examination of our cyber security capabilities and based on this analysis consider that key investments are required in the 2024-29 period to ensure our services remain protected from cyber threats.

10.3 Methods and approach

Our approach to develop the ICT forecast has considered the AER's guidance note regarding the assessment approach for non-network ICT capex assessment approach. This includes identifying whether the nature of ICT capex is recurrent or non-recurrent, which in turn specifies the methodologies that should be applied in developing forecasts.

For recurrent ICT capex, we have largely assessed the need to maintain functionality of the existing system or service. This has included consideration of the underlying driver of expenditure, assessment of risk, and analysis of least cost option to address the driver. We have also considered whether the current capability can be provided through a lower cost operating solution.

We have several types of non-recurrent capex that have involved slightly different approaches to forecast capex, but all rely on a business case approach.

- **ICT applications –** We have relied on a business case assessment of the need of the new function, and alternative options.
- **Cyber security –** We have sought to identify the relevant security maturity level that we need to achieve based on a national cyber-security framework, [redacted]. We have considered the optimal timing, sequence, resource mix and delivery capabilities to achieve the target cyber security maturity level.
- **Operating Model Program capability uplift** – Due to the inter-related nature of this program, and the importance of sequencing in the context of our Operating Model, we have sought to undertake a business case assessment at the portfolio level. This includes options assessment and identifying options the optimal sequencing of work in the 2024-29 period.

23 During 2021–22, the ACSC received 95 cyber incidents affecting critical infrastructure.

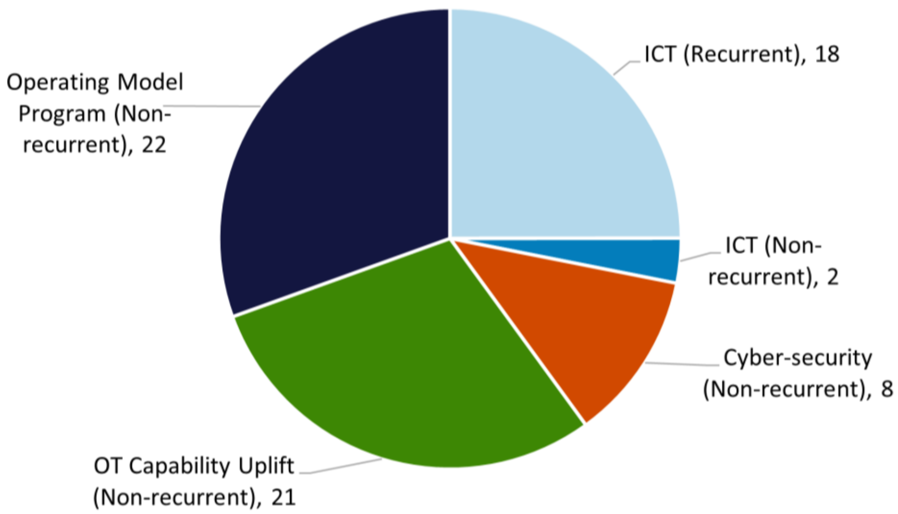
- **Operating Technology Capability Uplift** – Power and Water's current systems for managing the network are obsolete and or incapable of supporting the complex operational tasks required in managing the two-way flow of energy and intermittency from the increasing penetration of large scale renewable generation and DER more broadly. A business case has been developed which is based on a technology roadmap for developing the necessary capability. The recommended sub-projects is based on a staged approach to building capability, cognisant of the delivery challenges given the increased size of the ICT portfolio for the next period.

Our methodologies have considered the substitution possibilities of opex and capex, and in many cases the preferred option involves a mix of the expenditure types. Further, many ICT systems relate to other lines of business in our organisation. We have used our cost allocation methodology to determine the portion that relates to standard control services.

10.4 Description of programs by category

Figure 10.2 provides a breakdown of the program by sub-category.

Figure 10.2: Forecast non-network ICT capex for next regulatory period ($ million, real 2024)



The forecast is dominated by three major projects: Cyber security maturity improvement, the Operating Model Program, and Operational Technology Capability Uplift. The remaining capex is for recurrent activity in relation to hardware and software renewal.

The three solutions will also require a significant step change in operational expenditure, but nonetheless they represent the best overall solution. Refer to Attachment 9.02 for further details.

The proposed ICT projects for the next regulatory period have been developed cognisant of the AER's ICT assessment guidance note and have classified the projects as either recurrent or non-recurrent or a combination of the two and identified the potential benefits to the business and customers.

- Recurrent projects and programs typically entail refreshes and updates within five years. Recurrent expenditure is necessary to maintain the current level of service and risk. Recurrent expenditure is expected to be reasonably level in real terms and includes end-of-life replacements or major upgrades of our core systems.
- Non-recurrent projects are typically one-off investments to introduce new capability in response to a new business need and/or a regulatory obligation. Non-recurrent projects can also involve replacement of existing systems, but with a life-cycle of more than five years.

In the table below, we provide a summary of the ICT projects planned in the 2024-29 regulatory period, the classification and benefits.

Table 10.2 ICT Projects planned for the next period

Project name	Description	Recurrent / Non-recurrent	Benefits
Information Management	To improve RIN data, this project will improve data governance and embed the use of the enterprise data model.	Recurrent / Non-recurrent (50%/50%) Compliance and new obligations	Improved RIN data and quality of reporting.
Field Device and Telephony Communications Upgrade	All 3G enabled devices, such as modems and SIMs, need to be replaced with 4G or 5G enabled technology.	Recurrent / Non-recurrent (50%/50%) Maintaining existing services or functionality	This will increase network device visibility and provide Power and Water with the ability to roll out smart meters and improve service reliability.
Software Replacement	Routine software management is required to improve service delivery.	Recurrent (100%)	Improved service delivery.
Hardware Replacement	Routine software management is required to improve service delivery.	Recurrent (100%)	Improved service delivery.
ICT Minor Projects	The budget for this project covers any unforeseen ICT projects and initiatives for all of ICT.	Recurrent / Non-recurrent (50%/50%) Compliance and new obligations	Varies based on the actual projects that are identified annually and approved.
Customer Connectivity	This project looks at correcting the customer connectivity model between the systems of RMS, MAXIMO (enterprise asset management software), Meter Data Management System (MDMS) and GIS.	Non-recurrent (100%) Compliance and new obligations	Resolving this issue will improve the connectivity model and therefore outage management and network planning.

Project name	Description	Recurrent / Non-recurrent	Benefits
Cyber Security	The Security Legislation Amendment (Critical Infrastructure) Bill 2021 (Cth) amended the scope of the SOCI Act to include the energy sector.	Recurrent / non-recurrent (35% /65%)[24] Compliance and new obligations	This project will address the newly applicable requirements regarding cyber security, which will in turn improve both cyber security and overall network security for Power and Water.
Operating Model – Capability Uplift project (Physical to Financials)	This program falls under the umbrella of the OMP. It looks at the improvement of asset management and how Power and Water's financial assets are treated.	Non-recurrent (100%) Acquisition of new functionality	It will improve asset treatment, the capitalisation process, and ultimately Power and Water's financial performance and position.
Operating Model – Capability Uplift project (Asset Management & Capital Project Delivery)	Enable the optimisation of assets by effectively balancing cost, risk, and performance. Deliver projects effectively and efficiently from capital project planning, scoping, project management, and execution	Non-recurrent (100%) Acquisition of new functionality	Improved operational performance and leveraging economies of scale (as a multi-utility) by standardising processes and systems. Improved capital planning and maintenance strategies Improved network performance and resiliency Improved support for regional and remote communities.
Operating Model – Capability Uplift project (Optimise Service Delivery)	Support efficient and effective work planning, scheduling, dispatching, and closeout processes	Non-recurrent (100%) Acquisition of new functionality	Optimise planning and delivery of works management activities across field operations.
Operational Technology Capability Uplift (OTCU)	The OTCU project allows for real-time distribution monitoring, optimisation and control.	Non-recurrent (100%) Acquisition of new functionality	It will allow Power and Water to streamline distributed energy resource management, improve outage management and simplify complex device integration.

[24] The expenditure is 100% non-recurrent for the period FY23 to FY27. The average over the business case is 27% recurrent, 73% non-recurrent.

10.4.1 ICT Systems (recurrent)

We forecast $17.7 million on recurrent ICT capex comprising the following projects:

Hardware replacement [redacted]

Enterprise ICT infrastructure underpin our key ICT systems. The operational lifespan of 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.

We considered three broad options. Our analysis shows that deferring hardware upgrades to the following regulatory period was not credible due to the high risks including its impact to core business functions including risk of system failure. The option to replace hardware on a risk-assessed basis was preferred over option 3, migration to cloud computing (which offers essential computing, storage, and networking resources on demand, on a pay-as-you-go basis), primarily because of cost.

The scope of the proposed project includes procuring and installing server infrastructure to replace end-of-life servers and server infrastructure and decommissioning and disposal of retired infrastructure. The cost forecast is based on known replacement costs and the costs have been allocated to SCS based on our cost allocation methods.

Software replacement [redacted]

ICT applications underpin Power and Water's core business capabilities by providing the infrastructure and tools (systems) necessary to support and enable key business processes. We evaluate our applications each year to ensure that they remain under mainstream or extended vendor maintenance.

We upgrade applications when they become incompatible with contemporary operating systems and infrastructure. This needs to be done in order to mitigate the risk of failure that will adversely impact the availability of business systems and to minimise disruption to the ongoing operating capability of Power and Water. Business units have historically acquired the software they need to operate, however new license management rules and monitoring systems are now in place providing more visibility of software across the organisation, identifying opportunities to simplify procurement and reduce costs.

We have identified software applications will need to be updated over the 2024-29 period due to lack of vendor support and/or vital to supporting our transformation program. Our cost estimate is based on historical costs with upgrading applications.

Field device and telephony communication replacement [redacted]

We have been advised by our communications carrier (Telstra) that 3G mobile services are scheduled to be switched off in June 2024 except in regional and remote locations which will be progressively decommissioned.[25] 3G mobile services are utilised across multiple platforms and include mobile sim cards, mobile devices, smart meters, and data loggers. Further, Telstra has also advised that Integrated Services Digital Network (**ISDN**) and Public Switched Telephone Network (**PSTN**) services are being progressively switched off from mid-2022.

[25] Telstra has however advised that 3G services to these regions will be progressively decommissioned over the course of the next period

We examined three options:

- The first option was that we would not respond to the disconnection of the current services. This option is not technically or commercially viable. It would not provide the necessary telecommunications and telephony functionality to support core operations.
- The second option is to adopt the most cost-effective technically acceptable data and telecommunications service available for our urban, remote, and regional areas. This includes a combination of 4G, 5G, satellite, or National Broadband Network (**NBN**) services. The expenditure in this option relates to replacing obsolete devices or components within the devices with compatible devices/components. This option is preferred based on a combination of lowest cost (of the two credible options) and improved functionality to run our suite of refreshed ICT systems, which require higher data speeds and lower latency.
- The third option we examined was routers connected wirelessly using a mesh-like backbone (core network) structure. Some routers function as wireless access points (e.g. laptops and smart devices with wireless access) to attach themselves to the network. This was not the preferred option based on our cost analysis.

The scope of the preferred option is to continue the current program to replace the existing service with a modern equivalent service (upgrade to 4/5G Mobile, NBN and Satellite services).

Minor ICT projects [redacted]

This program recognises that ICT is dynamic and often requires investment in minor ICT projects that cannot be forecast in advance. The new initiatives largely relate to the pace of regulatory change and the need to implement operating changes. In the 2019-24 period we have implemented a large number of initiatives that were not initially forecast in our submission, including a legal case management system, upgrades to physical server rooms, training facilities, and upgrades to the devices that connect to the EMS.

Our forecast capex for 2024-29 draws on trend in the current 2019-24 period. We have also identified types of capex that may arise including to support compliance (e.g. ring-fencing regulation), cloud computing hosting capability development to secure cloud connections, and SCADA support such as replacement of switches and firewalls.

10.4.2 ICT applications (non-recurrent)

We forecast $2.2 million on new ICT applications. This includes two new minor programs to improve customer connectivity and a system to monitor our infrastructure.

Customer connectivity [redacted]

This project is proposed to address inaccurate customer connection information in our connection database/model that result in inaccurate regulatory reporting, inadequate outage notification, and incorrect calculation of Guaranteed Service Level payments to customers. The scope of the project is to improve modelling of where and how customers are connected to the network.

Information management [redacted]

Managing enterprise data allows for better-informed decision making and risk management based on available, findable and trustworthy information. We are currently at a relatively low level of information management maturity based on an internationally recognised framework.

Our analysis of options found that expanding on our current program to mature enterprise data enables the business to work better through explicit information accountabilities, visibility of information quality, and automation to support current and trustworthy views of Power and Water's information landscape. The proposed investment will allow Power and Water to achieve level 4 maturity (on a 5-level scale).

10.4.3 Cyber Security (recurrent and non-recurrent)

Power and Water's cyber security maturity is not adequate to comply with the obligations under the amended Critical Infrastructure Act nor robust enough in the face of the worsening cyber-attack landscape. This business case supports achievement of Security Profile level 2 or SP-2 (per the Australian Energy Sector Cyber Security Framework, AESCSF[26]) by the end of the 2024-29 regulatory control period. This means we need to commence work in the current regulatory period.

We have included $11.5 million in our forecast for the 2024-29 period for continuing our cyber security project.

The landscape for cyber-security has worsened recently as experienced by recent attacks on prominent commercial entities in Australia. Cyber security is critical for the customers that receive our essential services but also due to the potential for cascading failure to other sectors such as telecommunications.

[redacted]

[redacted]

- [redacted]
- [redacted]
- [redacted]

[26] The AESCSF has been developed through collaboration with industry and government stakeholders, including the Australian Energy Market Operator (**AEMO**), Australian Cyber Security Centre (**ACSC**), Cyber and Infrastructure Security Centre (**CISC**), and representatives from Australian energy organisations. The AESCSF leverages recognised industry frameworks such as the US Department of Energy's Electricity Subsector Cybersecurity Capability Maturity Model (ES-C2M2) and the National Institute of Standards and Technology Cyber Security Framework (NIST CSF), and references global best-practice control standards (e.g. ISO/IEC 27001, NIST SP 800-53, COBIT, etc.). The AESCSF also incorporates Australian-specific control references, such as the ACSC Essential 8 Strategies to Mitigate Cyber Security Incidents, the Australian Privacy Principles (**APPs**), and the Notifiable Data Breaches (**NDB**) scheme.

- [redacted]

[redacted]

[redacted]

[redacted]

10.4.4 Capability Uplift project (non-recurrent) – forms part of our Operating Model program

We forecast $20.8 million capex to uplift core ICT systems across multiple business workstreams including financial, metering, asset management, capital delivery and customer service.

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. Our Future Operating Model initiative identified the potential benefits from uplifting technical competencies across a range of core capability business functions.

The capability uplift project replaces legacy IT systems with new capabilities. Below we set out the identified needs, options assessment and preferred option.

Identified need

We have identified a need across five workstreams, which have been grouped into three tranches based on prioritisation of need and optimal sequencing. This is set out in Figure 10.3 below. Table 10.3 summarises the identified need for each workstream.

Figure 10.3: Capability workstreams and tranches

	CU Project Workstream	Description	Current Maturity	Systems to be Upgraded / Replaced	Key Customer Outcomes
Tranche 1	Meter to Cash	Deliver compliant and efficient metering and billing systems in line with NER requirements & address revenue management issues	LOW	Retail Management System (Gentrack)	✓ Delivers mandatory NT NER regulatory obligations by January 2024 ✓ Accurate tariff management and billing ✓ Addresses core operational inefficiencies
Tranche 1&2	Transform Customer Experience	Deliver a quality customer experience across the business with a single customer view (Tranche 1) and fit for purpose customer portal (Tranche 2)	LOW	Retail Management System (Gentrack)	✓ Advanced customer service and customer experience capabilities ✓ Improved brand and reputation
Tranche 2	Physicals to Financials	Improve the efficiency of financial processes to enable improved financial management and decision making	LOW	Financial Management System (Oracle)	✓ Resolves technical issues of P2F being at end of life ✓ Addresses core operational inefficiencies ✓ Addresses external financial reporting issues
	Standardise Asset Management	Enable the optimisation of assets by effectively balancing cost, risk, and performance	MEDIUM	Asset Management System (Maximo)	✓ Improved operational performance and leveraging economies of scale (as a multi-utility) by standardising processes and systems
	Capital Project Delivery Consolidation	Deliver projects effectively and efficiently from capital project planning, scoping, project management, and execution	LOW	Project Server (Microsoft)	✓ Improved capital planning and maintenance strategies ✓ Improved network performance and resiliency ✓ Improved support for regional and remote communities
Tranche 3	Optimise Service Delivery	Support efficient and effective work planning, scheduling, dispatching, and closeout processes	MEDIUM	Asset Management System (Maximo)	✓ Optimise planning and delivery of works management activities across field operations

Options analysis

Our business case identifies the preferred timing and scope of works for the 2024-29 period based on deriving the maximum net benefit and the optimal sequencing of the program. We analysed four options that were all premised on having already delivered Tranche 1 by the end of the 2024-29 regulatory period (i.e. meter to cash and part 1 of transform the customer experience):

- Option 1 was to not undertake any workstreams after Tranche 1. This option was not preferred as it did not address fundamental system limitations, serviceability, compliance, or risk with operating legacy systems.
- Option 2 was to undertake all the workstreams in Tranches 2 and 3. This was the preferred option on the basis that it delivered the highest net present value of positive $4.1 million, and that deliverability was achievable.
- Option 3 was to deliver base capability in components of Tranches 2, but defer Tranche 3 (Service Delivery) to the 2029-34 regulatory period. This option was not preferred on the basis that it yielded a negative net present value of $11.9 million. This was due to Inefficient sequencing that separates interrelated capabilities, increases costs due to stop start nature, and that it does not maximise efficiency opportunities.
- Option 4 was to deliver Physical to Financials in Tranche 2, defer delivery of Asset Management and Capital Project Delivery to July 2026 and not deliver Tranche 3. This option was not preferred as it yielded a negative net present value of $2.4 million. This was due to the core interdependency between Physical to Financials and Asset Management & Capital Project Delivery.

The NPV for each of the options by considering net annual benefits with a 1-year realisation delay from each implementation to account for solution embedding. Benefits for each implementation are as derived by KPMG and further discounted by Power and Water to ensure a conservative assessment, totalling approximately $6.8 million per annum. The key benefit streams included reduction in staff numbers, avoided ICT costs associated with maintaining legacy ICT systems, and optimised asset programs. In addition to quantified benefits, we also identified qualitative benefits including improved compliance, service delivery, and customer experience.

Table 10.3: Needs for underlying workstreams

Workstream	Identified need
Meter to cash (Tranche 1)	The project provides a new Meter Data Management System and customer billing operations capability. The project will be delivered by the end of the 2019-24 regulatory period. The project was prioritised on the basis that the current metering system does not provide the functionality our new compliance obligations under Chapter 7A of the NT NER including data validation, editing and estimation. Further the current metering system was inefficient requiring manual processes to extract required data. The project also involves replacing our end of life billing system which has limited functionality and integration to associated systems. This has led to poor customer outcomes in terms of billing accuracy and disputes. The new system provides for automation of billing that integrates with metering data and other systems such as GIS. The meter to cash project also delivers Phase 1 of the transform customer experience capability uplift (see below) by introducing self service capabilities for customers to support accurate and efficient billing and making historical data available. The planned program will be completed in the 2019-24 period, therefore no forecast capex is included in the 2024-29 period.
Transform customer experience (Tranche 1)	We have identified that our systems require improvement to deliver on customer expectations, for a simple positive experience in their interactions with us. We identified a need for customers to be able to monitor status of service requests, track their usage of services, and track enquiries and complaints through to resolution. We also identified that customers want to interact with Power and Water through their preferred communication channel and receive consistent messaging. For this reason, we considered there was a need for a centralised system that could provide a 'single view' of the customer, and to invest in enabling a customer portal. The planned program will be completed in the 2019-24 period, therefore no forecast capex is included in the 2024-29 period.
Physicals to Financials (Tranche 2)	Our current financial management system (Oracle) is a more than 20 years old and is largely technically obsolete. The system does not provide the mandatory financial management functionality that is available in a current version of Oracle, or the base capability to provide in depth reporting. This has impacted our ability to undertake audits without significant manual intervention. The project will integrate a suite of accounting data into a single financial management system and will provide for improved integration with financial data in our asset systems. The new system will streamline data and provide for a standard reporting framework including variance analysis reports. This will also streamline process workflows with clearly defined responsibilities between finance and other lines of business. The project will commence in the last year of the current 2019-24 regulatory period. The forecast capex in 2024-29 is $3.9 million.

Workstream	Identified need
Standardise Asset Management (Tranche 2)	Our current asset management system (Maximo) is largely obsolete despite a recent technical upgrade to maintain supportability. The system does not provide the functionality to support prudent asset maintenance and replacement decisions. It is out of date with our current organisational model, asset strategies and current business processes. The capability uplift will improve the accuracy and completeness of asset data. In turn, this will enable us to perform analytics that provide insight into optimal maintenance and replacement programs. The new systems will align with best practice asset management frameworks such as ISO55001. The system is a vital tool to help us extend asset lives in the context of the ageing of our network. The forecast capex in 2024-29 is $8.2 million
Capital Project Delivery Consolidation (Tranche 2)	A key plank of our capital delivery strategy is a capability uplift to support our Project Investment Delivery Framework. The new capability will provide consistent and standardised governance, tools, and metrics to support delivery of capital programs. This includes a 'single view' of the capital portfolio at any point in time, metrics and reporting on individual projects, tracking with approved business cases and integrated resource planning. There would also be integration with the new financial and asset management systems. The forecast capex in 2024-29 is $5.6 million.
Optimise Service delivery (Tranche 3)	We have identified an opportunity to improve the efficiency of service delivery and realise synergies across the business through better works planning, scheduling and execution. The system would consolidate work plans across the business, identifying opportunities to bundle works to achieve efficiencies and provide longer lead times to suppliers. Our field staff and contractors would be able to employ mobile solutions to plan and manage activities, leading to improved efficiencies. The system would provide for enhanced scheduling capacity and resource allocation. The forecast capex in 2024-29 is $3.0 million.

We propose to complete the Capability Uplift projects during the 2024-29 regulated period and build upon the high deliverability capability of the existing project team.

10.4.5 Operational Technology Capability Uplift (non-recurrent)

We have included $21.6 million to uplift our OT capabilities in our capex forecast. OT is a secure computing environment that helps monitor, detect issues, operate and control network assets. We currently have limited OT capability on our distribution networks. Our processes are almost completely manual, dependent on key resources, and do not provide timely or accurate visibility of the network.

The primary driver relates to the increasing complexity with managing a changing generation mix on our distribution network and the challenges of planning and managing the associated challenges. In addition, our current OT is not sufficient to meet compliance obligations such as reporting of outages to support the AER's application of a Service Target Performance Incentive Scheme. In addition, our current OT is inadequate to meet cyber security threats.

Key issues include:

- Our low voltage network is not controlled through SCADA. We are the only network that still relies on pinboards, limiting our accuracy and timeliness to respond to incidents.
- Our asset data is inaccurate, incomplete, duplicated and not easily accessible. The inaccuracies lead to sub-optimal network decisions that impact assets and customers.
- We do not have a 'populated' enterprise data model which do not have an overarching identifier across systems for each asset. This leads to excessive manual effort to manage data in multiple systems.
- We do not have an Outage Management System (OMS) that can provide reliable data on outage information including restoration times. This is leading to compliance issues with both our jurisdictional regulator and limiting the ability of the AER to apply a service target performance scheme that ultimately provides incentives to improve reliability for customers. We are the only network in Australia without an OMS.
- We are reliant on staff knowledge for an understanding of the network, rather than a systemised approach that relies on timely and reliable data and processes. This leads to key personnel risk together with an inability to keep up with growing complexity.

The target state is a contemporary, integrated suite of systems, enabled by a sufficiently complete and accessible set of standing and real-time data, and sufficient trained staff to operate and leverage the capabilities. With contemporary tools, adequate data, and the right staff, Power and Water can effectively manage the network despite the rapidly changing landscape of distributed and large scale energy resources, less synchronous machines, and electric vehicles.

The capabilities and supporting systems and data being proposed are often referred to collectively as advanced distribution management system ('ADMS'). Whilst our focus is on fit-for-purpose electricity distribution management capabilities, the scope of the project supports improved network planning and operations across generation, transmission, distribution, and NTESMO (NT Energy System and Market Operator) – it is therefore not an ADMS implementation project, but a project to coordinate and address foundational elements and enablers to support ADMS/ADMS functionality overall.

We have undertaken analysis of three broad options based on initial studies and vendor estimates. The first option is to rely on multiple platforms across multiple vendors to provide specific OT capabilities. While this option allows for simpler implementation, the costs would be much higher and there would be limited opportunities to integrate data and also has more cyber security risk. The second option is a new consolidated platform built from the ground-up thereby avoiding the need for exhaustive analysis of the current state and the need for data migration and cleansing. This option is not preferred on the basis of much higher costs than the other two options, and the difficulty in operating the network while the platform is being built.

The third option is preferred which is a staged, capability-based upgrade of existing EMS platform with managed integration for advance point solutions. The scope includes the uplift and introduction of platforms to support improved network planning and operations with a focus on regulated distribution capabilities, and enablers relating to data quality and data management.

A 'doing nothing' approach will not enable Power and Water to cope with the increasing complexity of managing the evolving distribution system using the current obsolete and largely manual systems and was not considered credible. In the next regulatory period the project expenditure is primarily directed to building distribution management capabilities, improving network data quality and data management, and staff capability.

11. Non-network other capex

Non-network other capex comprises property, fleet and plant. We forecast $129.4 million of capex in the 2024-29 period compared to $54.8 million in 2019-24. This reflects a 'one-off' new project of $89.8 million to consolidate our staff across five sites into one central location. When normalised for this project, non-network capex in 2024-29 is slightly lower than our estimate of capex in 2019-24.

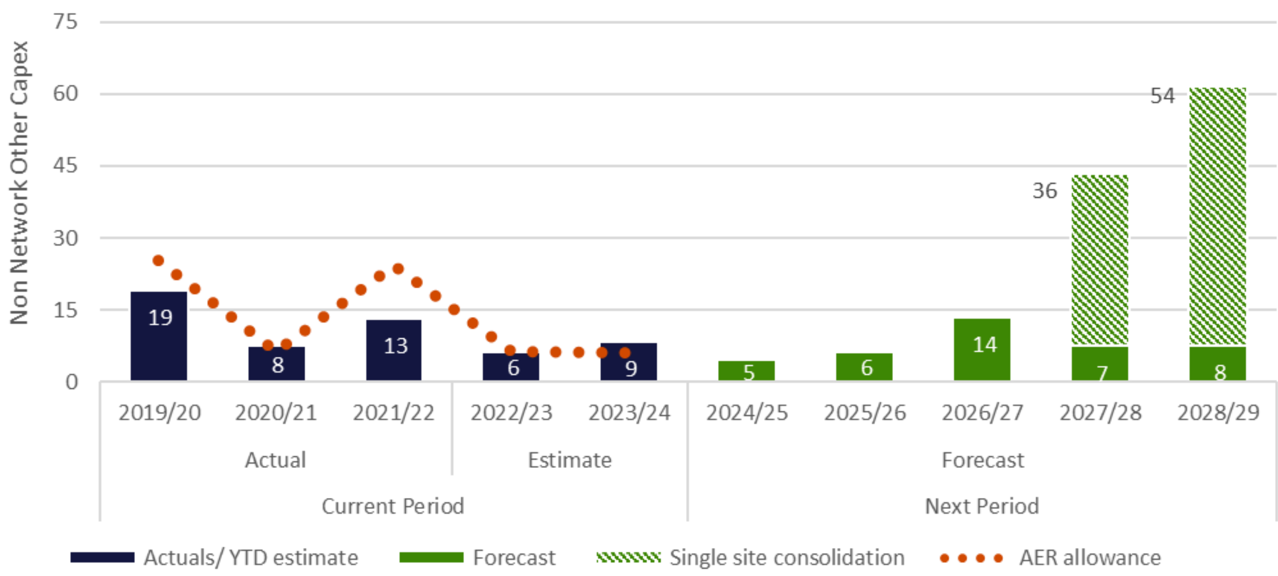
The purpose of this section is to set out the information and data that supports our proposed non-network other capex for the 2019-24 period. This includes an overview of proposed non-network other, identifying drivers of capex in the 2024-29 period, explaining the overall method and key inputs, and providing a description of the programs.

Non-network capex comprises our leases and investments in corporate property, fleet and plant. Leases are amortised consistent with the approach we applied in the current regulatory period, and included in the previous determination.

11.1 Overview of non-network other capex

We forecast non-network other capex of $129.4 million in the 2024-29 period, an increase of $74.6 million compared to the 2019-24 period as seen in Figure 11.1.

Figure 11.1: Forecast non-network other capex in 2024-29 compared to actual/estimated in 2019-24 ($ million real 2024)



This shows that the last two years of forecast capex are significantly higher than other years due to the single site consolidation project.

Other drivers of capex in this category include renewing our fleet leases to allow our field staff to perform their operations. We are also renewing our current property leases, noting that the single site consolidation will not impact the need for leases in this period.

We show the total non-network other capex by year in the 2024-29 regulatory period in the table below.

Table 11.1 Forecast non-network other capex in 2024-29 by year ($ million, real 2024)

Category	2024/25	2025/26	2026/27	2027/28	2028/29	Total
Non-network other capex	4.5	6.3	13.6	43.3	61.7	129.4

11.2 Drivers of Non-network other capex

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

11.2.1 Business as usual requirement to support our operations

The costs of commercial leases for existing properties that we rent, and remediation and other costs at sites that we own are as detailed in our Property Strategy (Attachment 8.76). We also include our fleet related capex as detailed in our Fleet Strategy (Attachment 8.75) and ongoing needs for plant, tools and equipment.

Collectively these reflect ongoing business as usual needs.

11.2.2 Consolidation of our staff into a single site

The high proportion of non-network (property and fleet) 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.

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.

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.

11.3 Methods and approach

We have applied different forecast methods depending on the nature of the investment. Consistent with our current approach for estimating lease costs, we capitalise the full amount of the operating or finance lease when we first enter or renew the lease.

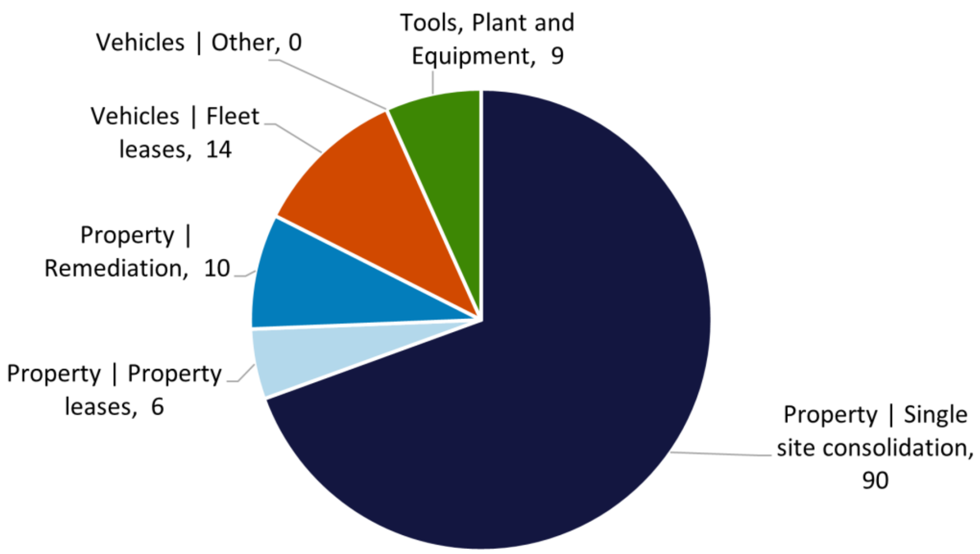
We have undertaken business cases to identify the need and preferred option to remediate or build new commercial properties. We note that the business case for the material one-off project to centralise most of our Darwin staff in one location is still at a conceptual stage of design.

In some cases, we have relied on historical expenditure to guide our forecasts of non-network other projects such as for plant and equipment.

11.4 Description of projects and programs

Figure 11.2 describes our non-network other program by key drivers. The capex related to consolidating most of our Darwin staff in one location accounts for about 69.4 per cent of proposed capex. Vehicle leases and property remediation account for a significant proportion of forecast capex.

Figure 11.2: Breakdown of non-network other capex (per cent)



11.4.1 Property capex

We forecast to incur $106.7 million of property capex related to standard control services in the 2024-29 period comprising the following projects:

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 our Mitchell Centre and Woods Street 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. The portion allocated to standard control services is forecast at $89 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.

Property leases ($6.4 million)

Power and Water is proposing $6.4 million capital expenditure for property leases for the next regulatory control period compared to approximately $21.2 million expected to be spent in the current regulatory control period. This difference is due to the timing of capitalisation of leases.

As discussed above, our property portfolio is dispersed and fragmented across many sites. We currently lease properties to house our staff. Our capex forecast includes the renewal of two leases that will occur in the 2024-29 period including Mitchell Street and Mitchell Street switching station.

Property remediation costs ($10.5 million)

We have identified 10 projects where upgrades to property facilities are required. The building compliance program addresses building-related non-compliance, environmental and security risks ($5.8 million). This represents the majority of our property-related costs.

We have included an additional $2.4 million for minor capital works such as office refurbishments and building upgrades to accommodate staff, and low value asset pool of a further $0.6 million.

We have also included installation and upgrade of physical and electronic security infrastructure throughout Corporate Sites to ensure the physical security of Power and Water’s resources and facilities ($1.6 million).

11.4.2 Fleet capex

We forecast to incur $14.0 million on motor vehicle capex including specialised fleet. The Power and Water network program of work is the key driver of fleet expenditure and have a material influence on the number and type of vehicles that are required to support the business. The different type of network investment also influences and drives the quantity and type of fleet assets required as described in our Fleet Strategy (Attachment 8.75).

Another key consideration is the replacement approach and criteria based on a combination of age, kilometre and condition based. Power and Water's electricity network in Northern Territory is vast and complex, with the network extending across difficult, harsh, and remote terrain and in demanding conditions. These conditions need to be taken into consideration when managing and maintaining the fleet, particularly when considering the replacement criteria.

Power and Water has considered the historical trend as well as expenditure drivers to develop a robust expenditure forecast for fleet to meet the ongoing operational and safety requirements of the regulated business.

11.4.3 Plant tools and Equipment

We forecast to incur $8.7 million on plant, tools and equipment. This 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; and furniture and fittings.

There is major risk associated with failure to maintain and replace plant, tools and equipment as and when the need arises. Failure to properly maintain plant, tools and equipment can lead to damage to network assets, unsafe operation practices and potentially worker safety.

We examined broad options to manage existing assets and develop new functionalities. This includes leasing, and replace and procure. The preferred option was replace and procure.

12. Capitalised overheads

We are forecasting a significant increase in capitalised overheads in the 2024-29 period. This is largely due to a change in approach to allocate overheads in 2021/22, which means that the forecast is not directly comparable to actuals and estimates in the current regulatory period. A further driver of change is the higher levels of direct capital activity in the 2024-29 period, which is forecast to increase capitalised overheads consistent with the AER's preferred forecast method.

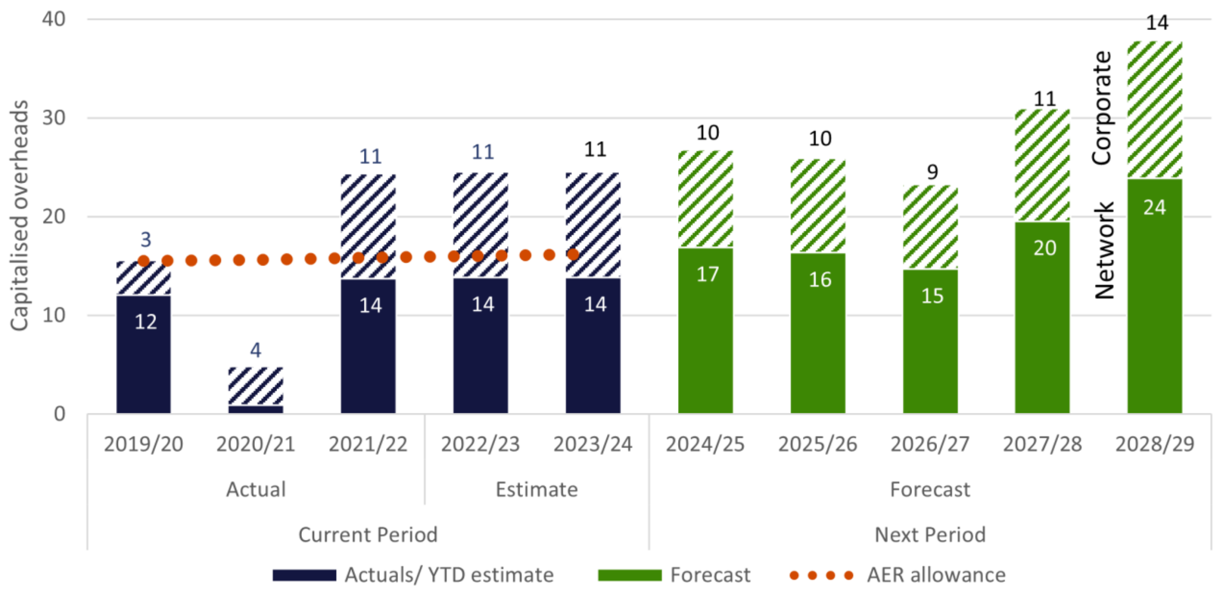
The purpose of this section is to set out the information and data that supports our proposed capitalised overheads for the 2024-29 period. This includes an overview of proposed capex, including the key drivers of capitalised overheads in the 2024-29 period.

12.1 Overview of capitalised overheads

Overheads are network and corporate costs that are shared costs across the business that we cannot directly allocate to a particular business activity. A portion of these costs are allocated as capitalised overheads based on our accounting practices and in accordance with our existing cost allocation method.

Capitalised overheads account for 25.2 per cent of the forecast capex in the 2024-29 period. In total, we are forecasting $144.7 million in the 2024-29 period compared to $91.9 million actuals/estimates in the current 2019-24 period, an increase of 57.6 per cent. The forecast capex is $65.5 million higher than the AER's regulatory allowance in 2019-24, as seen in Figure 12.1.

Figure 12.1: Forecast capitalised overheads in 2024-29 compared to actual/estimated in 2019-24 ($ million real 2024)



As discussed below, our 2024-29 forecast is not directly comparable with our 2019-24 actuals due to a change in accounting method in 2021/22.

12.2 Drivers of capitalised overheads in 2024-29 period

There are three drivers underlying our capitalised overhead forecasts compared to the current regulatory period.

12.2.1 Low level of capitalised overheads in 2020/21

In the second year of the period, we have reported capitalised overheads that are significantly lower than the AER's 2019-24 regulatory allowance. This is largely attributable to lower levels of capital activity than expected due to delivery constraints, resulting in a greater proportion of overheads being allocated to operating expenditure in these years.

This was further accentuated by a change in our approach in 2021/22 for allocating labour costs for capital projects. Under this change, a greater proportion of labour costs are now allocated directly to capital projects rather than being captured as a network overhead, in accordance with our AER-approved cost allocation method. This was based on analysis showing that our direct labour rates were not capturing the full cost of labour engaged in capital activity.

12.2.2 Change in accounting method for overheads in 2021/22

In the 2019-24 decision, the AER approved 16.9 percent of total capex as capitalised overheads. In its decision, the AER considered that our level of capitalised overheads expenditure was comparable to other distributors in the NEM.

In June 2022, we changed our treatment of shared resources to better allocate the network and corporate overhead costs to the activities they perform. This included making structural changes to the way we allocate overheads to capital projects to align with standard accounting practices and cost-reflective pricing. It has resulted in more overhead costs being attributed to direct maintenance activities and capital projects than had been done in prior years.

The change was prior to the 2021/22 financial year, and is already accounted for in the audited statutory accounts for that year. This change in our treatment of overheads and reporting also helps us move closer to having expenditure data that is comparable with other DNSPs.

It should be highlighted that our Cost Allocation Method (i.e. allocation between business units and services) has not changed, only the how overhead costs are attributed to services within our regulated electricity network business. See also our description of overhead cost allocation included in Attachment 9.01.

The process was guided by the requirements of the Australian Accounting Standards. To fully comply with Australian Accounting standards requirements, Power and Water performed a comprehensive assessment of support costs to quantify the appropriate level of capitalised overheads. The results of the assessment was a higher level of overhead capitalisation compared to approved allowances. It should be noted that the change has resulted in a reduction in the forecast opex allowance.

12.2.3 Higher levels of direct capex from 2022/23

We have used the AER's default method to forecast capitalised overheads that relies on trending actual total overheads in the 2021/22 base. We note that the method results in higher capitalised overheads in the last two years of the 2024-29 regulatory period, consistent with the higher levels of direct capex in those years.

12.3 Method to derive capitalised overheads forecast

We have forecast capitalised overheads using the default method contained in the AER's standardised capex model. This method trends from historical capitalised overheads, assuming that 75 per cent of those costs are fixed (i.e., stay constant in real terms) and 25 per cent vary with direct costs. To ensure that the resulting forecast aligns with our current accounting practices, we restated the historical capitalised overheads that were trended from to reflect those practices.

13. Contingent projects

We have identified five contingent projects in our 2024-29 regulatory proposal that relate to significant potential augmentations of our network to enable dispatch of low-cost renewable generation or to meet localised new demand associated with development of specific commercial projects in the NT. The projects are uncertain in terms of need, timing, scope and/or costs and we have therefore classified them as 'contingent', consistent with the NER, in order to avoid the risk of unnecessarily burdening our customers through capex allowances that may not be fully required.

We have defined triggers that are consistent with NER requirements and which, if and when they are met, will allow us to submit a Contingent Project Application for the AER's determination.

The purpose of this chapter is to set out key information in respect of five contingent projects that we have identified as part of this screening process.

13.1 Introduction

13.1.1 Meeting requirements in the face of likely significant change

In our 2019-24 regulatory determination we did not propose any contingent projects. In the 2024-29 period we are responding to a fast-paced environment as the NT Government implements the 50 per cent renewable target by 2030. We are also responding to new developments in the NT including land development and industrial hubs. In all cases, there is an element of uncertainty on the need, timing, scope, and cost of these projects.

13.1.2 Meeting NER requirements

The NT NER requires that we define appropriate 'trigger events' in our regulatory proposal that demonstrate the need for capital expenditure on each project. In accordance with the trigger event definitions in the NT NER[27], we must demonstrate that the occurrence of the trigger event must be probable during the 2024-29 period but is not sufficiently certain to include in our forecast capex. We need to specify clear and unambiguous trigger conditions or events that make the contingent project reasonably necessary, that result in a need for capex that applies at a specific location, and which is not otherwise dependent on some other condition or events that is not referred to in defining the trigger. The cost of the projects may ultimately be recovered from customers in the future if these predefined conditions are met. In the recent Transgrid draft determination, the AER provided additional guidance on projects that would be accepted as a contingent project including that the trigger event(s) must be demonstrably probable.

27 NT NER 6.6A.1(c)

13.1.3 Our process for identifying and defining the proposed contingent projects

We have applied the following four step screening process to identify contingent projects:

1. Identify potential projects not captured in our underlying inputs and assumptions to forecast capex in 2024-29. For instance, we identify specific industrial, commercial, land or infrastructure developments that, to the extent that they occur, may give rise to specific demand-driven augex projects that are not captured in our demand forecasts because they are not committed connections. We also identify probable transmission works relating to dispatch of renewable generation that were not included in our forecast capex on the basis of the uncertainty of those generation projects.
2. Determine if the projects are above the threshold in the NT NER for contingent projects of $15 million.
3. Determine if the project meets other requirements in the NT NER including that the investment does not relate to a restricted asset and would meet the capex objectives, criteria, and factors.
4. Determine appropriate trigger(s) for each project with reference to the NT NER requirements for such triggers.

13.1.4 Summary

Table 13.1 shows a summary of the five proposed contingent projects for the 2024-29 period. All estimated costs include a provision for overheads to reflect the total cost of the project.

Table 13.1 Contingent project capex in 2024-29 – including overheads ($ million, real 2024)

Contingent project	Estimated capex	Indicative timing
Shared transmission works to transport generation from a Renewable Energy Hub in Darwin-Katherine	120.8	Completion by end 2025/26
Unlocking existing large scale renewable generation in Darwin-Katherine	45.7	Completion by end 2026/27
Holtze-Kowandi land development	60.8	Completion by end 2026/27
Middle Arm commercial development	69.1	Completion by end 2028/29
Wishart commercial development	45.6	Completion by end 2026/27

13.2 Shared transmission works to transport generation from a Renewable Energy Hub in Darwin-Katherine

This contingent project relates to construction of shared transmission infrastructure to a connection point on a new Renewable Energy Hub (Hub) for the purpose of dispatching large scale renewable generation to customers in Darwin-Katherine. The transmission works will most likely be located close to the Channel Island to Hudson Creek 66 kV transmission line.

The estimated cost of establishment of the renewable hub has been based on Darwin-Katherine Electricity System Plan potential scope and costs of the project, with a cost estimate of $80 million (real 2022) and which when escalated is $120.8 million (real 2024 including overheads). The timing of the Hub remains uncertain, but we anticipate that it is probable that we would need to build the transmission infrastructure in the early part of the 2024-29 regulatory period, by the end of 2025/26.

13.2.1 Background

The Hub is a key initiative identified in the Darwin-Katherine Electricity System Plan to deliver 50 per cent renewable energy in the region by 2030. The concept is similar to actionable Integrated System Plan (**ISP**) projects in the National Electricity Market, which recognise the opportunities to lower transmission costs by co-locating renewable energy sources in a central location.

The Darwin-Katherine Electricity System Plan contemplates that the Hub would provide between 180 MW and 230 MW of large-scale solar and would be operational by 2025/26. The key benefits articulated in the Darwin-Katherine Electricity System Plan include:

- **Leverage capacity on existing transmission network**: The Hub would connect to the Channel Island to Hudson Creek 132 kV transmission line. This would have sufficient capacity to transfer generation after the planned retirement of the existing thermal generation at Channel Island power station, providing an opportunity to transport large-scale solar using existing energy infrastructure.
- **Maximise generation from solar**: Solar farms connected to the Renewable Energy Hub would have a secure, high-capacity network connection, with the best opportunity to maximise sent out solar energy (i.e. generation dispatch).
- **Lower connection and development costs**: Solar farms would be able to share development and connection costs, greatly reducing necessary upfront investment costs.

The likely transmission connection work consists of diversion and extension of 132 kV transmission lines, construction of a 132/22 kV substation, site studies, and project development overheads.

The Darwin-Katherine Electricity System Plan identifies the potential of market benefits to all customers from pursuing a 50 per cent renewable energy target. The construction of the Hub is a key initiative of this plan and therefore central to eliciting the identified market benefits.

13.2.2 Triggers

We have identified two triggers for the project.

1. A formal notification from a NT Government Minister to Power and Water Corporation, advising that the Government wishes to provide for a Renewable Energy Hub at a site near Darwin and advising the approximate required capacity and location of the Hub.
2. The completion of a RIT-T by Power and Water that:
   - Identifies a need to undertake shared transmission works to convey generation from a Renewable Energy Hub near Darwin within the regulatory period.
   - Identifies a preferred option consistent with the RIT-T guidelines that maximises the net economic benefit to all those who produce, consume and transport electricity.
   - Determines that the preferred option has a positive net economic benefit and/or is otherwise consistent with the National Electricity Objective at that time.

13.2.3 Evidence to support contingent project inclusion

The project meets the initial hurdles for acceptance as a contingent project. The project relates to the shared transmission network and is therefore not a restricted asset. Further, there are two sources of evidence to show that the project's cost estimate is likely to be materially higher than the $15 million threshold:

- Firstly, section 3.1 of the Darwin-Katherine Electricity System Plan identifies the potential scope and cost of the project, with a cost estimate of $80 million.
- [redacted]

We also consider the project reasonably reflects the capex objectives, criteria and factors in the NT NER. The project would enable transport of generation to customers from our network without constraints. There is a high likelihood the transmission works would yield a market benefit to customers due to the low cost of large-scale renewable generation relative to re-investing in thermal generation. This is evidenced in the NT Government analysis in section 5.3 of the Darwin-Katherine Electricity System Plan, which found significant savings from 50 per cent renewable energy. It would be highly unlikely that decentralised large scale renewable generation would yield the same benefit. There is also evidence to show that transmission works would be required to enable effective dispatch of the generation, as evidenced in the scoping studies recently undertaken by the Government.

We consider that our identified triggers are appropriate on the following basis:

- The triggers are specific and capable of objective verification. The formal direction by the NT Government would be in a form that can be transmitted electronically to the AER.
- The outcome of a RIT-T is required to be published on our public website and we will include it with our contingent project application (and which will include the information specified in NT NER clause 6.6A.2(b)).
- If the triggers occur, the project would be necessary to achieve the capital expenditure objectives. As discussed above, section 5.3 of the DKESP shows that the project would yield a market benefit.
- If the triggers occur, the transmission costs will relate to a specific location on our Darwin-Katherine transmission network. Section 3.1 of the DKESP notes that the Hub would be located south of Darwin near the existing Channel Island to Hudson Creek 132 kV line.
- The triggers above are sufficient to confirm the need, timing, scope and cost of the required project and no other conditions or events are required.
- The occurrence of a trigger event is probable during the 2024-29 regulatory control period for two reasons:
  - Firstly, the NT Government has a clear target of achieving 50 per cent renewable energy by 2030 consistent with other jurisdictions in Australia. The renewable energy hub is a clear policy intent as evidenced in section 3.1 of the DKESP and subsequent studies undertaken by the NT Government. In the absence of a renewable energy hub, the 50 per cent target would most likely not be met. This is because small scale solar is unlikely to provide sufficient generation production, and decentralised generation will most likely be heavily curtailed due to system strength issues.
  - Secondly, there is evidence to show that shared transmission works are required to transport renewable energy from the hub as seen in section 3.1 of the Darwin-Katherine Electricity System Plan [redacted].
- We consider the costs will be sufficiently certain if the trigger occurs. This is because the RIT-T will identify the preferred option and will provide a detailed scope and cost estimate.

13.3 Unlocking existing large scale renewable generation in Darwin-Katherine

The project need is to efficiently relieve constraints on our transmission network in Darwin-Katherine that limits the conveyance of renewable generation to our customers from existing and committed large-scale solar projects.

The estimated cost has been based on the estimated cost purchasing and installing a synchronous condenser to provide system strength and possibly system inertia, with associated substation works at a cost estimate of $30 million (real 2022), which when escalated is $45.7 million (real 2024 including overheads). The timing of project is estimated in the early part of the 2024-29 regulatory period, by the end of 2026/27.

We note that other options may become apparent in undertaking the RIT-T, including procuring the services of 'high specification' security Battery Energy Storage Systems (BESS) to relieve constraints. Security batteries are expected to be installed by generators between 2023 and 2030.

13.3.1 Background

The Darwin-Katherine transmission line currently limits the amount of renewable generation that can be dispatched into Darwin from large scale renewable generation due to system security constraints. In the absence of any other remedy, this constraint will persist unless demand grows near the location of the solar farms.

A further complication is current uncertainties regarding:

- The retirement of and (partial) replacement of synchronous generators.
- The rate of decline of system minimum load.
- The contribution over time of loads on the Darwin-Katherine system to fault level/system strength.
- The location and characteristics of new, currently uncommitted large-scale renewable generation.
- The effectiveness of the proposed high specification BESS in providing inertia and system strength.

Collectively these uncertainties mean that it is difficult to identify the optimal solution (technology, scale, timing, and cost) to address current and potential Darwin-Katherine system constraints.

A recent study undertaken for the Darwin-Katherine Electricity System Plan includes analysis to show that potential options to increase the dispatch of renewable generation include applying dynamic line ratings, procuring services from new grid scale batteries, and partially duplicating the Darwin-Katherine transmission line. The Darwin-Katherine Electricity System Plan notes that three 35 MW high specification BESSs are likely to be required by 2030 on the basis that applying one or more BESS to relieve constraints on the DKTL would provide a net benefit to customers. This is because renewable generation is significantly lower cost than the thermal generation that it would displace. Each high specification BESS is likely to cost well over $15 million.

A more recent study for the NT Government's Department of Industry Tourism and Trade suggests that a synchronous condenser(s) may be required to provide reactive power, system strength, and possibly inertia. The cost of a synchronous condenser (or two smaller synchronous condensers) is very likely to be well above the $15 million threshold, plus the cost of transmission substation works.

13.3.2 Triggers

We have identified two triggers for the project:

1. A formal notification from a NT Government Minister to Power and Water Corporation, advising that the Government wishes to accommodate more renewable energy in an area that requires transport of generation on the Darwin-Katherine transmission line and advising the approximate required additional capacity and location of that generation.
2. The completion of a RIT-T by Power and Water that:
   - Identifies a need to relieve transmission constraints on the Darwin-Katherine transmission line within the next regulatory period.
   - Identifies a preferred option consistent with the RIT-T guidelines that maximises the net economic benefit to all those who produce, consume and transport electricity in the NT.
   - Determines that the preferred option has a positive net economic benefit and/or is otherwise consistent with the National Electricity Objective at that time.

13.3.3 Evidence to support contingent project inclusion

The project meets the initial hurdles for acceptance as a contingent project. The project does not relate to a restricted asset. We have also undertaken initial analysis to suggest that a positive net benefit is likely, despite the cost to remove the constraint, which is very likely to be higher than $15 million.

We also consider the project reasonably reflects the capex objectives, criteria and factors in the NT NER. The project allows for more renewable generation to be reliably dispatched to customers, providing for lower generation cost.

We consider that our identified triggers are appropriate:

- The triggers are specific and capable of objective verification. The formal direction by the NT Government would be in a form that can be transmitted electronically to the AER. The outcome of a RIT-T is required to be published on our public website and we will include it with our contingent project application (and which will include the information specified in NT NER clause 6.6A.2(b)).
- If the triggers occur, the project would be reasonably necessary to achieve the capital expenditure objectives. Section 3.2 of the Darwin-Katherine Electricity System Plan provides evidence to show that dispatching the full amount of existing renewable generation on the Darwin-Katherine transmission line would result in security and reliability issues, and that this necessitates constraints on the transmission line. There is evidence in section 3.2 of the Darwin-Katherine Electricity System Plan that there is a net benefit to customers from relieving the constraint.
- If the triggers occur, the transmission costs will relate to a specific location on our Darwin-Katherine transmission network. Section 3.2 of the Darwin-Katherine Electricity System Plan notes that the current constraint is on the Darwin-Katherine transmission line that conveys renewable electricity to customers in the Darwin-Katherine distribution network.
- The triggers above are sufficient to confirm the need, timing, scope and cost of the required project and no other conditions or events are required.
- The occurrence of a trigger event is probable during the 2024-29 regulatory control period for two reasons:
  - Firstly, the NT Government has a clear target of achieving 50 per cent renewable energy by 2030, consistent with other jurisdictions in Australia. Relieving constraints on the Darwin-Katherine transmission line would assist with enabling the target to be met, and it is likely that the Government will take steps to ensure that energy market participants actively look for solutions.
  - Secondly, we consider Power and Water would be the likely participant that the Government would direct. This is because the constraint relates to our transmission network.
- We consider the costs will be sufficiently certain if the trigger occurs. This is because the RIT-T will identify the preferred option and will provide a detailed scope and cost estimate.

13.4 Holtze-Kowandi land development

The project need is to build distribution network infrastructure to meet demand for electricity from customers associated with a land development project committed by the NT Government in Darwin. We consider it probable that the Government will proceed with stages 1 to 3 of the announced land development in the 2024-29 period. If the Stage 3 development occurs, it will lead to material constraints in meeting the demand of customers, and the likely preferred solution would be the construction of a new zone substation.

The estimated cost of the capacity upgrade for the Holtze-Kowandi land development is based on the historical cost of establishing a new greenfields substation (Berrimah) of $40 million (real 2022) plus provision for a new transmission line and line entry to the new substation from Palmerston. The estimated cost when escalated is $60.8 million (real 2024 including overheads). The timing of project is estimated in the early part of the 2024-29 regulatory period, by the end of 2026/27.

13.4.1 Background

The Holtze Kowandi area comprises the districts of Holtze, Kowandi, Holtze North and Howard Springs North. As set out in the Northern Territory Planning Commission Greater Holtze Area Plan, many precincts in the area are scheduled to be developed in stages through to 2050.

13.4.2 Triggers

We have identified three triggers for the project:

1. An executed Connection Application and an approved HV Master Plan for Stage 3 of the land development in the Greater Holtze Area.
2. A Power and Water planning study demonstrating a likely material constraint in meeting the expected demand arising from Stage 3 of the land development.
3. The completion of a RIT-D by Power and Water that meets the following:
   - Identifies a need to undertake augmentation distribution works in the next regulatory period to meet demand for standard control services arising from Stage 3 land release in the Greater Holtze Area.
   - Identifies the preferred option consistent with the RIT-D guidelines that maximises the net economic benefit to all those who produce, consume and transport electricity.

13.4.3 Evidence to support contingent project inclusion

The project meets the initial hurdles for acceptance as a contingent project. The project does not relate to a restricted asset. Initial analysis suggests that the constraint arising from Stage 3 of the land release would be material and require the construction of a new zone substation. The cost of a new zone substation would be well above the $15 million threshold based on recent evidence from the estimated costs of building a greenfield zone substation in Berrimah.

We also consider the project reasonably reflects the capex objectives, criteria and factors in the NT NER. The project is demand-driven augex based on an identified need to meet higher peak demand on our network in an area which does not have the capacity to meet that demand. Similar to other demand driven projects we would identify the option that minimises the costs including analysis of demand management options.

We consider that our identified triggers are appropriate:

- The triggers are specific and capable of objective verification. The formal notification by the NT Government would be in a form that can be transmitted electronically to the AER. The planning study would similarly be made available to the AER. The outcome of a successful RIT-D is required to be published on our public website and we will include it with our contingent project application (and which will include the information specified in NT NER clause 6.6A.2(b)).
- If the triggers occur, the project would be reasonably necessary to achieve the capital expenditure objectives. As noted above, we have undertaken initial analysis to suggest that the expected load from Stage 3 of the land release would lead to material constraints to meet or manage the expected demand of new customers in the area.
- If the triggers occur, the distribution costs will relate to Greater Holtze Area in Darwin.
- The triggers above are sufficient to confirm the need, timing, scope and cost of the required project and no other conditions or events are required.
- The occurrence of a trigger event is probable during the 2024-29 regulatory control period for two reasons:
  - Firstly, the NT Government has committed budget to action the announcements of land releases in the Greater Holtze Area and this indicates that Stage 3 is likely to proceed in the 2024-29 area.
  - Secondly, our initial planning studies suggest that the forecast demand in Stage 3 would lead to material constraints on our distribution network that could not be managed unless we invest in a new zone substation.
- We consider the costs will be sufficiently certain if the trigger occurs. This is because the RIT-D will identify the preferred option and will provide a detailed scope and cost estimate.

13.5 Middle Arm commercial development

The project need is to build distribution network infrastructure to meet demand for electricity from new industrial and commercial customers that are expected to locate in the Middle Arm peninsula in Darwin.

We consider it probable that many new customers will seek connection to our distribution network in the area in the 2024-29 period, and that the aggregate demand will exceed the existing capacity of our infrastructure in the area. The magnitude of demand in the area would most likely lead to a preferred option of building a new zone substation or installation of higher capacity transformers.

The estimated cost of the capacity upgrade for Weddell is based on the historical cost of establishing a new greenfields substation (Berrimah) of $45.0 million (real 2022) plus provision for a new transmission line and line entry to the new substation and higher capacity substation rating. The estimated cost when escalated is $69.1 million (real 2024 including overheads). The timing of project is estimated in the early part of the 2024-29 regulatory period, by the end of 2028/29.

13.5.1 Background

The Middle Arm Peninsula is located near Palmerston in Darwin. The location already contains heavy industrial developments and is considered by the NT Government to be an area of strategic development due to its access to Darwin Harbour, railway and road infrastructure. The Kittyhawk estate is a key element of the planned expansion in the area.

Currently, the Weddell zone substation supplies nearby commercial load and one rural feeder. The substation will also supply the Kittyhawk Estate. The actual maximum demand on the substation in 2020-21 was 4.9 MVA. At the end of the upcoming determination period in 2029, the load on the substation is currently forecast to be in a range between 11.8 MVA and 14.4 MVA.

If the actual maximum demand exceeds 15 MVA, the Weddell zone substation in its current configuration will not meet the requirements of the Network Planning Criteria. Supply is required to be restored within 30 minutes in the case of a first contingency outage where there is more than one asset normally supplying the load. Since the travel time to Weddell substation would normally be at least 30 minutes, it is not reasonable to expect supply to be restored by manual switching within the 30 minutes target in the current arrangement. If the load is less than 15 MVA then class of supply G applies, in this case area demand is required to be supplied within three hours. This could reasonably be expected to be achieved in the current arrangement with no capital expenditure required.

The NT Government recently indicated that a load of approximately 25 MVA is expected in the Kittyhawk Estate. While the timing is uncertain, there is a reasonable probability that the load will connect in the 2024-29 regulatory period.

We have undertaken planning studies to identify the options if committed connections exceed 15 MVA. This includes replacing the existing zone substation with a greenfield (new) zone substation, replacing two transformers in the current zone substation with higher capacity transformers, installing an additional circuit breaker to improve the firm rating of the current zone substation, increase transformer rating, and remote control switching of the zone substation to improve restoration times.

While the preferred option is not certain, it is probable that replacing Weddell zone substation with a greenfield equivalent would be the preferred option given the expectation of significant growth in the area, and the need to replace existing infrastructure at the current zone substation.

13.5.2 Triggers

We have identified two triggers for the project:

1. Committed customer connections in the Middle Arm Peninsula in Darwin that, in aggregate, exceeds the existing capacity (15 MVA) of the Weddell zone substation.
2. The completion of a regulatory investment test for distribution by Power and Water that meets the following:
   - Identifies a need to undertake augmentation distribution works to meet demand for standard control services arising from new customer connections in the Middle Arm Peninsula.
   - Identifies the preferred option consistent with the RIT-D guidelines that maximise the net economic benefit to all those who produce, consume and transport electricity.

13.5.3 Evidence to support contingent project inclusion

The project meets the initial hurdles for acceptance as a contingent project. The project does not relate to a restricted asset. Initial analysis suggests that it is probable that committed customers will connect in the 2024-29 period and that the aggregate level of demand will significantly exceed the current capacity of Weddell zone substation. Our initial analysis suggests that the replacement of the existing zone substation is likely to be the preferred option. A new zone substation would be well above the $15 million threshold based on recent evidence on the estimated costs of building a greenfield zone substation in Berrimah.

We also consider the project reasonably reflects the capex objectives, criteria and factors in the NT NER. The project is demand-driven augex based on an identified need to meet higher peak demand on our network in an area which does not have the capacity to meet that demand. Similar to other demand driven projects we would identify the option that minimises the costs including analysis of demand management options.

We consider that our identified triggers are appropriate:

- The triggers are specific and capable of objective verification. Committed connections information could be supplied to the AER on a confidential basis including the forecast load and timing. The outcome of a RIT-D is required to be published on our public website and we will include it with our contingent project application (and which will include the information specified in NT NER clause 6.6A.2(b)).
- If the triggers occur, the project would be reasonably necessary to achieve the capital expenditure objectives. As noted above, we have undertaken initial analysis to suggest that the expected load from likely committed connections would lead to material constraints to meet or manage the expected demand of new commercial customers in the area.
- If the triggers occur, the distribution costs will relate to the Middle Arm Peninsula.
- The triggers above are sufficient to confirm the need, timing, scope and cost of the required project and no other conditions or events are required.
- The occurrence of a trigger event is probable during the 2024-29 regulatory control period. Committed connections are forecast to utilise the spare capacity at Weddell zone substation, meaning that the project would be triggered even for a relatively small increase in demand from new connections. The material provided by the NTG of potential large connections and the strategic importance placed on the project means there is a high probability of committed connections in the 2024-29 period. The size of potential connections also makes it probable that we would need to invest in a new zone substation.
- We consider the costs will be sufficiently certain if the trigger occurs. This is because the RIT-D will identify the preferred option and will provide a detailed scope and cost estimate.

13.6 Wishart commercial development

This contingent project relates to construction of a new Wishart zone substation in place of the existing temporary Wishart 'Nomad' modular substation, although we note that other options may become apparent in undertaking the RIT-T. The increase in supply capacity to the Wishart supply area will be required if currently large uncommitted projects in the area develop as proposed.

The estimated cost of the new substation is based on the historical cost of establishing a new greenfields substation (Berrimah) of $30 million (real 2022) and which when escalated is $45.6 million (real 2024 including overheads).

The developer of the two development precincts, one in East Arm and one in Wishart is the Land Development Commission (LDC), a NT Government Business Division that works with government departments and the private sector to develop projects. The timing of the commencement and rate of demand growth in both precincts is uncertain, but we anticipate that it is probable that we would need to build the new substation in the early part of the 2024-29 regulatory period, by the end of 2026/27.

13.6.1 Background

Berrimah zone substation (ZSS), Palmerston ZSS and Wishart modular substation (MSS) provide supply to the 11 kV network. There is currently limited interconnection capacity between Wishart MSS and Palmerston ZSS primarily due to the limitations of 11 kV feeders.[28] Berrimah and Wishart distribution feeders have a degree of interconnection that enables the transfer of load between the two substations in the event of a contingency event (such as a transformer outage) at either substation.

Berrimah ZSS is currently being rebuilt due to major components at the existing ZSS reaching end-of-life. The new Berrimah substation is scheduled to be completed in 2023 and will be located adjacent to the current substation with essentially the same configuration of 2 x 66/11 38 MVA transformers and the same DTC to contiguous substations, including 3.3 MVA to Wishart MSS.

Wishart MSS is located adjacent to Hudson Creek Terminal Station and is currently supplied at 66 kV from Archer ZSS. Wishart MSS comprises a 10 MVA 'NOMAD' mobile substation which was installed in 2015 as a temporary measure to supply forecast increasing load in the area, deferring the need to either commission a permanent Wishart ZSS or to add a third transformer at Berrimah substation.

The firm capacity of Wishart MSS will increase from 3.3 MVA to 10.7 MVA in FY2024 by increasing the DTC to contiguous substations.

The 'Central' demand forecast for Wishart MSS includes two new committed developments:

- [redacted]
- [redacted]

With the 10.7 MVA firm capacity of the Wishart MSS, the central demand forecast is expected to be able to be supplied in accordance with the requirements of the planning criteria at least 2028/29 (i.e. the end of the next regulatory period). Accordingly, no expenditure is included in the 2024-29 capex proposal for augmentation of the supply capacity of Wishart MSS.

28 Voltage regulation issues limit the supply capacity of 11 kV feeders

Over five years ago, based on testimony from LDC and associated developers, Power and Water expected the Truck Central and subsequent stages of the Wishart development to be well advanced by now. However, development growth only started picking up slightly in 2022. Similarly, proposed developments in East Arm [redacted] have been very slow to come to fruition, despite developers' expectations.

Notwithstanding the effects of the pandemic, Power and Water considers it prudent to wait until firm commitments to the identified developments have been made *and* discernible load growth is occurring before committing to further major network augmentation in the area.

After several years of flat maximum demand, two currently uncommitted 'spot' or 'block' loads from developments in the Wishart supply area would, if they proceed as proposed, result in the Wishart MSS firm capacity being significantly exceeded:

- [redacted]
- [redacted]

With these two loads, the High demand forecast is 32.6 MVA by 2028/29, which is well in excess of the firm capacity of 10.7 MVA. Even under normal operating conditions, the demand would greatly exceed the supply capacity, requiring load shedding.

Based on advice from the LDC, applications for connection are expected to be submitted to Power and Water for both developments within the next 12 months. [redacted]

The following options have been considered if the Wishart Estate data centre proceeds as planned:

1. New Wishart Zone Substation with two step down transformers.
2. New Wishart Zone Substation with one step down substation.

[redacted] does not proceed in the next RCP, at least the following three options would be considered:

1. New diesel generation at Wishart MSS.
2. New BESS at MSS.
3. Purchase of a second Wishart NOMAD modular substation.

At this stage, the preferred option is likely to be to construct a new Wishart ZSS, replacing the Wishart MSS, in the next regulatory period. It would deliver approximately 41 MVA firm capacity which would suffice until at least 2028/29, beyond which a third transformer might be required.

13.6.2 Triggers

The proposed triggers are:

1. One or both of the following spot loads from developments in the Wishart supply area are classified as committed loads:
   - [redacted]
   - [redacted]
2. Total actual plus committed peak demand at Wishart MSS is likely to be more than 15 MVA within the next regulatory control period.
3. The completion of a RIT-D by Power and Water that:
   - Identifies a need to undertake augmentation distribution works to meet demand for standard control services arising from new developments in the Wishart supply area.
   - Identifies the preferred option consistent with the RIT-D guidelines that maximise the net economic benefit to all those who produce, consume and transport electricity.

13.6.3 Evidence to support contingent project inclusion

Power and Water prepares spatial demand forecasts for individual network elements including our distribution feeders, zone substations and transmission lines. The underlying trend is based on the last six years of historical data, with significant new connections added. Prospective new connections are considered as committed and are included in the Central forecast if they satisfy the following criteria:

- Executed HV connection agreement, including the HV head works.
- Approved HV Master Plan.[29]

The Central forecast of 10.7 MVA by 2028/29 includes the existing demand plus the [redacted]. The 'Low' forecast of 4.6 MVA by 2028/29 excludes any new significant connections. The 'High' demand forecast of 32.6 MVA by 2028/29 builds on the Central forecast by adding the non-committed loads. [redacted]

The cost estimate for the establishment of a greenfields Wishart Zone Substation, comprising of 2 x 27/30 MVA transformers, is based on the cost estimate for the recent establishment of the greenfields Berrimah Zone substation.

[29] Power and Water requires evidence from developers that the agreed timelines and other requirements are progressing to plan (e.g. evidence of works in progress); otherwise developers are required to submit an updated HV Master Plan (e.g. updated staging timeframes, updated estimated maximum demands, change in subdivision layouts) for re-approval.

We consider that our identified triggers are appropriate:

- The triggers are specific and capable of objective verification. The artifacts confirming the criteria for a 'committed load' have been satisfied would be in a form that can be transmitted electronically to the AER. The outcome of a RIT-D is required to be published on our public website and we will include it with our contingent project application (and which will include the information specified in NT NER clause 6.6A.2(b)).
- If the triggers occur, the project would be reasonably necessary to achieve the capital expenditure objectives. As noted above, we have undertaken initial analysis to suggest that the expected load from the identified new developments would lead to material constraints to meet or manage the expected demand of new customers in the area.
- If the triggers occur, the distribution costs will relate to the Wishart supply area in Darwin.
- The triggers identified above are sufficient to confirm the need, timing, scope and cost of the required project and no other conditions or events are required.
- The occurrence of a trigger event is probable during the 2024-29 regulatory control period for two reasons:
  - Firstly, the LDC has indicated that it intends to formally apply for connections for both the [redacted] in the near future.
  - Secondly, our initial planning studies suggest that, if these developments proceed, the forecast demand would lead to material constraints on our distribution network that could not be managed unless we invest in a new zone substation.
- We consider the costs will be sufficiently certain if the trigger occurs. This is because the RIT-D will identify the preferred option and will provide a detailed scope and cost estimate.

Contact

Australia: 1800 245 092
Overseas: +61 8 8923 4681
powerwater.com.au

PowerWater