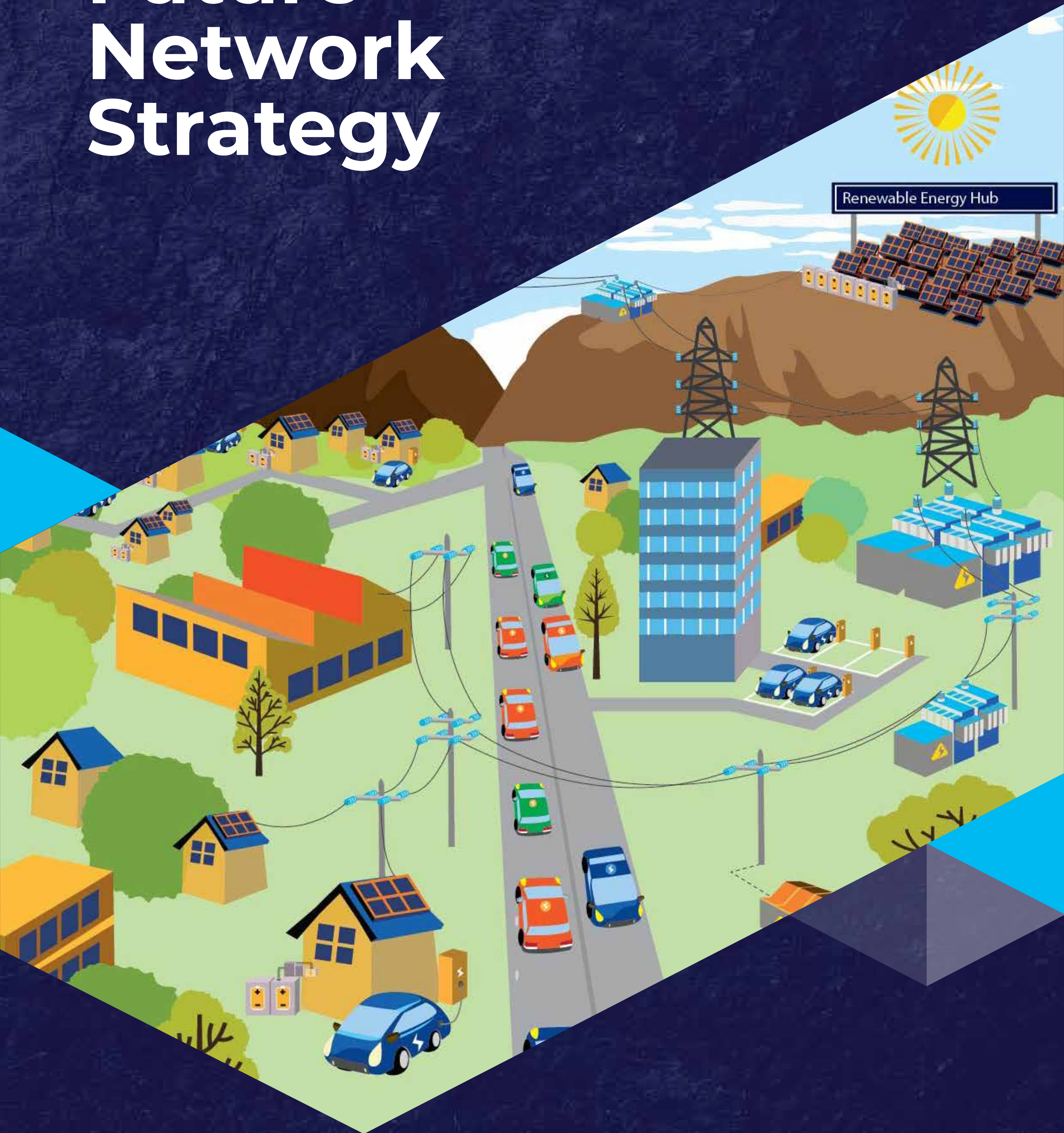
PowerWater

Future Network Strategy



@powerwatercorp

About this report

This document outlines a long-term roadmap to address key drivers of change impacting our network including the transition to renewable energy in the NT. The scope of the strategy extends to our three regulated electricity networks in Darwin-Katherine, Alice Springs and Tennant Creek.

We have structured the document as follows:

- Chapter 1 provides context on the pivotal changes impacting the electricity system and our strategic priorities to adapt to the changes.
- Chapter 2 identifies the objectives of the Future Network Strategy demonstrating how we are seeking to maximise opportunities and navigate challenges from the key drivers of change.
- Chapter 3 identifies focus areas and initiatives for our network activities that together deliver the objectives of the Future Network Strategy.
- Chapter 4 identifies the optimal timing of initiatives from now to 2040 with reference to three key time-periods.

Appendix A provides information on our Distributed Energy Resources (DER) integration strategy as required by the Australian Energy Regulator's (AER) Integration expenditure guidance note.

Our Future Network Strategy has influenced the development of our Strategic Asset Management Plan and Asset Management Plans. It has also been pivotal to developing business cases and expenditure requirements for our upcoming 2019-24 regulatory proposal to the AER.

We will monitor and update the Future Network Strategy every three to five years. This is necessary given the unprecedented rate of change in new technologies and policy settings. New information may require us to fine-tune, pivot and deviate from the roadmap. As part of these updates, we may broaden the scope of this strategy to apply to our unregulated networks.

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Contents

Summary

Based on feedback from our customers and stakeholders, we have developed a comprehensive Future Network Strategy that identifies four key focus areas to 2040. The Strategy aims to embrace key drivers of change that provide both opportunities and challenges for our business. Our overriding objective is to improve customer outcomes as we support the transition to renewable energy.

We are living in a period of rapid and unprecedented change in the electricity industry. Our small network is being disrupted by global trends from climate change to electric vehicles to market uncertainty. We also expect to face significant local changes in the NT including the ageing of network assets, the need to refresh ICT assets and growing demand for electricity in the NT.

Our Future Network Strategy seeks to embrace the pivotal changes impacting our business to maximise opportunities for our customers and navigate challenges. The ultimate objective is to improve outcomes for our customers including affordability, maintaining reliability and security of supply, playing our part in a sustainable and prosperous NT, and improving choice and equity.

The Future Network Strategy reflects the feedback of our customers and industry stakeholders on how our network should evolve. We held two Future Network Forums with industry stakeholders. We also extensively discussed key priorities and values with our residential and business customers. The key message was that stakeholders wanted us to be progressive, customer-led and mindful of affordability.

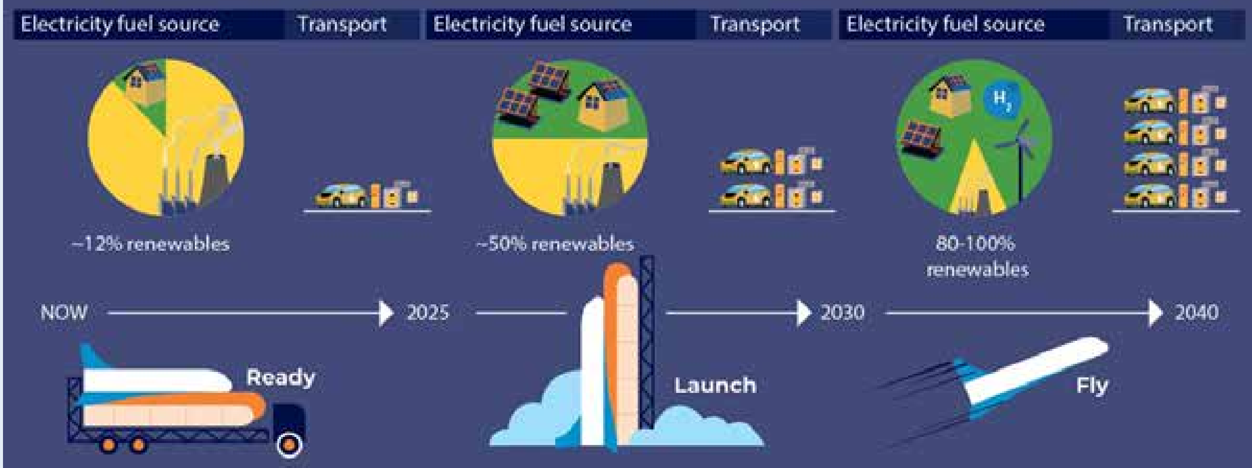
The feedback has been instrumental to identifying strategic priorities for the business, which has shaped key focus areas in this Future Network Strategy. Our strategy recognises that renewables are much lower cost than emissions technology in the NT, and that we need a 'razor sharp' focus on navigating network challenges to pass through lower costs to our customers. We have also identified initiatives that increase our scale and better utilise our network assets, improving the efficiency of our network services. Finally, we have identified initiatives that will help us better design the network to meet upcoming challenges from ageing network assets and increasing climate change weather events impacting our network.

The Future Network Strategy provides a roadmap on the timing of initiatives that balances the need to be on the 'front foot' in adapting to drivers of change while ensuring our investment is prudent and efficient. This recognises that change is rapid and uncertain, and that our response needs to be agile and adaptable. For this reason, we have sought to develop a roadmap over three time-periods that progressively roll-out initiatives – now to 2025 ("Ready"), 2025 to 2030 ("Launch") and 2030 to 2040 ("Fly").

Figure 1 is a visual summary of our Roadmap to 2040 that brings together our objectives, focus areas and initiatives and timeframes for implementing initiatives.

Figure 1 – Future Network Summary

The When | Phasing



The How | Initiatives

- Dynamic Operating Envelopes
- Pilot storage batteries
- Export tariff and incentives

- Maximise existing solar farm generation
- Build a renewable hub
- Plan for a future transmission network

- Tariff reform
- EV off peak charging
- Energy efficiency for low income

- Extend asset lives
- Optimise the network
- Improve resilience

1. Context

Our small network will face pivotal changes in the decades ahead, driven by the urgent need to decarbonise our energy systems and meet growing demand from electric vehicles. We are also facing internal drivers of change as we manage ageing network assets and renew our legacy ICT systems. Our Future Network Strategy considers how our network can adapt to meet key strategic priorities.

Historically, our role in the regulated NT electricity systems has been to deliver large-scale gas generation to our customers one-way. Rooftop solar has been a game-changer over the last decade as our customers see the benefits of fueling their homes with small-scale solar. Our network is now responsible for exporting renewable energy from our customers' solar installations.

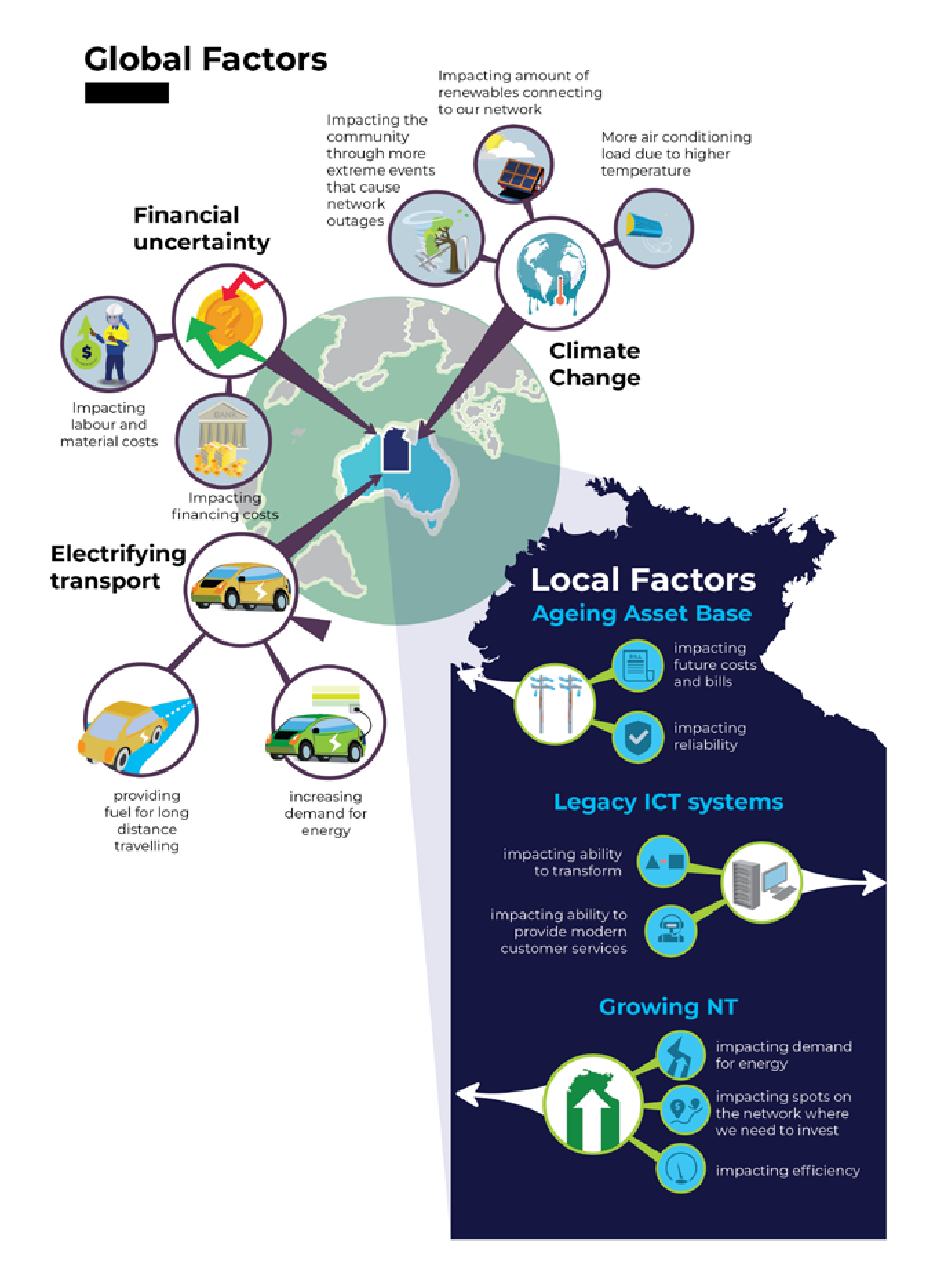
This is only the start of a fundamental shift in our electricity system, as climate change shifts our mindset to renewable energy and electric vehicles. In this chapter, we discuss the paradigm drivers of change impacting our network, what our customers have told us is important when adapting to the new world and how our strategic priorities have provided a lens for the Future Network Strategy.

1.1 Drivers of change

Our small network is being disrupted by global and local change factors, as identified in **Figure 2.** The global changes include climate change, electrification of transport and uncertain financial markets. The local changes include ageing of our network assets, the need to replace legacy ICT systems, and growing population and businesses in the NT.

This is only the start of a fundamental shift in our electricity system, as climate change shifts our mindset to renewable energy and renewable-charged cars.

Figure 2 – Global and local changes impacting our network



Global changes

Over the coming years, key global change factors will deeply impact our business including responding to climate change, electrification of transport, and financial uncertainty.

Concerns about the impact of **climate change** has led to unprecedented and fast-paced change in energy systems around the world, as we shift from carbon emission to renewable technologies. Over the last decade, our customers have led the charge in greening our energy systems with about 20 per cent of our customers having installed a rooftop solar installation.

This will markedly accelerate under the Northern Territory Government's (NTG) policy of delivering 50 per cent renewable energy by 2030. In October 2021, the NTG released the Darwin-Katherine Electricity System Plan (DKESP) that charted a pathway to decarbonise the energy system in the region and outlined how the NT energy system needs to operate in 2030 to maintain reliability and security. **Figure 3** is the NTG's forecast growth in renewables on the Darwin-Katherine Electricity System, underscoring the role of large-scale solar farms and battery storage to supplement growth in small-scale solar. There is also a clear expectation in the DKESP that the energy system will continue to decarbonise toward net zero emissions in the coming decades.

Our network is the vital link to ensure renewable generation is transported to our customers while safeguarding the reliability and security of the power system. We will need to design our networks and innovate to meet the challenges with hosting small and large-scale renewable generation. We will also need to proactively design our transmission network and streamline our connection processes after 2030 when we expect a greater scale and diversity of renewable energy.

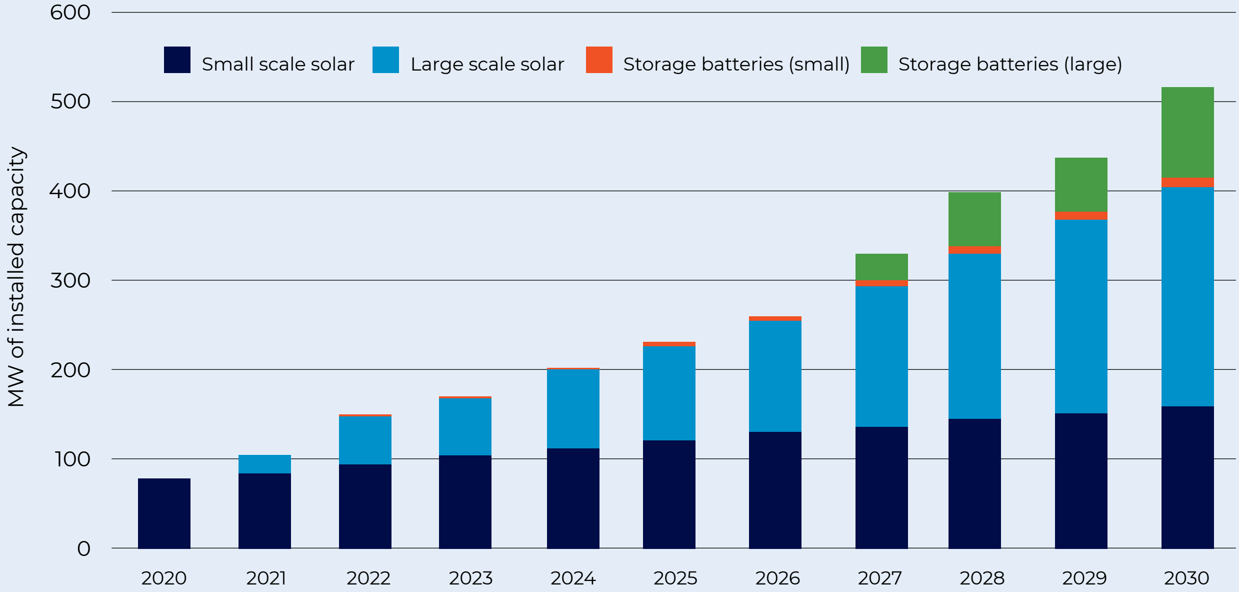
Climate change is expected to impose network resilience and reliability risks across our network. The NT Government, in partnership with CSIRO, found that climate change will result in more intense cyclones, more high fire risk days and higher risk of flood events over the next 30 years. Extreme temperature, fires, floods and extreme winds can damage lines and substations and reduce the efficiency and capacity of the network. Weather-related events cause a large portion of electricity outages in the NT and often result in the reliability of supply.

The global shift to **electric vehicles** is expected to fundamentally change the composition of vehicles on the road in the NT. While there are perceived barriers to EV uptake in the NT such as range anxiety, it is likely that more customers will drive an EV by 2040, consistent with the forecasts for other states and territories in Australia as seen in **Figure 4**. The growing uptake of electric vehicles in the NT is likely to have a significant impact on electricity consumption and demand from our regulated networks.

We are also entering an era of **financial uncertainty** with a recent spike in inflation and interest rates. This will impact our borrowing costs for past and new capital expenditure, which influences the revenue we recover from customers for our services.

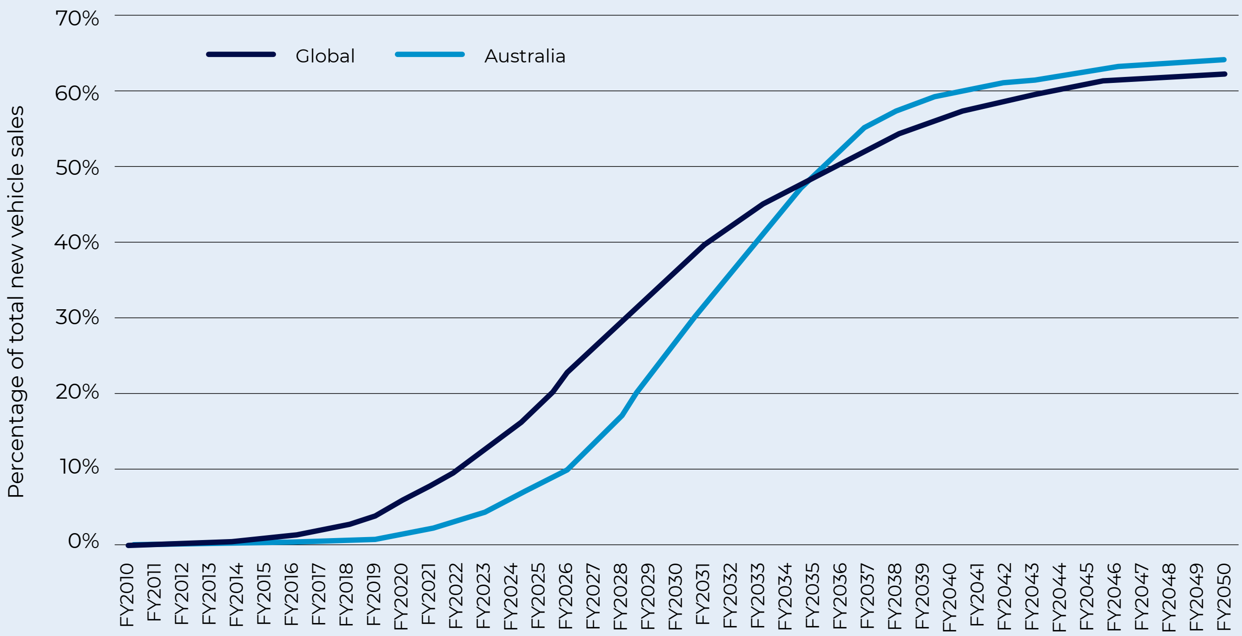
Our network is the vital link to ensure renewable generation is transported to our customers while safeguarding the reliability and security of power.

Figure 3 – Forecast installation of renewable energy (MW) in Darwin-Katherine electricity system



Source – Darwin-Katherine Electricity System Plan Input Data, Tab: Summary Table

Figure 4 – Forecast of new sales of electric vehicles in Australia and globally



Source: Bureau of Infrastructure, Transport and Regional Economics (BITRE), 2019, Electric Vehicle Uptake: Modelling a Global Phenomenon, Research Report 151, BITRE, Canberra ACT

Local drivers of change

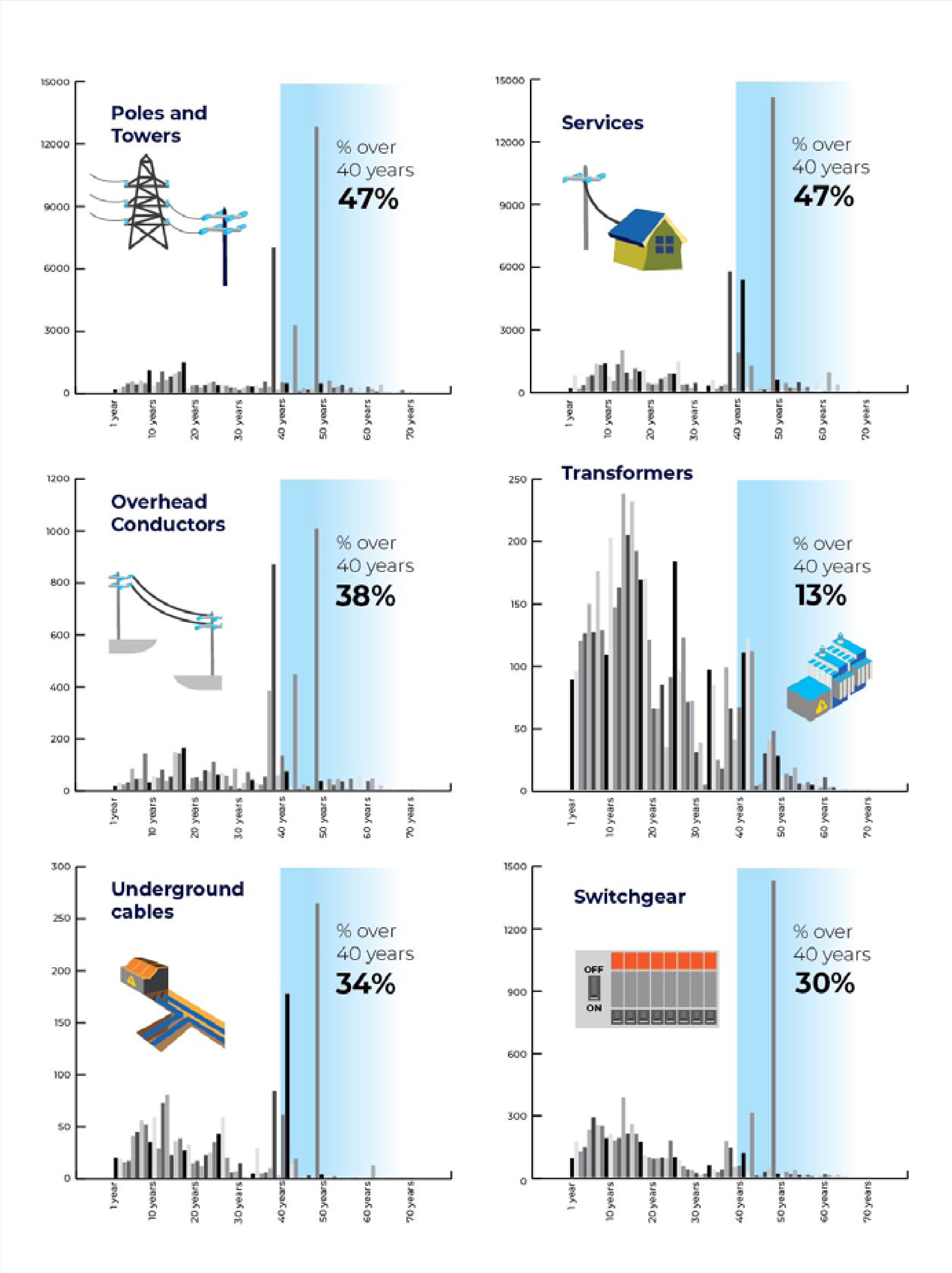
Over the next two decades, we will also face significant changes from ageing assets and meeting higher demand for electricity from increasing population and business activity.

A large cohort of our network assets were built after Cyclone Tracy in 1974. These assets will reach or exceed their expected technical life over the coming decades. **Figure 5** shows that a significant proportion of our assets in 2021-22 were over 40 years of age across all asset classes except transformers. This is largely driven by a spike in population in the years following Cyclone Tracy. By 2040, many of our assets will be over 60 years of age if they remain in service, well beyond the expected technical life. We will need to prudently manage these assets and minimise steep rises in our replacement capex levels.

In addition, our existing fleet of ICT systems have not been refreshed for a generation except for our metering and billing systems which are currently being updated. We have not kept pace with other utilities in Australia, with a significant proportion of our ICT assets built about 15 to 20 years ago. This impacts our ability to manage our ageing network assets, and results in time consuming manual work.

A key change factor that will impact the business over the next two decades is the projected increase in demand from residential and commercial developments in the NT. The NTG has set an ambitious target of creating a $40 billion economy by 2030. Several major infrastructure projects have already been announced and we anticipate increased connections from large users over the coming years together with higher population. This will drive an increase in energy consumption and demand at peak times for our network services, together with the expected increase from electric vehicles.

Figure 5 – Age of our network assets by asset class in 2021-22



1.2 Our stakeholders' vision and priorities for the future

Over the last 18 months, we have spoken to our residential customers in our Peoples Panels, business customers and our industry stakeholders about the future of our network. Hearing directly from our customers on what matters most, their values, preferences, and pain points has significantly shaped the development of our Future Network Strategy and where we need to improve.

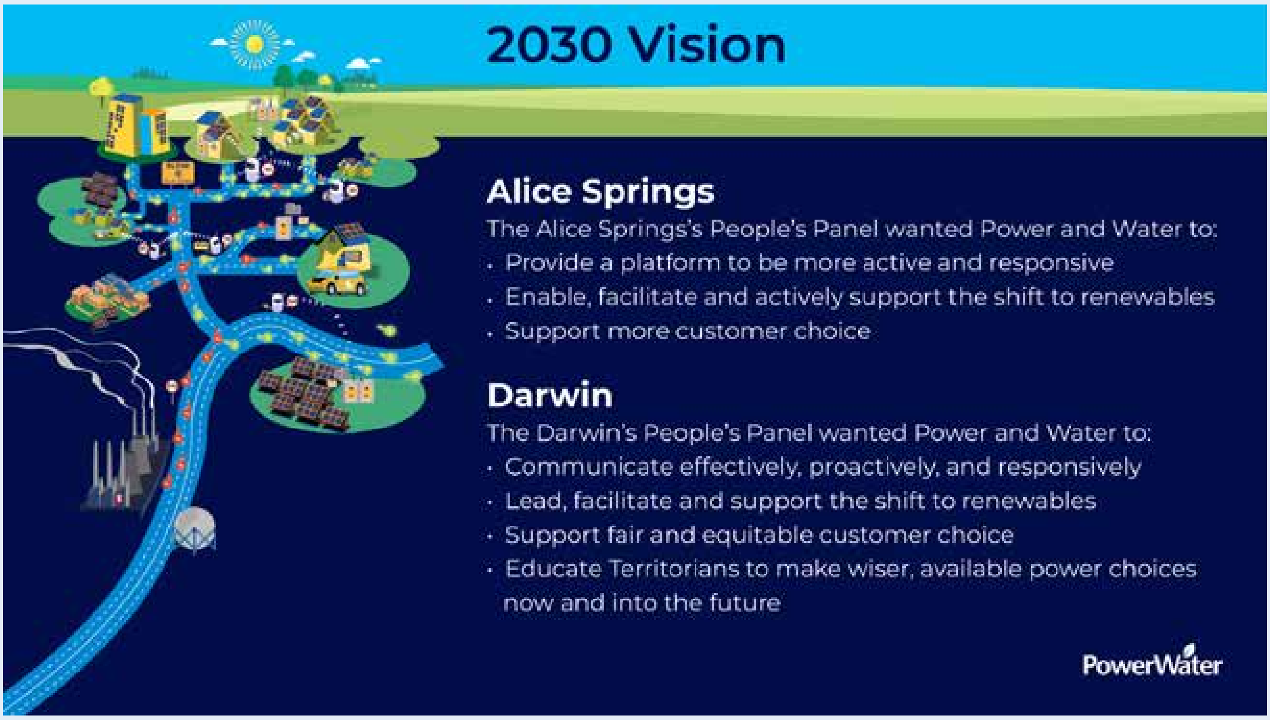
Customers wanted us to be more innovative, look for ways to improve affordability while thinking ahead and looking towards the future.

Figure 6 identifies the vision of our customers in our People Panels in Darwin-Katherine and Alice Springs. It reveals a strong preference to shift energy production to renewables and to enable customer choice. There is also a clear expectation that we proactively look ahead to the future and provide customers with relevant information to support smart power choices.

We also invited industry stakeholders to Future Network Forums in November 2021 and June 2022. Stakeholders wanted us to:

- Invest more now for a future which enables more solar in the system.
- Facilitate more efficient utilisation of network infrastructure.
- Prioritise affordability for households and businesses.

Figure 6 – Vision of our customers in our People Panels in Darwin-Katherine and Alice Springs



1.3 Strategic priorities

Based on our discussion with customers, we identified key strategic priorities for our business as seen in **Figure 7.** The starting point for the Future Network Strategy was to identify the focus areas and initiatives that relate to the strategic priorities discussed below.

Strategic Priority one – Facilitating renewables

Under NTG policy, we expect that 50 per cent of energy consumed will come from renewable generation by 2030. Approximately 30 per cent will come from large-scale renewables that connect through our transmission network. About 20 per cent is expected to come from roof-top solar connected to our smaller customers' houses and exported back into the grid.

We see great benefits from unlocking renewables in the NT. Our current electricity system is predominantly powered by gas, which is a relatively costly fuel source. In contrast, solar is abundant in the NT and the technology is significantly lower cost than gas. Building a network that can facilitate large-scale transmission and household exports can provide lower generation costs for all customers that outweighs new expenditure on the network.

We recognise the engineering challenges in a rapid shift to renewables. For the transmission network, we will need to build lines to connect generation located in different areas to the current thermal generation stock and ensure the network can securely transport the renewables to the load centres. For our distribution network we will need to manage challenges from two-way flow of exports.

Strategic priority two – Improving utilisation

One of the keys to unlocking affordability is providing more power to customers while minimising new expenditure. A key strategic priority is to encourage new and existing customers to use electricity in off peak periods that coincide with low cost solar. Early analysis shows that electric vehicle charging times are one of the key levers to improving utilisation beyond 2030, together with growing demand for electricity from residential and commercial growth.

Strategic priority three – Managing the health of our network

A key strategic priority is safely maintaining the reliability of the network as our assets age over the next 20 years while minimising cost increases for customers. As discussed in section 1.1, a large cohort of our assets were built at the time of Cyclone Tracy and will be older than their expected manufacturing life over the next 20 years.

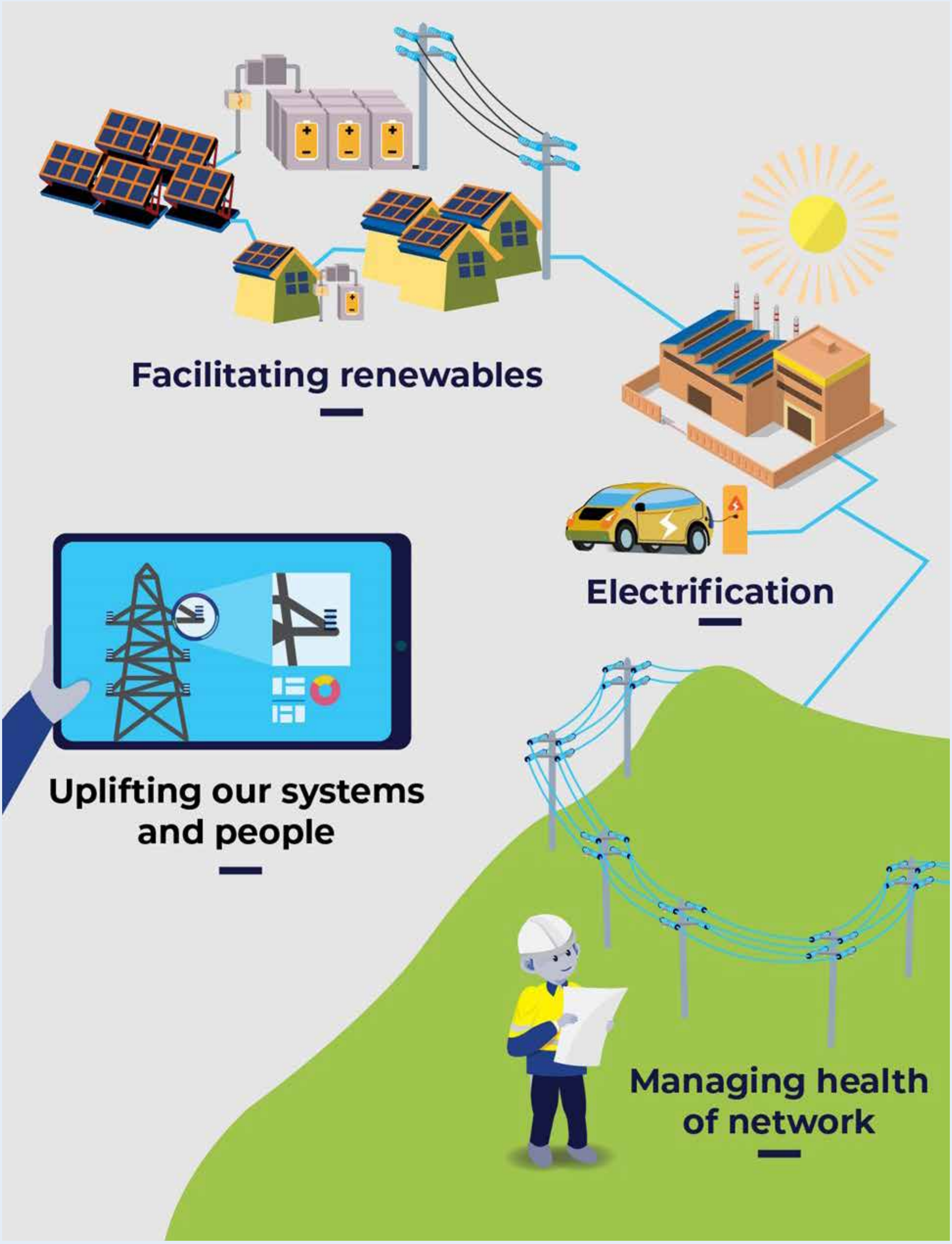
We will need to develop strategies that extend the life of assets, utilise new technology to minimise renewal capital expenditure, and ensure we have systems to help us identify which assets should be replaced as a priority due to condition and risks.

Strategic priority four – Uplifting systems and people

We currently operate with an aged fleet of ICT systems that are not equipped to meet the increase in activity we expect over the next 20 years. Further, we face resource challenges as a relatively small population that is geographically remote from other places in Australia.

It is vital that we invest in smarter systems and organisational change that allows us to meet new demands for our network services while keeping a lid on our costs.

Figure 7 – Strategic priorities for our network that have been incorporated into the Future Network Strategy



2. Objectives of the Strategy

The objectives of our Future Network Strategy have been framed around the feedback of our customers and stakeholders. While our customers wanted us to embrace a clean energy future, they also wanted us to consider affordability, reliability, impact to the NT more broadly, and customer choice and equity. **Figure 8** sets out the key objectives of the Future Network Strategy, which are further discussed below.

2.1 Lower bills

A key objective of the Future Network Strategy is to facilitate lower electricity and transport bills for our customers. Our strategy identifies three opportunities to drive lower prices. Firstly, we see an opportunity to reduce the network portion of the electricity bill by facilitating an increase in electricity consumption in the NT and by incentivising customers to use energy in off-peak periods. This should help to overcome our scale disadvantages while minimising investment in new network infrastructure to meet demand.

Secondly, our strategy has looked at how we can facilitate lower generation costs in the NT. The Darwin-Katherine Electricity System Plan showed that transitioning to low-cost renewables from high emission technology has significant cost savings. This can be seen in **Figure 9** which shows that pursuing a 50 per cent renewables by 2030 results in significant savings compared to re-investing in today's emissions technologies. We see that our network plays a vital role in ensuring that low-cost renewables can be transported to customers with minimal constraints, thereby minimising the generation costs borne by customers.

Thirdly, our analysis shows that electricity is a far cheaper than petrol or diesel to fuel vehicles. This will have a material impact on lowering transport bills for households and businesses in the NT.

2.2 Reliable and secure electricity

Our customers have told us that we need to safeguard the long-term reliability of the network. They understood the engineering challenges entailed in transitioning to a renewable energy system. Customers were also conscious that our asset base will rapidly age over the next 20 years, and that the network will need to adapt to increasing climate change events. In this context, our Future Network Strategy is premised on safeguarding the security and reliability of the network.

2.3 Green and prosperous NT

Our strategy considers the environmental and economic value of facilitating growing renewables in the NT energy system. Climate research shows that the NT environment will be impacted significantly by climate change events. This includes persistence of hotter temperatures and more extreme weather events. Our customers considered it vital that we play our local part in abating climate change by supporting a transition to clean energy.

The benefits of greener energy systems will also provide economic benefits to the NT. With our abundance of resources and our proximity to international markets, we have a great opportunity to grow our export market. International markets will place a higher value on products developed in a renewable energy system.

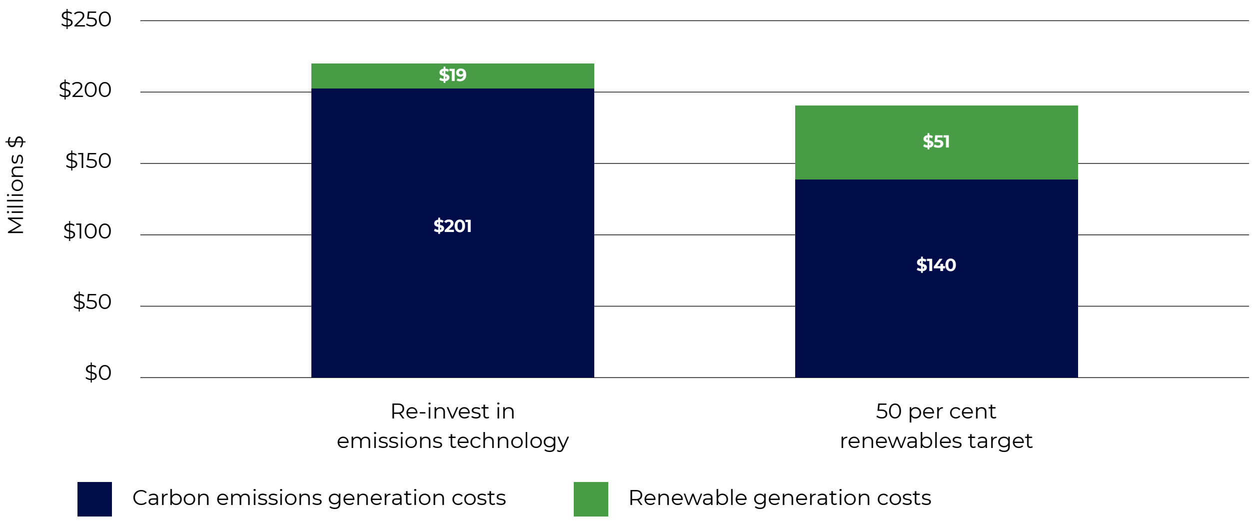
2.4 Customer choice and equity

Our customers have led the way in decarbonising our energy systems. About 20 per cent of our residential customers have a rooftop solar connection. Over the next two decades, we also expect customers will install more home storage batteries and drive electric vehicles. A key objective of our strategy is to limit constraints on how customers use their technology.

Our People Panels also emphasised that our decisions must consider equity between customers. In particular, we should more directly consider initiatives that improve the experience of low-income households. For this reason, a key objective of our strategy is to promote customer choice in how they use technology and improve the experience of all customers including low-income households.

Figure 8 – Objectives of the Future Network Strategy

Figure 9 – Comparison of costs of renewable generation compared to re-investing in emissions technology

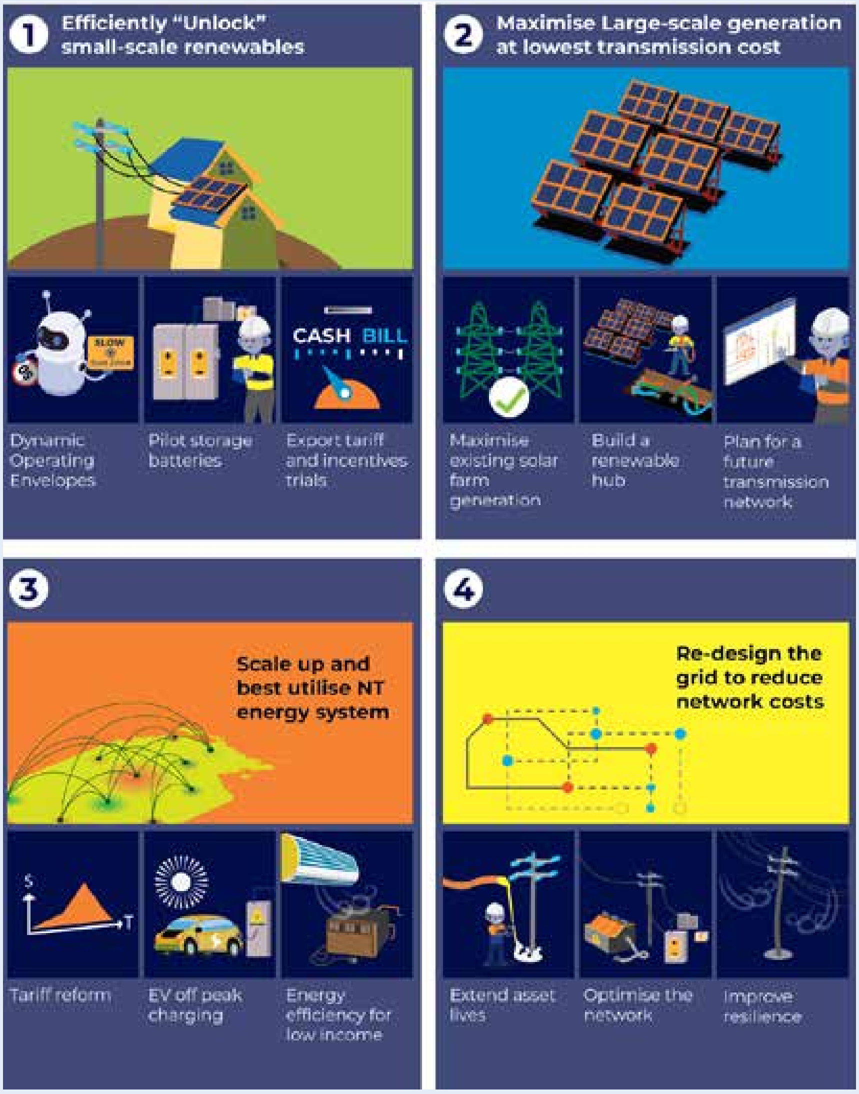


3. Focus areas and initiatives

We have identified focus areas and initiatives that together will help achieve the objectives of the Future Network Strategy. We will focus on unlocking low-cost small and large renewable energy, improving the scale and utilisation of the grid, and re-designing the network to lower future network costs.

Our strategy has identified key 'focus areas' over the next 20 years that would enable us to achieve the objectives. This is set out in **Figure 10** and discussed in the following sections.

Figure 10 – Focus areas and initiatives for the Future Network Strategy



Focus area 1 – Efficiently unlock small scale renewables

Small-scale solar has significantly grown over the last five years. In 2022, more than 10 per cent of underlying energy consumption was produced by rooftop solar with about to 1 in 5 customers installing a roof top solar system.

Small-scale solar has fundamentally changed the role of our distribution network. Rather than one-way delivery of energy to customers, our network conveys solar exports back into the grid. Our network has been highly adaptable to these changes, with minimal need to apply any constraints on our customers. This has meant that we have been able to pass on lower generation costs to our customers.

Our network is facing emerging constraints as small-scale solar increases on the network. **Figure 11** shows actual and forecast residential solar connections from 2017 to 2050. This shows that small-scale solar connections will continue to increase over the forthcoming decades driven by new residential precincts and a higher proportion of existing homes connecting solar.

The most pressing challenge to hosting increasing small-scale solar is security risks during “minimum demand” events. System security requires a minimum level of large mass thermal generation to anchor the system when disturbances arise. A ‘minimum demand event’ is a 30 minute interval where the threshold minimum level of thermal generation cannot be dispatched because household solar is delivering the bulk of energy needs. This occurs on mild days when energy demand is relatively low due to minimal air conditioner use, but the sun is maximising solar production. **Figure 12** provides a visual description of why minimum demand events are expected to increase as more small-scale solar systems are installed by customers.

We also expect localised voltage constraints to increase in future years, but we have limited visibility to understand the extent of the issue. Voltage issues occur when the network infrastructure cannot manage reverse flow from small-scale solar exports.

Figure 11 – Number of residential customers with solar installed

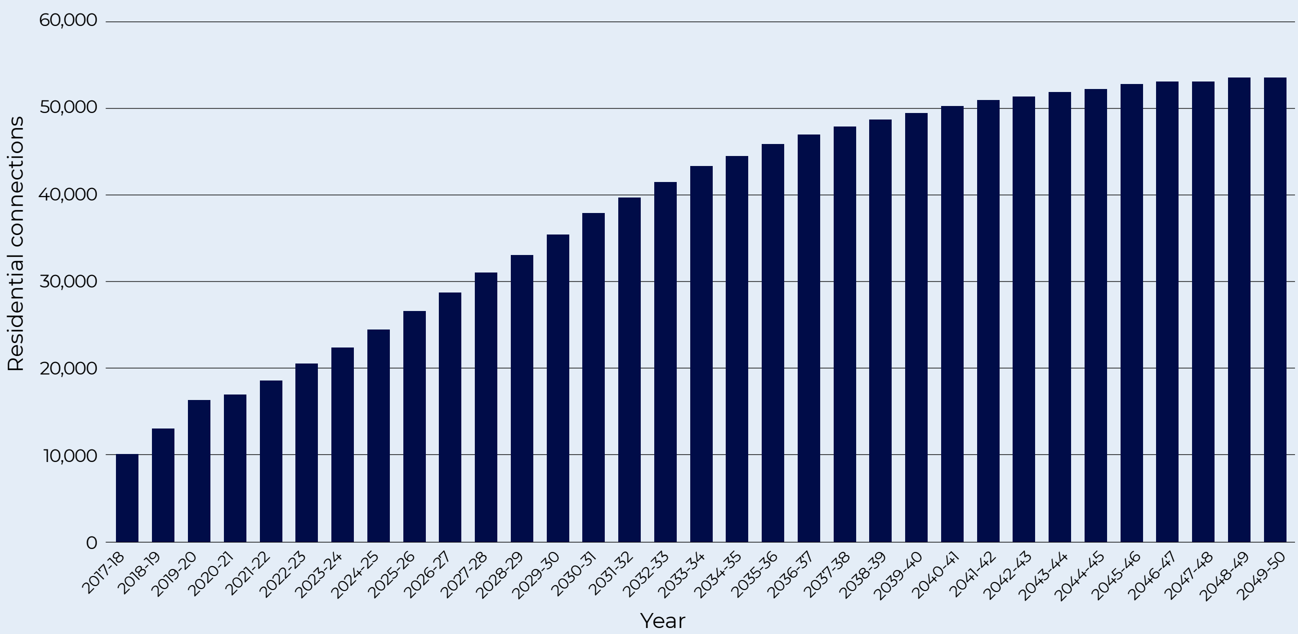
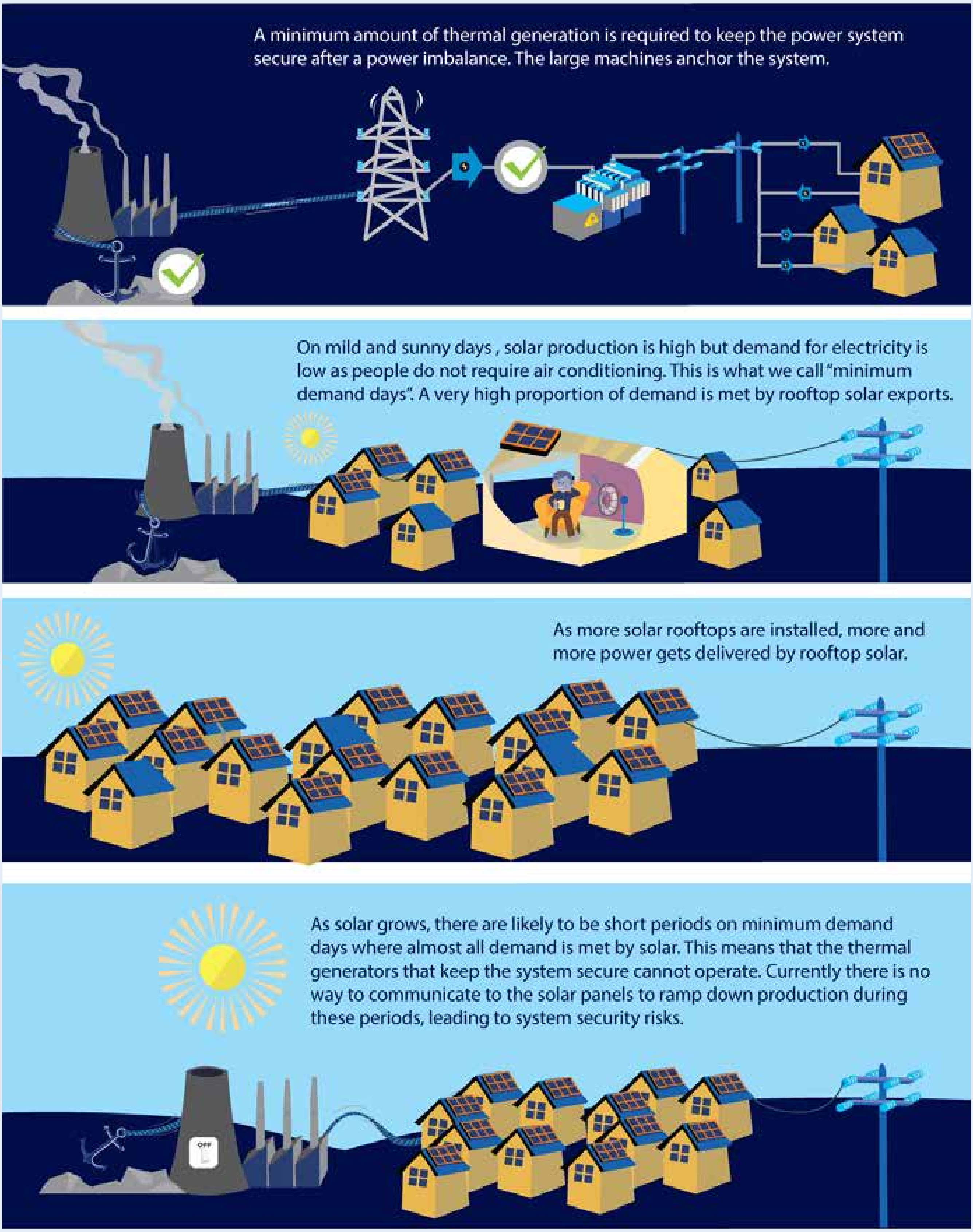


Figure 12 – Minimum demand events



Our strategy has identified the following initiatives to efficiently unlock small-scale renewables.

Dynamic Operating Envelopes

Our analysis shows that increasing uptake of small-scale solar will lead to 'minimum demand events' that increase over time unless managed effectively. **Figure 13** shows that minimum demand events are forecast to occur in 2028 in Darwin-Katherine and will increase significantly each year unless the problem is mitigated. Currently, there are limited mechanisms to communicate to solar panels to ramp down solar exports during minimum demand events.

A blunt solution is to set 'static exports' that limit the amount of energy a customer can inject back into the grid all year round. The disadvantage is that our customers would be constrained even when there is sufficient capacity to host low-cost renewable energy, and this would lead to higher generation costs for all customers.

Our Future Network Strategy identifies a solution used in other jurisdictions such as South Australia termed "Dynamic Operating Envelopes" (DOEs). DOEs curtail solar exports at times of minimum demand but allow customers to export at all other times in the year. **Figure 14** provides a visual of how DOEs operate on a minimum demand day. Effectively, the solution can forecast when minimum demand events are likely to arise, and through technology communicate to connected solar panels to 'slow down' exports onto the network.

The prevailing advantage of DOEs is that they allow for maximum dispatch of low cost renewable energy. They also provide the capability for our network to better manage electric vehicle charging in the future, which is discussed further in Focus Area 3. A further advantage is that they limit controls we place on customer installations increasing customer choice. Finally, DOEs will also enable us to manage and monitor expected voltage constraints as solar penetration increases.

We undertook a business case assessment of options to address hosting capacity constraints. A cost benefit analysis of the options showed that investing in DOE capability is the most prudent and efficient option to meet the identified needs. This solution is also consistent with the preferences of our customers to efficiently facilitate renewables in the NT energy system.

The high-level scope of work for DOEs includes four key components:

- The state estimation and constraints engine uses engineering data from meters to forecast minimum demand events. This will rely on investment in low voltage visibility, which will also be used to identify when voltage constraints are likely to bind from increasing solar penetration.
- We will require a third-party trader to communicate limits and constraints to consumer devices, which will incur third party agent fees.
- Internal ICT resources will be required to provide a significant amount of new enabling services and modify existing services.
- A range of supporting activities are required to realise the benefits of the DOE investment, including hosting of forums with customers to understand their expectations and preferences.

We are undertaking initial investment under our Demand Management Innovation Allowance to trial low voltage visibility and will commence rolling out DOEs from 2028 when we expect minimum demand events to first arise. We will then proceed to scale up DOEs beyond 2030 when minimum demand events accelerate.

A vital aspect of our investment in DOEs is to undertake a review and update our connection processes, standards and policies for small-scale solar.

We undertook a business case assessment of options to address hosting capacity constraints.

Figure 13 – Forecast of minimum demand events by 30 minute intervals

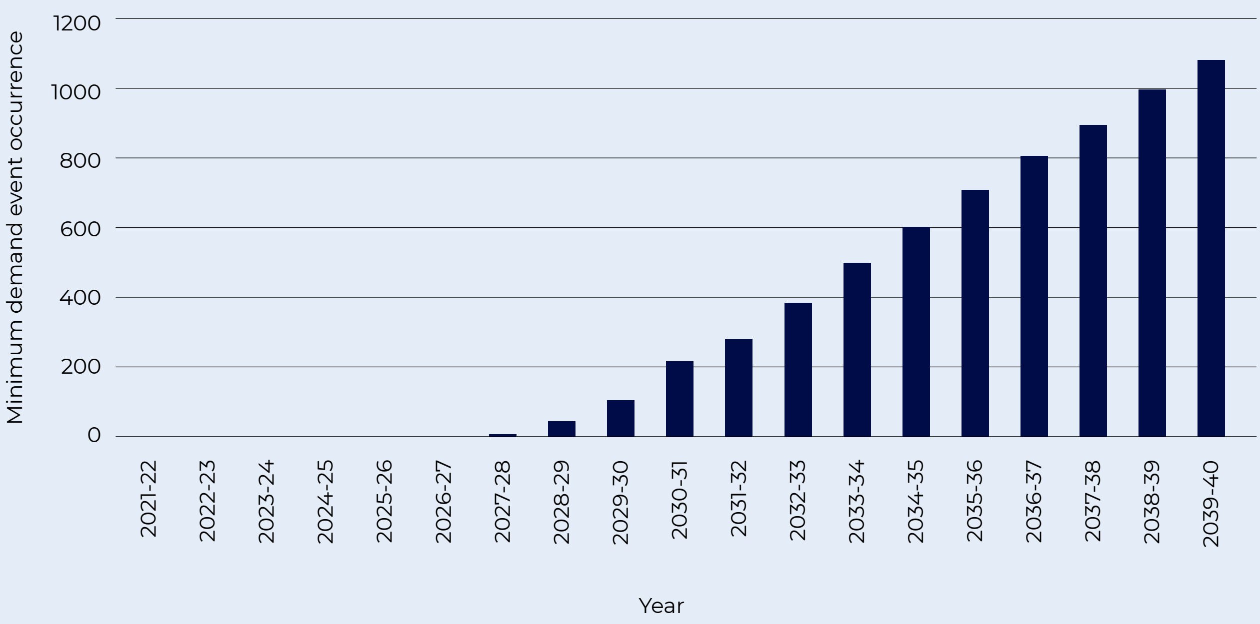


Figure 14 – Dynamic Operating Envelopes ramping down solar production on minimum demand days

Pilot battery storage

Batteries capture excess solar in the day and discharge the energy in the evening and night. The technology could assist with helping mitigate minimum demand events. We also see a potential benefit of relying on battery power to help meet growing peak demand on our network, while also delivering lower cost renewable generation in the evening and night when the sun is no longer out.

In developing our Future Network Strategy, we took account of strong customer preferences for installation of community batteries. Our initial analysis however suggested there was not a strong economic case to demonstrate a benefit. This was due to battery technology being relatively expensive and limited benefits.

We expect batteries may start to deliver benefits beyond 2030. This is due to an expected fall in battery costs, and growing peak demand on our network.

With this in mind, we have identified an opportunity to trial large batteries located on our distribution network. This will provide insight on feasibility and operation of batteries in the future. **Figure 15** shows that we intend to undertake a trial in Darwin-Katherine and Alice Springs. We will utilise innovation schemes in the regulatory framework and potential external grants.

Trial export tariffs and incentives

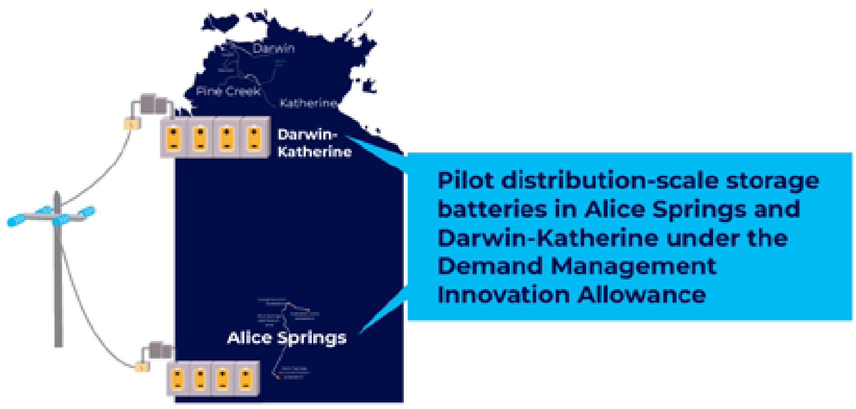
Under changes to our regulatory framework, we have an obligation to consider whether export tariffs can play a role in managing hosting capacity constraints. This is where customers incur a charge for exporting solar at times of network constraints such as during a minimum demand event.

Our Future Network Strategy considers there may be opportunities to apply export tariffs as a complementary measure to DOEs. In particular, we see that export tariffs may play an important equity role among our solar customers. Some of our customers may not have a solar panel that is DOE accessible, and therefore should be provided incentives to reduce exports similar to customers connected to DOEs. We also see an opportunity for tariff rewards for customers to store solar in the day through home batteries and discharge the power in peak periods.

Currently, our small customers are under the NTG Pricing Order are not subject to our network tariff structures. This limits the effectiveness of export tariffs and incentives. For this reason, we are proposing not to introduce export pricing just yet, but rather collaborate further with NT retailers and NT Government to design targeted trials that can inform our future network tariff design, provide evidence to support any proposed reforms to the NTG Pricing Order for either customer thresholds or tariff structures and test specific pricing innovations.

We consider that in the medium to longer term, there will be more need for export tariffs and incentives to influence the way our solar customers export and store solar energy.

Figure 15 – Battery trials in Darwin-Katherine and Alice Springs under our DMIA



Focus Area 2 – Efficient transmission network to deliver large scale renewables

In recent years, we have connected a significant amount of large-scale solar to our Darwin-Katherine transmission network. The Darwin-Katherine Electricity System Plan (DKESP) indicates that large-scale renewable generation and battery storage will deliver about 30 per cent of underlying energy by 2030. The DKESP also indicates significant growth in large-scale renewable after 2030 as we move towards net zero emissions. This includes potential for new technologies including wind and hydrogen.

Large-scale renewables are significantly lower cost than replacing the existing stock of thermal generation.

Our transmission network is the vital link to transport large-scale renewable energy to our customers. Our Future Network Strategy identifies initiatives that resolve constraints with dispatching generators currently connected to our network and building a large renewable hub closer to Darwin as depicted in **Figure 16**. We also see a role to further our transmission planning for the expected increase in renewable generation in the future.

Increase dispatch of existing renewable generation

The generators currently connected to the energy system in Darwin-Katherine are all located south of existing thermal generators on the Darwin-Katherine transmission line (DKTL). The security limit on the DKTL limits the amount of renewable generation dispatched into Darwin from large-scale renewable generation due to system constraints.

Consistent with the DKESP, we see an opportunity for new technology to resolve the constraint and enable much higher levels of large-scale renewable generation. The DKESP included analysis to show there are potential options to increase the dispatch of renewable generation including dynamic ratings, procuring services from new grid scale batteries, and partially duplicating the Darwin-Katherine transmission line. In addition, we note that the use of synchronous condensers may also offer a technical solution to resolve constraints.

There is initial analysis in the DKESP to suggest that the use of technologies to resolve the constraint may result in a net benefit to all customers, consistent with our objectives in the Future Network Strategy. This is because renewable generation is significantly lower cost than the thermal generation that it would displace. The lower wholesale price for electricity would therefore reduce customers bills more than offsetting the network investment.

We recognise that further analysis will need to be undertaken in line with a Regulatory Investment Test for transmission (RIT-T) to confirm there are options that result in a net positive benefit to customers, and that we proceed with an option that maximises net benefits.

Our Future Network Strategy identifies initiatives that resolve constraints with dispatching generators currently connected to our network, and building a large renewable hub closer to Darwin.

Figure 16 – Unlocking large-scale renewables in Darwin-Katherine

Support development of a renewable hub

We are currently working with the NTG on its initiative to locate a renewable energy hub close to our existing transmission network. The hub would co-locate solar farms and large-scale batteries, enabling more efficient dispatch into Darwin.

The Renewable Energy Hub is a key initiative identified in the DKESP to deliver 50 per cent renewable energy in the region. The concept is similar to Renewable Energy Zones under the Integrated System Plan in the National Electricity Market. These projects recognise opportunities to lower transmission costs by co-locating renewable energy sources in a central location. The DKESP contemplates that the Hub would provide between 180 and 230MW of large-scale solar and would be operational by 2025-26.

The DKESP identifies the potential of market benefits to all customers from pursuing a 50 per cent renewable energy target including:

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

The DKESP notes that transmission works would be required to divert and extend the current 132kV transmission line and construct a substation.

Plan a transmission network beyond 2030

Beyond 2030, we expect that the NT energy system will further accelerate towards a fully renewable energy system. However, given the pace of technology developments it is difficult to identify the fuel source and location for new renewables. The DKESP notes the potential for more solar renewable energy hubs, solar transported over long distances, hydrogen, wind farms, and bio-fuel.

It is vital that we stay on the front-foot in planning an efficient and secure transmission network to meet future sources of renewable generation beyond 2030. This includes considering the likely sources of new generation, identifying areas where generators may co-locate, and developing transmission rings that provide for capacity and security of supply.

A further aspect of our transmission planning is to ensure we have a 'fit for purpose' connection process to manage the commissioning of higher volumes of variable renewable generators and energy storage. We intend to work collaboratively with large-scale generators to further improve the connection process and studies required to assess the impact of each connection.


MODEL X

Focus Area 3 – Scale up and best utilise the NT energy system

Our regulated networks are relatively small compared to other places in Australia, limiting our ability to extract economies of scale in our service delivery. This has been a key impediment to lowering electricity costs in the NT as we have a small customer and consumption base to spread our fixed costs.

We see an opportunity to increase the scale of our energy systems over the next 20 years. A combination of population growth and large industry will significantly increase energy consumption. Further, we expect an acceleration of electric vehicles from 2030 onwards that has the potential to materially increase the average consumption of electricity used by our customers. Our strategy is focused on facilitating greater electricity uptake in the NT and encouraging use of electricity in off-peak periods that reduce electricity costs.

We see that a mix of innovative tariffs, automated EV charging, and targeted energy efficiency incentives are instrumental to improving the utilisation of the energy system.

Tariff reform

We will be introducing changes to our network tariffs that encourage large industrial customers to connect to our network, and which incentivise our customers to use energy in off-peak periods.

This recognises that complex tariffs can be a barrier for mass industry to locate in the NT. Our super user tariff provides a simple design that will encourage new industry to connect to parts of our transmission network with spare capacity. Super users will greatly increase the scale of our business and will provide opportunities to lower our cost to serve for all customers.

We will also be introducing a 'time of use' design tariff for our residential customers. The tariff provides very low prices in the day to encourage customers to shift their use of energy appliances to the middle of the day. This is when there is ample capacity on the network and greater access to low-cost solar generation. Tariffs are set higher in the evening in summer when our network faces high demand. A key element of our strategy is to work with the NTG and energy partners on mechanisms that allow the customer to respond to our network tariffs. We will also be rolling out more smart meters to ensure that innovative tariffs can be applied.

EV off-peak charging

Our Future Network Strategy sees an opportunity to improve our customers' outcomes from increasing EV uptake. EVs provide a great opportunity to lower average electricity costs if charging occurs in off-peak periods. Each EV adds about 30 per cent more consumption to a typical household. We see that tariffs will be vital to incentivising customers to use electricity in off-peak periods in the day rather than the evening peak. Automated charging using the DOE solution discussed in Focus Area 1 provides further opportunities for customers to shift charging to the daytime. **Figure 18** shows how time of use tariffs and automated charging can shift consumption to the middle of the day.

Energy efficiency for low-income households

Our strategy has also identified future opportunities for innovative demand management schemes. In particular, we see an opportunity for energy efficiency schemes targeted at low-income households. In our engagement sessions, stakeholders noted that low- income households often reside in rental accommodation with poor insulation and inefficient cooling appliances. This is leading to high electricity bills for customers on low budgets. Our strategy identifies opportunities to use Demand Management schemes that may provide incentives for energy efficiency in rental properties, particularly if this assists in helping us manage constraints on the network in the evening peak.

Figure 17 – Placeholder (turn into infographic)

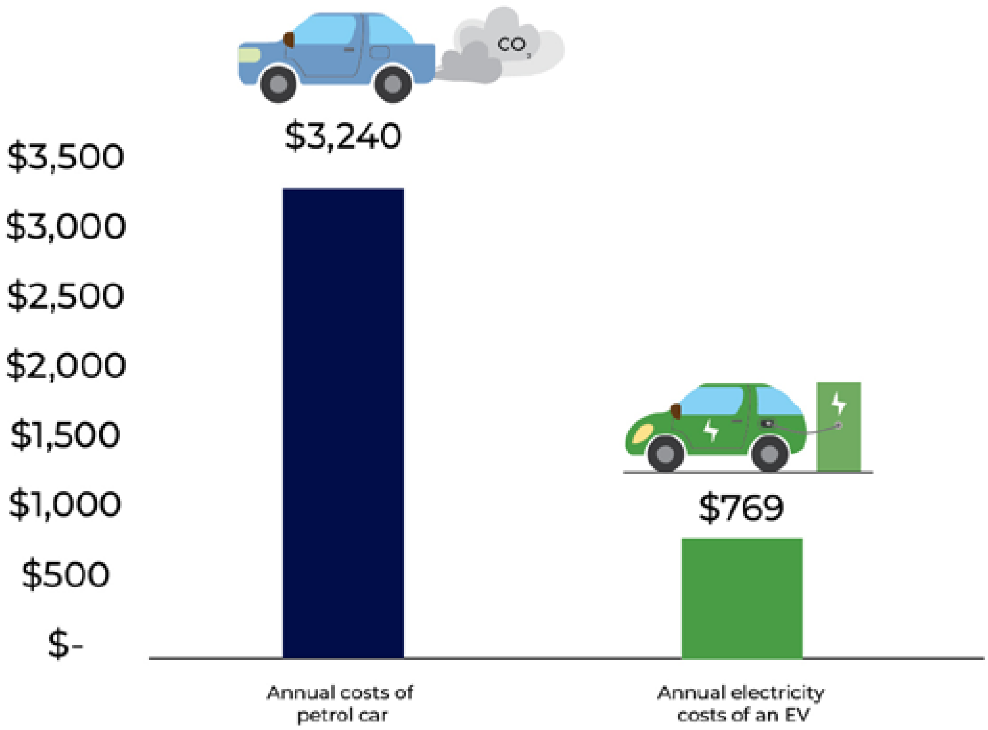
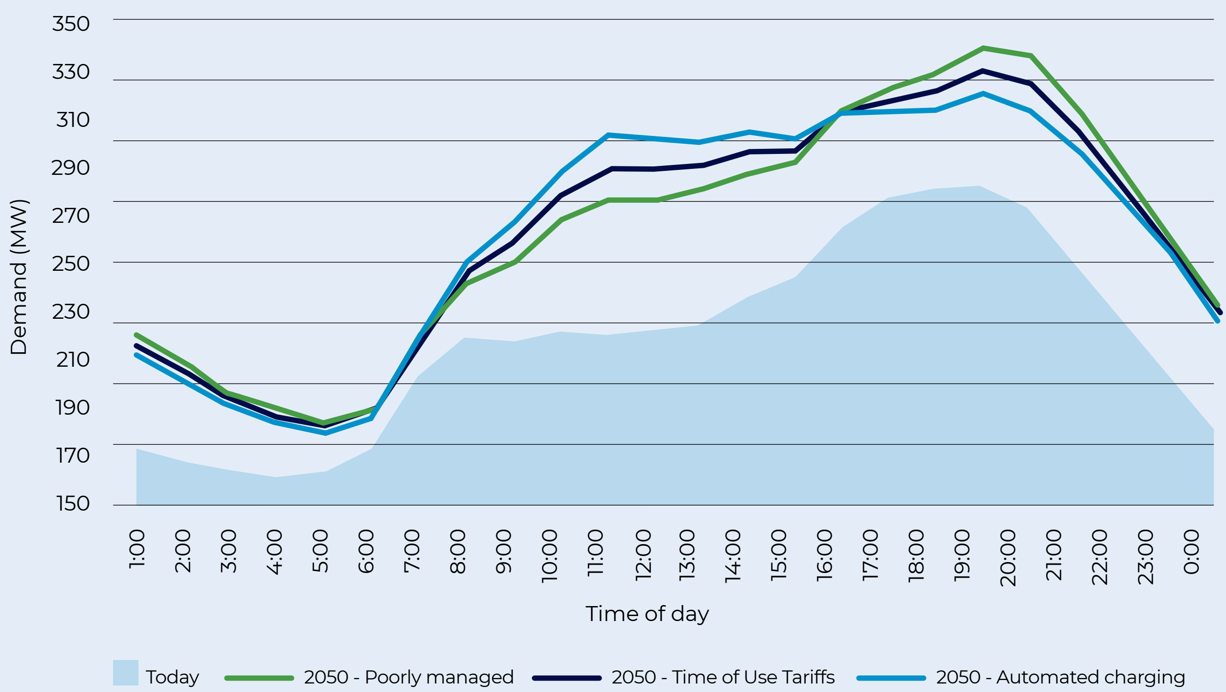


Figure 18 – EV charging scenarios



Focus Area 4 – Re-design the grid to reduce network costs

We will face a significant challenge over the next 20 years to minimise our capital and operating expenditure. A large proportion of our assets were installed at the time of Cyclone Tracy about 50 years ago. This cohort of assets is likely to face condition issues when operated beyond their technical life. This will place upwards pressure on our replacement and maintenance costs. We also expect to face increasing emergency response costs associated with tropical storms and cyclones, as climate change events become more pronounced.

Our customers have been leading the discussion on how new technology and thinking can help us mitigate the expected changes in our operations. Based on these discussions, our Future Network Strategy has identified key initiatives to re-design the grid as seen in **Figure 19.**

Manage ageing assets

Our peer networks in Australia have been operating their assets well beyond their technical life through improved asset management strategies and IT systems. The NT's extreme climate means that our assets are subject to more wear and tear over their lifetime, but we still see a role for similar strategies to extend asset life. This will have the effect dampening and smoothing an expected increase in replacement over the next 20 years.

Over the next 20 years, we will invest in systems and expertise to help us extend the lives of assets. This includes maintenance strategies and systems that provide visibility on condition and performance issues and allow for corrective maintenance and life extension. We will also continue to apply our new risk quantification framework that can help understand the relative risks from deferring replacement. This approach has underpinned our upcoming replacement program over the next decade.

Optimise the network

New technology may provide some of the tools to help us retire rather than replace assets, keeping a lid on the replacement wave ahead. For example, we are currently looking at microgrid solutions for some parts of our unregulated areas rather than re-building existing infrastructure. The learnings will be applied to more isolated parts of our regulated network, where there may be opportunities for stand-alone power systems.

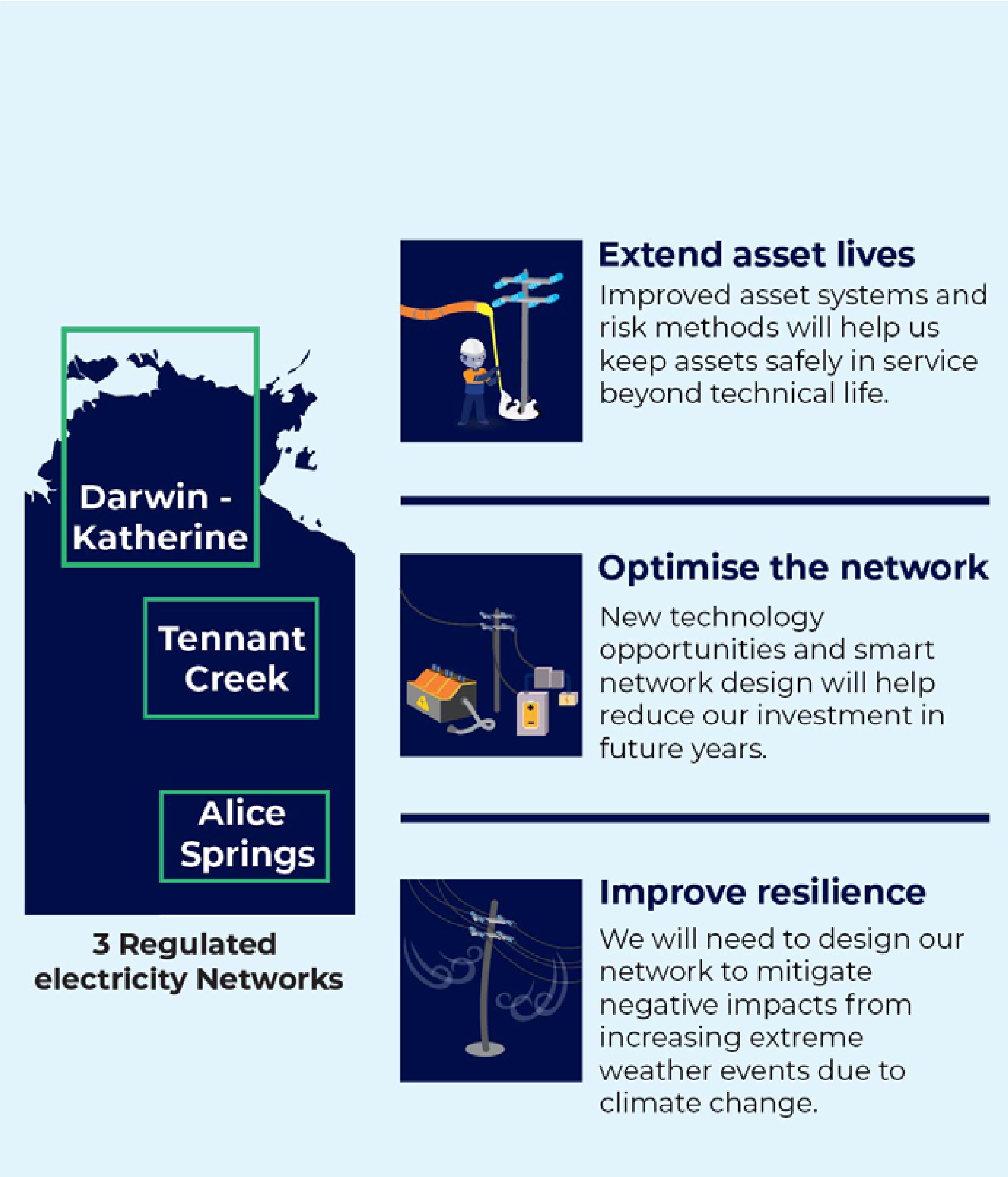
We will also consider opportunities provided by solar and batteries in our distribution system to reduce the capacity of replacement assets. Over time, there may be a role for customers' technologies to be used as a back-up (redundancy) for the network rather than re-building additional network infrastructure.

Improve resilience to climate change events

We have extensive experience with restoring power to our customers after cyclones and major storms. The predicted increase in extreme weather increases the risk of outage time to our customers and higher safety risks. We will undertake resilience studies to understand the types of risks we will face in upcoming years and the optimal mitigation strategies. This may include smarter asset design and operation and safeguarding critical assets.

Our customers have been leading the discussion on how new technology and thinking can help us mitigate the expected increase in our operations.

Figure 19 – Initiatives to re-design the grid by 2040



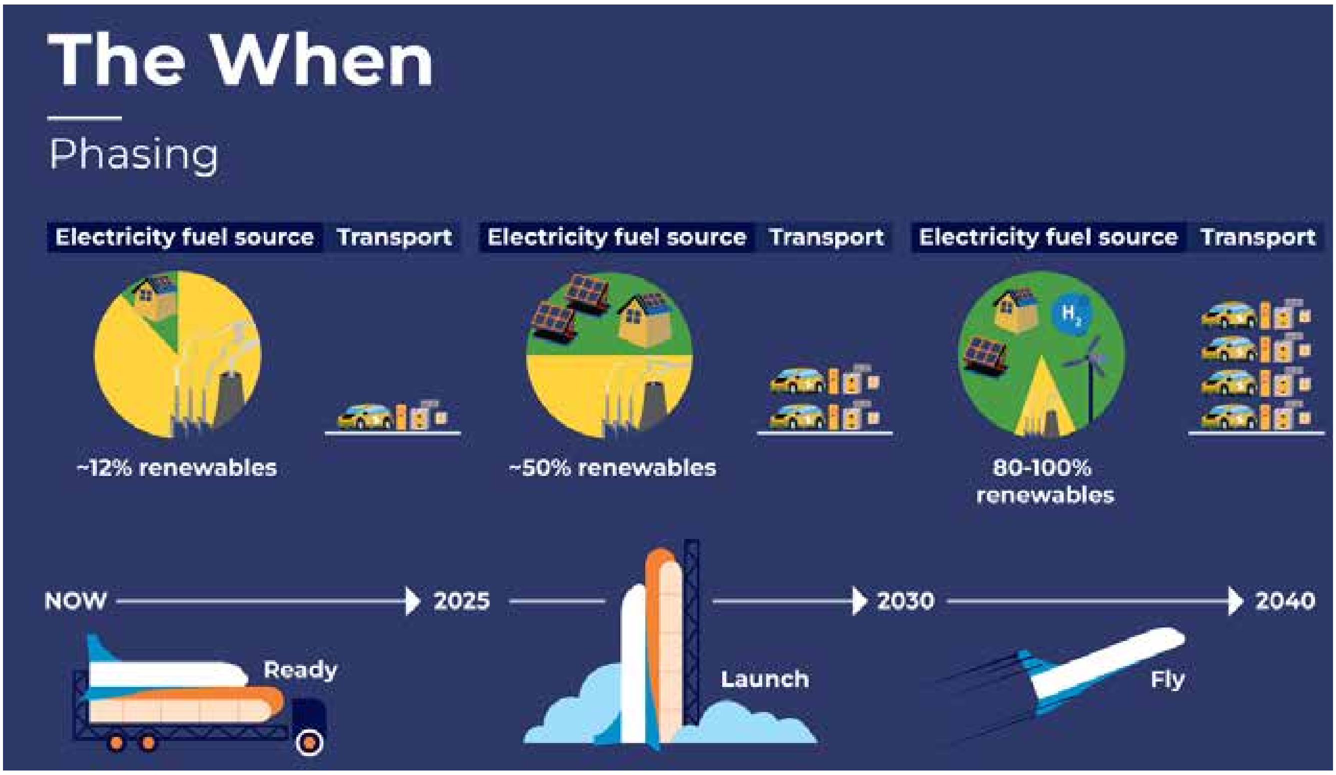
4. Phasing of initiatives

Our Future Network Strategy has considered the optimal phasing of the initiatives in our focus areas. We have identified three key phases to 2040. The phasing reflects the need for early research and planning, scaling up implementation over time and balancing the need to be proactive while developing solutions that are proportionate to the need.

Our Future Network Strategy is framed around a long-term road map to 2040. This recognises that we need to plan ahead and address multiple drivers with efficient investment. At the same time, our approach recognises that technology developments are rapid, and that we will need to pivot when new drivers or technology emerges. Our roadmap also recognises the need for research, studies and pilots to ensure that we understand issues and have tested feasibility and efficiency when implementing options.

Figure 20 identifies three key phases of the roadmap, which are further discussed in this chapter. The "Ready" phase commenced in 2022 and is directed at research, studies and analysis to improve the effectiveness of our initiatives. The "Launch" phase (2025 to 2030) is focused on implementing initiatives proportionate to emerging opportunities and challenges. The "Fly" phase (2030 to 2040) is focused on scaling up our initiatives to meet emerging challenges. **Figure 20** also shows the key changes we expect in the energy mix to 2040, together with the acceleration of electric vehicles in the NT.

Figure 20 – Phasing of initiatives



4.1 Ready (Now to 2025)

We expect solar to grow from about 15 per cent of the energy mix in our regulated regions to about 30 per cent by 2025. This will be driven by increasing penetration of small-scale solar by our customers and increasing connection of large-scale solar farms. While fossil fuel cars will still dominate the mix of vehicles in the NT by 2025, we expect more Territorians will start to purchase electric vehicles.

The "Ready" phase is about ensuring we implement initiatives carefully through research, studies, economic analysis and peer review. Since 2021-22, we have been undertaking analysis on future drivers impacting our network and have engaged extensively with our customers on planning our response. In 2022, we undertook a Future Readiness Plan that sought to examine multiple facets of a changing energy landscape including the impact of solar on our regulated impacts, the feasibility of community batteries and the likely impact of electric vehicles on demand and energy consumption. The Readiness Plan provides a solid base to identify the extent of issues and identify optimal solutions.

Following on from the readiness plan, we will investigate the feasibility of technologies that can provide visibility of our low voltage network. This will help us identify emerging voltage issues and help us prepare for implementing DOEs. We will also be undertaking initial studies and early planning for transmission works to connect and dispatch large-scale renewables.

4.2 Launch (2025-2030)

Between 2025 and 2030, we expect solar to further accelerate in our regulated networks, comprising 50 per cent of the energy mix. In Darwin-Katherine, we expect that the co-location of solar farms in a Renewable Energy Hub, and increased dispatch of existing generation on the DKTL will result in large-scale renewables accounting for most of the renewables in the system. In this phase, we also expect that more of our customers will take up an EV although fossil fuel cars will likely be dominant.

The focus of the "Launch" phase will be implementing solutions that efficiently unlock large-scale generation including transmission works to transport energy from the Renewable Energy Hub. We will also look to implement solutions that address constraints with dispatching existing generators on the DKTL. We will also focus on a progressive roll out the DOE solution to proportionately address minimum demand challenges from increasing uptake of small-scale solar.

Our network tariff structures will also start to provide a signal for customers to use energy in off-peak periods. We will also be implementing a super user tariff to attract large-scale industry to the NT, thereby increasing the scale of our network.

In the "Launch" phase, we expect to implement new systems that will help us extend asset life and identify new planning tools to help us design the network more efficiently. We will also be focusing on resilience planning as a means of mitigating the expected increase in extreme weather events from climate change.

4.3 Fly (2030 to 2040)

Beyond 2030, we expect that renewables will start to dominate the energy mix with the potential for 80 to 100 per cent of energy production being supplied by a renewable source. We consider that a diversity of renewable technologies may be viable at this stage including hydrogen, wind warms and bio-mass. Between 2030 and 2040, we also expect a marked acceleration in EV sales in the NT consistent with forecasts in the rest of Australia.

The focus of the launch phase is fully implementing the DOE solution such that we can maximise small-scale solar production while managing minimum demand and emerging voltage constraints. The DOEs will work in unison with tariff structure reforms to give customers the right signals to charge EVs and use energy appliances in off peak periods. We also expect more opportunities to utilise distribution storage batteries as technology costs fall and peak demand increases from EVs.

In the 2030 to 2040 period, we expect that more of our asset base will be beyond their expected manufacturing life and this will require a mix of monitoring, asset management systems, and risk frameworks to mitigate reliability events while keeping a lid on our replacement capex.

Appendix A – DER integration strategy

The AER's final DER (Distribution Energy Resources) integration expenditure guidance note requires us to provide information on our DER strategy. DER include resources of located in our customer's premises such as small-scale solar, home batteries, electric vehicles and energy management systems.

The growing uptake of DER in our regulated networks has been a key input into developing our overall Future Network Strategy. For example, Focus Area 1 relates to managing forecast constraints with exporting our customer's solar. We also discuss how an uptake in electric vehicles provides opportunities to improve utilisation of the regulated networks to deliver both electricity and transport saving for our customers.

In this appendix, we address each of the AER's requirements as set out in Table 1 below.

Table 1 – Addressing AER's requirements for a DER integration strategy

Requirement	Information
Explain proposed approach to export-related planning and investment against alternative options.	This has been addressed in Chapter 3 of the Future Network Strategy, which highlights analysis demonstrating a need for export planning due to forecast minimum demand events from increasing solar exports. We noted that the preferred option was to implement DOEs, relative to alternatives such as static zero exports and export tariffs. Our business case for Dynamic Operating Envelopes (Attachment 8.61) provides further analysis of the need and the options considered in planning for exports in the 2024-29 period. Our Tariff Structure Explanatory Statement (Attachment 11.02) also provides more information on why we are not proposing export pricing in our tariffs but that we will consider export trials.
Present information specifically relating to how DER integration is managed through the different elements of its regulatory proposal (i.e. connection services, pricing, expenditure) and discuss how its proposal is appropriate to meet expected consumer outcomes.	We have discussed our approach to solar integration in Focus Area 1 of Chapter 3 of this document. Section 8 of the document "Capex attachment" (Attachment 8.01) identifies forecast capex in 2024-29 related to managing solar exports including investment in DOEs. The document "RBC - DER CAPEX Dynamic Operating Envelopes (Hosting Capacity)" (Attachment 8.61) provides options analysis to show that DOEs are the preferred option that maximises customer benefits. We also note significant support from customers for maximising solar in the electricity system. Section 6 of the document "Opex step change" (Attachment 9.02) outlines the basis for seeking a step change to facilitate our Future Network Strategy including those relating to implementing the DOE solution, increasing complexity associated with connecting renewables, network planning and system support services, and increased need for stakeholder engagement and change management. Section 12 of the document "Connection policy" (Attachment 8.62) identifies when static exports may be applied, noting that other options would be preferred if they were least cost for customers. Section 6.4 of the document "Tariff Structure Statement – Explanatory Statement" identifies why our proposed tariff structures have not incorporated export pricing as yet, due to limitations with the NTG pricing order. We note that our mix of solutions are consistent with the feedback of our stakeholders as demonstrated in section 1.2 of this document. Our customers wanted us to invest more now for a future which enables more solar in the system.

Requirement	Information
An explanation of the approach to identifying demand for (and providing for) distribution services for supply from DER	We note that the forecast constraint on exporting solar is the exceedance of the minimum demand threshold. We have described our approach to forecasting system minimum demand for each of our regions in the document "System Minimum and Maximum Demand Forecast Report" (Attachment 8.48). This shows how we have incorporated factors such as historical growth rate in solar and returns on solar in determining the expected decline in minimum demand to 2030. We note that we have limited visibility to understand how increasing solar exports will impact voltage constraints on the network. This will improve with the data we are gathering through our Low Voltage Visibility and State Estimation project.
The trade-offs between different options the network considered and why the network has proposed the particular approach around DER integration and management	This is addressed in the options analysis in Section 3 of the document "RBC – DER CAPEX Dynamic Operating Envelopes (Hosting Capacity)" (Attachment 8.61). The options analysis considered four credible options and selected the preferred option of DOEs based on achieving the highest maximum benefit to customers.
A comparison of the DNSP's proposed capital expenditure to support the provision of export services against its actual or committed capital expenditure and an explanation of any material difference.	This is set out in section 8.1 of the document "Capex Attachment" (Attachment 8.01). This shows that we had no direct DER capex in the 2019-24 period but are proposing capital expenditure of $13 million in the 2024-29 period due to the implementation of DOEs.
Network voltage analysis	As discussed above, we have limited visibility to ascertain the degree of voltage issues from current and future bi-directional solar. We note that information on reported voltage issues and complaints is provided in section 2.2 of the document "Capex Attachment" (Attachment 8.01).
DER penetration forecasts for the electricity distribution network over the medium to long term (at least 10 years) and the expected forecast demand for export services on network.	We have identified our export solar forecasts in section 4.1 of the document "System Minimum and Maximum Demand Forecast Report" (Attachment 8.48) and our forecast of electric vehicles in section 4.3 of the document for ten years.

Requirement	Information
Evidence of how DNSPs will structure their tariffs to meet the forecast increase in demand for export services (supported by consumer behaviour modelling).	Section 6 of the document "Tariff Structure Statement Explanatory Statement (Attachment 11.02) includes an export tariff transition strategy that provides information on our approach to using export pricing to meet increased solar exports. In summary, the Pricing Order means that Power and Water cannot assume any behavioural response from tariff designs for most of our customers. Power and Water is therefore proposing to not introduce two-way pricing just yet, but rather collaborate further with NT retailers and NT Government to design targeted trials that can inform our future network tariff design, provide evidence to support any proposed reforms to the Pricing Order for either customer thresholds or tariff structures and test specific pricing innovations. These trials will inform our future approach to pricing design.
A clear summary of the various elements of DER integration expenditure, in terms of augmentation, ICT capex and opex. Where the DNSP has identified deferred augmentation and/or replacement expenditure as a benefit associated with its proposed investment, it should demonstrate that its forecast of augmentation and/or replacement expenditure has been adjusted in a consistent manner.	We note that the document ""RBC – DER CAPEX Dynamic Operating Envelopes (Hosting Capacity)" (Attachment 8.61) identifies long term benefits of deferred augmentation in relation to implementation of DOEs. We note that the benefits are long-term and not realised in the 2024-29 regulatory period. For this reason, we have not adjusted the forecast capital expenditure for the 2024-29 period.
Details of activities undertaken and actual expenditure in the current regulatory period to manage DER integration	Currently, our management of solar exports relates primarily to addressing reported voltage issues, which to a degree may have some relationship to solar exports. However, we have limited visibility at this point.
Transparent references to expenditure items in the reset RIN.	Our Reset RIN separately identifies capital expenditure as export services, consistent with the AER's standard control services capex model.

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