Attachment PWCR02.1

SCS Opex Base Year Justification

2019-20 to 2023-24

29 November 2018

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1. Purpose and structure of this document

The purpose of this document is to provide an overview of our revised operating expenditure (opex) base year to address issues raised by the Australian Energy Regulator's (AER) September 2018 Draft Decision for our 2019-24 regulatory control period.

The remainder of this document is structured as follows:

- Section 2 provides a summary of our revised base year:
  - We provide an overview of the AER's Draft Decision.
  - We identify the changes from our Initial Regulatory Proposal.
  - We identify how we have considered the AER's findings.
- Section 3 provides details of adjustments that we have undertaken to proactively remove non-recurrent expenditure from our revised base year. This includes Tropical Cyclone Marcus (TC Marcus), direct and indirect labour, and professional fees.
- Section 4 provides an overview of our approach to incorporating efficiencies in our revised base year.

The document then largely focuses on the base year amendments, both due to the removal of non-recurrent expenditure and efficiencies, at the expenditure category level:

- Section 5 sets out how we have addressed the AER's Draft Decision on our maintenance expenditure and provides our revised base expenditure forecast.
- Section 6 sets out how we have addressed the AER's Draft Decision on our vegetation management expenditure and provides our revised base expenditure forecast.
- Section 7 sets out how we have addressed the AER's Draft Decision on our network overheads' expenditure and provides our revised base expenditure forecast.
- Section 8 sets out our revised base corporate overheads' expenditure forecast.
- Section 9 sets out our revised base emergency response expenditure forecast.
- Section 10 sets out our revised base non-network expenditure forecast.

- Section 11 outlines the other adjustments made to our base year expenditure forecast.
- Section 12 provides the results of our labour benchmarking.

2. Overview of our revised opex base year

This section provides a summary of issues raised by the AER, identifies changes from our Initial Regulatory Proposal, and provides an overview of how we have addressed the AER's Draft Decision.

Please note that throughout this document a reference to our opex base year refers specifically to our base year opex for the provision of Standard Control Services, defined in the AER's Draft Decision on the classification of Northern Territory distribution services[1]. All dollar values are provided in Real $2018-19, unless otherwise specified.

2.1 Overview of AER findings

The AER largely accepted our proposed approach to forecasting opex, including the use of 2016-17 as the base year. The AER, however, rejected our proposed 10 per cent top-down efficiency adjustment and replaced it with category-level adjustments that it determined after reviewing our 2016-17 expenditure. The AER made category-level adjustments to our maintenance expenditure, vegetation management expenditure and network overheads' expenditure as it did not consider them to be reflective of our ongoing opex requirements for the 2019-24 regulatory control period.

We welcome the AER's approach to assessing our Initial Regulatory Proposal opex. The approach has allowed us to target our review of potential efficiencies or potential efficiency targets in our Revised Regulatory Proposal, rather than continuing with the top-down unallocated efficiency adjustment we proposed in our Initial Regulatory Proposal.

The AER engaged with us throughout its consideration of our Initial Regulatory Proposal on opex – and this is reflected in its Draft Decision. We appreciated the opportunity to clarify our proposal and to respond to questions the AER raised. We also welcome the AER's continued engagement since its Draft Decision.

2.2 How we have changed our Initial Regulatory Proposal

Whilst we have used the AER's adjustments for non-recurrent expenditure and efficiency measures as a guide for our revised base year, we do not agree that

[1] AER, September 2018, Draft decision – Power and Water Corporation, Attachment 12: Classification of services.

the base year opex proposed in the Draft Decision is sufficient to meet our ongoing opex requirements.

We are, however, committed to driving efficiencies within our business. In doing so, we have cut $14.6 million (18 per cent) from our revised base year by removing both non-recurrent expenditure and applying efficiencies to our proposed expenditure. Given the latest available information, this is the lowest level of expenditure that we believe is necessary without resulting in significant customer, safety or reliability impacts. How we operate and maintain our assets and provide customer service is critical to our customers' service experience and the safety of our staff and the communities within which our assets operate.

We are mindful of our recent history and the significant improvements that we have implemented since the failures at Casuarina zone substation in 2008. Prior to 2008, the level of maintenance performed on our network assets was limited. The lack of strategic planning resources resulted in a failure to define maintenance strategies based on an understanding of asset failure modes and associated risks of failure. Our customers experienced the consequences of this through poor reliability outcomes.

Since 2008, we have developed and implemented contemporary asset management and maintenance practices. During the 2014-19 regulatory control period, we have seen a downward trend in our maintenance spend as we have had access to better data, gained a better understanding of our asset maintenance requirements and therefore also better targeted our expenditure.

We have proposed further efficiencies to apply to our opex during the 2019-24 regulatory control period and our opex forecasts are our best understanding of what we need to provide safe and reliable services at the required service performance levels. If these forecasts are cut further beyond the substantial cuts we have proposed, we risk lower service performance and greater safety risk.

2.2.1 Approach

We have updated our base year opex to start with our 2017-18 audited opex, rather than 2016-17. As explained in our Initial Regulatory Proposal, we consider that our more recent actual opex year provides a better indication of what will be required in the future to meet our regulatory obligations and to deliver the outcomes that our customers expect.

However, to ensure that only expenditure reflective of our ongoing requirements is included in our opex base year, we have taken a proactive and detailed review of our 2017-18 costs to remove all non-recurrent expenditure.

We have also identified both specific efficiencies and efficiency targets at the expenditure category level in our Revised Regulatory Proposal. This is unlike the approach we took in our Initial Regulatory Proposal, where we included a top-down 10 per cent efficiency reduction that recognised there was room for improvement in our expenditure forecast but did not allocate it out.

We removed the following from our 2017-18 audited opex:

- Non-recurrent expenditure from TC Marcus, which caused us to incur more emergency response expenditure than normal;
- Non-recurrent professional fees that we incurred to help with our transition to the national framework and to prepare our first regulatory proposal under the AER that will not be required in future determinations;
- Non-recurrent direct and indirect labour costs; and
- Identified inefficiencies or potential efficiency targets from maintenance, network overheads and corporate overheads. The efficiency enabling initiatives in our Target Operating Model and our ICT capital program facilitate the efficiencies that we have proposed and are not in addition to them.

We also retained our GSL and capitalisation adjustments and adopted the AER's provisions' adjustment, updating all three to reflect 2017-18 audited opex.

2.3 Updated opex base year

Table 2-1 provides our audited 2017-18 opex and our revised base year opex forecast once we have removed non-recurrent expenditure and applied the efficiency savings, along with the other adjustments mentioned above.

Table 2-1 – 2017-18 Expenditure & base year adjustments

$M, Real 2018-19	2017-18 Actual	*Non-recurrent expenditure*	*TC Marcus normalisation*	*Efficiency adjustment*	RRP base year
Base year opex					
Maintenance	14.5	-	1.9	(2.2)	**14.2**
Vegetation management	4.2	-	-	-	**4.2**
Emergency response	9.2	(0.7)	(1.9)	-	**6.6**
Network overheads	39.1	(7.2)	-	(3.1)	**28.8**
Corporate overheads	13.8	-	-	(1.3)	**12.5**
Non-network	7.4	-	-	-	**7.4**

$M, Real 2018-19	2017-18 Actual	*Non-recurrent expenditure*	*TC Marcus normalisation*	*Efficiency adjustment*	RRP base year
Balancing item	0.1	-	-	-	**0.1**
Other adjustments					
GSLs	(0.1)	-	-	-	**(0.1)**
Provisions	(0.4)	-	-	-	**(0.4)**
Capitalisation of leases	(6.3)	-	-	-	**(6.3)**
Total	**81.5**	**(8.0)**	**-**	**(6.6)**	**66.9**

Table 2-2 below compares our base year opex from our Initial Regulatory Proposal, the AER's Draft Decision, and our Revised Regulatory Proposal. Our Initial Regulatory Proposal and the AER's Draft Decision were based on 2016-17 audited expenditure whereas our Revised Regulatory Proposal is based on 2017-18 audited expenditure, as explained above.

Table 2-2 – Base year opex

$M, Real 2018-19	PWC IRP	AER DD	PWC RRP
Base year opex			
Maintenance	17.8	13.1	14.2
Vegetation management	4.9	3.9	4.2
Emergency response	6.8	6.8	6.6
Network overheads	30.6	25.8	28.8
Corporate overheads	8.2	8.2	12.5
Non-network	7.7	7.7	7.4
Balancing item	(0.2)	(0.2)	0.1
Other adjustments			
GSLs	0.0	0.0	(0.1)
Provisions	-	(0.8)	(0.4)
Capitalisation of leases	(5.5)	(5.5)	(6.3)
Efficiency adjustment[1]	(7.0)	-	-
Total			
Base year expenditure	**63.3**	**59.1**	**66.9**
Base year adjustments (%)[2]	*10%*	*14%*	*18%*

[1] The efficiency adjustments have been undertaken at an expenditure category level for the AER's Draft Decision and our Revised Regulatory Proposal.

[2] Base year adjustment percentage excluding the 'other adjustments' of GSLs, provisions and capitalisation of leases.

2.4 Supporting documents and models

The following documents and models have been provided with our Revised Regulatory Proposal to support our base year opex:

- PWCR02.2 – Ernst & Young – Cost Allocation Method: Independent Report – 29 Nov 18 – PUBLIC.
- PWCR02.3C – Pinnacle ArborPro – Power & Water Corporation Vegetation Management Forecast for the 2019 to 2024 Regulatory Control Period – 29 Nov 18 – CONFIDENTIAL.
- PWCR02.3P – Pinnacle ArborPro – Power & Water Corporation Vegetation Management Forecast for the 2019 to 2024 Regulatory Control Period – 29 Nov 18 – PUBLIC.
- PWC0R4.4 – SCS Opex Model – 29 Nov 18 – PUBLIC.

In the sections below, we explain the nature and purpose of each document and how they support our opex base year.

3. Non-recurrent expenditure

This section provides details of adjustments that we have undertaken to proactively remove non-recurrent expenditure from our base year. This includes TC Marcus, direct and indirect labour, and professional fees.

Consistent with our Initial Regulatory Proposal and the AER's Draft Decision, we have also made an adjustment to reflect the fact that, from 1 July 2019, we will start to capitalise leases in accordance with new Australian Accounting Standards. This non-recurrent expenditure has also been removed from our base year opex and is discussed further in Section 11.

3.1 Approach

As previously mentioned, we have updated our base opex to start with 2017-18 audited opex, rather than 2016-17. We consider that our more recent year of opex provides a better indication of what is required in the future to meet the regulatory obligations we face and deliver the outcomes that our customers expect.

However, to ensure that only expenditure reflective of our ongoing requirements is included in our opex base year, we have taken a proactive and detailed review of our 2017-18 costs to remove all expenditure determined to be non-recurrent. This, along with our proposed efficiency adjustments, is to ensure that the proposed expenditure included in our Revised Regulatory Proposal is both prudent and efficient.

3.2 TC Marcus

TC Marcus hit Darwin on 17 March 2018 and was officially named as the most damaging storm the city has faced since Tropical Cyclone Tracy in 1974.

Heavy rainfall, damaging winds in excess of 130km per hour and fallen trees caused major damage to our network infrastructure, leading to 28,584 customers (33 per cent of our customer base) being without power, and more than 500 line spans down once the Cyclone had passed.

Our crews worked tirelessly and managed to reconnect 11,203 customers within the first 24 hours. Despite this, our restoration efforts were hampered by delays in clearing and removing fallen vegetation, with approximately 200 customers without power 11 days after the event.

3.2.1 TC Marcus expenditure

We incurred $2.6 million in opex associated with TC Marcus against our emergency response expenditure category between March and June 2018. Approximately 90 per cent of this expenditure was for labour costs.

This expenditure was analysed to determine the incremental versus business-as-usual expenditure for the purpose of understanding what component should be included in our base year to reflect recurrent costs.

Incremental opex was determined to be the additional, above business-as-usual, costs that we have incurred in relation to TC Marcus. To determine the incremental opex, we:

- Compared the overtime labour costs for network opex (vegetation management, maintenance and emergency response expenditure) in the TC Marcus period with the three year trimester average. This was also compared against data at the expenditure category level to validate the approach.
- Business-as-usual labour resources diverted from normal activities (i.e. maintenance to emergency response) were not considered to be incremental costs as these relate to labour that would have otherwise been utilised by us, and are therefore not an additional cost associated with the Cyclone.
- Compared the purchasing costs for emergency response opex in the TC Marcus period with the three year trimester average; and
- Compared inventory costs in the TC Marcus period to historical data, which showed that inventory data is highly volatile. There was no evidence of incremental costs relating to TC Marcus, and it was deemed that any inventory for TC Marcus was reallocated to capex in accordance with our capitalisation policy.

Table 3-1 below provides the breakdown of TC Marcus opex by cost type (labour, inventory and purchasing) and whether it is considered incremental or business-as-usual expenditure.

Table 3-1 – TC Marcus opex

$M, Real 2018-19	Incremental	BAU	Total
Labour	0.5	1.5	2.0
Inventory	0.0	0.1	0.1
Purchasing	0.2	0.2	0.5
Total	**0.7**	**1.9**	**2.6**

As shown above, the majority of the costs were diverted from business-as-usual operating expenditure, and only a small proportion ($0.7 million) related to incremental costs.

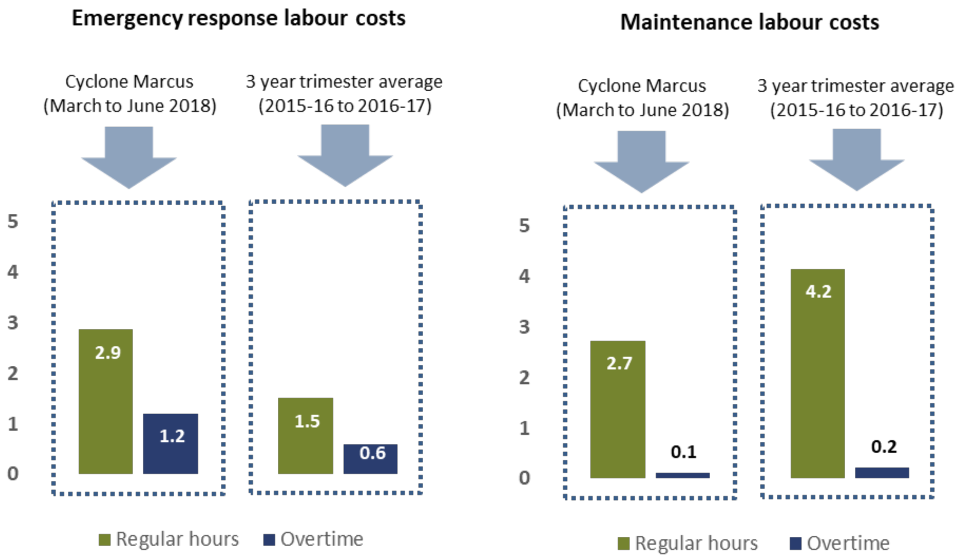
We also assessed the capex associated with TC Marcus and the sum of both the incremental opex and capex was determined to be less than the materiality threshold required to submit a cost pass through. Therefore, we have not sought to recover the costs of TC Marcus from network customers through a cost pass through application to the AER in the 2014-19 regulatory control period.

3.2.2 Impact on base year

We consider the incremental opex associated with TC Marcus to be non-recurrent expenditure and we have therefore removed this amount from our base year emergency response opex in line with the base-step-trend approach.

The remaining business-as-usual opex was a diversion of non-routine maintenance resources to emergency response resources. This is demonstrated in the charts below, which show that emergency response labour costs were significantly higher in the TC Marcus period than their three year trimester average, whereas maintenance labour costs were significantly lower.

Figure 3-1: Labour costs by category ($M, Real 2018-19)



To allow for historically consistent base year reporting, we have:

- Normalized the TC Marcus expenditure by reallocating the business-as-usual TC Marcus opex from the emergency response opex category to the maintenance opex category; and
- Removed the incremental emergency response opex from our base year.

Table 3-2 below demonstrates historical emergency response and maintenance expenditure, along with 2017-18 expenditure before and after the base year adjustments for TC Marcus.

Table 3-2 – Emergency response and maintenance opex

$M, Real 2018-19	2015-16	2016-17	2017-18	*Incremental Cost adj.*	*Normalised*	2017-18 adj.[2]
Emergency Response	6.8	6.8	9.2	(0.7)	(1.9)	6.6
Maintenance	18.5	17.7	14.5	-	1.9	16.5
Total	**25.3**	**24.5**	**23.7**	**(0.7)**	**-**	**23.0**

Note: the value for 2016-17 differs from Table 2-2 due to slightly different inflation assumptions being used in the Initial Regulatory Proposal for the 2017-18 and 2018-19 years (for $2018-19 conversion).

Table 3-2 demonstrates that:

- The total spend on emergency response and maintenance is largely consistent between years, although we have had a downward trend in our maintenance spend.
- 2017-18 represents a significant increase in emergency response opex due to TC Marcus, and a corresponding decrease in maintenance opex.
- After removing the incremental non-recurrent costs, and normalizing for the business-as-usual expenditure reallocated from maintenance, the adjusted expenditure at the category level is more in line with historical expenditure and representative of a standard base year.

[2] Note that these adjustments are just for TC Marcus and do not represent any efficiency adjustments that Power and Water are proposing to our base year opex. Efficiency adjustments are addressed specifically in the expenditure category sections of this attachment.

3.3 Labour

3.3.1 Direct labour recoveries

In 2017-18, our scheduled capex program was considerably lower than our previous year's expenditure and also lower than the average of our forecast 2019-24 capex, as demonstrated in Table 3-3 below. This has resulted in a reduction of our labour being utilised to complete capital works, and therefore more expenditure is treated as opex in our accounts. This opex is non-recurrent and therefore has been removed from the base year.

Table 3-3 – Direct capex

$M, Real 2018-19	2016-17	2017-18	Average 2019-24
Direct capex	69.9	43.9	62.1

Similarly, there was a decrease in maintenance work in 2017-18, which means less direct labour attributed to opex. The residual labour has been included in our 2017-18 network overheads opex but has been determined to be non-recurrent and therefore removed from our base year.

These amount are provided in Table 3-4 and also addressed in Section 7.

3.3.2 Indirect labour

In accordance with our AER-approved Cost Allocation Method (AER-approved CAM) [3], we capitalise our indirect labour costs between capex and opex in the same proportion as direct expenditure, i.e. we apply the ratio of direct capex to direct total expenditure (capex/totex – our 'capitalisation rate') to our indirect labour costs. A low capitalisation rate in 2017-18 has resulted in more expenditure being treated as opex than is required in the future.

To take this into account, and ensure that our opex forecast is only reflective of our ongoing requirements, we have removed the non-recurrent amount of indirect labour that is in our network overheads' opex that would normally be treated as a capitalised overhead. This decrease in opex has been offset in our capitalised overheads' forecast. This amount is provided in Table 3-4 and is also addressed in Section 7.

[3] Power and Water Corporation, 2017, Cost Allocation Method for Distribution Services v1.0.

3.3.3 Impact on base year

Table 3-4 below provides the impact of the removal of non-recurrent direct and indirect labour on our base year.

Table 3-4 – Non-recurrent expenditure – labour (Network overheads)

$M, Real 2018-19	2017-18
Direct Labour - capex	3.5
Direct Labour - maintenance	0.7
Indirect Labour - Impact of low capitalisation rate	1.0
Total	**5.2**

3.4 Professional fees

The legislative and regulatory framework within which we operate is undergoing extensive changes. The NT Government is committed to continuing to adopt a more harmonized approach to the regulation of the NT's electricity networks with jurisdictions in the National Electricity Market, as appropriate for the NT.

In order to transition to the new framework, we have established a significant internal priority project, Transition to the National Electricity Rules, which comprises four programs of work:

- 2019-24 Distribution Determination;
- NT Transitional Negotiations (NER Derogations);
- Transition to Compliance; and
- Jurisdictional Code Review.

In order to advance these programs of work, particularly the 2019-24 Distribution Determination, we have had to rely on external assistance. This is due both to the difficulties with sourcing permanent staff in the NT and the need to engage specialist expertise.

We have reviewed our expenditure on professional fees in 2017-18 to ensure that only expenditure representative of our ongoing requirements has been included in our base year opex. This amount is provided in Table 3-5 and discussed further in Section 7.

Table 3-5 – Non-recurrent expenditure – professional fees (Network overheads)

$M, Real 2018-19	2017-18
Professional fees	2.1

4. Base year efficiencies

4.1 Approach

We have identified both specific efficiencies and efficiency targets at the expenditure category level for our Revised Regulatory Proposal. This is unlike the approach taken in our Initial Regulatory Proposal, where we included an unallocated top down 10 per cent efficiency reduction that recognized that there was room for improvement in our 2016-17 expenditure. We did nominate a 50 per cent split between maintenance and network overheads in our Initial Regulatory Proposal but this was assumed for presentational purposes rather than the result of a targeted review.

4.2 Efficiencies

In accordance with the approach adopted by the AER in its Draft Decision, we have reviewed the efficiencies applied to both our vegetation management and maintenance expenditure categories. Whilst we do not agree with the AER's expenditure forecast, we recognise that there is opportunity to further reduce our vegetation management and maintenance expenditure from the 2016-17 levels proposed in our Initial Regulatory Proposal.

Our response to the AER's Draft Decision is outlined in Section 5 for maintenance and Section 6 for vegetation management.

4.3 Efficiency targets

We have applied a 10 per cent efficiency target to both our recurrent network overheads and corporate overheads opex.

We consider that a number of our priority projects, such as our Target Operating Model and ICT capital program, will be essential in realising these efficiencies. This is consistent with our Initial Regulatory Proposal where they were recognised as an important part of achieving the top down 10 per cent efficiency reduction.

Consistent with our approach in our Initial Regulatory Proposal, the efficiency enabling initiatives in the Target Operating Model and the ICT capital program facilitate the category level efficiency targets that we have proposed and are not in addition to them.

Whilst we are yet to define the individual initiatives that will be implemented, with a continued focus and commitment to driving efficiencies through our business, we believe that our base year efficient levels are achievable by 2023-24. Given the significant impact that achieving our proposed efficiencies will have on our business, in addition to increased regulatory obligations throughout the period, we do not believe that an additional opex productivity growth factor is appropriate in our circumstances. The Draft Decision notes that we will have strong continuous incentives to make efficiency improvements.

There will be a cost associated with transitioning towards realising the benefits of organisational change. We have committed to including these future efficiencies in our base year opex but recognise that they will be achieved over the 2019-24 regulatory control period with us, rather than our customers, proactively funding the transition costs.

4.4 Impact on base year

Table 4-1 below provides the impact of both the specific efficiencies and efficiency targets in our proposed base year.

Table 4-1 – Proposed efficiencies

$M, Real 2018-19	2017-18
Maintenance	2.2
Network overheads	3.1
Corporate overheads	1.3
Total	**6.6**

5. Maintenance

This section explains and justifies our revised base year maintenance expenditure.

5.1 Activities included

Our activities include operational repairs and maintenance of the distribution system including high voltage and low voltage assets, plus testing, investigation, validation, and correction costs not involving capex.

Our maintenance expenditure is split into routine and non-routine maintenance opex activities, with a description of each provided below.

Our approach to determining the level of routine and non-routine maintenance is based on the principles of “objective need” and risk management. In other words, we optimise maintenance activity by prioritising activity based on our assessment of asset condition, likelihood of failure and the consequences.

Routine activities performed are described as preventative maintenance within our asset management systems, policies, and processes. They are principally cyclical in nature and allow us to:

- Prevent asset failure through scheduled maintenance activities that restore asset condition, particularly where asset components have a demonstrated wear-out or time-based failure risk;
- Confirm an asset’s condition is acceptable based on defined performance criteria that directly impacts the safe operation of the network; and
- Identify assets that are approaching end-of-life or are in a condition where failure risk is above acceptable risk tolerance. These assets are then treated appropriately through non-routine repairs or replacement.

Non-routine activities (or corrective maintenance) are undertaken in response to an identified trigger which includes defects identified during routine maintenance and by our customers, follow-on work from emergency response activities and programs to correct asset “type-issues” that present a risk and can be treated cost effectively through repairs.

Typically, any non-routine activity request is vetted prior to commitment to ensure that the activity is prudent based on the risk associated with the particular asset defect or condition. The vetting process is a qualitative assessment by the responsible maintenance planner for the asset class. It requires consideration of the risk created by the defect with regard to system security, safety (public and maintainers) and reliability. The process is described in our guidelines and, when in doubt, the decision is escalated to management. This ensures activities associated with rectifying low risk conditions are deferred or completed in conjunction with other unavoidable activities on the same asset. Work is bundled when it is efficient to do so, reducing mobilisation costs.

5.2 Our initial proposal

Our Initial Regulatory Proposal noted that our routine and non-routine maintenance costs are higher than comparable networks. We presented a number of operating efficiency factors, which we consider have a material impact on our operating environment and therefore the operating expenditure we incur for the maintenance of our transmission and distribution network. We have therefore not sought to re-present how these factors impact our maintenance opex relative to other networks.

When compared to other networks, we recognised that there appears to be some room to reduce our maintenance opex. However, prior to making any base year efficiency adjustments we recognised that:

- Although on some measures our base year looked comparable or higher relative to other networks, most of the difference is explained by our unique circumstances; and
- We have already achieved cost reductions over the last four years.

In our Initial Regulatory Proposal, we included a reduction to our maintenance opex over the 2019-24 regulatory control period. We proposed a top-down efficiency adjustment of 10 per cent to our base year opex, which would be partly realised by a reduction in maintenance expenditure (for presentational purposes we assumed 50 per cent of the total efficiency adjustment).

After submitting our Initial Regulatory Proposal, we provided the AER with detailed information pertaining to the build-up of our maintenance opex, the condition of our assets and our asset reliability performance.

5.3 Response to information requests

The AER sought additional information on our proposed routine and non-routine maintenance costs as part of its review of our initial opex proposal. In our responses to the AER, we provided further details of:

- Our approach to asset management, and specifically how the focus of our inspection and maintenance activities has changed over the last 10 years, as we transitioned from a reactive management approach to maintenance practices based on ‘objective need’, asset condition and risk.

- Maintenance reviews undertaken in 2013 and 2016 relating to the optimisation of routine maintenance activities and specifically changes to the frequency of inspection and maintenance intervals. These reviews have driven the significant downward trend in routine maintenance, in particular.

- Asset management strategies as documented in our Asset Strategies Procedure document, including the inspection and maintenance frequencies for each of our maintenance activities by asset class and compared with industry peers.

- Output asset reliability measures including SAIDI and SAIFI that demonstrated strong improvement in reliability performance to our customers from 2010, which has largely stabilised/slightly degraded since 2014-15.

- Asset defect trends over time, which indicate improving asset condition. These improvements have been leveraged to extend periods between inspections and maintenance activities, lowering costs.

- Details of our defect vetting process, which outlines the classification and prioritisation of defects and target response times.

- Identification of a number of specific factors that, in our view, influence the ratio of routine and non-routine maintenance, particularly in the northern region where the vast majority of our assets and customers are located. These factors can be loosely grouped into the following:

    - Operating environment impact on assets;

    - Operating environment impact on workforce;

    - Scheduling opportunities to maximise efficiency;

    - High proportion of non-routine costs associated with distributed assets;

    - Ageing distribution line and cables assets; and

    - Risk management maturity and asset failure history data quality.

In addition, we advised the AER that the following changes were completed during 2014-19 regulatory control period and have resulted in improved efficiency in the delivery of our routine and non-routine maintenance:

- Introduction of mobile devices to record maintenance results for distribution assets in 2014. This allows maintenance and inspection results to be recorded in the field and integrated with the asset management ICT system for the creation of work orders and asset condition measures.

- Optimisation of individual asset maintenance timing and frequencies within zone substations and remote ends, including both primary and secondary assets, where possible. This minimises mobilisation and network switching required to gain safe access to equipment for maintenance and testing. This process began in 2013-14 and was refined in 2014-15.

- Integration of the routine maintenance plan with the System Control Planning Guidelines to minimise the likelihood of cancelled outages. This process began in 2015-16 and is ongoing.

5.4 AER Draft Decision

In reviewing our proposed maintenance opex, having regard to the information we provided and its own analysis of other regulatory proposals, the AER derived an alternative forecast of maintenance opex based on its own category analysis. In doing so, the AER set aside the top down total opex efficiency adjustment we proposed in our Initial Regulatory Proposal.

The AER's Draft Decision focused on two primary elements of our Initial Regulatory Proposal:

- The AER considered that our frequency of inspections and maintenance activities was high relative to industry peers, and applied an efficiency adjustment to two asset categories; and

- The AER adjusted our maintenance opex further to account for its assessment of inadequate risk management and inspection practice alignment.

5.4.1 Inspection and maintenance frequencies

From a review of the information that we provided, the AER concluded that[4]

> *'we have found that there are opportunities for Power and Water to reduce inspection and maintenance frequencies'*

and that

[4] AER, September 2018, Draft decision – Power and Water Corporation, Attachment 6: Operating Expenditure, p. 33 and p. 37.

‘there are efficiencies that can be made to better align Power and Water’s practices with those of the broader industry’

The AER stated in its Draft Decision that it reached this view by:

- Assessment of asset defect and asset reliability information, which suggests that with high priority defects reducing and reliability improving, it is efficient for us to reduce our inspection and maintenance frequencies; and
- Having regard to good electricity industry practice in terms of inspection and maintenance frequencies.

The AER considers that the changes we implemented in 2016-17 provide a source of future efficiencies as they are fully realised over the following two years. The AER undertook a detailed review of our Asset Strategies Procedure, and identified opportunities to:

- Reduce inspection frequency for lines and poles, applying a 55 per cent reduction to the associated routine and non-routine maintenance expenditure; and
- Reduce distribution and zone substations and associated plant maintenance, applying a 33 per cent reduction to the associated routine and non-routine maintenance expenditure.

The AER did not make any adjustments to other assets. It noted, however, that:

‘similar observations can be made for other inspection rates, including for underground feeders and related assets’[5]

In the Draft Decision, the AER made a total adjustment of $3.6 million in its alternative estimate of base year maintenance opex for inspection and maintenance efficiencies.

5.4.2 Risk management & inspection alignment efficiencies

In addition to adjustments to account for a reduced frequency of inspections and maintenance, the AER concluded that

‘There is opportunity for Power and Water to use a risk based classification of defects that account for service level

[5] AER, September 2018, Draft decision – Power and Water Corporation, Attachment 6: Operating Expenditure, p. 38.

> *implications, and not just the physical state of the asset, to inform and prioritise its inspection and maintenance activity. Using this approach it could also improve the alignment of its asset inspection practices to enable efficiencies.'*[6]

The AER assessed that further efficiencies of 6 to 8 per cent of maintenance opex are possible by adopting a risk management approach to inform inspection and maintenance activity and improve the alignment of asset inspection practices.

In the Draft Decision, an adjustment of 6 per cent (or $1.1m) was included in the alternative estimate of base year maintenance opex.

5.4.3 Draft Decision expenditure

A comparison of our Initial Regulatory Proposal to the AER's Draft Decision is shown in the table below.

Table 5-1 – Comparison of Initial Regulatory Proposal and Draft Decision – Maintenance

$M, Real 2018-19	PWC IRP	AER Draft Decision
Base year[1]	14.2	13.1
Variance to IRP		(1.1)

[1]We proposed a top-down efficiency adjustment of 10 per cent to our base year opex, which would be partly realised from a reduction in network overheads expenditure. For presentational purposes, we assumed 50 per cent of the total efficiency adjustment would come from maintenance in our Initial Regulatory Proposal and that is replicated in the table above.

5.5 Revisions to our initial proposal

5.5.1 2017-18 Maintenance expenditure

The table below provides the 2016-17 audited expenditure, and 2017-18 audited expenditure before and after normalising for TC Marcus. The normalization is a reallocation of expenditure from emergency response opex, and does not represent an increase to our total 2017-18 expenditure.

[6] AER, September 2018, Draft decision – Power and Water Corporation, Attachment 6: Operating Expenditure, p. 26.

Table 5-2 – Maintenance opex

$M, Real 2018-19	2016-17	2017-18	2017-18 with normalisation for TC Marcus
Maintenance opex	17.7	14.5	16.5

Note: the value for 2016-17 differs from Table 2-2 due to slightly different inflation assumptions being used in the Initial Regulatory Proposal for the 2017-18 and 2018-19 years (for $2018-19 conversion).

In 2017-18, resources normally occupied on maintenance opex tasks were diverted to TC Marcus' emergency response activities. As a result, maintenance expenditure was lower than normal. The portion of these emergency response activities that represents business-as-usual activity has subsequently been re-allocated to normalise non-routine maintenance expenditure for base year analysis. Due to our small size, resources from all maintenance groups participated in the TC Marcus response. The costs associated with TC Marcus were allocated by apportioning them to asset categories in line with the maintenance group involved and an assessment of the work conducted in the response.

For further information on TC Marcus and its impact on our 2017-18 opex, refer to Section 3.

In the following chart, we show the breakdown of actual routine and non-routine maintenance costs for the 2008-09 to 2017-18 period, aligned with the regulatory information notice maintenance categories in our Category Analysis Regulatory Information Notice. The increase in maintenance activity and expenditure is evident from 2011-12 to 2012-13. Reviews in 2013 and 2016 drove the reduction in maintenance expenditure, as demonstrated in Figure 5-1 below. This was made possible by ongoing improvement to asset information, asset reliability and a more mature approach to risk management.

Figure 5-1 – Historical routine and non-routine maintenance opex ($M, Real 2018-19)

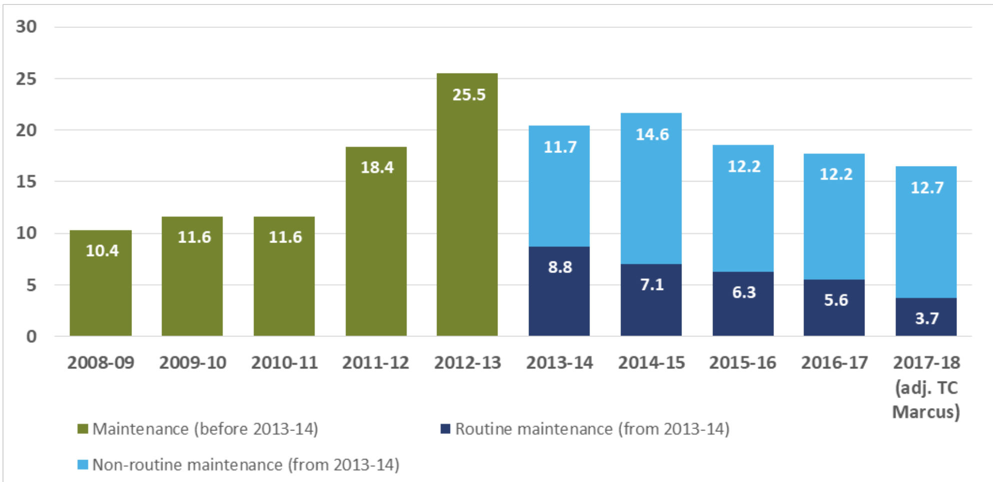


Figure 5-1 adjusts for the impact of TC Marcus on our maintenance expenditure. Notwithstanding this adjustment, there was still a reduction in maintenance opex in 2017-18.

We reviewed the causes of the lower maintenance expenditure in 2017-18, compared to previous years. Our routine maintenance program varies from year to year depending on which assets become due each year, according to the schedule of inspections and maintenance, and the level backlog carried over from the previous year. The variation in routine maintenance can be in the order of 10 per cent[7] between years. 2017-18 represented a low year in the cycle, while activities scheduled for 2018-19 are planned to exceed those of 2017-18.

Non-routine maintenance was slightly higher than previous years and this may be due to a similar cyclic nature in the completion of these activities, as a result of a greater level of routine activity in 2016-17 generating a larger non-routine program in 2017-18.

5.5.2 Our approach

The AER's approach to assessing our Initial Regulatory Proposal maintenance opex has allowed us to target our review of potential efficiencies, rather than continuing with the top-down unallocated efficiency adjustment proposed in our Initial Regulatory Proposal.

[7] Based on routine maintenance forecasts generated from Maximo, our asset management system.

We have updated our forecast maintenance expenditure to reflect the 2017-18 costs as per our audited regulatory information notice submission to the AER in October 2018.

The 2017-18 maintenance expenditure was normalized for the impact of TC Marcus, and was then assessed, in light of the AER's proposed efficiencies to our 2016-17 base year, to determine what efficiencies could be applied to our actual 2017-18 expenditure as the revised base year expenditure.

We reviewed the basis for the Draft Decision and, after undertaking our own analysis and comparison against similar utility peers, we agree with the AER that there is opportunity to further reduce inspection frequencies and improve our approach to risk management during the 2019-24 regulatory control period. However, we do not wholly accept the AER's analysis or method of adjustment.

The AER applied an adjustment to routine and non-routine expenditure based on its analysis of inspection and maintenance frequencies. It then further adjusted both routine and non-routine maintenance based on its assessment of our risk management maturity.

We have not made an adjustment to non-routine maintenance based on our analysis of inspection and maintenance frequencies. We consider this to be double-counting the efficiencies of a reduction in the frequency of routine maintenance and improved assessment of defects through the maturing of risk management practices.

Additionally, non-routine maintenance is not scheduled. However, the AER's approach assumes we have a control mechanism over the frequency at which essential non-routine maintenance is conducted, in addition to the application of a risk based decision as to whether an asset defect should or shouldn't be rectified.

Our analysis has sought to distinguish more clearly the opportunities and outcomes of both maintenance frequency benchmarking and risk management. It does this in a more targeted way that reflects their direct but different impacts on expenditure at the routine and non-routine maintenance category level.

We have considered that the following achieves the objectives of a prudent and efficient maintenance approach:

- Adjusting inspection/repair cycles for routine maintenance for optimal level of cost, efficiency and risk; and
- Adjusting risk-based repair policy for non-routine maintenance based on work priority for optimal level of cost, efficiency and risk.

5.6 Review of Draft Decision findings: inspection and maintenance frequencies

We considered the data provided by the AER in its Draft Decision to ascertain whether the analysis established a need to review our proposal. Our approach was to consider whether the analysis was sufficiently robust to infer that our proposed maintenance opex was inefficient relative to our peers. The results of our assessment for each aggregate asset class grouping are explained in more detail below. The resulting efficiency adjustments have been calculated based on the ratio of current and proposed frequencies, which is consistent with the AER's approach in its Draft Decision.

5.6.1 Lines and poles

We currently undertake 3 yearly inspections of our distributed assets. The AER considered that industry peers were undertaking inspections on a 4 or 5 year cycle and longer. The AER concluded that good electricity practice is an inspection cycle of 4.5 years and it applied this to us.

In making its adjustment to the maintenance opex, the AER assumed that we were currently undertaking inspections more frequently than the stated 3 years, and made a reduction to the associated expenditure on a ratio assuming movement from a 2 year inspection cycle to 4.5 years. The AER did not provide evidence to support its assertion that we were completing a 2 year inspection frequency of overhead assets.

We reviewed the comparisons made by the AER to industry peers, and used a similar methodology to quantify improvements that can be made to the 'lines and poles' inspection program if the frequency of inspections is adjusted from 3 to 4.5 years, as shown in Table 5-3.

Table 5-3 – Historical and proposed routine maintenance opex for 'lines and pole' assets

$M, Real 2018-19	2013-14	2014-15	2015-16	2016-17	2017-18	Proposed Base Year
Lines & poles	0.9	0.7	0.7	0.6	0.4	0.3

5.6.2 Earthings, distribution substations, zone substation property & pillars

Distribution substation inspections are undertaken concurrently with the 3 yearly distributed asset inspections. For other assets in this grouping, the frequency of inspections and testing varies by asset type including some distribution switchgear on a 5 year inspection cycle and LV pillars at 10 years.

The AER considered that industry peers were undertaking inspections and testing on a range of distribution substation plant on a 4 or 5 years cycle. The AER concluded that good electricity practice was 4.5 years and made an adjustment for us on this basis.

We reviewed the comparisons made by the AER to industry peers, and used a similar methodology to quantify improvements that can be made to the 'earthings, distribution substations, zone substation property & pillars' inspection program if the frequency of inspections is adjusted from 3 to 4.5 years, as shown in Table 5-4.

Table 5-4 – Historical and proposed routine maintenance opex for 'earthings, distribution substations, zone substations property & pillars' assets

$M, Real 2018-19	2013-14	2014-15	2015-16	2016-17	2017-18	Proposed Base Year
Earthings, distribution substations, zone substations property & pillars	3.8	2.7	2.7	2.4	1.4	1.0

5.6.3 Other assets: Zone substations (other assets), distribution switchgear and secondary systems

We undertake inspections of our zone substation plant on a cycle of between 2 and 6 years, depending on the risk of the substation plant. Secondary system maintenance is undertaken on a cycle of between 1 and 3 years. In addition, substation inspection, pest control and grounds maintenance is undertaken more frequently depending on environmental conditions.

The AER did not make any direct comparisons to industry peers or make any efficiency adjustments. However, in its Draft Decision, the AER noted an expectation that we would provide analysis of additional efficiency opportunities for these asset categories in our Revised Regulatory Proposal.

Our comparison to industry peers demonstrates that further improvements can be made to the inspection program to reduce the frequency of activities. The efficiencies gained in extending the inspection and maintenance frequency for routine maintenance are in these asset categories.

The level of adjustment for 'other assets' reflects our assessment of the criticality of those asset types in the context of network security and public safety, as well as the close alignment between maintenance tasks in these categories to reduce outages, particularly on our transmission circuit elements.

Table 5-5 – Historical and proposed routine maintenance opex for other assets - 'zone substation (other assets), distribution switchgear and secondary systems maintenance' assets

$M, Real 2018-19	2013-14	2014-15	2015-16	2016-17	2017-18	Proposed Base Year
Other assets	4.0	3.5	2.9	2.6	1.8	1.6

5.6.4 Proposed inspection and maintenance frequency efficiencies

We consider that our refined approach, summarized in Table 5-6, provides a more targeted assessment of the opportunities that exist specifically for routine maintenance activities.

Table 5-6 – Efficiency adjustment to routine maintenance by improved inspection / repair cycles

$M, Real 2018-19	Routine Maintenance	Current inspection frequency (Years)	PWC Proposed Change (Years)	Efficiency Adj. (%)	Opex Reduction
Lines and poles	0.4	3.0	4.5	(33%)	(0.1)
Earthings, distribution substations, zone substations property & pillars	1.4	3.0	4.5	(33%)	(0.5)
Other assets	1.8	3.0	3.5	(14%)	(0.3)

5.7 Review of Draft Decision findings: defect management and risk

In its Draft Decision, the AER stated that our high priority defects are reducing and low priority defects are increasing[8]. Given the asset and work management improvements from 2008 to today, fewer high priority defects should be expected. While the trend is evident, the impact is exaggerated for several reasons:

- The data reflects the number of work orders created. Whilst we consider that there is a direct relationship between the number of defects and the number of work orders, the data is not the number of asset defects we have recorded.

[8] AER, September 2018, Draft decision – Power and Water Corporation, Attachment 6: Operating Expenditure, p. 33.

- In 2015-16, enhancements to the inspection mobility solution:
    - o Enabled the capture of defects corrected on site, not visible in the earlier years of the data, which creates a step change in our data.
    - o Exposed existing defects in our system for inspectors to avoid duplication.

In its analysis of our submission, the AER concluded that

> *'There is opportunity for Power and Water to use a risk based classification of defects that account for service level implications, and not just the physical state of the asset, to inform and prioritise its inspection and maintenance activity.'*[9]

Our asset defect classification procedure outlines the framework for prioritisation of defects, based on a qualitative assessment of risk to service levels, health and safety and system security. An excerpt from our assessment guidelines for maintainers is shown in Figure 5-2 below.

Figure 5-2 – Asset defect classification procedure

Priority Level	Health, Safety & Environment	System Security	Asset Capacity
1	Immediate Very High or Extreme threat to HS&E.	System not secure.	Power interrupted to customers.
2	High HS&E threat likely at any time.	Asset functional failure likely at any time and will make system unsecure	Asset cannot be operated to full capacity and customer interruptions likely at any time
3	Low to Medium threat to HS&E but likely to deteriorate further.	Unlikely to threaten system security but likely if it deteriorates further.	Reduced capacity does not directly affect reliability but likely to deteriorate further.
4	No or Low threat to HS&E and further deterioration unlikely to increase threat.	No threat to System Security and further deterioration unlikely to increase threat.	Reduced capacity has no direct impact on operations and further deterioration unlikely.

We agree with the AER that the use of a more quantitative analysis of risk will further improve our approach to asset management. The application of a more

[9] AER, September 2018, Draft decision – Power and Water Corporation, Attachment 6: Operating Expenditure, p. 26.

rigorous risk assessment methodology is expected to reduce the timeframe and volume of defects required to be addressed. In turn, these changes are likely to reduce non-routine maintenance expenditure.

To develop an alternative proposed adjustment to non-routine expenditure based on maturing risk management practices, we reviewed a sample of work completed in prior years that had been assessed as of low priority. Based on this, the level of adjustment proposed is what we consider prudent defects, particularly for assets accessible by the public.

Typical examples of low priority defects include:

- Faded warning signs;
- Replacement of pole stay guards (hurdles) and pedestrian markers;
- Paint rectification on steel enclosures;
- Repair of lighting in buildings;
- Repairs to cracked concrete pole collars; and
- Minor oil leaks on zone substation transformer pipework.

The above defects relate to either a duty of care to the public to warn them of a hazard associated with our assets or a condition that would lead to accelerated degradation of the asset which may result in a significantly higher repair cost and/or a shorter asset life.

The above analysis has revealed that many current low priority defects would not lead to adverse service level outcomes if uncorrected. However, the impact would be a greater risk to the public and our personnel. They could also result in higher costs resulting from the response to injury or premature asset replacement activity. Whilst there is no economic or risk quantification, the completion of these defects is in line with work place health and safety obligations, and organizational policies. Additionally, feedback from our Customer Advisory Council with regard to our capital program clearly demonstrates a lack of support for us to defer the repair of defects that present a public safety hazard.

We reviewed the priority 4 defects and approximately 50 per cent are related to public safety and should be completed. Our Revised Regulatory Proposal has been adjusted to reflect the cost of this activity, and is shown in Table 5-7 below. The remaining priority 4 defects that will be left unresolved result in increased risk. These will ultimately require resolution through increased capital funding in the longer term and are currently unquantified.

For the protection and other zone substation assets, we have proposed a slightly higher reduction due to the lower public safety risk and other control and monitoring measures available to manage these risks, such as oil sampling.

5.7.1 Proposed risk management & inspection alignment efficiencies

Table 5-7 provides our proposed efficiency adjustments to non-routine maintenance relating to risk management and inspection alignment efficiencies.

The proposed efficiency adjustment only applies to non-routine maintenance, but is higher than the 6 per cent proposed by the AER based on our reviews of low priority work orders and in consideration of additional scheduling alignment opportunities.

Table 5-7 – Efficiency adjustment to non-routine maintenance by improved risk management and inspection alignment

$M, Real 2018-19	Non-routine Maintenance	Efficiency Adj. (%)	Opex Reduction
Lines and poles	2.1	10%	0.2
Earthings, distribution substations, zone substations property & pillars	6.3	10%	0.6
Other assets	4.2	12%	0.5
Total	**12.6**	**-**	**1.3**

5.8 Review of Draft Decision findings: network reliability

The Draft Decision also include reference to our improving reliability performance as further evidence of inefficiency in maintenance opex. The improvements in system reliability performance as a composite measure are reflective of a number of factors and strategies and cannot be linked solely to the effectiveness of the maintenance program.

Our performance targets set by the Utilities Commission are at a feeder category level. As shown in the charts below, urban and short rural feeder reliability has fluctuated around target levels and is generally trending upwards. Again, SAIFI is showing a steeper increase over the last few years, approaching target levels. 2017-18 CBD feeder results have also reinforced an increasing trend for both SAIDI and SAIFI due to a combination of several “one-off” asset failures and human error during switching activities.

Figure 5-3 – CBD feeder category performance against target

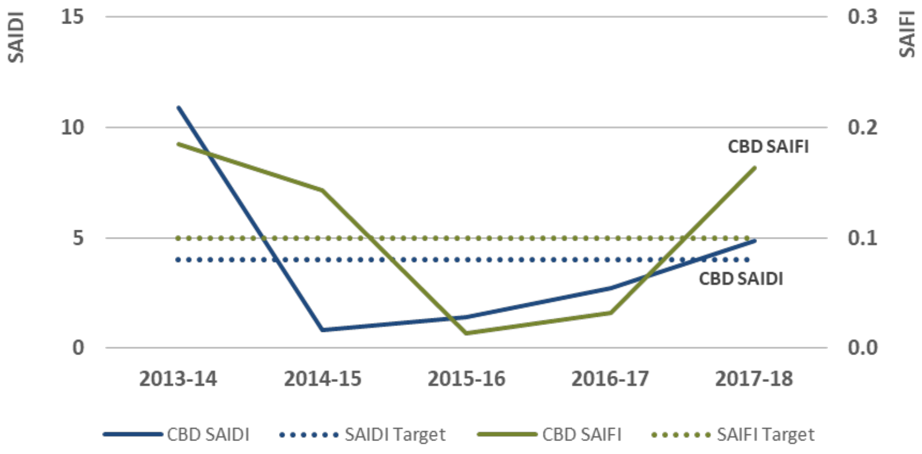


Figure 5-4 – Urban feeder category performance against target

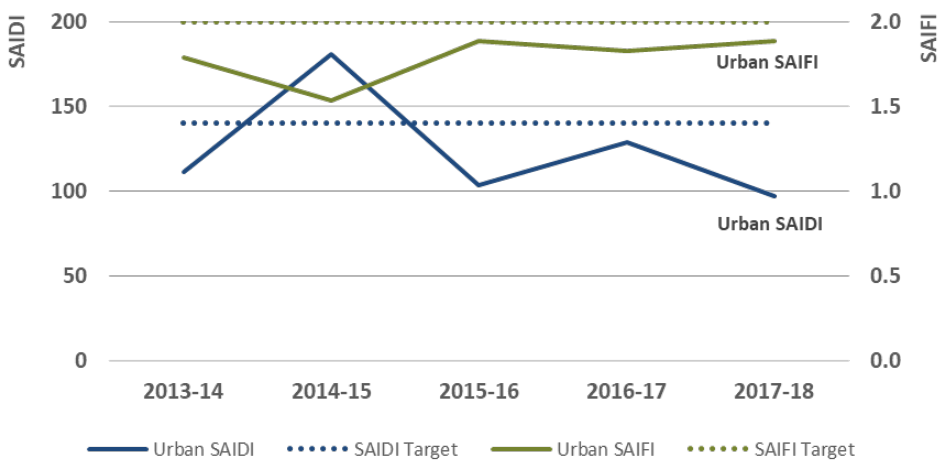
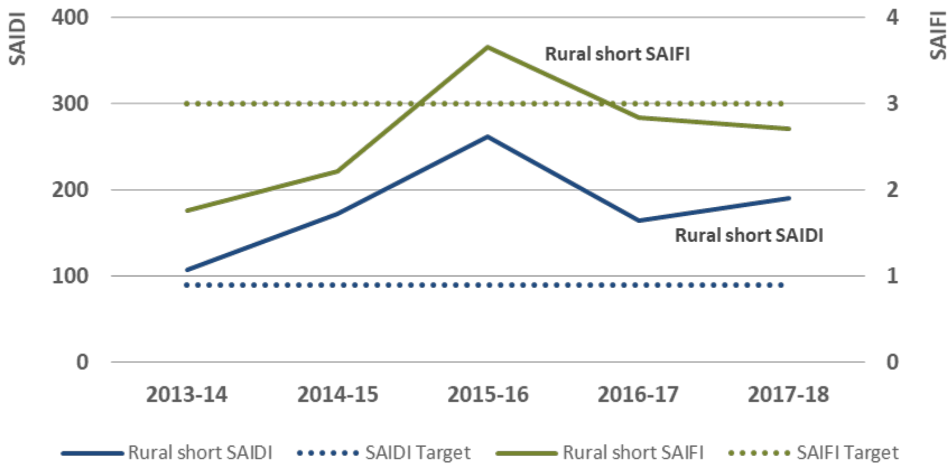


Figure 5-5 – Rural Short feeder category performance against target



As demonstrated in the charts above, the assertion that reliability is improving is arguable, and does not support the AER's view that we are over maintaining. If our maintenance opex is cut further beyond the substantial reductions we have proposed, we risk lower service performance, particularly for those feeder categories that are already showing a decline in reliability performance.

5.9 Revised base year maintenance expenditure

We have described above the AER's rationale for the individual efficiency adjustments included in its Draft Decision. In applying its efficiency adjustments to the base year maintenance opex, the AER included both routine and non-routine maintenance activities.

Changes to inspection and maintenance frequencies are primarily related to routine maintenance activities, and more rigorous risk assessment of defects is primarily related to non-routine maintenance. Accordingly, any adjustments to forecast maintenance expenditure should be similarly proportioned, and not applied to the total maintenance opex forecast.

In the development of an alternative maintenance opex forecast in our Revised Regulatory Proposal, we have considered the implications of changes to both the inspection and maintenance frequencies across our program, and the broader adoption of risk-based asset management, including application to the management of defects.

Table 5-8 provides our proposed maintenance opex efficiencies.

Table 5-8 – Maintenance opex efficiencies

$M, Real 2018-19	Efficiency estimate
Less frequent inspections & maintenance	0.9
Use of risk management & improved inspection alignment	1.3
Total	**2.2**

Table 5-9 details the efficient base year maintenance opex that we have proposed in our Revised Regulatory Proposal.

Table 5-9 – Base year maintenance opex

$M, Real 2018-19	RRP 2017-18 efficient base year
Maintenance opex	14.2

We are mindful that to be too aggressive in our approach to reducing maintenance expenditure would place increasing pressure on our assets in what is the arguably the harshest operating environment in Australia. Strategic planning also requires an even higher focus to ensure the balance between asset performance, risk and cost are balanced; something that will be highly challenging given our size and difficulty in attracting and retaining these resources.

6. Vegetation management

This section explains and justifies our revised base year vegetation management expenditure.

6.1 Activities included

We are responsible for maintaining safe clearance of all vegetation in proximity to power lines we own and operate. Typical vegetation management activities include:

- Removing, altering, or managing vegetation to maintain safe or regulated clearances from distribution or transmission assets; and
- Tree cutting, undergrowth control, root management, waste disposal, use of herbicide and growth retardants, and encouragement of low-growth vegetation to prevent the establishment of high-growth vegetation.

Vegetation management does not include "beautification" works, lawn mowing e.g. from natures strips, or office gardens, interior plant and aesthetic vegetation works, or any work done in proximity to non-network assets.

Our tree trimming obligations stem from the Northern Territory National Electricity Rules (NT NER).

Vegetation management obligations[10]:

A Network Service Provider must…..arrange for: management, maintenance and operation of its network to minimise the number of interruptions to agreed capability at a connection point on or with that network by using good electricity industry practice.

6.2 Our initial proposal

Our Initial Regulatory Proposal provided analysis that demonstrated our cost reductions in the 2014-19 regulatory control period, and compared them to other networks, including analysis regarding the points of difference. We have not presented this information again here.

[10] NT NER, Clause 5.2.3.e1.(3).

6.3 Response to information requests

After we submitted our Initial Regulatory Proposal, we provided additional information to the AER related to the proposed changes in vegetation management strategies, in particular the 2017 Pinnacle ArborPro (Pinnacle) report[11] findings and the status of implementation of the report's recommendations.

6.4 AER Draft Decision

In reviewing our proposed vegetation management opex, having regard to the information that we have provided through information requests and its own analysis of other regulatory proposals, the AER derived an alternative forecast of vegetation management opex and cut our base year allowance by 20 per cent.

The AER's Draft Decision includes consideration of four primary factors for efficiencies in vegetation management opex:

1. The AER considers that the implementation of the recommendations in Pinnacle's report would enable significant efficiencies.
2. The AER's experience from assessing other distribution network service providers' proposals.
3. The AER considers that we would be in a position to substantially implement the efficiencies prior to the commencement of the 2019-24 regulatory control period.
4. Previous high level estimates provided by us that there was a potential for 20-25 per cent savings in a 2016 review of routine maintenance frequencies and vegetation management.

A comparison of the Initial Regulatory Proposal to the Draft Decision is shown in the table below.

[11] Pinnacle ArborPro, August 2017, Project PWC16-212 - Darwin Vegetation Management Analysis Project Report.

Table 6-1 – Comparison of Initial Regulatory Proposal and Draft Decision – Vegetation management

$M, Real 2018-19	PWC IRP	AER Draft Decision
Base year	4.9	3.9
Variance to IRP		(1.0)

6.5 Revisions to our initial proposal

6.5.1 2017-18 Vegetation management expenditure

The table below provides both the actual 2016-17 audited expenditure included in our Initial Regulatory Proposal and actual 2017-18 audited expenditure.

Table 6-2 – Vegetation management opex

$M, Real 2018-19	2016-17	2017-18
Vegetation management opex	4.9	4.2

It is important to note that 2017-18 expenditure does not reflect the average cost of vegetation management under our current practices as there was no vegetation management activity conducted in the regions of Tennant Creek and Alice Springs in 2017-18. This is due to the implementation of a 2 year maintenance cycle, as previously recommended by Pinnacle. Vegetation management opex in the southern region is estimated to be $0.9 million in 2018-19 and the current forecast for 2018-19 for total vegetation management is approximately $5 million.

Under current practices, the average annual or "base" cost for vegetation maintenance should be considered to be close to $4.6 million. We have chosen to accept the lower 2017-18 expenditure of $4.2 million as our base year for the reasons outlined in the following sections.

6.5.2 Approach

We have updated our expenditure to reflect the 2017-18 actual costs as per our audited regulatory information notice submission to the AER in October 2018.

We reviewed the basis for the Draft Decision and, after undertaking our own analysis and comparison against peers, we agree that there is opportunity to further reduce our vegetation management expenditure from the 2016-17 levels presented in our Initial Regulatory Proposal. We, however, do not wholly accept the AER's analysis, for the reasons outlined further below.

In order to assess the ongoing viability of the proposed efficiencies, we reengaged Pinnacle to develop a bottom-up build of our recurrent efficient expenditure requirements.

6.6 Review of Draft Decision findings

While we agree with the AER that the potential exists for further efficiency improvements as a result of implementing the recommendations in Pinnacle's 2017 report, the quantification of these benefits appears to be a subjective assessment by the AER. We are aligning our vegetation management practices with other distribution network service providers for a number of reasons, however there are several important considerations that we believe the AER has overlooked in its Draft Decision, including:

1. The rate of vegetation growth, particularly in the northern regions (urban and rural residential areas) will not change and this is where most management activity and expenditure occurs. While inspection frequencies will ultimately be reduced through the implementation of the report's recommendations, the volume of vegetation being cut on average will not significantly change unless a significant amount of tree removals were to occur in the urban and rural residential areas around Darwin.

2. The AER does not appear to have considered the vegetation density of different businesses in any of its analysis. This is of particular concern given vegetation density is the primary driver of vegetation management activity.

3. We are limited by the willingness of customers to accept the harder cut backs of vegetation, something that has not been supported in our customer engagement forums to date. This sentiment will almost certainly apply to tree removals as well.

   > *'Across all groups, most were in favour of keeping tree-trimming to twice a year as they felt the impact on their bill was minimal and that the savings were not worth the potential risk of more outages, given how quickly vegetation grows in the area, or the visual impact of more severely cut trees.'* [12]

   The AER does not appear to have included an allowance for tree removals or considered the additional cost of widening corridors, or the risk of not being able to achieve the widening required.

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[12] Newgate Research, March 2017, Customer Attitudes to Power and Water's Future Service Delivery.

4. The isolation of our three separate networks and limited competitive tension in the market for these services. This has been demonstrated in the information on our previous vegetation management tenders provided to the AER and there has been no change in the market to improve expectations for future tenders. While we have aimed to better quantify expected work volumes and move towards similar strategies applied by other distribution network service providers, the success of this strategy is dependent on the market's response.

   The primary goal of Pinnacle's 2017 report was to better define the required work program and align it with industry practice to reduce risk for potential new participants in the market. A secondary outcome was the identification of efficiency opportunities, however the market's response to future tenders remains a significant factor in our ability to achieve lower vegetation management expenditure.

5. While other distribution network service providers experience similar conditions in parts of their networks to ours, the AER's conclusion that we are similar to Ergon Energy and Essential Energy is not a sound assessment. Ergon Energy and Essential Energy service vast areas of western Queensland and New South Wales, which are characterised by low rainfall that limits vegetation growth. Extensive use of SWER (41 per cent[13] and 16 per cent[14] compared with none for us) also minimises the footprint of overhead lines and associated vegetation exposure in these western areas.

   We face significant challenges associated with high growth rates, productivity impacts due to heat and humidity, and high average wind speeds that all apply to over 80 per cent of our overhead network, including almost all of our sub-transmission network and generator connection points.

   For larger utilities, like Essential Energy and Ergon Energy, increased costs associated with maintaining challenging environments within parts of their networks are materially offset due to economies of scale, their access to a much more competitive market and ability to draw on a significant resource pool when an issue does emerge.

[13] Ergon Energy, September 2017, Distribution Annual Planning Report: 2017-18 to 2021-22.

[14] Essential Energy, December 2017, Asset Management Distribution Annual Planning Report 2017.

6. The AER has used a high level assessment figure from 2016 that discussed the potential for 20 to 25 per cent savings to our 2015-16 expenditure levels of $5.4 million rather than our 2016-17 levels.

We do, however, acknowledge that our own assessment of potential efficiencies as a result of Pinnacle's recommendations was limited in our Initial Regulatory Proposal. Without further analysis of the impact on vegetation expenditure, the AER has justifiably challenged the efficiency and prudency of our initial forecast based on its experience with other distribution network service providers.

6.6.1 Status of the recommendations

The initial analysis of our vegetation management practices and opportunities provided by Pinnacle did not include in-depth analysis of the costs associated with establishing the vegetation zone approach, or quantify the ongoing volume of work. The key driver for the work was to define the required work volumes and other improvement opportunities to be considered for the development of our next vegetation contract.

In response to an information request from the AER, we described our progress towards implementing the recommendations. We have progressed much of the work associated with enabling systems to better record vegetation management data, however transition planning is still in very early stages. There is also significant work required to align our service provider's management systems with our own to facilitate the efficient transfer of data to our systems. This is currently a very manual process that takes several weeks of data cleansing.

Many of the efficiency opportunities require material changes to the vegetation management contract structures, vegetation clearance standards and procedures defined in the current contracts, as well as a significant volume of additional work over a period to widen vegetation clearances. The widening of vegetation corridors is particularly dependent on customers' acceptance of different visual appearance of vegetation in residential areas as a result of tree removals and more aggressive trimming.

Historically, we have experienced the consequences of poorly managed changes in vegetation strategy and the rapid escalation of vegetation related reliability issues that can occur due to the fast growth rates in the northern region. Our approach to the strategy change has been considered and must be taken in context with the resource challenges and customers' desire not to sacrifice visual aesthetics in the community for limited savings.

In response to an information request, we also noted that there would be no actual change to frequencies, other than that already implemented for the southern region, prior to the new contract(s) commencing in July 2019. The significant volume of additional work required to achieve desired inspection and trim frequencies also requires careful planning for each zone, negotiation with customers and tree owners and direct monitoring of regrowth to validate assessments of clearances required to achieve desired frequency.

It is our expectation that the initial assessment, planning and establishment of new cutting frequencies will take several years. A significant volume of 'inter-cycle' trimming will be required to manage the vegetation that cannot be cut back or removed to achieve target cycles for an extended period of time and in some cases indefinitely, particularly where trees are protected for environmental or cultural reasons. As an example, we cannot currently remove any tree in the Alice Springs Township without consultation with the Aboriginal Area Protection Authority (AAPA), regardless of the tree species or age. This same requirement extends to any Crown land.

The scope of the change has presented significant challenges to the small team of asset and contract managers, all of whom were also maintaining business-as-usual activities, particularly during the previous 18 months while these resources have also been heavily engaged in the preparation of our first Regulatory Proposal to the AER.

In summary, while there has been progress towards implementing the proposed changes, there is still a significant amount of activity required in our systems, processes and within the network itself to fully implement and realise the benefits of the proposed strategy. This does not align with the AER's conclusion that we would be in a position to substantially implement efficiencies prior to the commencement of the 2019-24 regulatory control period.

6.6.2 Interstate comparisons

The AER has benchmarked our vegetation management opex per km of route length against customer density. We have considered this comparison and make the following observations:

- The AER has used an average of our costs that includes years of higher expenditure in 2014-15 and 2015-16. The expenditure included in our Initial Regulatory Proposal's base opex represented a reduction from these levels and therefore using a longer term average in the comparison misrepresents our Initial Regulatory Proposal and the improvements made in recent years.

- Customer density has no relationship to vegetation management expenditure. Based on the hypothesis put forward by the AER, two networks with identical customer densities should have similar vegetation management expenditure, which fails to consider whether the utilities exist in similar operating environments, for example in a desert or densely vegetated tropics.

- Similarly, opex per route line length does not account for the differences in vegetation between the service areas of each business. The extreme example above of two electricity networks in desert versus tropical environments applies in the same way.

We have undertaken further benchmarking analysis that takes into account the differing vegetation densities between distribution network service providers[15]. In the figure below, cost has been compared against vegetation density measured in trees per km, as the density is the key driver for vegetation expenditure. That is, the more trees there are per km to trim/remove, the greater the cost per km will be.

Figure 6-1 - Total vegetation cost / Route km vs. Vegetation density ($000, Real 2018-19)

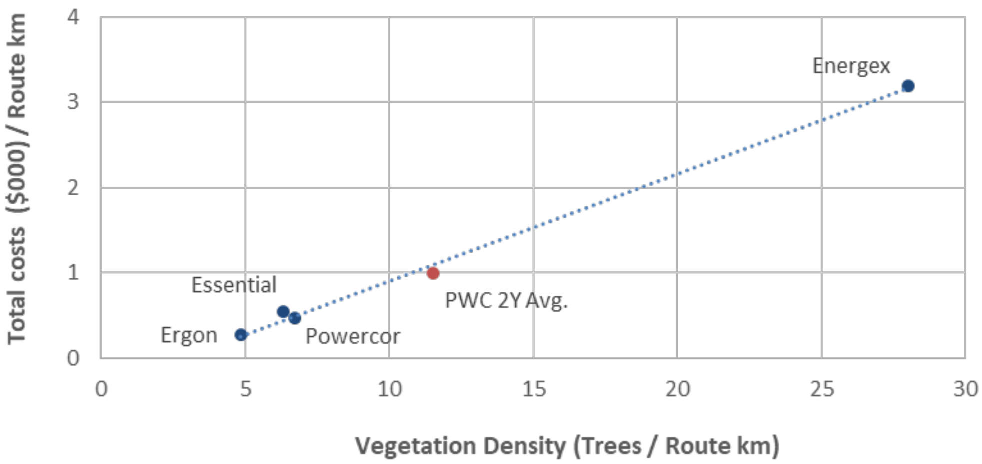


Figure 6-1 above shows that there is a very linear relationship between total vegetation costs and vegetation density with no utility varying significantly from the trend line.

[15] We have sourced data from regulatory information notices submitted to the AER for 2016-17. We included a two year average for Power and Water that includes both 2016-17 and 2017-18 expenditure.

Figure 6-2 - Inspection, trimming and audit cost / Route km vs. Vegetation density ($000, Real 2018-19)

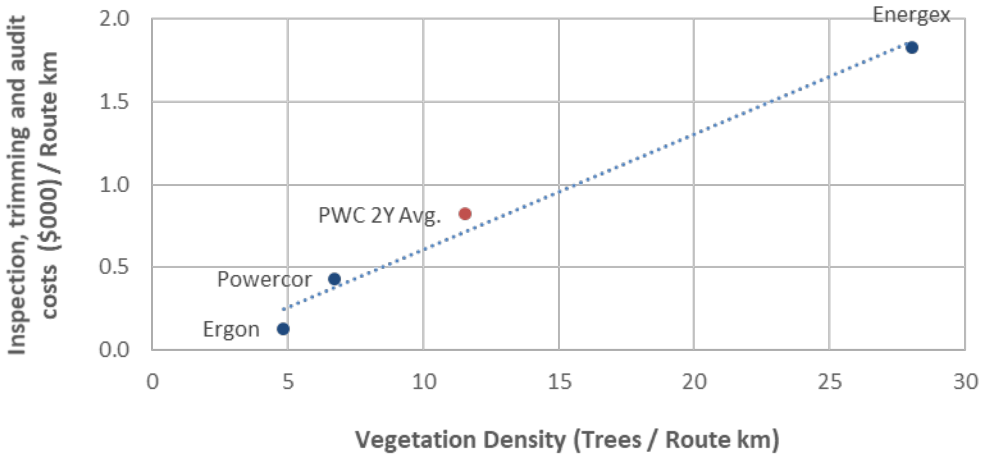


Figure 6-2 shows our inspection, trimming and auditing costs for 2016-17 and 2017-18 (averaged out) to be only marginally above the trend line[16].

The ratio of urban to rural maintenance spans is also likely to have an impact on cost as urban trimming will often involve additional costs for traffic control and removal of cut vegetation. However, there is insufficient public data available to assess the impact that the ratio of urban to rural maintenance spans has on the cost for the various utilities.

In addition to the benchmarking results in Figures 6-1 and 6-2 above, we have completed additional analysis of vegetation management data provided to the AER by other distribution service providers. The following observations can be made:

- We compare poorly with peers on high level measures such as vegetation opex per km. This is unsurprising given differences in vegetation density between businesses, our isolation from major centres and markets, and economies of scale.
- At a category level, we compare favorably with other business on a cost per maintenance span basis. This is demonstrated in Figure 6-3 below, which shows a declining trend in our vegetation management spend per maintenance span to more comparative levels.

[16] We have sourced data from regulatory information notices submitted to the AER for 2016-17. We included a two year average for Power and Water that includes both 2016-17 and 2017-18 expenditure.

- At a category level, we compare favorably with other businesses on a cost per tree basis. This is demonstrated in Figure 6-4 below, which shows a declining trend in our vegetation management spend on a per tree basis to more comparative levels.

Figure 6-3 – Vegetation management cost per maintenance span (Real 2018-19)

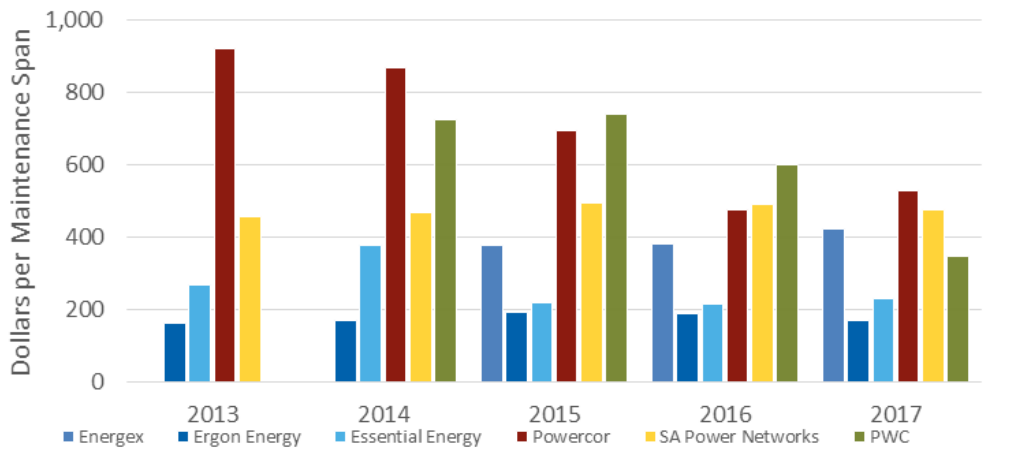
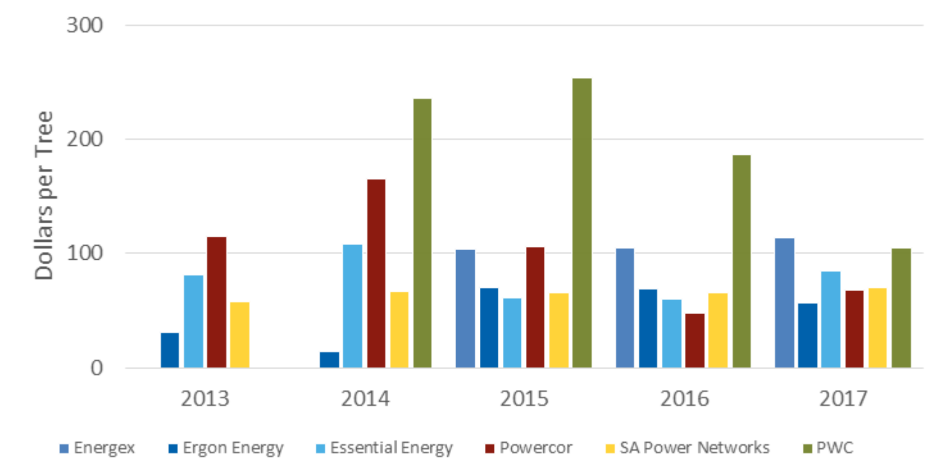


Figure 6-4 – Vegetation management cost per tree (Real 2018-19)



In summary, using measures that relate to vegetation management expenditure drivers, such as vegetation density and maintenance spans, we are already performing comparably to other businesses. Our ability to meet the challenge of maintaining 2017-18 expenditure levels is dependent on both external stakeholders, who have previously indicated that they are unsupportive of changes to tree trimming practices, and the market environment.

6.6.3 Our revised proposal

In order to determine the cost associated with implementing the original recommendations of Pinnacle's report, and the resultant efficiencies in the vegetation management program, we have reengaged them to provide further analysis of each of the following components of a bottom-up vegetation management forecast:

- Routine inspection and treatment program;
- Corridor clearance program;
- Ground clearance;
- Hazard tree treatment;
- Internal management costs associated with the vegetation program;
- Additional clearing costs to implement the cycle times for the vegetation zones, as recommended in Pinnacle's original report; and
- Additional tree removals in the Alice Springs' regions to remove unsuitable tree species that have been planted under powerlines and are now becoming a maintenance issue. An allowance for additional trimming has also been included until the problem trees have been removed.

The output of Pinnacle's additional analysis has shown that the efficiency opportunity is not as significant as that estimated by the AER (20 per cent) and that there are a variety of risks that will limit our ability to achieve even a more moderate efficiency target.

The risks identified by Pinnacle include:

- The new tender rates being higher than forecast, especially with limited competitive tension in the Territory market for these services;

- Our ability to reduce the number of "cycle buster"[17] spans as planned because of customer opposition;

- The analysis uses productivity rates typical in other utilities and not what is currently achieved in the Territory. The rates may not be achievable in the Territory's hot and humid climate, or at least for a significant proportion of the year. It also does not consider the accessibility issues during the Territory's wet season;

- The longer cycle times increasing trimming requirements, reducing productivity and hence offsetting the reduction in inspection costs achieved through less frequent inspections;

- Estimated treatment requirements being less than actual future requirements; and

- Our ability to develop a balanced work program that limits inconsistent resourcing requirements from year-to-year and avoids increased mobilisation and on-boarding costs for the service provider.

The analysis provided by Pinnacle demonstrates that average annual expenditure above 2017-18 levels is likely to be required during the 2019-24 regulatory control period and that there will still be a significant amount of inter-cycle trimming required.

There is a significant and quantifiable amount of work required to widen vegetation clearance zones and remove vegetation to achieve the proposed cycle times, and much of this work is required in residential areas where residents are not under any obligation to allow us to establish the clearances required to achieve proposed cycle times. A risk-based approach has been used in the analysis and the likelihood of gaining tree owner approval to remove trees in cycle buster spans has been applied.

Pinnacle's report entitled "Power & Water Corporation Vegetation Management Forecast for the 2019 to 2024 Regulatory Control Period" provides full details of this analysis and bottom-up forecast, and is at Attachment PWCR02.3C[18].

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[17] Cycle buster span is a term we have created to describe spans within a zone which require trimming at a higher frequency than that defined for a zone. Typically these would be due to large overhanging trees that cannot be removed due to the owner not allowing removal, being of a protected species, or culturally significant.

[18] PWCR02.3C - Pinnacle ArborPro - Power Water Corporation Vegetation Management Forecast for the 2019 to 2024 Regulatory Control Period - 29 Nov 18 – CONFIDENTIAL.

Given the material underlying risks and the results of Pinnacle's bottom-up forecast, we consider that the actual 2017-18 expenditure, representing a 13 per cent reduction on our 2016-17 expenditure, is the minimum expenditure requirement necessary for the efficient management of vegetation in the vicinity of our overhead electricity assets. Whilst the 2017-18 expenditure is not representative of our current expenditure requirements, we believe it is achievable in the 2019-24 regulatory control period with both the implementation of the key recommendations and the realization of the benefits of our proposed ICT capital program.

Specifically, the Outage Management System, Maximo upgrade and enhanced mobility projects will provide the most significant opportunities to better understand both the performance of vegetation management in terms of task efficiency and reliability outcomes. These projects are planned for completion in the second half of the 2019-24 regulatory control period and therefore they are likely to have a more substantial impact on the subsequent regulatory control period.

Revised base year vegetation management expenditure

Table 6-3 below provides our base year vegetation management opex, which represents a 13 per cent reduction to our Initial Regulatory Proposal.

Table 6-3 – Base year vegetation management opex

$M, Real 2018-19	RRP 2017-18 efficient base year
Vegetation management opex	4.2

7. Network overheads

This section explains and justifies our revised base year network overheads' expenditure.

7.1 Activities included

Network overhead costs relate to the provision of network, control and management services that cannot be directly identified with specific operational activity (such as routine maintenance, vegetation management, etc.).

7.2 Our initial proposal

We presented a number of differences in our operating environment factors compared with other distribution network service providers, such as our extreme weather and network characteristics, which drive our costs. We have not represented this information.

Our Initial Regulatory Proposal noted that there was some room to improve our network overhead expenditure. The 10 per cent efficiency target in our proposal was intended to come partly from a reduction in network overhead expenditure (for presentational purposes we assumed 50 per cent of the total efficiency adjustment), and the Target Operating Model would contribute towards us achieving this stretch target.

7.3 Response to information requests

After we submitted our Initial Regulatory Proposal, we provided additional information to the AER, including further information on our revised capitalisation approach, implemented to bring us more in line with the practices of other distribution network service providers; our regulatory costs and professional fees; key projects and initiatives implemented this current regulatory control period; and our service level agreement expenses.

7.4 AER Draft Decision

The AER did not accept the network overhead base year opex proposed in our Initial Regulatory Proposal and developed an alternative estimate of network overhead opex using our historical expenditure as the basis. An allowance was included to incorporate the additional costs the AER considered were required over the 2019-24 regulatory control period. In doing so, the AER set aside the efficiency adjustments proposed in our Initial Regulatory Proposal.

A comparison of our Initial Regulatory Proposal to the AER's Draft Decision is shown in the table below.

Table 7-1 – Comparison of Initial Regulatory Proposal and Draft Decision – Network overheads

$M, Real 2018-19	PWC IRP	AER Draft Decision
Base year[1]	27.1	25.8
Variance to IRP		(1.1)

[1]We proposed a top-down efficiency adjustment of 10 per cent to our base year opex, which would be partly realised from a reduction in network overheads expenditure. For presentational purposes we assumed 50 per cent of the total efficiency adjustment would come from network overheads in our Initial Regulatory Proposal and that is replicated in the table above.

7.5 Revisions to our initial proposal

7.5.1 2017-18 network overheads expenditure

Table 7-2 below shows our 2017-18 audited network overheads expenditure, broken down into the main cost types.

Table 7-2 – Network overheads opex

$M, Real 2018-19	2016-17	2017-18
Corporate allocations	3.8	3.2
Professional fees	3.4	6.5
Service Level Agreement expenses	2.9	2.8
Personnel costs	14.8	21.8
Vehicles	0.6	0.5
Other	4.8	4.0
Total	**30.2**	**38.8**

A brief description of each cost type is provided below:

- Corporate allocations: Power Networks receive an allocation of certain costs incurred outside of it (such as legal and financial services) under our AER-approved CAM[19].

[19] Power and Water Corporation, 2017, Cost Allocation Method for Distribution Services v1.0.

- Professional fees: this category captures the costs incurred for the engagement of external advice and expertise.
- Service Level Agreement expenses: these are costs incurred by Power Networks as a result of Service Level Agreements (agreements that outline the services and responsibilities of both parties and associated charging arrangements) with other Power and Water business units.
- Personnel costs: this category includes personnel costs such salaries, overtime, recreation level, superannuation, apprentice and contract labour, as well as on-costs and personnel labour recoveries.
- Vehicles: this category captures the costs associated with Power Networks' fleet, as well as any other vehicle hire charges.

The increase in professional fees is reflective of the increased regulatory burden we are experiencing as we transition towards the adoption of the National Electricity Law and Rules. Our total Power Networks' personnel costs have remained relatively stable between the two years; the increase in 2017-18 overheads is largely reflective of the allocation process. These costs are addressed in our assessment of non-recurrent expenditure to ensure that our costs are minimised.

In addition, as discussed in further detail in Section 8, 2017-18 is the first year that Appendix 1 of the AER-approved CAM, which details how we allocate out our shared corporate costs between our business units, has been applied to our audited opex.

Prior to 2017-18, we applied a cost allocation method that was developed before our transition to the NT NER, and was not approved by the AER. The AER-approved CAM applies refreshed causal cost drivers at a more granular level to our current corporate structure, ensuring a more appropriate allocation of costs between our business units. This ensures that we recover a prudent level of costs from our electricity network tariffs.

This change in the allocation of costs has resulted in an increase of corporate costs being allocated to the Power Networks' business unit. The majority of the cost impact is experienced in the corporate overheads expenditure category, however, network overheads also increased by $1.1 million as a result of the change in cost allocation.

7.5.2 Approach

We have updated our network overheads' expenditure to reflect the 2017-18 costs as per our audited regulatory information notice submission to the AER in October 2018.

The 2017-18 expenditure was then reviewed to remove costs we considered to be non-recurrent and not representative of our future expenditure requirements. We also assessed it to determine whether further efficiencies could be made on our remaining recurrent expenditure.

We consider this, rather than adopting the approach taken by the AER, results in base opex that is most reflective of our ongoing requirements.

7.6 Non-recurrent spend

We have carefully reviewed our audited 2017-18 expenditure to ensure that only recurrent expenditure representative of our future expenditure requirements has been included in our base year spend for network overheads.

7.6.1 Professional fees

The legislative and regulatory framework within which we operate is undergoing extensive changes. The NT Government is committed to adopting a more harmonized approach to economic regulation of the NT's electricity networks with jurisdictions in the National Electricity Market, as appropriate for the NT.

The Department of Treasury and Finance on behalf of the NT Government is undertaking a progressive adoption of the National Electricity Law and Rules from 1 July 2016, as provided for under the *National Electricity (Northern Territory) (National Uniform Legislation) Act*, including exemptions as necessary to ensure the costs do not outweigh the benefits to Territorians in the longer term.

Mature, well-established distribution network service providers in other jurisdictions have operated under the national framework for many years and have been able to respond gradually as it has evolved. However, the current framework is new for us and we are on a steep-learning curve as we begin to apply it. This has resulted in a significant internal priority project, Transition to the National Electricity Rules, which has the following four programs of work under it:

- 2019-24 Distribution Determination;
- NT Transitional Negotiations (NER Derogations);
- Transition to Compliance; and
- Jurisdictional Code Review.

In order to advance these programs of work, particularly the 2019-24 Distribution Determination, we have needed to rely on external assistance. This is due both to the difficulties with sourcing permanent staff in the NT and the need to engage specialist expertise.

In 2017-18, we spent $6.5 million on professional fees and Table 7-3 provides a further breakdown of the drivers of these costs.

Table 7-3 – 2017-18 professional fees opex

$M, Real 2018-19	2017-18
2019-24 Distribution Determination	3.9
NT Transitional Negotiations & Jurisdictional Code Review	0.4
Regulatory Information Notice	1.0
Business-as-usual	1.2
Total	**6.5**

For the purposes of our opex base year, we assessed what expenditure would be required to fulfil our obligations during the 2019-24 regulatory control period. Table 7-4 provides a breakdown of our recurrent (by driver) and non-recurrent professional fees' expenditure.

Table 7-4 – Recurrent & non-recurrent professional fees' opex

$M, Real 2018-19	2017-18
Recurrent expenditure	**4.4**
2024-29 Distribution Determination	1.8
NT Transitional Negotiations & Jurisdictional Code Review	0.2
Regulatory obligations / Transition to compliance	1.4
Regulatory Information Notice	0.5
Business-as-usual	0.6
Non-recurrent expenditure	**2.1**
Total	**6.5**

As shown in Table 7-4, $2.1 million of our 2017-18 professional fee expenditure is determined to be non-recurrent and we have therefore removed it from our opex base year. The remaining $4.4 million is recurrent expenditure that we require on an annual basis for the 2019-24 regulatory control period.

2024-29 Distribution Determination

We have removed the non-recurrent professional fees that we incurred to prepare our Initial Regulatory Proposal to the AER that will not be required in future determinations.

We undertook a significant amount of work for the first time as we developed our Initial Regulatory Proposal under the NT NER. This included the initial development of documents such as our Strategic Asset Management Plan and the individual Asset Management Plans. In doing so, we relied on external expertise and these costs are included in our 2019-24 Distribution Determination costs in Table 7-3.

We do not consider that these costs will be required to complete our 2024-29 Distribution Determination and have therefore removed them from our base opex.

We have allocated 60 per cent of the remaining recurrent distribution determination costs spent in 2017-18 to the development of our 2024-29 Distribution Determination, in line with the standard approach applied by the AER.

Regulatory information notice

We submitted our first regulatory information notice to the AER on 16 March 2018. This included the submission of historical expenditure going back to 2005-06 and required significant external resources, including a comprehensive external audit of our historical data.

Submission of regulatory information notices are now an annual regulatory requirement, however, we have only allocated 50 per cent of the 2017-18 expenditure as recurrent. Our external audit requirements will reduce as we will only be required to audit one year of financial data each year. We also expect to require less external support as this regulatory obligation transitions to a business-as-usual requirement and is resourced further by internal staff.

The remaining 50 per cent of costs have been excluded from our base opex.

Business-as-usual

Our business-as-usual costs include professional fees relating to annual pricing submissions, workplace reviews and assistance with the development of standards and planning documentation. We have reviewed our 2017-18 professional fees and determined that only 50 per cent of our business-as-usual costs are required on an annual basis throughout the 2019-24 regulatory control period.

The remaining 50 per cent of costs have been excluded from our base opex.

NT Transitional Negotiations & Jurisdictional Code Review

As previously mentioned, the Department of Treasury and Finance on behalf of the NT Government is undertaking a progressive adoption of the National Electricity Law and Rules. Significant further regulatory changes are still expected, but there remains uncertainty about their nature, likelihood and timing. That uncertainty is likely to continue into the 2019-24 regulatory control period, with material changes expected during that period.

We are involved in the transition to ensure that bespoke instruments and differential rules suitable for the NT are developed.

We are also involved in the comprehensive review of the current jurisdictional codes, which was expected to be completed prior to July 2019. However, there have been significant delays with the program of works. The codes that are yet to be finalised are:

- Electricity Retail Supply Code;
- System Control Technical Code;
- Network Technical Code and Planning Criteria;
- Ring Fencing Code; and
- Loss Factor Code.

It is expected that the programs will continue throughout the 2019-24 regulatory control period, albeit at reduced levels. Therefore, we consider that 50 per cent of the 2017-18 expenditure is required on an ongoing basis to fulfil these programs of work.

The remaining 50 percent of costs ($0.2 million) has been allocated to fulfill our ongoing and future regulatory obligation requirements.

Regulatory obligations / Transition to compliance

We have accepted the AER's Draft Decision to reject our proposed connections, Type 7 metering compliance, MDMS and planning resources step changes on the basis that our revised base opex is sufficient to cover the costs of current regulatory obligations, the transition towards our future compliance obligations, and the costs underpinning the step changes included in our Initial Regulatory Proposal.

As outlined above, 60 per cent of the remaining recurrent distribution determination costs spent in 2017-18 have been allocated to the development of our 2024-29 Distribution Determination. We consider that the remaining 40 per cent, along with 50 per cent of the NT transitional negotiations/code review expenditure, is required to manage the transition towards, and maintenance of, the regulatory obligations expected in the 2019-24 regulatory control period.

We have experienced a significant increase in our workload as we have transitioned to the national framework. We did not consider that our 2016-17 opex was reflective of the regulatory burden that we will face in the 2019-24 regulatory control period. However, there has been an uplift in our 2017-18 expenditure, reflecting the increased workload.

These costs are likely to transition from professional fees to personnel costs as we recruit to the required positions over the 2019-24 regulatory control period.

Planning and engineering

We have relied on external support to manage the increased regulatory burden, and to ensure that we meet the minimum expectations of the AER and other stakeholders including various customer advocacy groups.

As this becomes our business-as-usual approach, we consider it prudent to lessen our reliance on specialist advice and build up the capability internally.

We have removed the costs associated with the initial development of significant internal documentation such as our Strategic Asset Management Plan and the individual Asset Management Plans. There will, however, continue to be a cost associated with maintaining these documents to ensure that they continue to be reflective of best practice and our work program. This will rely on the development of our systems and processes to support a more quantitative risk management approach to decision making.

We currently have limited internal capability to progress the maturing of our asset management approach whilst also concurrently maintaining our operational responsibilities. We have relied on specialist advice to assess the risks and benefits of investments using quantified values for reliability risks. Building these skills internally will ensure that we continue to appropriately rank and prioritise our investments and adopt best practice methods.

We recognise the need to keep pace with contemporary practices of peer distribution network service providers. Improvements in our asset management practices and investment assessments will reduce costs and improve reliability outcomes for customers in the long term.

During the 2019-24 regulatory control period we will also be required to meet new compliance obligations for developing and planning our network under Chapter 5 of the NT NER commencing on 1 July 2019. We are not currently required to analyse our demand forecasts to the degree required by Chapter 5 of the Rules. Further, we do not have dedicated resources to develop and administer the demand management engagement framework required under the NT NER.

From 1 July 2019 we will also be required to develop a Distribution Annual Planning Report (DAPR) under Chapter 5, which will require us to develop system and data reporting methods to produce the final report. The DAPR is an extensive report requiring significant input and coordination, and represents a material increase to our current reporting requirements.

Connections

Chapter 5A of the NT NER will apply in the NT replacing the current connections process outlined in the Electricity Networks (Third Party Access) Act.

Amongst other things, Chapter 5A requires the provision of Basic and Negotiated Connection Services to be extended to all customers wanting to connect to or upgrade existing connection services to the network. This will require a significant increase in administrative resources over and above the current discretionary arrangement of offers only being extended to the larger and/or more complicated network connections or upgrades (i.e. only about 25 per cent of current connections).

In addition to the extension of offers being made to all future customers (basic or negotiated) requiring new or upgraded connection services, the new regulatory obligations proposed require the implementation and administration of an associated Capital Contributions Policy.

7.6.2 Labour

Direct labour recoveries

In 2017-18, our scheduled capex program was considerably lower than our previous year's expenditure and also lower than the average of our forecast 2019-24 capex, as demonstrated in Table 7-5 below. This reduced our labour being utilised to complete capital works, and therefore more expenditure is treated as opex in our accounts. This opex is non-recurrent and therefore has been removed from our base year.

Table 7-5 – Direct capex

$M, Real 2018-19	2016-17	2017-18	Average 2019-24
Direct capex	69.9	43.9	62.1

Similarly, there was a decrease in maintenance work in 2017-18, which means less direct labour attributed to opex. The residual labour has been included in our 2017-18 network overheads opex but has been determined to be non-recurrent and therefore removed from our base year.

These amount are provided in Table 7-6 below.

Table 7-6 – Non-recurrent expenditure – direct labour

$M, Real 2018-19	2017-18
Direct labour - capex	3.5
Direct labour - maintenance	0.7
Total adjustment	**4.1**

Indirect labour

In accordance with our AER-approved CAM, we capitalise our indirect labour costs between capex and opex in the same proportion as direct expenditure, i.e. we apply the ratio of direct capex to direct total expenditure (capex/totex – our 'capitalisation rate') to our indirect labour costs. A low capitalisation rate in 2017-18 has resulted in more expenditure treated as opex than required in the future.

To take this into account, and ensure that our opex is only reflective of our ongoing requirements, we have removed the non-recurrent amount of indirect labour that is in our network overheads opex that would normally be treated as a capitalised overhead. This decrease in opex has been offset in our capitalised overheads forecast. This amount is provided in Table 7-7 below.

Table 7-7 – Non-recurrent expenditure – indirect labour

$M, Real 2018-19	2017-18
Indirect labour - Impact of low capitalisation rate	1.0

7.6.3 Capitalisation of leases

As discussed further in Section 11, we have made an adjustment to reflect the fact that, from 1 July 2019, we will start to capitalise leases in accordance with new Australian Accounting Standards.

7.6.4 Adjustment for non-recurrent expenditure

Table 7-8 below provides our network overheads' non-recurrent expenditure that has been removed from our base opex.

Table 7-8 – Network overheads - non-recurrent expenditure adjustment

$M, Real 2018-19	2017-18
Professional fees	2.1
Direct labour	4.1
Indirect labour	1.0
Total adjustment	**7.2**

Note that we have removed the lease cost adjustment at the total opex level (rather than at the expenditure category level) and therefore Table 7-8 does not take the removal of that non-recurrent expenditure into account. It is accounted for in the 'capitalisation of leases adjustment' line item in Tables 2-1 and 2-2.

7.7 Efficiency adjustment

We have applied a 10 per cent efficiency target to our recurrent network overheads' opex.

Whilst we are yet to define the individual initiatives that will be implemented in order to achieve these efficiency targets, several of our priority projects, such as our Target Operating Model and ICT capital program, will be essential in realizing these efficiencies. These projects were also recognised as an important part of achieving the top down 10 per cent efficiency reduction to our total opex proposed in our Initial Regulatory Proposal.

7.7.1 Target Operating Model

Our Target Operating Model program is intended to transition the organisation to a new Operating Model to improve the capability embedded in organisational structures, processes, systems, data and personnel. This will allow us to deliver better value for our customers and the NT.

This is a Power and Water portfolio-wide initiative, and is supported by the Corporation's other priority projects, in particular our ICT capital program. Investments in upgrading and implementing new ICT systems will assist us in implementing and progressing organisational change.

The Operating Model program is focused on the following capability areas:

1. Establish a **24/7 Operations Hub** to service the whole of the NT with real-time operations' support, which will provide better fault response and improved customer outcomes.
2. Establish centralised **Asset Management** and **Capital Project Delivery** functions to drive improved and standardised practices and governance.

This is seeking to leverage the progress made within Power Networks in recent history.

3. Establish a centralised **Service Delivery/Works Management** function and system to enable a standard approach to works' planning, scheduling and dispatch and integrated resource planning.
4. Delivery of **improved customer billing and service outcomes**. This includes addressing issues with our Meter Data Management and Billing systems, driving regulatory compliance and end-to-end traceability of meter asset and consumption data.
5. Increased **commercial acumen**, including end-to-end supply chain management and integrating finance processes into core operations, and focus to change from understanding the financials to enhancing financial performance.
6. People & Culture will drive **consistent job titles, structure and training frameworks** across Power and Water.

The project is in its infancy and scoping stage rather than decision and implementation stages.

The first Blueprint Phase of the program has recently been completed and a high level Roadmap has been developed to achieve the above mentioned capability improvements.

The Roadmap sequencing is still being worked through at an Executive Leadership Team and Board level to align with the business priorities and to ensure the sequencing of the initiatives under the other priority projects are also aligned, including ICT systems implementation.

At this early stage, we expect the program will run throughout the 2019-24 regulatory control period.

7.7.2 Impact on base year

Our Initial Regulatory Proposal included a top down 10 per cent efficiency reduction, recognizing that there was room for improvement in our 2016-17 expenditure. We took this proactive forecasting initiative to create stretch for our management team to find efficiencies in our business.

The Target Operating Model program, whilst in its infancy stage, was recognised as an important part of achieving this stretch target. The efficiency enabling initiatives in the Target Operating Model and our ICT capital program facilitated the 10 per cent that we proposed in our Initial Regulatory Proposal and were not in addition to it.

These priority projects are also considered essential in order to achieve our Revised Regulatory Proposal network overheads' efficiency target.

It is anticipated that benefits' realisation associated with the Operating Model will occur throughout the organisation, and not just within Power Networks, as organisational capability is increased, for example through:

- Better process streamlining;
- Process automation through system investment;
- Reduction in manual labour associated with poor data access or poor system integration;
- People improving their output due to capability and practice improvement;
- Optimised resource allocation;
- Reduction in safety incidents; and
- Improved funding allocation due to improved asset management practices.

There will be a cost of realizing these benefits. We have committed to including these future efficiencies in our base year opex but recognise that they will be achieved over the 2019-24 regulatory control period with us, rather than our customers, proactively funding the transitional costs.

7.7.3 Efficiency adjustment

Table 7-9 below provides our networks overheads efficiency adjustment. This expenditure has been removed from our base opex.

Table 7-9 – Network overheads – Efficiency adjustment

$M, Real 2018-19	2017-18
Efficiency adjustment	3.1

7.8 Revised base year network overhead expenditure

Table 7-10 below provides our base year network overheads' opex after we have removed our non-recurrent expenditure and applied an efficiency adjustment, in total accounting for $9.9 million (26 per cent) of our 2017-18 audited network overheads' spend.

Table 7-10 – Base year network overheads opex

$M, Real 2018-19	RRP 2017-18 efficient base year
Network overheads opex	28.8

We have removed the lease cost adjustment at the total opex level (rather than at the expenditure category level) and therefore Table 7-10 does not take the removal of that non-recurrent expenditure into account. It is accounted for in the 'capitalisation of leases adjustment' line item in Tables 2-1 and 2-2.

8. Corporate overheads

This section explains and justifies our revised base year corporate overheads' expenditure.

8.1 Activities included

Corporate activities are carried out by several corporate functions within Power and Water. The costs of those activities are allocated to business units – including Power Networks – according to our corporate cost allocation process.

8.2 Our initial proposal

Our Initial Regulatory Proposal compared our corporate overheads with those of our interstate peers and demonstrated that we benchmarked favourably. It also provided information about our specific network characteristics, such as our exposure to high labour rates and our dispersed and diverse micro networks, and how they drive our corporate overheads' expenditure. We have not presented this information again.

8.3 AER Draft Decision

The AER, in its Draft Decision, recognised that our corporate overheads' opex has decreased over time, and did not identify any efficiency reductions, as shown in Table 8-1 below. The AER noted that we updated our corporate cost allocation methodology to align with the AER-approved CAM[20] in 2017-18 but they did not incorporate the impact, as it was not applied in the 2016-17 base year used in our Initial Regulatory Proposal.

The AER committed to reconsidering our corporate overheads' opex if we provided further information on the updated cost allocation approach in our Revised Regulatory Proposal.

Table 8.1 – Comparison of Initial Regulatory Proposal and Draft Decision – Corporate overheads

$M, Real 2018-19	PWC IRP	AER Draft Decision
Base year	8.2	8.2
Variance to IRP		0.0

[20] Power and Water Corporation, 2017, Cost Allocation Method for Distribution Services v1.0.

8.4 Revisions to our proposal

8.4.1 2017-18 corporate overheads expenditure

The table below provides both our 2016-17 audited expenditure, and 2017-18 audited corporate overheads expenditure.

Table 8-2 – Corporate overheads opex

$M, Real 2018-19	2016-17	2017-18
Corporate overheads opex	8.1	13.8

Note: the value for 2016-17 differs slightly from that in Table 8-1 due to slightly different inflation assumptions being used in the IRP for the 2017-18 and 2018-19 years (for $2018-19 conversion).

As foreshadowed with the AER through the information request process, 2017-18 is the first year that Appendix 1 of the AER-approved CAM, which details how we allocate out our shared corporate costs between our business units, has been applied to our audited opex. Prior to 2017-18, we applied a cost allocation method that was developed before our transition to the NT NER, and was not approved by the AER.

8.4.2 Approach

We have updated our expenditure to reflect the 2017-18 costs as per our audited regulatory information notice submission to the AER in October 2018. This ensures that not only the latest available expenditure data is used but, importantly, our expenditure is based on the AER-approved CAM.

8.4.3 Change in cost allocation approach

The AER-approved CAM applies refreshed causal cost drivers at a more granular level to our current corporate structure, ensuring a more appropriate allocation of costs between our business units. This ensures that we recover a prudent level of costs from our electricity network tariffs.

This change in the allocation of costs has resulted in an increase of corporate costs being allocated to the Power Networks' business unit. Importantly, however, there has not been a material change in total Power and Water corporate costs (that are then allocated between business units including Power Networks) between 2016-17 and 2017-18. This is demonstrated in the table below.

Table 8.3 – Total Power and Water corporate costs before allocation to business units

$M, Real 2018-19	2016-17	2017-18
Total corporate costs prior to allocation to Power Networks	56.4	54.6

We engaged Ernst & Young to undertake an independent review of our allocation of total corporate costs to ensure consistency with the AER-approved CAM. Ernst & Young concluded that:

- The allocators applied in our Corporate Cost Model are consistent with the allocators set out in Appendix 1 of the AER-approved CAM; and
- The allocation methodology applied in the Corporate Cost Model is consistent with the methodology set out in the AER-approved CAM.

Further information on Ernst & Young's review can be found at Attachment PWCR02.2[21].

8.4.4 Impact of cost allocation change

Table 8-3 above demonstrates that our total corporate costs have not materially changed between 2016-17 and 2017-18. However, Power Networks' share of corporate costs has increased between the two years, as shown in Table 8-2.

To calculate the impact of the change in approach, we have applied the previous cost allocation approach[22], not approved by the AER, to our total 2017-18 corporate costs in order to get Power Networks' share under that scenario. Table 8-4 compares this amount to Power Networks' allocation of corporate costs with the AER-approved CAM applied.

Table 8-4 shows the increase in corporate costs allocated to Power Networks that is driven by the application of the AER-approved CAM.

Table 8.4 – Power Networks' 2017-18 corporate overheads with different cost allocation approaches

$M, Real 2018-19	Non-AER approved CAM	AER-approved CAM
2017-18 corporate overheads opex	8.8	13.8

[21]PWCR02.2 – Ernst & Young – Cost Allocation Method: Independent Report – 29 Nov 18 – PUBLIC.

[22] This was the approach applied to Power and Water's 2016-17 opex included in our Initial Regulatory Proposal.

The corporate cost types most impacted by the change in cost allocation approach are as follows:

- Finance;
- Human Resource operations;
- Facilities;
- Managing Director;
- Insurance;
- Training Unit; and
- Business Systems & Information Management.

Under the previous cost allocation approach, the majority of these costs were allocated using a relatively even split across all business units within Power and Water. This approach did not result in an allocation of costs that was reflective of the cost of providing services to the individual business units. For example, under the previous approach, a significant proportion of Human Resource costs were allocated out using a relatively even split across all business units within Power and Water. Whereas, under the AER-approved CAM, Human Resource costs are allocated out on a FTE basis, ensuring a more appropriate allocation of costs between our business units.

The change in cost allocation approach also has an impact on our network overheads' expenditure category, although to a much lesser extent.

8.4.5 Non-recurrent spend

Our audited 2017-18 expenditure has been carefully reviewed to ensure that only recurrent expenditure representative of our future expenditure requirements has been included in our base year spend for corporate overheads.

Capitalisation of leases

As discussed further in Section 11, we have made an adjustment to reflect the fact that, from 1 July 2019, we will start to capitalise leases in accordance with new Australian Accounting Standards.

8.4.6 Efficiency adjustment

As part of our commitment to achieving efficiencies, we have applied a 10 per cent efficiency target to our recurrent corporate overheads' opex.

Whilst we are yet to define the individual initiatives that will be implemented in order to achieve these efficiency targets, we consider that some of our priority projects, such as our Target Operating Model and ICT capital program, will be essential in realising these efficiencies, just as they were also recognised as an important part of achieving the top down 10 per cent efficiency reduction proposed in our Initial Regulatory Proposal.

Consistent with the approach taken in our Initial Regulatory Proposal, the efficiency enabling initiatives in the Target Operating Model and the ICT capital program facilitate the 10 per cent that we have proposed and are not in addition to them.

There will be a cost associated with transitioning towards realising the benefits of organisational change. We have committed to including these future efficiencies in our base year opex but recognise that they will be achieved over the 2019-24 regulatory control period with us, rather than our customers, proactively funding the transitional costs.

Section 7.7 provides further information on our priority projects, including an overview of the capability areas that are the focus of our Target Operating Model and an update of the current status of the project. We have not re-presented it here but it is also relevant to our corporate overheads' expenditure.

8.5 Revised base year corporate overhead expenditure

Table 8-5 below provides our base year corporate overheads opex after we have applied our efficiency adjustment.

Table 8-5 – Base year corporate overheads opex

$M, Real 2018-19	RRP 2017-18 efficient base year
Corporate overheads opex	12.5

We have removed the lease cost adjustment at the total opex level (rather than at the expenditure category level) and therefore Table 8-5 does not take the removal of that non-recurrent expenditure into account. It is accounted for in the 'capitalisation of leases adjustment' line item in Tables 2-1 and 2-2.

9. Emergency response

This section explains and justifies our revised base year emergency response expenditure.

9.1 Activities included

Emergency response expenditure is limited to the expenditure associated with our initial response to outages and other high-risk events that require the immediate dispatch of crews. In accordance with our policy, emergency response is required:

- where there is an incident that results in actual or imminent danger to personnel or equipment;
- where there is an actual or imminent likelihood of an outage; and
- to assist emergency services in the performance of their duties.

Activities generally include:

- response to customers reporting outages;
- response to events in the system, such as network faults and urgent alarms associated with network assets e.g. fire alarm; and
- response to internal or external reports to dangerous conditions such as trees touching lines or car accidents, which may not directly cause an outage but present a risk to the public, personnel, equipment or facilities.

Emergency response obligations[23]:

A Network Service Provider must arrange for: restoration of the agreed capability at a connection point on or with that network as soon as reasonably practicable following any interruption at that connection point.

9.2 Our initial proposal

Our Initial Regulatory Proposal provided information on the NT's climate and our management approach to responding to emergency response activities. We demonstrated that there have been no significant changes to emergency

[23] NT NER, Clause 5.2.3.e1.(4).

response activities and costs in the last four years, and that our expenditure represented expected ongoing operations in the short term.

We compared our emergency response expenditure with our peers interstate and we also included information on specific emergency response cost drivers. We have not presented this information again.

We concluded that it was unlikely that emergency response cost reductions will be a key contributor to achieving our proposed 10 per cent opex efficiency target as:

- After adjusting for our unique circumstances, we are comparable with other distribution network service providers; and
- To propose a reasonable level of base year expenditure, we have already achieved cost reductions of nearly 9 per cent over the last four years.

9.3 AER Draft Decision

The AER recognised in their Draft Decision that our emergency response opex has decreased over time, does not make up a material proportion of our total opex, and concluded that there is less scope for inefficient practices.

Therefore, the emergency response base year opex included in our Initial Regulatory Proposal was accepted and the AER did not apply any efficiency reductions to it, as shown in Table 9-1 below.

Table 9-1 – Comparison of Initial Regulatory Proposal and Draft Decision – Emergency response

$M, Real 2018-19	PWC IRP	AER Draft Decision
Base year	6.8	6.8
Variance to IRP		0.0

9.4 Revisions to our proposal

9.4.1 2017-18 Maintenance expenditure

The table below provides both our 2016-17 audited expenditure, and 2017-18 audited expenditure, and demonstrates the uplift in expenditure due to TC Marcus in 2017-18.

Table 9-2 – Emergency response opex

$M, Real 2018-19	2016-17	2017-18
Emergency response opex	6.8	9.2

9.4.2 Tropical Cyclone Marcus

As explained in further detail in Section 3, we recorded $2.6 million in opex associated with TC Marcus against our emergency response expenditure category between March and June 2018. This expenditure was analysed to determine the incremental versus business-as-usual expenditure for the purposes of understanding what component should be in our base year to reflect recurrent costs.

9.4.3 Approach

We have updated our expenditure to reflect the 2017-18 costs as per our audited regulatory information notice submission to the AER in October 2018. We then removed non-recurrent expenditure and normalised our expenditure to take into account the impact of TC Marcus.

9.5 Revised base year emergency response expenditure

The incremental opex associated with TC Marcus is considered to be non-recurrent expenditure and we have therefore removed this amount from our base year emergency response opex in line with the base-step-trend approach adopted for our 2019 Distribution Determination opex forecasts.

The remaining business-as-usual opex was a diversion of non-routine maintenance resources to emergency response resources. Therefore, it has been reallocated to the maintenance opex category to normalise the level of activity and expenditure.

Table 9-3 below provides our base year emergency response opex, which represents a minor reduction from the 2016-17 spend included in our Initial Regulatory Proposal base year opex.

Table 9-3 – Base year emergency response opex

$M, Real 2018-19	RRP 2017-18 efficient base year
Emergency response opex	6.6

Table 9-4 demonstrates that:

- The total spend on emergency response and maintenance is largely consistent across the years, although we have seen a downward trend in our maintenance spend.
- 2017-18 represents a significant increase in emergency response opex due to TC Marcus, and a corresponding decrease in maintenance opex.

- After removing the incremental non-recurrent costs, and normalizing for the business-as-usual expenditure reallocated from maintenance, the adjusted expenditure at the category level is more in line with historical expenditure and representative of a standard base year.

Table 9-4 – Emergency response and maintenance opex

$M, Real 2018-19	2015-16	2016-17	2017-18	Incremental Cost adj.	Normalised	2017-18 adj.
Emergency Response	6.8	6.8	9.2	(0.7)	(1.9)	6.6
Maintenance	18.5	17.7	14.5		1.9	16.5
Total	**25.3**	**24.5**	**23.7**	**(0.7)**	**-**	**23.0**

Note: the value for 2016-17 differs from Table 2-2 due to slightly different inflation assumptions being used in the Initial Regulatory Proposal for the 2017-18 and 2018-19 years (for $2018-19 conversion).

For further detail on the assessment of TC Marcus incremental versus business-as-usual expenditure, refer to Section 3 of this document.

10. Non-network

This section explains and justifies our revised base year non-network expenditure.

10.1 Activities included

Non-network opex is directly attributable to the maintenance and operation of non-network assets such as motor vehicles, building and property, and IT and communication assets.

10.2 Our initial proposal

Our Initial Regulatory Proposal provided comparisons with our peers interstate and demonstrated that we compared favourably on a cost per customer basis and on a cost per kilometer basis after adjusting for lack of scale via customer density. We have not sought to present this information again.

10.3 AER Draft Decision

The AER's partial performance indicator (PPI) benchmarking of non-network costs indicated that our opex per customer is in the middle of distribution network service providers with similar customer densities. Given this, and that our non-network spend has remained relatively constant since 2013-14 and does not make up a material proportion of our total opex, the AER accepted the non-network base year opex in our Initial Regulatory Proposal and did not apply any efficiency reductions to it, as shown in Table 10-1 below.

Table 10-1 – Comparison of Initial Regulatory Proposal and Draft Decision – Non-network

$M, Real 2018-19	PWC IRP	AER Draft Decision
Base year	7.7	7.7
Variance to IRP		0.0

10.4 Revisions to our proposal

10.4.1 2017-18 non-network expenditure

The table below provides both our 2016-17 audited expenditure, and 2017-18 audited expenditure.

Table 10-2 – Non-network opex

$M, Real 2018-19	2016-17	2017-18
Non-network opex	7.7	7.4

10.4.2 Approach

We have updated our expenditure to reflect the 2017-18 costs in accordance with our audited regulatory information notice submission to the AER in October 2018.

10.4.3 Non-recurrent spend

Our audited 2017-18 expenditure has been carefully reviewed to ensure that only recurrent expenditure representative of our future expenditure requirements has been included in our base year non-network expenditure.

Capitalisation of leases

As discussed further in Section 11, we have made an adjustment to reflect the fact that, from 1 July 2019, we will start to capitalise leases in accordance with new Australian Accounting Standards.

10.5 Revised base year non-network expenditure

Table 10-3 below provides our base year non-network opex, which represents a minor reduction from the 2016-17 spend included in our Initial Regulatory Proposal base year opex.

Table 10-3 – Base year non-network opex

$M, Real 2018-19	RRP 2017-18 efficient base year
Non-network opex	7.4

We have removed the lease cost adjustment at the total opex level (rather than at the expenditure category level) and therefore Table 10-3 does not take the removal of that non-recurrent expenditure into account. It is accounted for in the ‘capitalisation of leases adjustment’ line item in Tables 2-1 and 2-2.

11. Base year adjustments

This section outlines the other adjustments we have made to our base year opex.

11.1 Provisions

In accordance with the AER's Draft Decision, and updated for actual 2017-18 audited expenditure, we have removed $0.4 million for movements in provisions from our base year opex.

11.2 GSLs

In line with the approach taken in both our Initial Regulatory Proposal and the AER's Draft Decision, we have removed $0.1 million for GSLs from our base year opex. This amount has been updated to reflect our audited 2017-18 opex.

11.3 Capitalisation of operating leases

We lease most of our fleet and some of our property. Historically, we treated our leases as 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, recognizing both an asset for the right to use the leased asset and an obligation to make lease payments over the lease term.

As discussed in the preceding chapters, we have removed the operating lease opex included in our audited 2017-18 actual expenditure as it is considered non-recurrent for base year purposes. This is line with the approach taken in both our Initial Regulatory Proposal and the AER's Draft Decision.

Table 11-1 outlines the opex, at an expenditure category and total level, which has been removed from our base year. This is also represented in the 'capitalisation of leases adjustment' line item in Tables 2-1 and 2-2.

Table 11-1 – Base year lease adjustment

$M, Real 2018-19	2017-18
Network overheads	0.8
Corporate overheads	0.3
Non-network	5.2
Total	**6.3**

12. Labour benchmarking

This section provides the results of our labour benchmarking analysis.

12.1 We agree that further labour cuts are not needed

In its Draft Decision, the AER noted that:[24]

> *Our PPI [partial performance indicator] analysis suggests that Power and Water's labour expenditure does not benchmark well compared to other distributors*

and that:

> *We found that Power and Water has the highest internal labour ASL [average staffing level] per 100,000 customers across the distributors we have benchmarked. We consider this is above the efficient level.*

Ultimately, however, the AER did not separately reduce the labour costs built into our base opex – as well as the other adjustments it made to set opex to what it considered an efficient level – to avoid double counting.

We agree with this outcome for two key reasons:

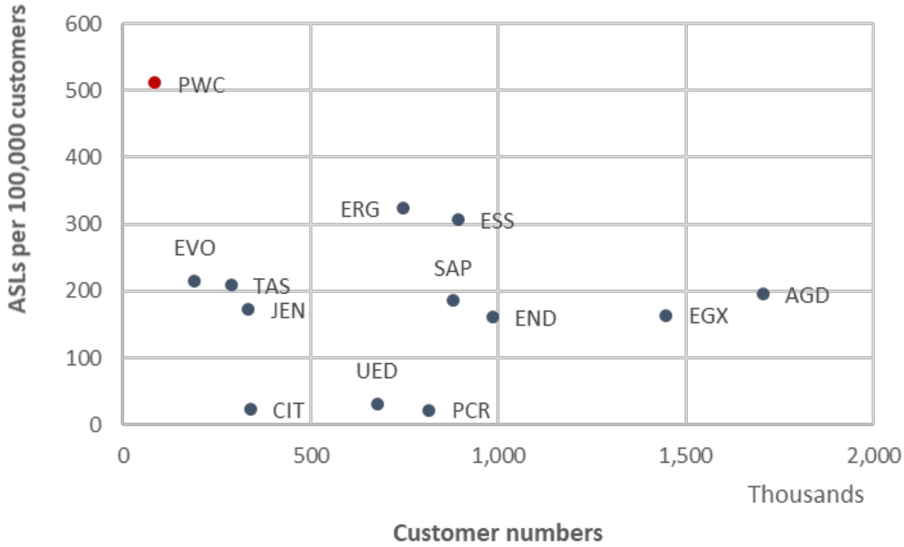
- Our PPI analysis (below) suggests that although we do not benchmark favourably on some measures, our performance improves when the data is presented in other ways; and
- Most of our proposed base year adjustments reduce labour costs (e.g. fewer routine maintenance inspections mean fewer staff are needed to inspect) – and so it would be a double count to further reduce labour costs based purely on PPI analysis that does not recognise those adjustments.

12.2 Our ASLs are comparable to relevant network peers

As the Draft Decision notes, and represented in Figure 12-1 below, our total ASL looks high compared to other networks when presented on a per 100,000 customers basis.

[24] AER, September 2018, Draft decision – Power and Water Corporation, Attachment 6: Operating Expenditure, p. 57.

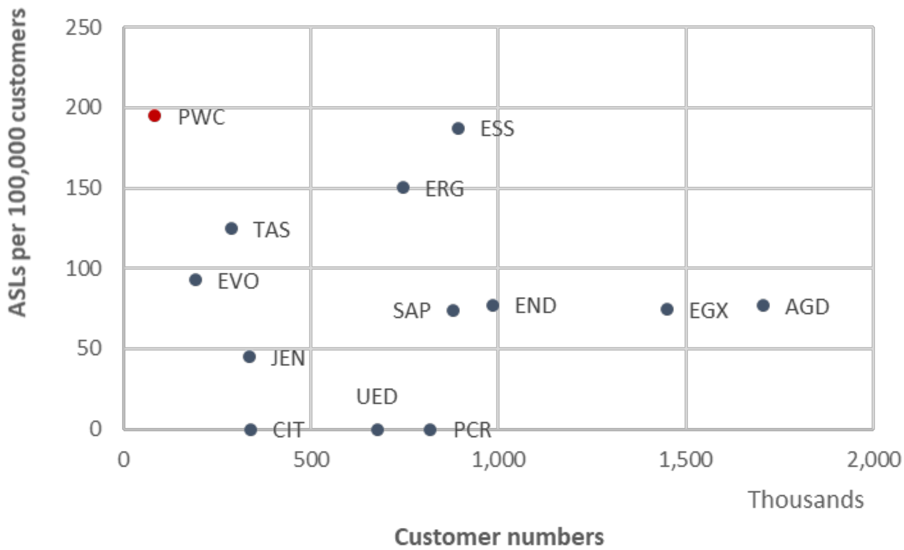
Figure 12-1 – Total ASLs per 100,000 customers vs. Customer numbers



However, if we look at just direct expenditure ASLs, then our ASL is comparable to that of predominately rural networks that cover similar environments to us, such as Essential Energy and Ergon Energy. Refer to Figure 12-2 below.

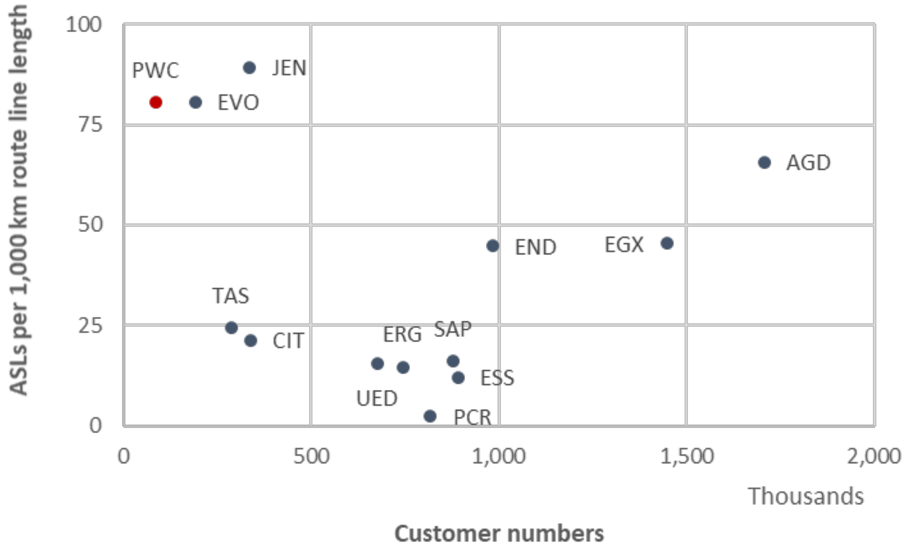
Figure 12-2 also highlights that some private networks (e.g. CitiPower, Powercor and United Energy) do not report any direct expenditure ASLs, which is likely due to either fully outsourcing such activities or interpreting the regulatory information notice requirements in a way that does not pick up staff that undertake those activities (e.g. because the service provider is part of a group of companies).

Figure 12-2 –Total direct expenditure ASLs per 100,000 customers vs. Customer numbers



Alternatively, if we consider network overhead and direct expenditure ASLs per 1,000 km route line length, then our ASL is comparable to other smaller networks like EvoEnergy and JEN, as shown in Figure 12-3.

Figure 12-3 – Network overhead and direct expenditure ASLs per 1,000 km route line length vs. Customer numbers



We recognise that there are different ways to present ASL data and that each presentation could lead to different conclusions. We may also be criticised for being selective in the presentations shown. Our point is simply that it is important to be careful when interpreting ASL data, especially when done so on a total ASL per 100,000 customers.