Attachment 04.1P

Capex Overview Document

2019-20 to 2023-24

16 March 2018

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1. Purpose and structure of this document

This document explains and justifies, at a high-level, our capital expenditure (capex) for our standard control services (SCS) for our 2019-24 regulatory control period.[1] It supports our Regulatory Proposal to the Australian Energy Regulator (AER) and references other supporting documentation and models, which further explain and justify the detail of our capex forecast.

This document should be read in conjunction with our documents entitled:

- "Response to Schedule 1 of AER's RIN"; and
- "Addressing the capex and opex objectives, criteria and factors in the NT NER".

Unless otherwise stated, all historical and forecast capex numbers in this document are presented in real 2018-19 dollars and include only direct costs and escalations (i.e. they exclude capitalised overheads, albeit section 10 separately discusses these capitalised overheads in detail).

The remainder of this document is structured as follows:

- Section 2 provides an overview of our capex forecast. It:
  - overviews customer insights and responses from our engagement program;
  - explains the categories that we use to forecast, explain and justify our capex;
  - overviews the key drivers of our capex;
  - summarises our capex forecast by category; and
  - details the hierarchy of documents and models that support our capex forecasts.
- Section 3 reviews our historical capex in the current and previous regulatory periods, including by reference to the Utilities Commission's (UC) capex allowances.
- Section 4 explains our capital governance framework that supports our capex forecast, including:
  - our asset management framework;

[1] We operate electricity distribution and transmission assets. The NT Government has deemed that transmission assets will be treated as distribution assets for the purposes of economic regulation – see section 9 of the National Electricity (Northern Territory) (National Uniform Legislation) Act.

  - our investment governance framework; and
  - our risk management framework.

- Section 5 explains our capex forecasting methods, inputs and assumptions applied to the expenditure forecast.
- Section 6 explains and justifies our replacement capex (repex) forecast.
- Section 7 explains and justifies our augmentation capex (augex) forecast.
- Section 8 explains and justifies our connections capex and customer contribution forecasts.
- Section 9 explains and justifies our non-network ICT capex forecast.
- Section 10 explains and justifies our non-network other capex forecast.
- Section 11 explains and justifies our capitalised overheads forecast.

2. Overview of our capex forecast

This section provides an overview of our capex forecast and introduces a range of general issues relevant to our capex forecast.

2.1 Highlights

Our forecast total net capex for the next period is $382.97 million, or an annual average of $76.6 million. This compares to:

- $302.9 million in the current period, or an annual average of $60.6 million; and
- $485.6 million in the previous period, or an annual average of $97.1 million.

Our proposed asset replacement capex of $148.6 million is a significant decrease from $175.5 million in the current period. This is due to the completion of works in the current period, improved asset management practices, and a more targeted approach to managing our highest risk assets.

We are utilising improved asset information to identify a number of emerging issues that present an unacceptable level of risk, from which we are proposing priority projects. These include the replacement of the Berrimah Zone Substation, the treatment of steel poles in the Alice Springs network and the replacement of underground cables in the Darwin system.

The proposed augmentation expenditure of $60.6 million has also reduced from $76.4 million in the current period. Regional system peak loads are declining overall, however growth is evident in some localised areas. We have targeted projects to meet the expected demand, as forecast by AEMO, including in the areas of Wishart, East Arm and Berrimah.

We will meet the requirements of new connections to our network, which we expect to be similar to historical levels. This includes continuing to support the connection of renewables, which provides benefits to all customers through the alignment of peak solar photovoltaic (PV) output and system peak demand. It is our most efficient demand management tool. However, an increasing number of solar PV systems connecting to our network are starting to impact the performance and technical compliance of the distribution system. To address this issue efficiently and enable customers to connect solar PV systems, we have implemented several operational changes to defer capex for as long as possible. However, based on our PV forecast, we have included provision in our augex forecast to manage these issues as they move beyond efficient operational solutions.

We will comply with regulatory obligations or requirements, in accordance with our 1 July 2017 regulatory baseline, including maintaining current average quality, reliability, security of supply and safety across our networks. During our customer and stakeholder engagement program, we received strong support for improving the reliability for poor performing rural and urban parts of our network and have included provision for this in our forecast.

We have included provision for major upgrades or replacement of our four key ICT systems[2] in our non-network ICT capex of $40.5 million. Our ICT capex focuses on: responding to customer and stakeholder feedback to improve customer service outcomes; upgrading systems to support our network operations in line with industry standards; improving the accuracy and integrity of our core systems; refreshing applications and infrastructure in line with industry practices; and implementing tools to improve the reliability of enterprise data and reporting function capability.

Our non-network other capex involves capex on fleet, buildings, property, minor capex and tools and equipment consistent with other networks that are necessary to deliver customer outcomes. We are capitalising leases from 1 July 2019 in accordance with new Australian Accounting Standards. The effect of the changes is that, from 1 July 2019, the full amount (over its term) of a lease must be capitalised up-front when it is first entered into, or is renewed. Accordingly, we have increased our non-network other capex to $69.4.0 million in the next regulatory control period.

We have forecast our capitalised overheads using the base-step-trend approach applied to opex, which reflects a change from the current period. We only capitalise for regulatory purposes the corporate and network overheads cost centres that we capitalise for statutory purposes in accordance with our Statutory Capitalisation Policy. These corporate and network overheads are capitalised for regulatory purposes in proportion to the ratio of direct capex to total direct costs, as set out in our Cost Allocation Method.

2.2 Overview of customer insights and responses

Over the past 12 months, we have undertaken the most extensive network engagement program in our history through which we captured a wide variety of views and feedback, including from:

- Residential and small to medium non-residential customers, whose retail prices are regulated under the NT Government's Electricity Pricing Order (Pricing Order);
- Major Energy Users, being the largest energy consumers in the NT whose retail prices are not protected by the Pricing Order; and

[2] Asset Management System (IBM Maximo), Geographic Information System (ESRI ArcGIS), Revenue Management (Gentrack) and Finance (Oracle).

- Government and consumer representative bodies, including hardship agencies and industry and consumer representative bodies.

The key outcomes of this engagement are detailed in our "Engagement Overview" (see Attachment 1.4). The key insights and responses most relevant to our capex program for our SCS are as follows:

- **Reliability and responsiveness –** there was strong support for our proposal to:
  - maintain current reliability and responsiveness levels for most customers (at a system level); and
  - focus on improving reliability for poor performing rural and urban areas (e.g. Lovegrove in Alice Springs, Virginia and Stuart Park in Darwin) at a cost equivalent to approx. $1.70 extra per customer, per year.

  Consequently, our capex plan supports maintaining average performance whilst making targeted investments to improve service outcomes for our worst-served customers.

- **Customer funded initiatives** – there was limited support for the options to:
  - offer in-home energy audits for households experiencing financial difficulty to help identify ways they can reduce their energy costs;
  - continue with a customer funded engagement program; and
  - see more overhead power lines moved underground.

  Consequently, we will:

  - not pursue any new discretionary user funded initiatives in our regulatory proposal and cost forecasts; and
  - fund our future engagement program by realising opex savings elsewhere in the business.

- **Communication preferences –** there was strong support for improving how we communicate with our customers. Consequently, we will look to redesign the Power and Water App to include push notifications, invest in a Customer Relationship Management System to better respond and track service issues with customers, and invest in an Outage Management system to enable SMS notifications.

2.3 Capex categories

We forecast, explain and justify our capex in this document using the following categories:

- Repex;
- Augex;
- Connections capex;
- Non-network ICT capex; and
- Non-network other capex.

We have also forecast our customer contributions and capitalised overheads.

These categories are consistent with those that are detailed in the AER's written Reset RIN.

2.4 Capex drivers

There are a range of requirements that inform our capex forecast, including regulatory compliance and service obligations. Consistent with the asset management approach described in section 4.1, these requirements are reviewed and prioritised according to risk, to ensure that the proposed capex is prudent and efficient, and is in the long-term interests of our customers.

Accordingly, there are a range of key drivers that have a material influence on the development of the capex forecast, including:

- localised growth in demand in the areas of East Arm, Berrimah and Palmerston that reflect increasing developments in those areas;
- strengthening the power system to withstand significant events, in accordance with the requirements of the Network Technical Code and Network Planning Criteria to maintain security of supply and network reliability;
- maintain an acceptable risk profile by replacing high risk assets to ensure the continuing safe operation of the electricity network, and to maintain current service levels. Our ability to identify, understand and mitigate risks is significantly improved through better data and analysis;
- how we communicate with our customers, which requires us to have appropriate customer and asset management ICT systems to meet the future requirements of consumers and the network to which they connect; and
- changes in the accounting treatment of leases under Australian Accounting Standards, whereby expenditure that was previously expensed will need to be capitalised from 1 July 2019.

Each category of our capex forecast responds to these and other investment drivers, as illustrated in Figure 2-1. We explain the nature of our capex drivers further in sections 6 to 11 below in the context of the justification of our capex forecasts.

Figure 2-1 – Capital expenditure categories

Capex type	Capex category	Capex driver
Network capital expenditure	Replacement	Condition and risk driven
		Compliance driven
		Reliability and quality of supply driven
	Augmentation	Load driven
		Compliance driven
		Reliability & quality of supply driven
	Connections and gifted assets	Customer request
Non-network capital expenditure	Non-network ICT	Network operations
		Remediate the core
		ICT application and infrastructure refresh
		Customer service
		Enterprise
	Non-network Other	Properties
		Fleet
		Tools and equipment

2.5 Our capex forecast

As is explained further below, our capital forecast reflects a prudent level of expenditure by:

- reducing the level of our replacement expenditure consistent with a targeted approach to risk-based investment decisions;
- managing the needs of the network, including by deferring augmentation where practical. This includes continuing to deploy, and making provision to deploy, the nomad modular (mobile) substation to defer capex;
- investigating and deployment of demand management solutions during the next regulatory period;
- prioritising our response to compliance obligations based on the highest areas of risk to maintain the safety of our network and manage the impact to consumers;
- targeting essential ICT upgrades and replacements to: (i) improve customer service outcomes; (ii) support our network operations; (iii)

improve the accuracy and integrity of our core systems; (iv) refreshing applications and infrastructure; (v) improve the reliability of enterprise data and reporting function capability;

- capitalising leases from 1 July 2019 – which relate to our fleet and property capex – in accordance with new Australian Accounting Standards; and
- capitalising network and corporate overheads in proportion to the ratio of direct capex to total direct costs, as set out in our Cost Allocation Method (CAM).

Table 2-1 details our capex forecast for our next regulatory period by capex category.

Table 2-1 – Capex forecast ($M, Real 2018-19, SCS)

	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Replacement	34.92	38.51	33.44	22.01	19.71	148.60
Augmentation	7.39	5.76	15.46	17.59	14.40	60.59
Connections (including gifted assets)	12.65	13.38	13.56	11.49	11.59	62.67
Non-Network ICT	10.76	9.43	7.36	4.89	5.05	37.50
Non-Network Other	27.89	5.57	24.96	5.66	5.35	69.43
Capitalised overheads	13.01	13.19	13.39	13.56	13.71	66.86
Total gross capex	**106.63**	**85.84**	**108.18**	**75.19**	**69.80**	**445.64**
Less capital contributions	-12.65	-13.38	-13.56	-11.49	-11.59	-62.67
Less asset disposals	-	-	-	-	-	-
Total net capex	**93.98**	**72.46**	**94.62**	**63.70**	**58.21**	**382.97**

2.6 Supporting documents and models

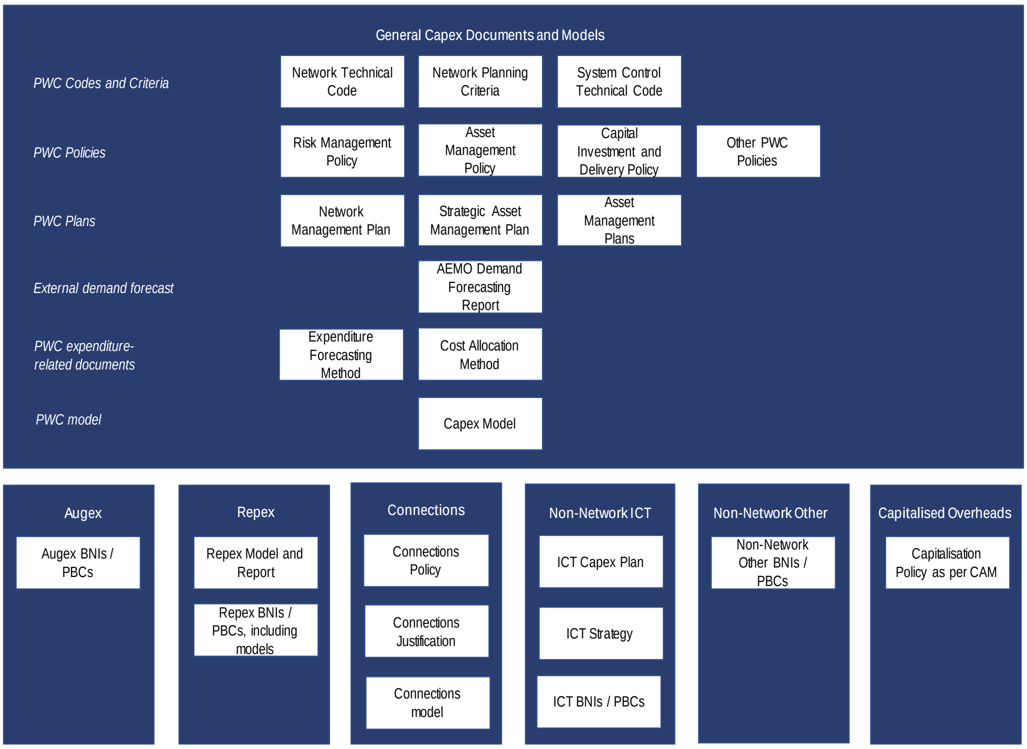
Figure 2-2 illustrates our hierarchy of documents and models that support our capex forecast, which we have submitted to the AER with our Regulatory Proposal. We have:

- various documents and models that apply to several capex categories; and

- other documents and models that apply to specific capex categories.

In sections 6 to 11 below, we explain the nature and purpose of each document and model and how they support our capex forecasts.

Figure 2-2 - Hierarchy of capex documents and models



Key: BNI – business need identification; PBC – preliminary business case

3. Review of historical capex

In this section we examine the actual/estimated capex from the previous and current regulatory periods, and compare it to the UC's allowances.

3.1 Utilities Commission's capex allowances

The UC did not set an explicit capex allowance for the 2009-14 regulatory period. Instead, it established a required revenue to which it applied X factors derived using a Total Factor Productivity (TFP) approach.

The UC changed its approach for the current regulatory control period and set our annual revenue requirements by reference to capex allowances, which are detailed in Table 3-1.

Table 3-1 – UC allowances – excluding metering[3] ($M, Real 2018-19, SCS) [4]

	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Total gross capex	90.00	64.13	51.10	60.36	71.77	337.36
Total net capex[5]	76.17	50.03	36.67	45.59	56.66	265.11

3.2 Historical expenditure

Table 3-2 details our actual capex for our previous regulatory period. As noted, there was no explicit UC allowance against which this can now be compared.

Table 3-2 – Actual capex for previous regulatory period – excluding metering ($M, Real 2018-19, SCS)

	2009-10 Actual	2010-11 Actual	2011-12 Actual	2012-13 Actual	2013-14 Actual	Total
Replacement	11.75	29.54	42.96	40.71	47.93	172.89
Augmentation	70.34	62.21	36.73	70.56	32.82	272.66
Connections (including gifted assets)	10.86	13.46	15.33	16.90	16.02	72.58

[3] Type 1-6 metering capex has been removed from previous and current period capex in line with the service classification for standard control services in the 2019-24 regulatory control period.

[4] The UC NTRM appears to have mistakenly excluded gifted assets from the forecast capex, this table reflects the corrected totals.

[5] Net capex equals gross capex less capital contributions and asset disposals.

	2009-10 Actual	2010-11 Actual	2011-12 Actual	2012-13 Actual	2013-14 Actual	Total
Non-Network Other	2.62	1.67	2.48	2.32	1.46	10.55
Capitalised overheads	0.44	0.45	0.34	1.88	1.30	4.40
Total gross capex	**96.01**	**107.33**	**97.83**	**132.38**	**99.53**	**533.07**
Less capital contributions	-3.33	-6.61	-12.36	-16.60	-8.59	-47.49
Less asset disposals	N/A	N/A	N/A	N/A	N/A	N/A
Total net capex	**92.68**	**100.72**	**85.47**	**115.77**	**90.94**	**485.59**

Table 3-3 details our actual and estimated capex for our current regulatory period.

Table 3-3 – Actual and estimated capex for the current regulatory period – excluding metering ($M, Real 2018-19, SCS)

	2014-15 Actual	2015-16 Actual	2016-17 Actual	2017-18 Estimate	2018-19 Estimate	Total
Replacement	48.08	45.37	29.75	21.27	31.04	175.51
Augmentation	25.61	18.77	13.51	14.49	4.03	76.42
Connections (including gifted assets)	18.03	14.73	12.31	11.07	11.58	67.73
Non-Network Other	1.19	1.34	3.40	5.16	5.37	16.46
Capitalised overheads	0.21	0.14	0.11	-	-	0.46
Corporate assets[6]	N/A	N/A	N/A	N/A	19.77	19.77
Total gross capex	**93.13**	**80.36**	**59.09**	**51.98**	**71.80**	**356.36**
Less capital contributions	-9.89	-10.49	-9.85	-11.07	-11.58	-52.89
Less asset disposals	-0.12	-0.12	-0.31	-	-	-0.55
Total net capex	**83.11**	**69.75**	**48.92**	**40.91**	**60.22**	**302.91**

[6] As discussed in section 3.2.2, this is a one-off allocation associated with use of assets held at the corporate level.

The above tables show that the composition of the capex program has changed significantly from a focus on augmentation related projects during the previous period (59 per cent of gross capex minus connections) to replacement based projects and programs in the current period (61 per cent of the gross capex minus connections).

3.2.1 Observations from the previous period

Prior to the 2009-14 regulatory period, investment in developing and maintaining the transmission and distribution electricity networks was limited.

In September and October 2008, several electrical equipment failures at Casuarina Zone Substation resulted in widespread, sustained power disruption to Darwin's northern suburbs. Consequently, the NT Government established an independent enquiry headed by Mervyn Davies to investigate these events as well as Power and Water's operational response and electrical substation maintenance practices in Darwin.[7] The enquiry's report described the situation as of February 2009 as follows:

> *"Over a period of decades the approach to substation maintenance across Darwin has shifted from what was originally a very traditional approach involving routine preventative maintenance as the dominant task type, to one which is now a minimalist approach, dominated by corrective and breakdown tasks.*
>
> *This shift is considered to have come about as the inevitable outcome of attempts by those responsible for delivering maintenance to cope with competing demands and budgets constraints, in an environment which required little or no systemic reporting of either asset condition or maintenance works delivery. And an asset and works management system that so poorly served and demoralised the delivery workforce that it was ultimately switched off.*
>
> *Along with this shift there has been a gradual erosion of workplace skills and custodial pride in the condition of the assets. Given the age and likely condition of PAWCs substation assets a new approach to Substation maintenance is required."*

The enquiry led to a comprehensive improvement program to re-establish asset management practices, develop maintenance practices and remediate poor condition assets. During this remediation process, it became apparent that most major substations were in poor condition, often beyond repair and with a high risk of failure. Furthermore, a number of incidents occurred at other zone substations that narrowly avoided major outages in the

[7] https://www.powerwater.com.au/__data/assets/pdf_file/0019/35173/Mervyn_Davies_Enquiry_-_Final_Report_-_June_2011.pdf

subsequent years, including the Snell Street Zone Substation Failure; and Hudson Creek Failure (System Black).

A significant zone substation replacement program was planned and initiated to address the identified issues (and continues to be implemented). At the same time, Darwin was experiencing high levels of economic activity, growth and several new substation sites were constructed, or expanded during the same period.

A large proportion of the capital spend was focussed on large scale projects, such as establishing and replacing zone substations. Asset management focussed on end-of-life management of major sites – maintaining safety was a priority, until asset knowledge and asset data could be improved from systemised maintenance, data capture and development of engineering capability.

The issues identified during this time continued into the current regulatory period. The improvements to asset management practices have highlighted emerging and increasing risks in the distribution network, not previously well understood, which form an increasing component of the capital program.

3.2.2 Observations from the current period

Table 3-4 compares our annual actual and estimated capex against the UC's allowance for the current regulatory period.

Table 3-4 – Comparison of annual actual and estimated gross capex to UC allowances for current period ($M, Real 2018-19, SCS)

Current RCP	2014-15 Actual	2015-16 Actual	2016-17 Actual	2017-18 Estimate	2018-19 Estimate	Total
UC allowance [8]	90.00	64.13	51.10	60.36	71.77	337.36
Actual / estimated	93.13	80.36	59.09	51.98	71.80	356.36
Variance to UC allowance ($)	3.13	16.23	7.98	-8.37	0.03	19.00
Variance to UC allowance (%)	3%	25%	16%	-14%	0%	6%

Table 3-4 shows that the total gross capex is forecast to be within 6 per cent of the UC's allowance by the end of the current regulatory control period.

The total capex profile in Table 3-4 and in Table 3-3 illustrate a generally decreasing trend during the current period, excluding the impact of the transfer of Corporate Assets in 2018-19. Prior to 2017-18, Power Networks incurred an allocation of costs from Power and Water for the use of assets held at the corporate level. The value of the allocation was commensurate with the depreciation associated with those assets. These assets are expected to be acquired by the Power Networks' business for regulatory purposes – and captured in the SCS' RAB – in 2018-19. These assets are used to provide our SCS and include IT, property and other assets held at corporate.

The general reductions in our other capex categories reflect our efficient resourcing and delivery approach, whilst maintaining an acceptable corporate risk profile, and managing within a decreasing capex allowance.

During the current regulatory period, our capex program has delivered most of the major projects forecast during the last period including:

- upgrading the 132kV Elizabeth River crossing transmission line;
- replacing the 66kV outdoor switchyard at Casuarina Zone Substation;
- replacing Tennant Creek Zone Substation;
- replacing McMinns Zone Substation;
- constructing Wishart Modular Zone Substation;
- installing an additional transformer at Palmerston Zone Substation; and

[8] The UC NTRM appears to have mistakenly excluded gifted assets from the forecast capex, this table reflects the corrected totals.

- constructing the Archer to Palmerston transmission line.

Most notably, our capex program has:

- improved customer reliability and staff safety outcomes by replacing poor condition assets, including oil filled switchgear (at distribution and zone substations);
- contributed to reduced maintenance spend by installing modern equipment;
- met the demand requirements of localised growth, especially in the Palmerston area; and
- improved system resilience to extreme events, such as through transmission line works at Elizabeth River and additional works at Hudson Creek Zone Substation, including primary system configuration, replacements and secondary system upgrades.

The areas of overspend against our capital allowance were contributed by:

- our developing understanding of our actual costs as we improved our recording systems and cost management practices. Previously, our recording systems did not provide a reliable estimate of our project costs and our cost management practices were not consistent; and
- immature asset management and risk management practices.

We have implemented several improvements to address the identified issues, including by:

- improving the application of our capital investment framework, including establishing a project management office and strengthening project gating and governance framework;
- strengthening our capability in financial and regulatory management, including by establishing a regulatory team dedicated to supporting the regulated network services;
- improving our cost management and accounting practices, including by developing our capability in our field crews to capture cost information from projects; and
- maturing our asset management and risk management approach to assist in prioritising our response to emerging risks, as well as ensure positive customer outcomes.

These improvements have been applied to the development of our capex forecast for the next regulatory period.

4. Capital governance

This section describes the capital governance and asset management framework that we have applied to develop our capex forecast, and explains how this will be delivered in the next regulatory period.

4.1 Asset management framework

We aim to operate our network so that we can continually provide the required functionality and meet our specified performance and compliance requirements in a sustainable manner.

The Asset Management Policy[9] reflects our intentions and the direction provided by our senior management, which is applied throughout the asset management process, from the development of plans to their execution. It applies to all levels of the organisation including the asset owner, general managers and all staff.

Our Asset Management Framework supports how we manage our assets in a sustainable manner to meet the current and evolving needs of our customers. This framework is explained in our Strategic Asset Management Plan[10] (SAMP). It has been developed to be consistent with:

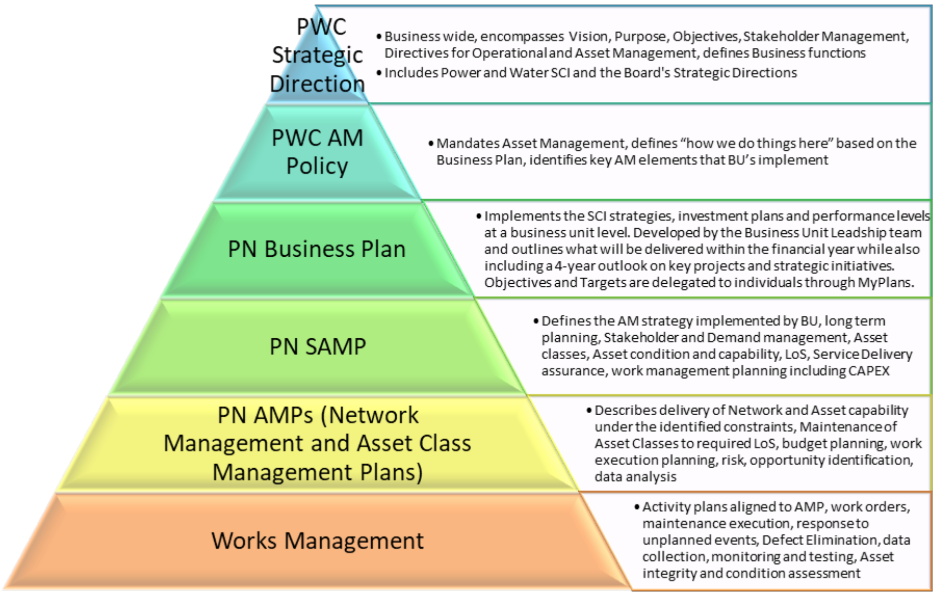
- our legislative and regulatory obligations;
- current standards for asset management systems, specifically the ISO 55000 suite; and
- our existing management systems and frameworks, including safety management system, environmental management system and emergency management framework.

Our Asset Management Framework consists of a set of interrelated documents, systems and processes that together provide the essential information that enables our asset management practices. This framework provides the linkage between asset management practices to the strategic direction and vision of the organisation as illustrated in Figure 4-1 and is explained further in our SAMP.

[9] Power and Water Corporation, Asset Management Policy.

[10] Power and Water Corporation, Power Networks Strategic Asset Management Plan, 2017.

Figure 4-1 – Asset Management Framework



We develop Asset Management Plans (AMPs) and a Network Management Plan (NMP) for the following 10 years through an annual Power Networks' business planning process. These plans provide the link between our strategy and objectives and individual business (i.e. Power Networks) objectives. Responsibility for delivery is then cascaded down to individual members of staff.

The business planning process is led by our Strategy and Planning group, whilst Power Networks' plans are coordinated through Power Networks' Business Management group. A draft business plan (Our Plan) is produced in January-February for the following financial year. This is then reviewed by the business and a draft Statement of Corporate Intent (SCI) is submitted to the Department of Treasury and Finance (DTF) in February. Our final SCI is submitted to the Legislative Assembly for shareholder approval in May, with internal communication of Our Plan during May-June.

We have a range of objectives, which impact on asset management. Some of these are externally agreed and others are commitments that are developed and agreed within the business.

4.1.1 Network Planning

Investment in new assets for changes or growth in demand is governed by the Network Technical Code and Network Planning Criteria[11]. This can drive

[11] Power and Water Corporation, Network Technical Code and Network Planning Criteria, Version 3.1, December 2013

investment in any of our assets classes and network systems to maintain network security levels and meet customers demand as it grows.

The Network Technical Code and Network Planning Criteria also places obligations on us to ensure that our network and customers' installations and equipment connected to our network can be operated and maintained in a secure and reliable manner, and that new loads and generators connected to the network do not compromise the security and reliability of supply to all network users.

The Electricity Industry Performance Code outlines the reliability targets set by the UC. In addition to operational matters, meeting these standards of service also influences the network planning for the application of new technology and network design.

4.1.2 Safety, Environment and Security

Some of our assets are relatively old, dating from the period after the Second World War through to 1978, when electricity supply in the NT was arranged by the Commonwealth Department of Works (under various guises). This period also includes the rebuild of the network following Cyclone Tracy in 1974. Their age profile means that the safety, environmental and reliability risks that these assets now pose are in some cases no longer acceptable to society today. This drives various investment programs to ensure compliance with new legislation or regulatory requirements.

We are committed to influencing the development of new legislation which will have an impact on the operation of the network. We will put in place time-based operationally feasible programs to ensure compliance with any new legislation. Any non-compliance with legislation will be identified and raised through our business risk process.

Although not currently applicable in the NT, the Electricity (Network Safety) Regulations that are now in force in several other jurisdictions have been incorporated into the SAMP in compliance with the Government Owned Corporations Act. The Australian Standard AS 5577 'Electricity Network Safety Management System' (AS5577) was also the basis of the development of the Safety Management and Mitigation Plan (SMMP), which became a licence requirement in 2015.

4.1.3 Efficient operation of the network

We make investments consistent with the efficient operation of the network. This may happen as assets or parts of assets become unreliable as they reach the end of their asset life increasing operational costs. Investments may also be made in new Network Planning or System Control technology to enhance the efficient operation of our network and reduce long term costs.

4.1.4 Maintenance of assets

Asset maintenance is developed with a strong consideration of asset failure modes, the risk that they present and the opportunity to prevent failure costs effectively. Maintenance intervals and activities are in our Maximo asset management system, which is utilised for Service Delivery to manage works.

Higher value maintenance investment programs, such as power transformers, are undertaken with a focus on capturing the asset condition. These programs are prioritised and optimised by Asset Management annually to meet the obligations of the *Network Technical Code and Network Planning Criteria* and service standards.

4.1.5 Asset class objectives

Our business objectives are predominantly delivered through the approved AMPs and NMP. These plans are essential to meet our customers' needs as they detail how we intend to discharge our obligations as a network operator which, if not adequately managed, would lead to a deterioration in performance or increased risk.

Each asset class and feeder category poses different asset risks and consequential business risks. Therefore, each is subject to different objectives, as set out in our AMPs and the NMP.

Our plans generate the capex and opex work plans and programs that provide a rolling view of the management of our assets, priority areas and forecasts for expenditure.

The capex forecast for the next regulatory period has been prepared consistent with these plans, the asset management framework and supporting elements described above.

4.2 Investment governance framework

The investment governance framework is described in our Capital Investment and Delivery Policy [12]. This document details our commitment to achieving value for money through prudent decision making and efficient and effective expenditure delivery. It commits us to having a governance framework to achieve this purpose. This governance framework consists of approval gateways, monitoring and control mechanisms, performance metrics, authority delegations, policies, procedures, systems and audit programs.

4.2.1 Asset development lifecycle

Our Capital Investment and Delivery Policy, and the associated Capital Investment and Delivery Framework – An Overview[13], distinguish between five phases in the development of our projects. Each phase has specific objectives and outputs to ensure the systematic development of a project:

- *Investment planning* – the aim of this phase is to ensure the need for an investment is justified by demonstrating a logical linkage with corporate

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[12] Power and Water Corporation, Capital Investment and Delivery Policy.

[13] Power and Water Corporation, Capital Investment and Delivery Framework – An Overview.

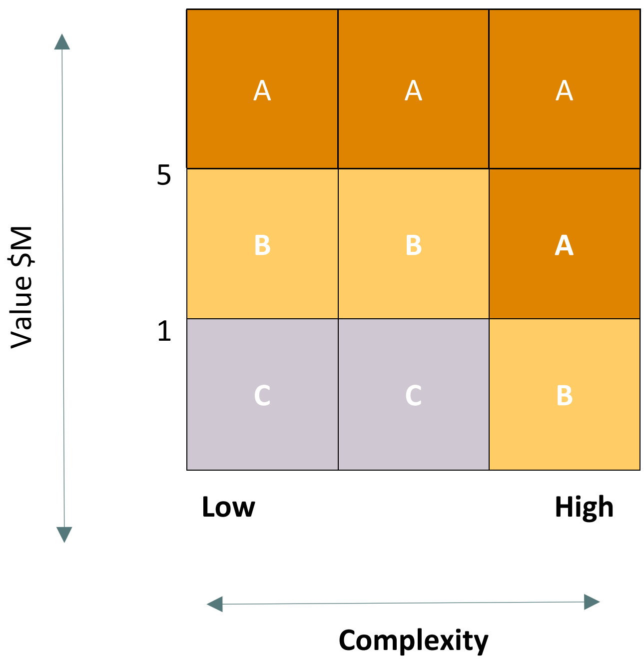
objectives and service requirements, relative priority and that the timing of the project is optimal;

- *Project development* – this phase is critical as it contributes to prudent decision making and efficient delivery. Prudency is promoted through robust options development and selection and efficiency is enhanced through the design development and project execution planning processes;
- *Commitment* – the goal of this phase is to ensure efficient delivery of a project through effective market engagement and refinement of management plans, project costs and schedule prior to final funding commitment;
- *Delivery* – safe and efficient execution is the intent of this phase by following the approved strategies, execution plans and effective project management; and
- *Review* – performance, effectiveness and an analysis of benefits delivered are examined in this phase. The objective of this phase is to close the cycle and demonstrate that the original investment need has been met.

4.2.2 Project governance

In the interest of efficiency, developing a governance framework requires consideration of the size and complexity of the project, to ensure governance mechanisms and effort applied is commensurate with the risk it represents. The matrix in Figure 4-2 outlines our project classification methodology, thereby determining its governance path as it passes through its project phases.

Figure 4-2 – Project Classification Matrix – project types A, B, C



We use business case gateways to ensure that each investment is prudent and that the resulting projects are planned and developed sufficiently. The following are our project governance gateways:

- *Business Need Identification* – requests acceptance of the need to address the identified issue/s and seed funding required to complete activities (e.g. development and analysis of options) to reach the next gateway;
- *Preliminary Business Case* – requests approval of the preferred solution and funding required to complete activities (e.g. detailed design of the preferred option or going to market) to reach the next gateway;
- *Business Case* – requests approval to commence delivery of the project in accordance with the defined scope, cost, timeframes, risks and benefits identified;
- *Final Business Case* – requests approval of additional funding if procurement outcomes mean that more money is required than was approved in the Business Case;
- *Project Over-Expenditure/Project Variation Request* – requests approval of changes to a project (scope, cost, timeframes, risks, benefits) once it is in the delivery phase; and
- *Post Implementation Review* – provides information on the project benefits realised (and still to be realised) and the lessons learnt.

The governance process has sufficient flexibility to manage various delivery models and for projects less than $1 million, two gateways – the preliminary and final business cases – are bypassed.

Table 4-1 provides further details of our governance gateways and the corresponding project values, and cost estimation accuracy required.

Table 4-1 – Overview of governance gateways

Gateway	Purpose	Timing	Project type	Typical elements	Target cost accuracy
BNI – Business Need Identification	To demonstrate the need to invest and the supporting logic	During the Investment Planning Phase	All Projects and Programs	• Base cost estimate • Clear investment logic • Quantitative measures of success • Primary Investment Driver • Key milestones	+/-35%
PBC – Preliminary Business Case	To demonstrate a robust development, analysis and selection of options	During the Project Development Phase	A, B	• Full options analysis (cost and non-cost) • Draft Project Risk register • Scope and requirements	+/- 20%

Gateway	Purpose	Timing	Project type	Typical elements	Target cost accuracy
				definition for preferred option	
BC – Business Case	To demonstrate that sufficient project development prior to going to market	End of Project Development Phase	A, B, C	• Complete Management Plans • Procurement / Delivery Strategy • Detailed cost estimate • Detailed schedule	+/- 10%
FBC – Final Business Case	To ensure VFM has been achieved through the market engagement process	End of Commitment Phase	A, B	• Procurement recommendation • Updated cost estimate	+/- 5%
OE – Over expenditure	To govern any expenditure (or proposed) over that approved	During Delivery Phase	All Projects and Programs	• Quantification and reasons for cost over-run • Substitution recommendation	n/a
PIR –Post Implementation Review	Demonstrate that benefits have been delivered through the investment and to inform continual improvement	After completion of the Delivery Phase	A and Programs B&C if an OE occurred	• Confirm delivery benefits • Project performance summary • Improvement recommendations	n/a

We have supported our capex forecasts for the next regulatory period with BNIs and PBCs, which we have provided to the AER. This Capex Overview Document identifies the BNIs and PBCs that are relevant to each of our capex categories.

4.2.3 Capital decision making

We have three main bodies to oversee and control project lifecycles, which apply to all major projects: project concept, project development & commitment, project delivery and project review:

- *The Investment Review Committee (IRC)* – this is an executive level committee that provides advice/recommendations to the Chief Executive on projects/programs[14] for approval at each of the governance gateways. All proposals undergo technical, financial and quality reviews as appropriate prior to being considered by the IRC;

- *Program Control Group (PCG)* – this is an executive level committee that assesses the status and performance of our Portfolio of Work and provides related advice/recommendations to the Chief Executive. The PCG is chaired by the Chief Executive with the Executive Leadership Team serving as members; and
- *Project Management Office (PMO)* – this provides a consistent approach to initiating, delivering, reporting and reviewing projects. It supports the business in the project/program approval process, providing advice regarding the process and requirements, analyses and reports on the status and performance of our portfolio of projects. It administers the IRC and PCG processes, including by developing a high-level overview (dashboard) of our project portfolio performance and a summary of individual priority project performances is provided to the Board.

In addition, major capital investment projects require DTF approval.

The PMO was first formed in June 2016 and reviewed the existing governance frameworks and processes, and proposed changes that led to the creation of a new IRC and PCG. The PMO developed the project thresholds, classification criteria, tools, templates, reporting requirements and reports, enabling the PMO, IRC and PCG to commence in their current form from 2016-17.

These three bodies operate across the organisation, with additional program control groups and steering committees established at a divisional level as required for high profile projects. For example, the Power Networks Program Steering Committee is a senior leadership level business unit committee that provides oversight to projects and the full investment portfolio. It advises the Power Networks Executive General Manager about investment planning, approvals and delivery oversight.

We also established a Steering Committee, comprising representatives of the Board and Executive, to oversee the development of the regulatory proposal for the next regulatory period. This Steering Committee provided strategic direction to the Regulatory Reset Team and contributed to, and reviewed, the regulatory proposal, tariff structure statement and supporting documentation. The IRC reviewed and approved the BNIs and PBCs through our project governance gateways, and the Steering Committee approved them for inclusion in the five-year capex forecast that is reflected in this Capex Overview Document and our regulatory proposal.

[14] that meet the IRC/PCG criteria, including capex projects with a value greater than $1M

4.3 Risk management

Risk analysis is an integral part of the investment decision-making process to balance competing drivers such as network performance and cost. Contemporary asset management practice applies risk and value based decision-making frameworks. This ensures that investment decisions are made as consistently as possible, and balances our objective to deliver a safe, reliable and affordable network.

Investment decisions principally revolve around three matters: “what” needs to be done; “how” does it need to be done; and, “when” does it need to be done.

The “what” requires the clear and precise identification of the need for an investment. For example, this may be associated with an identified capacity constraint, or an asset in poor condition and becoming increasingly likely to fail. Correctly defining the need is crucial to identifying the most prudent and efficient solution. For example, a capacity constraint should not be identified as a need to augment, but rather a need to relieve the constraint. This allows for the appropriate and full consideration of all feasible options for meeting the need – that is, the “how”.

Deciding on the “how” requires comprehensive analysis of all reasonably practicable options to meet the need. The life-cycle cost of each option is generally the central determinant of the most likely option to be successful in the evaluation of all options to meet the need. That is, the option with the lowest life-cycle cost that meets the need is the most likely option to be selected.

The final matter to determine in the decision-making process is “when” the investment needs to be made. Both premature and belated investments introduce unintended consequences, such as a lack of available capital to mitigate higher risks, or the manifestation of undesirable performance or safety consequences. Determining the correct timing requires an understanding and consideration of how the risk changes over time.

4.3.1 Risk management policy and framework

Our Capital Risk Management Policy defines our expectations and objectives resulting from the delivery of systematic risk management practices and defines the risk management approach and responsibilities for risk management activities. Our Risk Management Framework outlines the procedures and processes that make up our Risk Management Framework, which align with the Australia/New Zealand Standard *“AS/NZ 4360: Risk Management”* and are applied across our business.

4.3.2 Risk management approach

The capex objectives in clause 6.5.7 of the NT NER effectively require our capex forecast to achieve a risk level that meets regulatory or legislative requirements, and where these requirements do not exist, sufficient to maintain the existing risk profile.

Assessment of risk forms an integral part of our asset management process, and has also been undertaken at the capex portfolio level for individual projects. We have applied our risk framework in the following way to objectively maintain the risk profile over time:

- *Capex portfolio* – a risk assessment guide has been developed based on the corporate risk framework for application to the capex forecast that is specific to the risks associated with our Power Networks division. The risk ratings are aggregated for the capex forecast, and used as part of the portfolio optimisation process as described in section 5.3;
- *Major capex projects* – for major capital projects we applied a qualitative assessment of the current, inherent and residual (target) risk ratings as a part of the project governance framework; and
- *Specific replacement programs* – for specific replacement programs we have developed an asset health and criticality framework that seeks to assess the risk of an asset category. Modelling the risk at the asset class level, a current risk scenario based on current failure rates can be developed to demonstrate the current risk level contribution by different asset class. The benefits of the investment in the next regulatory period can be demonstrated by the expected change in risk based on the expenditure levels in each asset class.

The development of an asset health and criticality methodology is a recent initiative intended to support the decision-making process by providing a perspective on the risk within an asset group. The addition of a value framework (still under development) to the asset health and criticality framework will allow greater consideration and comparison of risks between asset classes. This allows for investment decision-making to be prioritised towards those assets and issues that comprise the greatest risk on the network. The application of the asset health and criticality methodology has been focussed on major asset classes at this time due to the limitations of available asset condition data.

4.4 Recent improvements

In recent years, we have made significant improvements to the development and application of our asset management strategies, practices and particularly our approach to managing risk. We have placed significant emphasis on improving our understanding of our assets, and the risks that are present in our network. In the current regulatory period, we have adopted a more targeted approach to the mitigation of identified risks, consistent with the maturing of our asset management systems, data and capability. This approach continues into the next regulatory period.

These initiatives are driving greater efficiency in our business and are reflective in our proposed capex forecast. Improvements in the development and application of our asset management and capex investment processes include:

- taking a more rigorous and consistent approach to capex project approval, including introduction of a project management office and formal project approval and review process;
- applying additional processes for review and challenge, which have occurred using both internal and external resources, to provide a greater level of assurance in the development of a prudent and efficient expenditure forecast;
- improving our project governance process to improve the transparency of decision making, including implementation of a Steering Committee to oversee the development of the five-year capex forecast for the next regulatory period;
- improving our approach to condition assessment and to capturing inspection and condition information;
- introducing a health and criticality framework to our asset management decisions (as described above);
- developing formal asset class management plans and strategies to provide greater direction to the priorities for our capital (and maintenance) works programs; and
- applying top-down and bottom-up forecast development process.

5. Overview of capex forecasting methodology, inputs and assumptions

This section describes our capex forecasting methodology, inputs and assumptions that has been applied to develop our capex forecast.

5.1 Forecasting methods

We submitted our Expenditure Forecasting Method to the AER in May 2017, in accordance with clause 6.8.1A of the NT NER. We have applied the following four methods set out in that document to prepare our capex forecast:

- *Scoped capex* – this capex is forecast by scoping and costing individual projects;
- *Programmed capex* – this capex is forecast based on programs of work for different asset classes. Forecasts are based on a build-up of volumes and unit costs. We use a variety of techniques to forecast both volumes and unit costs, depending on the asset class;
- *Pooled capex* – this capex is forecast at an aggregate level, typically based on either a single historical year or a historical trend; and
- *Benchmarked capex* – this capex is benchmarked by applying the AER's repex model as a check against our own replacement capex forecast.

We have applied multiple approaches to forecast our various capex categories:

- because it is not feasible or appropriate to use a single approach to forecast all elements of every capex category; and
- in the case of repex, to benchmark our forecasts using the AER's repex model.

The forecasting approaches that we have used for our capex categories are presented in Table 5-1.

Table 5-1 – Forecasting methods applied to capex categories

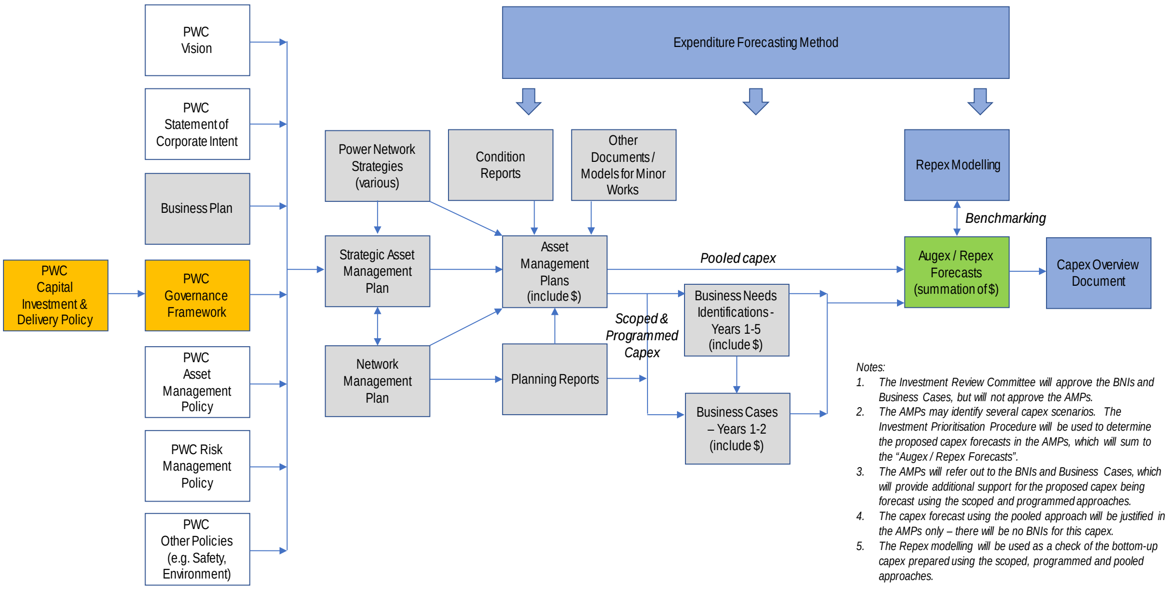
Expenditure Type	Scoped	Programmed	Pooled	Benchmarked
1. Replacement	✓	✓	✓	✓
2. Augmentation	✓	✓	✓	
3. Connections			✓	
4. Non-Network ICT	✓	✓	✓	
5. Non-Network Other				
a. Buildings / Property	✓	✓	✓	
b. Fleet		✓		
c. Tools and Equipment			✓	

Expenditure Type	Scoped	Programmed	Pooled	Benchmarked
			✓	

We explain further in sections 6 to 11 below how we have applied these four forecasting methods to prepare our capex forecasts. We provide further detail in our capex project/program supporting information - BNIs and PBCs - about the practical application of our forecasting methods for our individual projects and programs.

Figure 5-1 overviews the general process applied to develop our core network capex forecast.

Figure 5-1 – Overview of capex forecasting process



5.2 Capex key assumptions

Clause S6.1.1 of the NT NER requires us to provide in our regulatory proposal the key assumptions that underlie our capex forecast. These key assumptions are detailed in Table 5-2.

Table 5-2 – Key capex assumptions

Issue	Assumption
1. Company structure and ownership arrangements	Our forecasts reflect Power and Water's current company structure and ownership arrangements.
2. Regulatory obligations and requirements	Our forecasts are based on legislative and regulatory instruments applicable to Power and Water and as in force on 1 July 2017.[15]
3. Security of supply and network reliability	Our forecasts will maintain, but will not improve, system-wide security of supply and network reliability, consistent with clause 6.5.7 of the NT NER.
4. Service classification	Our forecasts reflect the service classification in the AER's F&A paper.
5. Maximum demand, customer and connection growth	Our forecasts are required to meet the maximum demand, customer and connection growth forecasts prepared by AEMO. As the independent market operator, AEMO's forecasts are reasonable and credible.
6. Connections policy	Our forecasts reflect Power and Water's proposed new connections policy that complies with Chapter 5A of the NT NER.
7. Cost allocation and capitalisation	Our forecasts reflect the cost allocation method that has been submitted to the AER, which includes our approach to capitalisation.
8. Unit rates	The unit rates that Power and Water has applied in developing its capex forecasts are representative of the costs that will be incurred in the next period.
9. Cost escalations	The cost escalations that Power and Water has applied in developing its forecasts are representative of the increased costs that we will incur in the next period.
10. Inflation	The inflation that Power and Water has applied in developing its forecasts is representative of the inflation-related costs that will be incurred in the next period and is consistent with the AER-preferred inflation forecasting method.
11. Current period capex program	Our capex forecasts for 2019-20 to 2023-24 assume that we will deliver our forecast capex program for 2017-18 and 2018-19.

Our Directors have certified the reasonableness of these key assumptions, in accordance with clause S6.1.1(5) of the NT NER.

[15] We have included in the regulatory baseline the new Electricity Industry Performance Code (Standards of Service and Guaranteed Service Levels) that the UC published on 25 October 2017. This updates, merges and replaces the Retail Supply Electricity Standards of Service Code and Guaranteed Service Level Code.

5.2.1 Application of cost allocation method

We have submitted our CAM for our distribution services to the AER for approval.

We developed our CAM in accordance with clause 6.15 of the NT NER and the AER's Cost Allocation Guidelines. It details how we attribute and allocate costs to, and within, our distribution services, including when preparing forecast capex to be submitted to the AER in accordance with clause 6.5.7 of the NT Rules.

We confirm that we have applied our CAM in preparing the capex forecasts for the next regulatory period that we present in this Capex Overview Document. This is reflected in our Capex Model, which we have also provided to the AER with our Regulatory Proposal.

5.2.2 Cost estimation methodology and unit rates

Our capex forecasts reflect the costs of the work required to efficiently expand and maintain our network to achieve safe and reliable performance outcomes.

Our cost drivers differ from our peer Distribution Network Service Providers (DNSPs) in the National Electricity Market (NEM), due to a range of factors including the size, and nature of our network, our location and our customer base. As discussed previously, we have undertaken an extensive review of our asset management and operating practices to lower our costs, whilst meeting our customers' needs. These initiatives will continue to improve the cost efficiency throughout the next regulatory period, and have already been reflected in our capex forecast.

Our cost estimation methodologies vary between capex categories, and in some cases even between programs and projects within them. The most appropriate costing methods have been applied to each project and program, based on the availability of data (including historical cost information), estimation accuracy and delivery strategy. We have applied the following cost estimation methodologies:

- *Bottom-up estimates* – The bottom-up approach aggregates cost components to estimate the cost of a project based on the scope of works. This is more typically applied to augmentation projects where the project undergoes a detailed engineering process provided by an external engineering consultancy, where industry standard costing systems are applied to provide a high level of confidence in the cost estimate; and
- *Historical estimates* – The historical cost estimation approach has been used where past costs are deemed to reflect an efficient cost to deliver the scope of works. This is more typically applied to volumetric programs or recurring projects and where there is a high level of stability in costs for activities over time, employing a similar delivery strategy.

The majority of our capital plan has utilised historical estimates. In undertaking the analysis, an average has been applied to the historical expenditure to develop an average cost for each activity. The average unit costs are then compared against the unit costs applied by our peer DNSPs in the NEM, to determine the reasonableness of these estimates. Where there is insufficient information available to generate an average unit cost from historical expenditures, or concerns over the accuracy of the available data, an average of the cost estimates used by our peer DNSPs has been applied.

We consider that the cost estimates we have applied for the next regulatory period reflect an efficient level of cost. An explanation of these methodologies and models are provided in the supporting documentation with each capital project or program.

5.3 Top-down review of bottom-up forecast

We prepared several versions of our five-year capex program, which we stress-tested through our Steering Committee governance processes. We made cuts to our forecasts using this top-down assessment approach by identifying what capex could be reasonably deferred or avoided having regard for the risk profile of the capex program. As a result, we are now proposing to the AER a reduced forecast capex program from what we initially developed, which we believe is both prudent and efficient.

As mentioned in section 5.1, and discussed further in section 6, we commissioned Nuttall Consulting to assess our replacement forecast using the AER's repex model.

6. Replacement capex

This section explains and justifies our repex forecast.

6.1 Purpose and scope

Repex is required to replace or refurbish our existing assets, and is typically driven by asset condition and related risks, including technical obsolescence.

As noted in our Capital Investment and Delivery Policy, the key driver of our repex is efficiently maintaining the service performance of our network as assets reach the end of their technical lives, or become obsolete, to meet our customers' expectations for our reliability, safety and compliance obligations.

Our repex forecast comprises projects and programs driven by:

- *Condition and risk* – replacement projects and programs to address an identified condition, technical obsolescence or risk to safety and continuity of supply;
- *Compliance driven* – replacement projects to meet the requirements of the Network Technical Code and Network Planning Criteria; and
- *Reliability and quality of supply* – replacement projects required to meet a reliability and power quality obligation or technical standard, including in response to customer feedback.

6.2 Overview of key drivers

6.2.1 Condition and risk of asset failure

Deteriorating condition and/or health of network assets typically results in a high risk of failure that presents an elevated risk to the safety of people (including members of the public) and extended outages to supply. In many cases, rapid deterioration and increasing risk are evident at the end of the asset's technical (or design) life that can be validated with modelling of operational behavior to predict failure before it occurs. The consequences associated with failure can be catastrophic, including where an oil-filled device fails explosively, resulting in potentially fatal injuries to a worker or member of the public. It is important that sufficient information is gathered to understand the operating characteristics and failure modes to treat the risk of failure before it occurs.

We have adopted a prudent approach to maintaining our service performance and addressing the current and emerging safety issues present in our network. This approach is detailed in our SAMP and reflected in our AMPs for each asset class. Our objective is to target our capex to maximise the benefits for our consumers across our capex portfolio. We have sought to prioritise our expenditure using a risk-based prioritisation approach.

Our condition and risk-driven capex therefore reflects:

- the replacement of assets at the end of their life to minimise the whole of life cost;

- the deferral of large repex using targeted refurbishment and risk management initiatives; and
- investments in new technologies to enable us to predict asset failures more accurately and improve our response to such events.

Some of our repex is driven by technical obsolescence, including where vendor or manufacturer support has been withdrawn and spares are exhausted, as this can present major risks to parts of our network. These issues particularly impact protection and control, and secondary systems assets where unavailability of support and/or spares can result in extended outages.

6.2.2 Compliance with technical codes

We regularly review compliance with the Network Technical Code and Network Planning Criteria, as part of our annual planning process. As our network information and asset data has been improving, our annual planning review has identified areas of imminent non-compliance with our technical requirements.

As with our augex planning, we have undertaken detailed investigations of these areas of imminent non-compliance and developed targeted projects and programs to mitigate the highest areas of risk on a prioritised basis, whilst ensuring we adhere to strict safety requirements and maintain our service performance.

6.2.3 Meet and manage our reliability and power quality obligations

We are committed to maintaining the average service performance across our network, consistent with the capex objectives in clause 6.5.7 of the NT NER.

Since implementing the reliability improvement program during the current regulatory period, our reliability metrics have stabilised and the trend is considered reflective of underlying reliability performance.

We continue to report the five worst performing feeders and associated actions for each reliability category, and we monitor this performance closely.

As discussed in section 2.2, customers and other stakeholders supported a program to target areas of poor performance. Consequently, we propose addressing this as part of our capex forecast for the next regulatory period.

Power quality is a growing issue, principally voltage management. We have developed a set of program initiatives to meet the regulatory requirements including to maintain statutory voltages. We will focus on addressing the worst performing areas on the network, including in response to growth of solar PV.

6.3 Forecasting method

We use four approaches to forecast our repex, depending on the asset category:

- *Method 1 – Scoped Capex* | We have forecast some of our repex on an individual project basis. This is only for large projects that we can scope and cost on a discrete basis. Projects are designed to meet our planning criteria and other regulatory obligations;
- *Method 2 – Programmed Capex* | We forecast some of our repex based on a build-up of volumes and unit costs. Volume forecasts are based on:
  - assets reaching the end of their technical life, having regard for their age and condition;
  - asset obsolescence, including arising from an unavailability of specific skills to maintain old assets;
  - prescribing a set number of units for replacement each year (for example, to address a low-consequence risk that requires mitigation but does not warrant the immediate replacement of the entire asset family); or
  - historical asset replacement volumes.

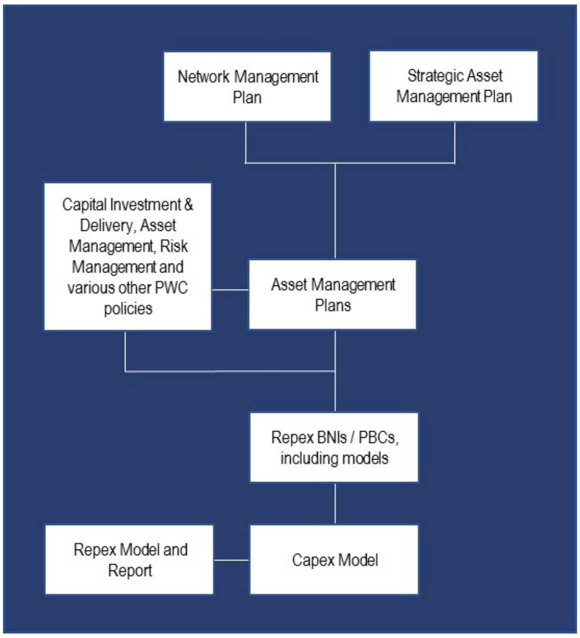
  Unit rates may be based on:

  - our historical costs;
  - costing models; or
  - cost estimates from external independent consultants or service providers;
- *Method 3 – Pooled Capex* | For some asset categories, it is not feasible to forecast our repex on volumes and unit costs. For example, it is not possible to forecast accurately the volume of faults for a given asset class, or the cost of replacing failed assets due to the different types of assets in the class, but the annual cost of replacements may be relatively stable. In these cases, we forecast our required capex based on our historical capex expenditure; and
- *Method 4 – Benchmarked Capex* | We commissioned Nuttall Consulting to apply the AER's repex model to benchmark our repex forecasts prepared using the above three methods.

6.4 Key supporting documents

Figure 6-1 illustrates the relationship between the key documents that support our repex forecast.

Figure 6-1 – Repex key supporting documents



The following documents are relevant to our repex forecast:

- *SAMP* – This document gives effect to a common strategic asset management process across our business. It converts organisational objectives into asset management objectives for developing our AMPs. The AMPs consider attributes of the asset portfolio including current age, condition, and capability, actual and forecast performance to highlight key areas that need to be addressed. The SAMP specifies the approach of the asset management system in the development of AMPs through the application of the risk management framework and the requirements of the Asset Management Policy;
- *NMP* – This provides the analysis of our network regarding our network reliability, capacity, security and supply quality. The original intent of the document was to provide our stakeholders with an insight into the challenges that we face and how we intend to respond. The document also outlined general investment intentions, technical data, demand forecasts and network performance, including outage performance, utilisation and security. With the transition to the AER, the function of the NMP is being refined to focus predominately on the technical network data and capability of the interconnected assets. Other documents, such as the Distribution Annual Planning Report (DAPR) will fulfil the original intent of the NMP of providing published information about our network;
- *Policy and Strategy documents* – These documents set out our internal policies, including for example in relation to capital investment and delivery, governance, asset management, risk management, security, health and safety, emergency, environment and sustainability;
- *AMPs* – These documents are developed and updated using the latest information provided through the SAMP. Each AMP proposes a recommended implementation strategy that optimally meets our

business and asset management objectives over a 10-year period. A consolidation of all AMPs is then assessed for deliverability with constraints identified in terms of resource or access availability;

- *BNIs and PBCs* – These documents provide supporting information about individual projects and programs that are included in our capex forecast. They explain: (i) the nature of the capex; why and when it is required; (ii) options considered; (iii) the forecasting method used, including any validation; and (iv) the project benefits. Section 6.5 lists the BNIs and PBCs that are relevant to our Repex forecast;
- *Repex model and report* – We commissioned Nuttall Consulting to benchmark our repex using the AER's repex model. Nuttall Consulting's model and report are discussed further below; and
- *Capex model* – This model is an Excel spreadsheet that calculates and supports our capex forecast.

6.5 Repex forecast

Table 6-1 breaks down our Repex forecast of $148.60 million for each year of the next regulatory period. It includes a brief description of each project and program and a reference to the supporting documents that we have provided with our Regulatory Proposal that explain and justify them in detail.

Table 6-1 – Repex forecast by driver ($M, Real 2018-19)

	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Condition and risk driven	31.84	36.11	31.79	21.20	18.88	139.82
Compliance driven	2.55	1.87	1.11	0.27	0.28	6.08
Reliability & Quality of Supply driven	0.53	0.53	0.54	0.54	0.55	2.69
Total Repex	**34.92**	**38.51**	**33.44**	**22.01**	**19.71**	**148.60**

Table 6-1 shows that the majority of our repex (94 per cent) is comprised of condition and risk-driven projects and programs.

6.5.1 Condition and risk-driven programs

As identified above, our condition and risk driven programs are required to maintain our service performance and address current and emerging safety risks in our network. The proposed condition and risk-driven repex forecast of $139.8 million is broken down by asset category in Table 6-2.

Table 6-2 – Condition and risk-driven programs, 2019-20 to 2023-24 ($M, Real 2018-19)

Asset category	Total expenditure
Poles	20.9
OH conductors	5.2
UG cables	32.1
Services	0.4
Transformers	25.0
Switchgear	17.2
Other	39.1
Total	139.8

In Table 6-2, the highest capex category is Other. The next highest is underground cables, reflective of the poor condition of the LV and HV cables installed in the Darwin area, and to which we have increased expenditure associated with the inclusion of several corrective programs to address the identified risk.

The poles expenditure has also increased significantly from previous years due to the inclusion of a program to address the elevated safety risk associated with below ground corrosion of the steel distribution poles in the corrosive soils' environment in and around the Alice Springs area.

The capex associated with transformers and switchgear reflects ongoing refurbishment and replacement activities associated with these asset categories, albeit at lower levels of expenditure from previous years.

Selecting an appropriate forecasting method

As described in section 4, our asset management strategy and practices have been rapidly improving in recent years, and the information being received about the condition of our assets has similarly been improving. We have long considered that the network, adoption of standard equipment, design standards and operating practices has differed from the DNSPs in the NEM due to several factors including diverse and isolated locations, customer base and notable environmental factors including, climate and flora and fauna. Compounded by the low level of accurate asset and condition data for its assets, and absence of sufficient historical failure data, our ability to accurately forecast future requirements was significantly limited.

We had also considered that our unit costs were consistently higher than those of other DNSPs for similar reasons.

Reviewing of our forecasting methods

In reviewing our forecasting models and methods, we focused on improving the asset data records, fault information and cost information to inform the future asset replacement requirements. Many of these workstreams were undertaken in parallel, and as data became available the models and tools were developed to predict the future replacement needs based on historical replacement rates.

Similarly, as historical cost information becomes available the cost components were reviewed and compared with peer DNSPs from the NEM to understand any local environmental factors than may apply to explain the variances.

In developing the required systems to develop a prudent and efficient forecast, we had essentially satisfied the input requirements for use of the AER's repex model, albeit we had not initially applied the AER's repex model. Given our planning approach, our repex forecast was developed using the bottom-up and predictive methods and the AER's repex model was subsequently used as a means of top-down review and verification of the efficiency of our forecast.

Review of the AER's repex model outputs

We have commissioned Nuttall Consulting to benchmark our repex using the AER's repex model. We have provided the version of the model prepared by Nuttall Consulting, and its associated report, to the AER with our Regulatory Proposal.

Nuttall Consulting assessed approximately $100 million (69 per cent) of our repex forecast using the Repex Model.

Nuttall Consulting undertook three model studies. Each study reflects a forecast prepared by the model, using a different set of the model's planning parameters (i.e. asset lives and unit costs). The three studies use asset lives that are calibrated to reflect the last five years of our reported replacement volumes. They are uniquely defined by variations in the unit cost parameter set used for each study, as follows:

- *Study 1 - historical unit costs* – This study uses a set of unit costs that are calibrated to reflect the last five years of the DNSP's repex and replacement volumes as reported in its RIN;
- *Study 2 - forecast unit costs* – This study uses a set of unit costs that are calibrated to reflect the DNSP's repex and replacement volume forecasts over its next regulatory period, as reported in its RIN; and
- *Study 3 - AER's benchmark unit cost* – This study uses a set of unit costs that the AER has calculated as the average historical unit costs (as calculated above) across all the NEM DNSPs.

Nuttall Consulting observes that "*Typically, the lowest repex forecast from the studies using the DNSP's historical and forecast unit costs (Study 1 and Study 2) is used to define the alternative estimate for each DNSP*"[16].

Nuttall Consulting's results of the three studies are shown in Table 6-3 against our forecast.

Table 6-3 – Comparison of AER repex model and bottom-up forecast ($M, Real 2018-19) [17]

Asset category	DNSP repex forecast	Repex model – Study 1	Repex model – Study 2	Repex model – Study 3
Poles	20.86	30.10	12.20	7.70
OH conductors	5.22	5.50	9.80	6.80
UG cables	32.10	64.20	53.50	72.70
Services	0.40	2.00	0.10	0.60
Transformers	24.98	19.80	29.50	36.70
Switchgear	17.15	27.20	22.90	20.60
Total (modelled)	100.70	148.80	128.00	145.10
Variance to DNSP forecast (%)		48%	27%	44%
Other (unmodelled)[18]	39.12			
Total	139.82			

Applying the AER's repex model results in an expenditure forecast between 27 and 48 per cent higher than our proposed repex forecast, when compared on a like-for-like basis.

We support Nuttall Consulting's conclusion that:

> *"Our assessment, using the AER's repex model and the method the AER has applied previously, supports PWC's repex forecast.*
>
> *PWC's forecast over the five-year assessment period is significantly below all the key studies considered by the AER, ranging between 68% and 79% of the repex model study forecasts. These results suggest that the assessed component of PWC's repex forecast ($100.5 million) would be significantly below the AER's alternative estimate, which was estimated by us to be $127.9 million."*[19]

The asset categories have been separated in Table 6-3 to provide an indication of the differences between our forecast and the repex model. These

[17] *Ibid*, page 12.

[18] The Other category refers to the asset categories not included in the AER repex model.

[19] *Ibid*, page 4.

differences are best explored in the review of the replacement projects that comprise the expenditure forecast.

6.5.2 Condition and safety driven projects

As described above, we have prepared our repex forecast based on a bottom-up development of identified projects and programs. We then reviewed this using a combination of top-down methods.

The major projects and programs contained in the condition and risk-driven Repex is shown in Table 6-4. A summary of the largest projects and programs (>$5M) is provided in the subsequent sub-sections.

Table 6-4 – Condition and risk-driven repex by project and program ($M, Real 2018-19)

Project/Program	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Condition and Failure Based Replacement Pooled Forecast	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Various cable replacements	5.3	8.2	5.1	3.0	3.7	25.4
Replace Berrimah ZSS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Alice Springs Corroded Poles	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Various SCADA and Communications' replacement	1.1	1.8	7.1	1.8	0.7	12.3
Various pole and tower refurbishment	2.2	2.0	2.0	2.1	2.1	10.3
Various power transformer replacements	0.5	1.8	5.5	2.5	0.0	10.3
Various protection & control replacement	2.9	3.3	0.8	0.8	0.8	8.5
Other minor projects	1.1	1.2	1.2	0.8	0.7	5.0
Total condition and risk-driven repex	31.8	36.1	31.8	21.2	18.9	139.8

Table 6-4 shows that almost 60 per cent of our condition and risk-driven repex forecast is made up of three projects/programs, namely:

- Condition and Failure Based Replacement Pooled Forecast;
- Various cable replacements; and
- Replace Berrimah ZSS.

We examine the projects and programs detailed in Table 6-4 below.

Condition and failure based replacement pooled forecast

The condition and failure based replacement pool totals [redacted], as shown in Table 6-4. This relates to assets within the low value asset pool. Further details are available in BNI 25.

Table 6-5 - Condition and failure based replacement pooled forecast ($M, Real 2018-19)

Project/Program	2019-20	2020-21	2021-22	2022-23	2023-24	Total
BNI 25 Condition and Failure Based Replacement Pooled Forecast	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Condition and Failure Based Replacement Pooled Forecast	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

We have developed a model to forecast the replacement volumes and expenditure for assets where condition data is not available to prepare a technical condition-based forecast, and where the need for replacement is identified through periodic inspections by field crews. These asset types would generally be considered 'volumetric' in nature, that is, a high volume of assets replaced each year but with each asset having a relatively low cost. The forecast has been developed using the following key forecasting approaches:

- *Trending* – the trend of asset failures in service has been used to forecast future replacement requirements. A flat trend using historical data based on the P50 level or a line of best fit (using linear regression) has been used depending on the asset type; and
- *Probabilistic* – a probabilistic approach has been used to forecast the expenditure required for asset replacement due to condition. This approach forecasts based on the age profile, conditional probability of failure and historical volumes and unit costs.

The asset categories to which this program relates includes:

- Overhead conductors;
- Pole top structures;
- Underground cables;
- Service lines;
- Transformers;
- Switchgear;
- Other – connectors;
- Other – surge arrestors; and
- Other – pillars.

Other asset classes including Poles and SCADA, network control and protection systems are modelled using discrete analysis. The rationale for modelling these assets separately is discussed in further detail in each of the corresponding AMPs.

Various cable replacements

We will undertake targeted replacement of HV and LV cables at specific locations based on assessed condition at a cost of $25.4 million as shown in Table 6-6. Further details are available in the AMP – Cables along with the nominated BNI/PBCs.

Table 6-6 – Various cable replacement forecast ($M, Real 2018-19)

Project/Program	2019-20	2020-21	2021-22	2022-23	2023-24	Total
BNI 20 Darwin Northern Suburbs High Voltage Cable Replacement Program	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BNI 5 Darwin – Replace Port Feeder	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BNI 21 Darwin Cullen Bay and Bayview Low Voltage Cable Replacement Program	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Various cable replacement	**5.3**	**8.2**	**5.1**	**3.0**	**3.7**	**25.4**

The underground cable portfolio consists of a variety of cable types, although XLPE type cables make up the majority. Different cable types have been used depending on the preferred technology at the time of installation, or functional requirements such as different voltage levels. Each cable type presents different challenges, with associated risk and expenditure implications.

There are three primary current and emerging challenges in relation to our underground cable assets that we propose to address during the next regulatory period:

- *Aluminium screened HV XLPE cables in the northern suburbs of Darwin* – The program will replace approximately 46 kilometres of the target XLPE cable in the next regulatory period. These cables have identified sheath and insulation damage. The damage is due to moisture ingress and the subsequent corrosion of aluminium screens, which cause swelling and cracking of the cable sheathing. The damaged sheathing exacerbates moisture ingress resulting in screen corrosion and water treeing of the XLPE insulation. These failure modes have led to accelerated cable insulation and cable termination failure. In addition, cable screens are an integral component to the high voltage earthing system. The loss of cable screen continuity reduces the effectiveness of the earthing system as a whole and increases step and touch voltages. As corrosion continues, the earthing system performance will continue to degrade and increase the risk to the public and field crews during abnormal system conditions. Testing of the cables and inspection of replaced cables has confirmed the concerns associated with the damaged sheathing throughout the population;

- *LV mains cables in the Cullen Bay and Bayview suburbs of Darwin* – a report prepared by Safearth Consulting in August 2017[20] found that the design in the Cullen Bay and Bayview area is non-compliant with applicable standards[21] and contributes to an increased risk to worker and public safety; and
- *Port distribution feeder* – targeted replacement of cable sections in known water ingress areas to reduce the high number of faults and corresponding outages to consumers on the Port feeder.

Replace Berrimah ZSS

We are replacing the existing Berrimah Zone Substation with a new 2 x 20/27MVA transformer, 66/11kV zone substation located directly adjacent to the existing substation. This project will commence in 2017-18 to meet the required completion date of June 2021, with the expenditure in the next regulatory period as shown in Table 6-7. Further details are available in BNI 2.

Table 6-7 – Berrimah Zone Substation ($M, Real 2018-19)

Project/Program	2019-20	2020-21	2021-22	2022-23	2023-24	Total
BNI 2 Replace Berrimah Zone Substation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Berrimah Zone Substation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Consistent with good industry practice, our asset management strategy requires prudent replacement of zone substation primary plant and secondary systems prior to failure to reduce safety and reliability risk and to optimize the whole-of-life cost of the assets. A recent safety related event resulting in staff injury at Berrimah Zone Substation has highlighted the risk associated with operating obsolete assets.

The Berrimah Zone Substation comprises a 66kV outdoor air insulated 66kV switchyard, two 66/11kV 25/31.5/38MVA power transformers, and an 11kV indoor metalclad switchboard and associated secondary systems. Many of the assets are at, or approaching the end of their serviceable life, with the five ASEA HLC minimum oil 66kV circuit breakers in the poorest condition of the installed assets presenting a high risk of explosive failure.

This project is required to be completed by June 2021 to manage safety and reliability risks.

[20] Safearth Consulting, Earthing System Investigation Report, Package Substation Earthing – Cullen Bay, August 2017.

[21] AS/NZS3000.

Alice Springs corroded poles

We are planning to treat corroded steel poles in the Alice Springs urban area that are at highest risk of failure at an estimated capital cost of $12.6 million in the next regulatory period, as shown in Table 6-8. Further details are available in BNI 1.

Table 6-8 – Alice Springs Corroded Poles ($M, Real 2018-19)

Project/Program	2019-20	2020-21	2021-22	2022-23	2023-24	Total
BNI 1 Alice Springs Corroded Poles	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Alice Springs Corroded Poles	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

The failure of a steel power pole in Alice Springs in December 2014 drew concern regarding the condition of pole assets in the Alice Springs area. The pole had been in service for approximately 40 years before it failed, which is considerably less than the expected service life. This incident triggered an investigation of the condition of pole footings for poles of similar design in Alice Springs and specifically the soils identified in the High Salinity Area (HSA), as this was a significant contributing factor to the failure. The findings of the investigation have been progressively actioned, including development of new works practices to manage the identified worker safety risk associated with replacement of the identified at risk poles.

A targeted replacement program of the high-risk poles has been developed to prudently reduce the level of risk to an acceptable level over the next two regulatory periods. For all options considered, urban distribution poles were considered to present a higher safety risk than rural poles or service poles in urban areas of Alice Springs.

Various SCADA and Communications replacement

The continued operation of the SCADA system ensures the Power Network Operator can manage the electricity network from a centralised control room and provide efficient response and recovery from system outages and events. Several systems require replacement as the assets will be beyond vendor support or are obsolete, whereby parts are no longer available. Further details are provided in the capex supporting information, including the AMP - SCADA.

Table 6-9 – Various SCADA and Comms replacement ($M, Real 2018-19)

Project/Program	2019-20	2020-21	2021-22	2022-23	2023-24	Total
BNI 12 Darwin – Energy Management System Upgrade	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BNI 16 Various SCADA and Communications replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BNI 17 SCADA and	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Project/Program	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Communications Battery Replacement Program						
Total Various SCADA and Comms replacement	**1.1**	**1.8**	**7.1**	**1.8**	**0.7**	**12.3**

Darwin – Energy Management System Upgrade

The Energy Management System (EMS) is a fundamental tool for the Power Network Operator to efficiently manage the electricity network from a centralised control room. A loss of EMS service reduces the ability of the Network Operator to safely and efficiently manage the real-time operations of the electricity network, associated with switching, outage management, contingencies, performance and dispatch.

Following a system refresh in 2013-14 to extend the operating life of the EMS, a high proportion of the application, operating systems and support software will be out of support or extended support by 2020[22], placing the system in an unsupported state. Driving the assets to this extent presents increased risk of asset failure, and extended outages due to lack of available support. Utilities operating SCADA/EMS applications beyond the support date often experience steadily decreasing levels of support competency as core vendor staff gravitate away and have less familiarity with the core software on a shrinking customer base. Whilst GE will continue to provide a level of 'legacy support' on a time and material basis, security and software patches are not developed by GE which may impact the overall reliability and availability of the system.

This project will migrate the existing GE EMS software to the current revision levels of the product and return the existing GE EMS system to a 'fully supported' status for both software and hardware.

SCADA replacement projects

Two projects (BNI 16 and BNI 17) are included to replace SCADA and Communications assets that have reached the end of their serviceable life and are now using obsolete technology and/or are no longer supported by the vendor. Vendor support is critical to having equipment repaired, resolving software/firmware bugs, updating security patches to guard against cyber threats, and general overall support in programming and maintaining this equipment.

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[22] In addition, server hardware will be out of vendor support by March 2018. The majority of Workstations will also be out of support by December 2017

Various pole and tower refurbishments

Four projects have been identified to replace pole tops and refurbish various transmission towers and distribution poles across our network. These programs are shown in Table 6-10. Further details are provided in the capex supporting information, specifically the AMP – Poles and Towers.

Table 6-10 – Various pole and tower refurbishment ($M, Real 2018-19)

Project/Program	2019-20	2020-21	2021-22	2022-23	2023-24	Total
BNI 32 Transmission Tower Earthing System Refurbishment Program	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BNI 35 Transmission Tower Corrosion Protection Life Extension Program	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BNI 26 Darwin Coastal Pole Top Corrosion Replacement Program	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BNI 31 Transmission Line Pole Top Corrosion Replacement Program	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Various pole and tower refurbishment	**2.2**	**2.0**	**2.0**	**2.1**	**2.1**	**10.3**

Transmission Tower Earthing System Refurbishment Program

Transmission tower earthing systems are integral to the safe operation and reliability of the transmission network, particularly in urban populated areas, and due to the extreme lightning experienced in the northern region. During storms direct strikes to transmission lines are common. As the performance of earthing systems deteriorate, hazardous step and touch voltages will rise. A secondary issue of insulator back-flash also occurs, damaging insulators affecting their performance over time and enabling corrosion to start on damaged metal parts due to the loss of galvanizing.

Recent condition assessments of tower earthing systems have identified consistent poor performance, indicating that earthing systems have been damaged physically or due to corrosion, reducing their performance. A large proportion of transmission insulators also have observed back-flash damage reinforcing the assessment that earthing performance is poor on many towers. The proposed program includes the refurbishment of tower earthing components, including below ground earthing conductors and potential changes to insulator configuration to reduce back-flash damage where earthing performance required by current Australian standards is not achievable due to soil conditions or changes to infrastructure since original installation.

Transmission Tower Corrosion Protection Life Extension Program

Replacement of the corrosion protection of 50 of the oldest transmission towers in the Darwin area is required to extend their life. Structural inspections performed identified that the original galvanizing of 69 per cent of the 72 towers inspected was reaching end-of-life, or had already reached end-of-life, at the time of inspection.

Replacement of corrosion protection prior to end-of-life prevents loss of steel section that may compromise the structural integrity of the towers. It also reduces the cost and increases the longevity of the protection system as no action is required to remove established corrosion which requires more aggressive blasting, and subsequent environmental controls (pollution, noise) in what are typically urban areas of Darwin.

Darwin Coastal Pole Top Corrosion Replacement Program

Poles in Darwin's urban foreshore suburbs are at highest risk of above ground corrosion due to the tropical climate and proximity to salt water. They are also more exposed to severe weather events such as tropical lows and cyclones. The majority of poles in the network that pre-date Cyclone Tracey are located in these areas. The number of steel LV and HV crossarms identified with advanced corrosion has been consistent in recent years, however the level of corrosion is very difficult to identify visually until complete loss of section has occurred i.e. when holes in crossarms are visible. The program will involve the targeted replacement of crossarms at highest risk of corrosion based on age, proximity to the coastline and recent observed corrosion areas. New procedures are being developed to efficiently identify crossarms at risk.

Transmission Line Pole Top Corrosion Replacement Program

Corroded insulators on the critical 132kV lines connecting Hudson Creek substation to the Channel Island Power Station, as well as crossarms on the 66kV line between Strangways substation and the Weddell Power Station are being targeted for replacement. Specific risks associated with crossarm and insulator failure include:

- Risk to personnel regularly climbing towers and poles to perform detailed inspections, conduct maintenance or emergency repairs;
- Public safety risk arising from failure of towers and pole top structures resulting in serious injury (or death) to the public or damage to property; and
- System security risks associated with loss of either 132 CI-HC Line A & B lines as critical connection points between Channel Island power stations and Darwin network.

Various power transformer replacements

Four projects have been identified to replace power transformers across our substation sites. Due to the poor condition and explosive failure risk of the remaining items of plant at these substation sites, additional replacement of switchgear, control and auxiliary equipment has also been included for some sites as shown in Table 6-11. Further details are provided in the capex supporting information, specifically the AMP – Transformers.

Table 6-11 – Various power transformer replacements ($M, Real 2018-19)

Project/Program	2019-20	2020-21	2021-22	2022-23	2023-24	Total
BNI 10 Darwin – Replace Humpty Doo ZSS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BNI 7 Darwin Replace 66/11kV Centreyard ZSS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BNI 4 Darwin – Replace Cosmo Howley Transformers	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BNI 33 Pine Creek 132kV Transformer Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Various power transformer replacements	**0.5**	**1.8**	**5.5**	**2.5**	**0.0**	**10.3**

We manage 74 power transformers located in 32 separate zone substations. The transformers have primary voltages ranging from 132kV down to 11kV and capacities from 125 MVA down to 0.5MVA. The power transformer asset class is a significant proportion of our assets and drives several inspection and maintenance activities. This is due to the criticality of the assets and the aggressive nature of the environment in which they are located.

Deterioration of the paper insulation inside transformers is the primary driver for transformer failure. The deterioration is measured through oil analysis and the presence of trace chemicals. When moisture dissolves into transformer oil, it acts to accelerate the rate of paper deterioration, measured by assessing the paper's degree of polymerisation (DP). The high humidity and rainfall in the NT increases the ability of water to dissolve into the transformer oil. As transformers age and corrode or seals deteriorate, the ability of water to ingress into the transformer increases, further deteriorating the transformer.

Operational measures such as oil filtering to remove contaminants (predominately water, but also other contaminants) are undertaken. Once saturated however, intensive oil filtering of transformers is not effective at removing moisture as proven after multiple attempts in the Humpty Doo Zone Substation. Online oil filtering has been successful at preventing moisture increases if installed with the transformer prior to commissioning or early in its life. For older saturated transformers in the network, online filtering equipment has not proved as successful as reported by other Australian utilities, however this has been linked to filters not operating reliably in Darwin's tropical climate.

The asset health and criticality framework has been applied to the power transformer asset class to provide the basis for calculating the risk associated with these assets.

The remaining life is calculated based on the full data set of asset age and DP values for in service and decommissioned transformers. A regression of the data is taken to determine the relationship between age and condition for transformers in the environmental and operational circumstances of the NT.

The effective age of each transformer is calculated in the same manner and the remaining life is calculated based on the 53 year life expectancy. [23]

Six of the transformer fleet have less than 10 per cent (i.e. less than five years) of their life remaining, and these transformers have been targeted for priority replacement in the next regulatory period.

Various protection and control projects

In addition to inclusion of an asset class replacement program for our protection and control relays, we have identified a specific project to replace protection and control relays on our radial Darwin to Katherine 132kV transmission line. Further details are provided in the capex supporting information, specifically the AMP – Protection.

Table 6-12 – Various protection and control projects ($M, Real 2018-19)

Project/Program	2019-20	2020-21	2021-22	2022-23	2023-24	Total
BNI 3 Darwin – Upgrade DKTL Secondary Systems	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BNI 19 Protection Relay Replacement Program	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Various protection and control projects	**2.9**	**3.3**	**0.8**	**0.8**	**0.8**	**8.5**

Upgrade DKTL Secondary Systems

The Darwin to Katherine 132kV Transmission Line (DKTL) runs from Channel Island Power Station to Manton, Batchelor, Pine Creek and Katherine Zone Substations. It was constructed in 1986 and predominantly contains original secondary systems equipment. Secondary systems are critical to maintaining the security and reliability of the electricity network and supply to customers.

As identified in the corresponding asset management plan, the protection and control relays on this transmission line are:

- operating beyond the design life;
- operating outside of rated tolerances;
- end of serviceable life;
- obsolete relay technology; and
- high level of component failures.

[23] The regression calculated the expected life of a transformer to be 53 years based on reaching a DP value of 200.

Targeted replacement of the highest risk secondary systems of the DKTL transmission line to be completed by June 2021 to limit risk to the system and manage assets at the end of life. As part of this work, standard technologies will be applied and relevant substations upgraded to modern design standards for the secondary systems. The Manton, Pine Creek and Katherine zone substation sites require most of the corrective works.

Protection Relay Replacement Program

Historically, the majority of relay replacement works were included in our substation replacement and refurbishment activities. As these projects are completed, and the asset management focus has shifted to a targeted asset replacement and refurbishment, a dedicated protection relay replacement program has been developed to replace selected schemes for:

- distribution feeder/transformer OCEF Static relays;
- transformer differential;
- distance protection; and
- bus tie relays.

Other minor projects

Four projects have been included that address targeted asset replacement, where the condition of the nominated assets is considered to present an unacceptable level of risk, for the safety of the public and our workforce, and to maintain current levels of service. The projects are listed in

Table 6-13, with full details provided in the associated capex supporting information.

Table 6-13 – Other minor projects ($M, Real 2018-19)

Project/Program	2019-20	2020-21	2021-22	2022-23	2023-24	Total
BNI 24 Single phase substation refurbishment	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BNI 14 66kV HLC Circuit Breaker Replacement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BNI 15 Substation Fire Protection Equipment Replacement Program	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BNI 27 Substation DC System Replacement Program	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Other minor projects	**1.1**	**1.2**	**1.2**	**0.8**	**0.7**	**5.0**

6.5.3 Compliance-driven projects

Two projects have been included to meet our compliance obligations with the Network Technical Code and Network Planning Criteria totaling $6.1 million as shown in
Table 6-14.

Table 6-14– Compliance driven Repex ($M, Real 2018-19)

Project/Program	2019-20	2020-21	2021-22	2022-23	2023-24	Total
BNI 22 Darwin Lake Bennett Conductor Clearance Rectification Program	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BNI 18 SCADA and Communications Compliance and Safety Program	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total compliance driven repex	**2.6**	**1.9**	**1.1**	**0.3**	**0.3**	**6.1**

Lake Bennett conductor clearance rectification

The Lake Bennett feeder is in breach of statutory safety standards and is in poor condition. The feeder was constructed in the mid-1970's and recent investigations[24] called to attention a range of defects, including failure to meet safe ground clearance, burnt conductor damage, single and multiple broken strands, and conductor corrosion. The investigation found that, on average, the low clearance standard is exceeded by 0.8 metres and up to a significant 1.9 metres in some instances. The investigation also found that the feeder fails to meet minimum ground clearance with between 2.0 metres and 2.3 metres at most road crossings inspected.

A program is proposed to raise the conductor to the required statutory clearance levels for those spans determined to be in breach of the minimum requirements. Due to the current condition of the conductor, and operational difficulties associated with working on the type of construction, the conductor will be upgraded to align with the current design standards. This will require replacement of the remainder of the conductor on the line.

SCADA and communications compliance and safety program

Several substation sites have been determined to be in breach of the Network Technical Code and Network Planning Criteria[25] because they do not meet the required diversity in the communication paths that are required for independent protection schemes. Currently, the identified zone substations have both communications paths provided by a single fibre or microwave radio link. Loss of the single fibre or microwave link will result in the loss of both protection services between the zone substations, which could result in the requirement to take the powerline out of service until the protection

[24] Completed in August 2017.

[25] Refer section 2.9.2 of the Network Technical Code and Network Planning Criteria.

services are fully restored. Adding an additional communications path will allow the provision of two fully independent protection services for the plant at each zone substation.

6.5.4 Reliability and quality of supply projects

A reliability and quality of supply project has been included to target improvement to the reliability of the worst performing feeders on our network. It is not expected that targeted improvements to poorly served customers will lead to improvements to overall network performance, but rather, contribute to addressing deteriorating performance and maintaining current performance.

The proposed expenditure is separated into a repex components and an augex component. The repex component shown in Table 6-15 is $2.7 million of the total of $7.1 million.

Table 6-15– Reliability and Power Quality driven ($M, Real 2018-19)

Project/Program	2019-20	2020-21	2021-22	2022-23	2023-24	Total
BNI 28 Poor performing feeder program	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Reliability and power quality driven repex	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

As noted in section 2.2, customer feedback received during engagement program supported improving performance for poorly served customers.

Performance of individual feeders will be analysed annually to identify the feeders or feeder areas with poorly served customers based on the performance ratio between average performance and poorly performing feeders. This approach also allows for consideration of the impact of other asset replacement program on reliability, ensuring solutions are delivered as efficiently as possible.

A range of solutions are employed to provide reliability improvement including:

- sectionalising feeders using automatic protection devices to reduce customers affected by outages;
- automating field switching devices to improve fault finding and restoration times;
- installing additional protection or guards to prevent vermin contacting lines;
- replacing open wire lines with insulated or covered conductors;
- upgrading of pole top hardware to improve insulation levels;
- improving the resilience of infrastructure to storm and bushfire damage through removal of hazard trees; and

- introducing “smart” feeder analysis to perform predictive analysis of developing faults to identify and possibly prevent developing asset failures.

7. Augmentation capex

This section explains and justifies our augex forecast.

7.1 Purpose and scope

Augex is required to manage network capacity constraints in our network system due to growth in maximum demand as well as compliance power quality and performance. These activities include upgrades in our low voltage networks, distribution substations, high voltage feeders, zone substations and transmission systems.

Our augex is forecast to allow us to maintain our asset utilisation rates at appropriate levels, and so that we can meet our safety, reliability, security of supply and other compliance obligations.

There are three categories of augex:

- *Load driven* – projects to meet electricity demand as forecast by AEMO;
- *Compliance driven* – projects to meet the requirements of the Network Technical Code and Network Planning Criteria; and
- *Reliability and power quality driven* – projects to meet a reliability and power quality obligation or technical standard, including in response to customer feedback.

7.2 Overview of key drivers

7.2.1 Localised demand growth

As noted in our Capital Investment and Delivery Policy, the key driver of augex is growth in maximum demand caused by population growth or specific development within localised parts of our distribution network where there are forecast to be capacity constraints.

We commissioned AEMO to prepare and document a maximum demand forecast to support our regulatory proposal – see section 9 of the regulatory proposal document. AEMO's report identifies the following drivers of maximum demand in our three networks:

- Darwin-Katherine:
  - is a wet season peaking network with high air-conditioning load;
  - residential and commercial PV is expected to grow between 2017 and 2027 from 10 per cent to 30 per cent of maximum demand, which is

expected to push maximum demand later in the day by two to three hours;
- maximum demand is forecast to decline to 2020 as large industrial load moves to self-supply and then to decline slightly throughout the next regulatory period as PV penetration increases; and
- AEMO forecasts positive growth over the regulatory period at four zone substations due to new industrial and residential development, but negative growth at our other zone substations[26].

- Alice Springs:
  - is a summer peaking network with both cooling and heating load;
  - residential and commercial PV is expected to grow between 2017 and 2027 from 20 per cent to 40 per cent of maximum demand, which is expected to push maximum demand later in the day by an hour; and
  - AEMO forecasts declining demand over the regulatory period due to regional population changes and increasing penetration of PV.[27]

- Tennant Creek:
  - is a summer peaking network with both cooling and heating load;
  - residential and commercial PV is expected to grow between 2017 and 2027 from 3 per cent to 7 per cent of maximum demand; and
  - maximum demand is forecast to remain flat until 2018, and then, with the introduction of a relatively large load, to grow by about 2MW between 2018 and 2019 and to remain flat thereafter.[28]

We have targeted projects in the areas of localised growth in the demand forecast as shown in Figure 7-1, specifically the Wishart and Archer zone substations where capacity constraints will exist.

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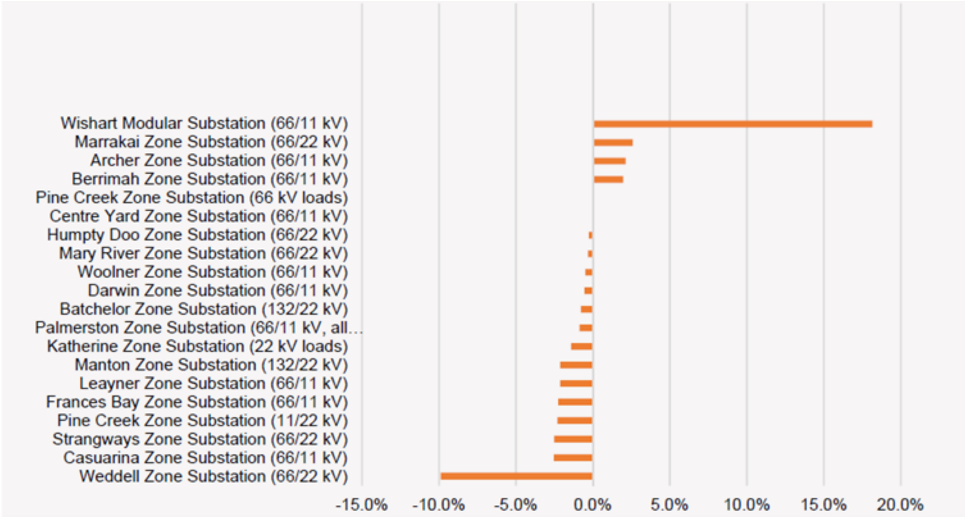
[26] AEMO, Power and Water Corporation – Maximum Demand, Energy Consumption and Connection Forecasts – 2017 Implementation of Forecasting Procedure, September 2017, page 10.

[27] Ibid, page 14.

[28] Ibid, page 20.

Figure 7-1 – Demand forecast by zone substation



7.2.2 Compliance with Network Technical Code and Network Planning Criteria

We regularly review compliance with the Network Technical Code and Network Planning Criteria, as part of our annual planning process. As the network information and asset data has been improving, our annual planning review has identified areas of non-compliance with our technical requirements and obligations.

As with our repex planning, we have undertaken detailed investigations of these areas of non-compliance, and have developed targeted augex projects and programs to mitigate the highest areas of risk on a prioritized basis, whilst ensuring we adhere to strict safety requirements and maintain our service performance. These include low ground clearance; fault level upgrades, and network security analysis.

7.2.3 Meet and manage our reliability and power quality obligations

We are committed to maintaining the average service performance across our network, consistent with the capex objectives in clause 6.5.7 of the NT NER.

Since implementing the reliability improvement program during the current regulatory period, our reliability metrics have stabilised, and the trend is considered reflective of underlying reliability performance. We continue to report the five worst performing feeders and associated actions for each reliability category, and we monitor this performance closely.

As discussed in section 2.2, customers and other stakeholders supported a program to target areas of poor performance. Consequently, we propose addressing this as part of our capex forecast for the next regulatory period.

7.2.4 Increasing connection of solar PV systems

We are experiencing a steady increase in the uptake of solar PV panels connecting to our network, both domestically and commercially. This is particularly pronounced in Alice Springs, which has historically been part of the Solar Cities program. This increased uptake of solar panels is causing voltage issues in the low voltage distribution network where the changes to traditional voltage profiles are impacting the ability of the network to maintain adequate voltage regulation. For example, the legacy distribution transformers in the network are designed predominately for boosting voltages and contain minimal buck taps as required to managed bi-directional power flow.

The AEMO demand forecast assumes that by 2026-27 PV installation will increase to 15 per cent of households in Darwin-Katherine network and 20 per cent of households in the Alice Springs network.

During the current regulatory period we have implemented several operational changes to defer capital investment if possible and reduce operational expenditure. However, based on the forecast installation of the PV system, augmentation work is required in localised areas.

Current and emerging issues that have been identified on the network and projects and programs developed to target high risk areas, including areas of non-compliance, are discussed below. Further information and analysis is contained in the Power Quality Management Plan.

7.2.5 Flat demand profile limits traditional demand management opportunities

The demand profile across our Darwin-Katherine network is reasonably flat and is generally consistent across each day, with a load factor of more than 60 per cent. Daily peak demand is also reasonably flat and consistent between 8am and 10pm, and is driven largely by the use and continual operation of air conditioners. This indicates that all assets are utilised reasonably consistently and therefore it is more difficult to remove assets from service for prolonged periods of time and exploit traditional opportunities for load shifting and demand management.

During the wet season the load profile becomes flatter (more consistent) with less difference between the peak and the trough and the demand is about 10 per cent higher.

We are continuing to investigate and develop demand management opportunities as an option for the deferral of expenditure in response to changing consumer behaviours on our network. Currently, the coincidence of the peak PV generation with the system peak demand is providing an efficient, broad scale demand reduction at the regional level.

7.3 Forecasting method

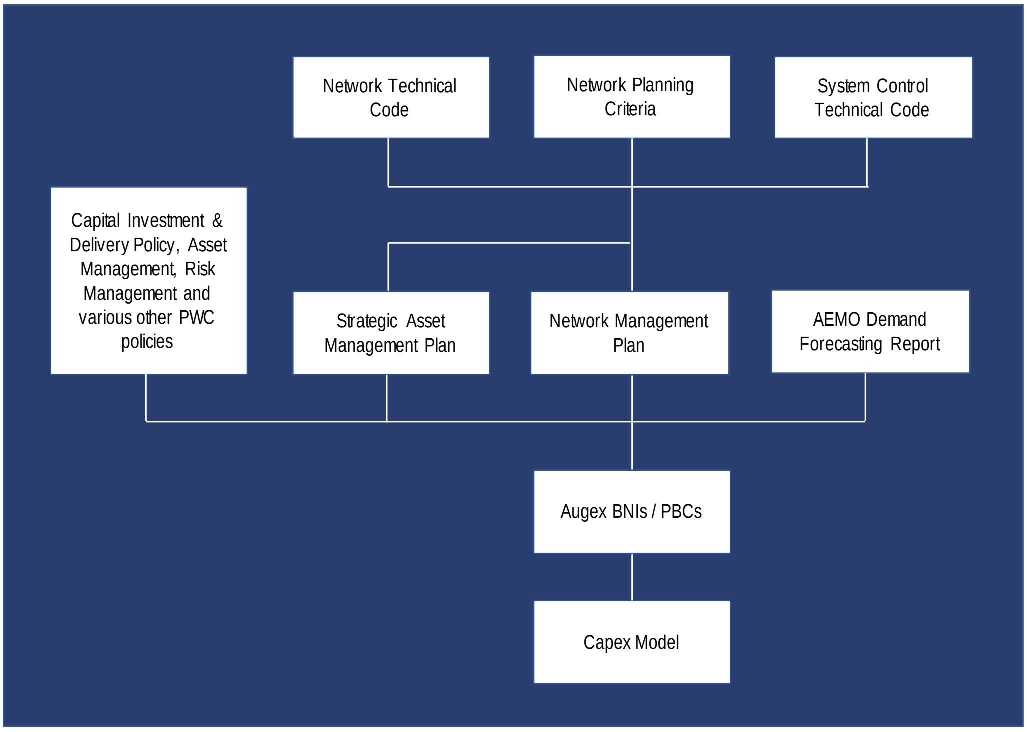
We have used three methods to forecast our augex:

- *Method 1 – Scoped Capex* | We have forecast some of our augex on an individual project basis. This is for any large, projects that we can scope and cost on a discrete basis. Projects have been designed to meet jurisdictional planning criteria and other regulatory obligations;
- *Method 2 – Programmed capex* – this capex is forecast based on programs of work for different asset classes. Forecasts are based on a build-up of volumes and unit costs. We use a variety of techniques to forecast both volumes and unit costs, depending on the asset class; and
- *Method 3 – Pooled Capex* | For some asset categories it is not feasible to base forecast augex using scoped projects. In these cases, we have forecast our required capex based on our historical augex expenditure.

7.4 Key supporting documents

Figure 7-2 illustrates the relationship between the key documents that support our Augex forecast

Figure 7-2 – Augex key supporting documents



Our augex forecast has regard for, and gives effect to, the following documents:

- *Network Technical Code and Network Planning Criteria* – The Northern Territory Electricity Networks (Third Party Access) Code (Network Access Code) is established in Part 2 of the *Northern Territory Electricity Networks (Third Party Access) Act* (TPA Act). Clause 9(2) of the Network Access Code requires the network provider to prepare and make publicly available a:

  - *Network Technical Code* | This sets out technical requirements designed to ensure that the network and the customer installations and equipment connected to the network may be operated and maintained in a secure and reliable manner; and
  - *Network Planning Criteria* | These are designed to ensure that new loads and generators connected to the network do not compromise the security and reliability of supply to all network users.

- *System Control Technical Code* – This sets out:
  - requirements to achieve a secure system;
  - procedures for generation plant scheduling and ancillary services;
  - requirements for the operation of a power system and connected equipment;
  - requirements on system participants so the interconnected power system complies with the Network Technical Code and Network Planning Criteria; and
  - provisions for the operation and administration of I-NTEM for the Darwin-Katherine system.

- *Policy documents* – As discussed for repex, these documents set out our internal policies, including for example in relation to capital investment and delivery, governance, asset management, risk management, security, health and safety, emergency, environment and sustainability.

- *AEMO demand forecasting report*[29] – We commissioned AEMO to prepare this report to state the key modelling outcomes and underlying assumptions that it adopted in implementing the *2017 PWC Maximum Demand and Customer Connections Forecasting Procedure*. AEMO specifically implemented this procedure to develop demand forecasts to be submitted to the AER with our Regulatory Proposal for the next regulatory period.

We have two key plans that are relevant to our augex forecast:

- *SAMP* – As discussed for repex, this document describes how our systems and strategies deliver on our Asset Management Policy. It aligns our stakeholders' requirements, organisational objectives and our resulting asset management objectives so that our assets are managed and operated prudently and efficiently; and

- *NMP* – As discussed for repex, this provides the analysis of our network about our network reliability, capacity, security and supply quality. The original intent of the document was to provide our stakeholders with an

[29] AEMO, Power and Water Corporation – Maximum Demand, Energy Consumption and Connection Forecasts – 2017 Implementation of Forecasting Procedure, September 2017

insight into the challenges that we face and how we intend to respond. The document also outlined general investment intentions, technical data, demand forecasts and network performance, including outage performance, utilisation and security. With the transition to the AER, the function of the NMP is being refined to focus predominately on the technical network data and capability of the interconnected assets. Other documents, such as the DAPR will fulfil the original intent of the NMP of providing published information about our network.

The following documents and models demonstrate, validate, explain and justify our augex forecast:

- *BNIs and PBCs* – As discussed for repex, these documents provide supporting information about individual projects and programs that are included in our capex forecast. Section 7.5 lists the BNIs and PBCs that are relevant to our augex forecast; and
- *Capex model* – As discussed for repex, this model is an Excel spreadsheet that calculates and supports our capex forecast.

7.5 Augex forecast

Table 7-1 breaks down our augex forecast for each year of the next regulatory control period.

Table 7-1 – Augex forecast ($M, Real 2018-19)

Project/Program	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Load driven	2.9	1.2	10.7	11.8	10.6	37.3
Compliance driven	3.0	3.0	2.3	4.2	2.3	14.8
Reliability and quality of supply driven	1.5	1.5	2.5	1.5	1.5	8.5
Total Augex	7.4	5.8	15.5	17.6	14.4	60.6

Table 7-1 shows that the majority of our augex (62 per cent) is comprised of load-driven projects in response to growth in electricity demand in localized parts of our network.

7.5.1 Load-driven projects

Our forecast load-driven augex projects and programs contained are detailed in Table 7-2. These projects are in response to the AEMO demand forecast discussed in section 7.2.1. An overview of the largest projects and programs is provided in the following sub-sections.

Table 7-2 – Load driven Augex projects ($M, Real 2018-19)

Project/Program	2019-20	2020-21	2021-22	2022-23	2023-24	Total
A-BNI 1 Darwin - Construct Wishart Zone Substation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
A-BNI 8 Overloaded Feeders / Distribution Augmentation Program	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
A-BNI 2 Darwin - Archer ZSS Augmentation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
A-BNI 11 Tennant Creek - Upgrade Tennant Creek 22/11kV Transformers	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Load driven augex	**2.9**	**1.2**	**10.7**	**11.8**	**10.6**	**37.3**

Darwin - Construct Wishart Zone Substation

Peak demand in the areas surrounding the existing Berrimah Zone Substation has been increasing steadily over the last ten years due to the connection of customers in new and existing commercial and industrial estates. Load in the Berrimah /Wishart area is expected to increase through to the wet season of 2021.

A mobile 'NOMAD' 10MVA substation[30] was established at Wishart in 2015 to support forecast load growth in the Wishart and East Arm (port) areas, providing needed voltage support and provide alternate supply capacity in the event of a transformer failure at Berrimah Zone Substation.

The NOMAD mobile substation has prudently deferred the installation of a new substation at Wishart or a third transformer at Berrimah Zone Substation. Without additional transformer capacity in the Berrimah/Wishart load area, there is insufficient firm capacity to meet forecast load growth beyond the time that the replacement Berrimah Zone Substation is commissioned.[31] As detailed in the AEMO demand forecast (and as discussed in section 7.2.1), the Wishart and East Arm areas are undergoing significant growth over the next regulatory period.

The proposed project will establish a permanent Wishart zone substation to follow the commissioning of the new Berrimah Zone Substation (in 2021). The replacement Berrimah Zone Substation and the new Wishart Zone Substation will most effectively meet the growing area demand and maintain security requirements.

[30] NOMAD 1 x 66/11kV 10MVA mobile substation.

[31] The replacement project proposes 2 x 20/27MVA transformers.

Overloaded feeders / Distribution augmentation program

Works over the past five years has significantly reduced the number of overloaded feeders under normal conditions. However, there are a larger number of feeders that are overloaded beyond planning levels under contingency conditions and areas of localized growth where feeder overloading is forecast to occur under normal conditions.

As a part of the forecasting process, the 5-year HV feeder forecast is annually reviewed for possible overloading under normal conditions and contingencies to ensure compliance with the Network Technical Code and Network Planning Criteria, and projects are prioritised for action. The short lead time of block loads of only one to two years in advance of connection further complicate this process.

Feeder overloading is managed through various methods of demand management and augmentation to ensure the most cost effective method is applied.

Darwin - Archer Zone Substation augmentation

The load growth in the Palmerston area has averaged 5.5 per cent per annum from 2011 to 2017 and is the largest localised growth area in the NT.

The significant growth in the City of Palmerston is projected to continue into the near future, with several land developments near completion, including: Gateway Shopping Centre, Palmerston Hospital, Wishart Industrial Estate and continued residential expansions of the new suburbs of Zuccoli and Mitchell Creek. As detailed in the AEMO demand forecast in section 7.2.1, significant localized growth is forecast for the Palmerston/Archer load area over the next regulatory period.

We will defer installation of a third 66/11kV, 20/27 MVA transformer and a new 11kV switchboard section at Archer Zone Substation by connection and operation of the NOMAD transformer. The NOMAD substation will cater for the increased demand in the Palmerston area and provide a reliable supply during prolonged credible contingency events.

7.5.2 Compliance-driven projects

The major projects and programs contained in the Compliance-driven augmentation expenditure is shown in Table 7-3. A summary of the largest projects and programs is provided in the following sub-sections.

Table 7-3 – Compliance-driven Augex projects ($M, Real 2018-19)

Project/Program	2019-20	2020-21	2021-22	2022-23	2023-24	Total
A-BNI 9 Darwin distribution substation fault level replacement program	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
A-BNI 4 Darwin - transmission line uprating	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
A-BNI 12 SCADA and communications Optus cable extension program	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
A-BNI 7 Darwin - Hudson Creek spare 132kV transformer	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
A-BNI 15 Power transformer online moisture treatment	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Compliance driven augex	**3.0**	**3.0**	**2.3**	**4.2**	**2.3**	**14.8**

Darwin distribution substation fault level replacement program

Development of the network over time has resulted in an increase of fault levels across the distribution network. Single phase fault levels have been mitigated through the installation of Neutral Earthing Resistors (NER) at most zone substations, however three phase fault levels have increased with additional generation and transformation capacity.

The network currently includes some 11kV switchgear installations where the system fault levels exceed, or are encroaching on the equipment rating.

This project will upgrade installations where the distribution switchgear no longer meets the minimum system fault levels. The affected switchgear is mainly located in the Darwin region, with the majority installed in the distribution areas of Palmerston and Darwin City. These areas are characterised by high pedestrian traffic, and therefore high safety consequence associated with explosive switchgear failure. The risk of catastrophic equipment failure and the potential injury to workers and the public are key drivers for investing in the replacement of this switchgear.

As a responsible network operator worker safety, public safety and supply reliability are fundamental to our investment decisions. Additional benefits from this investment include maintaining network reliability, and compliance with the requirements of the Network Technical Code and Network Planning Criteria.

Darwin - transmission line uprating

As the development of Darwin and surrounds has occurred, some transmission line sections have been identified as not complying with statutory line clearances to ground, presenting an unacceptable safety risk. Some crossings have been addressed in the current period, and a survey of each transmission line undertaken to confirm the full extent of the issue. The information collected will be incorporated into a capacity model to identify maximum line ratings and minimum ground clearances by simulating a range of system and weather conditions. Accordingly, sections of transmission lines that are posing the greatest safety risk will be rectified to ensure compliance with statutory line clearances to ground. These upgrades will also have the advantage to defer future capital replacement or construction of new transmission lines and reduce system and market constraints.

Darwin - Hudson Creek spare 132kV transformer

Hudson Creek is a critical hub for the supply of electricity to the Darwin region. It connects the generation centres of Channel Island and the Darwin Katherine Transmission line to the greater Darwin region load. The existing network can operate with two out of the three 132/66kV transformers at Hudson Creek in service (N-1) but a second event would result in loss of load throughout the Darwin area as there is insufficient capacity available from Weddell Power station, or any other supply points.

As a result, the current network design does not comply with the Network Technical Code and Network Planning Criteria. The long lead time associated with manufacturing and installation of a replacement transformer (12 to 18 months) presents an unacceptable level of risk associated with an N-2 event at this site.

The reliance on Hudson Creek substation for maintaining supply to the network poses a unique risk. A project has been included to source a strategic spare transformer for this site to mitigate the risk of extended supply interruptions in the event of a N-2 event, as the most prudent and efficient solution to mitigate this risk and ensure compliance.

Power transformer online moisture treatment

The climatic conditions experienced in the NT because of the tropical monsoons, which bring high humidity and high rainfall, result in an extreme challenge in limiting the water content in power transformer insulating oil. Over time, the presence of high water levels in the insulating oil will reduce the serviceable life of the transformer through the degradation of the paper.

All new transformer installations have online oil filtering as a standard requirement, and it has been shown to reduce maintenance costs and provide other operational benefits. A project has been included to install new water filtrating devices to those sites that do not comply with the current design standards, to reduce the water content in the insulating oil that will provide a reduction in operational expenditure and maximise the asset life. This has been included in Augex rather than Repex as these sites have not previously had online oil filtering installed.

7.5.3 Reliability & power quality-driven projects

The major projects and programs contained in the reliability and power quality-driven replacement expenditure is shown in Table 7-4. An overview of the largest projects and programs is provided in the following sub-sections.

Table 7-4 – Reliability & power quality-driven projects ($M, Real 2018-19)

Project/Program	2019-20	2020-21	2021-22	2022-23	2023-24	Total
A-BNI 13 All Regions Poorly Performing Feeder Improvement Program (Augex Component)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
A-BNI 5 Power quality compliance program	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
A-BNI 3 Katherine Voltage Rectification	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Reliability and power quality driven	**1.5**	**1.5**	**2.5**	**1.5**	**1.5**	**8.5**

Poor performing feeder improvement program

A reliability and quality of supply project has been included to target improvement to reliability of the work performing feeders on our network. It is not expected that targeted improvements to poorly served customers will lead to improvements to overall network performance, but rather, contribute to addressing deteriorating performance or maintaining current performance.

As discussed in section 6.5.4, the proposed expenditure is separated into a repex component and an augex component. The augex component represents $4.4 million of the total of $7.1 million.

As noted in section 2.2, customer feedback received during engagement program improving performance for poorly served customers. Following analysis of the performance of individual feeders, a range of solutions are employed to provide reliability improvement, as discussed in section 6.5.4.

Power quality compliance program

We must comply with the quality of supply requirements, principally concerning voltage management to enable customers' electrical equipment to function as designed and without damage or reduction in expected service life. We have developed a set of program initiatives to meet the current regulatory requirements, including maintaining statutory voltages within Australian Standards (AS 61000). We will focus on addressing the worst performing areas on the network, including in response to growth of solar PV.

The bulk of power quality issues emerge on the LV distribution network. We have identified solutions to address these emergent issues, including:

- LV network (distribution) augmentation;
- 11kV voltage set point reduction;
- install reactive or capacitive compensation; and
- investigations and corrective works.

The ongoing management of power quality issues is challenging due to the complexity of the issues involved, and the disproportionate impact that many of these issues have on the low voltage networks in the NT.

In addition to the above projects, a reactive compensation project (PRK31430) will address the high voltages experienced in the Katherine area, specifically in the 22kV and 415V networks because of the voltage levels on the 132kV transmission line. This is due to the lack of additional voltage regulation available in these networks.

8. Connections capex and customer contributions

This section explains and justifies our forecast for our Connections capex and customer contributions. We provide further detail in our “Connections Capex Justification Document” – Attachment 7.1.

8.1 Purpose and scope

Connections capex is required to service new, altered or upgraded connections for residential, commercial and industrial customers. This comprises:

- capex that we directly incur ourselves, the cost of which we recover from our customers through cash contributions in accordance with our proposed Customer Connection Services Policy;[32] and
- gifted assets that are built by third parties and given to us to operate and maintain.

We therefore receive two types of customer contributions – cash contributions and gifted assets.

8.2 Overview of key drivers

Unlike our other capex categories, our customers determine the nature, quantum and timing of our connections capex. Connections are therefore strongly correlated with the level of economic activity.

In accordance with the AER’s RIN, we have presented our forecast expenditure as a gross amount by not excluding customer contributions from the forecast. The forecasts exclude overheads.

8.3 Forecasting method

We forecast our gross connections capex using the following steps:

- We developed a unit cost per connection type based on our 2016-17 aggregate cost per connection type, divided by the number of connections per customer type;[33]
- We developed the annual volumes per connection type based on AEMO’s forecast.[34] The AEMO report is based on 10 years of history and applies

[32] Power and Water Corporation, Customer Connection Services Policy, 2017.

[33] This is an “off the point” value on the basis that it is the most recent and reliable data. Further, a sensitivity check was undertaken using a 4-year average which resulted in a 10 per cent increase over the “off the point” value.

[34] AEMO, Power and Water Corporation – Maximum Demand, Energy Consumption and Connection Forecasts – 2017 Implementation of Forecasting Procedure, September 2017.

regression coefficients based on gross state product and population. AEMO's connections forecast categories are different to the connection categories used by the AER and ourselves. The year-on-year incremental changes in customers was converted to an annual percentage change and applied each year, starting from 2017 as the base year; and

- We developed a forecast for gifted assets based on 2016-17 values. These are predominantly provided via real estate developers. History indicates that there is not a close correlation between gifted assets and connections capex.

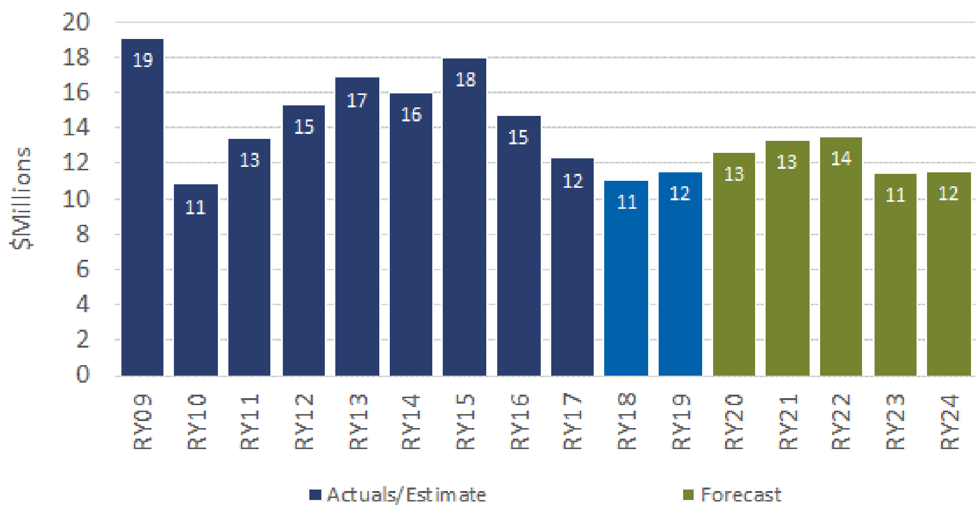
8.4 Connections capex forecast

Table 8-1 details our forecast gross connections capex (including gifted assets) for our next regulatory control period. Figure 8.1 details the trend in our connections capex over the period 2008-09 to 2023-24.

Table 8-1 – Forecast connections capex including gifted assets 2019-20 to 2023-24 ($M, Real 2018-19)

	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Connections (including gifted assets)	12.65	13.38	13.56	11.49	11.59	62.67

Figure 8.1 – Historical and forecast connections capex and gifted assets 2008-09 to 2023-24 ($M, Real 2018-19)



Our forecast connections capex including gifted assets is 8 per cent lower than our expected expenditure for the current regulatory period. This is driven by the AEMO connection volumes forecast.

Our gifted assets are largely consistent with the current period. Our cash contributions are forecast to be higher than the current period, reflecting the changes in our proposed Customer Connection Services Policy – PWC07.2, under which we will essentially fully recover the costs of our connection works.

9. Non-network ICT capex

This section explains and justifies our Non-Network ICT capex forecast. We provide further detail in our our ICT Capex Plan.

9.1 Purpose and scope

Our Non-network ICT capex includes:

- ICT sourced directly by our Power Network business unit; and
- the share of our corporate ICT attributed, or allocated, using our CAM to our Power Networks' business unit that relate to our distribution services.

Our Non-network ICT capex forecast covers:

- upgraded existing enterprise-wide systems, including our retail management system (billing system), financial management system and asset management systems;
- new capability that builds on existing platforms where possible, including systems for:
  - customer relationship management;
  - meter data management;
  - network planning;
  - works management (investment planning, dynamic works scheduling, mobility solutions, integrated project portfolio management);
  - outage management;
  - business management (including estimation and quote management; operational risk reporting, drawing management system);
  - business to business solution;
  - RIN data collection; and
  - SCADA and communications.
- the maintenance of existing software and hardware to minimise operational risk.

Our Non-network ICT capex excludes ICT-related capex for our SCADA, network control and metering.

9.2 Overview of key drivers

ICT for the electricity industry is undergoing rapid changes. To continue to align ICT with business needs, we have developed an ICT Strategy[35] for the next ten years that is built on four key objectives:

- enhance the return on investment for existing ICT systems;

[35] Power and Water Corporation, ICT Strategy, 2017

- develop common applications for whole-of-enterprise challenges to support needs such as mobile computing;
- implement supplementary business applications as necessary to support individual business units; and
- continue to leverage NT Government for ICT foundation services, such as desktop, data centre, and telephony.

We expand on these key objectives in our ICT Strategy, which we have provided to the AER with our regulatory proposal.

We have presented our Non-network ICT capex for the next regulatory period in the three categories[36] as set out in the AER's Reset RIN. Table 10-1 details these three categories and their key drivers.

Table 9-1 – Non-network ICT capex categories and drivers

ICT category	Key driver
ICT asset extensions	Extend existing ICT assets to broaden their functionality.
ICT asset replacement	Replace an existing ICT asset with its modern equivalent where the asset has reached the end of its economic life.
ICT capability growth	Acquire, develop and implement new ICT assets to meet a business purpose or capacity requirement.

We have also grouped our Non-network ICT capex forecast against the primary business driver:

- *Network Operations* – This covers network planning, works management, outage management, network business management, system operations and RINs;
- *Remediate the Core* – This covers our revenue management system, financial management system and asset management systems (i.e. Maximo and ESRI upgrade);
- *ICT Application and Infrastructure Refresh* – This covers refreshes of our enterprise application and enterprise infrastructure;
- *Customer service* – This covers our customer relationship management and meter data management systems; and
- *Enterprise* – This covers our data and reporting program.

[36] We have not forecast any ICT asset remediation capex, which is the fourth ICT capex category included. Minor operating lease and minor capex are treated separately.

9.3 Forecasting method

We have used three approaches to forecast our Non-network ICT capex:

- *Method 1 – Scoped Capex* – We have forecast some of our Non-network ICT capex on an individual project basis. This is for any large, discrete projects that we can scope and cost on a discrete basis;
- *Method 2 – Programmed Capex* – We have forecast some Non-network ICT capex based on a build-up of volumes and unit costs. Volume forecasts are based on:
  - assets and applications reaching the end of their technical life, having regard for their age and condition;
  - asset obsolescence and vendor support;
  - prescribing a set number of units for replacement each year; or
  - historical asset replacement volumes.

  Unit rates are based on:
  - our historical costs;
  - costing models; or
  - cost estimates from external independent consultants or service providers.
- *Method 3 – Pooled Capex* – For some asset categories it is not feasible to forecast Non-network IT capex using scoped projects or programmed capex. In these cases, we have forecast our required capex based on our historical capex.

Table 9-2 details which method we have used to forecast our three Non-network ICT capex categories set out in the AER's Reset RIN.

Table 9-2 – Forecasting methods by Non-Network ICT capex by category

ICT category	Expenditure Forecasting Method
ICT asset extensions	• Method 1 – Scoped Capex
ICT asset replacement	• Method 1 – Scoped Capex • Method 2 – Programmed Capex • Method 3 – Pooled Capex
ICT capability growth	• Method 1 – Scoped Capex

9.4 Key supporting documentation

Our Non-network ICT capex forecasts are based on the following documents:

- *ICT Strategy*[37] – this document details our ICT strategy for the ten-year period, commencing 1 July 2017. It provides: business and technology context; key business principles and strategic themes for ICT; an overview of our ICT architecture; our ICT operating model and capabilities; our governance framework; and our sourcing and delivery model;
- *ICT Capex Plan*[38] – this document describes and justifies our corporate Non-network ICT capex forecast for the next regulatory period, including demonstrating how it meets the objectives, criteria and factors in the NT NER; and
- *BNIs and PBCs* – as discussed for other capex categories, these documents provide supporting information about individual projects and programs that are included in our capex forecast. These are referenced in our ICT Capex Plan.

9.5 Non-Network ICT forecast

Table 9-3 details our Non-Network ICT capex forecast for each year of the next regulatory period in the AER's three Reset RIN categories.

Table 9-3 – Non-Network ICT capex forecast by ICT category ($M, Real 2018-19)

	2019-20	2020-21	2021-22	2022-23	2023-24	Total
ICT asset extensions	1.6	1.0	0.2	0.0	0.0	2.8
ICT asset replacement	5.4	7.1	4.1	1.6	2.1	20.4
ICT capability growth	3.7	1.4	3.0	3.2	2.9	14.3
Total Non-Network ICT	**10.7**	**9.4**	**7.4**	**4.9**	**5.0**	**37.4**

These three items are reflected in our I-BNI 1.

Table 9-4 details our Non-Network ICT capex forecast for each year of the next regulatory period against the five business drivers. We overview these forecasts in the following sub-sections. Further information is provided about our ICT forecast for each key business driver in our ICT Capex Plan.

[37] Power and Water Corporation, ICT Strategy, 2017.

[38] Power and Water Corporation, Power Networks - ICT Capital Expenditure Plan, 2017.

Table 9-4 – Non-Network ICT capex forecast by key business driver ($M, Real 2018-19)

	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Network Operations	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Remediate the Core	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ICT Application & Infrastructure Refresh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Customer Service	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Enterprise	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Non-Network ICT	**10.7**	**9.4**	**7.4**	**4.9**	**5.0**	**37.4**

9.5.1 Network operations

Our network operations' ICT capex forecast for the next regulatory period comprises six components totaling [redacted] as illustrated in Table 9-5.

Table 9-5 – Network operations' ICT capex forecast ($M, Real 2018-19)

	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Network Planning	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Works Management	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Outage Management	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Network Business Management	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
System Operations	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
RINs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Network operations ICT	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

The nature of the six components of our network operations' ICT capex forecast is as follows:

- *Network planning* – this will enhance our system planning tools by providing reliable and timely generation, consumption, forecast and network data. It will do this by integrating key existing ICT applications to enable modelling of distribution systems utilisation and creation of appropriate forecasts of future network demands, for prudent and timely network replacement and augmentation planning;
- *Works Management* – this comprises four streams of work, mainly related to improving efficiency of the field workforce:
  - undertaking network investment planning and forecasting;
  - using ICT solutions to improve scheduling of work;

  - improving access to ICT systems in the field, in particular the enterprise asset management system; and
  - implementing an ICT solution for project management activities;

- *Outage Management* – this will introduce an Outage Management System (OMS) to support our response to faults, incidents and outages, which will allow for a greater efficiency in fault location, repair and reporting;
- *Network Business Management* – this comprises five streams of work, mainly related to improving our overall business management:
  - estimating and quotation management;
  - fleet management;
  - operational risk reporting;
  - drawing management; and
  - enterprise business agreement (EBA) interpreter;
- *Electricity Retail Supply Code* – in our role as the Network Provider in the NT we must provide many of the services that AEMO provides in other Australian jurisdictions to facilitate retail competition. These services include facilitating several business-to-business (B2B) transactions, including NMI discovery and customer transfers. This is investment in the ICT systems to provide these services efficiently and effectively; and
- *RINs* – this will leverage existing business intelligence tools to enable us to produce the suite of financial and non-financial information required to respond to the RINs issued by the AER.

9.5.2 Remediate the core

Our Remediate the Core ICT capex forecast for the next regulatory period comprises three components totaling [redacted], as illustrated in Table 9-6.

Table 9-6 – Remediate the core ICT capex forecast ($M, Real 2018-19)

	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Revenue Management System	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Financial Management System	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Maximo and ESRI Upgrade	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Remediate the core ICT	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

The nature of the three components of our Remediate the Core ICT capex forecast is as follows:

- *Revenue Management System* – we currently use Gentrack software as the revenue management system. This project will upgrade the system from version 3.4 to version 4.13. Included in the overall cost of the project is an upgrade of the billing system ICT infrastructure, external vendor costs and internal testing and training;

- *Financial Management System* – this involves extending the use of our current FMS Oracle platform supporting the upgraded version of Maximo and the opportunities to simplify reporting capabilities across the Finance area; and
- *Maximo and ESRI Upgrade* – this involves a program of work to bring our core enterprise asset management systems in line with industry system support and to address the critical issues to improve the accuracy/integrity of its data and systems. Although the program of work will commence in 2017, the work will continue into the regulatory period.

9.5.3 ICT application & infrastructure refresh

Our ICT application and infrastructure refresh capex forecast for the next regulatory period comprises two components totaling [redacted], as illustrated in Table 9-7.

Table 9-7 – ICT application & infrastructure refresh capex forecast ($M, Real 2018-19)

	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Enterprise Application Refresh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Enterprise Infrastructure Refresh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total ICT Application & Infrastructure Refresh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

The nature of the two components of our ICT application and infrastructure refresh capex forecast is as follows:

- *Enterprise Application Refresh* – this involves refreshing the following ICT enterprise application assets:
  - HPE Records Manager (RM8);
  - SAP Business Objects (Business Intelligence);
  - Oracle Fusion Middleware;
  - Intranet (Squiz);
  - Oracle Application Express (Oracle APEX) (Small Systems);
  - Cognos TM1;
  - Internet/Self Service (Squiz);
  - ESRI (GIS);
  - CribMaster (Inventory Management);
  - NEC Q-Master;
  - Outage Management System;
  - Microsoft Office;
  - Internet Explorer; and

– Microsoft Exchange.

- *Enterprise Infrastructure Refresh* – enterprise ICT infrastructure underpins our key enterprise business applications, which in turn support our critical business processes. This involves refreshing critical ICT enterprise infrastructure to meet planned business demands on ICT services and maintain reliability of infrastructure services that underpins our core business processes and systems for reliability supply of network services.

9.5.4 Customer service

Our customer service capex forecast for the next regulatory period comprises two components totaling [redacted], as illustrated in Table 9-8.

Table 9-8 – Customer service ICT capex forecast ($M, Real 2018-19)

	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Customer Relationship Management	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Meter Data Management	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Customer Service ICT	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

The nature of the two components of our customer services ICT capex forecast is as follows:

- *Customer Relationship Management* – this involves implementing a new Customer Relationship Management (CRM) system to provide functionality for enhanced interactions with customers and support the strategic goal of achieving a more customer focused business. The will improve our ability to manage electricity customer information, preferences, engagement and interactions, required to address customer concerns as part of our obligations as a DNSP; and
- *Meter Data Management* – we are in the process of implementing a Meter Data Management System (MDMS) to improve asset utilisation, reduce financial risks associated with Advanced Metering Infrastructure (AMI) and support the development of new billing arrangements.

9.5.5 Enterprise

Our enterprise capex forecast for the next regulatory period is [redacted], as illustrated in Table 9-9.

Table 9-9 – Enterprise ICT capex forecast ($M, Real 2018-19)

	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Total Enterprise ICT	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Our Enterprise ICT capex will:

- deliver an enhanced business reporting capability;

- provide a more intuitive and responsive business reporting framework;
- enable information to be efficiently and effectively identified, retrieved, processed and reported on for decision making purposes; and
- replace the need for other reporting solutions such as BIRT, Crystal Reports and FSG.

10. Non-network Other capex

This section explains and justifies our Non-network Other capex forecast.

10.1 Purpose and scope

Our Non-network Other capex for our SCS includes:

- *Fleet* – We lease our vehicle fleet through the NT Government's fleet service provider, NT Fleet. Our service vehicle fleet comprises light, heavy and specialist vehicles that enable field crews to access the distribution network to maintain the assets, repair infrastructure at the end of its useful service life, respond to emergency situations and construct new infrastructure when required. The administrative pool vehicles enable support staff to travel between the various locations from which we provide our services;
- *Buildings and property* – We lease and acquire buildings and property from which we provide our services. This includes fitting-out offices to accommodate our employees and contractors;
- *Tools and equipment* – We acquire tools and equipment to construct, repair and maintain our distribution system; and
- *Minor capex* – We have other minor capex to support the provision of our distribution services.

Due to a change to Australian Accounting Standard AASB 16 *Leases*, we will treat operating leases as capex from 1 July 2019.

10.2 Overview of key drivers

Table 10-1 details the key drivers of these three categories.

Table 10-1 – Non-network Other capex key drivers[39]

Category	Drivers
Fleet	The size of our vehicle fleet is commensurate with the services that we must provide. Darwin-Katherine has a monsoonal climate and Alice Springs and Tennant Creek experience major dust storms, long hot summers and below freezing temperatures. It is essential to have a reliable, well-maintained fleet for the safety, reliability, quality and security of the supply of our services.
Buildings and property	The buildings and property are essential to our provision of distribution services.
Tools and	The tools and equipment that we require are commensurate with our need

[39] We have not forecast any ICT asset remediation capex, which is the fourth ICT capex category included.

Category	Drivers
equipment	to construct, repair and maintain our distribution system. They are therefore essential to the safety, reliability, quality and security of the supply of our services.
Minor capex	The minor capex assets enable the delivery of electricity network services. In the absence of these, the program of work may not be delivered effectively or efficiently.

10.3 Capex forecasting method

We have forecast our Non-network Other capex using three methods:

- *Method 1 – Scoped capex* | We have forecast some of our Non-network Other capex on an individual project basis. This is for large, discrete projects that we can scope and cost on a discrete basis;
- *Method 2 – Programmed capex* | We have also forecast some of our Non-network Other capex based on a build-up of volumes and unit costs. Volume forecasts are based on:
  - assets and applications reaching the end of their technical life, having regard for their age and condition;
  - asset obsolescence and vendor support;
  - prescribing a set number of units for replacement each year (for example, to address a low-consequence risk that requires mitigation but does not warrant the immediate replacement of the entire asset family); or
  - historical asset replacement volumes.

  Unit rates may be based on:

  - our historical costs;
  - costing models; or
  - cost estimates from external independent consultants or service providers.
- *Method 3 – Pooled capex* | For some asset categories it is not feasible to forecast Non-network Other capex using scoped projects or programmed capex. In these cases, we forecast our required capex based on our historical capex.

Table 10-2 details which method we have used to forecast our three categories of Non-network Other capex.

Table 10-2 – Forecasting methods by ICT capex category

Category	Expenditure Forecasting Method
Fleet	• Method 2 – Programmed capex
Buildings and property	• Methods 1, 2 and 3 – Scoped, Programmed and Pooled capex
Tools and equipment	• Method 3 – Pooled capex
Minor capex	• Method 3 – Pooled capex

We lease our fleet and some of our property. Historically, we treated our leases as operating expenditure (opex) by accounting for lease payments in the year in which they were incurred.

Australian Accounting Standard AASB 16 Leases recently changed. The effect of this change is that, from 1 July 2019, the full amount (over its term) of an operating or finance lease must be capitalised up-front when it is first entered into, or is renewed. From 1 July 2019, our leases will therefore be reflected on our balance sheet, recognising both an asset for the right to use the leased asset and an obligation to make lease payments over the lease term.

10.3.1 Fleet

We have many small leases for our fleet – one for each of our vehicles that directly support the provision of our distribution services. We have capitalised the remaining value of our existing fleet leases as at 1 July 2019 in 2019-20.

The volume of vehicles is expected to remain constant over the next regulatory period. At the end of a lease period, the vehicle is replaced with another of a similar type. For example, light vehicle would be replaced with light vehicle, and a heavy truck replaced with heavy truck. The replacement schedule is a condition of the leasing arrangements between Power and Water and NT Fleet.

The unit cost for each vehicle is the lease rate charged to Power and Water by NT Fleet. Power and Water has assumed that the lease cost will remain constant in real terms for the duration of the next regulatory period. Given the relatively constant purchase price of vehicles, we consider this to be a prudent approach.

Because our fleet lease renewals are also spread relatively evenly over time, our capitalised lease profile is relatively stable between 2020-21 and 2023-24 (i.e. after the first year of the period, 2019-20, when all of the existing fleet leases are capitalised). For further information regarding our treatment of fleet leases, refer to Attachment 1.20.

10.3.2 Buildings and property

Our buildings and property capex forecasts comprise three components – a business-as-usual component, change in treatment of property leases, and one major project relating to the 19 Mile Depot and access road upgrade.

We currently have two rural depots – 19 Mile (that we own) and East Arm (that we lease). Our strategy is to upgrade 19 Mile, not to renew the lease at East Arm and co-locate both current crews at 19 Mile.

The 19 Mile Depot and access road require upgrading:

- so that we can deliver future works south of 19 Mile Depot; and
- for general public safety, as there is currently no acceleration lane when accessing the Stuart Highway North bound.

The forecast for this project was prepared by engaging an external quantity surveyor who provided estimates based on both historical data and concept drawings.

Consistent with the new Australian Accounting Standard, we have capitalised the remaining value of our existing property leases as at 1 July 2019 in 2019-20. In the remaining years of the next period, the full value of each new or replacement lease entered into is recognised as capex as the present value of future lease payments. For further information regarding our treatment of property leases, refer to Attachment 1.20.

10.3.3 Tools and equipment

Our capex forecast for tools and equipment was prepared using the pooled forecasting method, as we consider our historical capex to be the best indicator of our future requirements, amended for the removal of extraordinary items.

10.3.4 Minor capex

Our capex forecast for minor capex was prepared using the pooled forecasting method, as we consider our historical capex to be the best indicator of our future requirements.

10.4 Key supporting documentation

Our Non-network Other capex forecasts are based upon BNIs and PBCs that have been prepared for each Non-network Capex category. These documents provide supporting information about individual projects and programs.

10.5 Non-network Other capex forecast

Table 10-3 details our Non-network Other capex forecast for each year of the next regulatory control period for our three categories of Non-network Other capex.

Table 10-3 – Non-network Other capex forecast ($M, Real 2018-19)

Next RCP	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Fleet	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Buildings and property	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Tools and equipment	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Minor capex	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Non-Network Other	**27.89**	**5.57**	**24.96**	**5.66**	**5.35**	**69.43**

11. Capitalised overheads

This section explains and justifies our forecast of capitalised overheads.

Capitalised overheads are unallocated opex that is capitalised according to our regulatory capitalisation approach, provided for in our CAM.

11.1 Our Statutory Capitalisation Policy

Before 2016-17, our Statutory Capitalisation Policy capitalised labour, invoiced contract and service costs where they directly related to capital projects and did not include indirect support costs.

In 2016-17, we extended our application of the Statutory Capitalisation Policy to include the capitalisation of an allocation of indirect support costs where they were deemed to be integral to the acquisition or construction of capital assets, provided they complied with AASB 116 *Property, Plant and Equipment*.

We developed an accounting treatment and methodology for the capitalisation of these indirect support costs from 2016-17, in accordance with AASB 116. The extension of our existing methodology was not considered to be a change in accounting policy by either our Board or our external auditor. As a result, there were no prior year adjustments made.

11.2 Our Regulatory Capitalisation Approach

We capitalise for statutory purposes our corporate and network overhead accounts in accordance with our Statutory Capitalisation Policy.

We capitalise the same corporate and network overheads for regulatory purposes, but do so in proportion to the ratio of direct capex to total direct costs. If the ratio changes, the fraction of unallocated costs capitalised also changes. This is provided for in our CAM.

Our regulatory capitalisation approach recognises:

- our primary purpose as a DNSP is to build, operate and maintain assets, and all indirect costs support this;
- if we outsourced construction of assets, the capitalised cost would include the complete allocation of overheads from the provider; and
- for equity between insourcing and outsourcing, the treatment must be similar.

We understand that there is a wide range of capitalisation approaches and outcomes across DNSPs in the NEM, with the amount of overheads capitalised ranging from 20 per cent to 50 per cent of overheads. Our proposed capitalisation approach results in a forecast that falls within this range.

Our regulatory capitalisation approach, and opex forecasts, will ensure that only efficient overhead costs are recovered through either capitalised overheads or our base year opex, so that there are no gaps or over-recoveries.

11.3 Capitalised overheads forecast

Table 11-1 details our capitalised overhead forecast for each year of the next regulatory period.

Table 11-1 – Capitalised overheads forecast ($M, Real 2018-19)

	2019-20	2020-21	2021-22	2022-23	2023-24	Total
Capitalised overheads	13.01	13.19	13.39	13.56	13.71	66.86