Transmission and Distribution Annual Planning Report 2024

About this report

The 2024 Transmission and Distribution Annual Planning Report (TDAPR) provides information to our stakeholders on Power and Water Corporation's plans for its electricity networks in Darwin-Katherine, Alice Springs and Tennant Creek.

The report provides stakeholders with information on our network performance, demand forecasts, system limitations and proposed projects.

Detailed information on asset numbers, voltage regulation, system limitations and contingency scenarios have been published as a separate Appendix to this report.

Contents

Acknowledgment of Country

Power and Water acknowledges the Traditional Owners of the land we live, work and operate on and their connections to land, sea and community. We pay our respects to Elders past, present and future.

Message from the Chief Executive Officer

I am pleased to present the 2024 Power and Water Transmission and Distribution Annual Planning Report (TDAPR).

The TDAPR is an integral part of our **communications to stakeholders** on our current service performance, new initiatives we have in place and any changes to our 10 year programs of works. We are pleased that many of our stakeholders use our report as a reference document.

In April 2024, the Australian Energy Regulator approved our plans for the 2024-29 regulatory period following extensive engagement with and input from customers and stakeholders.

This year's TDAPR zones in on **key strategic focus areas** for our electricity network business.

Chapter 3 of the TDAPR demonstrates how we are actively enabling renewables in our regulated regions. Like everything in the Northern Territory, our **transition to renewables is a unique story** with its own drivers and challenges.

We have **abundant sunshine** that can produce high levels of renewable solar energy in the day. However, unlike other states, we do not have ready access to wind that can help deliver renewable energy at night. We also have other **unique challenges** including smaller power systems that place security limits on how much solar we can deliver through our networks.

We are **actively implementing efficient solutions** to enable maximum delivery of solar from our customers' rooftops and large-scale solar farms.

This includes developing an exciting technology that can ramp down solar for moments when the network security is at risk, but which enables maximum export at other times. We have also **lowered network prices** in the middle of the day to incentivise customers to make use of plentiful solar and to help reduce demand for energy in the peak evening period.

We also describe our role in **modernising our network** to enable large-scale solar. We have already **connected about 70 MW** of large-scale solar to our network, and are looking at efficient ways to increase the dispatch potential of these units.

We are also working with other Northern Territory bodies in **facilitating a proposed Renewable Energy Hub** close to Darwin.

We are also working **ahead of the curve** in trialling new technologies that can unlock renewable energy. We're working with the Australian Renewable Energy Agency to install **16 community batteries**. We are developing standards that will enable **electric vehicles to discharge power back into the grid.** This means cars that charge during the day using abundant solar energy will one day be used to power homes at night.

Chapter 4 of this year's TDAPR also highlights an innovative new approach to **long-term planning** in our regions. The first iteration of the **Alice Springs Network Strategy** was developed in 2024. It sets out a **25 year long-term plan** to optimally develop the Alice Springs network with consideration to major changes occurring in the power system.

We hope you enjoy perusing this year's TDAPR, and we welcome any feedback on changes or information that you require.

Djuna Pollard
Chief Executive Officer

1. Summary

In this year's report we focus on the activities we are undertaking to enable renewables in the Northern Territory. We also highlight our new approach to developing long-term network strategies and provide findings from our first iteration for the Alice Springs network. Consistent with previous reports, we provide an overview of our network and performance, our asset management practices and demand forecasts, together with a description of our work programs to address constraints over the 10 year planning outlook.

This summary is designed for stakeholders who want a quick understanding of our future plans.

1.1 Our network and performance (Part A)

Power and Water is a multi-utility that provides essential electricity, electricity, water, sewerage and gas services to customers in urban and remote areas in the Northern Territory. Our purpose is to make a difference to the lives of Territorians.

Our regulated electricity network comprises 3 stand-alone networks – Darwin-Katherine, Alice Springs and Tennant Creek. We provide transmission and distribution services to about 73,000 residential customers and 11,400 non-residential customers. **Figure 1** depicts our 3 regulated networks in the Northern Territory and key data.

Our unique characteristics impact on our planning methods and costs to serve. We have the smallest numbers of customers of all regulated networks in Australia, which creates diseconomies of scale. We also operate in extreme climate including cyclones and adverse humidity in the Top End.

Chapter 2 of the TDAPR provides more details on our regulated networks.

Over the last decade, improvements on the network have improved the reliability of services provided to customers. In 2023-24, the average annual outage time experienced by our customers was 29 minutes. The number of outages experienced by each customer each year was 1.8 interruptions.

The weather heavily influences annual statistics. Our performance over the last 5 years continues to be significantly better than historical averages. **Figure 2** and **Figure 3** compares our 5 year performance to annual reliability performance since 2006 for both duration and number of interruptions.

Reliability performance varies considerably across our customer base with outage length and frequency much higher for customers in rural areas of the regulated networks. We are striving to improve the performance for customers in the worst affected areas while balancing our costs.

Chapter 2 of this report outlines our 2023-24 performance in more detail, including specific programs to improve reliability performance by network region. We also identify our performance on other measures such as keeping within voltage limits.

Power and Water is a multi-utility that provides essential electricity, water and sewerage, and gas services to customers in urban and remote areas in the Northern Territory. Our purpose is to make a difference to the lives of Territorians.

Figure 1 – Snapshot of Power and Water's electricity network

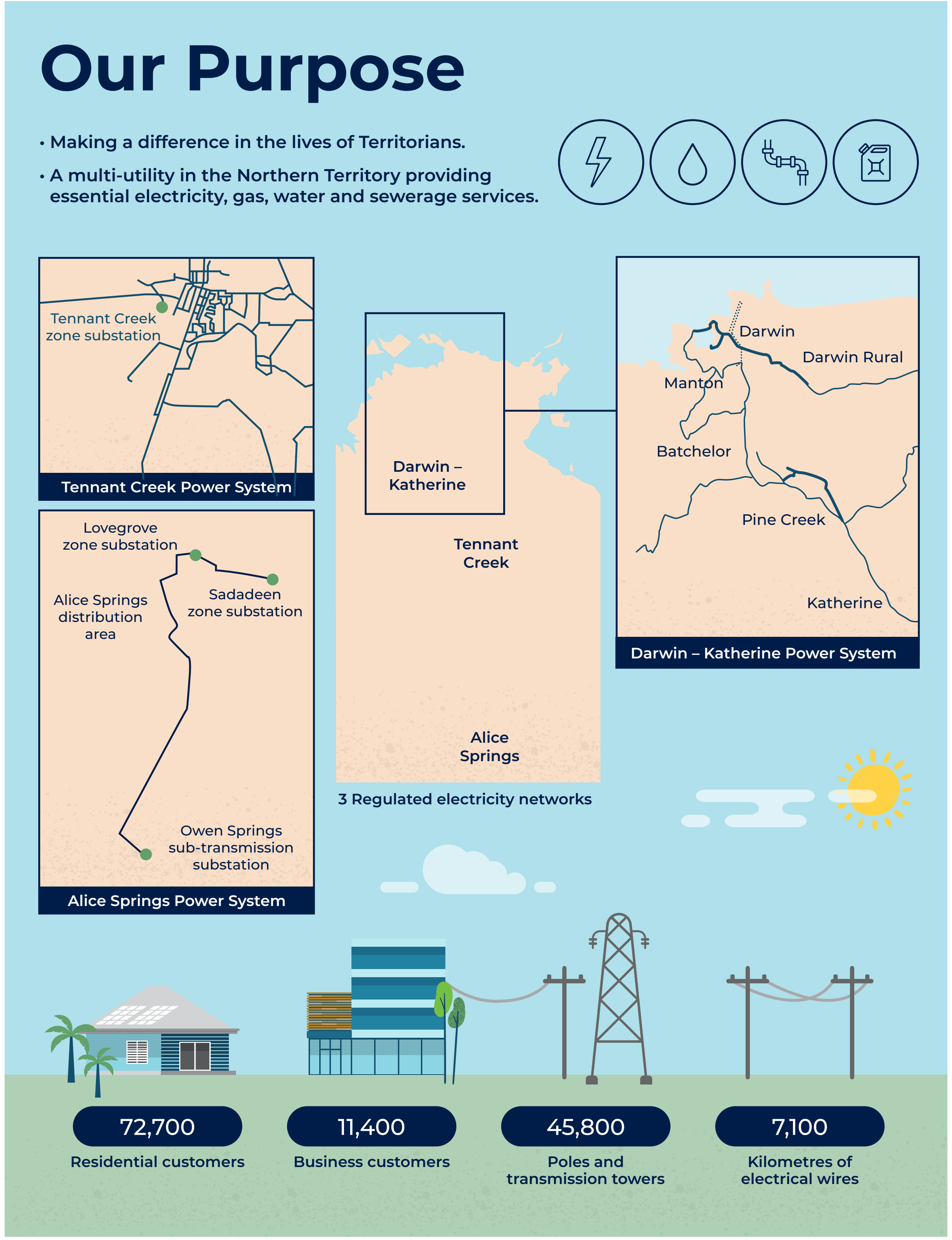


Figure 2 – Average duration of interruption per customer

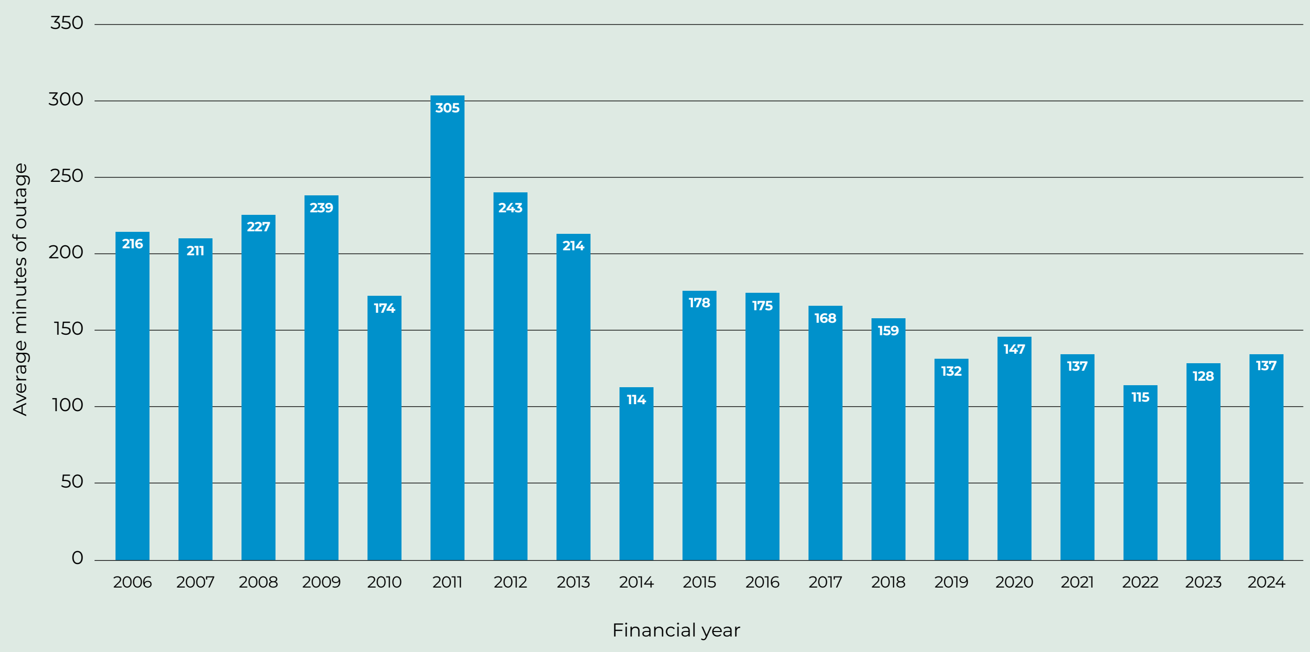
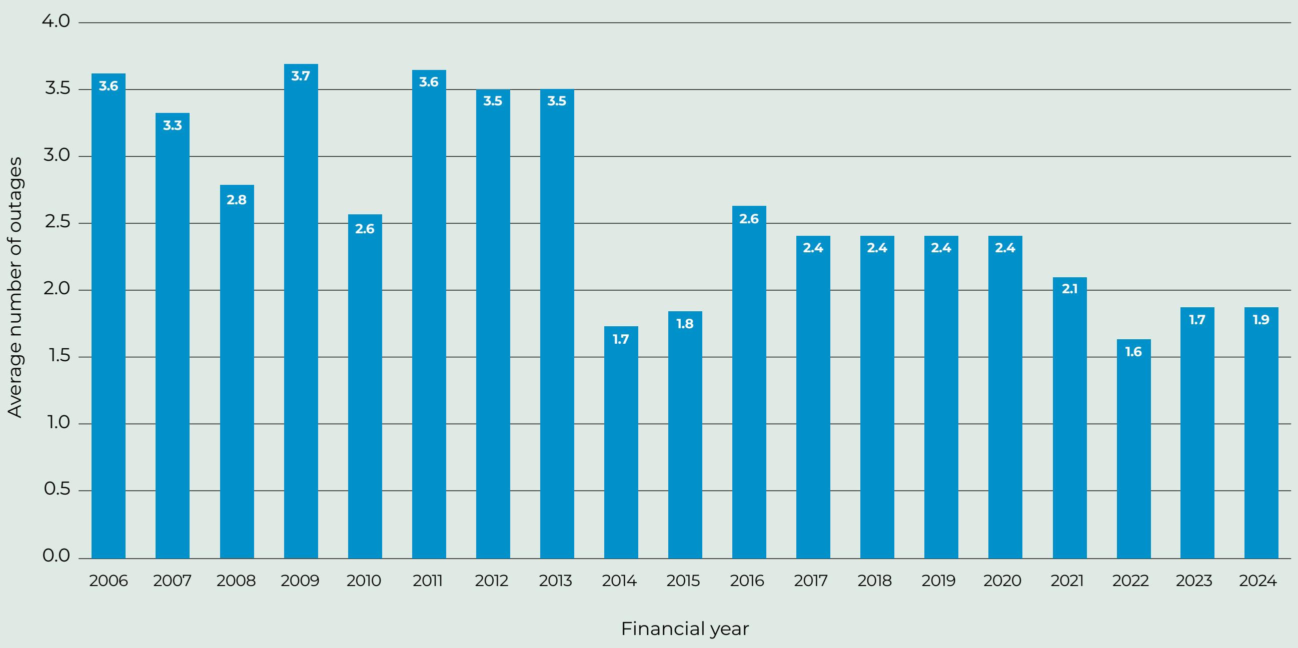


Figure 3 – Number of interruptions per customer



1.2 Strategic Focus Areas (Part B)

In the TDAPR 2024, we have provided stakeholders with more information about 2 strategic focus areas for our regulated network business.

Actively enabling renewables for Territorians

In 2024, we published the Future Network Strategy, which describes an overarching framework to actively facilitate renewable energy for our customers.

The Future Network Strategy identifies efficient initiatives to enable our network to securely transport growing solar resources in the Northern Territory. The TDAPR provides an update on our implementation of the initiatives:

- **Maximise small-scale solar** – Rooftop solar can deliver about 50% of electricity demand in the middle of the day in the dry season in Darwin and spring in Alice Springs. However, this level of small-scale solar can create challenges for network security. We are progressing with our plans for a modern technology solution that can ramp down solar production at times when network security is at risk. This allows for maximum export of solar at all other times without static limits or limiting connections.
- **Modernise our network to integrate large-scale renewables** – Despite the security challenges involved, we have already connected about 70 MW of potential large-scale generation to our network. We are currently investigating efficient options to increase the dispatch potential of these generators. In addition, we are working with other Northern Territory bodies on activating a proposed Renewable Energy Hub.
- **Ahead of the curve in trials** – We're working with the Australian Renewable Energy Agency to install 16 community batteries. A community battery connects to rooftop solar, enabling us to capture energy in the day and discharge at peak evening times. We are also working on standards that will enable EVs to discharge power back into the grid. This means cars that charge during the day using abundant solar energy can be used to power homes at night.

Chapter 4 provides more details on our implementation plans.

Alice Springs Network Strategy

Power and Water is committed to developing long-term strategic plans for each of our regions. This year we developed the first iteration of the 2025-2050 Network Strategy for Alice Springs. The purpose was to identify an efficient long-term path to reconfigure and expand the network to meet future drivers of investment.

Alice Springs is located about 1,500 km south of Darwin and has a unique geography. The town is divided by the MacDonnell Ranges with our network running through 'The Gap'. North of The Gap is an 11 kV network servicing the CBD, while south of The Gap has less demand but significant land for new developments.

The Alice Springs power system is likely to face accelerated change in the medium to long-term. The key factors impacting the development of the network include:

- likely deterioration in condition of major assets on the backbone of the network including transformers and switchboards
- potential for significantly higher demand for electricity as more customers connect electric vehicles and from new residential and commercial developments south of The Gap
- the need to integrate increasing levels of small-scale renewable electricity in Alice Springs, with the prospect of large-scale renewable energy zones in the medium-term.

Our network strategy sought to identify the optimal pathway for developing the network to 2050. This includes changes to the voltage and substation configuration as we progressively replace ageing infrastructure and meet higher levels of demand. The preferred pathway is to build a new substation south of The Gap at Norris Bell under scenarios where there is high demand growth from EV uptake and increased residential and commercial developments.

Chapter 5 provides more details on the Alice Springs Network Strategy.

In 2024, we published the Future Network Strategy, which described an overarching framework to actively facilitate renewable energy for our customers.

1.3 Planning the network (Part C)

Power and Water has a strategic asset management system that reflects a 'whole of lifecycle' approach to efficiently manage our assets.

As part of the framework, we undertake regular planning reviews to identify emerging system limitations and solutions. A key focus of our planning is identifying lower cost non-network solutions to address limitations.

Asset management improvements

We have evolved our asset management capabilities including:

- improving our risk quantification methods, which have enabled more targeted investment programs
- evolving our strategic capabilities including a Future Network Strategy and are progressing the development of regional network strategies
- developing online monitoring techniques to improve asset reliability and maintenance efficiencies.

Further information on our asset management approach and methods are at Chapter 6.

Demand forecasts

Demand forecasts are an important input to identifying emerging capacity constraints on our network.

We forecast peak demand for electricity at both a system level (system demand forecast) for Darwin-Katherine, Alice Springs and Tennant Creek, and at a locational (spatial) level for zone substations and distribution feeders.

We have implemented material improvements to our forecast methodology over the last 2 years:

- Using 'feels like' temperature metrics that take into account humidity as well as temperature.
- Separately assessing demand correlations on weekdays in non-holiday periods to provide greater precision in our demand forecasts.
- Using longer term trends for historical data.

These demand forecasts directly inform our investment requirements.

Further information on our demand forecasts are at Chapter 7.

1.4 Ten year outlook (Part D)

We have identified key projects and costings over the 10-year planning outlook (2024-25 to 2033-34) for both our transmission and distribution networks.

Below, we summarise our forecast of key constraints on the network that give rise to replacement and augmentation projects.

We also identify major projects over $15 million, including uncertain projects that we identify as 'contingent' upon the occurrence of a trigger event.

Replacement capex to address asset condition

Replacing our ageing network assets will be the primary driver of capital expenditure over the next decade. A large cohort of our network assets will be more than 50 years old by 2025.

Asset management planning is directed at keeping these assets in service through targeted maintenance and robust risk management. Our targeted programs will replace assets that pose material reliability, safety or environmental risk. We have also applied age-based modelling to forecast the volume of assets likely to fail in service.

The 3 major replacement projects or programs over $15 million include:

- **Berrimah zone substation ($40.7 million)** – We are replacing the current substation due to multiple condition issues. The project is already underway and is due to be completed by the end of 2027. We note that the forecast costs for this project have risen markedly since last year's TDAPR, consistent with market conditions.
- **Darwin high voltage cables ($72.3 million)** – We are replacing a portion of cables in the northern suburbs of Darwin due to insulation and sheath issues from water ingress. This program has already commenced and will continue over the 10-year planning period.
- **Alice Springs corroded poles ($19.6 million)** – We are refurbishing poles that are corroded and may lead to safety issues. The program is underway and will continue over the 10-year planning period.

Augmentation capex to address capacity limitations

Augmentation capex is forecast to be well below past levels of capex. While we forecast strong demand growth in our 3 regions over the next decade, our analysis suggests that no major projects will be required.

The minor planned augmentation programs include managing overloaded 11 kV feeders, maintaining reliability for worst performing feeders and managing voltage issues.

We have also identified a series of 'contingent projects' that are material projects, highly probable of proceeding in the 10-year planning horizon, however uncertain in terms of timing, scope and costs.

These include 3 projects related to integrating large-scale renewable energy into the network, There are a further 3 projects related to new land and commercial developments.

We will keep stakeholders informed of these developments in future TDAPRs. We will undertake consultations with our stakeholders as part of the Regulatory Investment Test process required under the Northern Territory National Electricity Rules.

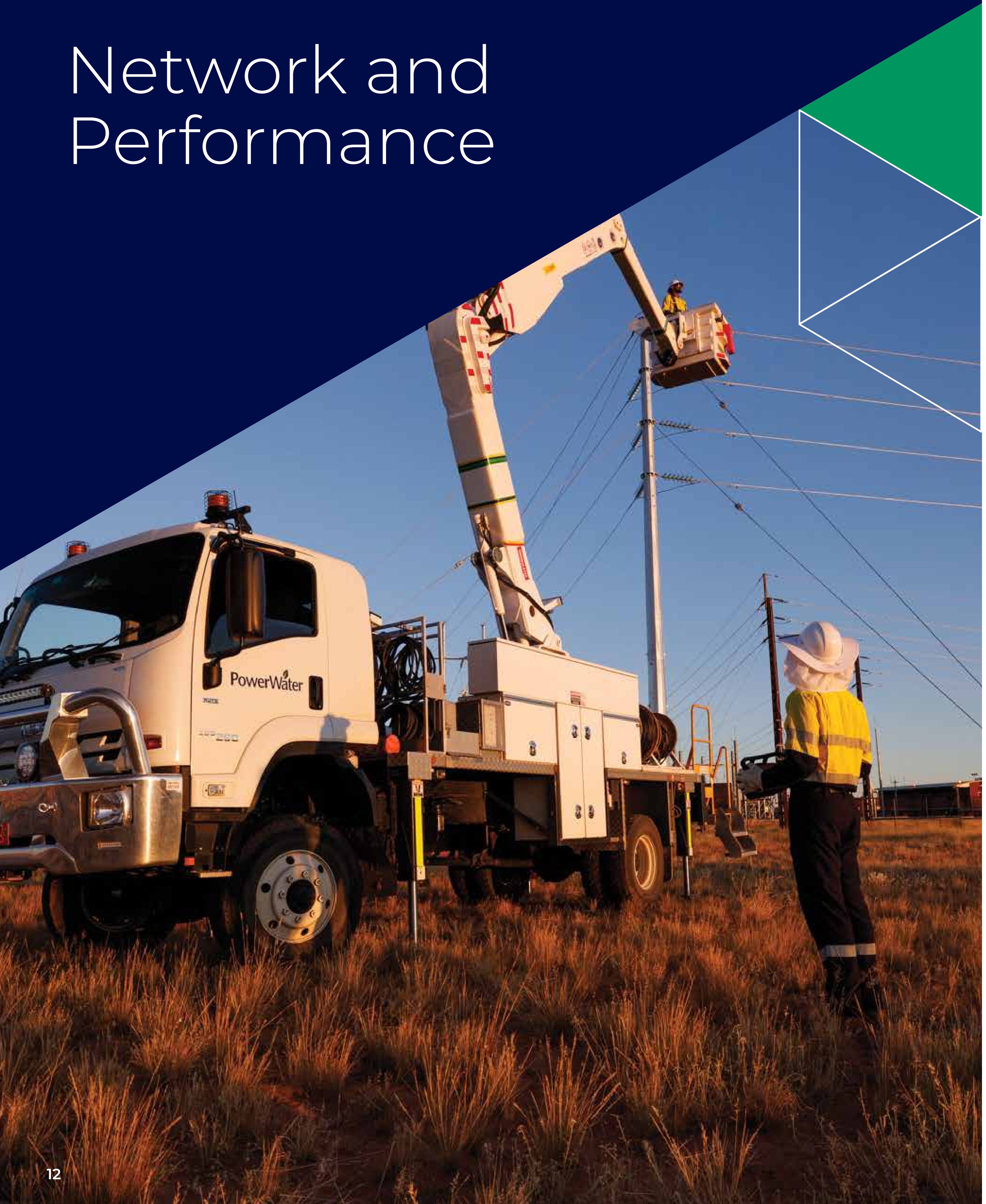
A detailed description of system limitations and proposed solutions is set out in Chapters 8 and 9.

We also have identified a series of 'contingent projects' which are material projects, highly probable of proceeding in the 10-year planning horizon, however are uncertain in terms of timing, scope and costs.

Corroded poles in Alice Springs

PART A

Network and Performance



2. Overview of our network

We provide electricity services to more than 90 communities in the Northern Territory over a landmass of 1.3 million square kilometres. We operate 3 stand-alone electricity networks – Darwin-Katherine, Alice Springs and Tennant Creek, which are regulated by the Australian Energy Regulator. These networks transport about 1,700 GWh of energy annually to more than 73,000 residential customers and 11,000 businesses across these regions. Each of our networks are unique, operating under different designs and environments. These characteristics necessitate the need for a flexible network planning approach that allows for tailoring to different network drivers and characteristics.

2.1 Power and Water's role

Power and Water is a Northern Territory Government Owned Corporation that provides electricity, water, sewerage and gas services to our customers. **Figure 5** identifies the services we provide to urban and remote communities in the Northern Territory.

The Power Services division of Power and Water plans, builds, operates and maintains our distribution and transmission electricity networks.

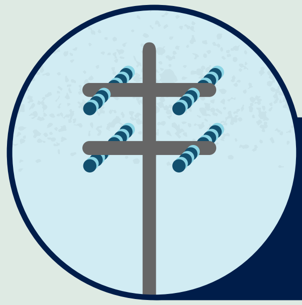
Most of our electricity network services are regulated by the Australian Energy Regulator (AER) under the Northern Territory National Electricity Rules (NT NER). A key reason for regulation is that customers have very limited alternatives for electricity. Regulators protect customers by reviewing our expenditure plans to ensure they are prudent and efficient, and regulating the amount of revenue we can collect.

We transport energy produced by large-scale gas and solar generators using our poles, cables, conductors and transformer assets to residential and business customers. In recent times, our role has further expanded to include exporting electricity from customers' rooftop solar. **Figure 5** identifies the population of assets currently on the network.

The Power Services division of Power and Water plans, builds, operates and maintains our distribution and transmission electricity networks.

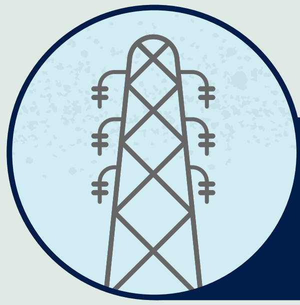
Figure 4 – Power and Water's services and locations

Figure 5 – Asset count and description of the regulated electricity networks in Darwin-Katherine, Alice Springs and Tennant Creek.



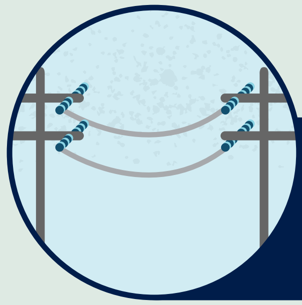
42,500
Distribution poles

Poles support the conductors that transport electricity at 22 kV and 11 kV.



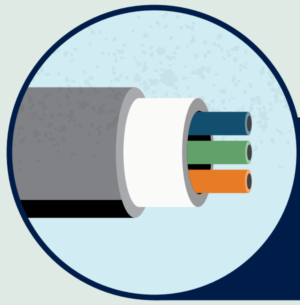
3,300
Transmission towers

Support the conductors that carry electricity at 132 kV from the generators to a transmission substation.



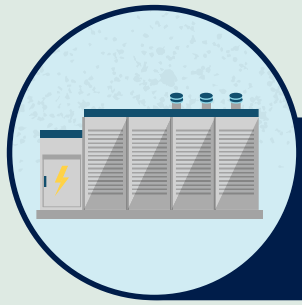
5,500 km
Overhead conductors

Overhead lines that conduct electricity throughout the network.



1,700 km
Underground cables

Cables built underground that conduct electricity through various parts of the network.



4,900
Transformers

Transformers reduce the voltage through the network as part of the transportation process.

57,200
Service lines

The final line that connects the network to customers premises that can be above ground or underground.

Asset populations have been rounded to the nearest hundred. More information can be found in Appendix A.

Conductors at Lake Bennett, Darwin

Alice Springs People's Panel

2.2 Network operating circumstances

Power and Water's regulated electricity is unique in Australia and is not easily comparable to network peers. In the following sections, we identify our unique operating characteristics.

Small-scale

We have the smallest electricity network compared to other networks in the National Electricity Market (NEM) on measures such as customers, energy volumes and peak demand.

Our lack of scale leads to a cost disadvantage when compared to other networks in the NEM. We also have to meet the same regulatory obligations as larger networks with less customers to spread the costs of meeting these obligations.

Transmission network

While our customer and energy volumes are small relative to peer network businesses, our transmission networks in Darwin-Katherine and Alice Springs cover a large geographical area with more than 750 km of transmission line, more than 3,250 towers and 5 sub-transmission substations. Being a transmission operator also means we need to ensure that large-scale generators can connect safely to our network.

Extreme weather

Power and Water operates in extreme environments particularly in Darwin, which has sustained high humidity in the wet season and is prone to destructive cyclones and frequent tropical storms. We also have extreme heat compared to other places in Australia.

These conditions tend to increase our emergency management costs compared to other networks and can lead to more wear and tear of our network assets. Weather also impacts on labour productivity in humid weather, with our field crews' productivity impacted by the extreme conditions.

Unique regulations

Like all other networks, we have licence and reporting obligations and must comply with environmental regulations. We also have unique obligations that impact our costs:

- Travel to sensitive environmental areas requires mitigation practices which increase time and cost to undertake network activities.
- The Northern Territory has many sites of cultural significance and all programs of work need to assess and mitigate against adverse cultural heritage impacts leading to additional costs.

2.3 Our customers and community

Power and Water's purpose is to make a difference to the lives of Territorians.

Our electricity networks provide essential energy to about 84,000 customers across our 3 regulated networks. We deliver almost 1,700 GWh of electricity to power homes and businesses.

Over 85% of our customers are residential, requiring electricity for essential appliances such as fridges, televisions, air conditioning, mobile charging and cooking. Many of our residential customers have rooftop solar. As active participants in the energy market, many of these customers want the ability to connect and export their customer energy resources such as rooftop solar.

Electricity is also a vital input for all Northern Territory businesses and is a critical input for some of our larger industries. While business customers only represent a small portion of our customer base (approximately 15%) they account for 70% of energy consumption.

Our People Panels

In 2022, we established our People's Panels in Darwin-Katherine and Alice Springs. Our People's Panels reflect the diversity of our residential customers.

The panels were originally convened for customers to provide feedback on our 5 year regulatory proposal. The feedback was instrumental in shaping our focus areas, expenditure plans and tariff designs. Our customers wanted us to:

- enable more renewables but be sensible by assessing the costs and benefits
- manage our assets from a long-term perspective
- provide more information and awareness to help customers make more informed decisions about their energy use
- be more innovative by undertaking trials and pilots of new technologies
- think ahead and make smarter more efficient decisions in managing the network to support the community now and into the future.

Our intention is to maintain our People's Panels as the core of our engagement with customers and expand its role to other services provided by Power and Water.

2.4 Our 3 regulated networks

Our regulated networks provide electricity to geographically disconnected regions in the Northern Territory. Each of our regions have distinct geographic and customer characteristics. Our role is to ensure that all our customers receive reliable, safe and efficient electricity to their premises.

An exciting challenge for us is navigating drivers of change for each of our regions including the transition to renewable energy. This has led to the concept of network strategies for each region – providing a 30 year outlook on designing the network of the future. In Chapter 5, we discuss the first Network Strategy for Alice Springs.

Alice Springs

The regulated network supplies the township and surrounding rural areas of Alice Springs.

The network is relatively small compared to Darwin and other regulated networks in Australia, servicing about 10,200 residential households and about 1,800 business customers. **Figure 6** provides key data on our customers in Alice Springs.

The MacDonnell Ranges pass along the south, with 'The Gap' geographically splitting the north and south of Alice Springs. Most of our customers are located north of The Gap, which comprises the CBD, older commercial areas and the majority of residential customers. Energy is supplied at 11 kV from Lovegrove zone substation. South of The Gap is predominantly commercial and industrial customers with energy supplied at 22 kV.

Darwin-Katherine network

The Darwin–Katherine Interconnected Sytem supplies the city, suburbs and surrounding areas of Darwin and Palmerston, the township of Katherine and its surrounding rural areas. We have about 60,500 residential customers and about 8,800 small, medium and large business customers. About 10% of total energy consumption is in Katherine, which is more than 300 km from Darwin.

The region accounts for about 90% of the total energy consumed from our regulated regions. **Figure 7** shows key data for the Darwin-Katherine network.

Currently, most of the generation is located at Channel Island, south of Darwin. The 132 kV Darwin-Katherine transmission line from Channel Island connects Manton, Batchelor, Pine Creek and Katherine. There is a zone substation and distribution infrastructure in each of these locations. The 66 kV transmission lines connect from Hudson Creek to zone substations in the urban areas of Darwin. The 66 kV network also supplies the rural areas of Darwin from Strangways to Humpty Doo to Mary River.

Tennant Creek network

The Tennant Creek network is significantly smaller than Alice Springs and Darwin-Katherine. It supplies the township of Tennant Creek, surrounding rural areas and the remote community of Ali Curung. The network supplies 1,500 residential customers and about 250 business customers.

Figure 8 provides data on Tennant Creek customers and energy use.

The network is relatively simple with a single power station and an adjacent zone substation. Electricity is generated at 11 kV and stepped up to 22 kV at the zone substation where power is transported to customers through 22 kV distribution feeders. We have a dedicated field crew in Tennant Creek, considering the town's distance from Alice Springs and Darwin-Katherine. The network is relatively long at more than 400 km, with about 3,250 poles.

An exciting challenge for us is navigating drivers of change for each of our regions including the transition to renewable energy.

Figure 6 – Key data on Alice Springs

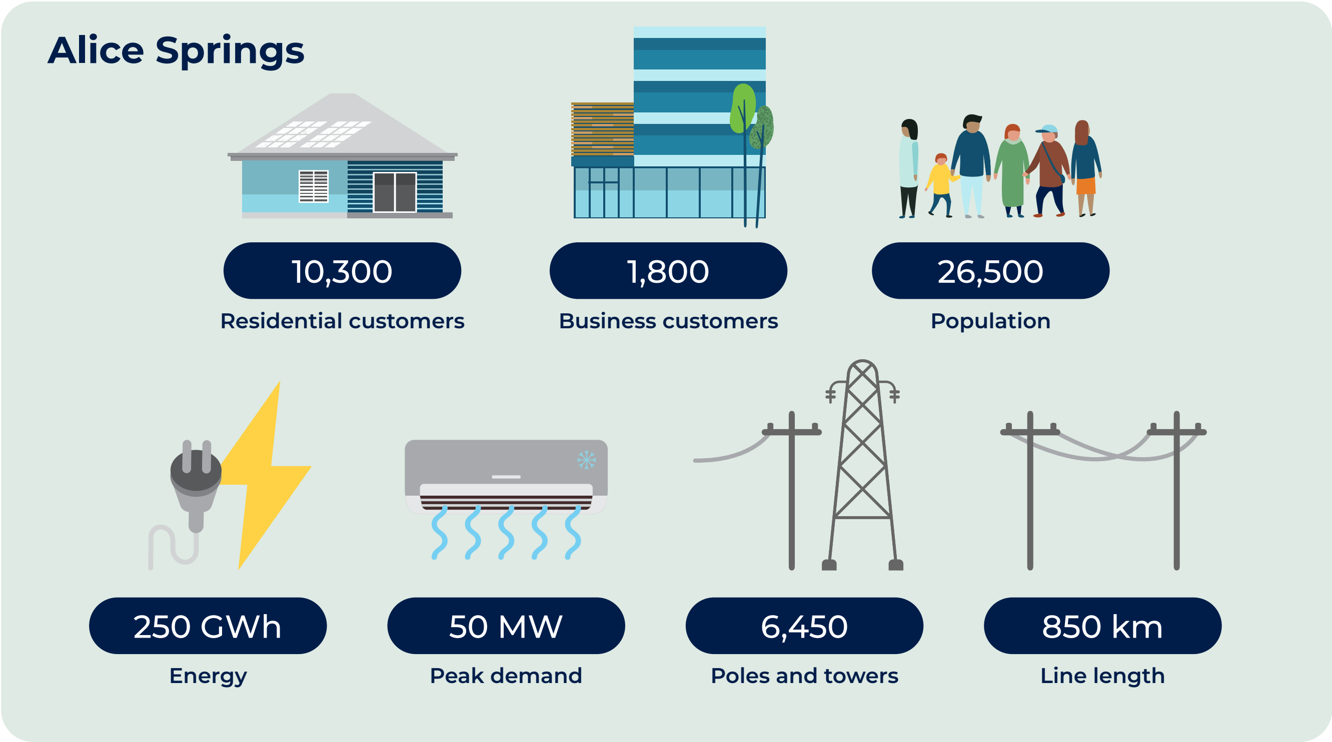
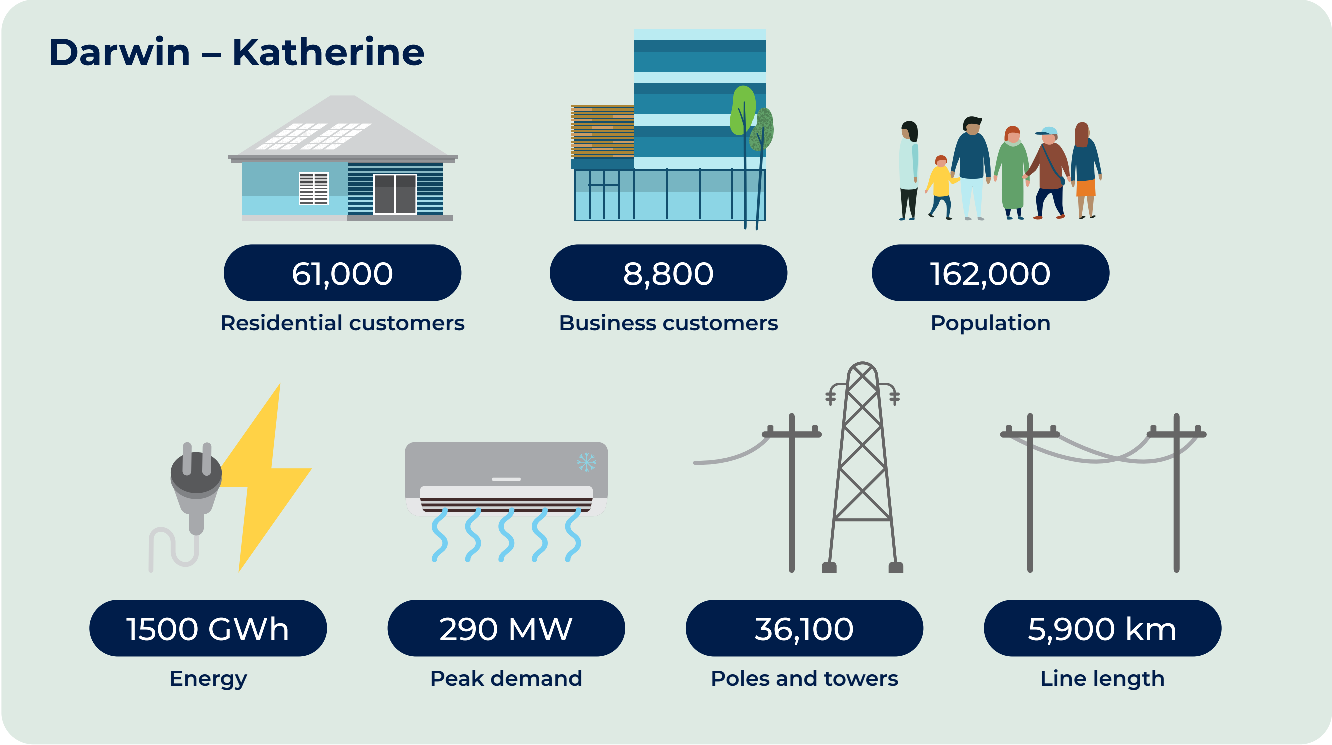
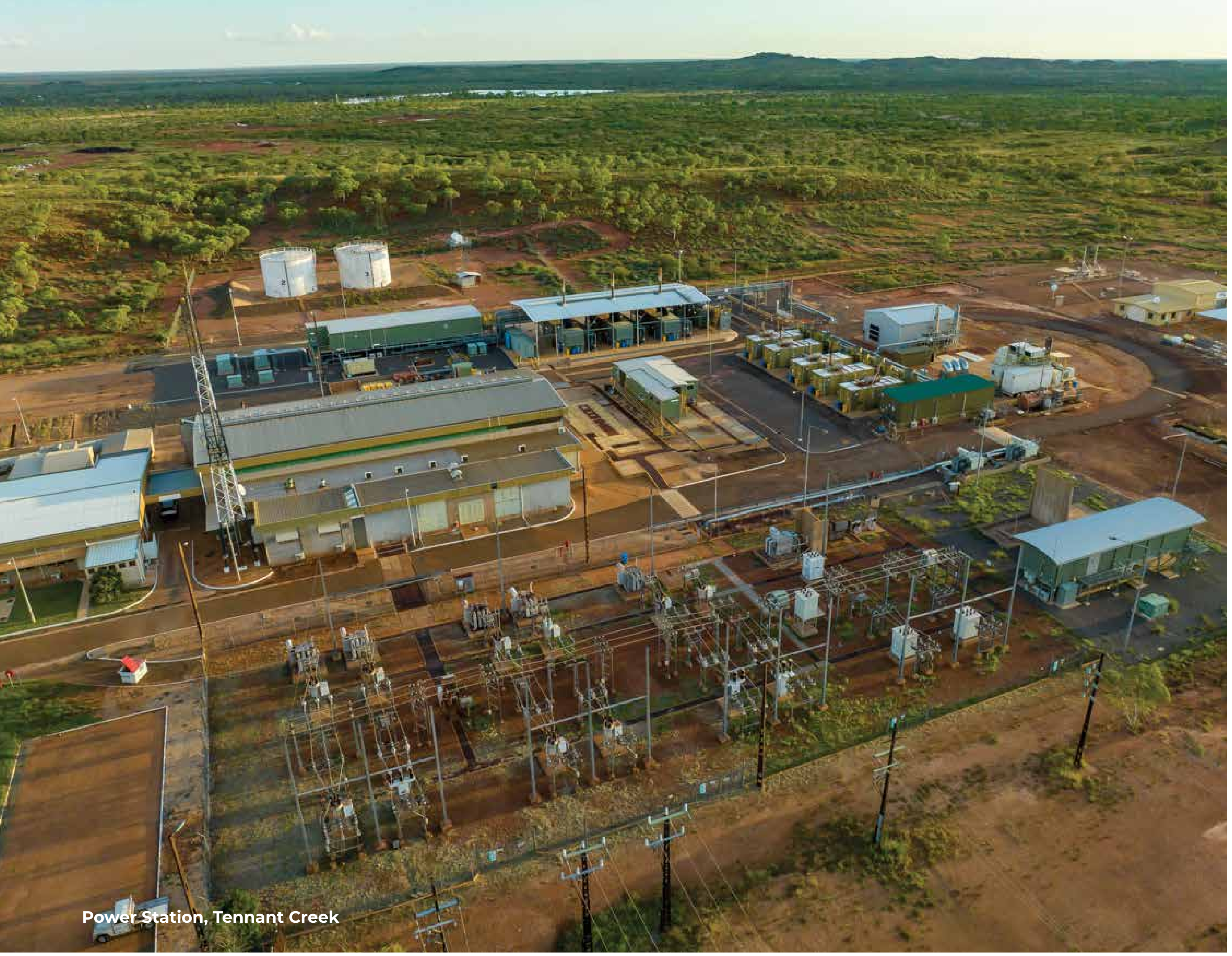


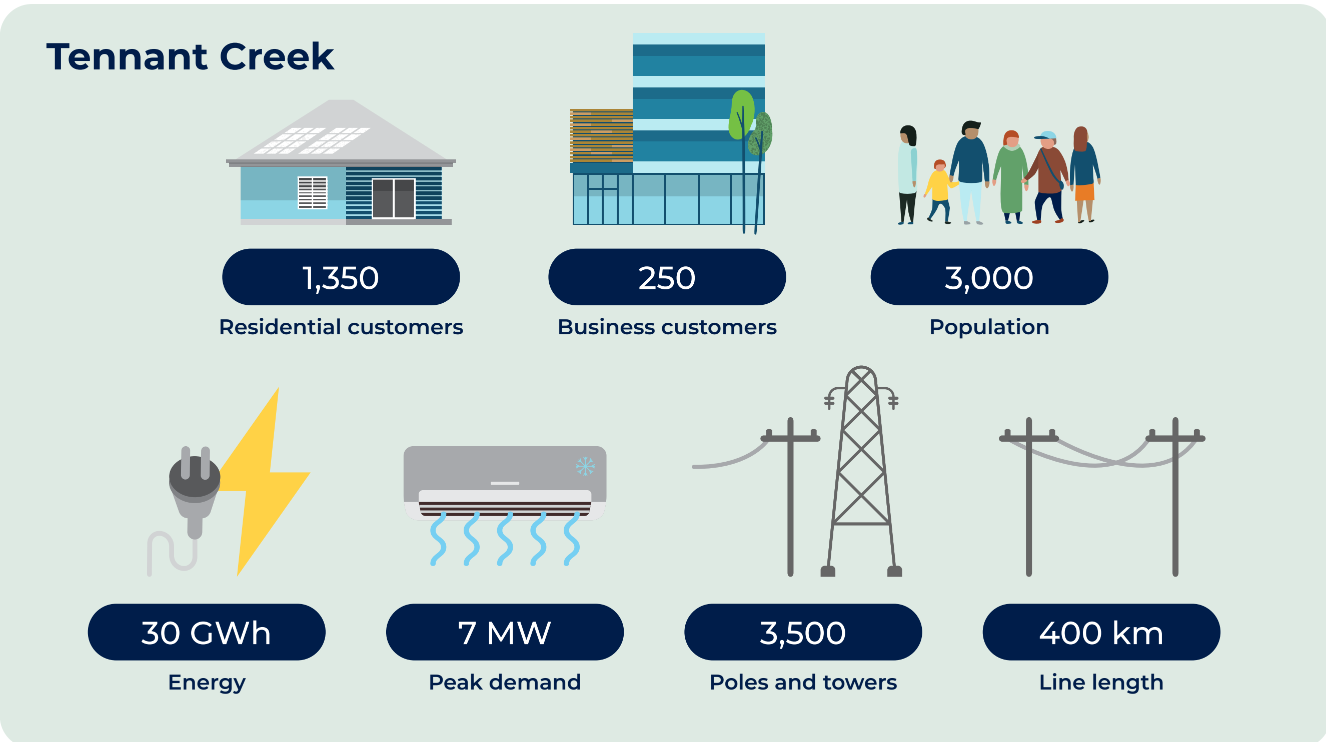
Figure 7 – Key data on Darwin-Katherine data





Power Station, Tennant Creek

Figure 8 – Key data on Tennant Creek



3. Network performance in 2023-24

Over the last decade, Power and Water has significantly improved reliability for customers. In the 2023-24 period, we maintained reliability performance across the network and were able to meet our reliability performance targets except for the Darwin CBD. We received fewer voltage quality complaints from our customers, while continuing to support an increase in small-scale solar on the network. However, we expect voltage issues will emerge on our transmission network in the future as thermal generation retires and is replaced by large-scale solar generation.

The TDAPR provides an opportunity for our stakeholders to assess the performance of our network on an annual basis. The typical measures of network performance include reliability and quality of supply.

5.1 Reliability performance

Our customers expect us to minimise the frequency and duration of power interruptions. In this section, we report our reliability performance against key metrics set out in our regulatory requirements.

The NT Electricity Industry Performance Code (EIP Code) is the applicable regulatory instrument for setting our reliability metrics and targets. The EIP Code provides a framework for setting reliability measures and standards for Power and Water's regulated network, as well as reporting our performance to the Northern Territory Utilities Commission.

We have a robust compliance process to ensure we monitor and maintain compliance with our jurisdictional requirements. This includes periodically reviewing and correcting data, reviewing performance trends compared to thresholds, and initiating investigations into the need for network investment.

In this section we describe how Power and Water performed in 2023-24 against the key metrics in the EIP Code, including reliability performance by feeder category and worst performing feeders.

Power and Water is not subject to the AER's Service Target Performance Incentive Scheme (STPIS) for the 2024-29 period. For this reason, we do not provide a submission to the AER on our performance against the scheme, nor do we provide forecasts of our performance. However, we still report our reliability performance in our response to the AER's Regulatory Information Notice (RIN). Reporting definitions are slightly different in the EIP Code and RIN, and therefore our performance data differs in each of our reports.

Feeder performance in 2023-24

The EIP Code requires Power and Water to propose reliability targets for each regulatory control period for approval by the Northern Territory Utilities Commission. This includes targets for System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) by feeder category on the distribution network.[4] SAIDI is the annual average minutes off supply per customer and SAIFI is the annual average number of interruptions experienced per customer.

The Utilities Commission has reviewed our performance targets for the 2024-29 regulatory period with a reduction in Urban and Rural Long SAIDI and SAIFI. We will start reporting against the new targets from the current (2024-25) financial year. In the following table we have reported against the targets for the previous (2023-24) financial year.

[4] In calculating the performance metrics, the Code requires that all transmission networks are classified as distribution networks and their performance is reported as for the distribution network. For clarity, any reference to the distribution system also includes the transmission system in the remainder of this section.

Table 1 reports our aggregate 2023-24 SAIDI and SAIFI performance by feeder category against the targets approved by the Commission under the EIP Code. As seen in the table, we met our performance targets across all feeder categories except for CBD feeders. The high levels of SAIDI and SAIDI on CBD feeders was primarily due to 2 cable faults and a zone substation fault. These outages each affected a large number of customers and had extended resolution timeframes due to travel, complex fault finding and multiple switching operations required for isolation and repair.

Our annual performance can differ markedly from year to year due to weather and other unpredictable activity. In recent years we have shown improvement in reliability and our performance in 2023-24 has generally remained consistent indicating that performance has stabilised.

Performance by region

The 3 network regions of Darwin-Katherine, Alice Springs and Tennant Creek have very different performance characteristics. While we have targets set for each feeder category, we do not have a target for the whole of network or for each individual region.

As noted in the next section, we are required to report feeders that lead to high levels of outage, which provides a level of insight into whether some locations of our network are receiving a poor level of reliability compared to other locations. **Figures 9 to 12** show the performance of SAIDI and SAIFI in Darwin, Katherine, Alice Springs and Tennant Creek respectively. Regional analysis can be volatile from year to year particularly in small regions where an outage can have a marked impact on the reported results.

Yearly performance is impacted by weather events and issues such as animal activity and vegetation growth. For this reason, it is more appropriate to consider performance over longer time series to identify emerging trends. The longer term data suggests that performance has improved over the last 5 years in Darwin, Alice Springs and Tennant Creek. However, the data suggests that Katherine is experiencing a slight deterioration in reliability over the last 5 years.

We have been working to improve reliability in Katherine through our worst performing feeder program, where we have targeted projects based on outage causes. This includes installing additional overhead switches to enhance feeder reliability, together with replacement of conductors and bat protection on rural feeders. We also expect to improve reliability through our replacement of secondary systems on the Darwin-Katherine transmission line, which will enable a faster response to transmission faults impacting the Katherine region.

Our annual performance can differ markedly from year to year due to weather and other unpredictable activity.

Table 1 – 2023-24 Reliability performance compared to approved target in EIP Code

	Adjusted SAIDI			Adjusted SAIFI		
Feeder category	**Performance target**	**Actual performance**	**Performance**	**Performance target**	**Actual performance**	**Performance**
CBD	4	41.07	Target not met	0.1	0.6	Target not met
Urban	140	79.53	Target met	2	1.16	Target met
Rural short	190	158.16	Target met	3	2.230	Target met
Rural long	1500	1191.71	Target met	19	10.64	Target met
Whole of network	175.8	137.04	Target met	3	1.87	Target met

Whole of network is not an EIP Code target. The data has been based on a weighted average of targets and performance based on customers in each category.

Figure 9 – Darwin reliability performance

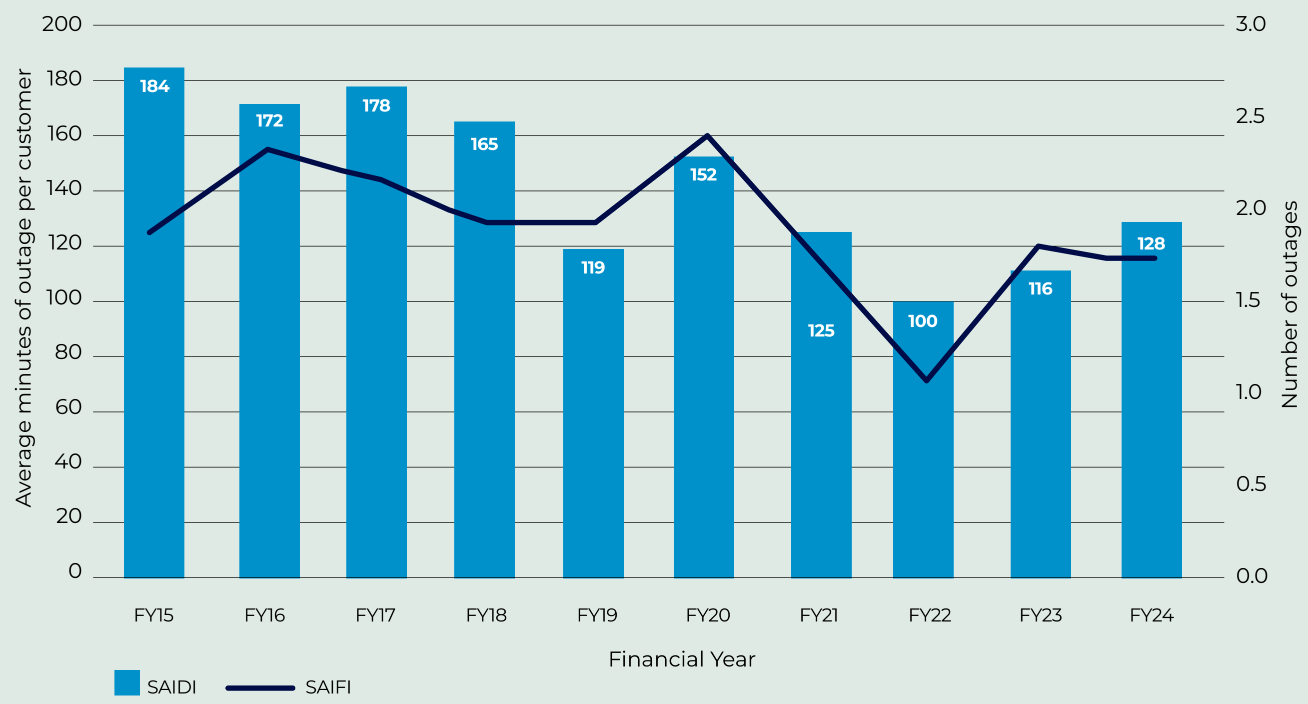


Figure 10 – Katherine reliability performance

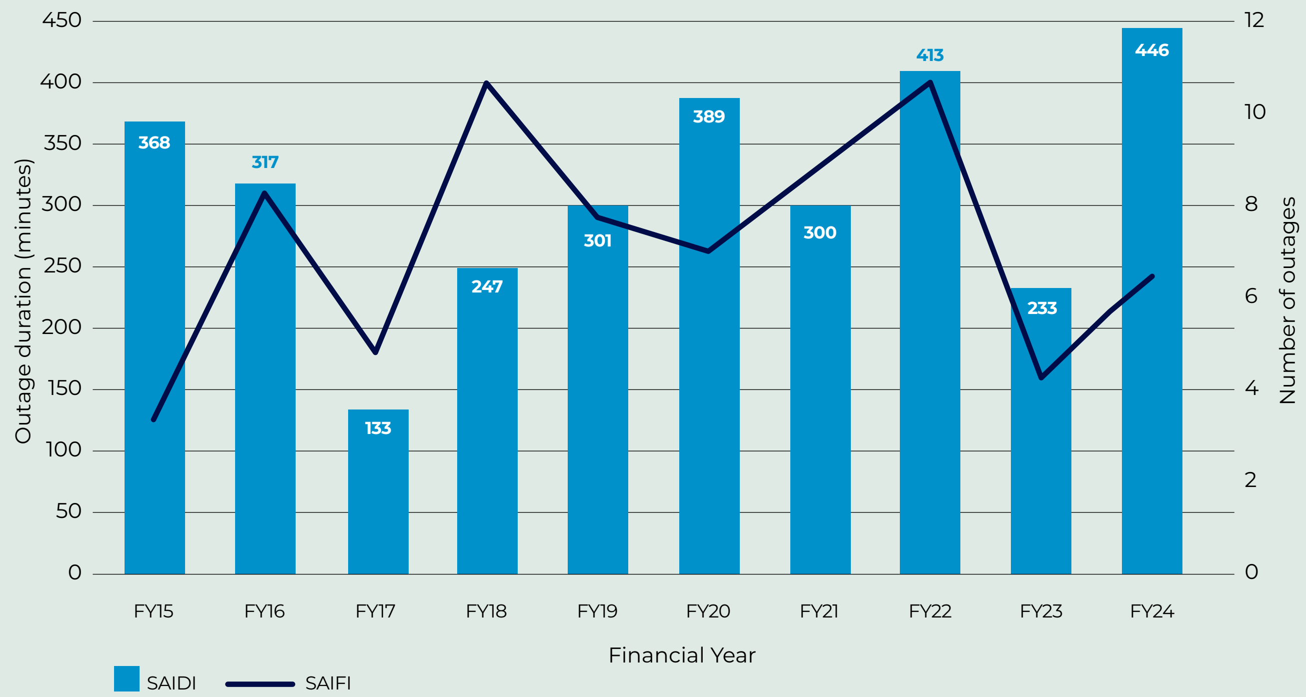


Figure 11 – Alice Springs reliability performance

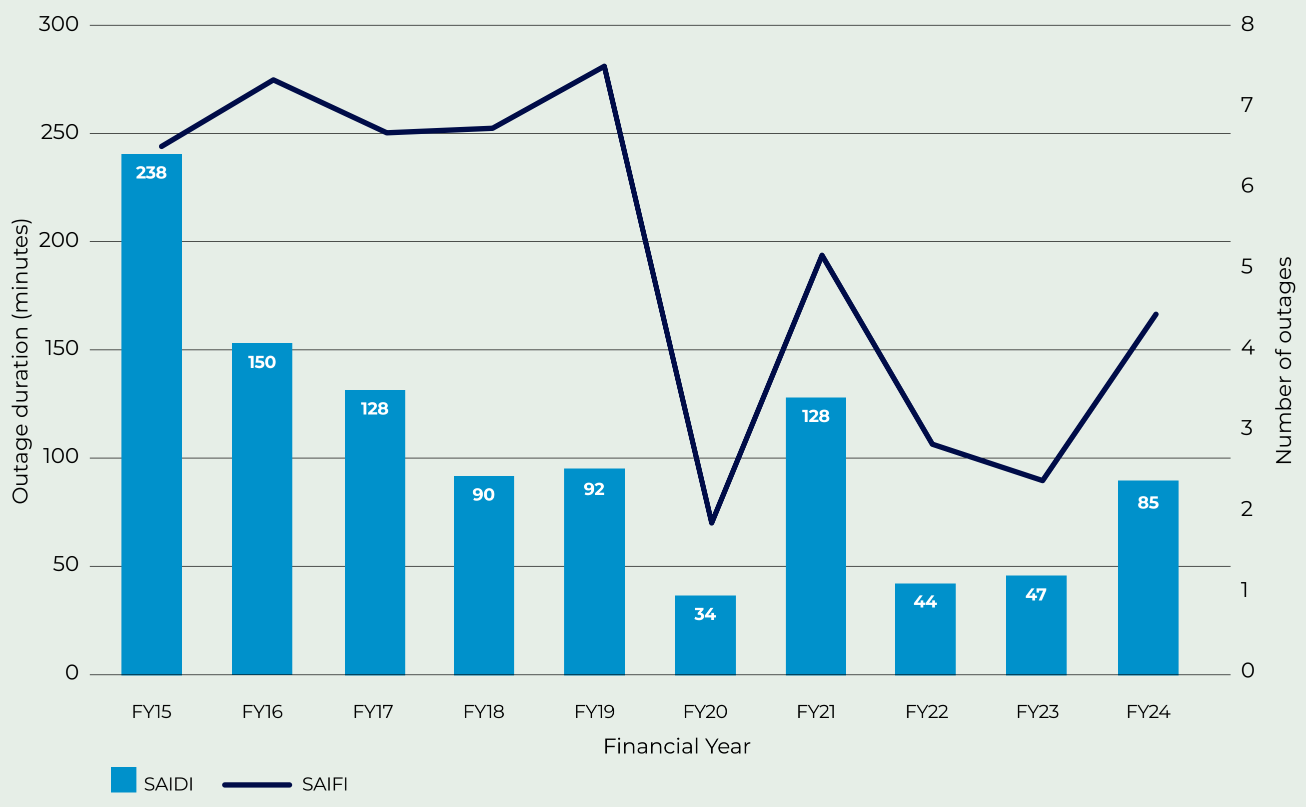
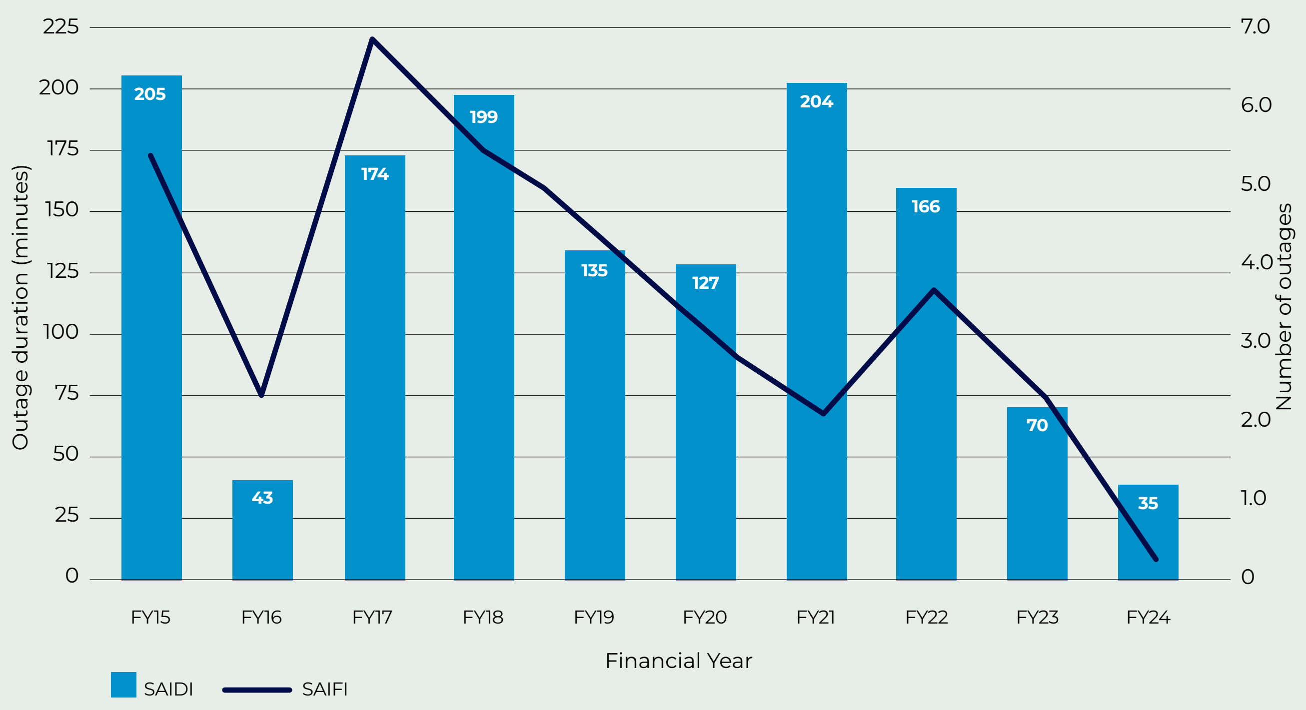


Figure 12 – Tennant Creek reliability performance



Worst performing feeders in 2023-24

The EIP Code also requires us to measure and report on the 5 worst performing feeders by CBD, urban, and short and long rural areas. We have only 3 rural long feeders on our regulated networks. For this reason, these will always be reported as worst performing feeders.

The metrics recognise that some of our customers receive worst reliability than others and we should strive to improve performance for these customers where it is efficient and prudent.

Table 2 sets out our 5 worst performing feeders by category for 2023-24. We outline the dominant causes of interruptions and its impact on SAIDI for the feeder. We also identify if the same feeder was identified as worse performing in 2022-23.

Customers connected to our rural feeders experience significantly worst reliability than customers connected to our CBD and urban feeders. This is due to limited interconnection to transfer load from an adjacent feeder, which facilitates restoration of supply following an outage. The length and location of the feeders also means it takes longer to find the cause of the issue.

This year, 5 feeders have remained on the list. This demonstrates both the expected volatility in performance between feeders and also indicates that our actions are generally improving performance.

Improving reliability performance

Each year, we are required to set out actions to improve performance of worst performing feeders. The underlying rationale is to identify cost effective and enduring methods to improve reliability for the customers receiving energy from worse performing feeders.

Based on our performance in 2023-24, we will not undertake specific reliability works in the Darwin CBD. Our performance in the Darwin CBD has generally met the targets in previous years, however there appears to have been some deterioration. We plan to monitor and review performance during the 2024-25 year to determine the most prudent and efficient approach to arrest the deterioration.

Further, our planned replacement program over the next 10 years should contribute to improving CBD performance. In particular, we are planning to replace distribution substations to improve fault level capacity and will also be investing in programs to rectify underground cables.

Our urban feeders have consistently met performance targets and therefore no specific actions are proposed in response to the poor performing feeders assessment. However, our network investment portfolio addressing other specific issues is expected to result in improvement to the performance of these feeders, particularly the underground cable replacement programs.

For rural short feeders, we have a range of initiatives in place to improve performance. This includes improving network switching capability, monitoring the effectiveness of recently installed electrostatic animal protection and improving vegetation management at Darwin River.

The rural long feeders have continued their trend of improving performance in recent years due to upgrades undertaken and we have an ongoing program in place to apply bat protection on the Ali Curung feeder.

The metrics recognise that some of our customers receive worse reliability than others, and we should strive to improve performance for these customers where it is efficient and prudent.

Table 2 – Worst performing feeders

Category	Feeder name	SAIDI	Cause and impact on reported minutes	Same feeder as identified in 2023 TDAPR
CBD	11ML09 DALY	152	Primarily due to a single outage caused by high voltage cable failure.	Yes
CBD	11WS03 DASHWOOD	129	Primarily due to a single outage caused by high voltage cable failure.	No
CBD	11WS02 LITCHFIELD	43	Primarily due to a single outage caused by equipment failure.	No
CBD	11ML01 DPAC	39	Primarily due to a single outage caused by high voltage cable failure.	No
CBD	11WS04 LINDSAY 1	34	A single outage due to substation equipment failure.	Yes
Urban	11SD11 GOLF	323	Primarily due to two outages caused by failure of overhead connecting wires.	No
Urban	11PA08 YARRAWONGA	299	Mainly due to outages caused by cable faults.	No
Urban	11CA25 BRINKIN	284	Primarily due to outage caused by high voltage cable failure.	No
Urban	11ML02 LARRAKEYAH	270	Primarily due to a single outage caused by failure of HV Bridges.	Yes
Urban	11BE19 HIDDEN VALLEY	238	Primarily due to an outage caused by failure of a distribution substation.	No
Rural short	22TC09 WARREGO	2570	Primarily due to outages caused by weather conditions.	No
Rural short	22BR104 HERMANNSBURG	1425	Primarily due to an outage caused by failure of overhead conductor.	No
Rural short	22KA03 FLORINA	839	Primarily caused by weather and unknown transient faults. Historical bat issues in this region means it is likely that transient faults are animal related.	Yes
Rural short	22MT06 LAKE BENNETT	716	Primarily due to outages related to weather and vegetation. There was also a conductor failure.	No
Rural short	22SY15 DARWIN RIVER	703	Primarily due to outages related to weather and vegetation.	Yes
Rural long	22SY04 DUNDEE	1314	Met category target. The outages were mainly due to a fault on an overhead switchgear and distribution substations.	Yes
Rural long	22KA10 MATARANKA	963	Met category target. The outages were mainly due to conductor failure and vegetation.	Yes
Rural long	22TC01 ALI CURUNG	425	Met category target. The SAIDI performance was mainly due to outages caused by weather events. There was also a notable contribution of an overhead conductor failure caused by bushfire.	Yes

5.2 Quality of supply performance

Quality of supply relates to voltage disturbances that can impact a customer's energy supply and appliances. Currently, Power and Water's Network Technical Code and Network Planning Criteria sets out a target standard for quality of supply delivered to customers.

For steady state voltage, we must apply the Australian Standards for our low voltage and high voltage network.[5] The standards set out requirements for voltage fluctuations harmonics and voltage imbalance.

We monitor power quality issues by analysing customer complaints and actively monitoring voltage levels at our substations. We have permanently installed monitoring equipment in all zone substations and use portable equipment to undertake cyclic monitoring of distribution substations. We use power quality and geographical data to develop electrical models of low voltage so we can better predict power quality issues.

The 2-way flow of rooftop solar can impact voltage quality. With increased penetration of rooftop solar PV, we expect that the network will likely experience increasing voltage issues. Currently, we have limited visibility of voltage constraints except for customer complaints, which are not a reliable metric of performance over time. We are investing in a new solution that can provide increasing analytics at street level on the performance of the network using existing smart meter data.

We investigate cost-effective options to resolve identified quality of supply issues. Options include distribution transformer tap adjustments, upgrading or installing additional distribution transformers, segmenting the local low voltage network between transformers, upgrading the capacity of conductors and phase balancing.

We are investigating the deployment of community batteries, which are expected to assist with voltage issues at a local level where batteries are installed in the low voltage network.

Voltage quality audits

We conduct regular audits of voltage quality, using a random sample of customers. In 2024, we continued to use data obtained from smart meters to assess power quality. The meters measure and record voltage information for a period of 90 days, with measurements averaged over 10-minute intervals.

Table 3 identifies the percentage of time that voltage was above or below the limits prescribed in our regulatory obligations. Power quality has improved in Darwin and Tennant Creek, but there has been a slight deterioration in high voltages in Katherine and Alice Springs.

We monitor power quality issues by analysing customer complaints and actively monitoring voltage levels at our substations.

Table 3 – Percentage of time where voltage was above or below limits

Voltage zone	Darwin	Katherine	Alice Springs	Tennant Creek
Below limits (<216 V)	0.00%	0.01%	0.00%	0.00%
Above limits (>253 V)	0.00%	4.00%	0.75%	0.00%

[5] The relevant standards are AS60038 and AS61000.3.100. The range of LV supply is specified in AS61000.3.100. This is re-produced in Appendix B of the 2023 TDAPR.

Substation, Katherine

The key findings for this year are:

- Darwin and Tennant Creek are not showing any material issues with voltage quality based on the sample size.
- Alice Springs had some infrequent high voltage events, suspected to be driven by solar PV uptake. We are installing reactors to manage this issue and will continue to monitor this voltage quality to assess if the intended outcome has been achieved.
- Katherine is above the limits for a significant proportion of the time. This had reduced from 2020-21 to 2022-23 but has increased again during 2023-24. The residual issues are expected to be resolved by the new reactors that are currently being installed.

Low voltage quality audits are only one aspect of understanding the extent of issues with the quality of power supply. Customer complaints provide another means of identifying issues with power quality as discussed below.

Customer complaints in 2023-24

In 2023-24 we received only 5 complaints about quality of supply from customers, consistent to 2022-23 and still much lower than the average of 34 complaints per year from 2018-19 to 2021-22.

Customer complaint data is not a reliable metric of performance over time. **Figure 13** compares the number of complaints by category over the last 6 years. We investigated each complaint by our customers to understand the underlying issue.

Figure 14 compares the underlying causes. It shows that in 2023-24 the main cause of an identified complaint was unable to be identified.

Figure 13 – Quality of supply complaints

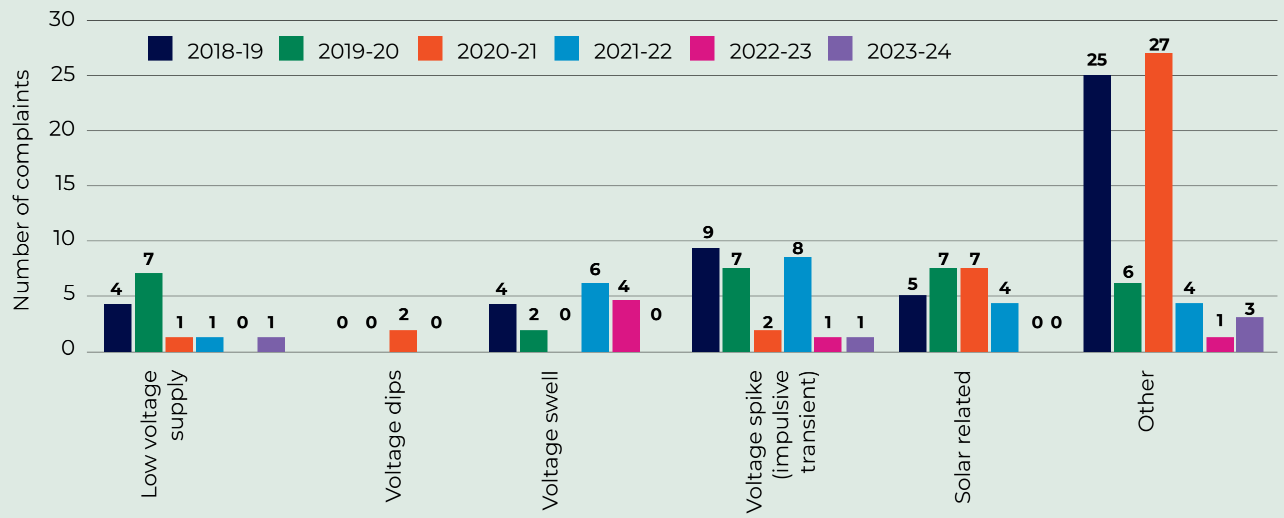
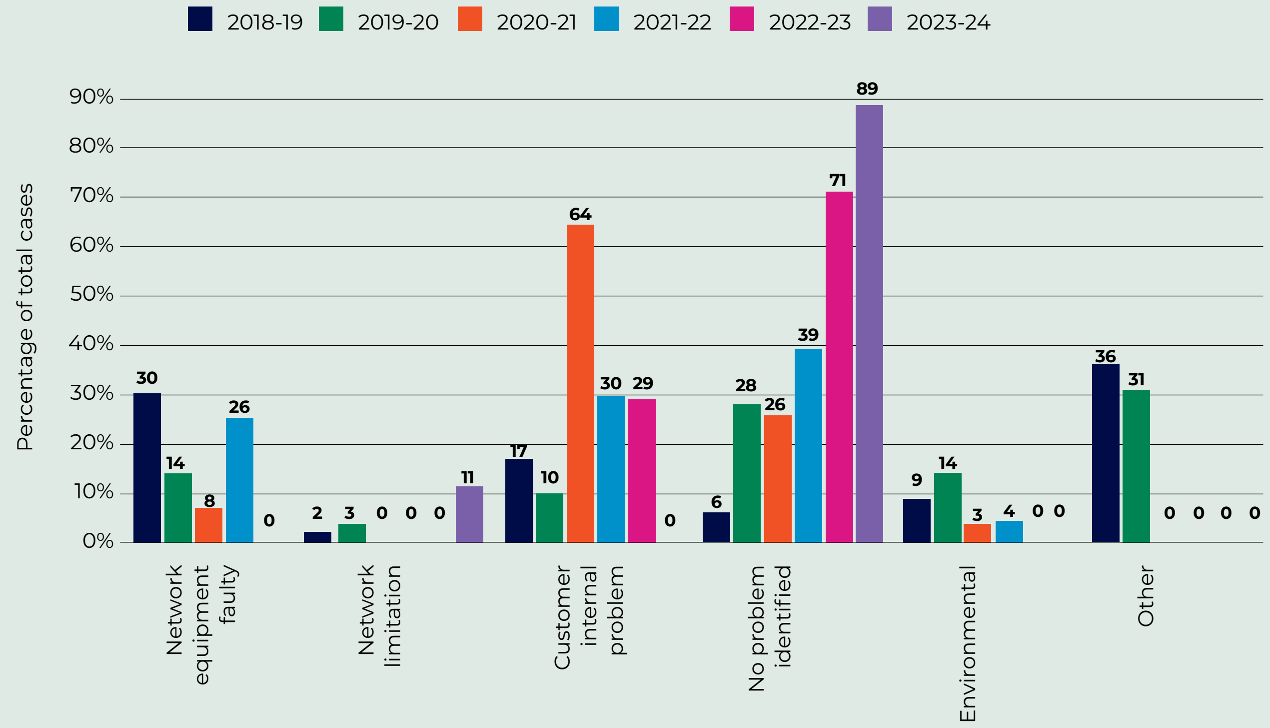


Figure 14 – Quality of supply causes



Planning to address emerging quality of supply issues associated with rooftop solar

Power and Water has a quality of supply program for the planning period that aims to resolve low voltage issues over time. A key focus is reducing augmentation costs associated with 2-way energy flow from rooftop solar. As solar penetration increases in our regulated regions, we expect to encounter increasing issues with voltage control. Key initiatives of our future planning are set out below. We note that increasing solar penetration is also impacting our transmission network.

Targeted augmentation

Power and Water undertakes targeted reconfiguration of the low voltage network in areas that are most impacted. This is likely to be older suburbs where there has been significant new housing development with solar.

Dynamic Operating Envelopes

As identified in our Future Network Strategy, we are focusing on using new technology to help address emerging voltage issues and to avoid unnecessary network investment.

Our planned Dynamic Operating Envelopes (DOE) solution will enable us to control residential solar PV and other energy resources to more efficiently manage voltage excursions and transient constraints that would otherwise require significant capital investment to resolve. As discussed in Chapter 8, we have modified the timing and scope of the DOE initiative in response to feedback provided in the AER's draft decision.

A key focus is to undertake studies on voltage performance of our distribution network, through the GridQube network visibility project. This reflects that Power and Water can only currently assess voltage issues through customer complaints. The GridQube program provides greater visibility on voltage issues at the street level using smart meter data. This will enable more detailed reporting in next year's TDAPR, particularly in respect of accurate data on export hosting capacity for which we currently have no evidence based method of reporting.

Network batteries

We are planning to undertake battery trials under the Demand Management Innovation Allowance and through ARENA funding. Installation of batteries that can be controlled by Power and Water to charge when there is high solar PV generation (i.e. midday) and then discharge during high demand when there is less sun. This will help avoid the need for investment in new infrastructure to meet growing peak demand and will improve network use.

Building understanding and capability with these new technologies will help us improve quality of supply at a lower cost to our customers.

5.3 ICT update

Our Information and Communications Technology (ICT) strategy is directed at supporting key improvements to our business to uplift core capabilities and strengthen cyber security. This will be achieved primarily by replacing outdated and obsolete assets and systems with modern equivalents. This will provide improved functionality and visibility of our operations that will allow us to enhance the efficiency of our business practices.

Focus areas include:

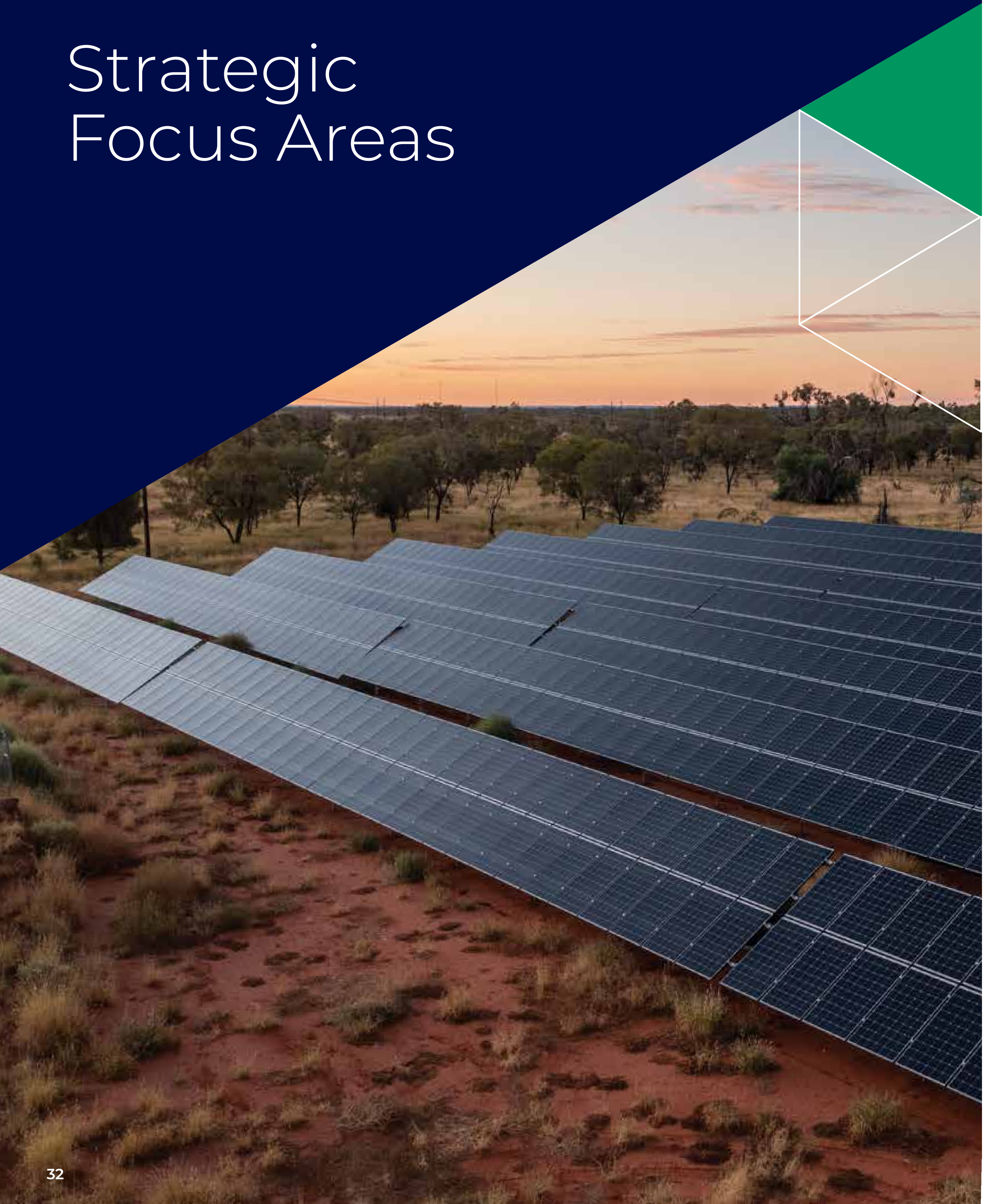
- driving efficiency to support our Operating Model initiatives – we have identified key investments to upgrade and implement new ICT systems to improve the efficiency of our services
- improving how we communicate with customers – we have identified changes to our customer relationship management system that improve our ability to respond to customers' enquiries and to communicate outage times.

Building our understanding and capability with these new technologies will help us improve quality of supply at a lower cost to our customers.

People's Panel discussing Future Network Strategy

PART B

Strategic Focus Areas



4. Actively enabling renewables in the Northern Territory

In 2024, we published our Future Network Strategy that provided an overarching framework to actively facilitate renewable energy for our customers. This identified efficient initiatives to enable our network to securely transport growing solar resources in the Northern Territory. We are progressing with our implementation plans to maximise small-scale solar, modernise our network to integrate large-scale renewables, and we are ahead of the curve in trialing community batteries and electric vehicle batteries to unlock more renewable energy.

The Northern Territory has abundant sunshine, with one of the highest irradiance index in the world. This provides a great opportunity to generate significant amounts of cost-effective renewable solar energy.

This has prompted investment by our customers in rooftop solar panels, and incentivised large-scale solar proponents to locate in the Northern Territory.

Our network is the key to unlocking both small and large-scale solar sources in our regulated regions. Our Future Network Strategy is a long-term roadmap to facilitate renewable energy.

We have achieved a lot already – but we're just at the start of the journey.

4.1 Maximising small-scale solar

There are times when solar is providing more than 50% of the total energy needed across the Darwin-Katherine electricity system, and we are recording similar peaks in Alice Springs. **Figure 15** shows the maximum solar for a 30 minute interval in the Darwin-Katherine region.

The majority of that power is coming from rooftop solar systems that are connected to our network. About one in 5 customers have solar on their roof, and we expect that number to grow significantly by 2050 as the population expands and more customers invest in solar. By 2050, we expect that more than half our customers will have a solar panel as seen in **Figure 16.**

Given our network has traditionally provided power one way to customers, there are challenges in facilitating the supply of rooftop solar back into the network and coping with issues such as elevated voltage and low demand.

We are trialling technology that can help us manage solar when the system is at risk. The technology works by communicating to solar panels to automatically ramp down solar exports on very sunny days. The technology will mean that all customers can connect their solar to our network, and export onto our network when the system is not at risk. We think this technology will help boost the amount of home grown solar in the Northern Territory while keeping the network secure. **Figure 17** provides a visual description of the challenges and solutions.

We are also pressing ahead with tariff reforms that provide incentives for customers to use more energy in the day when solar is available. This is through lower network prices in the day and higher prices during peak times. There are plans to trial tariffs that provide customers with incentives to use batteries to store solar in the day and discharge at night. This comes on top of recent tariff reforms proposed by the Northern Territory Government.

Figure 15 – % of demand for electricity met by solar and other fuel sources on the day of maximum solar output in Darwin-Katherine in 2023-24

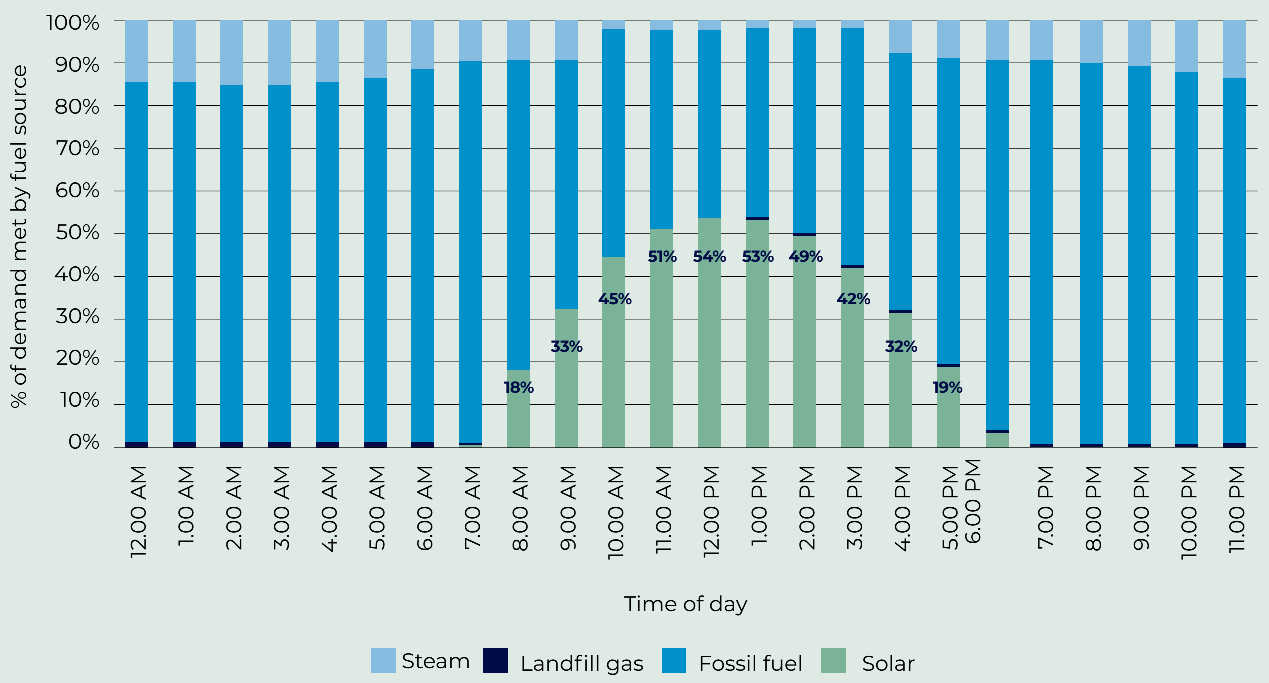
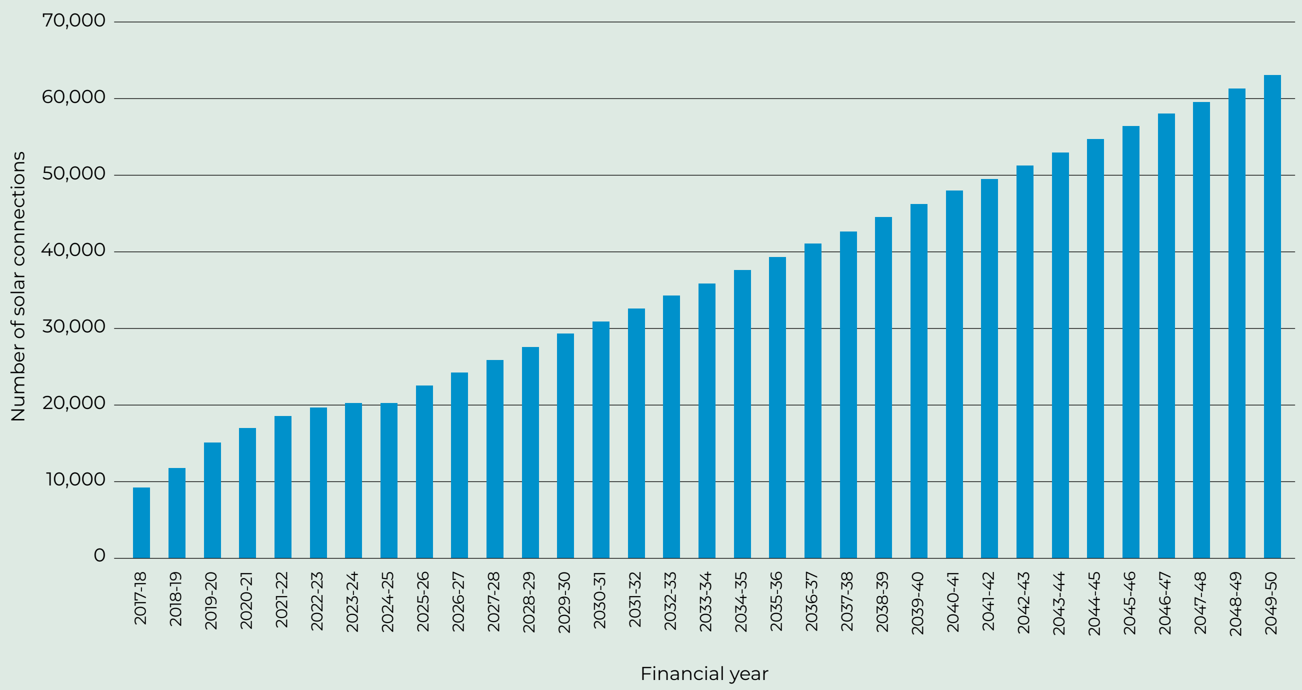
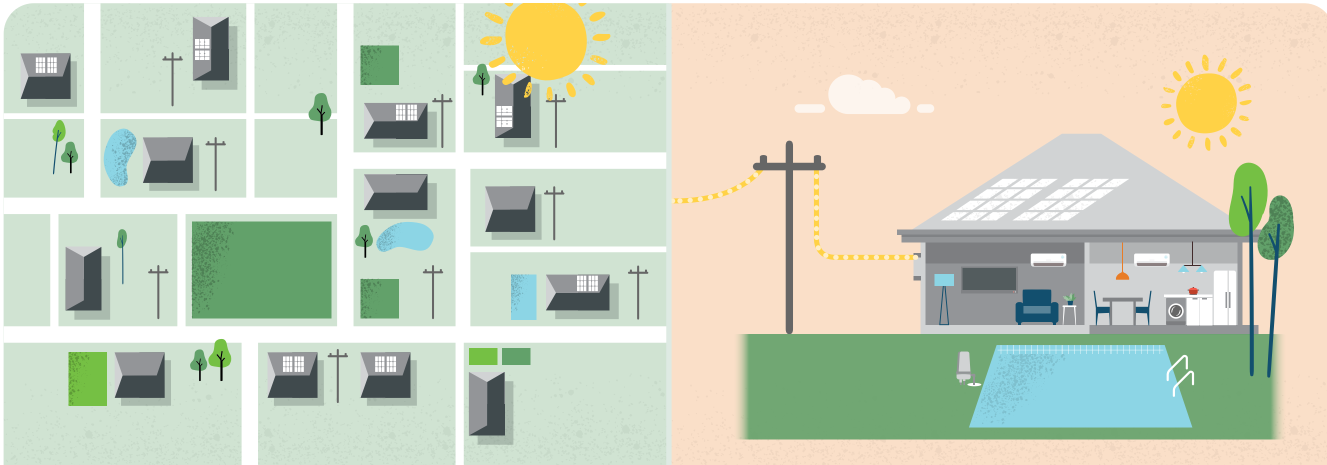


Figure 16 – Actual and forecasts of solar connections 2017-18 to 2049-50



Solar Panels – Alice Springs

Figure 17 – Challenges and solutions for small-scale renewables



On sunny, mild days, our networks will find it challenging to manage the exports from growing numbers of solar panels. One approach is to put 'year-round' limits on how much solar can be exported. However, this would waste an opportunity to use the full potential of solar panels.

We are trialling new technology that can help us flexibly manage the challenging periods when there is too much solar exported onto our network. This includes the Dynamic Operating Envelope, which communicates to solar panels to ramp down solar when the network is at risk. This would allow customers to export to full potential at all other times.

4.2 Modernising our network to integrate large-scale solar

Large-scale solar has the potential to significantly reduce reliance on traditional forms of power generation.

In the next 5 years, we expect that large-scale renewables will replace a high proportion of the electricity currently supplied by thermal generation at Channel Island Power Station.

While this is an exciting prospect, our fundamental obligation is to ensure the network remains secure as we transition from thermal generation to renewable energy. The key challenges include:

- System strength – the ability of the power system to maintain and control the voltage waveform. Unlike thermal generation, solar generators do not create a voltage waveform.
- Voltage control – thermal generation inherently provides reactive power to absorb voltage fluctuations, however renewable energy does not have the same capabilities.

A key plank of our Future Network Strategy was to actively develop efficient solutions to facilitate large-scale renewables to meet these challenges. We have significantly upscaled our teams and resources to enable efficient connection of large-scale solar.

Large-scale solar farms

Recently, we have brought solar installations online at Robertson Barracks and RAAF Darwin, taking large-scale solar generation up to around 15 MW capacity in the Darwin-Katherine electricity network.

Four more large-scale solar farms with a maximum capacity of 55 MW are connected on the Darwin-Katherine line and expected to generate significant quantities of renewable energy.

We are already thinking ahead of the curve in how we can maximise dispatch of these solar farms. Our initial studies on system strength suggest that there will be a shortfall in system strength if the large-scale generators are fully dispatched.

System strength declines when large-scale renewables are located far away from synchronous generation and when a high proportion of energy is met by renewable sources.

The key challenge is that most large solar farms connected to the Darwin-Katherine transmission line are a significant distance from Channel Island Power Station where the bulk of today's synchronous generation lies. Our economic analysis shows there is likely to be a benefit to customers from investing in solutions that increase renewable generation. This relates to the lower fuel costs of large-scale solar relative to thermal generation and the value of emissions savings.

As noted in Chapter 9, the AER has classified this as a 'contingent project' based on the current uncertainty of scope and costs. This recognised that Power and Water will undertake industry consultation under the Regulatory Investment Test for Transmission (RIT-T) to ensure that all options are considered and assessed, including solutions proposed by external stakeholders. The RIT-T also provides transparency on our economic analysis allowing for further scrutiny on whether the project is in the best interests of customers.

Renewable Energy Hub

Power and Water is also planning for a proposed Renewable Energy Hub, which would create a collective of large-scale renewable installations in one place with the potential to generate more than 200 MW of energy.

Rather than building hundreds of kilometres of transmission lines as seen in other parts of Australia, it is proposed the Hub could be located close to existing electricity transmission and generation assets in Darwin.

The hub would connect to the Channel Island to Hudson Creek 132 kV transmission line. This would have sufficient capacity to transfer generation from the hub to the Darwin-Katherine network after the retirement of the existing thermal generation at Channel Island Power Station.

Figure 18 shows the key projects connected and new projects that we are enabling.

Figure 18 – Large-scale solar projects being enabled by Power and Water

4.3 Staying ahead of the curve

A key challenge for the Northern Territory is diverse sources of renewable energy in addition to solar, particularly at night when the sun is not shining. Batteries hold the key to this exciting prospect, capturing the sun's energy in the day and discharging the power at night.

Over the past 3 years, the Northern Territory has had the highest take-up of 'solar batteries' in Australia.

The next level is community batteries, which offer a solution where multiple houses are connected to a shared battery, allowing more rooftop solar to be connected and used by the homes involved.

Power and Water is working with the Australian Renewable Energy Agency to install 16 community batteries in the Darwin-Katherine network as part of an initial rollout, and we're in discussions about the next phase.

The growing popularity of electric vehicles also presents opportunities. Electric vehicle batteries are typically much larger than a standard home battery and Vehicle to Grid (or V2G) enables electric vehicles to discharge power back into the grid for household use. This means cars that charge during the day using abundant solar energy can be used to power homes at night. We are working on standards with a view to implementing V2G technology in our system.

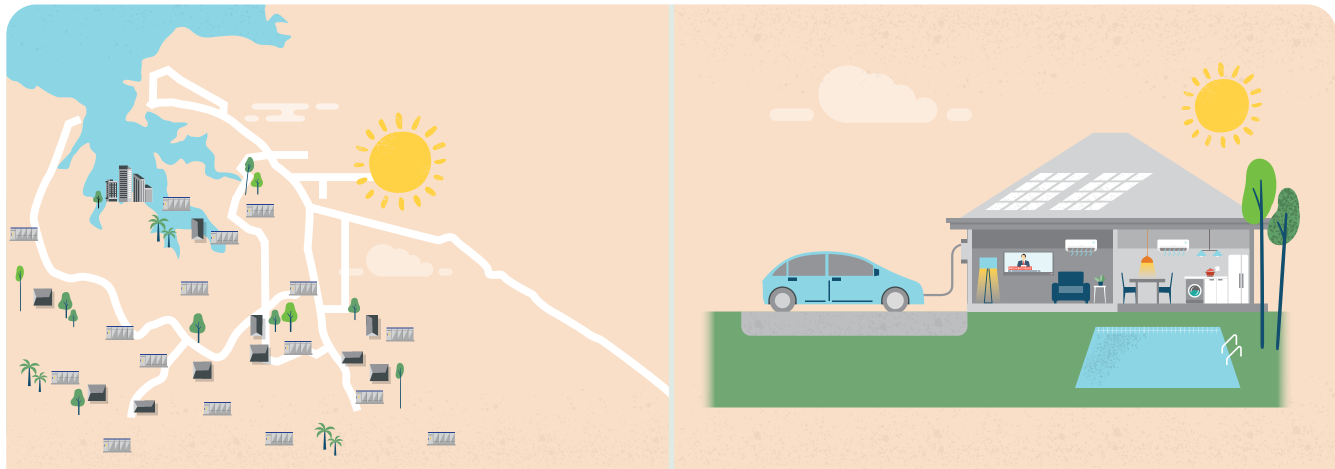
The renewable energy sector is developing quickly, with innovation happening at a global and local level. By working with business, industry and partner agencies, we are aiming to create a network of renewable energy that will deliver power both when we make it and when we need it.

And we're not just helping enable change across the Territory's energy system. Our Environmental Plan sets out the ways in which Power and Water will continue to reduce the environmental impacts of our own day to day operations through initiatives like rooftop solar installations on our substations, reducing water use, lowering our emissions and minimising waste. We are also empowering our workforce to ensure we make sustainability a 24/7 organisational commitment.

Renewable energy has the power to create a green and prosperous Northern Territory, with more choice and flexibility for customers – and Power and Water is excited to be part of this transformation.

Figure 19 provides a visual of the exciting new technologies.

Figure 19 – Community batteries and electric vehicles



A community battery is where multiple houses are connected to a shared battery, allowing more rooftop solar to be connected and used by the homes involved. We're working with the Australian Renewable Energy Agency to install 16 community batteries in the Darwin – Katherine network as part of an initial rollout.

Electric vehicles also offer an exciting power supply using the batteries in the car, which are traditionally much larger than standard home batteries. We are working on standards that will enable EVs to discharge power back into the grid. This means cars that charge during the day using abundant solar energy can be used to power homes at night.

5. Alice Springs – network strategy

Power and Water is committed to developing 25 year 'big picture' plans for our 3 regions that reflect the transformational macro changes impacting our energy system. This year we developed the first iteration of the 2025-2050 Network Strategy for Alice Springs. The purpose was to identify an efficient long-term path to meet multiple drivers of change including demand from electric vehicles, replacement of deteriorated assets, and integrating renewables into the power system. The Network Strategy informs our investment decisions over the 10-year planning period ensuring our current plans align with the efficient long-term development of the network.

We expect transformational change across our 3 regulated regions. This includes a fundamental change to our network design as we transition to renewable energy. We also expect increases in demand for electricity as customers incrementally switch to electric vehicles and the Northern Territory population and economy grows. In addition, we expect that we will need to replace our ageing infrastructure.

In last year's TDAPR we noted that long-term planning is critical to designing an optimal network, and highlighted our plans to develop strategic network plans for each of our regulated networks.

Considering all drivers in an integrated manner will enable us to solve multiple constraints, resulting in lower levels of expenditure. This will help improve service outcomes and reduce pressure on network prices for customers.

This year we undertook our first iteration of a 2025-2050 Network Strategy for Alice Springs. We plan to undertake similar network strategies for the Darwin-Katherine and Tennant Creek networks over the coming years.

The Network Strategy informs our investment decisions over the 10 year planning period ensuring our current plans align with the efficient long-term development of the network.

5.1 Uniqueness of Alice Springs

Alice Springs is located approximately 1,500 km south of Darwin, which makes it uneconomical to connect to an interconnected system.

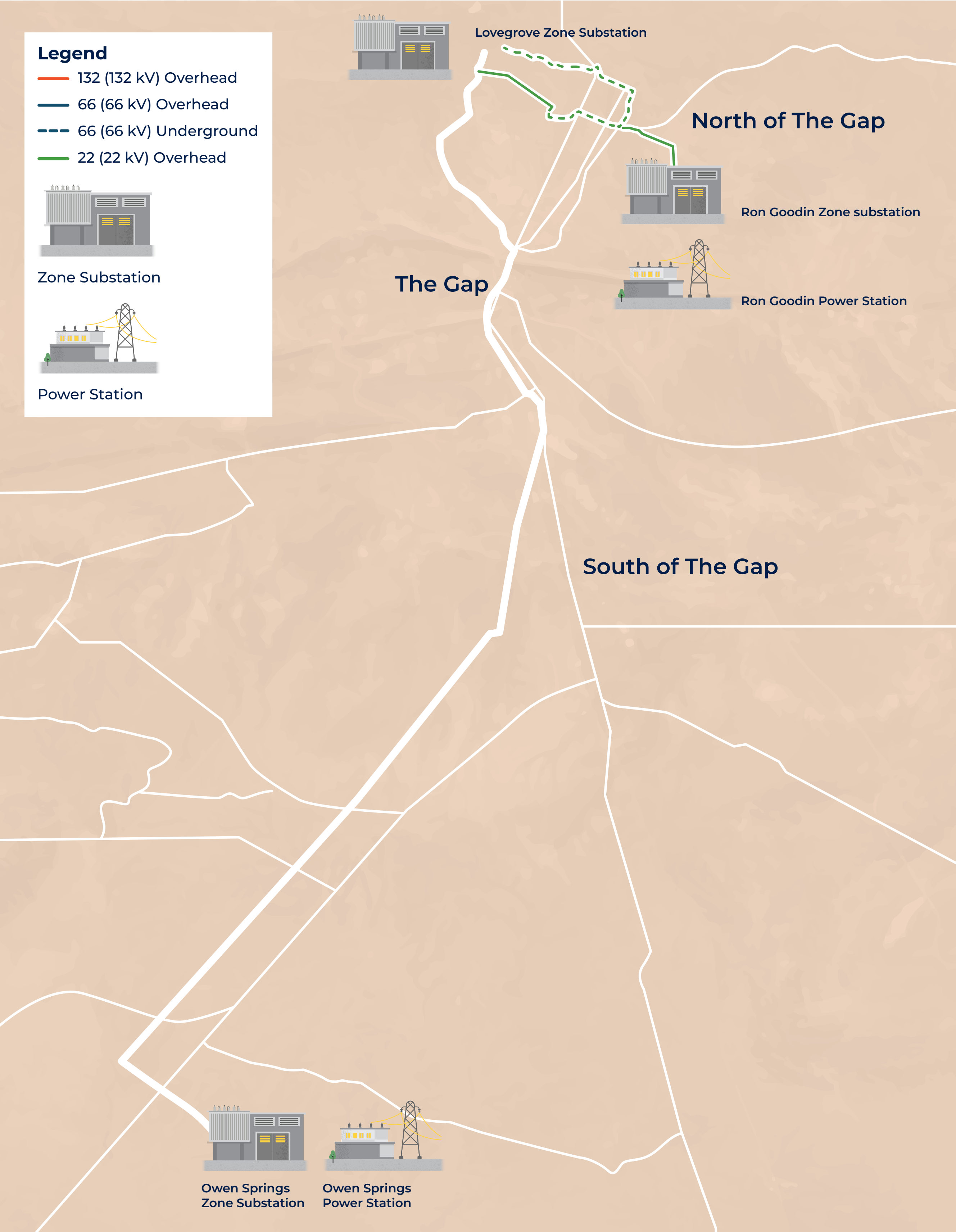
The stand-alone electricity network in Alice Springs is relatively small compared to other networks in Australia, providing power to approximately 10,000 residential households and 1,700 business customers.

The MacDonnell Ranges pass along the south of Alice Springs and geographically splits it into two regions. 'The Gap' is a natural valley through the ranges and the primary connection between the two regions, which is reflected in the configuration of the electricity network.

North of The Gap is supplied at 11 kV and is comprised of the Alice Springs CBD, older commercial areas and most residential customers. The region south of The Gap is comprised of predominantly commercial and industrial customers and is supplied at 22 kV. Most future load growth, including future residential development, is expected south of The Gap.

Owen Springs Power Station is the primary power station with a firm capacity of 90 MVA. Subtransmission is supplied at 66 kV from Owen Springs Power Station to Lovegrove zone substation. **Figure 20** is a map of the Alice Springs power system and network.

Figure 20 – Map of Alice Springs network



5.2 Drivers of change to 2050

The Alice Springs electricity system is likely to face accelerated change in the medium to long-term. The key factors impacting the development of the network are set out below.

Replacement of key assets

The replacement value of the network is approximately $500 million. This provides a gauge to the historical costs of developing the Alice Springs network over time. The cost breakdown of each asset fleet is shown in **Figure 21.**

The transmission network assets reflect the need to transport electricity from Owen Springs Power Station to Lovegrove substation via The Gap. It comprisesmore than 200 transmission poles strung across 33 kilometres of 66 kV overhead conductor. There is an additional 14 km of underground transmission cable.

The distribution network is comprised of zone substation equipment at Lovegrove, Sadadeen and Brewer. There are more than 6,000 poles on the distribution network, which support more than 500 kilometres of high voltage overhead conductors and more than 100 km of low voltage conductors. There are also 100 km of high voltage underground cable, and close to 100 km of low voltage cable. There are more than 550 distribution substations.

The condition of major assets on the backbone of the network including transformers and switchboards is expected to deteriorate over the next 25 years:

- Sadadeen 22 kV switchboard – Current condition and risk assessment identify a need to replace the switchboard by 2026 due to the high risks of keeping the asset in service.
- Lovegrove 11 kV switchboard – The switchboard was installed in the early 1980s. We expect a need to replace the asset will arise by 2035.
- Sadadeen transformers 2 and 3 – The 22/11 kV transformers are 33 years old and expected to have about 10 years remaining life based on recent oil analysis. We expect a need to replace the asset by 2035.
- Lovegrove transformer 2 and 3 – The 22/11 kV transformers are 39 years old and expected to have about 10 years remaining life based on recent oil analysis. We expect a need to replace the asset by 2035.
- Sadadeen transformer 1 – The 22/11 kV transformer is relatively new and in good condition. However, based on standard lives, we expect a need to replace the asset by 2040.
- Lovegrove transformer 1 – The 22/11 kV transformer is 17 years old. However, based on standard lives, we expect a need to replace the asset by 2040.

Increasing demand

There is currently sufficient capacity to meet demand at peak times under critical contingencies. **Figure 22** shows the load duration curve compared to capacity under N-1 demonstrating that current capacity is sufficient to meet even peak loads. However, the backbone of the network will require additional capacity if peak demand increases over the medium-term including the potential need for additional transformers or zone substations. The key drivers of change include:

- Electric vehicles – About 65% of customers in Alice Springs have one or more vehicles, with an average of 1.6 cars per household. As customers choose to take up electric vehicles, we expect a significant increase in consumption including on peak days of energy use. Each electric vehicle can add 3 MWh or about 50% of a typical customer's energy consumption in Alice Springs. Our forecasts of electric vehicle penetration has sought to examine take up of the primary and secondary vehicle by customers in Alice Springs.
- Residential developments – We expect that more residential developments will occur south of The Gap where there is more land available.
- Commercial developments – Master land plans identify commercial and industrial land south of The Gap for non-residential development.

Integrating renewables into the network

About 1 in 5 customers have a solar panel in Alice Springs. Customers currently use the network to export about 10,500 MWh of energy into the low voltage network, close to 10% of total energy consumed in Alice Springs.

We expect that solar uptake will continue in Alice Springs. This is because a high proportion of new homes are expected to be built with solar. Growing rooftop solar is already challenging in Alice Springs and new technologies (see section 3.1) are required to manage exports on sunny and mild days.

We also note there are likely to be large-scale solar developments in Alice Springs that we need to consider when developing an optimal long-term network plan.

Figure 21 – Replacement value of Alice Springs network

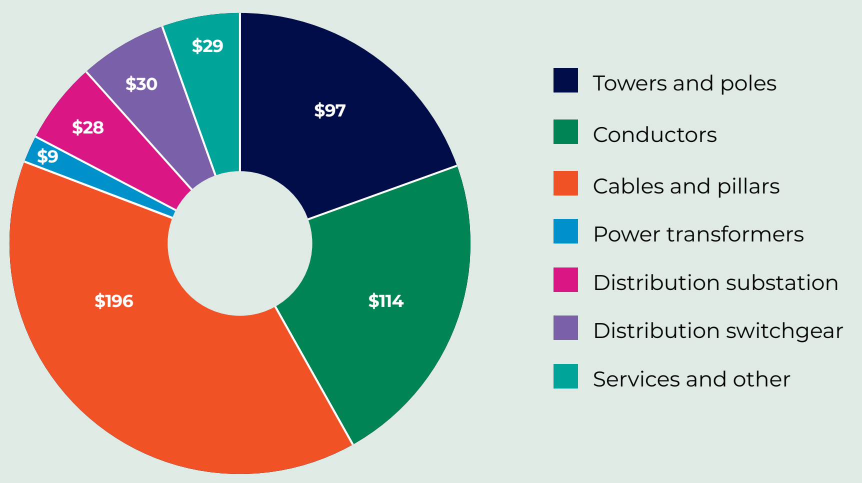
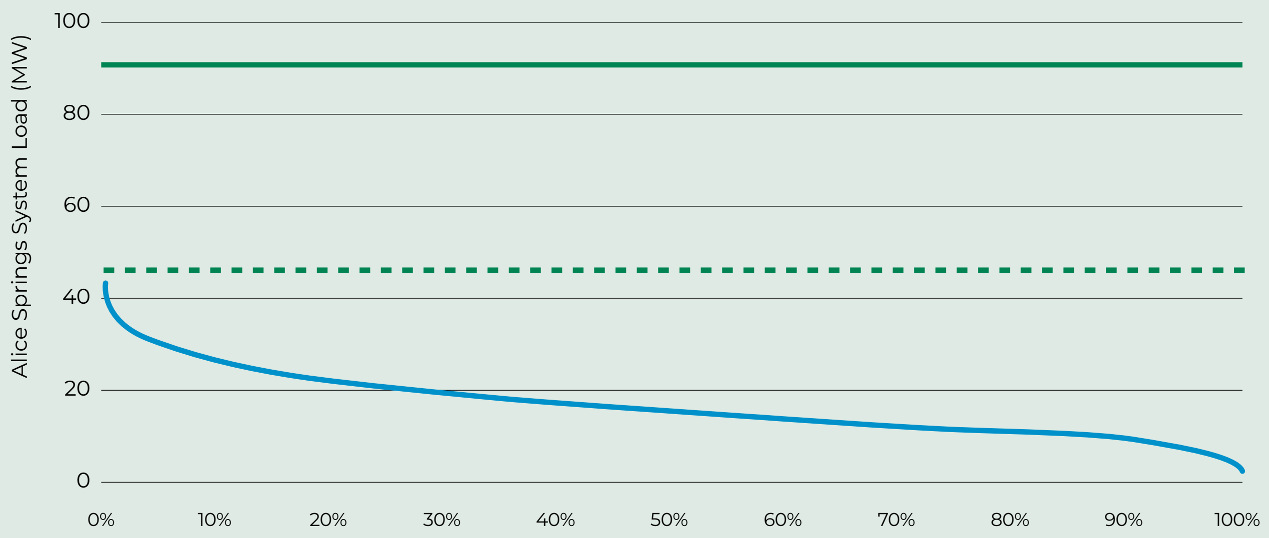


Figure 22 – System duration curve



5.3 Future state scenarios

A 25 year outlook is inherently uncertain given rapid changes in technology and customer preferences. For this reason, we sought to test investment plans against potential scenarios so that we could investigate the efficiency and prudency of potential pathways, and also understand decision points which may require a change from the pathway.

We identified 4 scenarios to test investment pathway options. The scenarios differ in terms of peak demand drivers including electrical vehicle uptake, renewable energy growth, and the level of tariff reform and dynamic controls to manage peak demand and export of customer energy resources.

Under all scenarios, we considered the timing of condition based replacement of major assets is unlikely to vary.

Vibrant

Under this scenario, Alice Springs' population would increase significantly by 2050 consistent with the current Northern Territory planning targets. The growth areas for new homes is predominantly south of The Gap.

Energy consumption per customer would significantly increase under this scenario due to high uptake of electric vehicles and electrification mirroring projections of uptake in New South Wales and Queensland in the Australian Energy Market Operator's 2024 ISP. This would be offset to a degree by energy efficiency housing and appliance use, and greater self-consumption from solar and batteries.

In this scenario, we would expect higher demand to bring forward investments in large-scale solar, which could be co-located with the industrial land use zone.

Small-scale solar would continue to increase and be accompanied by greater penetration of home batteries. This would enable opportunities for orchestration of customer energy resources such that less solar is curtailed in the day hours. Similarly, under this scenario customers shift demand to off-peak periods in the summer, particularly charging electric vehicles in the daytime to coincide with solar. This scenario requires significant tariff reform.

Out of Control

An 'out of control' level of growth in Alice Springs' has similar levels of growth in demand as the vibrant scenario with the same assumptions on high population growth, electrification of vehicles and gas, and industrial and commercial growth south of The Gap.

However, there is a lack of tariff incentives and dynamic controls to manage customer energy resources and appliances such as electric vehicles. The key issues that emerge include a very high increase in peak demand relative to Vibrant Alice Springs, bringing forward the need for new infrastructure.

Under this scenario, the network would require higher levels of investment to control solar to meet network challenges.

Steady as you go

Under this scenario, we assume that Alice Springs grows at the same rate as the last 5 years. This includes a small increase in population and commercial customers, continued uptake of small-scale solar with only an incremental increase in battery storage, and no significant changes in tariff reform for smaller customers.

We would still expect a significant increase in energy per customer due to electric vehicle uptake. However the uptake of EVs is delayed and much slower than projected for customers in New South Wales and Queensland. Electrification of gas in this scenario is negligible, as customers stick to gas.

The lack of investment in batteries, together with slower pace of reform in tariff design and limited dynamic controls means that small-scale solar is not well managed. For this reason, peak demand grows at a quicker pace than energy consumption, albeit at lower levels than Vibrant or Out of Control scenarios.

Same as today

Under this scenario, there is no material increase in customers in Alice Springs. In effect, south of The Gap does not increase in scale as commercial and residential developments do not proceed. Under this scenario, we assume electric vehicle sales are even more delayed than the Steady Alice scenario.

The increase in energy consumption from electric vehicles is more than offset by customers installing solar and using it to power their own needs.

The material differences between the scenarios relate to electrical vehicle update as seen in **Figure 23**. As discussed in the previous sections, we have employed a novel approach that reflects the type of car travel in the Northern Territory. We consider that the primary car of a customer is used for long distance travel, and customers would delay buying an EV. However, the second car is assumed to be more for local travel and customers would be more willing to purchase an EV due to charging accessibility.

The uptake of EVs in each scenario, together with the rate of residential and commercial development impact the forecast of peak demand. This is also impacted by the level of tariff reforms and dynamic controls. **Figure 24** and **Figure 25** are the forecasts of peak demand for the 11 kV and 22 kV networks in Alice Springs.

A 25 year outlook is inherently uncertain given rapid changes in technology and customer preferences.

Figure 23 – Forecast uptake of EVs for customers primary and secondary car by 2050

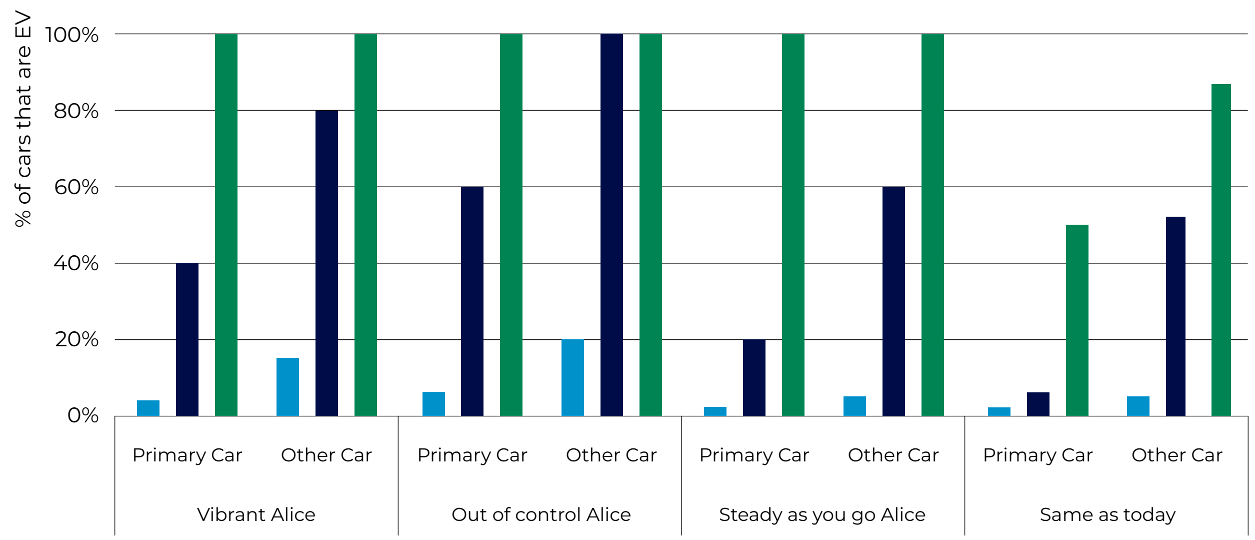


Figure 24 – Peak demand for different scenarios for Alice Springs' 11 kV network

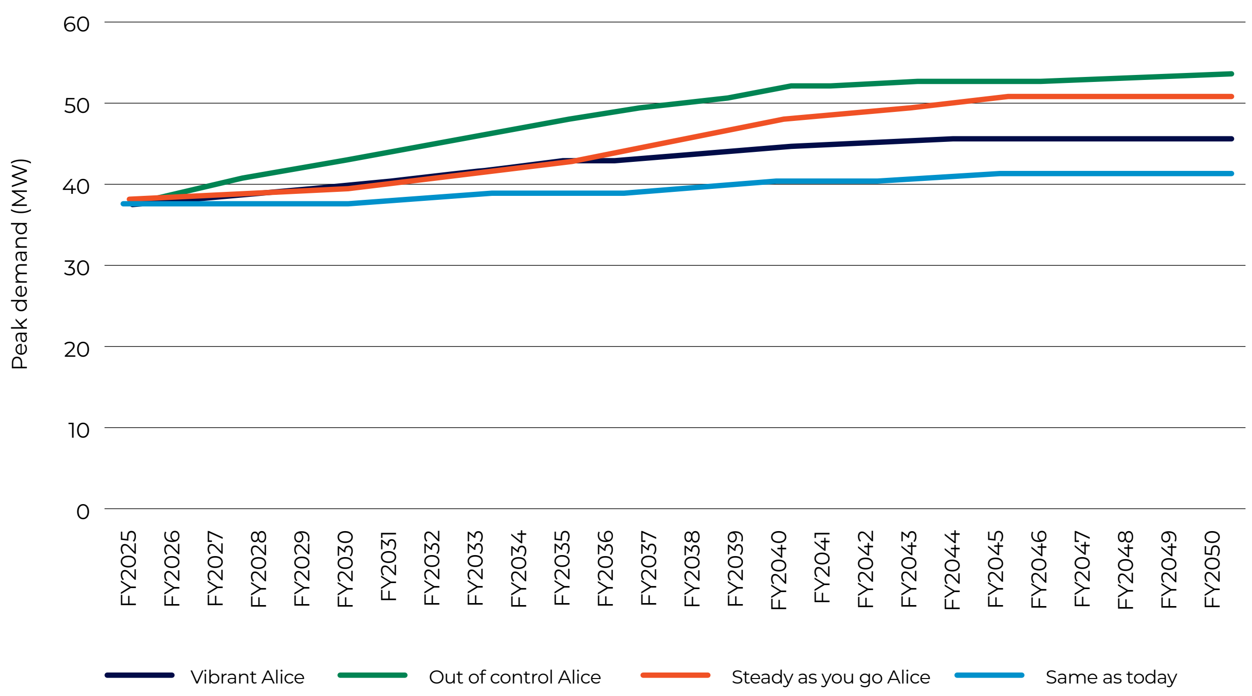
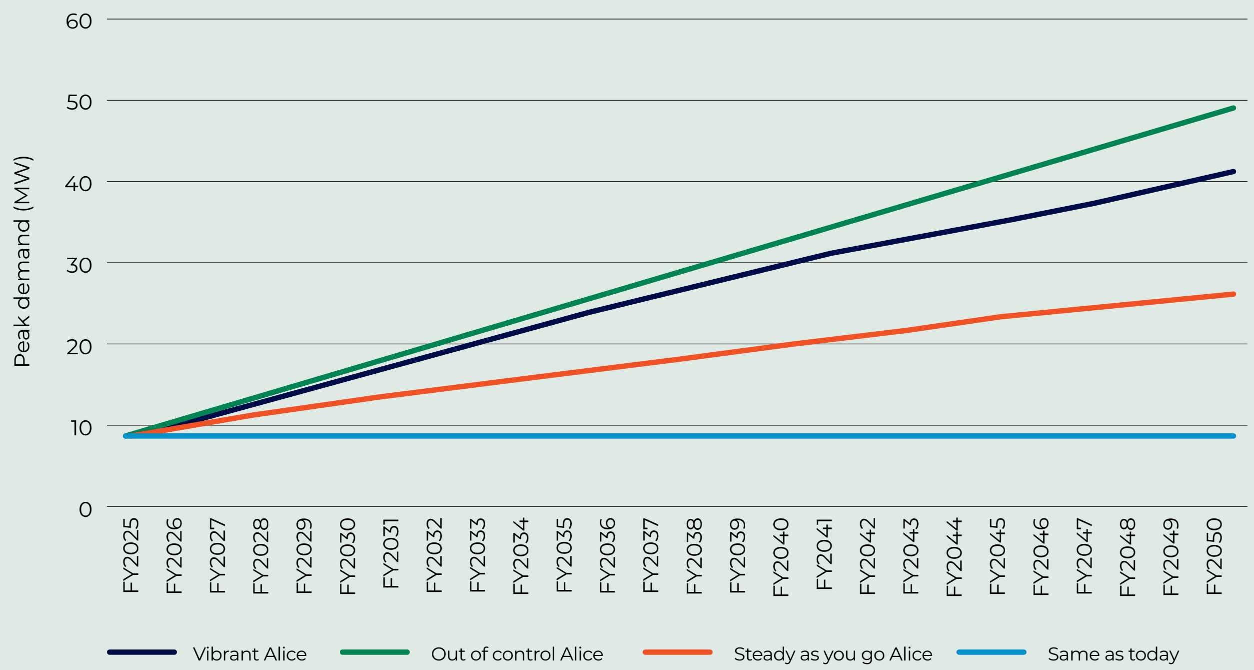


Figure 25 – Peak demand for different scenarios for Alice Springs' 22 kV network



5.4 Options assessment

We assessed options to develop the Alice Springs network under each of the 4 scenarios. The options took into account the challenges with the current configuration of the network, opportunities to streamline the configuration as assets are progressively retired, and the need to cater for future demand scenarios.

Options assessment

We identified 6 pathways for the development of Alice Springs based on meeting the identified needs under each of the 4 scenarios including:

- Option 1 – This retains the current network configuration, replacing current network assets with an equivalent modern asset and building a new zone substation at Norris Bell (south of The Gap) at the time that forecast demand exceeds capacity.
- Option 2 – The same as option 1, except for future increases in demand being met by building a new transformer at Lovegrove substation.
- Option 3 – Re-configures the network by retiring the 22 kV switchboard at Sadadeen, using new 22 kV cables from Lovegrove substation and converting Sadadeen to 11 kV. Future increases in demand would be met by either building a third transformer at Lovegrove or a new Norris Bell Zone Substation based on net present value assessment at that time.
- Option 4 – The same as Option 4, but retains Sadadeen at 22 kV through 22/11 kV transformers.
- Option 5 – Reconfigures the network by decommissioning Sadadeen switchboard with cables, then progressively retires 22 kV assets north of The Gap and builds Norris Bell Zone Substation to meet future 22 kV demand south of The Gap.
- Option 6 – Converts Alice Springs to 22 kV. Replaces all 11 kV distribution with 22 kV assets. Demand growth is addressed by building Norris Bell Zone Substation or installing a 3rd 66/22 kV transformer at Lovegrove based on net present value assessment at that time.

Preferred pathway

We assessed the preferred pathway through net present value analysis and a qualitative assessment of risks and benefits. The net present value analysis used best practice cost-benefit analysis by applying a methodology similar to the AER's Regulatory Investment Test.

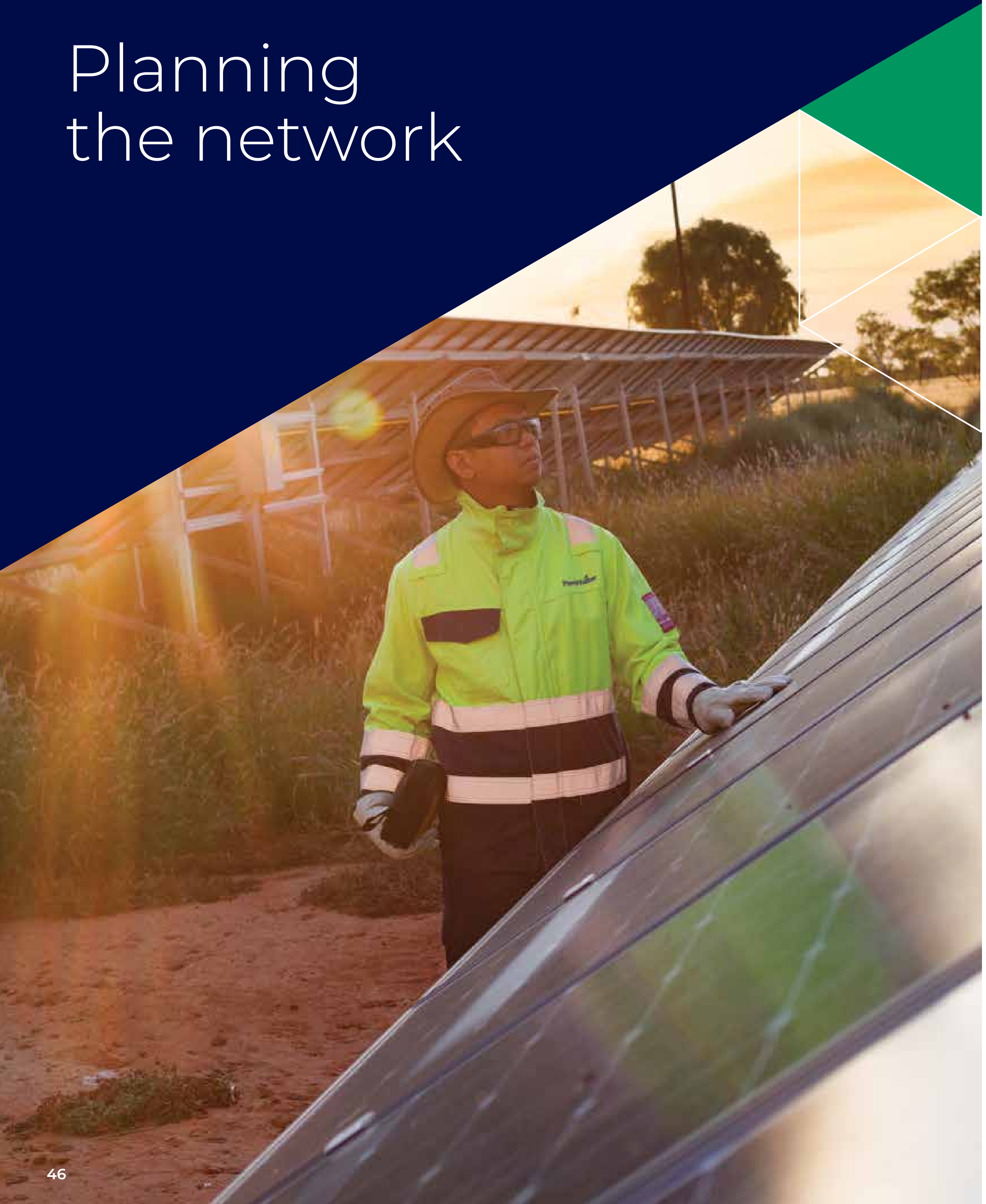
The preferred pathway was Option 3 in scenarios where there is high demand. High demand scenarios have been given extra weight in our cost benefit studies based on the expectation for population growth and electric vehicles.

Option 5 was ranked highest in cases where forecast demand was lower, and should it be considered under situations where electric vehicle uptake is subdued or where developments south of The Gap are delayed.

This is our first iteration of the Alice Springs network strategy, and we will update and refine the strategy over time as circumstances and information changes.

PART C

Planning the network



6. Asset management and network planning

Power and Water has a strategic asset management system that reflects a 'whole of lifecycle' approach to efficiently manage our assets. As part of the framework, we undertake regular planning reviews to identify emerging system limitations and solutions. A key focus of our planning is identifying lower cost non-network solutions to address limitations. In this year's TDAPR we identify key improvements to our planning approach, including strategic long-term planning for each of our regions, system strength and voltage studies, and a new method for spatial demand forecasts.

The purpose of this section is to describe our framework for maintaining assets and planning our network. We provide a brief outline of key network planning obligations, describe our asset management processes, and set out the planning approach for identifying investment needs and options.

6.1 Obligations impacting our activities

Power and Water is subject to specific Northern Territory and national regulations that direct and influence the way we manage, operate and plan our network. The key planning obligations that directly influence our planning decisions are described below.

Our planning decisions are also based on other regulations such as corporate responsibility, worker safety and the environment. Further, we have a regulatory obligation to adhere to good electricity industry practice when providing network access services and in planning, operating, maintaining, developing and extending the electricity network.

Network Technical Code and Network Planning Criteria

Power and Water must comply with an obligation under the NT Electricity Reform (Administration) regulations to publish a Network Technical Code and Network Planning Criteria. In March 2020, we published a document that combines the two requirements.[7]

The Network Technical Code sets out network performance criteria including frequency, quality of supply, stability, load shedding, reliability, steady state criteria, and safety and environmental obligations. It also sets out power system security requirements. The Network Planning Criteria identifies the supply contingency criteria that we must use to plan and operate our network.

The criteria relate to:

- Supply contingency – the ability of the supply system to be reconfigured after a fault (contingency) so that supply to customers can be restored.
- Steady state – the adequacy of the network to supply the energy requirements of users within the equipment ratings, frequency and voltage limits, taking account of planned and unplanned outages.
- Stability – to ensure the power system can return to a steady-state or equilibrium operating condition following a disturbance.
- Quality of supply criteria – this relates to operating the system within the acceptable voltage and current ranges.

[7] The documents can be accessed on our website at: https://www.powerwater.com.au/developers/power/technical-code-and-planning-criteria.

Northern Territory Electricity Industry Performance Code (EIP Code)

The EIP Code applies to our regulated networks of Darwin-Katherine, Alice Springs and Tennant Creek. The code influences the way we plan the network to achieve reliability targets and address worst performing feeders on our network. The EIP Code also requires us to provide an annual report to the Utilities Commission on the 5 worse performing feeders for each feeder category.

This includes information on the SAIDI performance on each of the identified feeders, a statement that explains the performance and action we intend to take to improve performance. We discussed our network performance for 2023-24 and outlined our reliability program to address reliability issues in Chapter 2.

Northern Territory National Electricity Rules (NT NER)

Power and Water is subject to planning obligations under Chapter 5 of the Northern Territory NER. This includes obligations to forecast demand on elements of our network, obligations to undertake annual planning and report on outcomes, and specific obligations with respect to connecting large customers and embedded generators.

Chapter 5 of the Northern Territory NER also requires us to manage, maintain and operate our network to minimise interruptions to connected customers, and restore the network as soon as reasonably practical following an interruption.

Potential new obligations

The Northern Territory Government is continuing to reform the electricity market. A key focus area is improving the efficiency of Essential System Services (ESS) of the power system.

Power and Water will likely have procurement responsibility for locational voltage and system strength requirements. This would mean we need to prudently incur expenditure to safeguard the network and power system when thermal generators are replaced by inverter-based technologies such as solar that do not intrinsically provide ESS.

In February 2022, the National Electricity Rules were amended to allow electricity distribution businesses to implement Stand Alone Power Systems (SAPs). SAPs typically comprise solar panels, batteries and back-up generators.

They can include both microgrids and individual power systems and are generally used when it is not economic to build long power lines to connect remote communities.

The arrangements for SAPs have not yet been adopted in the Northern Territory NER. We will continue to work with the Northern Territory Government to understand when these arrangements are likely to be implemented. In the meantime, we will continue to build our understanding of the costs and benefits associated with implementing SAPs solutions in parts of our unregulated network.

The Northern Territory Government is continuing to reform the electricity market. A key focus area is improving the efficiency of Essential System Services (ESS) of the power system.

6.2 Improvements to planning

Power and Water is implementing significant changes to our approach to capital planning.

Strategic Network Plans for each region

We recognise that long-term planning is critical at a time of significant transformation of the Northern Territory electricity systems. We expect significant and fast paced change in both the generation mix and the demand for electricity in all our regions. This will come at a time when many of our assets are reaching the end of their technical life.

For this reason, we are undertaking strategic network plans for each of our regulated networks. This will provide an opportunity to efficiently design the network to address multiple drivers of investment, such as demand growth, asset condition and ESS.

Considering all drivers in an integrated manner will enable us to align investments and consider non-network solutions to resolve multiple constraints with lower levels of investment. This will help us to optimise the network over the long-term, provide improved service outcomes and lower costs for customers.

We have completed the first iteration of the 2025-30 Alice Springs Network Strategy and will develop similar strategies for the Darwin-Katherine and Tennant Creek regulated networks.

We expect the Regulated Electricity System Investment Plan (RESIP) to be published in 2025 and we will need to make sure our strategic planning aligns with the RESIP.

System strength and voltage studies

Power and Water is responsible for undertaking studies to assess system strength and fault levels, network voltages and to assess the ability of our assets to transmit the required power through the network.

Power and Water has recently completed a network wide study to assess fault levels at each bus of all of our zone substations to ensure that the fault levels are within the design parameters of the assets and still sufficient for our protection device settings.

We have also recently undertaken load flow and dynamic studies to assess the impact of changes to generation on parts of the system so we can mitigate any issues and enable the transition to renewable energy.

These types of studies will become increasingly important as the existing synchronous generation retires and is replaced by predominately renewable generation.

Spatial demand forecasts

Peak demand forecasts are an important input to identifying emerging capacity constraints on our network. As discussed in Chapter 6, we forecast peak demand for electricity at both a system level (system demand forecast) for Darwin-Katherine, Alice Springs and Tennant Creek, and at a locational (spatial) level for zone substations and distribution feeders.

Chapter 6 identifies key improvements to our forecast methodology that were implemented last year and have continued this year including:

- using 'feels like' temperature metrics that take into account humidity as well as temperature
- separately assessed demand correlations on weekdays in non-holiday periods to provide greater precision in our demand forecasts
- excluding drivers found to not be correlated with demand
- using longer term trends for historical data.

These demand forecasts directly inform our investment requirements and the projects described in Chapter 9.

Regulatory Investment Tests procedure

The Regulatory Investment Test (RIT) is an investment justification required under the Northern Territory NER. The RIT has specific requirements relating to customer consultation, consideration of non-network solutions and the type and depth of economic analysis.

There are different requirements for distribution and transmission projects, and these are termed the RIT-D and RIT-T, respectively. RITs apply to new projects that meet the thresholds and requirements. To ensure that we are ready for this change, we have amended the RIT procedure that will guide our project development engineers through the process to ensure all RIT requirements are met. No projects required a RIT consultation in 2023-24.

Engineers assessing risk

6.3 Asset management framework

Our asset management strategy seeks to efficiently provide a safe, secure and reliable electricity network service to our customers. To meet this objective, we have a Strategic Asset Management System (SAMS)[8] that draws on industry best practice and international standards to set out how Power and Water will manage our assets and the key artefacts that will document and communicate it.

The Asset Management Policy sets out the guiding principles for applying the SAMS. It also demonstrates the commitment of our senior leadership to effective asset management.

The Strategic Asset Management Plan (SAMP) aligns our corporate objectives to our asset management objectives.[9] The SAMP reflects a 'whole of lifecycle' approach to asset management through planning and design of new assets, maintaining and operating existing assets, and renewal and retirement of assets. The SAMP also describes challenges being faced at a network level and management strategies.

Asset Management Plans (AMPs) describe how each individual asset class contributes to achieving the asset objectives. The AMPs assess asset condition, specific performance issues and asset challenges, and describe the identified plans to address any gaps compared to the asset objectives and to achieve the required performance.

Asset maintenance

Our maintenance activities seek to cost effectively ensure assets remain functional and in service. Routine activities include inspections, patrols, surveys, testing, repair of assets and switching activities. Non-routine activities are predominantly directed at restoring asset condition or performance, or rectifying defects.

Our approach to routine and non-routine maintenance is based on the principles of objective need and risk management. Our goal is to optimise maintenance by prioritising activities based on asset condition.

The intensity of maintenance activities for each asset class is dependent on several factors including the existing condition and performance of the assets, operating environment, location of asset and demand profile. The appendices identify our maintenance strategies for each asset class.

Over the last decade, we have made significant improvements to our asset maintenance framework. The recent roll-out of mobile field devices for maintenance work enabled asset information to be captured and entered directly into our asset management system. This initiative has been critical to improving our understanding of asset condition and performance.

We are also currently reviewing and developing online monitoring techniques to improve asset reliability and maintenance efficiencies.

Our inspection and condition monitoring practices have evolved and will continue to be optimised through maturing risk management practices. Our maintenance strategies are set out in the appendix to this report.

Asset renewal and retirement

We apply an economic assessment as part of our risk quantification procedure to identify the optimal time to retire or replace assets.

Our framework considers the asset's condition and failure modes, the likely risks of failure on safety, security and reliability of services to customers, and the relative maintenance and capital costs. In some cases, our decision making will be influenced by demand growth or customer upgrade requirements. Essentially, our decision making is based on an economic assessment of risks, costs and benefits.

Our approach recognises that the criticality and consequence of asset failure varies among different network assets. For this reason, we apply different strategies to our asset classes based on risk profile, capital value and criticality to reliable and safe operation of the network. The replacement strategies include:

- Replace on failure (functional failure) – the asset has low criticality, and where asset condition information is difficult or costly to gather. In these cases, it is more economical to keep the asset in service provided the maintenance costs do not justify replacement.
- Condition-based (conditional failure) – the function provided by the asset is critical and the cost of risk exceeds the replacement cost. In these cases, we need a clear measure that the asset is not providing the level of service required. This can include reliability, safety and power quality performance.
- Planned (proactive replacement) – there are emerging risks such as safety or environmental risks, change in technology, or legislative and compliance changes. In these cases, asset condition may be measurable and can be used to prioritise replacements or spread replacement activity over longer timeframes to eliminate significant spikes in expenditure and associated resources.
- Demand-driven – we identify that the existing installed capacity is insufficient to supply the forecast demand. This recognises that there may be synergies in the timing of replacement to meet a demand driver.
- Customer driven – the individual customer requests new or increased capacity. Similar to above, this recognises there may be synergies in retiring an existing asset in degraded conditions at the time of an upgrade.

Our asset management strategy seeks to efficiently provide a safe, secure and reliable electricity network service to our customers.

[8] Power and Water, Strategic Asset Management System, August 2022. The SAMS is a framework that sets out the information and documentation required for Asset Management, it does not refer to a software system.

[9] Power and Water submitted our SAMP to the AER in January 2023. This can be downloaded from the AER's website.

6.4 Methodologies for planning the network

Under our asset management framework, we undertake regular reviews of our network to determine emerging issues and solutions. As we operate standalone transmission and distribution networks in our regulated areas, we have no joint planning requirements or activities.[10]

In 2021, we extended the planning outlook from 5 to 10 years for our distribution network. This aligned our transmission and distribution networks and is a sensible approach given the need for long-term planning. We have retained the 10-year planning horizon for both transmission and distribution in this year's TDAPR.

Our planning process seeks to identify system limitations including:

Capacity constraints – On an annual basis, we forecast projected maximum and minimum 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. Our planning process considers if there is likely to be thermal constraints on our equipment with reference to the network planning criteria.

Condition of assets – Using a risk-based approach, we identify assets that should be replaced, retired, or more intensely maintained. The condition of assets is influenced by age, previous maintenance, environmental conditions such as exposure to salt, humidity, proximity to animals and extreme weather events.

Quality of supply issues – We monitor power supply issues based on customer feedback, and monitoring data from meters and zone substations. Quality of supply is impacted by a generator tripping or transmission fault, switching of network equipment such as reactive plant, installation and switching of customer loads, and embedded generation such as solar rooftop installations.

Fault levels – We regularly review whether the fault levels remain within our asset's fault level ratings and if the asset ratings comply with those prescribed in the Network Technical Code. Fault levels are impacted by changes in the configuration of the network particularly with the addition of generators, embedded generation, power transformers and large motors.

Distribution losses – We monitor the extent of distribution losses on the network and identify if action is required to minimise losses.

Non-network solutions – An integral aspect of our planning framework is to investigate whether non-network solutions can effectively defer or avoid investment. We understand that non-network solutions hold the key to improving affordability for our customers by reducing the cost of addressing network limitations.

6.5 Updated governance framework

Our investment governance framework was reviewed and updated during 2023-24 to the Investment and Delivery Framework (IDF). The key changes ensure a consistent approval process for all projects with the detail and approval authority based on project type and complexity/risk rather than just value.

Once a system limitation has been identified, we analyse whether it gives rise to an investment need. The first internal gateway for the creation of a project is the investment Brief. The purpose of the Brief is to demonstrate there is a need for investment and obtain approval to undertake further analysis that is required to develop options and project planning.

The next step for major projects is a formal Options Analysis (OA) to demonstrate that all credible options have been identified and assessed and the preferred option identified on an economic and technical basis.

The final step for investment development – for all investments – is a full business case. This demonstrates the need and options analysis, refines cost estimates through market testing if required and identifies the preferred option. For investments which did not require the OA stage, the options analysis in the business case should be detailed enough for the value and complexity of the investment.

After the completion of the project, we conduct a Post Implementation Review (PIR) to confirm whether the expected benefits have been delivered by the investment to inform continual improvement of the process.

[10] The Northern Territory NER requires that a network's TDAPR specify joint planning obligations and activities

Power and Water staff delivering on asset plans

7. Demand forecasts

Power and Water has a rigorous method to forecast maximum demand on our transmission lines, zone substations and distribution feeders. Our method relies on annual reviews of recent demand data and projections of new customer connections and embedded generation. At the system level, solar PV is causing minimum demand to occur during the middle of the day and is expected to continue decreasing, while maximum demand is occurring in the evening when solar PV generation is not available.

Demand forecasts are a key part of our planning process, helping us establish whether any element of our network will face a capacity limitation.

7.1 Methodology

Power and Water undertakes an annual review of demand forecasts commencing in April of each year. The timing of the review allows us to incorporate most recent data on maximum demand into our annual demand forecasts, which generally peaks in the November to March period. This coincides with the wet season in Darwin-Katherine and summer in Alice Springs and Tennant Creek.

As discussed in Chapter 6, we prepare maximum and minimum demand forecasts at a system level for each of the three regulated regions ('System demand forecasts'). The system demand provides an aggregate view of coincident consumption across the network.

We also undertake spatial demand forecasts of maximum demand at an individual zone substation and distribution feeders. Due to different load profiles, the sum of zone substation maximum demands is always greater than the system maximum demand.

The same demand forecasting methodology is applied at both system and spatial levels, with the difference being the input data.

The methodology has been designed to address Power and Water's key requirements, available data and to be consistent with industry best practice. Key elements include:

- 5 years of historical data (FY2019-20 to FY2023-24 inclusive) for zone substations and distribution feeders and 10 years of data (FY2014-15 to FY2023-24 inclusive) for system forecasts
- accounting for holidays and weekends in our analysis as the demand profile can be different to a weekday
- identifying and adjusting for abnormal system conditions, such as large customer outages
- removing identifiable major loads that are location specific (spot loads)
- normalising for weather conditions including 'feels like' temperatures that captures the impact of humidity. We also take into account solar irradiance for minimum demand day forecasts
- using regressions of normalised historical demand for each hour of the day against solar PV uptake, economic growth, building activity and population growth drivers
- as a final step we add back existing spot loads and forecast of the impact of anticipated spot loads
- add in electric vehicle charging demand forecast.

The results of the regression for each variable are assessed for their statistical significance and fit so the final forecast only considers drivers that are found to have a causal effect on historical consumption. Where no such drivers are found, or the results produced are deemed infeasible, linear trends of historical data are used.

7.2 System demand forecasts for the three regulated regions

Power and Water's maximum and minimum demand forecast at a regional level for the Darwin-Katherine, Alice Springs and Tennant Creek networks are shown in **Figures 26 to 31** Each region has different factors explaining the actuals compared to the previous year and the 10-year outlook.

Figure 26 – Darwin-Katherine maximum demand forecasts

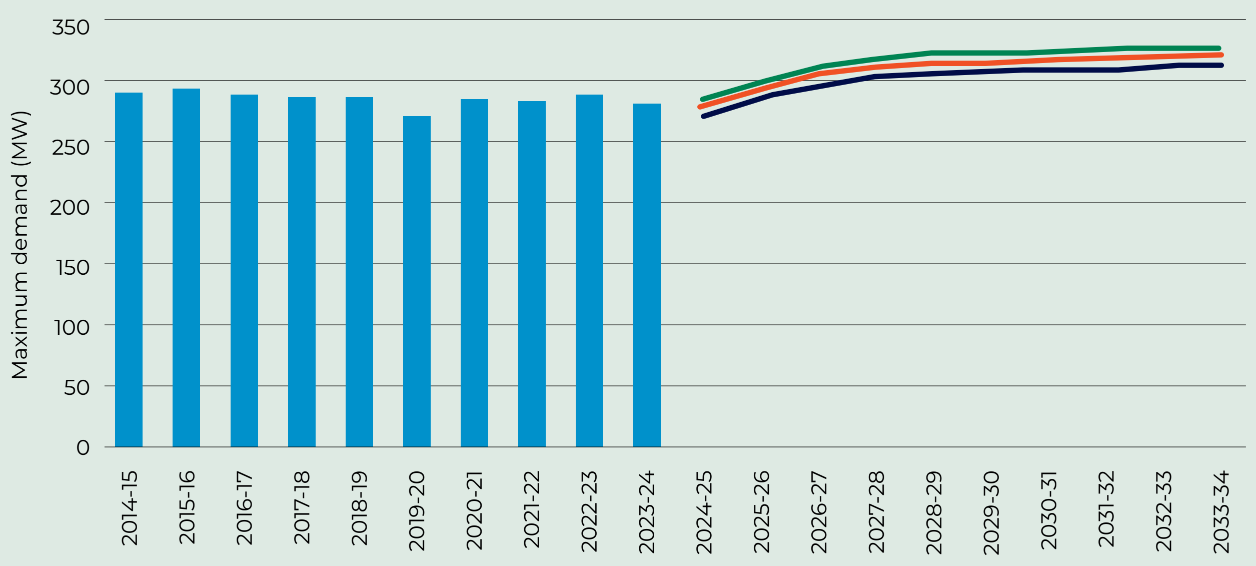


Figure 27 – Darwin-Katherine minimum demand forecasts

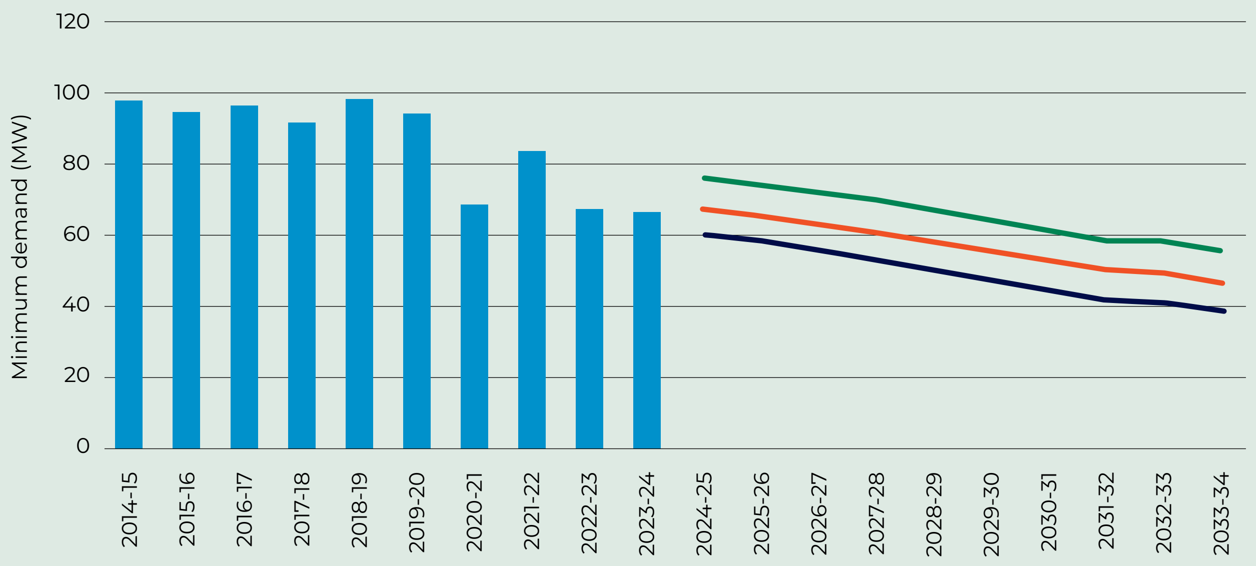


Figure 28 – Alice Springs maximum demand forecasts

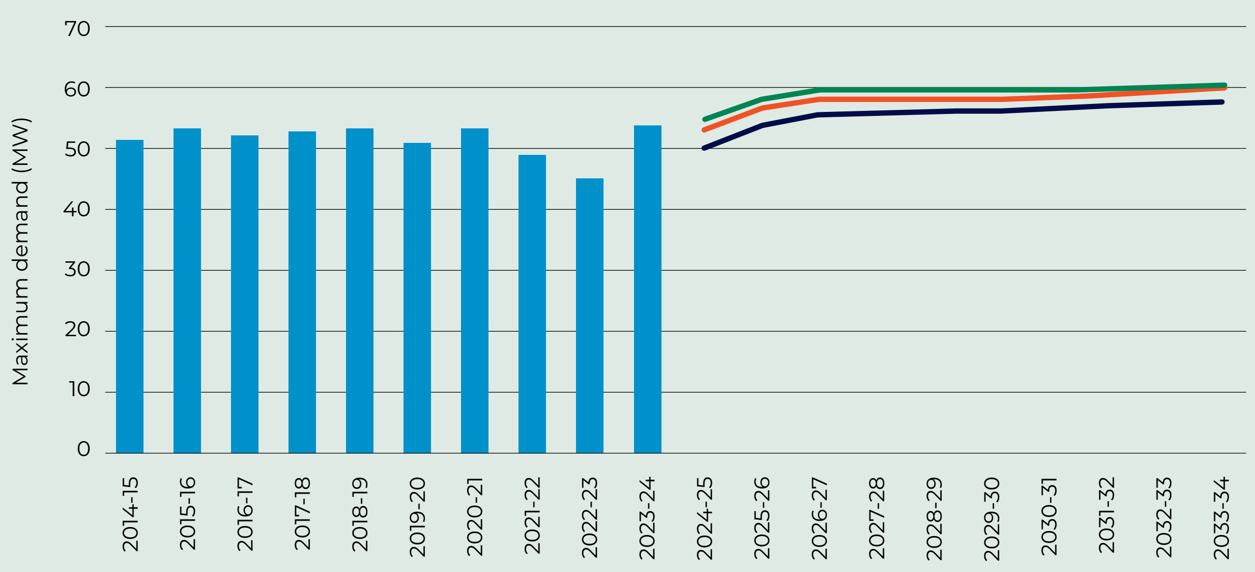


Figure 29 – Alice Springs minimum demand forecasts

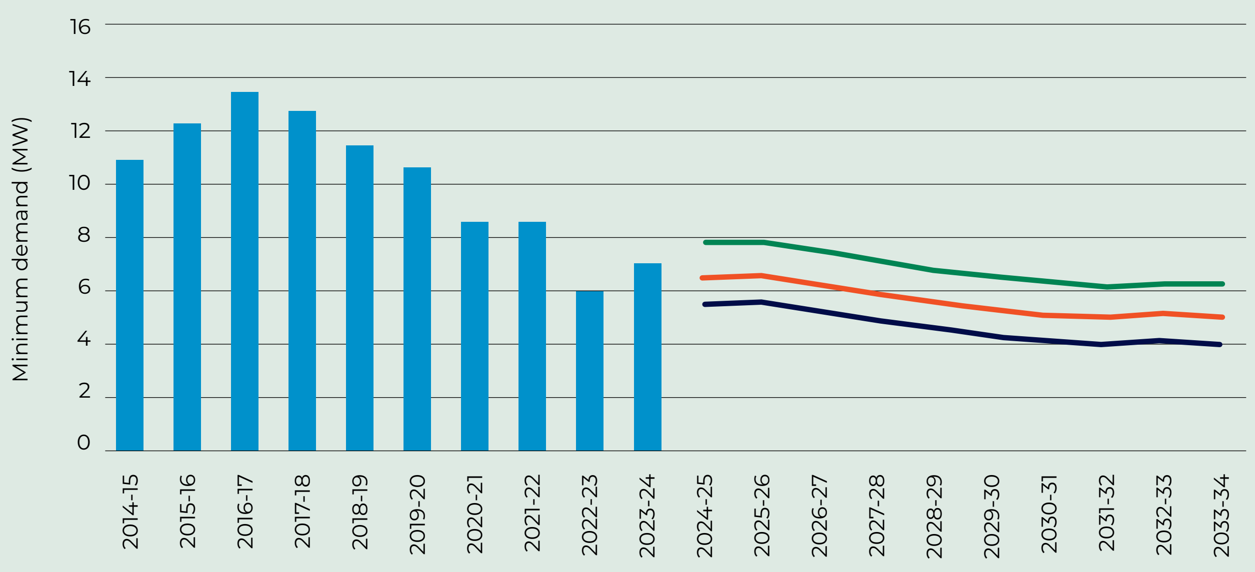


Figure 30 – Tennant Creek maximum demand forecasts

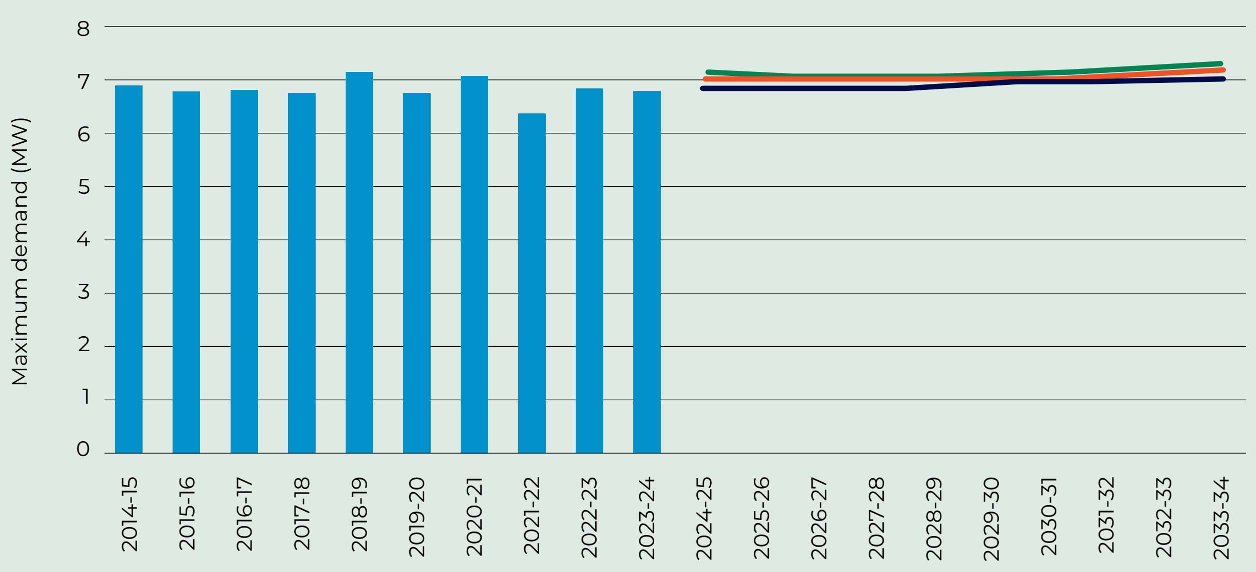
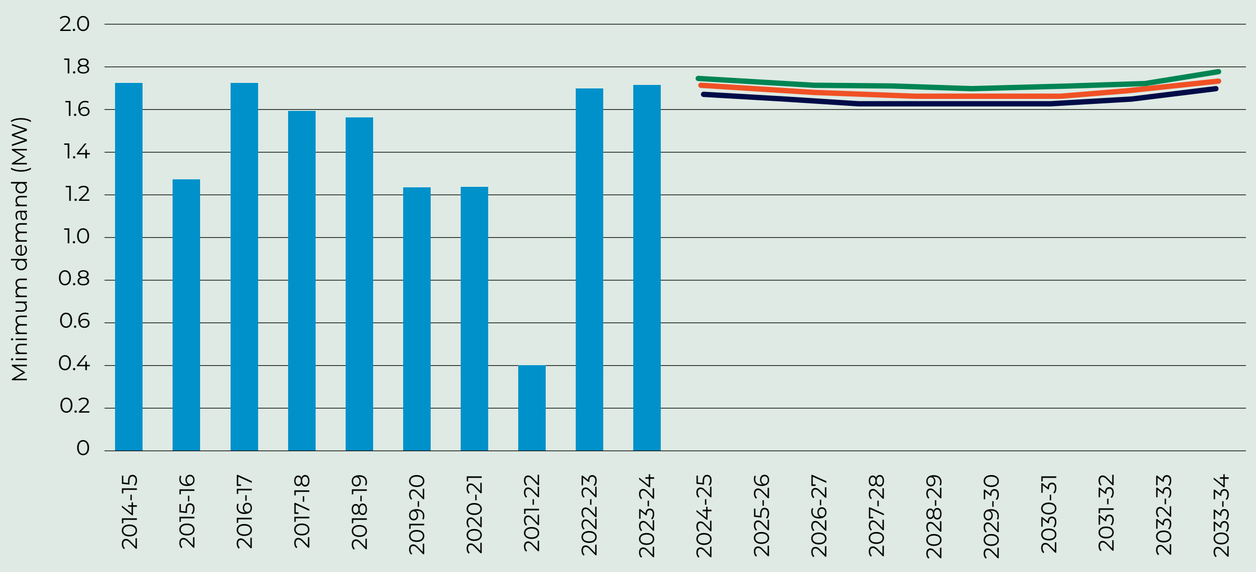


Figure 31 – Tennant Creek minimum demand forecasts



7.3 Distribution feeders

We forecast maximum demand on each distribution feeder on our network. The first step of the process is to identify the underlying trend in maximum demand growth on the feeder. We examine 5 years of demand, including the current year using 30-minute interval SCADA data excluding the impact of new spot loads,[11] embedded generation and temporary transfers.

Our next step is to adjust the 'base value' in the current year to incorporate the impact of permanent new connections, embedded generation and permanent transfers that occurred in that year.

The adjusted base value is then extrapolated from the first year of the planning period to develop a forecast trend for each feeder for the next 10 years. We then add the expected load from committed new connections and subtract the load from expected large-scale embedded generation. We also incorporate the impact of permanent load transfers between feeders. In this way, the method reflects the underlying trend in demand and the expectations of new load and embedded generation.

Our demand forecast has identified feeders with overloading issues as set out in the appendices accompanying this report. As discussed in Chapter 9, these limitations will be addressed through several approaches including load transfers from adjacent feeders with spare capacity and a dedicated program to address localised overloading.

7.4 Zone substations

Power and Water has 25 zone substations and one modular zone substation[12] that connect to distribution feeders. Zone substations meet the definition of the connection point between our transmission and distribution networks, as defined by the Northern Territory NER.

We forecast maximum demand for zone substations using the general approach described in section 7.1. Firstly, we use weather to correct the recorded maximum demand to normalise the impact of varying temperature across years, applying the 'feels like' temperature, which accounts for humidity. Secondly, we apply a diversity factor to spot loads to account for the different load profiles and time of day where individual peak demand occurs for each spot load.

We identify the linear underlying trend for each zone substation at 10% and 50% probability of exceedance (POE) using weather-corrected maximum demand for the preceding 10 years[13] (including the current year). We then add back the impact of committed connections and embedded generation.

The actual demand for 2023-24 and forecasts to 2033-34 for each zone substation are set out in the appendix, together with information on existing capacity under different contingencies.

The information identifies the zone substations where a system limitation has occurred under a 10% or 50% POE forecasts. Under our method of developing hourly forecasts we have noted that the time of peak demand is changing from the late afternoon to the early evening, which is largely being driven by increasing embedded solar PV. This has had a consequential impact on our demand forecasts for the zone substations.

The actual demand for 2023-24 and forecasts to 2033-34 for each zone substation are set out in the appendix, together with information on existing capacity under different contingencies.

[11] A spot load is a term used to describe large individual customers, typically HV customers and subdivision.

[12] The modular substation is known as the 'Nomad'. It is comprised of a transformer and switchgear in a standalone container that can be easily transported to address constraints as needed. It is currently deployed at the future Wishart zone substation site.

[13] The number of preceding years may need to be adjusted if there is a significant load increase or drop in load during a particular year.

Transmission towers, Darwin

7.5 Transmission lines

Power and Water has transmission lines in Darwin-Katherine and Alice Springs that transport power to our zone substations. Consistent with the distribution network, we forecast demand on transmission lines for a period of 10 years.

Our forecast method relies on zone substation and generation connection point forecasts. Our approach is to use the 50% POE zone substation forecasts described above, with an adjustment for load diversity. We also forecast generation at each of the existing and new connection points to the transmission network, together with any new load connecting to the transmission network.

We are expecting a lower demand forecast compared to our TDAPR last year. This is primarily due to changes to our methodology for spot loads. The demand forecasts for transmission lines are provided in the appendix and show the expected utilisation per year for a 10-year horizon.

7.6 Constraints and opportunities

To assist our current and potential future customers, we identify locations on the network where there are constraints or excess capacity under different possible network configurations, such as credible network outages. To assist with identifying constraints and opportunities we:

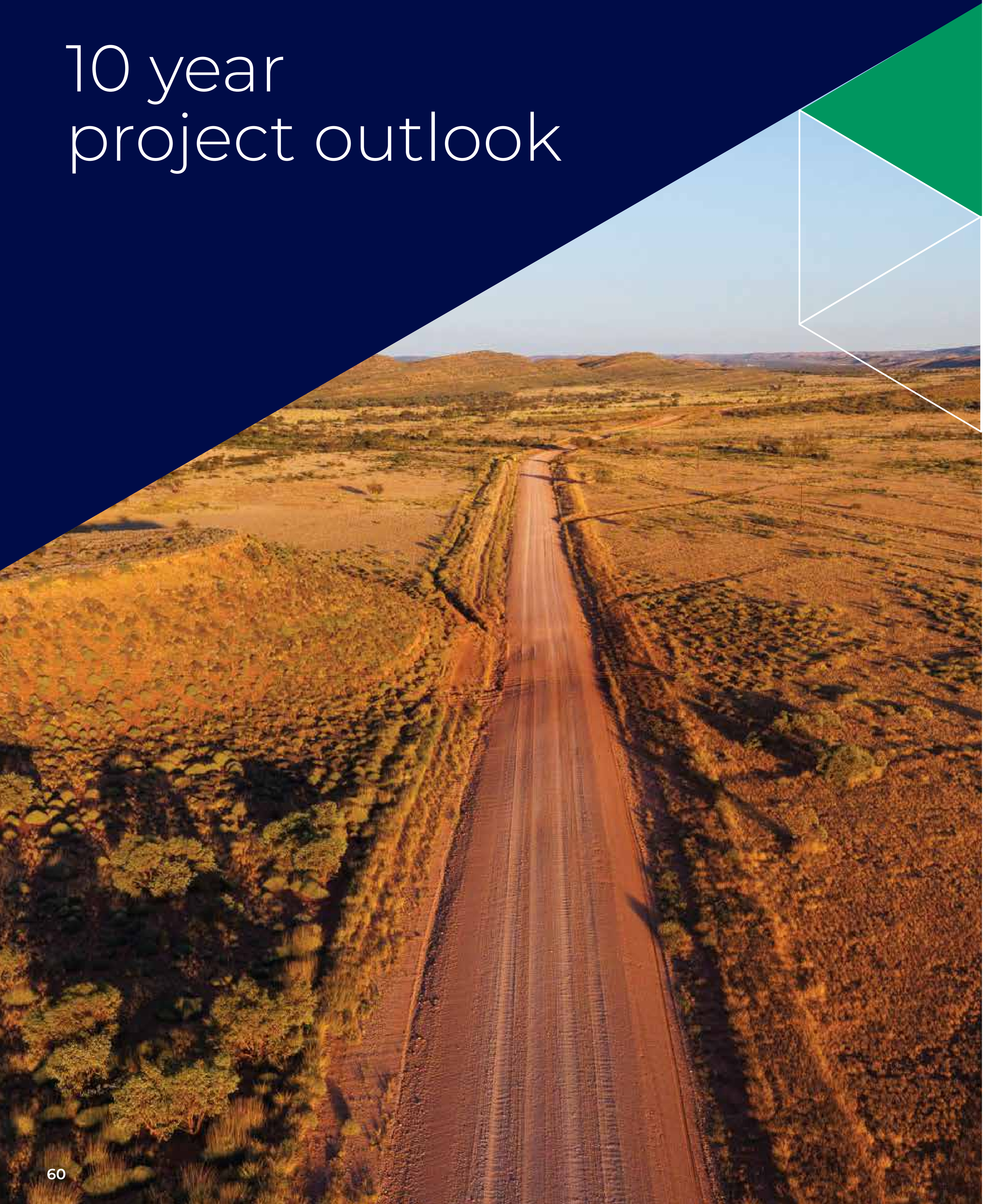
- provide the 10-year forecast of maximum demand, available asset capacity and identified constraints for each individual zone substation and for each of our 29 transmission lines
- undertake 20 contingency scenarios for our transmission lines in the Darwin-Katherine region and 4 scenarios in Alice Springs to identify the available capacity and any constraints during the planning period in the event of a transmission line outage
- identify a list of distribution feeders that are expected to exceed their capacity within the planning period.

This information is integral to Power and Water's planning processes. It helps to ensure that any emerging issues are identified early to allow sufficient time to engage with proponents registered on our Industry Engagement Register on the viability of using non-network solutions to address identified constraints. This can assist in reducing the cost of electricity to customers by identifying lower costs alternatives for addressing the identified network need.

We are implementing initiatives to improve our capability to forecast capacity constraints in particular with respect to DER, but have no adequate system in place at this stage to report on export constraints. This will be a key focus for next year's TDAPR.

PART D

10 year project outlook



8. Programs to address asset condition

Replacing our ageing network assets will be the primary driver of our committed capital expenditure over the next decade. A large cohort of our network assets will be more than 50 years old by 2025 and are likely to be approaching the end of their technical life. Our asset management planning is directed at keeping these assets in service through targeted maintenance and robust risk management. We have developed targeted programs aimed at replacing assets that pose material reliability, safety, or environmental risk and have applied age-based modelling to forecast the volume of assets likely to fail in service. The programs outlined in 2024 TDAPR are largely consistent with the 2023 TDAPR but have outlined any change in scope or costs.

In this section we identify system limitations related to asset condition. When our network assets fail it can lead to outages, safety incidents, non-compliance and create environmental risks.

In developing our forecast of transmission and distribution replacement, we have continued our practice of deferring replacement until absolutely required. Our targeted projects and programs focus on replacing assets in poor condition before they fail based on an assessment of the reliability, safety and environmental risks. We apply a risk quantification tool to identify the relative risks related to options including deferring replacement.

We have also developed an age-based model of likely asset failures over the 10-year planning outlook, assuming the targeted programs are in place. Our modelling suggests that our networks will continue to age despite our targeted programs and this will result in considerably more need for replacement activity over the 10-year planning horizon. We will continue to explore options to address asset condition, including non-network alternatives and look forward to stakeholders offering ideas to maximise the benefits and investment outcomes from our asset replacement programs.

Overall, we expect to incur materially more capex on our distribution network assets compared to our transmission assets.

As seen in **Figure 32,** about 40% of replacement expenditure over the planning period relates to the top 5 planned material programs and projects, with 27% relating to reactive projects and 33% on remaining projects.

Our breakdown of capex by category is set out in **Figure 33**. We expect that zone and terminal stations will be the dominant driver of capex over the next 10 years. This relates to 3 major zone substation replacement programs in Darwin as well as replacement of the critical 132 kV gas insulated switchgear at Channel Island Power Station. We also expect to incur significant capex on cables largely related to the replacement of cables in the northern suburbs of Darwin.

The following sections set out our replacement capex including our planned programs and projects, and our forecast of reactive volumes based on our aged-based modelling.

All dollars are presented in nominal dollars to ensure consistency with our Statement of Corporate Intent. We note that this does not align with capex forecasts for regulatory purposes, which are expressed in the dollar of the day.

Figure 32 – Breakdown of projects by type

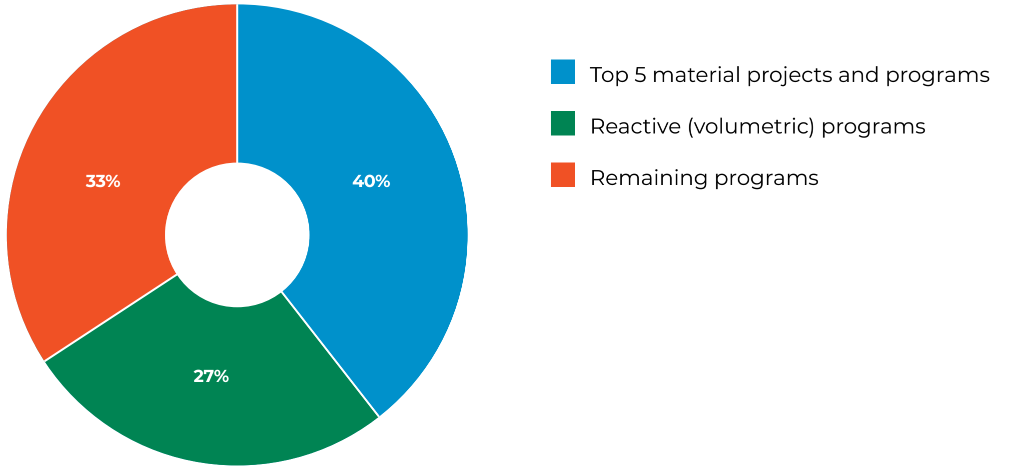
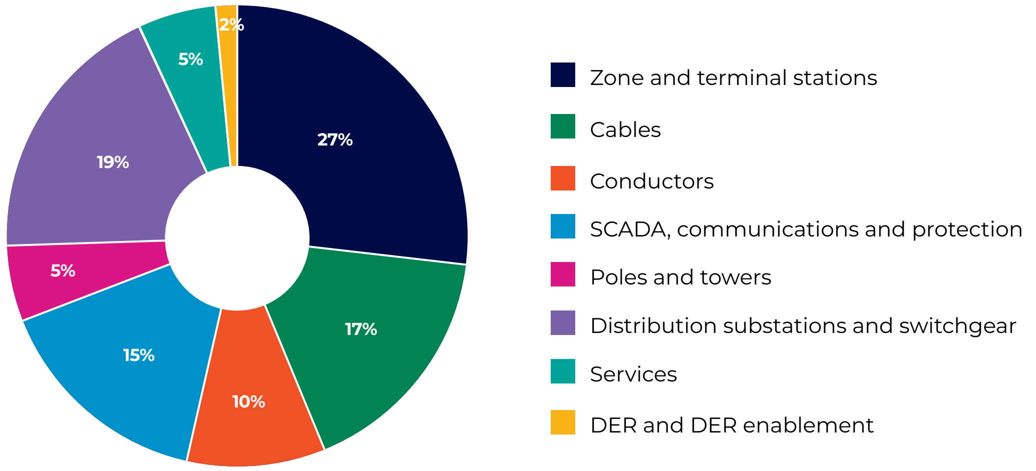


Figure 33 – Breakdown of replacement capex by asset class



8.1 Transmission towers and poles

Power and Water has about 3,200 transmission towers and 42,000 poles across our regulated network. These assets keep our overhead lines (conductors) at a safe height from the ground. Due to the harsh environment, Power and Water primarily uses steel poles and towers. The dominant cause of failure of steel poles and towers is corrosion due to soil conditions and tropical climate.

In this section we identify asset condition limitations, which give rise to a targeted program of more than $5 million across the 10-year planning horizon. We have also identified minor programs and the estimated replacement volume of other poles and towers based on high level modelling.

Alice Springs corroded poles ($19.6 million)

We are currently undertaking a major planned program to rectify corroded pole issues in Alice Springs. The underlying need for this program arises from corrosion of the pole caused by exposure to high salinity and alkalinity. Corrosion causes a loss of thickness in the base of the pole, which can lead to loss of strength to support the weight of conductors and transformers (termed 'tip load'). The consequences of pole failure include safety risk to the community and workers, outages to customers, property damage and the higher costs involved in reactive replacement of the pole.

In developing the Alice Springs corroded poles program, we developed an innovative new refurbishment approach that can keep the existing pole in service by re-butting the corroded pole. This involves removing the bottom section of the pole, welding on a new section and re-installing the pole in the ground. This method addressed the issue at a much lower cost than replacing the pole. However, historical data shows that about 3% of poles cannot be re-butted and require full replacement due to the assets attached to the pole or co-location of other underground utilities.

The program has addressed corrosion issues on approximately 3,000 poles with another 130 remaining in Alice Springs. However, the remaining poles are the complex poles with additional assets attached, accessibility or outage constraints and other underground utilities to be managed.

Due to the rebutting method and improved contracting for delivery, we have been able to roll out this program much more rapidly than forecast. We have identified that a similar mode of asset deterioration may be present in Tennant Creek and certain areas of Darwin. Once the program is completed in Alice Springs, we will investigate the other areas of the network and reallocate the budget to undertake refurbishment of the poles as required based on our risk assessment framework.

Transmission line pole top corrosion program ($5.6 million)

There is an ongoing program to replace insulators and cross arms on transmission towers in our Darwin-Katherine transmission network. This program was identified in last year's TDAPR. The project will be ongoing over the next decade and beyond.

Our transmission towers are subject to extreme tropical weather, with some located in inter-tide mangrove areas. This has resulted in corrosion on the insulators and cross arms of the towers, commonly termed the 'pole-top' components. This approach extends the asset life of the transmission tower by addressing components that have failed rather than replacing the tower.

Our analysis shows that the underlying cause for corrosion in insulators is oxidisation of the insulator pin due to leakage current, 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 ungalvanised 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 the ground.

In our planning assessment, we identified 3 options to address this issue including run to failure, inspection and replacement of defect items, and a targeted proactive replacement program. The targeted program was considered the option that was least cost given the risks with the 'run to failure' option and the high operating costs required to inspect all assets for a proactive replacement program.

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 data, structure age and criticality of assets for reliability. The program has a total cost of approximately $5.6 million to replace approximately 85 insulators and cross arms per year for the planning period. This is an ongoing program and the required volumes of replacements will be reviewed and reassessed as more condition data is available.

Pole anti-climb protection upgrade ($3.5 million)

This is a new project to upgrade the existing anti-climb protection on poles by installing the plate extension, hood and/or tube type anti-climb devices to improve deterrence from climbing our poles and therefore improve the safety of our network for the public.

Coastal Pole Top Corrosion Replacement Program ($2.5 million)

In 2018, we identified deterioration of pole tops that are located in coastal areas. As part of the 2019-24 regulatory submission, we initiated a program to address the issue. We expect to complete the current program during FY24.

However, as corrosion is an ongoing issue, we plan to initiate a new program in FY31 with a similar scope and volume of work to ensure each pole top is assessed and addressed at least once every 10 years. The expenditure is forecast to be $2.5 million.

Darwin transmission – earthing program ($1.2 million)

We have a program to address earthing issues with our transmission towers. Earthing mitigates insulator flashovers due to high voltage impulse when lightning hits a transmission line. Our analysis suggests the earthing is not performing due to physical damage and corrosion.

Inadequate earthing creates a safety risk for our employees working near the asset and for the public located close to the asset. Further, the assets are crucial for the security of the network.

Our options analysis identifies refurbishing the tower earthing components as the least cost option. As corrosion is an ongoing issue, we plan to continue this program on a periodic basis, with each tower inspected and remediated every 10 years. The current project will end in FY24 and recommence in FY31.

Transmission tower Corrosion Protection Life Extension Program ($1.0 million)

This project involves remedial works to address corrosion issues on transmission tower structures.

The program will primarily address the loss, or end of life, of galvanising on Lattice Type towers that are more than 40 years old. This is a continuation of a current project and will target10 towers per year.

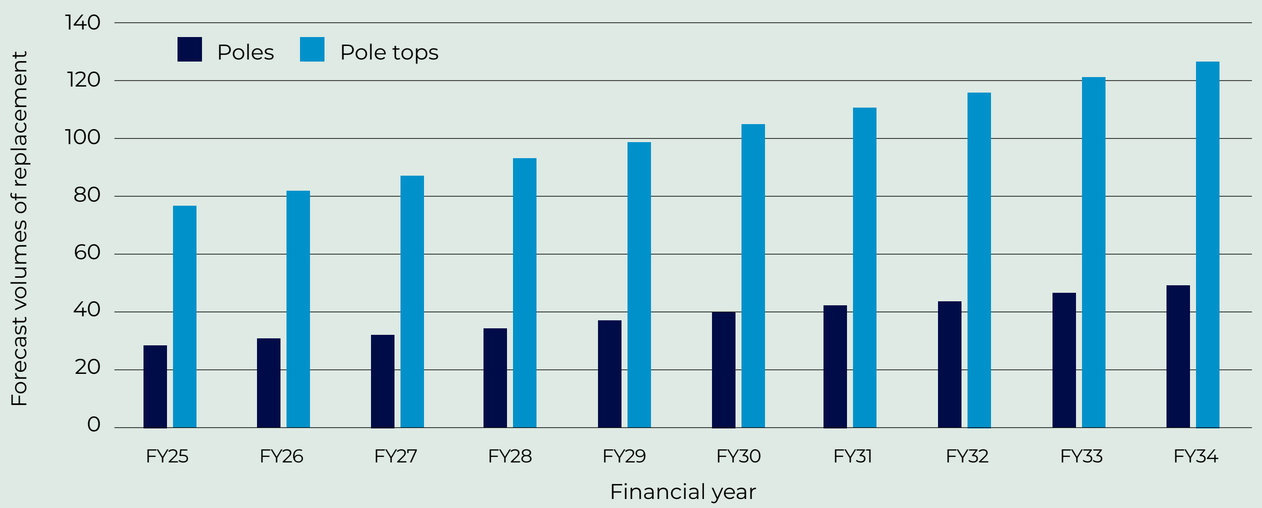
Physical Protection of Transmission Towers on Tiger Brennan Drive ($0.6 million)

Transmission towers supplying the Darwin CBD are located along Tiger Brennan Drive. A recent reassessment of the risk posed by vehicles demonstrated that additional work could be undertaken in some locations. A project to improve the mechanical protection of the towers was commenced during FY24 with an expected completion by FY26 and cost of $0.6 million.

Reactive replacement volumes ($16.9 million)

Our volumetric modelling forecast excludes the population of poles that are already included in the planned programs identified above. Our forecast is $7.5 million for poles and $9.4 million on pole tops. The forecast quantities for poles and pole tops are set out in **Figure 34.** Due to the ageing of assets, the model predicts increasing replacement volumes for each category.

Figure 34 – Forecast volume of pole replacements (excluding targeted programs)



Transmission conductors, Darwin

8.2 Conductors (Overhead lines)

Conductors are the metal wires that conduct electricity above ground, with poles and transmission towers to support them. We have about 5,100 km of overhead conductors comprised of about 700 km of transmission lines (132 kV and 66 kV), 3,400 km of high voltage distribution feeders and 1,200 km of low voltage conductors.

In this section we have identified asset condition limitations that give rise to a targeted program of more than $5 million. We have also identified minor targeted programs and estimated replacement volumes of other conductors using high level modelling. We generally replace portions of conductors rather than the entire length of the line.

Strangways to Humpty Doo ($6.8 million)

This is a major project with initial studies and feasibility started in FY23. The project seeks to increase clearance of the 66 kV transmission line between Strangways and Humpty Doo to the east of Darwin.

The need for the project arises from 2 issues. The primary issue is that many of the 118 spans that comprise the length of the 22 km conductor do not meet clearance requirements introduced retrospectively in 2010. To address these risks, we have been operating the line at a lower capacity of 7 MW, to reduce the number of spans that are non-compliant. Nevertheless, the radial line connects to 3 zone substations along the Arnhem Highway and provides a degree of continued 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.

We found that the most prudent and cost efficient solution to address the two issues was to temporarily reconfigure the 22 kV network so we can rebuild the entire line along its existing easement and then transfer the load back to the sub transmission line. The total forecast capex was estimated at $6.8 million and completion is expected during 2026.

Darwin – Cockatoo conductor replacement program ($6.0 million)

This is an ongoing program to replace the 22 kV conductors in the Lake Bennett and Manton Dam rural area to the south of Darwin.

There are 3 drivers of replacement. First, the type of conductor is an imperial gauge 'Cockatoo' type, which gives rise to complex challenges. The conductor is showing condition issues such as broken strands and conductor damage due to burning and are difficult to repair due to the weight, gauge, high stringing tension and equipment required. This has led to deteriorating and relatively poor reliability outcomes for customers in the area, given the radial nature of the line where there is no alternative source of supply when the conductor fails in service.

Secondly, the Lake Bennett feeder fails to meet compliance standards for clearance to ground. Lastly, the bat protection we use on the conductor is deteriorating due to extreme weather, leading to corrosion and risk of the conductor breaking and falling to the ground.

Our analysis quantified the risks with retaining the Cockatoo conductors in the Lake Bennett and Manton zone substation areas. There are compliance and safety risks with not addressing the mandated clearance issues. This is hard to mitigate given that approximately 65% of the conductor spans over road crossings are non-compliant. Further, we expect reliability to further decline for customers connected to the feeders. Our quantification analysis indicates that reliability is the most material of risks, followed by compliance penalties.

We examined 3 credible options to address the issues and risks identified above. This included replace on failure, install mid-span poles and install new conductors and a complete line re-build. The analysis indicated that installing mid-span poles and re-conductoring was the least cost option to address the identified network needs. The run to failure option resulted in high risks that would continue to grow over time. A complete line re-build had much higher costs to reduce the risks compared to mid span poles and re-conductoring.

The project delivery was slowed down during 2023-24 due to repriorisation of other projects that require the same field crew resources, accessibility (construction work can only be completed during the dry season) and difficulties with obtaining approvals.

We have currently replaced 12.7 km of Cockatoo conductor and the remaining 43 km will be progressively replaced with completion expected by 2026.

Small gauge steel conductor replacement ($1.5 million)

We have identified a potential emerging issue on the network related to small gauge (3/12 steel) conductors. These are an old type of conductor with low capacity but high tensile strength so it was used in areas where there was sparse connections and low load.

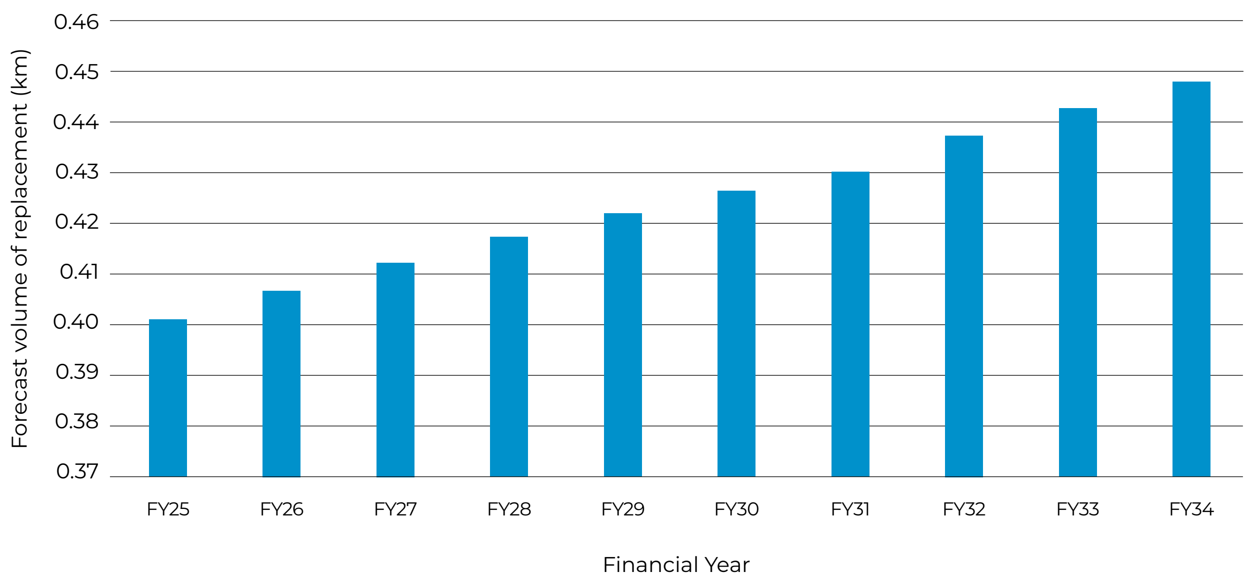
The conductor is approaching its end of life and we are undertaking inspections to ascertain its condition and any potential need for replacement. We have allowed for a program to start towards the end of the forecast period to allow time to understand the asset class and options to mitigate any potential risk.

Reactive replacement volumes ($0.6 million)

In addition to our targeted program, our modelling suggests that we will need to replace a significantly higher volume of conductors over the next 10 years, as seen in **Figure 35.** This is due to the ageing of conductors with a significant proportion older than their technical life by 2032-33.

Our volumetric modelling forecasts a steady rate of reactive replacement of conductors, which is relatively low in value. The modelling excluded the population of conductors related to targeted replacement programs. It is also based on the impacted span as measured in metres, rather than replacement of the whole length of conductor and accounts for our practice of repairing broken conductors where possible rather than replacement. As a result, only a very small fraction of the conductor population is replaced reactively.

Figure 35 – Forecast volume of conductor replacements (km, excluding targeted programs)



8.3 Service lines

Service lines are the overhead wiring infrastructure that is used to supply the electricity from the distribution network to a customer's premises. We have about 57,000 service lines, including 24,000 conductors (above ground) and 33,000 cables (underground).

We forecast capex of about $20.6 million, which includes a new planned program in Darwin ($20.3 million) and the residual for our volumetric forecasts of service line replacement of $0.3 million. This is discussed further in the section below.

Service lines planned program ($20.3 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 of services so there was limited data on the condition of service lines. However, 2 recent safety incidents involving condition issues with our overhead service lines has prompted a change in our asset management approach for service lines.

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. Additionally, we found instances of failure in the service clamp that attaches the wiring to the pole that could lead to the apparatus becoming energised and being touched by our workforce or the public.

The overriding risk from these condition issues relate to worker and public safety due to the proximity of service lines to people and the way in which they fail. 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. The 'run to failure' option is consistent with our historical approach to managing 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. This includes addressing the backlog of defects from our current inspection program. The second option was the least cost due to the higher quantified safety risks under the run to failure option.

The proposed scope of the project in the 2024-29 period is to replace 4,000 service lines (800 per year) at an average cost of $2,000 (real FY22 dollars) based on previous expenditure data. The forecast level of service lines has been based on defect data established in the 1,000 inspections to date. **Figure 36** forecasts service line replacements.

During the next regulatory period we will continue to assess the condition of the fleet. Our expectation is that the backlog of deteriorated service lines will be replaced during the 2024-29 period and the volumes will decrease to approximately 600 per year. We will update the replacement volumes required based on the additional data we obtain from our inspection and replacement program.

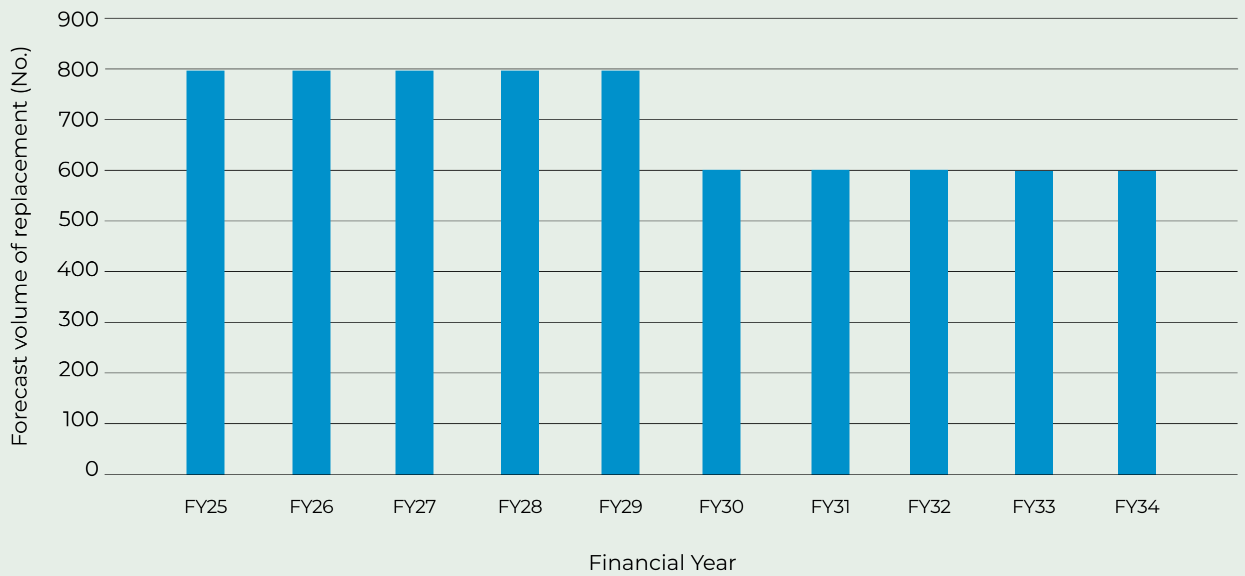
Reactive replacement volumes ($0.3 million)

Reactive replacement volumes are forecast using the volumetric model, which is adjusted to exclude the targeted replacement program for overhead service lines and accounts for underground services. It uses historical failures and the asset age profile to predict a very low level of replacement of $0.3 million for reactive replacement of overhead and underground service lines.

We have about 57,000 service lines, including 24,000 conductors (above ground) and 33,000 cables (underground).

Service lines delivering and exporting electricity, Alice Springs

Figure 36 – Forecast volume of service lines replacements



8.4 Cables

Underground cables are used to transport electricity using an insulated conductor below ground. We have about 1,648 km of underground cable, comprising about 39 km of transmission, 892 km of high voltage distribution cables and 717 km of low voltage cable.

In this section we have identified asset condition limitations that give rise to a targeted program of more than $5 million in the 10-year planning horizon. We have also identified minor programs and the estimated replacement volume of other cables based on high level modelling.

Similar to conductors, we generally replace segments of underground cables.

Darwin northen suburbs high voltage cable replacement ($72.3 million)

In the 2019-24 period, we have been progressively replacing high voltage cable in the Darwin northern suburbs with about 24 km completed so far. We are forecasting to replace an additional 84 km in the planning period.

The underlying need for the project is the condition of cables installed in the area. About 146 km 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 earthing screens when exposed to moisture and electrical stress. A compounding factor is that the cables installed in the northern suburbs have an aluminium screen that 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. 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% and 79% of the cable is very highly likely (95% 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% of the cable fleet, they contribute an average of 47% of the cable outages as measured by SAIDI and SAIFI. This risk will grow over time as the probability of failures rise. While the consequences of health impacts are significant, the probability of them materialising is very low and we have no historical data to use, so we have relied on probabilities suggested by Ofgem as documented in our Risk Quantification Procedure.

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 one-year to 20 years. The analysis demonstrates that a 16-year replacement is optimal. On that basis, we have identified that we should undertake an average of about 8 km 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 to Frances Bay 66 kV transmission cable ($5.7 million)

The Darwin to Frances Bay cable is part of the sub-transmission system connecting zone substations and is therefore critical to the security of the network.

Testing has identified that there is a minor partial discharge, which indicates that the insulation has deteriorated slightly. The deteriorated section is planned to be addressed through minor repair works and the cable is expected to remain serviceable until FY30. Testing will be undertaken periodically to monitor the condition of the cable.

While only 0.75 km in length, it has high costs due to its location in an urban setting. The need arises in 2030, so we have not progressed our options analysis.

Power and Water worker Darwin

Cullen Bay and Bayview ($5.5 million)

Replacement of low voltage cables in the Cullen Bay and Bayview areas of Darwin is an ongoing program from the 2019-24 period. We have replaced 2 km so far and we are planning to replace the remaining 3 km of cable by 2030. Due to the location and scope, this project has higher than normal administrative requirements. We have now appointed a dedicated project manager and civil contractor to ensure completion of the work within the required timeframe.

The cables were initially installed in the 1990s when the suburbs were first developed.

Poor installation techniques have led to water ingress in the cables. The water is reacting with compounds in the cable insulation leading to calcium adipate developing. Calcium adipate damages the cable insulation and expands cable joints and lugs (connects the cable to the terminal), eventually leading 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 performance.

The key risks arising from the condition issues include worker and public safety risks from the inadequate neutral earthing system and 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 arises, it could lead to extended outages for customers due to the difficulty in locating the fault from widespread degraded insulation.

Our options assessment examined 3 options, of which only 2 were feasible. This included run to failure, and a targeted proactive replacement and refurbishment program. 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 footpaths and other underground services, (which have been directly buried), together with the high risks of keeping the assets in service.

Under the recommended proactive replacement option, we would prioritise cable replacement based on evidence of condition. 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.

Darwin CBD cable tunnel ($1.2 million)

The electricity supply to the Darwin CBD is achieved through a network of underground cables that are installed in underground tunnels. The tunnels are typically more than 30 years old and built of reinforced concrete. The need for the project arises from the condition of the tunnels.

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 modifications to install 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 $1.2 million in the planning horizon.

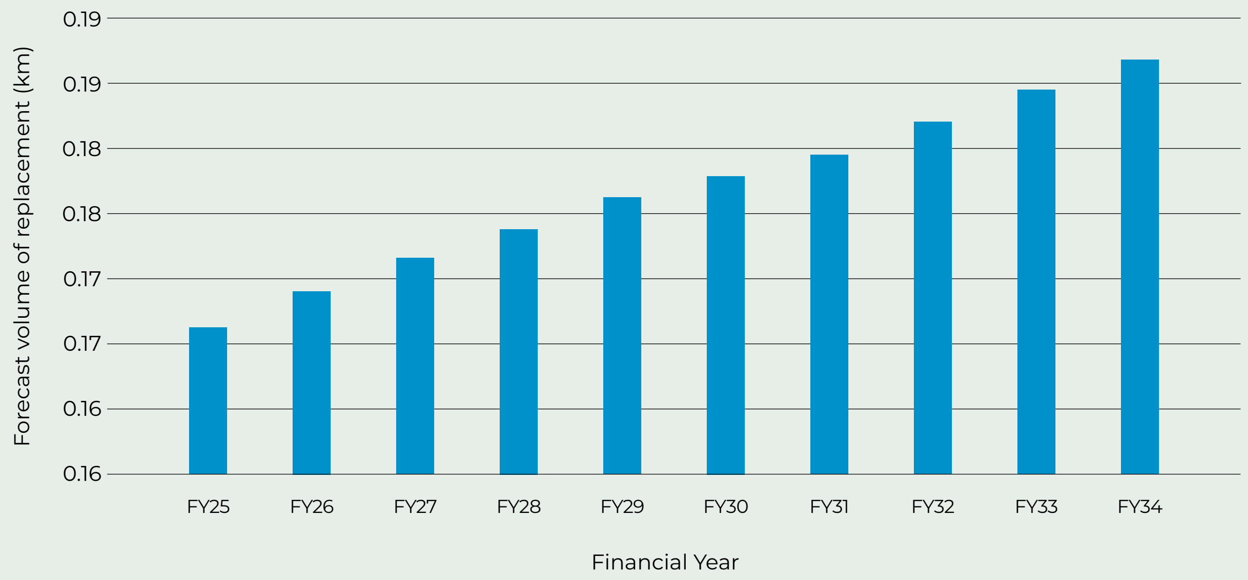
Reactive replacement volumes ($7.2 million)

Our volumetric modelling forecasts exclude the population of assets related to the cable replacements in Darwin's northern suburbs, Cullen Bay and Bayview. The results show that cable refurbishment will increase over the 2024-29 period, consistent with the incremental ageing of the population. **Figure 37** identifies the quantities of replacement by kilometres, noting that the usual practice is to patch the fault, which only requires replacement of 10 metres of cable on average.

This is a very small fraction of the cable population.


Engineers assessing plans, Darwin

Figure 37 – Forecast volume of cable replacement (km, excluding targeted replacement)



8.5 Transformers

Transformers step-down voltage as energy flows from the transmission network to the distribution network. Electricity is transported over long distances at high voltages (132 kV or 66 kV on our network) as it reduces the electrical losses and makes the network more efficient. However, our customers require energy at lower voltages to safely meet their needs, so the voltage is progressively stepped down using transformers.

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 22 kV or 11 kV, which is used on the distribution network. Zone substations are secure compounds with a significant amount of assets inside.

Distribution transformers that you can see attached to poles or in enclosers on the ground then convert the voltage from 22 kV or 11 kV to low voltage, which is supplied to customers.

In total we have 5 sub-transmission substations, 25 zone substations, 1 modular zone substation, and 4,903 distribution substations. In terms of the distribution substations, we have about 290 ground substations, 1,303 kiosk substations, 2,883 pole substations and 427 single phase substations. The volume of replacement for each asset type is provided below in **Figure 38.**

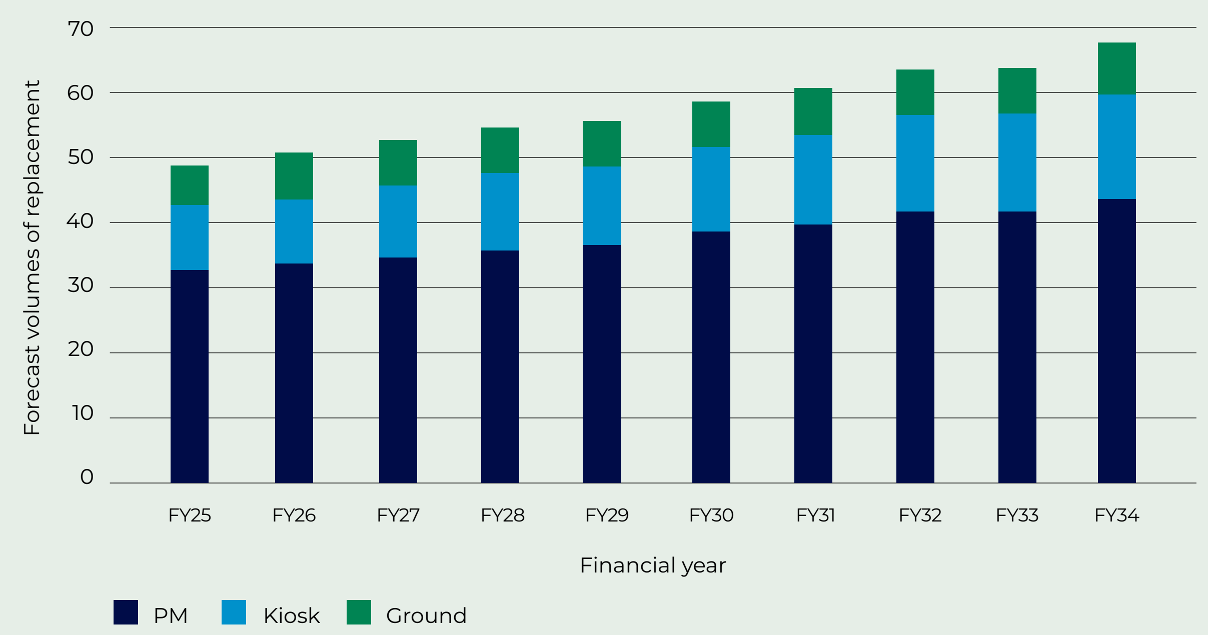
Since 2008, we have been progressively addressing condition issues with our zone substations in the aftermath of the zone substation failure in Casuarina.

We are forecasting $103 million on replacing transformers in the 2024-33 period. The majority relates to a major committed project to replace the existing Berrimah zone substation ($40.6 million)[14]. There are no other planned programs. This includes the forecast from our volumetric model that we will need to invest $30.4 million on replacing distribution transformers that reach end of life.

These programs are discussed below.

Since 2008, we have been progressively addressing condition issues with our zone substations in the aftermath of the zone substation failure in Casuarina.

Figure 38 – Forecast volume of distribution substations (excluding targeted program)



[14] The Berrimah Zone Substation replacement project cost also includes other zone substations assets but is included in here as it is driven predominately by transformer condition.

Berrimah zone substation ($40.7 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 only substantially commenced in FY23 with a cost of $11.5 million incurred to date. The project is planned for completion by the end of FY27.

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 expected to fail in the short-term. Most of these systems were original units installed in 1981 and there are on-going issues that require 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. Over the years, the switchboard was extended and the original bulk oil circuit breaker trucks were replaced by compatible vacuum circuit breakers, reducing the risk of fire and explosive failure. The main concern with this switchboard is that it 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 to provide arc fault 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 a green-field option (that is, re-building a new zone substation on an adjacent site), 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 2 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.

Palmerston Zone substation transformer 2 and 3 replacement ($25.8 million)

The Palmerston zone substation is located in the northern region of Palmerston and supplies customers at 11 kV. It has expanded over time and has an unusual arrangement as it is comprised of 3 transformers that convert electricity from 66 kV to 11 kV and 1 transformer that converts from 11 kV to 22 kV, primarily as a back-up supply to the Palmerston hospital.

There are several condition issues at Palmerston zone substation:

- Transformers 2 and 3 have both been assessed to be in deteriorated condition. Based on the internal insulation condition, we expect they will require replacement in 2030.
- The 11 kV to 22 kV transformer is a non-standard configuration and puts operational constraints on the 11 kV switchboard.
- 3 of the 4 switchboards are over 40 years old and approaching the end of their technical life. So far, they are not exhibiting any significant deterioration indicators but we will continue to monitor them.
- The building that houses the switchgear and protection systems is in poor condition and the roof leaks. We plan to repair the roof to enable us to defer any significant replacement works.

With the construction of Archer zone substation completed in 2011, the capacity constraints at Palmerston were resolved and now only condition-based issues remain.

We have developed an area plan to ensure prudent and efficient long-term investment decisions are made. We have found that aligning works with the potential future Holtze-Kowandi zone substation will enable us to simplify and standardise Palmerston zone substation by reducing it to a 2 transformer substation, with provision for a third based on demand growth. The 11 kV switchgear and buildings would be replaced at the same time.

The plan will reduce overall cost to customers and provide real options for future growth. The plan is subject to Holtze-Kowandi proceeding and will be reassessed periodically.

Single phase substation refurbishment and replacement program ($8.1 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. By the end of the period, we expect to have refurbished 45 and replaced 10 substations, which is a reduction compared to our expectation last year due to field crew constraints resulting in reprioritisation of other projects. 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 is 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 4 of the northern suburbs of Darwin. The primary mode of failure is oil loss leading to internal flash over (arcing). Since 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 3 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 and preferred credible option was to continue the existing proactive replacement and refurbishment.

Hudson Creek spare transformer ($3.2 million)

Hudson Creek substation is critical to the Darwin-Katherine System. It is the location where the 132 kV transmission network connects from the Channel Island generation and is converted to 66 kV for our sub transmission network. The transformers at Hudson Creek are currently around 36 years old and have had some issues in the past with oil leaks and water ingress. Due to the size and voltages of these transformers, they have a very long lead time of up to 1.5 years from placing an order to delivery. To manage risk to network security as these transformers approach the end of their expected serviceable lives, we will purchase a spare transformer so we can rapidly replace a transformer if one should fail.

Replace Cosmo Howley ($0.8 million)

Cosmo Howley is a zone substation that supplies an industrial customer. The zone substation has reached the end of its technical life and requires replacement. However, our customer notified us that the intended operations have changed and will only require 1.0 MVA, which we are able to provide through a micro substation rather than a full substation. This has significantly reduced the cost compared to the original full rebuild of the zone substation. The transformer has been received and the project is on track for completion by the end of FY25.

Centre Yard zone substation ($1.0 million)

The Centre Yard zone substation is located on the Cox Peninsula and supplies power at 11 kV to the local community.

The transformer at the zone substation is in poor condition and requires remediation while the remainder of the zone substation assets are also close to end of life. There is low demand in the area and uncertainty of any future development or load growth.

We assessed several options to manage this network constraint:

- 'Do nothing' and allowing it to run to failure, which would result in a prolonged outage while replacement assets were deployed.
- Replacing the zone substation with modern equivalent assets.
- Convert the existing 66 kV supply to 11 kV and decommission the zone substation.
- Establishing a Stand-Alone Power System and supplying via a new feeder or repurposing existing subsea cables.

The preferred option was to repurpose the existing 66 kV subsea cables by operating them at 11 kV and directly connecting to the 11 kV network with only distribution switches to provide isolation capability. A back-up generator will also be installed. This approach enables us to retire the existing zone substation and minimise cost to customers. This project will be completed during FY25.

However, this is a temporary solution (expected to last up to 10 years) as the subsea cables are close to end of life and have a number of condition and installation issues. We are currently assessing long-term permanent options:

- A new mine is being established on the Cox Peninsula that requires a new feeder to be constructed. We are assessing the economic benefit of extending this feeder to the Centre Yard zone substation.
- We are also undertaking further assessment of a Stand-Alone Power Supply to assess if it will be more economic in the long-term, particularly with the transition to renewable energy.

Both options are expected to cost in the order of $10 million.

Reactive replacement volumes ($23.9 million)

Our volumetric modelling forecast excludes zone substation transformers. The modelling forecasts that we will incur a total of $30.4 million for distribution transformers, comprised of $8.9 million on pole mounted substations, $11.7 million on kiosk mounted substations, and $9.7 million on ground mounted substations.

Berrimah zone substation

8.6 Switchgear

Switchgears are the switching equipment that are used to manage the power flow to different parts of the distribution network and protect the network from faults to ensure safe operation. We have 524 high voltage circuit breakers, 2,968 distribution switches and 8,108 distribution pillars.

In this section we have identified asset condition limitations that give rise to a targeted program over $5 million in the 10-year planning horizon.

We have also estimated replacement volume of other switchgear based on high level modelling.

Channel Island ZSS 132 kV GIS replacement

The existing thermal generation at Channel Island Power Station is connected to Gas Insulated Switchgear owned by Power and Water.
This switchgear is a highly critical and high value asset. During the past couple of years, a major scheduled maintenance task has been carried out and the asset is expected to remain in service until its end of life in or around 2035.

Due to the transition to renewable energy and planned decommissioning of some conventional generators, the configuration of this asset is uncertain at this time but is likely to require fewer circuit breakers. We are currently assessing the number of circuit breakers and configuration of the switchboard that will be required based on changes to the generation fleet and network needs. The expected cost of the replacement will be provided once the scope is confirmed.

Distribution pillars ($7.7 million)

This is a new planned program that we forecast to commence in the first year of the forecast period and is expected to be an ongoing program. Each year the project will replace 56 and rectify 200 distribution pillars through operational repairs.

These assets are part of our underground network, typically distributing low voltage supply to customers within a close proximity. A typical distribution pillar can be used to supply power to 2 to 8 lots depending on the location and load of individual customer(s).

The need for the program arises from the deteriorated condition of the base, outer enclosures and covers. 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 5,000 pillars over the last 5 years has identified about 20% have a defect, of which approximately 25% are critical to public safety. Our analysis also shows that a large proportion of pillars were built immediately after Cyclone Tracy (50 years old today) and that these assets are expected to further decline in condition as they continue to age beyond 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 customers' properties. In particular, damaged coverings expose or enable access to 'energised' elements of the asset, leading to potential for electric shocks. We have had 3 recent events where customers have been exposed to live parts and one of the incidents led to an electric shock.

We examined 4 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 incident. 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 prioritises assets where there is high foot traffic, high population density or close proximity 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 deemed not economic.

Distribution switchgear condition and fault-based program ($5.7 million)

This is the continuation of an existing program to address asset condition issues and insufficient fault level ratings with a type of distribution switchgear (Hazemayer Magnefix MD4). There are few switchgears installed in 1980s and 1990s that are now operating with fault levels that are close to or above the fault rating of these assets. This poses a risk to the safety of the public and our workers.

An increasing number of the population have been failing in service. The main failure modes are deterioration of the switchgear insulation and terminations, due to harsh service conditions, which can lead to explosive failures. In addition, development of the network over time has resulted in an increase of system three phase fault levels above 14.4 kA in some areas of the distribution network.

The key risk with failure of the substation relates to worker and public safety. There are no protective 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 3 recorded instances of asset 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 not be prudent given our recent experience with explosive failures. The preferred option is to target replacement on high-risk switchgear based on asset condition, and prioritised based on the fault level and the proximity of the location to the public. A third option is to alleviate fault levels through operational configuration; however, splitting bus configuration can lead to greater risk of outages for customers and therefore is less economical than targeted replacement. Currently the network contains 19 Hazemayer Magnefix switchgear installations where the system fault levels are found to either exceed or are encroaching on the equipment rating. The 19 identified high risk Hazemayer Magnefix switchgear will be replaced by the end of 2029. Each asset will require replacement of the padmount/package substation containing the switchgear installations, civil works, and re-termination of the cables. The cost of the project has been based on recent replacements.

Replacement of SF6 distribution switchgear with SF6 free Ring Main Units ($3.0 million)

There is evidence of an increasing trend in the number of failures of RM6 type distribution RMUs due to low gas. The failures pose a safety hazard to the public and our field crews while SF6 is a potent green house gas.

Further, we have identified an industry trend to move away from SF6 insulation with a preference for SF6 free 'green' options. We are also anticipating more stringent environmental regulations that will reinforce this trend.

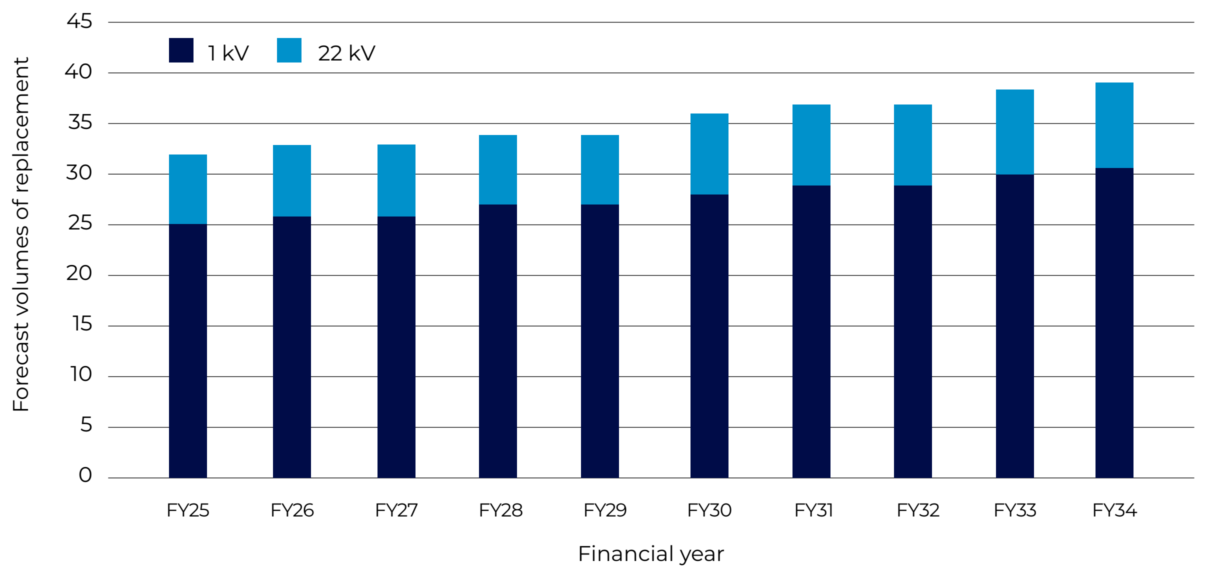
In order to remove the safety hazard and reduce the impact of these failures on greenhouse gas emission, this project will proactively replace these switchgears with SF6 free RMUs. This will facilitate safety, reliability and compliance with our environmental obligations and reduce the environmental impact due to our operations.

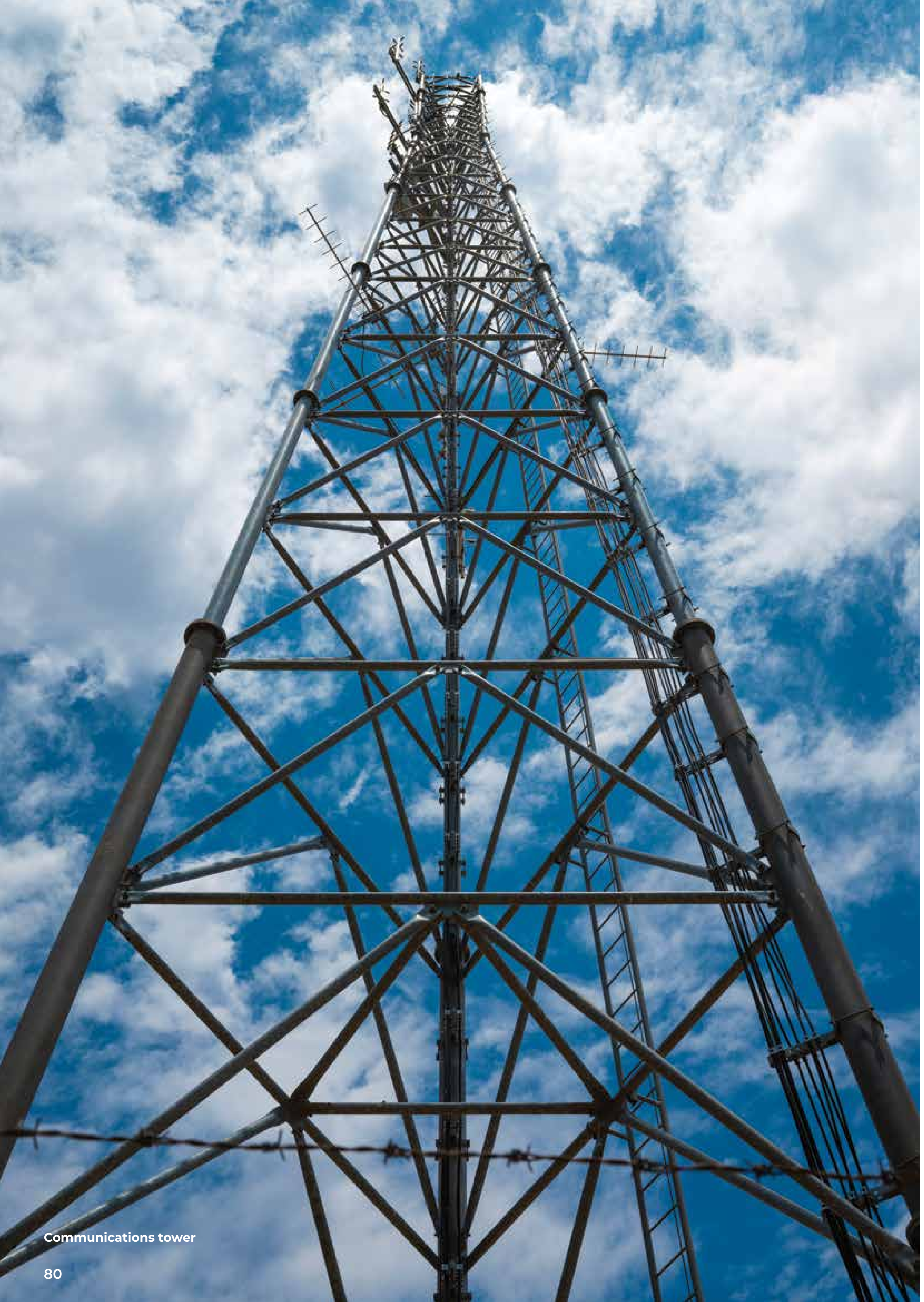
As a potential emerging issue we will investigate this further and have currently identified that the program should start in 2031 and is expected to run until all SF6 distribution is removed from the network.

Reactive replacement volumes ($27.7 million)

Our volumetric modelling forecasts excluded distribution pillars. The modelling forecasts that we will incur $20.1 million on distribution switches, and $7.6 million on circuit breakers. The volume of replacement for each asset type is provided below in **Figure 39.**

Figure 39 – Forecast volume of distribution switchgear (excluding targeted replacement)





Communications tower

8.7 SCADA, communications and protection

The network requires control systems, communication networks and protection equipment to manage the network securely and safely.

Electricity networks require an ecosystem of secondary assets to keep the network secure. This includes a Supervisory Control and Data Acquisition (SCADA) system that gathers, processes and displays information of the network as well as manage and control the network.

It also includes protection relays that 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. This connects network assets to the SCADA system and sends protection signals across the network to ensure protection operates as quickly and accurately as possible to maintain system security and safety.

Below we have identified asset condition limitations that give rise to a targeted program over $5 million in the 10-year planning horizon.

Protection relay replacement program ($26.1 million)

Protection relays monitor network parameters (voltages and currents) and protect the network from abnormal operation that can lead to an unsafe operation of assets. They protect assets against damage and the public from injury when operating conditions are abnormal or unsafe. We currently have more than 1,360 protection relays on the network, of which about a third relate to older static (first generation electronic relays) technologies. We have been progressively replacing our electromechanical and static relays over the past decade with intelligent digital technology.

The drivers of the program relate primarily to the poor functionality and obsolescence of remaining electromechanical and static relays on the network. Lack of vendor support exposes Power and Water to increasing risks due to inability to source spares or repair following asset failure and cyber vulnerabilities.

The relays on our 66 kV transmission network have compliance issues with the Technical Code that requires independent, redundant protection schemes on equipment operating at 66 kV and above. We have identified that 8 static protection relays operating at 66 kV are non-compliant. While the reliability of these relays has enabled us to manage the risks of non-compliance over time, there is new information suggesting physical signs of degradation and investment can no longer be deferred.

Further, there is a new requirement for more rapid reporting of faults and other events, which can only be achieved through improved recording capability at these locations.

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. 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.

We examined 3 options in our business case. 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. We expect further degradation in the condition of the assets, which will increase risk over time and does not provide for improved network flexibility. We also considered run to failure and replacement with a modern-day equivalent but this had similar issues and higher costs. The preferred option was to replace obsolete relays on a targeted basis over time with modern, faster acting and more configurable relays. This also enables more flexible solutions to manage the integration of more renewables.

The scope of the project involves replacing the identified relays across the transmission and distribution network. In addition, we would install data recorders in 8 locations. The program also allows for replacement of 3 relays due to failure.

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.

Energy Management System (EMS) ($13.3 million)

The EMS allows our control room to manage the power system in our 3 regulated regions, perform remote switching on our transmission network and identify and respond to network outages.

The purpose of the program is to ensure the EMS remains in a fully supported state for all hardware and software, is appropriately sized, to improve cyber security and support the increasing proportion of renewable generation.

The current refresh of software and hardware is already underway and the program will ensure this continues as required to achieve the above outcomes.

Multiprotocol Label Switching (MPLS) migration ($16.1 million)

Consistent with our regulatory obligations, we operate a communications network that provides information and control signals between our SCADA and network assets and protection signalling. 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 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. 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. There are also 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.

The program will:

- replace 210 multiplexors with an MPLS-IP solution. Significant progress has been made rerouting services across six communications sites but some critical services need careful planning before the SDH multiplexors can be fully retired
- replace the 22 digital radio switches, of which 2 have been completed
- upgrade LAN at 10 substations, develop a testing facility and purchase critical spares. These have not yet been started.

This program is a continuation of our existing replacement program based on condition and obsolescence, but with a focus on transitioning to a new technology rather than a 'like for like' replacement.

Other minor programs less than $5 million ($15.8 million in total)

There are 10 other minor planned programs in this asset class:

- **Communication battery replacement ($3.1 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. 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.
- **Code compliance and safety program ($3.2 million)** – ensures the communications systems remain compliant with the requirements of Power and Water's Network Technical Code and Planning Criteria. The program is based on historical expenditure to address compliance breaches as they are identified. This includes rectification of single points of failure, separation of assets to ensure full redundancy and security hardening of legacy network devices.
- **Access track refurbishment ($2.7 million)** – the access roads to remote communications facilities deteriorate over time and need to be repaired. The current condition of 8 access tracks is a safety risk to our filed crew and significant refurbishment is required to ensure the ongoing safety of our people.
- **Microwave systems retirement ($2.2 million)** – the microwave communications system supports our protection systems to clear 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 30 of our 64 microwave terminal units, meaning that technical assistance, replacement assets and software and firmware patches will no longer be available.

  We examined 3 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 on page 83).
- **Sadadeen to Lovegrove fibre optic cable replacement ($1.75 million)** – the existing fibre optic cable is installed in an arrangement termed a 'folded loop', meaning the same cable is used for communications in both directions and there is no redundancy. Replacing sections of the fibre optic cables and installing in an alternative configuration will resolve this issue.

Humpty Doo zone substation, Darwin

- **Alice Springs to Darwin communications link replacement ($1.1 million)** – a critical existing communications link between Darwin and Alice Springs is relied upon for controlling the Alice Springs network. The link has poor availability and reliability that is below industry accepted levels, resulting in a level of risk that is unacceptable. The preferred option is to establish a new link with higher levels of service.
- **Dense Wavelength Division Multiplex (DWDM) retirement ($0.5 million)** – DWDM systems are used to increase the data carrying capacity of optical fibre cables. The technology is vital to provide a link between the Hudson Creek Control Centre and the Disaster Recovery Control Centre in emergency situations such as cyclones. The vendor has already issued an end of support notice that commenced in 2019. The risk of retaining these assets on the network will increase over time as they deteriorate with age and possibly become vulnerable with respect to cyber security. Our options analysis shows that it will be lower cost to install 12 km of fibre to connect the 2 centres, leveraging other planned projects that use fibre, and then retire the DWDM system.
- **Communication huts refurbishment ($0.4 million)** – communications huts contain critical communications assets. Our analysis has identified that 8 communication huts are in deteriorated condition from degraded roof seals and water proofing, deterioration of paint that makes corrosion more extensive and severe, and inadequate power supply. The 'do nothing' option increases the risk that the communication assets will fail in service.

  The preferred option is to undertake works to remediate the huts including regalvanising metal surfaces and structural steel, repaint the hut to prevent further corrosion, replace the roof seals and ensure the hut is waterproof, and migrate power source from Telstra to Power and Water owned assets.
- **Antenna monitoring devices ($0.4 million)** – antennas are currently only inspected visually and any electrical issues are only addressed reactively. A new monitoring device has been trialled at McMinns zone substation and has provided good condition data that can be used to enhance our asset management of these devices and support improved performance. This device will be installed at 8 critical communications locations.
- **Communications hut electrical supply ($0.4 million)** – one of our remote communications huts has experienced a high frequency of outages due to lightning and electrical surges. This project will investigate the causes and undertake works to resolve the issue.

8.8 Other

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

Below we have identified asset condition limitations that give rise to a targeted program over $5 million in the 10-year planning horizon.

Alice Springs network re-configuration ($15.3 million)

Alice Springs is supplied from 2 main zone substations, one at Lovegrove and the other at Sadadeen. The area north of The Gap is supplied at 11 kV while the area south of The Gap is supplied at 22 kV. Electricity is generated at the Owen Springs Power Station and transmitted to Lovegrove at 66 kV where it is stepped down to 22 kV to supply Sadadeen zone substation and then to 11 kV to supply the distribution network.

This is a complex arrangement that is the result of organic growth of the network and the location of the old Ron Goodin Power Station, which is located adjacent to Sadadeen zone substation.

Changes to the location of the generation source and planned retirement of Ron Goodin Power Station have changed the way power flows on the network, and therefore the functional requirements of the assets. Currently, technical constraints make it difficult to restart the network if there is a system black event.

In addition to the change in power flows, many assets are in deteriorated condition and are expected to require replacement between 2025 and 2035. These include:

- the 22 kV switchboard at Sadadeen, which has reached the end of its technical life and is being carefully managed to remain in service until it can be decommissioned in or around 2026
- 4 of the 6 22 kV to 11 kV transformers are expected to require replacement based on condition between 2032 and 2035
- the 11 kV switchboard at Lovegrove is expected to require replacement based on condition in 2030.

Power and Water has undertaken an extensive analysis of the network and consultation with Territory Generation and Northern Territory Electricity System and Market Operator (NTESMO) to identify all the assets requiring replacement and identify other constraints and considerations.

We have developed a long-term plan that will avoid stranded assets and provide real options. The plan will be adjusted periodically as new information arises or asset condition changes at a different rate than expected without creating stranded assets.

Our plan has considered the retirement of Ron Goodin Power Station, the collocated battery system, Uterne solar farm, evolution of the network with solar PV and electric vehicles, and expected growth areas.

The initial action is to install 2 cables from the 22 kV switchboard at Lovegrove zone substation that will connect to an existing cable near The Gap. These will provide a 22 kV supply from Lovegrove directly to the 22 kV network south of The Gap.

Concurrently, the 2 22 kV express ties between Lovegrove and Sadadeen will be disconnected from the Sadadeen 22 kV switchboard and reconnect directly to the transformers. This will enable the 22 kV switchboard to be decommissioned, rather than replaced, without restricting investment options or creating stranded assets. The retirement of the Sadadeen 22 kV switchboard resolves the immediate risk on the network. The cost of this is forecast to be $7.4 million, compared to an estimated $15 million to $20 million to do a 'like for like' replacement of the 22 kV switchboard, including the switchroom and secondary systems which are also at end of life.

The next steps are to progressively replace assets (as they reach their end of life) in a way that will result in our planned optimised network.

While further analysis is required and new information will need to be considered over the entire period of the area plan, the long-term approach is to simplify the network by:

- removing 22 kV assets from Lovegrove and Sadadeen so north of The Gap is only 11 kV
- establishing a zone substation south of The Gap that will supply at 22 kV.
- deferring expenditure at each step as long as possible so we can avoid stranded assets and be adaptable in case new options arise or network needs change.

This will take up to 20 years and be dependent on load growth. We have identified a series of steps to enable this transition with minimal investment, while managing risk, until the new zone substation is required. The cost of the full reconfiguration is expected to be $15.3 million.

Zone substation minor works program ($11.6 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. 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 2 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 and adjusted downwards to account for the impacts of other zone substation works in our forecast. Option 2 was shown to result in increasing risk over time, but much less than Option 1. We considered that the higher short-term risks could be tolerated without increasing the forecast capex.

The majority of forecast capex relates to the building, amenities, civils and grounds.

Darwin – upgrade transmission secondary systems ($7.1 million)

The Darwin-Katherine transmission line is the main supply for the townships of Pine Creek and Katherine.

The secondary systems in the terminal substations on the line at Manton, Batchelor, Pine Creek and Katherine have exceeded their operational life and technical support. The equipment is experiencing increasing failures and without support are technically and economically difficult to repair. This has led to a high number of unplanned outages.

Our analysis identified replacement as the most economical option. We did not identify any viable non-network options. Work has already commenced and will be complete by the end of 2024.

Zone substations fire replacement systems ($5.7 million)

Fire suppression systems are required to be installed at all zone substations and comprise a fire indicator 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 13 Fire Indicator Panels and 118 gas cylinders for the suppression system at 12 zone substations.

Zone substation DC replacement ($3.1 million)

Zone substation switchgear and protection systems require DC supply (i.e. battery systems) to ensure operation during loss of network supply. Due to the ageing of the battery systems, there is a need to manage assets that reach the end of their serviceable life on an ongoing basis. Our analysis has found that battery systems will reach end of life at 16 substation locations in the 2024-29 regulatory period and will continue at a rate of approximately 3 per year for the forecast period.

Zone substations receive electricity from bulk supply substations and transform the energy to a lower voltage for distribution along powerlines to distribution substations.

9. Programs to address capacity, voltage and fault limitations

Our program reflects continued investment in reliability and compliance programs together with new investment to address condition and risk issues. It also reflects a new type of investment on our network to facilitate growing small-scale renewables. We have not identified any credible non-network solutions for addressing constraints through this year's planning processes. However, we welcome stakeholder ideas and feedback on solutions we may not have considered.

In the following sections, we identify our network constraints that give rise to new investment on the network. These include capacity constraints, reliability and quality of supply constraints, faults and non-compliance.

We outline our forecast capital programs to address these constraints including on our transmission and distribution network.

Our augmentation program consists of our base line forecast as well as additional potential investments, known as 'contingent projects', that may be required if certain events occur.

Figure 40 shows our forecast augmentation expenditure compared to historical expenditure with the base line expenditure and contingent projects separated. **Figure 41** shows the proportion of our augmentation program expenditure (excluding contingent projects) in each augmentation category for the next decade.

While the total cost of programs is of the same magnitude as last year, our portfolio of projects has changed in the 10-year outlook:

- We are forecasting lower capex on capacity related investments due to lower peak demand forecasts at a spatial level. This is due to a new method of examining the potential demand from spot loads as discussed in section 8.1.
- This year we have forecast a program to increase the capacity of our network to facilitate increasing distributed energy resources and for the investment in Battery Energy Storage Systems (BESS). The new projects enable us to flexibly manage minimum demand issues on our network, without imposing static limits all year on export capacity. These include dynamic operating envelopes and installation of community batteries.
- We have 2 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 upgrade our transmission lines and a program to replace specific distribution substations in Darwin CBD that will also address rising fault issues (discussed in section 7).

Our program reflects continued investment in reliability and compliance programs together with new investment to address condition and risk issues.

Figure 40 – Forecast augmentation capex

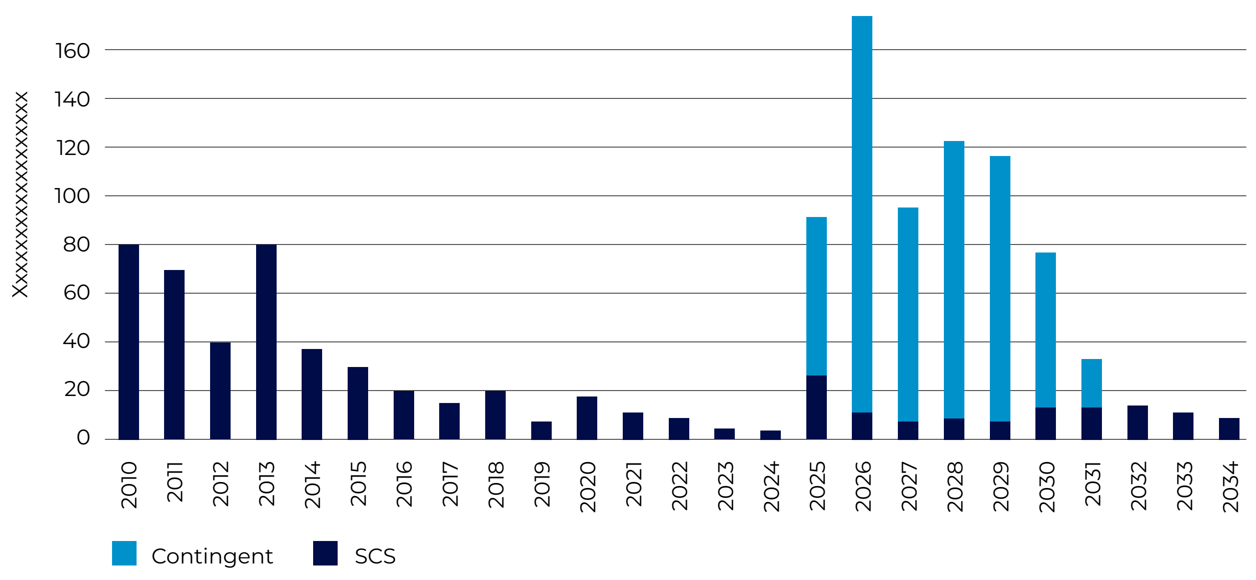
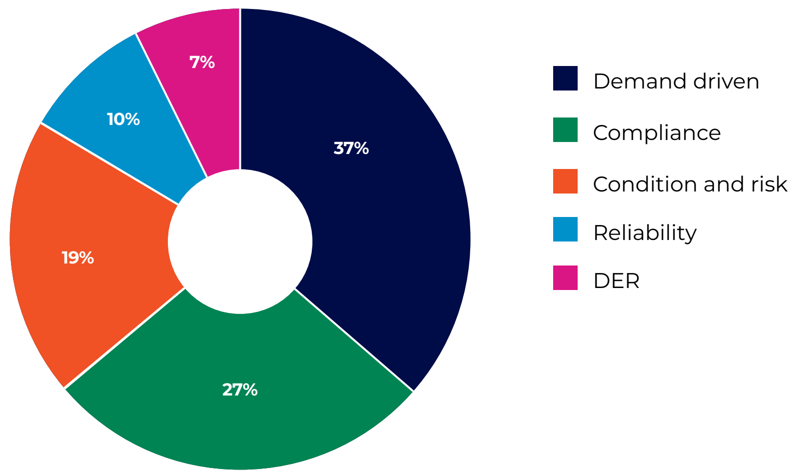


Figure 41 – Categories of augmentation (excluding contingent projects)



9.1 Capacity constraints

We upgrade or build new infrastructure when our assets cannot securely meet peak demand in an area of the network. This is termed demand driven capex.

A key change from last year is that our peak demand forecast has reduced and we have found that all our large zone substations and transmission lines will be able to accommodate the forecast peak demand growth due to existing capacity and ability to transfer load under contingencies.

This is largely attributable to our assessment of capacity on the network at a spatial (local) level compared to peak demand growth forecasts. While there are differences between each of our regions, aggregate growth in zone substation forecasts in the 2024-29 period is not forecast to exceed network capacity.

The growth is largely attributable to 'spot loads' on the network particularly in Wishart, Berrimah, 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.

We revised our approach for estimating 'spot loads'. A load was considered to be 'committed' only if a negotiated connection agreement had been signed or a letter of offer signed by the customer. This is a more stringent requirement that provides more certainty that the connection will proceed and we are not over estimating the forecast and unnecessarily augmenting the network. Consequently, the peak demand forecast reduced and we have found that all our large zone substations and transmission lines will be able to accommodate the forecast peak demand growth due to existing capacity and ability to transfer load under contingencies.

However, there are some capacity constraints at zone substations that will need to be addressed, such as the capacity of cables from transformers to the switchboard or instrument transformers with inadequate ratings. We will also undertake a program to upgrade one of our 66 kV sub transmission lines due to a spot load and a program to upgrade our 11 kV feeders to address local constraints.

We have not identified constraints on any of our main distribution feeders but have identified constraints on some tee-offs in localised areas. Our approach has been to examine the capacity of each of our high voltage distribution feeders compared to the forecast demand growth in the area. We have applied the relevant contingency criteria to assess if there is sufficient capacity available on the distribution feeder. Where there is insufficient capacity we have considered options to address the shortfall including taking into account transfer capacity and non-network options.

The Northern Territory has several potential large projects that may lead to significant spot loads in pockets of our network. At the time of preparing the 2024 TDAPR, these spot loads are not committed, and therefore have been excluded from our capex forecast for 2025-34.

The projects that are probable to occur during the next regulatory period but remain uncertain with respect to scope, timing or cost have been included as contingent projects as described in section 8.3.

Tindal zone substation upgrade ($19.2 million)

Tindal zone substation is located in the Katherine region of our network. It is currently supplied by 2 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 extend an existing feeder to provide a third 22 kV supply to strengthen the resilience and security of supply to this substation.

The scope of the project is to rebuild part of the zone substation including replacing the existing transformers with 2 larger ones, replacing all the switchgear, protection and upgrading the buildings.

We have spent approximately $2.7 million so far with approximately $19.2 million remaining.

Overloaded feeder program ($8.5 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 5 MVA and 50 MVA of demand, we must restore load within 60 minutes. This is typically achieved via distribution transfer capacity (DTC) to contiguous feeders and/or substations to assist with restoration.

In the 2019-24 regulatory period, we addressed 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 7 cables in the forecast period. This was based on an analysis of the capacity of each high voltage feeder under an N-1 contingency and reviewing whether a capacity constraint arises due to an increase in peak demand growth.

We analysed 2 options, 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 was to continue our current practice of undertaking augmentation on feeders that are high risk (for example in commercial areas). We found the second option provides the highest net present value.

The scope of works addresses 7 feeders in the Darwin-Katherine network. We have identified specific works for each feeder including 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.

Lovegrove zone substation transformer upgrade ($5.6 million)

The 22/11 kV transformers at Lovegrove Zone Substation in Alice Springs have been identified to be in deteriorated condition based on analysis of the internal insulation, ongoing oil leaks and on load tap changer control and are forecast to reach end of life in around 2030. In addition, the demand at Lovegrove Zone substation is forecast to grow and exceed its firm capacity rating. As a result, we have identified a need to replace the existing transformers and increase the zone substation capacity.

We note that in line with the Alice Springs network development plan, we need to consider options including replacing the existing 22/11 kV transformers with larger capacity transformer or alternatively installing a 66 kV/11 kV transformer to continue progressing the network reconfiguration plan. Further analysis needs to be undertaken to identify the preferred option which must also consider other network drivers, the Regulated Electricity System Investment Plan being developed by NTESMO and certainty and timing of demand growth.

Further analysis will be undertaken during the next few years to confirm the preferred option, scope and timing. We have currently allowed $5.6 million in the forecast for this project.

Network design and planning project ($4.8 million)

This project addresses minor augmentation at zone substations. These minor projects at major substations address capacity issues or operational flexibility. This includes improving the cyclic rating 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 minor substation equipment. These projects help to defer major expenditure. We have used historical expenditure as a basis for our forecast capex in the planning period. This project is likely to cost $4.8 million.

Humpty Doo zone substation ($1.3 million)

There are 2 separate projects being undertaken to address condition and capacity issues at Humpty Doo. A project was included in the 2024-29 regulatory proposal to replace the existing transformers and switchgear due to condition. However, an increase in demand from a specific large customer resulted in the need to increase capacity and redundancy of the zone substation as well. The 2 components of the project are:

- Replace the existing transformers and switchgear with the Nomad (mobile) transformer. This will resolve the condition issues and provide the additional capacity required. However, it only provides N security meaning if it fails there is no back up from a second transformer. It is also a short to mid-term solution until other transformers are available for a permanent solution.
- Upgrade the distribution network to provide additional transfer capacity to Strangways zone substation. This will increase the total transfer capacity to approximately 5 MVA, which will provide the redundancy to Humpty Doo zone substation should the Nomad be out of service.

Both of these projects will be completed by the end of 2025 and will provide adequate capacity and security of supply to the Humpty Doo area.


Power and Water vehicle, Alice Springs


Transmission towers in Darwin-Katherine

9.2 Reliability constraints

Chapter 4 discusses our program to meet our Northern Territory Electricity Industry Performance Code (EIP Code) obligations. As part of the 2024 TDAPR we have undertaken additional analysis of forecast reliability capex over the next decade.

Worse performing feeder program ($8.5 million)

The EIP Code sets out requirements to maintain network reliability within defined targets and to report on the 5 worst performing feeders per feeder category and the actions being taken to manage those feeders.

The need for this program is 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 risk 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.

We typically invested about $0.72 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 location 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 managing (not improving) performance in rural locations and 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, such analysis does not consider the disproportionate impact on rural customers impacted by much higher levels of outage compared to other customers.

We examined 3 options:

- The 'do nothing' option assessed discontinuing our current approach to target investment at worst performing feeders. We considered this option is likely to result in Power and Water not meeting its rural short and rural long targets in the EIP Code over the 2024-29 period.
- Using historical expenditure as a basis to forecast annual capex in the planning 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.
- Improving our current performance by spending more capex in the planning period compared to historical averages. We considered this option would lead to a performance in excess of the regulatory threshold and was therefore not justifiable.

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

9.3 Voltage constraints

We also undertake augmentation works to meet the quality of supply criteria in our Network Planning Criteria.

Hudson Creek reactors ($6.8 million)

Power and Water is responsible for voltage control on the network. One option to meet this obligation is to install reactors to absorb reactive power and reduce voltage. A reactor at Hudson Creek will benefit the entire transmission and sub-transmission network. However, with the potential deployment of synchronous condensers, additional reactors may not be required. Further analysis is required to confirm the need, location and size of any network reactors. Our long-term planning has included an indicative allowance for $6.8 million for reactors on the transmission or sub transmission network, based on recent project costs.

Alice Springs voltage management ($5.5 million)

This program will rectify voltage issues at the Lovegrove Zone Substation in our Alice Springs network through the installation of 2 reactor capacitor banks.

The need for this program arises from minimum demand days in Alice Springs. This is when high solar PV output coincides with periods of relatively low demand particularly from commercial and industrial customers, and air conditioners for residential customers. These events increase voltage on the network significantly. Our load flow analysis demonstrates that we would not meet our voltage compliance obligations due to minimum loads from FY25, with performance deteriorating over time.

Our options assessment considered network and non network options, including demand management, static export limits, DOE and BESS. We found that the installation of reactors was considered preferable on the basis that it is a simple and proven technology and maximised the net present value. If the assets are no longer required, for instance when Dynamic Operation Envelopes (DOEs) become operational in Alice Springs, it could be relocated to another location on Power and Water's network.

The scope of the solution is to procure and install 5.5 MVAr of reactive compensation using 22 kV air-core shunt reactor units with 2, 2.75 MVAr stages. The project will include all associated switchgear, primary and secondary cables, protection and control systems to connect the reactors to the new circuit breakers on the 22 kV switchboard. The project is underway and will be completed by 2026.

Voltage rectification – Katherine ($2.9 million)

This program seeks to rectify voltage issues in Katherine through the installation of 2 reactor capacitor banks. Currently, Katherine Power Station is being run out of merit order to provide network support services to manage the voltage. Katherine Power Station is one of the more expensive power stations to operate and therefore it is not considered an economic long-term solution.

The option to install reactors was found to be preferred on the basis that it is a simple and proven technology. If the asset were no longer required, for instance if the synchronous condenser contingent project proceeds, the assets could be relocated to another location on Power and Water's network.

The scope of the solution is to procure and install two air-core shunt reactor units with total capacity of 5 MVAr with associated switchgear, undertake civil and fencing works, install primary and secondary cables from the reactor units to the new circuit breakers on the 11 kV switchboard and install protection and control systems for the operation of the reactor banks. This project is underway with completion expected at the end of 2025.

Power quality compliance program ($9.1 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 or suffer a reduction in expected life.

The need for the program arises from specific voltage issues we forecast to occur in the planning 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. New requirements for inverters to have both 'Volt-Var' and 'Volt-Watt' modes available have helped 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 3 options to address 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 only acting in response to a customer complaint, however this option does not address the undetected issues with voltage problems and may lead to higher risks in the future.
- Proactively identify power quality issues through load flow studies and system modelling, and initiate targeted projects based on the results. This is our current approach.

The third option is preferred due to the ability to target works where there are clear issues. We used historical trends to identify the forecast capex in this planning period. This is because works are undertaken on a site-by-site basis and it is difficult to identify the likely works in advance. The types of work we have historically undertaken include upgrading conductors or overloaded transformers.

9.4 Compliance constraints

Transmission line up-ratings ($9.7 million)

Each transmission line has a specified nominal rating. As more current flows through a transmission line, it heats up and expands, resulting in increased sag that reduces the clearance to the ground or other public assets.

Hence, the rating of a transmission line is usually determined by 2 factors: 1) the conductor's design temperature and 2) the safety clearance of the conductor from public assets. The conductors on the transmission line are required to operate below a certain temperature so they maintain compliance with clearance requirements.

An aerial LiDAR survey of each transmission line (66 kV and 132 kV) identified clearance issues.

We examined 3 options to address non-compliance:

- Option 1: 'Do nothing' does not address the risk and therefore was not accepted.
- Option 2: Rectify all non-compliances to ensure the design rating of the transmission line can be achieved.
- Option 3: Undertake a risk based approach to only correct non-compliance on approximately 12 sections. This means that the transmission line capacity may still need to be restricted at times.

We undertook a risk-based analysis of the 3 options and found that Option 2 had the highest NPV and is consistent with our current approach to managing the capacity of our transmission lines.

There were no credible non-network solutions identified that would mitigate this network issue.

Low clearance or easement compliance program ($10.1 million)

This is an ongoing program to address compliance issues with our distribution conductors. Throughout the year, conductors that breach requirements for minimum clearance from the ground and structures, or deviate outside of defined easements, are identified. A mitigation solution is developed on a case-by-case basis to meet the specific circumstances of the asset.

We assessed options to efficiently address these non-compliances. In our options assessment, we considered that doing nothing further would be a breach of our compliance obligations and expose customers and our workers to safety risks.
The preferred option was to address the low conductors as they are identified by developing a custom solution.

Since the solutions required vary for each individual conductor, the forecast has been based on the trend of historical expenditure.

9.5 DER constraints

In Chapter 4, we discussed our Future Network Strategy that includes a focus on unlocking low-cost renewable energy from our customers' solar panels. This has led to a rigorous business case to understand the constraints of our network in hosting solar exports and identifying efficient solutions. This follows on from last year's TDAPR where we noted key challenges and potential solutions.

The business case shows that our 3 regulated networks will not be able to accommodate the forecast increase in the uptake of rooftop solar, based on an assessment of our network hosting capacity. The analysis shows that we are experiencing non-compliance with voltage standards. Due to our inability to constrain rooftop solar output, this poses a risk to network security during times of minimum load. At the forecast rate of uptake, these issues will be exacerbated.

The following options to prevent network voltage non-compliance and minimum demand events caused by increasing solar penetration were identified as part of our strategy development process:

- Stricter Static Export Limits (base case) – revise the residential static export limit from 5 kVA to 2.3 kVA from 2028, to curtail solar year-round.
- Dynamic Operating Envelopes (DOEs) – Invest to establish foundational DOE capability to improve our understanding of the network need. This will enable us to identify the best approach to integrate DER in the long-term. The proposed investment to implement the core infrastructure for DER integration is $3.8 million by the end of FY29.
- Community batteries – Invest in community battery energy system storage (BESS) infrastructure to soak up solar during periods of network voltage non-compliance and minimum demand, and discharging during peak times to defer augmentation. This project has an expected cost of $46 million with potential for a grant (contribution) from ARENA of $11 million.
- Power partnerships – continue to deliver our power partnerships program to unlock demand management to defer augmentation and/or help address minimum demand issues. This is an ongoing program currently budgeted for $2.9 million.

We have identified that this suite of Distributed Energy Resources focused projects provides the most efficient approach to managing DER for all future scenarios we have considered in the Northern Territory. The approach is consistent with DNSP's in other jurisdictions and will enable dynamic management of solar PV, provide low-cost tools and capability to manage immediate compliance related risks, and enable us to better understand the hosting capacity and voltage performance of our network.

Further data on forecast hosting capacity constraints for our Darwin-Katherine network are provided in the appendices together with a description of our methods.

9.6 Other drivers of network augmentation

Our asset management processes identify emerging condition issues that necessitate investment in new assets.

Locks and Security of zone substations (total of $4.2 million)

The security of the network infrastructure program arises from the continued occurrence of incidents involving unauthorised access to zone substations and distribution enclosures. 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 $4.2 million.

Asset information (Drawing) update program ($3.4 million)

We have identified that there are approximately 8,000 drawings for minor asset upgrade works where the 'as-built' drawings have not been updated, or are not considered to be at an appropriate level of quality.

This program will update all the drawings to ensure that drawings will be up to date in our systems with accurate information. This will improve asset information for future planning and safety for our staff.

In addition, to ensure ongoing control of documentation revisions and to ensure quality we will implement a drawing management (software) system.

Substation assets

9.7 Contingent projects

Under the regulatory framework there is a mechanism to incorporate projects that are uncertain in terms of scope, costs and/or timing. These are known as 'contingent projects', meaning that while they are highly probable to proceed during the next regulatory period, there is too much uncertainty to include them in our ex-ante forecast. These projects are submitted with 'trigger events' that must occur before the AER is able to incorporate the projects and costs into our regulatory allowance.

We have identified 3 contingent projects that are required as a result of the transition to renewable energy. These include:

- **Proposed Renewable Energy Hub** – part of the Northern Territory's transition to renewable energy. The premise of the project is that lower cost renewables could be dispatched through centralising production close to the existing transmission infrastructure. The project would require Power and Water to build a new transmission line to the hub and a substation to inject generation to the existing transmission network. Latest costings from the Northern Territory Government suggest a capital expenditure of approximately $265 million based on the assessment of 7 options. Significant costing and funding uncertainty means that we have classified this as a contingent project.
- **Unlocking solar generation on the Darwin Katherine transmission line** – many large solar generators are located south of Darwin. There are transmission constraints on the Darwin-Katherine transmission line due to system security issues that result in curtailment of generation. The DKESP noted mechanisms to improve the dispatchability of this existing generation, including procuring services of grid-scale batteries. However, there is considerable uncertainty on technologies available, and the level of market benefit. We consider a RIT-T would provide a means of testing if there is a solution that maximises market benefit. Due to the level of uncertainty associated with this project we classified this as a contingent project in our 2024-29 regulatory proposal to the AER.
- **Managing the transition to renewable energy in Darwin-Katherine** – the transition to renewable energy and planned retirement of existing synchronous generation at Channel Island Power Station will result in risks to system security. Potential solutions include synchronous condensers or grid-scale batteries, however there is considerable uncertainty on technologies available and the timing of the issues emerging. Due to the level of uncertainty associated with this project we classified this as a contingent project in our 2024-29 regulatory proposal to the AER.

There are also 3 contingent projects that relate to growth in network demand requiring new zone substations to enable supply in new areas, or increase capacity in existing areas. These include:

- **Holtze-Kowandi land release** – the Northern Territory Government has announced the release of land near Darwin called Holtze-Kowandi. This is a significant land release that would entail the need for a new zone substation if housing and commercial demand occurs in the 2024-29 period. However, there is uncertainty on exact timing of when the load would materialise, hence the construction of the new zone substation was included in our 2024-29 regulatory proposal to the AER as a contingent project.
- **Commercial development in Middle Arm** – a new industrial zone will likely attract significant demand for electricity from large, new non-residential customers. There is uncertainty on how many industrial customers may seek connection and the resultant demand for grid services. It is likely that a significant load would require a new zone substation. Due to this uncertainty, the new zone substation was included in our 2024-29 regulatory proposal to the AER as a contingent project.
- **Development in East Arm** – an industrial precinct at East Arm may require significant investment in a new Wishart zone substation. Due to the uncertainty around the timing of this development, the new zone substation was included in our 2024-29 regulatory proposal to the AER as a contingent project.

List of Appendices

We have also published an accompanying Excel databook covering all technical data including asset population, maintenance strategies and demand forecasts for our transmission network and zone substations. The table below sets out the relevant data.

Appendix Number	Description of data and information in the appendix
Appendix A	Asset count reported in 2022-23 Category Analysis RIN
Appendix B	Voltage regulation standards
Appendix C	Maintenance strategies
Appendix D	Transmission lines – demand forecasts and system limitations
Appendix E	Transmission contingency analysis
Appendix F	Zone substations – demand forecast and system limitations
Appendix G	Distribution feeders – identified system limitations
Appendix H	Maps of the three regulated networks
Appendix I	System limitations template – transmission
Appendix J	System limitations template – distribution
Appendix K	Embedded generator information

Power and Water Corporation

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

powerwater.com.au

@PowerWaterCorp