DRAFT DECISION

Power and Water Corporation Distribution Determination 2019 to 2024

Attachment 6 Operating expenditure

September 2018

Inquiries about this publication should be addressed to:

Australian Energy Regulator
GPO Box 520
Melbourne Vic 3001

Tel: 1300 585 165
Email: AERInquiry@aer.gov.au

AER reference: 60610

Note

This overview forms part of the AER's draft decision on the distribution determination that will apply to Power and Water Corporation for the 2019–2024 regulatory control period. It should be read with all other parts of the draft decision.

The draft decision includes the following attachments:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

Attachment 8 – Efficiency benefit sharing scheme

Attachment 9 – Capital expenditure sharing scheme

Attachment 10 – Service target performance incentive scheme

Attachment 11 – Demand management incentive scheme

Attachment 12 – Classification of services

Attachment 13 – Control mechanisms

Attachment 14 – Pass through events

Attachment 15 – Alternative control services

Attachment 16 – Negotiated services framework and criteria

Attachment 17 – Connection policy

Attachment 18 – Tariff structure statement

Contents

Shortened forms

Shortened form	Extended form
ACS	alternative control service
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
augex	augmentation expenditure
capex	capital expenditure
CCP	Consumer Challenge Panel
CCP13	Consumer Challenge Panel, sub-panel 13
CESS	capital expenditure sharing scheme
CPI	consumer price index
DRP	debt risk premium
DMIAM	demand management innovation allowance (mechanism)
DMIS	demand management incentive scheme
distributor	distribution network service provider
DUoS	distribution use of system
EBSS	efficiency benefit sharing scheme
ERP	equity risk premium
Expenditure Assessment Guideline	Expenditure Forecast Assessment Guideline for Electricity Distribution
F&A	framework and approach
GSL	guaranteed service levels
MRP	market risk premium
NEL	national electricity law
NEM	national electricity market
NEO	national electricity objective
NT NER or the rules	National Electricity Rules As in force in the

Shortened form	Extended form
	Northern Territory
NSP	network service provider
opex	operating expenditure
PPI	partial performance indicator
PTRM	post-tax revenue model
RAB	regulatory asset base
RBA	Reserve Bank of Australia
repex	replacement expenditure
RFM	roll forward model
RIN	regulatory information notice
RPP	revenue and pricing principles
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SCS	standard control services
SLCAPM	Sharpe-Lintner capital asset pricing model
STPIS	service target performance incentive scheme
WACC	weighted average cost of capital

6 Operating expenditure

Operating expenditure (opex) refers to the operating, maintenance and other non-capital expenses incurred in the provision of network services. Forecast opex for standard control services is one of the building blocks we use to determine a service provider's annual total revenue requirement.

This attachment outlines our assessment of Power and Water's proposed opex forecast for the 2019–24 regulatory control period.

6.1 Draft decision

Our draft decision is to include total forecast opex of $305.9 million ($2018–19) in Power and Water's revenue for the 2019–24 regulatory control period, which is 9.8 per cent lower than Power and Water's forecast opex of $339.3 million ($2018–19).[1] We are satisfied our alternative estimate of forecast opex reasonably reflects the opex criteria.[2]

Stakeholder submissions presented different views about Power and Water's opex proposal (section 6.2.1). In particular, they questioned the efficiency of Power and Water's base opex, including a 10 per cent efficiency adjustment to base opex and capitalisation of costs proposed by Power and Water.

We have examined these issues in developing our alternative estimate of efficient opex, which we use to assess Power and Water's proposal. We used our standard 'base-step-trend' approach (section 6.3) to develop our alterative estimate.[3]

We have undertaken a high level bottom up review of key cost categories that make up base opex.[4] We considered this was appropriate in light of Power and Water's poor relative benchmarking performance, its proposal which proposed efficiency adjustments and other previous reports.

Our review of base opex has focused on the cost categories that are the most material and/or which we consider to have the greatest scope for identifiable efficiency improvement (section 6.4.1). As a result of this assessment, we consider we cannot use Power and Water's revealed opex as a starting point to forecast efficient opex over the 2019–24 regulatory control period.

We have forecast growth in prices and productivity using our standard approach. We have refined our approach to forecast output growth (section 6.4.2). We have

1 Includes debt raising costs.

2 NT NER, cl. 6.5.6(c).

3 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013.

4 Base opex is the opex in the base year, which Power and Water has proposed as 2016-17.

assessed Power and Water's step changes in accordance with our *Expenditure forecast assessment guideline* (the Guideline) (section 6.4.3).[5]

The main reasons why we have adopted a lower forecast opex than proposed by Power and Water are:

- we adopted a lower estimate of efficient base opex reflecting our review of Power and Water's opex components. This equates to $10.4 million per year or a 13.8 per cent adjustment to base year opex. This is higher than the $7.0 million per year or 10 per cent top down adjustment Power and Water proposed.[6]
- we adopted a lower estimate of the rate of change reflecting Deloitte Access Economics' (DAE) wage price index (WPI) forecast for the Northern Territory utilities industry. This is lower than the historical average of the South Australian utilities WPI from DAE and BIS Shrapnel that Power and Water used.
- we adopted part of the guaranteed service level (GSL) payments step change but did not include proposed step changes for implementing the national connections process, metering type 7 compliance, operating the metering data management system (MDMS) and additional network planning resources.

The reasons for our draft decision are set out in further detail in section 6.4.

Power and Water's proposed opex forecast and our draft decision are set out in Table 6.1.

Table 6.1 Power and Water's proposed opex and our draft decision ($million, $2018–19)

	2019–20	2020–21	2021–22	2022–23	2023–24	Total
Power and Water's proposed opex	66.0	66.9	68.0	68.8	69.5	339.3
AER draft decision	60.3	60.6	61.2	61.7	62.1	305.9
Difference	-5.8	-6.3	-6.8	-7.1	-7.4	-33.4

Source: Power and Water, Revenue proposal, post tax revenue model (PTRM), 31 January 2018; AER analysis.

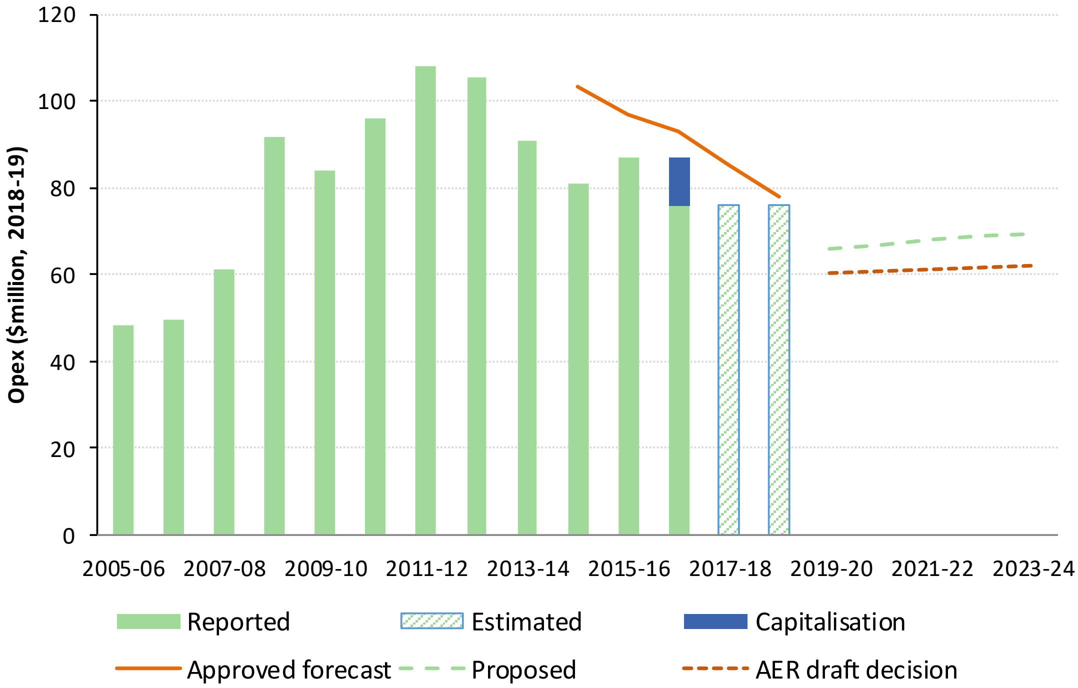
Note: Includes debt raising costs. Numbers may not add up to total due to rounding.

Figure 6.1 compares the opex forecast we adopted in this draft decision to Power and Water's proposal, the forecast the previous regulator (the Utilities Commission) approved for 2014–19 and Power and Water's actual opex in that period.

5 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013.

6 Power and Water's 10 per cent adjustment and our 13.8 per cent adjustment are not directly comparable as they are made off different bases. Power and Water's 10 per cent is taken off a lower base, after a $5.5 million adjustment for increased capitalisation has been made. On a consistent basis, Power and Water’s $7.0 million efficiency adjustment is 9.3 per cent of base year opex.

Figure 6.1 Our draft decision compared to Power and Water's past and proposed opex ($million, $2018–19)



Source: Power and Water, Regulatory accounts; Power and Water, Economic benchmarking RIN response; Utilities Commission NTRM; AER analysis.

Note: Includes debt raising costs.

In 2008, Power and Water faced major power outages due to a series of equipment failures, including an explosion in the Casuarina substation.[7] A Government inquiry (the Davies Review) was established, which in February 2009 recommended major changes to Power and Water's operational and maintenance practices.[8] Power and Water implemented the changed practices over the following years. This was a major driver of its increased opex from 2008–09.[9]

The 2014–19 Utilities Commission regulatory decision included a 27 per cent reduction to Power and Water's opex forecast based on benchmarking analysis.[10] The Utilities Commission's decision included a glide path to remove the 27 per cent difference it identified between Power and Water and the average of its peers by the end of the 2014–19 period.[11]

---

7 Power and Water, 2014 Network Price Determination, *Power and Water Initial Regulatory Proposa*l, p. 17.

8 *Independent enquiry into Casuarina Substation events and substation maintenance across Darwin*, Final Report, 4 February 2009.

9 Power and Water, *Networks pass through application*, 5 February 2013, pp. 1–2.

10 Utilities Commission, *2014 Network Price Determination, Part A—Statement of Reasons*, 24 April 2014, pp. 103–104, 110–111.

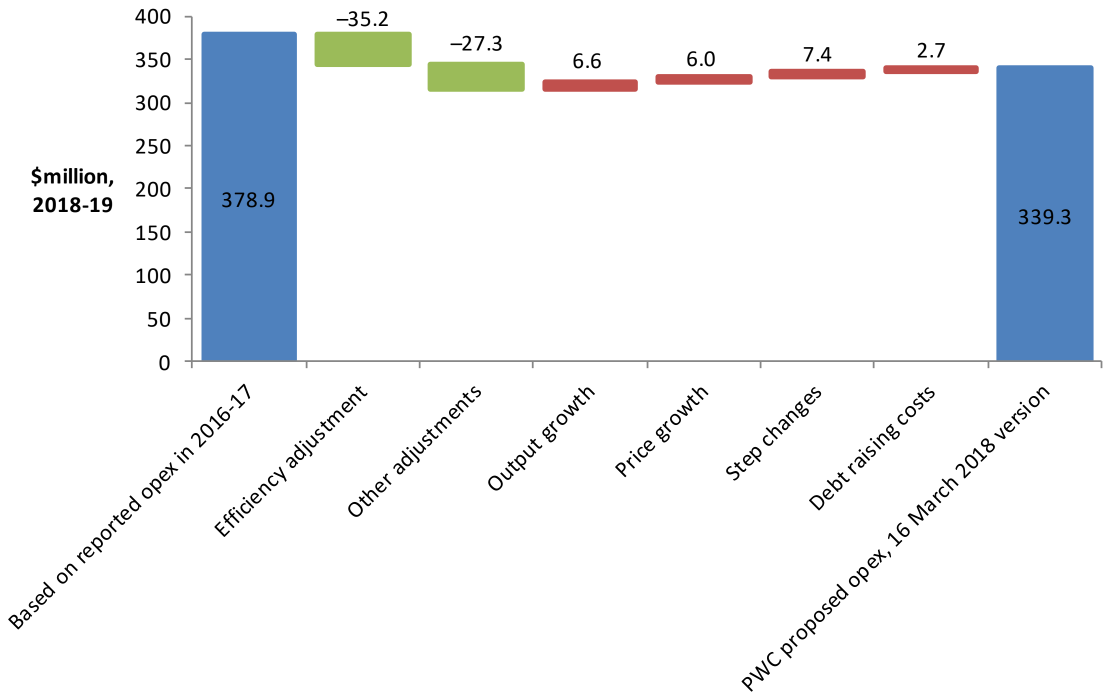
11 Utilities Commission, *2014 Network Price Determination, Part A—Statement of Reasons*, 24 April 2014, pp. 110–111.

6.2 Power and Water's proposal

Power and Water proposed total opex of $339.3 million ($2018–19) for the 2019–24 regulatory control period.[12] Power and Water stated this is a $50 million or 14.7 per cent[13] decrease from its expected actual expenditure in the current period.[14] The biggest driver of this decrease is Power and Water's change in capitalisation policy (i.e. accounting treatment of costs from opex to capex) and efficiencies Power and Water expects to achieve.[15]

In Figure 6.2 we separate Power and Water's proposed opex into the different elements that make up its forecast.

Figure 6.2 Power and Water's opex forecast ($ million, 2018–19)



Source: AER analysis; Power and Water, *Regulatory proposal*, 16 March 2018.

Note: Excludes movements in provisions.

We describe each of these elements below:

---

12 Power and Water, *Regulatory proposal*, 16 March 2018, p. 90; Includes debt raising costs.

13 Our analysis indicates Power and Water's forecast opex represents a $56.1 million or 14.2 per cent decrease from its expected actual expenditure in the current period. Power and Water, *PWC11.8CP - Economic Benchmarking RIN Workbooks - Consolidated - 16 Mar 18 - PUBLIC,* 16 March 2018; AER's analysis.

14 Power and Water, *Regulatory proposal*, 16 March 2018, p. 79.
Opex for 2017–18 to 2018–19 is estimated only. We have not yet received regulatory accounts for those years.

15 Power and Water, *Regulatory proposal*, 16 March 2018, p. 79.

- Power and Water used actual opex in 2016–17 as the base to forecast opex.[16] This would lead to a base opex of $378.9 million ($2018–19) over the 2019–24 regulatory control period.[17] Power and Water noted it may update its estimate of opex for 2017–18 with its audited actual opex for that year in its revised proposal.[18]
- Power and Water made the following adjustments to base opex prior to applying the rate of change:
    - Power and Water removed $5.5 million ($2018–19) from estimated opex in 2018–19 to reflect a change in capitalisation policy[19] in the next regulatory control period.[20] This is shown under "other adjustments" in Figure 6.2. This and one other minor adjustment[21] translates into a $27.3 million ($2018–19) reduction over the 2019–24 control period.[22] Power and Water's opex in its 2016–17 base year reflects its change in capitalisation policy in the current regulatory control period.
    - Power and Water applied a 'top-down' efficiency adjustment of 10 per cent,[23] which translates into –$35.2 million ($2018–19) over the 2019–24 period.[24] Power and Water made this adjustment after it removed the costs that will be capitalised from 1 July 2019.
- Power and Water included forecast labour price growth of $6.0 million ($2018–19).
- Power and Water included forecast output growth of $6.6 million ($2018–19).
- Power and Water proposed five step changes totalling $7.4 million ($2018–19) over the regulatory control period to meet the costs of complying with new regulatory obligations:[25]
    - national connections process— Power and Water will be required to comply with the national connections framework created by the introduction of Chapter 5A of the Northern Territory (NT) National Energy Rules (NER) and proposed $2.4 million ($2018–19) to administer the process.
    - metering compliance for type 7 meters—Power and Water proposed $0.1 million ($2018–19) to maintain a five year rolling sampling plan for these meters.

16 Power and Water, *Regulatory proposal*, 16 March 2018, p. 85.

17 This amount excludes debt raising costs.

18 Power and Water, *Regulatory proposal*, 16 March 2018, p. 85.

19 Power and Water, *Regulatory proposal*, 16 March 2018, p. 86.

20 In the next regulatory control period, Power and Water will begin capitalising building and vehicle leases consistent with Australian Accounting Standards 16 and therefore treat operating leases as capex.

21 The "other adjustments" in Figure 6.2 also includes a small GSL payments accounting adjustment.

22 Power and Water, *12.4 SCS opex model*, 16 March 2018.

23 Power and Water, *Regulatory proposal*, 16 March 2018, p. 86.

24 Power and Water, *Regulatory proposal*, 16 March 2018, p. 86.

25 Power and Water, *Regulatory proposal*, 16 March 2018, pp. 87–88; and more detail in: Power and Water, *03.2P - SCS and ACS Opex Step Changes* - 31 January 18.

- Meter Data Management System (MDMS) commissioning and early processing—Power and Water proposed $0.8 million ($2018–19) to comply with the verification, substitution and estimation obligations under Chapter 7A NT NER arrangements for metering.
- Planning resources—increased network planning resources to comply with the obligations under the NT NER. Power and Water proposed $2.7 million ($2018–19) to enhancing its planning function capabilities.
- Guaranteed Service Levels (GSLs)—an increase in GSL payments as a result of the revised GSL scheme under the Utilities Commission's Electricity Industry Performance Code. Power and Water proposed an additional $1.3 million ($2018–19).[26]

- Power and Water included a category specific forecast for debt raising costs of $2.7 million ($2018–19). Debt raising costs are transaction costs incurred each time debt is raised or refinanced.[27]

This resulted in total opex forecast of $339.3 million ($2018–19) for the 2019–24 regulatory control period.

6.2.1 Stakeholder views

Four submissions were received on Power and Water’s opex proposal, from the AER's Consumer Challenge Panel (CCP13), the Electrical Trades Union of Australia (ETU), Jacana and an anonymous party. A summary of these submissions is provided in Table 6.2 below.

Table 6.2: Submissions on Power and Water's opex proposal

Stakeholder	Issue	Description
Anonymous	High total opex forecast (due to high indirect costs)	While direct costs (maintenance, vegetation management, emergency response) appear reasonable, total opex is high for a small distributor. This is driven by the high level of indirect costs.[28] A variety of concerns were raised around these indirect costs: • There are efficiency benefits of being multi-utility as Power and Water can spread its indirect administrative costs over multi operational groups[29] • Transactions that have the appearance of related party transactions, or are not at arm’s length, should be examined, including the acquisition of corporate services obtained from the Department of Corporate and Information Services, and Service

[26] Power and Water subsequently revised its forecast to $0.9 million ($2018–19); Power and Water, response to AER information request IR024, 21 July 2018. Q14 - follow up information.

[27] Power and Water, *Regulatory proposal*, 16 March 2018, p. 90.

[28] Anonymous, *Submission on Power and Water proposal*, 16 May 2018, p. 5.

[29] Anonymous, *Submission on Power and Water proposal*, 16 May 2018, p. 1.

Stakeholder	Issue	Description
		Level Agreement expenses for the provision of distribution services by another division of Power and Water[30] • It is not clear the efficiencies from ICT initiatives are recognised or that the reductions in maintenance due to new and replaced assets have been incorporated.[31]
Anonymous	Cost premium for geography[32]	Regional distributors must maintain multiple depots to ensure service quality and responsiveness, just as Power and Water must. The fact that Power and Water's network is in three parts is therefore immaterial. It is not clear why there should be a unique cost premium in the Northern territory due to climate. Darwin-Katherine region is tropical (very similar to Far North Qld, but with fewer tropical cyclones). Alice Springs/Tennant Creek experience seasonal variation and lower rainfall (similar to inland regions in Qld and NSW) Humidity for Power and Water should also not be overestimated as it only impacts field staff in the field between October and April.
CCP13	Efficiency adjustment[33]	Efficiency adjustment of 10 per cent is material and should be welcomed by consumers. However, given the lack of data and narrative around the reasons, CCP13 has been unable to come to a view on an efficient level of opex. CCP13 recognises it may take some time to arrive at levels of efficiency that consumers expect from Power and Water.
Electricity Trades Union (ETU)	Efficiency adjustment[34]	The ETU is doubtful about Power and Water's ability to achieve the 10 per cent efficiency adjustment. It considers this target an 'arbitrary guess'.
CCP13	Capitalisation[35]	CCP13 asks us to consider the appropriateness of Power and Water's approach to capitalisation, noting that what is appropriate from an accounting perspective is not necessarily what is appropriate from a regulatory context.
Anonymous	Capitalisation – leases (appropriate treatment from regulatory context vs accounting)[36]	Treating operating leases as capital expenditure is logical from an accounting point of view, but it creates issues from a regulatory point of view. The return on investment creates a new revenue stream for the regulated business, despite the fact that there is no capital investment, per se. This accounting approach also removes incentive to seek out efficient lease costs: the higher the lease costs, the more revenue. In addressing this issue, it would seem appropriate to consider the capitalised leases as a component of opex, to be tested for efficiency with the rest of the opex; and, subsequently capitalise an amount of

30 Anonymous, *Submission on Power and Water proposal*, 16 May 2018, p. 4.

31 Anonymous, *Submission on Power and Water proposal*, 16 May 2018, p. 5

32 Anonymous, *Submission on Power and Water proposal*, 16 May 2018, pp. 2–3.

33 Consumer Challenge Panel subpanel 13, *Issues paper Power and Water electricity network revenue proposal 2019–24*, 16 May 2018; p. 39.

34 Electrical Trades Union, *Power and Water regulatory proposal 2019–24*, 16 May 2018, p. 2.

35 Consumer Challenge Panel subpanel 13, *Issues paper Power and Water electricity network revenue proposal 2019–24*, 16 May 2018, pp. 36–37.

36 Anonymous, *Submission on Power and Water proposal*, 16 May 2018, p. 3.

Stakeholder	Issue	Description
		efficient lease opex such that the net present value is zero.
Anonymous	Capitalisation of overheads[37]	This treatment does not provide a good incentive upon Power and Water to minimise its overhead costs. The capitalised overheads will be rolled in to the Regulatory Asset Base (RAB) so that it will receive a return on and return of investment, a quantum of which may be considered inefficient were it to be treated as opex. Capitalised overheads should be added back into Power and Water's opex forecast, which is then subject to the usual assessment of prudency and efficiency by the AER. Only then, when satisfied that the expenditure is prudent, should the capitalisation be added to the RAB.
Electrical Trades Union (ETU)	FTEs/labour[38]	Does not agree that NT direct employment costs are significantly higher than other jurisdictions for supply industry workers. There has been a proliferation of professional and managerial staff to technical staff with limited value add for consumers.

6.3 Assessment approach

We must form a view about whether a business's forecast of total opex 'reasonably reflects the opex criteria'.[39] In doing so, we must have regard to each of the opex factors specified in the NER.[40]

If we are satisfied the business's forecast reasonably reflects the criteria, we accept the forecast.[41] If we are not satisfied, we substitute an alternative estimate that we are satisfied reasonably reflects the opex criteria.[42] In making this decision, we take into account the reasons for the difference between our alternative estimate and the business's proposal, and the materiality of the difference. Further, we consider interrelationships with the other building block components of our decision.[43]

The Guideline together with an explanatory statement set out our intended approach to assessing opex in accordance with the NER.[44] We published the Guideline and the associated explanatory statement in November 2013 following an extensive consultation process with service providers, network users, and other stakeholders. While the Guideline provides for greater regulatory predictability, transparency and consistency, it is not mandatory. However, if we make a decision that is not in accordance with the Guideline, we must state the reasons for departing from the Guideline.[45]

---

37 Anonymous, *Submission on Power and Water proposal*, 16 May 2018, p. 4.
38 Electrical Trades Union, *Power and Water regulatory proposal 2019–24*, 16 May 2018, p. 2.
39 NT NER, cl. 6.5.6(c).
40 NT NER, cl. 6.5.6(e).
41 NT NER, cl. 6.5.6(c).
42 NT NER, cll. 6.5.6(d) and 6.12.1(4)(ii).
43 NEL, s. 16(1)(c).
44 AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013; AER, *Expenditure forecast assessment guideline*, *Explanatory statement*, November 2013.
45 NT NER, cl. 6.2.8(c)(1).

We apply the assessment approach outlined in the Guideline to develop our estimate of a business's total opex requirements (our alternative estimate). Our alternative estimate serves two purposes. First, it provides a basis for testing whether a business's proposal is reasonable. Second, we can use it as a substitute forecast if we determine a business's proposal does not reasonably reflect the opex criteria.

Below we further explain the principles that underpin this approach and provide a high-level overview of the 'base–step–trend' methodology.

6.3.1 Incentive regulation and the 'top-down' approach

Incentive regulation is designed to prevent network businesses from exploiting their natural monopoly position by setting prices in excess of efficient costs.[46] A key feature of the regulatory framework is that it is based on incentivising networks to be as efficient as possible. We apply incentive-based regulation across the energy networks we regulate, including electricity distribution networks. More specifically for opex, we generally seek to rely on the efficiency incentives created by both ex ante revenue regulation (where an opex allowance is granted over a multi-year regulatory control period) and the EBSS.

The incentive-based regulatory framework partially overcomes the information asymmetries between the regulated businesses and us, the regulator.[47]

Incentive regulation encourages regulated businesses to reduce costs below the regulator's forecast, in order to make higher profits, and ‘reveal’ their costs in doing so. The information revealed by the businesses allows us to develop better expenditure forecasts over time. Revealed opex reflects the efficiency gains made by a business over time. As a network business becomes more efficient, this translates to lower forecasts of opex in future regulatory control periods, which means consumers also receive the benefits of the efficiency gains made by the business. Incentive regulation therefore aligns the business’s commercial interests with consumer interests.

Our preferred general approach is to assess the business’s forecast opex over the regulatory control period at a total level, rather than to assess individual opex projects or programs. To do so, we develop an alternative estimate of total opex using a ‘top-down’ forecasting method, known as the ‘base–step–trend’ approach (section 6.3.2).[48]

Benchmarking a network business against others in the National Electricity Market (NEM) provides an indication of whether revealed opex can be adopted as 'base opex' (section 6.3.2.1) and, if not, what our alternative estimate of base opex should be. While benchmarking is a key tool, we will use a combination of techniques to assess

[46] Productivity Commission, *Electricity Network Regulatory Frameworks, volume 1, No. 62*, 9 April 2013, p. 188.

[47] Productivity Commission, *Electricity Network Regulatory Frameworks, volume 1, No. 62*, 9 April 2013, p. 189.

[48] A 'top-down' approach forecasts total opex at an aggregate level, rather than forecasting individual projects or categories to build a total opex forecast from the 'bottom up'.

whether base opex reasonably reflects the opex criteria.[49] We may make a negative adjustment to the business's revealed opex if we find it is operating in a materially inefficient manner. Material inefficiency is a concept we introduce in our Guideline.[50] We consider a service provider is materially inefficient when it is not at or close to its peers on the efficient frontier. We define this more precisely in the context of economic benchmarking below.

Given this is the first time we are assessing Power and Water's opex, and we have been unable to rely on Power and Water's revealed costs, or use total opex benchmarking to determine an alternative efficient amount, we have undertaken a more detailed bottom up assessment of individual opex categories. We have not used a 'top-down' approach to assess Power and Water's opex. Our preference is to use a 'top-down' assessment approach, including total opex benchmarking, to assess opex in the future. More details of our specific base opex assessment approach for this draft decision are in section 6.4.1.4.

Incentive regulation is designed to leave the day-to-day decisions to the network businesses.[51] It allows the network businesses the flexibility to manage their assets and labour as they see fit to achieve the opex objectives in the NER,[52] and more broadly, the National Electricity Objective (NEO).[53] This is consistent with the requirement that we consider whether the *total* opex forecast, and *not* the individual forecast opex components, reasonably reflects the opex criteria.[54]

The Australian Energy Market Commission (AEMC) supports this view of our role as the economic regulator. It stated: [55]

> The key feature of economic regulation of [distribution network service providers] in the NEM is that it is based on incentives rather than prescription…
>
> Importantly, under [incentive-based regulation], funding is not approved for [distribution network service providers'] specific projects or programs. Rather, a total revenue requirement is set, which is based on forecasts of total efficient expenditure. Once a total revenue is set, it is for the [business] to decide which suite of projects and programs are required to deliver services to consumers while meeting its regulatory obligations…

---

49 AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 32.

50 AER, *Expenditure Forecast Assessment Guideline*, November 2013, p. 22.

51 Productivity Commission, *Electricity Network Regulatory Frameworks, volume 1, No. 62*, 9 April 2013, pp. 27–28.

52 NT NER, cl. 6.5.6(a).

53 NEL, s. 7.

54 NT NER, cl. 6.5.6(c).

55 AEMC, *Contestability of energy services, Consultation paper*, 15 December 2016, p. 32.

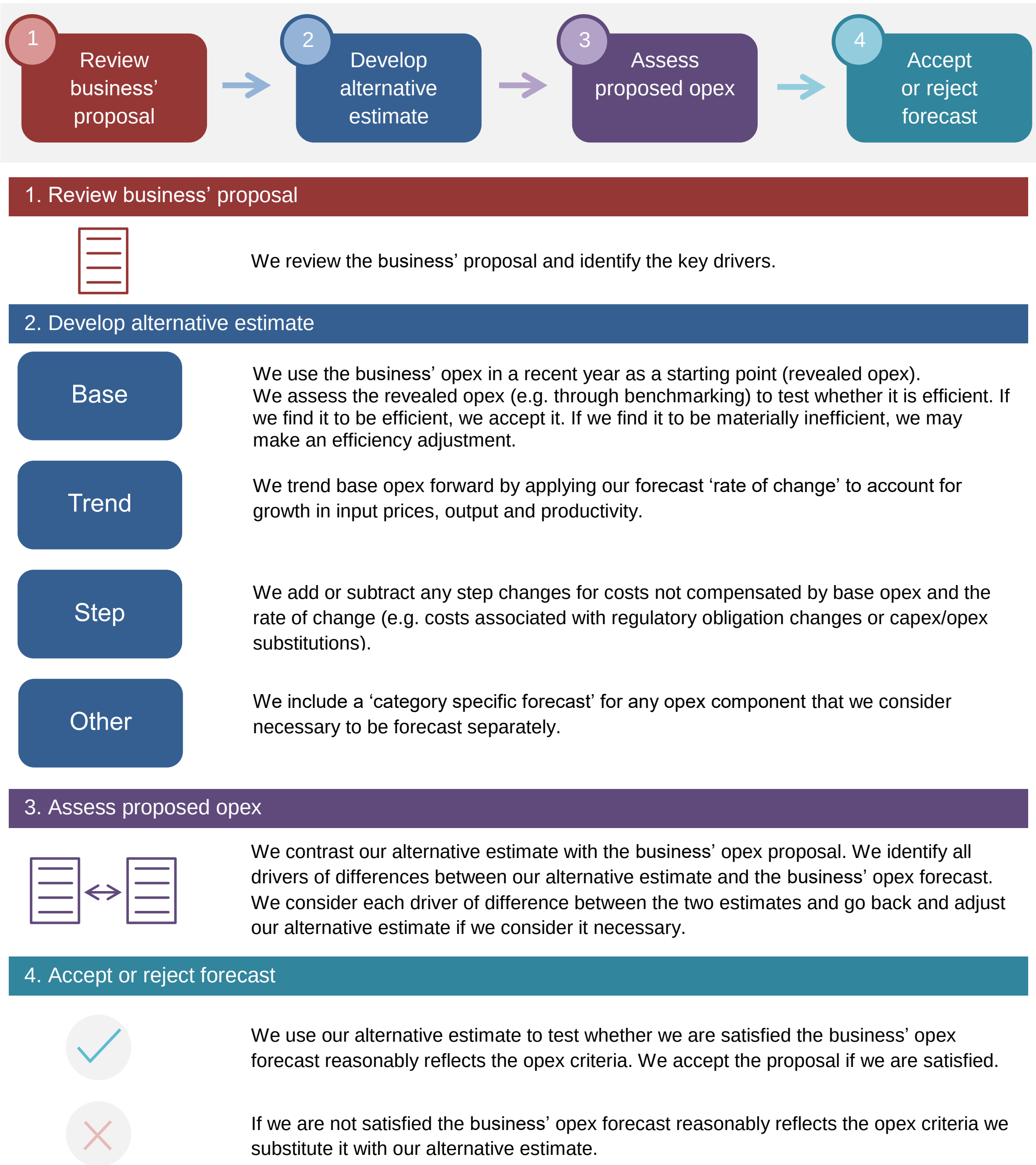
6.3.2 Base–step–trend forecasting approach

As a comparison tool to assess a business's opex forecast, we develop an alternative estimate of the business's total opex requirements in the forecast period, using the base–step–trend forecasting approach.

If the business adopts a different forecasting approach to derive its opex forecast, we develop an alternative estimate and assess any differences with the business's forecast opex.

Figure 6.3 summarises the base–step–trend forecasting approach.

Figure 6.3 Our opex assessment approach



6.3.2.1 Base opex

If we find the business is operating efficiently, our preferred methodology is to use the business's historical or 'revealed' costs in a recent year as a starting point for our opex forecast.

We do not simply assume the business's revealed opex is efficient. It may include an ongoing level of inefficient expenditure. We generally use our benchmarking results[56] and other assessment techniques to test whether the business is operating efficiently.

We consider revealed opex in the base year is generally a good indicator of opex requirements over the next period because the level of *total opex* is relatively stable from year to year. This reflects the broadly predictable and recurrent nature of opex.

A business may experience fluctuations in particular categories of opex, and the composition of total opex can change, from year to year. While many operation and maintenance activities are recurrent and non-volatile, some opex projects follow periodic cycles that may or may not occur in any given year, and some opex projects are non-recurrent.

Even if disaggregated opex categories have high volatility, total opex typically varies to a lesser extent because new or increasing components of opex are generally offset by decreasing costs or discontinued opex projects. Further, we expect the regulated business to manage the inevitable 'ups and downs' in the components of opex from year to year—to the extent they do not offset each other—by continually re-prioritising its work program, as would be expected in a workably competitive market. Our incentive-based, revealed cost, framework incentivises them to do so.

We also note that any volatility of total opex from year to year does not typically impact our choice of the appropriate base year if an EBSS is in place. A consequence of the operation of the EBSS is that the forecast net revenues (specifically forecast opex and EBSS rewards and penalties) are largely uninfluenced by the choice of base year. For example, although using a base year with unusually high opex would typically result in an increased opex forecast, a lower EBSS reward (or a greater penalty) would offset this increase. Where we do not apply an EBSS we must ensure the base year is reflective of average efficient expenditures going forward, as any irregularity will not be offset by a higher or lower EBSS carryover.

6.3.2.2 Rate of change

We trend base opex forward by applying our forecast 'rate of change'. We estimate the rate of change by forecasting the expected growth in input prices, outputs and productivity. We consider that the rate of change takes into account almost all drivers of opex growth.

56 AER, *Annual benchmarking report—Electricity distribution network service providers*, November 2017.

We forecast input price growth using a composition of labour and non-labour price changes forecasts. Labour costs represent a significant proportion of a distribution business's costs.[57] To determine the input price weights for labour and non-labour prices, we have regard to the input price weights of a prudent and efficient benchmark business. Consistent with incentive regulation, this provides the business an incentive to adopt the most efficient mix of inputs throughout the regulatory control period.

We forecast output growth to account for annual increase in output. The output measures used should be the same measures used to forecast productivity growth.[58] Productivity measures the change in output for a given amount of input. If the output measures differ from the productivity measures, they would be internally inconsistent and we cannot compare them like for like.

The output measures we typically use for distribution businesses are customer numbers, ratcheted maximum demand and circuit length. We do not typically adjust forecast output growth for economies of scale because we account for these in our forecast of productivity growth.

Our forecast of productivity growth represents our best estimate of the shift in the industry 'efficiency frontier'.[59] We generally base our estimate of productivity growth on recent productivity trends across the industry. However, if we consider historic productivity growth does not represent 'business-as-usual' conditions we do not use it to forecast future productivity growth.

We are currently reviewing our approach to forecasting productivity.[60] This review may change our approach going forward. As part of this review we will be looking to consult with all distributors and any other interested stakeholders. We will take the outcome of this review into consideration in our final decision.

6.3.2.3 Step changes and category-specific forecasts

Lastly, we add or subtract any components of opex that are not adequately compensated for in base opex or the rate of change, but which should be included in the forecast total opex to meet the opex criteria.[61] These adjustments are in the form of 'step changes' or 'category-specific forecasts'.

Step changes

Step changes should not double count costs included in other elements of the total opex forecast. As explained in the Guideline, the costs of increased volume or scale should be compensated for through the output growth component of the rate of change

---

57 AER, *Expenditure forecast assessment guideline, Explanatory statement*, November 2013, p. 49.

58 AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 23.

59 AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 24.

60 See https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/review-of-our-approach-to-forecasting-opex-productivity-growth-for-electricity-distributors.

61 AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 24.

and it should not become a step change.[62] In addition, forecast productivity growth may account for the cost of increased regulatory obligations over time—that is, 'incremental changes in obligations are likely to be compensated through a lower productivity estimate that accounts for higher costs resulting from changed obligations'.[63] Therefore, we consider only new costs that do not reflect the historic 'average' change as accounted for in the productivity growth forecast require step changes.[64]

To increase its maximum allowable revenue, a regulated business has an incentive to identify new costs not reflected in base opex or costs increasing at a greater rate than the rate of change. It has no corresponding incentive to identify those costs that are decreasing or will not continue. Information asymmetries make it difficult for us to identify those future diminishing costs. Therefore, simply demonstrating that a new cost will be incurred—that is, a cost that was not incurred in the base year—is not a sufficient justification for introducing a step change. There is a risk that including such costs would upwardly bias the total opex forecast.

The test we apply is whether the step change is needed for the opex forecast to achieve the opex objectives in the NER.[65] Our starting position is that only exceptional circumstances would warrant the inclusion of a step change in the opex forecast because they may change a business's fundamental opex requirements.[66] Two typical examples are:

- a material change in the business's regulatory obligations
- an efficient and prudent capex/opex substitution opportunity.

We may accept a step change if a material 'step up' or 'step down' in expenditure is required by a network business to prudently and efficiently comply with a new, binding regulatory obligation that is not reflected in the productivity growth forecast.[67] This does not include instances where a business has identified a different approach to comply with its existing regulatory obligations that may be more onerous, or where there is increasing compliance risks or costs the business must incur to comply with its regulatory obligations. Usually when a new regulatory obligation is imposed on a business, it will incur additional expenditure to comply. The business may be expected to continue incurring such costs associated with the new regulatory obligation into future regulatory control periods; hence, an increase in its opex forecast may be warranted.

We expect the business to provide evidence demonstrating the material impact the change of regulatory obligation has on its opex requirements, and robust cost–benefit analysis to demonstrate the proposed step change expenditure is prudent and efficient

---

62 AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 24.

63 AER, *Expenditure forecast assessment guideline, Explanatory statement*, November 2013, p. 52.

64 AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 24.

65 NT NER, cl. 6.5.6(a).

66 AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 24.

67 AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, pp. 11, 24.

to meet the change in regulatory obligations over time.[68] We stated in the explanatory statement accompanying the Guideline:[69]

> [Network services providers] will be expected to justify the cost of all step changes with clear economic analysis, including quantitative estimates of expected expenditure associated with viable options. We will also look for the [Network services providers] to justify the step change by reference to known cost drivers (for example, volumes of different types of works) if cost drivers are identifiable. If the obligation is not new, we would expect the costs of meeting that obligation to be included in revealed costs. We also consider it is efficient for [Network services providers] to take a prudent approach to managing risk against their level of compliance when they consider it appropriate (noting we will consider expected levels of compliance in determining efficient and prudent forecast expenditure).

By contrast, proposed opex projects designed to improve the operation of the business, which we consider as discretionary in the absence of any legal requirement, should be funded by base opex and trend components, together with any savings or increased revenue that they generate—rather than through a step change. Otherwise, the business would benefit from a higher opex forecast and the efficiency gains.[70]

We may also accept a step change in circumstances where it is prudent and efficient for a network business to increase opex in order to reduce capital costs. We would typically expect such capex/opex trade-off step changes to be associated with replacement expenditure.[71] The business should provide robust cost–benefit analysis to clearly demonstrate how increased opex would be more than offset by capex savings.[72]

In the absence of a change to regulatory obligations or a legitimate capex/opex trade-off opportunity, we would accept a step change under limited circumstances. We would consider whether the costs associated with the step change are unavoidable and material—such that base opex, trended forward by the forecast rate of change, would be insufficient for the business to recover its efficient and prudent costs. We would also consider whether the business would continue to incur the costs of a proposed step change in future regulatory control periods.

Step changes included in the total opex forecast are subject to the EBSS as we typically expect these costs to be forecast using a revealed cost approach in future periods. Applying an EBSS in conjunction with a revealed cost forecasting approach provides a constant incentive on the business to pursue efficiency gains, and ensures efficiency gains or losses are shared between consumers and the regulated business.

---

68 AER, *Expenditure forecast assessment guideline, Explanatory statement*, November 2013, pp. 51–52; AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 11.

69 AER, *Expenditure forecast assessment guideline, Explanatory statement*, November 2013, p. 52.

70 AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 11.

71 AER, *Expenditure forecast assessment guideline, Explanatory statement*, November 2013, p. 74.

72 AER, *Expenditure forecast assessment guideline, Explanatory statement*, November 2013, p. 52.

Category specific forecasts

A category specific forecast may be justified if, as a result of including a specific opex category in the base opex, total opex becomes so volatile that it undermines our assumption that total opex is relatively stable and follows a predictable path over time.

We may also use category specific forecasts to avoid inconsistency or double counting within our determination. We have typically included category specific forecasts for debt raising costs, the demand management incentive allowance (DMIA) and guaranteed service levels (GSL) payments. There are specific reasons for forecasting these categories separately from base opex. For example, we forecast debt raising costs separately to provide consistency with the forecast of the cost of debt in the rate of return building block of allowable revenue. For DMIA, we forecast these costs separately because we fund them through a separate building block.

Absent such exceptions, we expect that base opex, trended forward by the rate of change, will allow the business to recover its prudent and efficient costs. Again, the business has demonstrated its ability to operate prudently and efficiently at that level of opex while meeting its existing regulatory obligations, including its safety and reliability standards. We consider it is reasonable to expect the same outcome looking forward. Some costs may go up, and some costs may go down—so despite potential volatility in the cost of certain individual opex activities, total opex is generally relatively stable over time. As we stated above in relation to step changes, a business has an incentive to inflate its total opex forecast by identifying new and increasing costs, but not declining costs. Consequently, there is a risk that providing a category specific forecast for opex items identified by the business may upwardly bias the total opex forecast. By applying our revealed cost approach consistently and carefully scrutinising any further adjustments, we avoid this potential bias.

A category specific forecast is a forecast of an opex item or activity that we assess and forecast independently from base opex, and is not subject to the EBSS. Applying an EBSS where we do not rely on a revealed cost forecasting approach would not provide a sharing of efficiency gains or losses between consumers and the regulated business.

6.3.3 Interrelationships

In assessing Power and Water's total forecast opex we took into account other components of its revenue proposal, including:

- the impact of cost drivers that affect both forecast opex and forecast capex. For instance, forecast labour price growth affects forecast capex and our forecast of forecast price growth used to estimate the rate of change in opex
- the approach to assessing the rate of return, to ensure there is consistency between our determination of debt raising costs and the rate of return building block
- concerns of electricity consumers and stakeholders identified in the course of Power and Water's engagement with consumers.

6.4 Reasons for draft decision

Our draft decision is to include total forecast opex of $305.9 million ($2018–19) in Power and Water's revenue for the 2019–24 regulatory control period, which is 9.8 per cent lower than Power and Water's forecast opex of $339.3 million ($2018–19).[73] We are satisfied our alternative estimate of forecast opex reasonably reflects the opex criteria.[74] In particular we consider:

- the base opex costs relating to maintenance, vegetation management and network overheads do not reflect efficient costs for the regulatory control period 2019–24.
- the forecast price growth by Power and Water is overstated and does not reflect efficient costs
- other than in relation to Guaranteed Service Level costs, the step changes proposed by Power and Water are not required to address a material change in regulatory burden or can be met from within existing opex.

On this basis, we do not accept that Power and Water's proposed forecast reasonably reflects the opex criteria. Table 6.3 presents the components of our alternative estimate compared to Power and Water's proposal. It shows that the key differences are:

- we included a lower estimate of efficient base opex
- we included a lower rate of change
- we included part of the GSL step change but did not include proposed step changes for the national connections process, metering type 7, operating a metering data management system (MDMS) and additional network planning resources.

Table 6.3 Our alternative estimate compared to Power and Water's proposal ($million, 2018–19)

	Power and Water's proposal	Our draft decision	Difference
Based on reported opex in 2016-17[75]	378.9	375.1	–3.8
'Top-down' efficiency adjustment	–35.2	0.0	35.2
Individual cost category assessment reductions[76]	0.0	–52.2	–52.2

73 Includes debt raising costs.

74 NT NER, cl. 6.5.6(c).

75 Power and Water did not remove movements in provisions in its reported opex. We removed $0.8 million per year for movements in provisions.

	Power and Water's proposal	Our draft decision	Difference
Other adjustments[77]	–27.3	–27.3	0.0
2016-17 to 2018-19 increment	0.0	1.2	1.2
Output growth	6.6	5.4	–1.3
Price growth	6.0	0.2	–5.8
Productivity growth	0.0	0.0	0.0
Step changes	7.4	0.9	–6.5
Debt raising costs	2.7	2.6	–0.2
Total opex	339.3	305.9	–33.4

Source: Power and Water regulatory proposal; AER analysis.
Note: Numbers may not add up to total due to rounding.

We discuss the components of our alternative estimate below. Full details of our alternative estimate are set out in our opex model, which is available on our website.

There are several issues noted in the following sections where either Power and Water has foreshadowed changes may be made in its revised proposal or where we consider Power and Water may wish to provide further information. This, amongst other things, may result in changes between the draft and final decisions. In addition, Power and Water has submitted further information about the opex forecast in the draft decision and its ability to run its business at a lower level of opex than it proposed. Power and Water did not provide this information within a timeframe that has permitted us to take it into account for this draft decision. It has the opportunity to address these matters further in its revised proposal.

6.4.1 Base opex

This section sets out our view on Power and Water's proposed base opex of $63.3 million ($2018–19) for each year of the regulatory control period.

To forecast base opex Power and Water used its 2017–18 forecast, reflecting actual 2016–17 opex adjusted for inflation, of $75.8 million ($2018–19) and:

---

76 We identified operational efficiencies for maintenance and vegetation management expenditure, and instances where network overhead expenditure is not representative of ongoing efficient costs.

77 Power and Water made a reduction of $5.5 million ($2018–19) for capitalisation of leases (see Section 6.4.1.4: Non-network and Box 1) and added $13 451 ($2018–19) for GSLs (see Section 6.4.3: Guaranteed service levels). We incorporated these proposed adjustments.

- removed $5.5 million (7.2 per cent) of expenditure on building and motor vehicle leases, which will be capitalised from 1 July 2019 consistent with accounting standard AASB16
- applied a 'top-down' efficiency adjustment of 10 per cent, amounting to $7.0 million each year or $35.2 million ($2018–19) over the next regulatory control period
- added $13 451 ($2018–19) for GSLs costs (see section 6.4.3).

6.4.1.1 Overall view

We assessed the efficiency of Power and Water's opex in the 2016–17 base year using multiple techniques and information sources, including a detailed review of Power and Water's opex cost categories and its operating and maintenance practices. Based on our analysis, we concluded that Power and Water's revealed costs do not reflect efficient costs incurred by a prudent distributor.

Our approach differed from Power and Water's. As can be seen in Table 6.4, Power and Water applied a 'top-down' 10 per cent efficiency adjustment to total opex in the base year, equivalent to $7.0 million ($2018–19) per year. In contrast, we reviewed the efficiency of individual opex cost categories making up total actual opex in 2016–17 and where necessary made adjustments to those the categories, rather than total opex. We focused on those cost categories that are material in terms of total opex and/or where we consider there to be the greatest scope for identifiable efficiency improvement as indicated by Power and Water's proposal, partial performance indicator benchmarking and our review.

We have made adjustments to maintenance, vegetation management and network overhead expenditure. In relation to maintenance and vegetation management opex, our assessment compared Power and Water's operational practices to good electricity industry practice.[78] From this, we identified areas for cost savings, which we quantified and subtracted from base year opex. In relation to network overheads, we assessed whether base year expenditure was likely to be recurrent and representative of efficient costs going forward.[79] We composed an alternative estimate of network overheads which we substituted for Power and Water's expenditure in the base year.

The adjustments we made amount to $10.4 million ($2018–19) per year or a 13.7 per cent reduction to Power and Water's base year opex and are summarised in Table 6.4. As a result of our assessment, we consider we cannot use Power and Water's revealed opex as a starting point to forecast efficient opex over the 2019–24 regulatory control period. Our approach and the reasons for our view is set out in section 6.4.1.4.

---

78 Where we have referred to good electricity industry practice we have had regard to the specific evidence and submissions provided to us in relation to this determination, as well as our relevant experience arising from assessing the expenditure proposals of other network service providers in the NEM, and our internal expertise.

79 Our approach to assessing Power and Water's base opex is outlined in more detail in section 6.4.1.4.

We agree with Power and Water's proposal to remove $5.5 million ($2018–19) from base opex, reflecting lease costs that will be capitalised going forward under AASB16, and its proposed $13 451 ($2018–19) adjustment for GSLs. We have also removed movements in provisions from Power and Water's base opex, consistent with our standard approach. Our approach to exclusions from the base year are set out in section 6.4.1.3.

Table 6.4 - Power and Water and AER view of efficient base opex

Category	Power and Water's base year opex[80] $ million ($2018–19)	Our alternative estimate $ million ($2018–19)	Difference ($)	Difference (%)	Percentage of total opex (%)	PPI benchmarking[81]	Key reasons for our alternative estimate
Vegetation management	4.9	3.9	–1.0	-20.0	6.4	Very high	Power and Water's practices do not reflect good electricity industry practice[82] and accordingly expenditure in the base year is above efficient levels. We consider Power and Water can implement good electricity industry practice consistent with the recommendations of a consultant report (finalised in August 2017) Power and Water commissioned. Implementation of these recommendations has commenced but is not reflected in base opex.
Maintenance	17.8	13.1	–4.7	-26.3	23.5	Very high	1. Inspections and maintenance is carried out too frequently in the context of high priority defects reducing and reliability improving. Power and Water can align its inspection and maintenance frequencies with good electricity industry practice. Reductions in activity across a range of asset classes amount to a 20.3 per cent reduction to maintenance expenditure. 2. 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. Using this approach it could also improve the alignment of its asset inspection practices to enable efficiencies. Our estimated efficiencies of implementing such practices is equivalent to a 6 per cent reduction to maintenance expenditure.
Emergency response	6.8	6.8	–	–	9.0	Very high	
Non-network	7.7	7.7	–	–	10.2	Comparable	
Network overheads	30.6	25.8	–4.8	-15.6	40.4	Very high	Use of average historical opex given its significant increase (24 per cent excluding capitalisation) in 2016–17, with allowances incorporated in our alternative estimate where they are justified.
Corporate overheads	8.2	8.2	–	–	10.8	Very high	
Balancing item	–0.2	–0.2	–	–	-0.2		
Total opex	**75.8**	**65.4**	**–10.4**	**-13.7**		Very high	
Other adjustments[83]	-5.5	-5.5	-0.0				
Movement in provisions	0	–0.8	–0.8				
Total opex (adjusted)	**70.3**	**59.1**	**–11.2**				
'Top-down' efficiency adjustment	–$7.0	–	+7.0				
Estimate of efficient base opex	**63.3**	**59.1**	**–4.2**				

Source: Power and Water, *11.5CP - Category Analysis RIN Workbooks - Consolidated - 16 Mar 18 - PUBLIC*; Power and Water; *12.4 - SCS Opex Model - 16 Mar 18 - Public*; AER analysis.
Note: All dollars are real 2018–19. Power and Water made a reduction of 5.5 million ($2018–19) for capitalisation of leases and added 13 451 ($2018–19) for GSLs. We incorporated the proposed adjustments and removed $0.8 million for movements in provisions.

---

80 The categories of opex reflects 2016-17 reported actual opex.

81 Power and Water's relative costs have been categorised as 'very high', 'high', 'comparable', 'low' or 'very low' by comparing Power and Water's position against other distributors positions and exercising judgement to classify them into one of the above categories. See Attachment A for an explanation of partial performance indicator (PPI) benchmarking and results.

82 NT NER, Chapter 10. Where we have referred to good electricity industry practice we have had regard to the specific evidence and submissions provided to us in relation to this determination, as well as our relevant experience arising from assessing the expenditure proposals of other network service providers in the NEM, and our internal expertise.

83 Power and Water made a reduction of 5.5 million ($2018–19) for capitalisation of leases (see Section 6.4.1.4) and added $13 451 ($2018–19) for GSLs (see Section 6.4.3—Guaranteed service levels). We incorporated these proposed adjustments.

6.4.1.2 Choice of base year

Power and Water used 2016–17 as its base year in its regulatory proposal. It noted it expects to update the base year to 2017–18 in its revised regulatory proposal, once actual audited information becomes available.[84]

We consider opex typically to be relatively predictable over time. However, as shown in Figure 6.1, Power and Water's opex has been relatively volatile with large increases in reported opex in 2008–09 to 2011–12, some stability in 2012–13, but reductions since then. This can be attributed to past events that include equipment failures at the Casuarina zone substation in 2008 and the subsequent Government (Davies) review, the Utilities Commission 2009–14 determination, structural changes, and changes in cost allocation.

We agree with Power and Water's proposal to use 2016–17 as the base year. This is because it is the most recent year for which actual audited information is available and it is likely to best reflect Power and Water's current circumstances, relative to previous years. We note, however, that in 2016–17 there have been significant changes in some cost categories that we have examined.

6.4.1.3 Exclusions from base year

In choosing a base year, we need to decide whether any categories of opex incurred in the base year should be removed. For instance, if a material cost was incurred in the base year that is unrepresentative of future opex, we may remove it from the base year as including those costs may result in a total opex forecast that is inflated and not consistent with the opex criteria.[85] Power and Water removed $5.5 million (2018–19) of expenditure incurred in the base year on operating leases for building and motor vehicles. This is because Power and Water intends to capitalise these costs going forward, consistent with accounting standard AASB16, so they will be reported as capex not opex. We accept this adjustment will make base opex more reflective of future opex and have incorporated it in our alternative estimate as a $5.5 million reduction (see 6.4.1.4—Non-network).

In other circumstances a particular category of opex may be removed from the base year expenditure if it is more appropriate to forecast that category separately. We refer to these as 'category specific forecasts' (section 6.4.4). Power and Water proposed debt raising costs be forecast separately, consistent with our standard approach. We agree with this approach, although note that Power and Water's base year opex does not include debt raising costs.[86]

---

[84] Power and Water, *01.2 - Regulatory Proposal - 16 March 18 - PUBLIC*, p. 10.

[85] NT NER, cl. 6.5.6(c).

[86] Power and Water, response to AER information request IR031, 18 July 2018, Q.1.

We have removed movements in provisions[87] from the base year, consistent with our standard approach. We consider that changes in provisions should not be treated as actual reported opex for forecasting purposes. This is because changes in provisions reflect estimates of costs rather than the actual cost incurred in delivering network services. Power and Water did not remove changes in provisions from its opex forecast, so it is a source of difference between our base year estimate and Power and Water's proposal.

6.4.1.4 Efficiency of base year

This section sets out the approach we have taken to assess the efficiency of Power and Water's opex in the base year, and the details of our assessment including the reasons for our view.

Approach

Consistent with our Guideline[88], we have used multiple assessment techniques to review Power and Water's opex to form a view on whether expenditure in the base year is efficient, or whether an adjustment is required.

We have undertaken an assessment of Power and Water’s main opex categories (see Figure 6.4) which are vegetation management, maintenance, emergency response, non-network, network overheads and corporate overheads.

We formed a view during the assessment process that we could not necessarily rely on Power and Water's revealed costs and we needed to undertake a detailed assessment of its opex in the base year. Various information sources supported this view: Power and Water's relatively high and volatile opex over previous regulatory control periods; events surrounding the Davies review; the previous Utilities Commission regulatory determination, and structural separation of the retail and generation functions (all of which pointed to a variety of shortcomings in Power and Water's operational and governance processes); as well as Power and Water's own opex forecast which incorporated its own efficiency adjustment. Our view that we could not necessarily rely on revealed costs was also consistent with the indicative 'partial performance indicator' (PPI) benchmarking information that we and Power and Water prepared (see Appendix A for an explanation of PPI benchmarking and results). All of these factors suggested

---

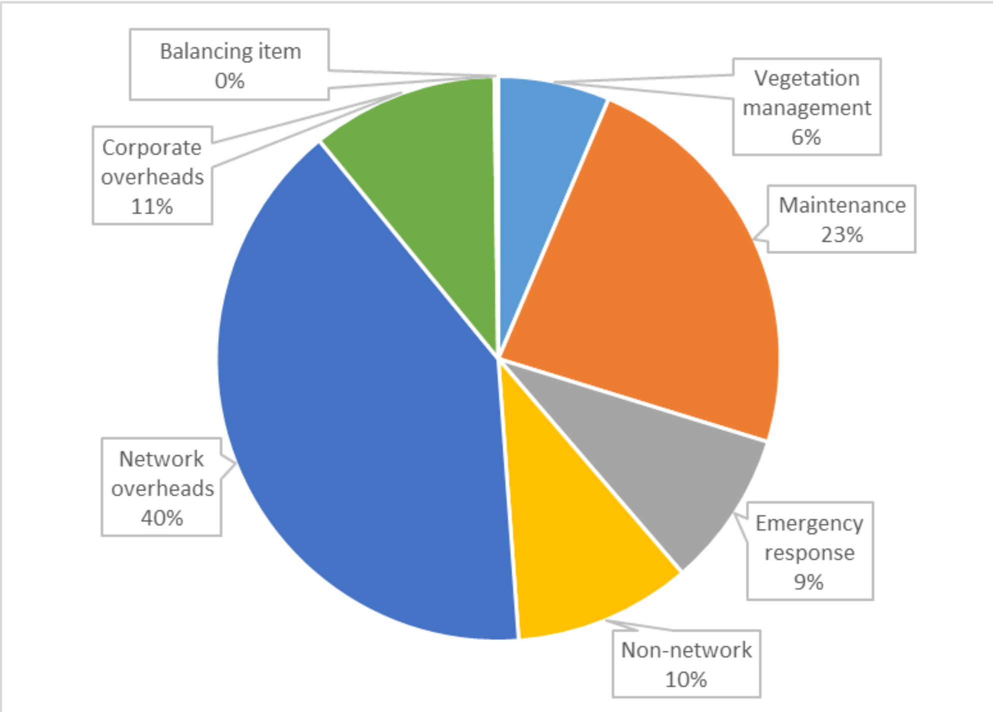
87 A provision is a type of accrual accounting practice. A business records a provision for an anticipated cost when it expects it will incur a cost in the future but the amount and timing of the cost has not yet crystallised. For accounting purposes, increases in provisions are typically allocated to expenditure, and, in particular, to opex. If a business considers it is likely it will incur a future cost, or it expects the amount of the cost will be higher to that it has previously recorded, reported actual expenditure will increase. This means a business may sometimes report increases in expenditure when it estimates there is a change in a liability it faces. It may not actually expect to incur the cost for some time and the cost will not necessarily eventuate in the amount predicted. Similarly, if a business no longer considers it will incur a future cost, or it expects the amount of the cost will be lower than that it has previously recorded, reported expenditure will decrease.

88 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013.

we needed to undertake an in depth assessment of whether an efficiency adjustment was required and if so, what the magnitude of the adjustment should be.

Through our review we identified areas for operational efficiencies (in relation to maintenance and vegetation management), and instances where base year opex was not representative of efficient costs going forward (in relation to network overheads). We quantified the cost savings we would expect and subtracted these from expenditure in the base year to determine our alternative estimate of efficient base year opex.

Figure 6.4 – Power and Water's expenditure categories 2016–17 ($2018–19)



Source: Power and Water, Category Analysis RIN, 22 May 2018.

We have focused our assessment on those categories of opex that are:

- the most material in terms of total opex (as per Figure 6.4) and/or
- where we consider there to be the greatest scope for identifiable efficiency improvement (as indicated by Power and Water's proposal, PPI benchmarking, and our review).

Using this approach, we have focused on maintenance, vegetation management, network overheads and corporate overheads, which represent 81.0 per cent of base opex, and where the available evidence pointed to achievable improvements. We have also considered to lesser degrees the emergency response, and non-network categories, which represents 19.2 per cent of opex.[89]

Our choice of assessment techniques has been tailored to individual opex categories reflecting the nature of expenditure and the information accessible to us.

To assess Power and Water's maintenance and vegetation management opex, we have reviewed asset management practices including inspection frequencies, risk assessment practices and vegetation cycle management, and compared those practices to good electricity industry practice. We have used time trend analysis of categories and subcategories. We have considered performance measures like System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI), which are measures of reliability. We have undertaken volume benchmarking across distributors particularly in relation to asset inspection frequency. These issues have been considered in the context of Power and Water's asset management history, the condition and performance of its assets, the local climatic circumstances and the broader business' operating environment.

To assess overheads, we reviewed the level and nature of particular costs incurred in the base year. We have examined Power and Water's historical overhead opex and considered whether these costs are expected to continue in the next regulatory control period.

As outlined in section 6.3.1, we have departed from our preferred top-down assessment approach for this draft decision. We have undertaken a more detailed assessment of individual opex categories. This is because it is the first time we are assessing Power and Water and we have been unable to rely on Power and Water's revealed costs or use total opex benchmarking[90] to determine an alternative efficient amount.

Under one of the opex factors, we are required to have regard to the most recent annual benchmarking report that has been published and the benchmark opex that would have been incurred by an efficient operator.[91] Power and Water has just transitioned to the NER and has not been included in previous annual benchmarking reports published by us. While this limits our ability to use the previous reports, for the purposes of this assessment we have prepared PPI benchmarking to inform our analysis of Power and Water's opex proposal and the efficiency of its revealed opex. In particular we have:

- prepared PPI benchmarking at category level and total opex level; and
- reviewed the PPI benchmarking submitted in Power and Water's proposal.

[89] The sum of maintenance, vegetation management, network overheads, emergency response, corporate overheads and non-network opex exceeds 100 per cent due to Power and Water's balancing item.

[90] This includes the total opex benchmarking that we undertake using econometric opex cost function models and multi-lateral partial factor productivity analysis.

[91] NT NER, cl. 6.5.6(e)(4).

The PPI analysis provides an indication of Power and Water's efficiency compared to other distributors (see Appendix A). The PPI benchmarking helped us to identify and prioritise opex cost categories for detailed review. The PPI benchmarking is also useful as a high-level cross-check that identified efficiency improvements are realistic and achievable. We consider the PPIs support the findings from our detailed review that Power and Water can achieve material efficiency gains by implementing good electricity industry practices.

We have not used the PPI benchmarking as the basis for making adjustments to base year opex for the purpose of our alternative opex estimate. Further work is required to integrate Power and Water in our benchmarking in a manner that would enable it to be used as the basis for making adjustments to base opex. This includes quantifying the impact of Power and Water's operating environment on its opex (see Appendix B). This will be a focus of our benchmarking forward work program following this regulatory determination process.

Assessment

Maintenance

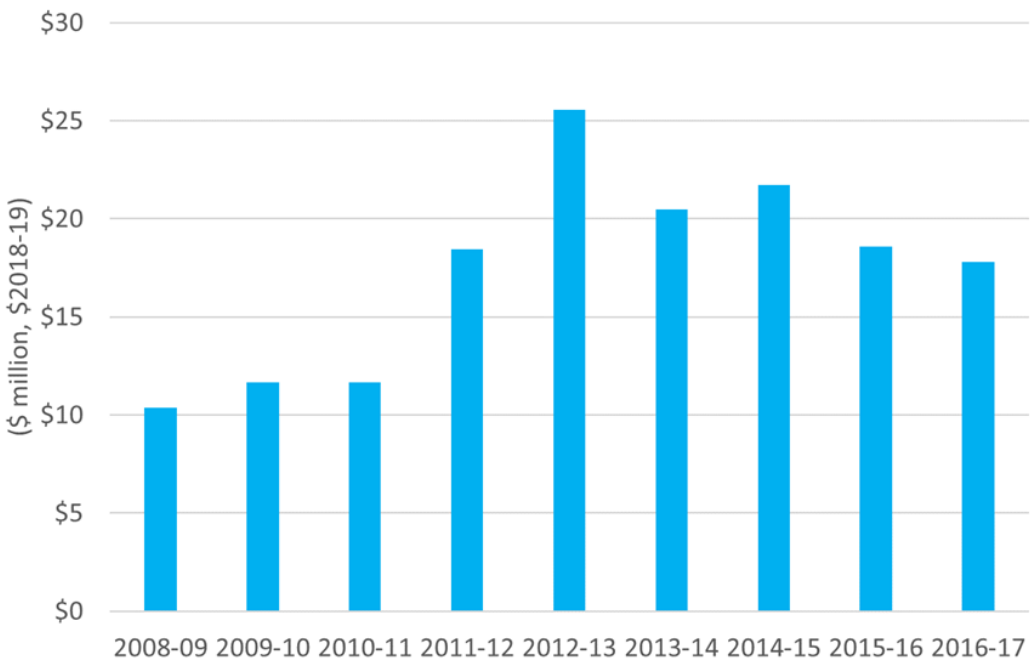
Power and Water's inspection and maintenance practices have improved over recent years, but we do not consider them to be consistent with good electricity industry practice.[92] Inspections and maintenance are carried out too frequently meaning the opex in this category is above efficient levels and not costs that would be incurred by a prudent operator providing the safe and reliable delivery of electricity. This is supported by Power and Water's and our PPI benchmarking and comparisons of Power and Water's practices against good electricity industry practice. We consider Power and Water can improve the efficiency of its maintenance base opex by $4.7 million or 26.3 per cent.

Maintenance costs are Power and Water's second largest cost category in 2016–17, comprising 23.5 per cent of total opex. Figure 6.5 illustrates that maintenance opex has decreased from 2012–13, when it peaked at $25.5 million, to $17.8 million in 2016–17. Over the last four years it has decreased by 13.1 per cent. These expenditures are significantly higher than in the period 2008–09 to 2010–11 when annual maintenance opex was $10–12 million per year.

---

[92] NT NER, Chapter 10. Where we have referred to good electricity industry practice in relation to a type of proposed expenditure, we have had regard to the specific evidence and submissions provided to us in relation to this determination, as well as our relevant experience arising from assessing the expenditure proposals of other network service providers in the NEM, and our internal expertise.

Figure 6.5 - Inspection and maintenance opex ($2018–19)



Source: Power and Water, Category Analysis RIN, 22 May 2018.

Prior to 2008 we understand the level of maintenance was limited and Power and Water's maintenance practices were reactive. Following the Casuarina Zone Sub Station failure in 2008, and the subsequent Davies review in 2008–09, Power and Water implemented a preventative maintenance plan in 2010–11 that was largely implemented by 2012–13.[93]

As illustrated in Figure A.2 (Appendix A), Power and Water's maintenance opex per circuit km against customer density over the period 2013–14 to 2016–17 is over three times higher than other businesses with similar customer densities.

In its proposal, Power and Water notes that when compared to other networks, there appears to be some room for improvement regarding maintenance.[94] It also observes the targeted efficiency adjustment (as part of achieving its 10 per cent target) only needs to be modest because most of the differences explained by its unique circumstances and its cost reductions over recent years.

We consider Power and Water's operating environment is likely to have some impact on its maintenance opex, including as a result of weather conditions that impact its asset condition and workability. While we have not yet quantified this impact, we note other businesses experience some similar environmental conditions, particularly Ergon

---

[93] Power and Water, response to AER information request IR002, 6 April 2018, Q1(a), p 1.

[94] Power and Water, *03.1 - Opex Base Year Justification - 16 March - PUBLIC*, p 48.

Energy, but also Essential Energy, and have significantly lower maintenance opex per circuit km.[95] An anonymous submission on Power and Water's proposal also noted climatic similarities with other distributors in Queensland and NSW. It stated it is therefore not clear there should be a unique cost premium in the NT due to climate.[96]

We have identified areas of Power and Water's inspection and maintenance practices that we consider do not meet good electricity industry practice, based on our experience from reviewing other networks' revenue proposals. We have identified improvements that, if implemented, would result in efficiencies and lower opex. In particular:

- less frequent inspections and maintenance
- the use of risk assessment to inform inspection and maintenance activity and inspection practice alignment across assets.

These changes as we have considered them predominately go to the volume of maintenance work undertaken.

Less frequent inspections and maintenance

As set out below, we have found that there are opportunities for Power and Water to reduce inspection and maintenance frequencies. In coming to this conclusion we have taken into account Power and Water's asset defect and asset reliability information, which suggests that with high priority defects reducing, and reliability improving, it is efficient for Power and Water to reduce inspection and maintenance frequencies. We have also had regard to good electricity industry practice in terms of inspection and maintenance frequencies.

Power and Water's proposal included information supporting the view that its inspection and maintenance frequencies are considerably higher than its peers. This included that it inspects 37.3 per cent of its assets per year, while the industry average excluding Power and Water was 14 per cent.[97] And that its inspection rates are the highest across the industry for several assets, including distribution substation transformers, pole tops and overhead lines, zone substation transformers, and distribution substation switchgear. These make up just under 50 per cent of Power and Water's maintenance opex.[98]

Power and Water's asset reliability information shows that high priority defects (priority 1 and 2[99] which have a greater impact on service level outcomes) have fallen by 43 per cent since 2014.[100] This can be seen in Figure 6.6.

---

[95] Ergon and Essential's networks are also subject to heat and humidity.

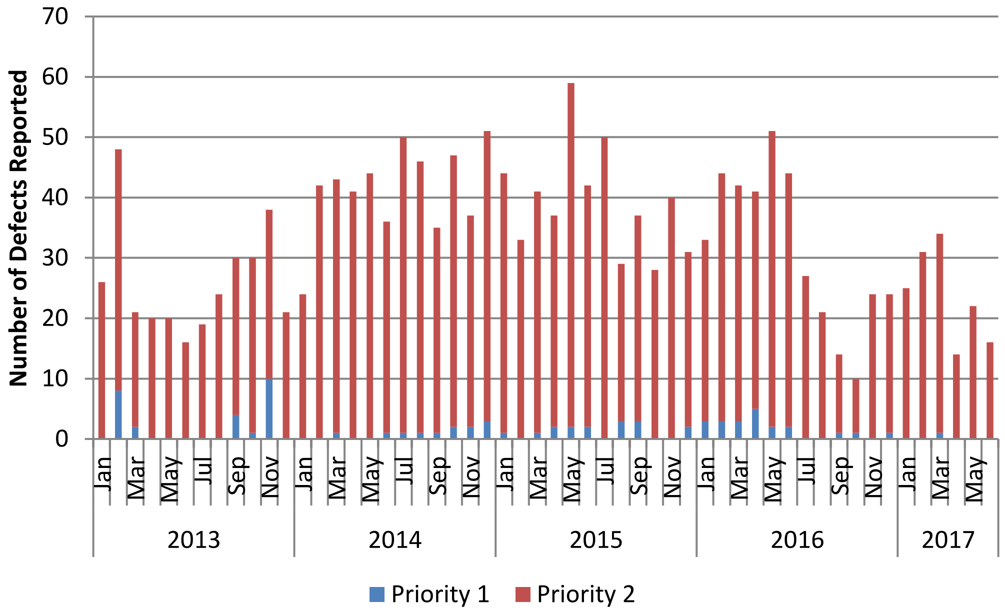
[96] Anonymous, *Submission on Power and Water proposal*, 16 May 2018, p. 2.

[97] Power and Water, *03.1 - Opex Base Year Justification - 16 March - PUBLIC*, p. 38–40.

[98] Power and Water, *03.1 - Opex Base Year Justification - 16 March - PUBLIC*, p. 39–40.

[99] Under Power and Water's defects classification scheme the target timeframe to repair are: priority 1 defects in less than 12 hours, priority 2 defects in less than 28 days, priority 3 defects in less than 39 weeks and priority 4 assets

Figure 6.6 - Number of priority 1 and 2 defects reported 2014–17



Source: Power and Water's monthly defects data.[101]

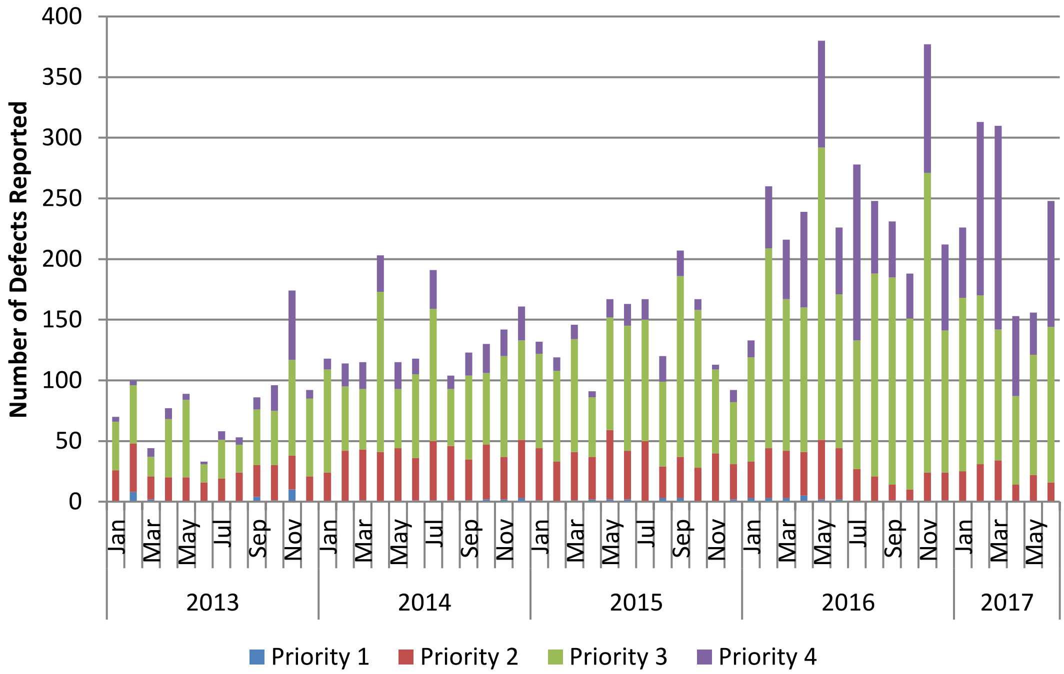
In addition, since 2014 there has been over a doubling in minor priority defects (priority 3 and 4, which are generally minor issues that are unlikely to impact service level outcomes). This can be seen in Figure 6.7 and suggests Power and Water's heightened inspection practices are over time identifying less important defects and remediating them in line with the repair timeframes detailed in its defects classification scheme.

at the next maintenance interval. Power and Water, response to AER information request IR002, 6 April 2018, Q(3), Power Networks Corrective Work Prioritisation Guidance (Defect Priority) - 20180406 – Public, p. 3.

100 Power and Water, response to AER information request IR017, 29 May 2018, action item 9, Monthly Defect Data. Calculated using the calendar year data and the percentage difference between the total P1 and P2 defects in 2014 and 2017 and assuming the first six months of 2017 is replicated in the second six months.

101 Power and Water, response to AER information request IR017, 29 May 2018, action item 9, Monthly Defect Data.

Figure 6.7 - Number of priority 1, 2, 3 and 4 defects reported 2014–17

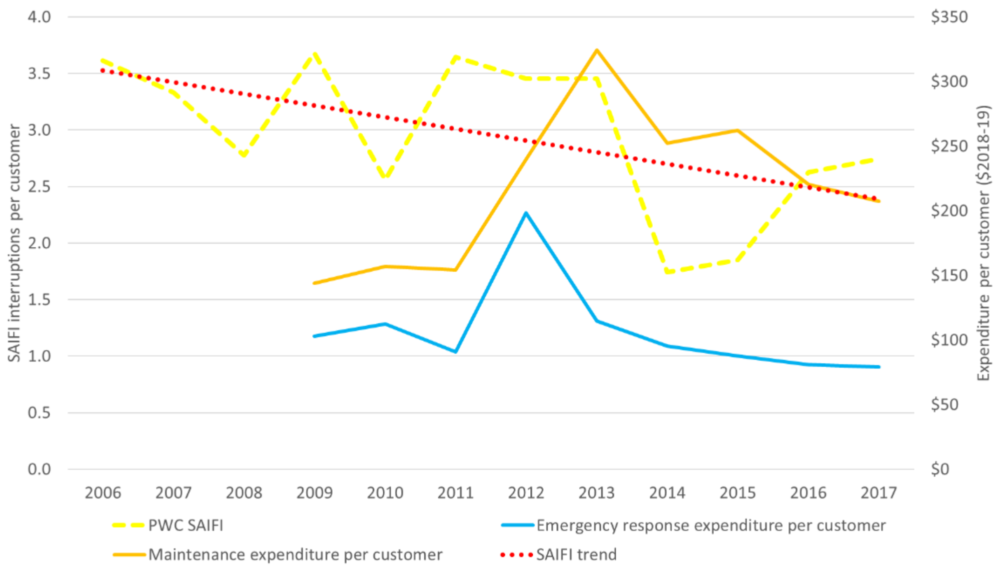


Source: Power and Water's monthly defects data.[102]

The improvements in Power and Water's reliability performance, reflecting the impact of Power and Water's preventative maintenance plan outlined above, can be seen in Figure 6.8 and 6.9. These illustrate the decreasing trend in the frequency and duration of interruptions per customer (SAIFI and SAIDI respectively), reflecting improved reliability, and how there is a similar downward trend in maintenance (and emergency response) opex per customer.

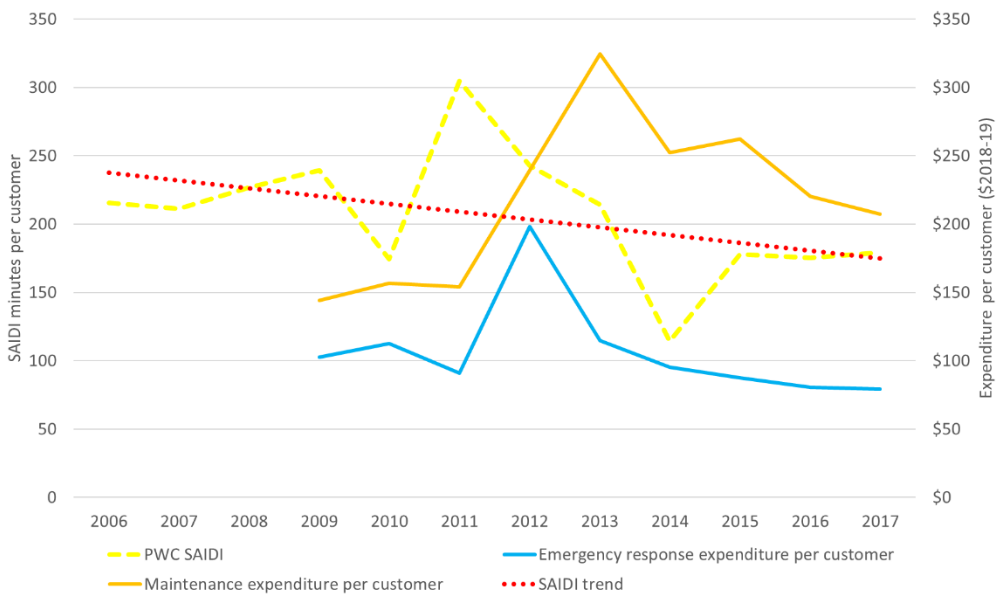
[102] Power and Water, response to AER information request IR017, 29 May 2018, action item 9, Monthly Defect Data.

Figure 6.8 - SAIFI excluding major event days and excluded events (interruptions per customer, whole of network)



Source: Power and Water, Category Analysis RIN, 22 May 2018; Power and Water, Economic Benchmarking RIN, 23 May 2018.

Figure 6.9 - SAIDI excluding major event days and excluded events (minutes per customer, whole of network)



Source: Power and Water, Category Analysis RIN, 22 May 2018; Power and Water, Economic Benchmarking RIN, 23 May 2018.

We would expect to see this pattern following the introduction of improved inspection and maintenance practices i.e. a decline over time in the high priority defects, but the heightened frequency of inspections finding lower priority defects, and improving reliability. We consider this is strong evidence that Power and Water can improve efficiency by reducing its inspection and maintenance frequencies.

In our assessment, we took into account confidential documents provided by Power and Water related to its maintenance expenditure (confidential appendix C). These, along with Power and Water's 2018 Power Networks Asset Strategies Procedure[103], in our view, support the finding that there are efficiencies that can be made to better align Power and Water's practices with those of the broader industry.

Power and Water commenced implementing changes in 2016–17 that we expect to deliver efficiencies and we consider it would take approximately two years before they could be fully realised. Power and Water's maintenance opex decreased by 4.2 per cent between 2015–16 and 2016–17. This is likely to have been driven by a variety of reasons, possibly including some efficiency improvements.

We have also identified opportunities for reduced inspection and maintenance frequencies to be achieved. This reflects the inspection and maintenance cycles Power and Water currently has in place in its 2018 Asset Strategies Procedure are higher than typical industry rates. In particular:

- inspection frequency for steel poles is currently on a three yearly cycle.[104] Based on our experience from reviewing other networks' revenue proposals, steel pole and line inspection cycles are generally 4 to 5 years or longer within the electricity industry, depending on local conditions such as proximity to salt laden or corrosive environments. We have applied a 55 per cent adjustment to this expenditure to reflect inspection frequency reducing, some of which we expect Power and Water has already achieved since the base year (confidential appendix C).
- Power and Water inspects and tests distribution earthing every 3 and 5 years respectively[105], voltage regulators every 3 and 2 years respectively[106], and pole transformers 3 yearly.[107] Based on our experience from reviewing other networks' revenue proposals, there are opportunities to align and integrate inspection of these types of assets within the line inspection program, with a 4 to 5 year inspection cycle unless specific circumstances dictated otherwise (e.g. known condition issues, high fire risk areas or critical loads). We have applied a 33 per cent efficiency adjustment to this expenditure to reflect on average a reduction in inspection frequency of one third.

103 Power and Water, response to AER information request IR002, 6 April 2018, Q3, Asset Strategies Procedure - 20180406 – Public.

104 Power and Water, response to AER information request IR002, 6 April 2018, Q3, Asset Strategies Procedure - 20180406 – Public, p. 30.

105 Power and Water, response to AER information request IR002, 6 April 2018, Q3, Asset Strategies Procedure - 20180406 – Public, p. 39.

106 Power and Water, response to AER information request IR002, 6 April 2018, Q3, Asset Strategies Procedure - 20180406 – Public, p. 42.

107 Power and Water, response to AER information request IR002, 6 April 2018, Q3, Asset Strategies Procedure - 20180406 – Public, p. 41.

We estimate these reduced inspection frequencies would result in a $3.6 million ($2018–19) or 20.3 per cent saving in Power and Water's 2016–17 maintenance opex. This is based on consideration of the inspection and maintenance cycles used more broadly across the industry for a range of asset types such as those noted above and is set out in Table 6.5.

Table 6.5 - Inspection and maintenance efficiencies ($million, 2018–19)

Assets	Base opex (2016–17)	Efficiency adjustment (%)	Opex reduction
Lines and poles	2.2	55%	1.2
Earthings, distribution substations, zone substations, pillars	7.2	33%	2.4
Other assets	8.3	–	–
Total	17.8	20.3	3.6

Source: Power and Water, Category Analysis RIN, 22 May 2018; AER analysis.

Numbers may not add up due to rounding.

Similar observations can be made for other inspection rates, including for underground feeders and related assets. We do not have disaggregated information on the maintenance opex for these assets and therefore have not quantified these possible efficiencies. Power and Water should provide this information as part of its revised proposal.

We consider this all suggests Power and Water is able to take a more informed, and less risk averse position to the inspection and maintenance rates it implemented after the Casuarina inquiries.

Use of risk management to inform inspection and maintenance activity and inspection practice alignment

Power and Water's risk assessment practices, which inform its inspection and maintenance program, are relatively undeveloped compared to good electricity industry practice.[108] We consider Power and Water could achieve efficiency improvements if it adopted a risk based classification of defects that accounts for service level implications, rather than based on just the physical state of the asset, when determining inspection and maintenance needs. This would involve adopting strategic asset management practices that incorporate risk management, including the use of failure mode, effects and criticality analysis (FMECA).

108 Power and Water, response to AER information request IR002, 5 April 2018, Q18—*PWC Risk Management Foundation Document - Risk Management Guidelines*, 22 July 2009, pp. 8–10.

It appears that Power and Water has plans to develop its risk management, asset management, and overall investment management practices, and has included ICT capex (Maximo and ESRI upgrade / reimplementation) to support these plans.[109] However, these practices were not in place in the base year.

We also note that in the information we have reviewed Power and Water's inspection and maintenance practices are presented for asset types.[110] These practices suggest there is a lack of alignment in the processes used by Power and Water across its assets. We consider there are opportunities for Power and Water to review its inspection and maintenance practices with a view to optimising the way in which it schedules inspection and maintenance work. Where Power and Water moved to a risk based asset management practice it could improve the alignment of its asset inspection practices to enable efficiencies e.g. by minimising the work required to inspect assets for different purposes.

We consider adopting a risk management approach to inform inspection and maintenance activity and aligning inspection practices is likely to enable efficiencies in the range of 6 - 8 per cent or more of maintenance opex. This takes into account our assessment of Power and Water's asset management maturity, the overall condition and performance of its assets and the environment in which it operates.

The above areas for improvement relate to the volume of inspection and maintenance work undertaken by Power and Water. As labour is a key input to maintenance opex, our examination of labour opex and workability considerations has informed us about the efficiency of Power and Water's unit cost of maintenance opex. We have not made any specific adjustments to maintenance opex for labour rates as Power and Water's unit cost of labour benchmarks relatively well—see the separate section on labour opex (including workability) below.

Inspection and maintenance efficiencies

We have identified opportunities for maintenance opex efficiencies comprising less frequent inspections and maintenance and the use of risk management to inform inspection and maintenance activity and enable inspection practice alignment. These adjustments result in a $4.7 million or 26.3 per cent efficiency reduction to maintenance base opex as summarised in Table 6.6.

Table 6.6 - Maintenance opex efficiencies ($2018–19)

Area of improvement	Efficiency estimate (% 2016–17 base)
Less frequent inspections and maintenance	20.3% ($3.6 million)

[109] Power and Water, *13.43P - ICT Capital Expenditure Plan - PUBLIC*, p. 76.

[110] Power and Water, response to AER information request IR002, 6 April 2018, Q3, Asset Strategies Procedure - 20180406 – Public.

Area of improvement	Efficiency estimate (% 2016–17 base)
Use of risk management and improved inspection practice alignment	6% ($1.1 million)
Total	26.3% ($4.7 million)

Source: AER analysis.

Numbers may not add up due to rounding.

This estimated efficiency is not significantly different from Power and Water's own view. As a part of its proposal Power and Water noted that as part of the overall 10 per cent ($7.0 million) annual opex efficiency target it is likely that maintenance costs will reduce.[111] Further, given the outcome of peer comparisons, and execution considerations, it assumed for presentation purposes that 50 per cent of the total efficiency adjustment would come from a reduction in maintenance opex.[112] This translates to an annual reduction of approximately 20 per cent or $3.5 million in maintenance opex.

Vegetation management

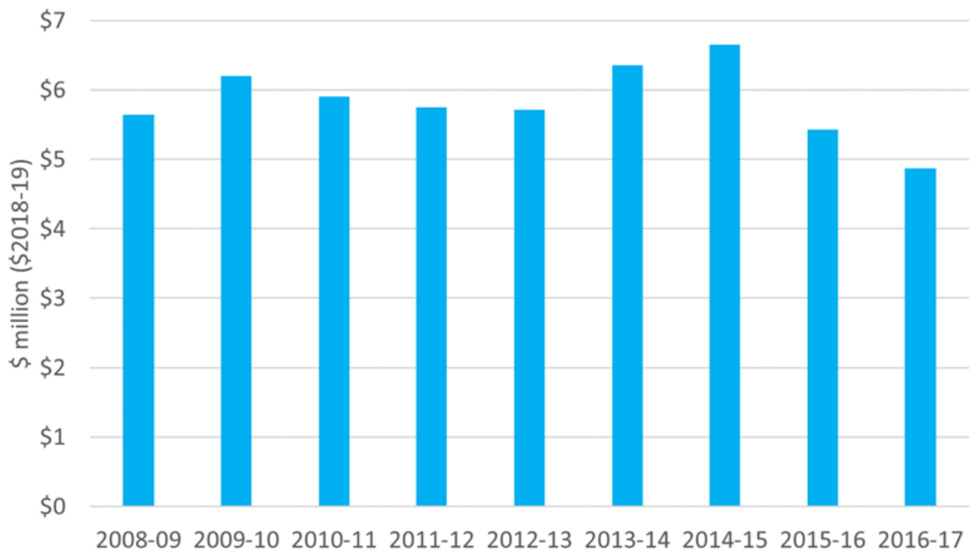
Power and Water's vegetation management practices have improved over time but we consider they do not reflect good electricity industry practice or efficient costs based on examining the results of Power and Water's vegetation management analysis project and our experience from reviewing other networks' revenue proposals. We consider Power and Water's vegetation management opex in the base year is $1.0 million ($2018–19) or 20 per cent higher than it should be over the next regulatory control period consistent with good electricity industry practices being in place. We consider Power and Water will have substantially implemented these efficiencies by the start of the regulatory control period.

Vegetation management costs make up 6.4 per cent of total opex in 2016–17. Figure 6.10 illustrates that vegetation management opex has decreased from 2014–15, when it peaked at $6.7 million, to $4.9 million in 2016–17. Over the last four years it has decreased by 23.3 per cent. The 2016–17 opex is now below vegetation management opex over the 2009–10 to 2011–12 period (around $5.9 million per year).

111 Power and Water, *03.1 - Opex Base Year Justification - 16 March - PUBLIC*, p. 48.

112 Power and Water, *03.1 - Opex Base Year Justification - 16 March - PUBLIC*, p. 48–49.

Figure 6.10 - Vegetation management opex ($2018–19)



Source: Power and Water, Category Analysis RIN, 22 May 2018.

As illustrated in Figure A.3 (Appendix A), Power and Water's vegetation management opex per km of route line length against customer density over the period 2013–14 to 2016–17 is around double most other businesses that have similar customer densities. We consider Power and Water's operating environment is likely to have some impact on its vegetation management opex relative to other distribution networks, including as a result of extreme weather conditions that affect the rate of growth of the vegetation, the local species, accessibility to undertake vegetation management and workability conditions. However, we note that other businesses that experience some of these environmental conditions, particularly Ergon Energy, but also Essential Energy, have significantly lower vegetation management opex per circuit km. An anonymous submission on Power and Water's proposal stated Power and Water faced similar climatic challenges to other distributors in Queensland and NSW. It stated it is therefore not clear there should be a unique cost premium in the NT due to climate.[113]

During our review of vegetation management opex, Power and Water told us that since 2013–14 it has collated vegetation management data.[114] The availability of this data triggered a vegetation management analysis project which is the basis for Power and Water's new vegetation management strategies.[115]

This vegetation management analysis project included a report from an external consultant (finalised in August 2017) that made a series of findings, observations and

---

113 Anonymous, *Submission on Power and Water proposal*, 16 May 2018, p. 2.

114 Power and Water, response to AER information request IR002, 6 April 2018, Q11(c), p. 13.

115 Power and Water, response to AER information request IR002, 6 April 2018, Q11(c), p. 13.

recommendations.[116] Power and Water noted that while the viability of all recommendations in the consultant's report were yet to be fully assessed, it expected the majority would be accepted and implemented as far as practical.[117] It also highlighted those recommendations that would be most significant in terms of achieving further efficiencies.

Power and Water noted one outcome of the vegetation analysis project commenced in 2017 – the development of Power and Water's asset management systems enabling the capture of vegetation activity by span.[118]

Further, in 2017–18, Power and Water started a process to develop a new structure for a single Northern Territory wide contract, with a view to implementing various recommendations from the vegetation management analysis project. It also noted that this new contract structure would ensure the tender attracted the maximum possible market participation, while still enabling smaller local service providers to bid for portions of the work in some instances.[119]

Power and Water detailed other changes occurring during 2016 with the formal extension of trimming frequency from 12 to 18 months for the Alice Springs and Tennant Creek networks. And that in early 2017 there was a significant change to the contract structure and resourcing for these networks, including the removal of permanent staff undertaking vegetation management.[120] This work is now done more cost effectively on a campaign basis where the necessary skilled resources and equipment are moved into these remote areas (i.e. Alice Springs and Tennant Creek), and once the work is completed the resources and equipment are withdrawn from the remote areas back to Darwin or interstate.

Subsequently, Power and Water advised that it foresees implementation of the recommendations over three stages - system enablement, contract development and prioritisation, validation and subsequent adoption or modification of proposed cycle times for each vegetation zones.[121] It noted that system enablement is largely complete (with ongoing improvements required), contract development is targeted for completion by June 2019 and that a complete and orderly transition to the vegetation zone basis of management is expected to take several years.[122] Power and Water also provided details of its progress against each of the recommendations.

We have examined the recommendations in the consultant's report and are of the view they reflect improvements that are consistent with good electricity industry practice based on our experience reviewing other network revenue proposals. Further, after

---

116 Power and Water, response to AER information request IR002, 6 April 2018, Q11(c), p. 13.

117 Power and Water, response to AER information request IR002, 6 April 2018, Q11(c), p. 13.

118 Power and Water, response to AER information request IR002, 6 April 2018, Q11(c), p. 13.

119 Power and Water, response to AER information request IR002, 6 April 2018, Q11(c), p. 13.

120 Power and Water, response to AER information request IR002, 6 April 2018, Q11(c), p. 13.

121 Power and Water, response to AER information request IR031, 18 July 2018, Q2, p. 2.

122 Power and Water, response to AER information request IR031, 18 July 2018, Q2, p. 2–3.

examining these recommendations[123], which include improved data collection (achieved partly through proposed ICT capex), improved cycle management and improved optimisation of minimum clearance standards, we conclude they could result in an annual reduction of $1.0 million or 20 per cent in vegetation management base opex. This reflects our estimation of the efficiencies from all recommendations in the consultant's report.

Power and Water provided confidential documents that we consider support our view that a 20 per cent efficiency adjustment to vegetation management is realistic and achievable (confidential appendix C).

We are of the view it should take Power and Water 12 to 24 months to substantially implement the recommendations in the consultant's report and achieve good electricity industry practice. Given the consultant's report was received in August 2017, and the next regulatory control period commences in July 2019, Power and Water has a reasonable opportunity to have these improvements in place before the start of the regulatory control period. From the information provided by Power and Water it appears to have already made good progress with implementing many recommendations. We have therefore applied the $1.0 million or 20 per cent annual efficiency adjustment to the base year opex.

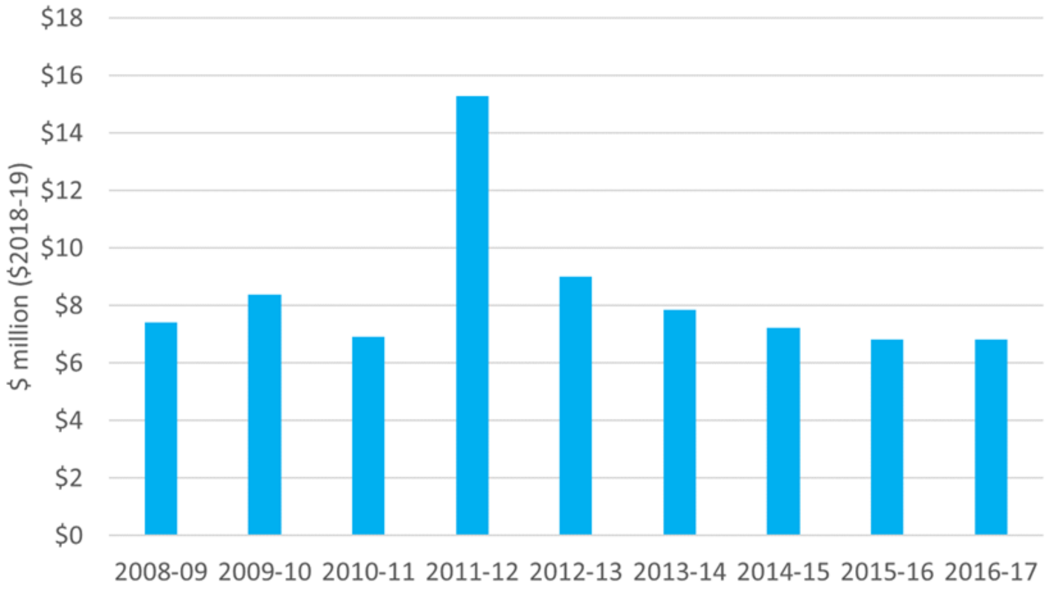
Emergency response

Power and Water's emergency response opex has decreased over time in parallel with improvements in its asset reliability. This is consistent with what we would expect to see. Reflecting this, the relative materiality of Power and Water's emergency response opex, the critical nature of these expenditures and our view there is less scope for inefficient practices we have not made any reductions to Power and Water's base emergency response opex.

Emergency response costs make up 9 per cent of total opex in 2016–17. Figure 6.11 illustrates that emergency response opex has decreased to $6.8 million in 2016–17 from $15.3 million in 2011–12, when it peaked with a one off expenditure. Over the last four years it has decreased by 13.3 per cent. The 2016–17 opex is now below emergency response opex over the period 2008–09 to 2010–11 (around $7.6 million per year).

123 Power and Water, response to AER information request IR002, 6 April 2018, Q11(c), pp 14-15.

Figure 6.11 - Emergency response opex ($2018–19)



Source: Power and Water, Category Analysis RIN, 22 May 2018.

As illustrated in Figure A.4 (Appendix A), Power and Water's emergency response opex per interruption against customer density over the period 2013–14 to 2016–17 appears to be around four times that of most businesses with similar customer densities. We consider Power and Water's operating environment is likely to have a significant impact on its emergency response opex, including as a result of extreme weather conditions, such as cyclones that impact the frequency and duration of emergency response events, the wet season that impacts accessibility and the humidity that impacts workability. We note, however, that other businesses that experience some of these environmental conditions—particularly Ergon Energy who also experiences cyclones, has a similar customer density and has significantly lower emergency response opex per interruption. As stated above, an anonymous submission on Power and Water's proposal noted climatic similarities with other distributors in Queensland and NSW.[124]

As set out in the section above on maintenance opex, Power and Water's reliability has been improving over time (see Figure 6.8 and 6.9). At the same time, as noted above, there has been a reduction in Power and Water's emergency response opex from 2011–12. We would expect to see these parallel reductions in reliability and emergency response opex and consider this is in line with improved emergency response practices.

---

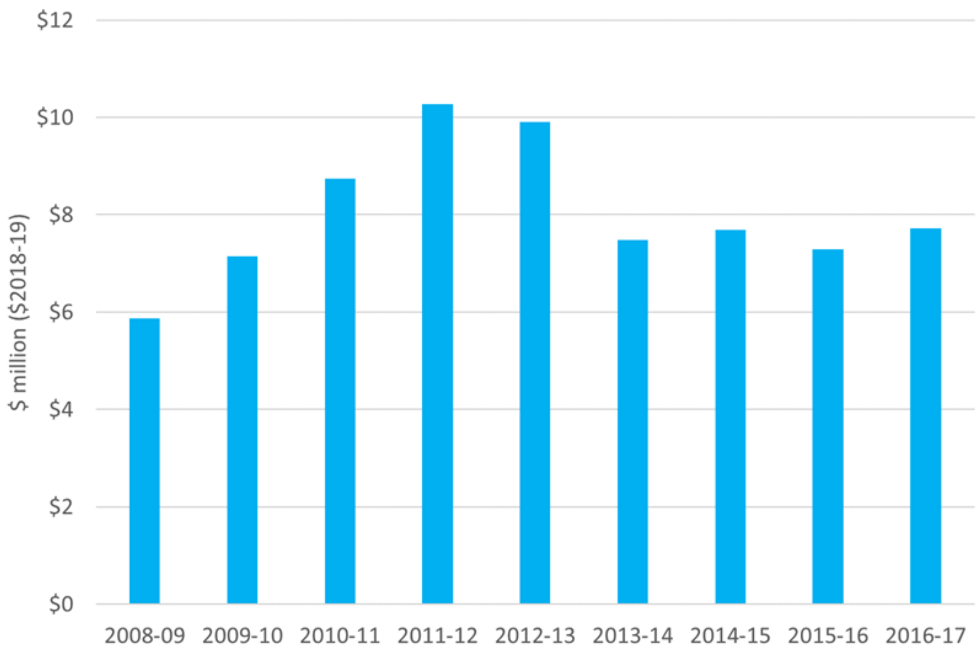
124 Anonymous, *Submission on Power and Water proposal*, 16 May 2018, p. 2.

Reflecting this, the nature of Power and Water's operating environment, and the critical nature of emergency response opex, we have not made any reductions to Power and Water's base emergency response opex.

Non-network

Power and Water's non-network opex makes up 10.2 per cent of total opex in 2016–17. Figure 6.12 illustrates non-network opex has decreased to $7.7 million in 2016–17 from a peak of $10.3 million in 2011–12. Over the last four years it has remained relatively constant with costs being between $7.3 and $7.7 million.

Figure 6.12 - Non-network opex ($2018–19)



Source: Power and Water, Category Analysis RIN, 22 May 2018.

The PPI benchmarking of non-network costs indicates that Power and Water's opex per customer is in the middle of those distributors with similar customer densities (see Figure A.5). Power and Water notes that its non-network costs perform well on a cost per customer and line length basis after adjusting for lack of scale via customer density.[125]

Power and Water proposes to capitalise $4.6 million of non-network costs relating to its leases for property and fleet under accounting standard AASB 16.[126] There have been some concerns about this capitalisation approach in submissions on the basis there are no benefits to consumers and overall costs may increase (return on and of the

---

125 Power and Water, *03.1 - Opex Base Year Justification - 16 March - PUBLIC*, p. 77–78.

126 Power and Water, response AER to information request IR004, 10 April 2018, Q1(d), p. 4.

lease asset, rather than opex lease payments).[127] We consider this capitalisation approach is consistent with Power and Water's Cost Allocation Methodology and note that customers should be no worse off under this treatment as Power and Water will only be recovering the net present value of the opex lease payments via our capex forecast. See Box 1 which outlines the proposed capitalisation approach and Attachment 5 (Capital expenditure) for further discussion of this issue.

Given that Power and Water's non-network opex has remained relatively constant since 2013–14, makes up 10.2 per cent of opex and from a PPI perspective benchmarks in the middle of those distributors with similar customer densities, we have not undertaken a detailed review of Power and Water's non-network expenditure and have not included any reductions.

Network overheads

Power and Water's network overheads make up a significant component of total base opex and have generally decreased over time until the 2016–17 base year (excluding the impact of its change in capitalisation policy).[128] We consider the 24 per cent increase in 2016–17 network overhead opex, excluding capitalisation, concerning and not reflective of ongoing expenditure requirements. Consequently, we developed an alternative estimate of network overhead opex using Power and Water's historical expenditure. This incorporates the additional costs we consider Power and Water requires over the next regulatory control period and reduced Power and Water's base year network overhead opex by $4.8 million ($2018–19).

Network overhead opex represents 40 per cent, or $30.6 million ($2018–19)[129] of Power and Water's total base year opex. Figure 6.13 below illustrates that Power and Water's network overhead opex has generally decreased over time until the 2016–17 base year, when network overheads increased by $7.5 million ($2018–19) or 24 per cent, excluding capitalisation (see Box 1 on the change in capitalisation). Each component of Power and Water's network overhead (other than corporate allocations) increased by more than 10 per cent in 2016–17.[130] This was offset by an $8.0 million ($2018–19) increase in indirect labour capitalisation costs[131], leaving network overhead opex relatively constant compared to 2015–16.

---

[127] Anonymous, *Submission on Power and Water proposal*, 16 May 2018, p. 3-4.

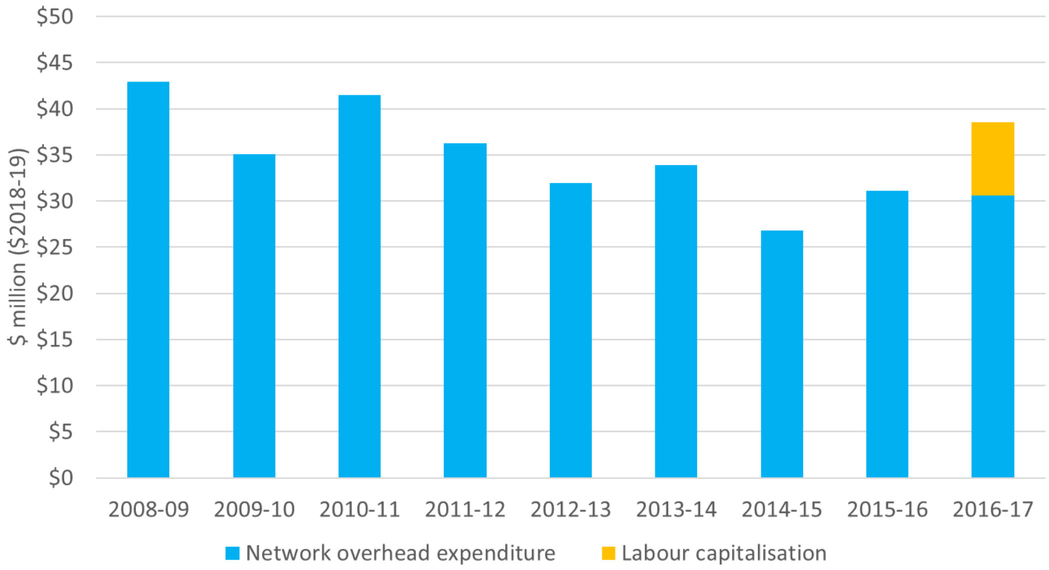
[128] See Box 1 for further discussion around capitalisation.

[129] Power and Water's category analysis RIN.

[130] Power and Water's network overhead was presented as being split into corporate allocations, professional fees, service level agreement expenses, personnel costs, vehicles and 'other'. Power and Water, response to AER information request IR007, 2 May 2018, Q2(c), p. 2.

[131] Power and Water, response to AER information request IR004, 10 April 2018, Q1(a,b), pp. 1–2. Power and Water, *11.2 Basis of preparation – Category analysis template for 2008–09 to 2016–17 - 7 February 2018 - PUBLIC*, pp. 132–133.

Figure 6.13 Power and Water's network overhead opex ($2018–19)



Source: Power and Water, Category Analysis RIN, 22 May 2018.

Box 1: Power and Water's revised capitalisation approach

Power and Water revised its capitalisation approach in 2016–17. Power and Water began capitalising overhead labour costs associated with the acquisition and construction of property, plant and equipment consistent with Australian Accounting Standard AASB116.[132] This brings Power and Water more in line with the practices of other distributors, noting that Power and Water's capital expenditure will still be examined to ensure they are prudent and efficient.

This revised capitalisation approach reduced Power and Water's opex in the base year by $11.3 million ($2018–19), or 14.9 per cent. Network overhead capitalisation makes up $8.0 million ($2018–19) of this, and corporate overhead capitalisation makes up the remaining $3.3 million.[133]

Further, Power and Water stated it will capitalise the costs of motor vehicles and building leases beginning 1 July 2019 in accordance with AASB16. Based on the actual costs Power and Water incurred in 2016–17, Power and Water removed $5.5

132 Power and Water, response to AER information request IR004, 10 April 2018, Q1(a,b), pp. 1–2. This is associated with property, plant and equipment.

133 Power and Water, response to AER information request IR004, 10 April 2018, Q1(a,b), pp. 1–2.

million ($2018–19) of opex from its base year to reflect its expectation of ongoing opex.[134]

As illustrated in Figure A.6 (Appendix A), Power and Water's network overhead totex is considerably higher than most of its peers. Power and Water's operating environment may have some impact on its network overhead opex (for example, the possibility of higher labour rates in the NT compared to most states).[135]

Power and Water submitted there appears to be room for improvement in its network overheads, and has notionally allocated half of its proposed 10 per cent base year efficiency adjustment to it.[136]

As noted above, Power and Water's network overhead (excluding capitalisation) increased by 24 per cent from 2015–16, representing the highest level of network overheads since 2010–11. While we acknowledge that Power and Water faced increased costs in transitioning to the NER, we are concerned this level of expenditure is not representative of Power and Water's ongoing network overhead opex requirements.

As a result, we developed an alternative estimate of Power and Water's network overhead opex. This uses Power and Water's average estimated backcast network overhead opex from 2013–14 to 2015–16 as a starting point.[137] This level of expenditure represents the costs Power and Water incurred historically to meet its electricity supply obligations adjusted for estimated capitalisation. We then examined the main drivers of Power and Water's network overhead opex in 2016–17 to determine whether any of the additional costs Power and Water incurred in 2016–17 will be required into the next regulatory control period.

Specifically, we examined the following network overhead costs (pre-capitalisation):[138]

- regulatory costs associated with transitioning to the NT NER and the 2019–24 distribution proposal of $3.1 million ($2018–19)
- professional fees not directly associated with its distribution proposal, but associated with the NT entering the NER of $0.5 million ($2018–19)
- personnel costs of $20.2 million ($2018–19)

---

134 Power and Water, response to AER information request IR004, 10 April 2018, Q1(c), p. 3. This is associated with leases.

135 All sector WPI across states; Australian Bureau of Statistics, 6345.0 Wage Price Index, Australia, June 2018.

136 Power and Water, *03.1 Opex Base Year Justification - 16 March - PUBLIC*, pp. 86–87.

137 As explained in Box 1, Power and Water applied a new capitalisation policy in 2016–17. Power and Water's backcast network overhead opex numbers are the network overhead opex it estimated it would have incurred under its current capitalisation approach. Power and Water, response to AER information request IR010, 3 May 2018, Q1, p. 4.

138 Power and Water, response to AER information request IR007, 24 April 2018, Q4(b,d), pp. 12–14; Power and Water, response to AER information request IR007, 2 May 2018, Q2(c), p. 2.

- 'other' costs of $5.0 million ($2018–19)
- service level agreement (SLA) expenses of $5.0 million ($2018–19)
- vehicle expenses of $0.6 million ($2018–19).

Regulatory costs associated with distribution determination and transitioning to the NT NER

Power and Water reported regulatory costs of $3.1 million ($2018–19) in its base year that was not incurred in other years. This includes $1.8 million ($2018–19) of professional fees for consultants and contractors, and $1.2 million ($2018–19) of regulatory labour expenditure.[139]

Power and Water states its transition to the NER has seen a significant increase in regulatory obligations that Power and Water is required to meet, such as embedding systems and processes that support regulatory information notice (RIN) reporting.[140] Power and Water expects to incur this $3.1 million on an ongoing basis each year of the following 2019–24 regulatory control period.[141]

At a high level, we do not consider that a full $3.1 million of regulatory costs each year reflect an efficient level of ongoing expenditure. This is because some of these costs will be associated with upfront initial activities associated with transitioning to the NER that are not ongoing, and 2016–17 is a year with a relatively higher workload.

As we noted above, we acknowledge there are additional responsibilities in transitioning to the NER, such as compliance with our guidelines and reporting arrangements. However, we do not consider Power and Water requires the same level of expenditure on an ongoing basis to meet those responsibilities. For example, costs associated with embedding systems and processes that support RIN reporting are not ongoing. Power and Water is also not at the start of its transition to the NER requirements, with the Utilities Commission 2014 network price determination for Power and Water adopting, where practicable, the approach used by the AER in setting distributor revenue caps on Power and Water.[142] This includes issuing RINs modelled on the AER's RINs.[143]

---

139 It also includes $0.05 million ($2018–19) of 'other' labour costs for uniform, protective clothing, safety and health and general operational expense. Power and Water did not further disaggregate this amount. Power and Water, response to AER information request IR007, 24 April 2018, Q4(b), p. 12.

140 Power and Water, response to AER information request IR007, 24 April 2018, Q4(c), p. 13.

141 Power and Water, response to AER information request IR007, 24 April 2018, Q4(c), p. 13.

142 Utilities Commission 2014–19 network price determination, framework and approach decision paper, November 2012, p. 1.

143 Utilities Commission 2014–19 network price determination, framework and approach decision paper, November 2012, p. 32.

We examined confidential information provided by Power and Water about the breakdown of its 2016–17 professional fees for consultants and contractors ($1.8 million) (confidential appendix C).

Taking into account this information, we do not consider all of the base year professional fees are required for each year of the following regulatory control period. This reflects our view that some of Power and Water's professional fees are not recurrent, and is discussed in more detail the confidential appendix C. Where Power and Water has largely justified recurrent and efficient professional fees as a result of increased regulatory obligations, we have included the expenditure in our 2016–17 network overhead alternative estimate ($2.2 million). Power and Water may wish to address the recurrent nature of its professional fees in its revised proposal.

Finally, we reviewed Power and Water's 2016–17 network regulation average staff levels (ASLs) both in terms of the changes over time and against other distributors. We consider that Power and Water's current level of FTEs and its associated level of expenditure in its base year is adequate in meeting its regulatory responsibilities going forward. We have included Power and Water's increase in regulatory labour expenditure of $1.2 million ($2018–19) in our alternative estimate.

Professional fees not directly associated with Power and Water's distribution determination

Power and Water reported an additional $0.5 million ($2018–19) of professional fees in 2016–17 associated with NER derogations and non-distribution related regulatory work.[144] Power and Water provided confidential information about the breakdown of this cost (see confidential appendix C).

We have examined Power and Water's expenditure on NER derogations and consider this should be largely completed before the commencement of the next regulatory control period. We have included $0.08 million ($2018–19) of additional professional fees in our alternative estimate that Power and Water has justified are recurrent. This is discussed in more detail in our confidential appendix C.

Personnel costs

Power and Water reported $20.2 million ($2018–19) of network overhead personnel costs (pre-capitalisation) in 2016–17. This is an 18.1 per cent increase from 2015–16. We sought information from Power and Water to substantiate this expenditure. Power and Water attributed this increase to an increase in full time employees, enterprise bargaining agreement salary increases, and top of the band bonuses.[145]

We subsequently sought further disaggregated information on each personnel cost driver to understand why it has increased by 18.1 per cent, why this level of

---

[144] Power and Water, response to AER information request IR007, 24 April 2018, Q4(d), p. 14.

[145] Power and Water, response to AER information request IR007, 2 May 2018, Q2(c), p. 2.

expenditure was not required in the past and why this level of expenditure is required going forward. Power and Water was unable to answer these questions.[146]

We do not consider Power and Water has substantiated why it requires this increase in personnel costs going forward. We also note that we have examined Power and Water's ASLs in the labour section of this draft decision and found that Power and Water has the largest amount of ASLs per 100 000 customers compared to all other distributors. Consequently, we have not incorporated Power and Water's increase in personnel costs into our alternative estimate.

'Other' costs

Power and Water reported $5.0 million ($2018–19) of 'other' costs (pre-capitalisation) in its 2016–17 network overhead opex. This is a 39.6 per cent increase from 2015–16. Power and Water initially attributed this increase to 'other operational costs', which consists of items such as freight, fixtures and fittings, subscriptions, and uniforms. Power and Water stated that this cost category is variable year-on-year.[147]

We sought further information from Power and Water on the drivers of the step up in 2016–17. Power and Water provided confidential information that we have taken into account in forming our view about the efficiency and recurrent nature of 'other' costs in the base year.

We do not consider we can rely on Power and Water's information on 'other' costs as it has changed over time in response to information requests. This is discussed in more detail in our confidential appendix C. As a result, we have not included Power and Water's increase in 'other' costs in our alternative estimate. Power and Water will have the opportunity to address this issue in its revised proposal, which will rely on updated and audited RINs.

Service Level Agreement expenses

Power and Water has a service level agreement (SLA) with System Control.[148]

An anonymous submission on Power and Water's proposal stated SLA expenses are for the provision of the distribution services by another division of Power and Water and is not an arm's length arrangement.[149]

We are not necessarily concerned whether arrangements do or do not reflect arm's length terms. A network operator which uses related party providers could be efficient

---

146 Power and Water, response to AER information request IR024, 9 August 2018, Q9, p. 1.

147 Power and Water, response to AER information request IR007, 2 May 2018, Q2(c), p. 2.

148 Power and Water's electricity distribution business unit purchases services from its System Control business unit. System Control is responsible for providing, on behalf of the electricity distribution unit the following regulated distribution services: operation of the network, planning and coordination of outages, and provision of a system fault calls receipt and dispatch facility.

149 Anonymous, *Submission on Power and Water proposal*, 16 May 2018, p. 5.

or it could be inefficient, and vice versa. However, given the nature of the relationship between System Control and Power and Water's electricity distribution business unit (common ownership), we have examined the prudency and efficiency of this expenditure.

Power and Water's SLA was $5.0 million ($2018–19) in 2016–17 (pre-capitalisation). This is a 10.2 per cent increase from 2015–16, despite costs being relatively constant from 2013–14 to 2015–16.[150] We sought information from Power and Water around how its SLA was established and to substantiate this increase. Power and Water provided this information in a confidential response. Overall, we do not consider Power and Water has sufficiently justified the higher expenditure in 2016–17 and that it is required on an ongoing basis. Our high level review of the SLA indicates that a cost of around $4 million is likely to represent efficient costs for these services. This is captured in Power and Water's average 2013–14 to 2015–16 network overhead expenditure, which we have used in deriving our forecast.

Vehicle costs

Power and Water's base year vehicle costs of $0.6 million ($2018–19) represents a 13.6 per cent increase from 2015–16.[151] Power and Water stated that 90 per cent of this increase was for a replacement truck crane, and the remaining increase related to minor vehicle repairs.[152] This increase does not appear to be reflective of annual and, recurrent costs, so we have not included it in our alternative estimate.

Table 6.7 summarises our alternative estimate for Power and Water's network overhead opex.

Table 6.7 Summary of our alternative estimate for Power and Water's network overhead opex

Summary	$million, ($2018–19)
Average 2013–14 to 2015–16 backcast opex	$23.5
Additional costs required on an ongoing basis	
Regulatory costs associated with distribution determination and transitioning to the NT NER	+$2.2
Professional fees not directly associated with Power and Water's distribution determination and NER derogations	+$0.1
Other costs	+$0
Personnel costs	+$0

150 Power and Water, response to AER information request IR007, 2 May 2018, Q2(c), p. 2.

151 Power and Water, response to AER information request IR007, 2 May 2018, Q2(c), p. 2.

152 Power and Water, response to AER information request IR007, 2 May 2018, Q2(c), p. 2.

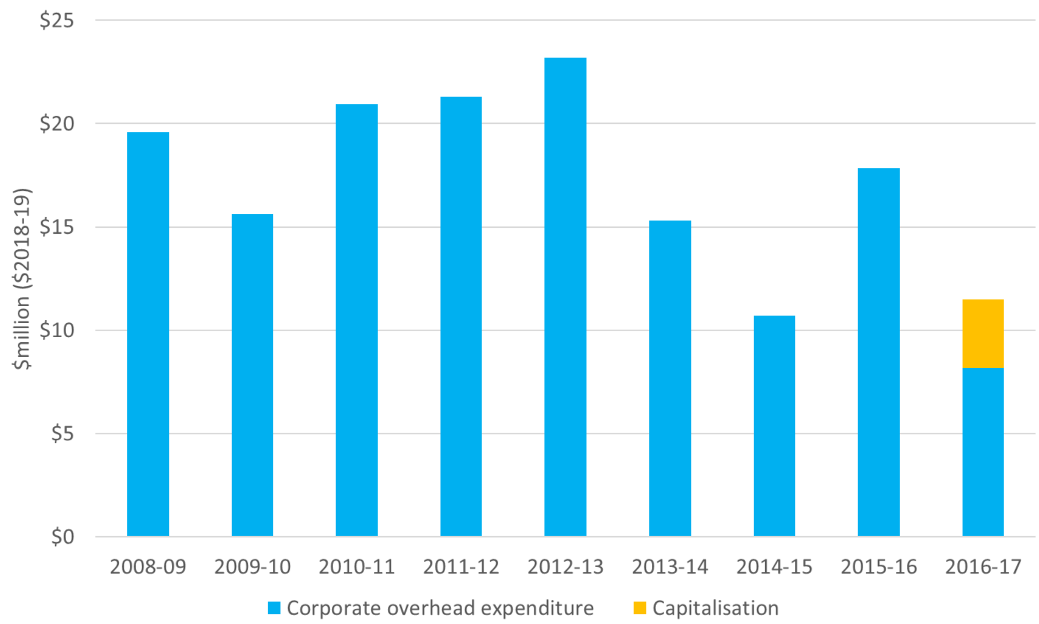
Summary	$million, ($2018–19)
SLA costs	+$0
Alternative network overheads opex estimate	**$25.8**

Corporate overheads

The corporate overhead allocated to Power and Water has generally decreased over time, and its average level per customer across the 2013–17 period is higher than most distributors.[153] We have not made any efficiency reductions to corporate overheads as a result of our review at this point.

Corporate overhead opex represents 11 per cent, or $8.2 million ($2018–19), of Power and Water's total opex in the base year. Figure 6.14 illustrates that Power and Water's corporate overhead opex has generally decreased over time, regardless of its change in capitalisation methodology.[154] Corporate overhead opex decreased by 36 per cent in 2016–17 excluding capitalisation, bringing it close to its level in 2014–15.

Figure 6.14 Power and Water's corporate overhead opex ($2018–19)



Source: Power and Water, Category Analysis RIN, 22 May 2018.Our PPI analysis in Figure A.7 (Appendix A) indicates that Power and Water's average corporate overhead (totex per customer) is higher than most distributors. This may in part reflect Power

153 Power and Water is a multi-utility that provides electricity distribution services, water services and waste water services. Corporate costs are allocated to Power and Water's electricity distribution unit according to its corporate cost allocation process along with the other businesses.

154 See Box 1 for further discussion around capitalisation.

and Water has the fewest customers of all distributors. We note that operating environment differences may also impact Power and Water's relative position due to:

- the possibility of higher labour rates in the NT compared to most states[155]; and
- Power and Water's multi-utility nature allowing it to spread costs across each of its operational groups.[156]

Power and Water stated its corporate overhead opex is comparable to other networks, benchmarks well on several PPI metrics, and that there appears to be little room for improvement.[157] It also stated it has achieved a 20 per cent cost reduction over the past four years ignoring capitalisation, in part due to its identified cost saving initiatives.[158]

We sought a disaggregated breakdown of Power and Water's corporate overhead opex over the current regulatory control period and examined:

- the changes in corporate overhead opex between 2014–15 and 2016–17, including its higher 2015–16 opex; and
- the changes in the main components of Power and Water's corporate overhead opex (facilities, HR operations, finance and business services information management (BSIM) operations).[159]

We found that while the main components of Power and Water's corporate overhead costs varied year-on-year, the overall fluctuations appeared reasonable. Power and Water explained that various cost increases over the period were due to its structural separation and its staff moving across different business units.[160] Further, the majority of Power and Water's opex increase from 2014–15 to 2015–16 was due to one-off increases in BSIM projects.[161]

In the process of examining these cost categories, Power and Water identified that its audited RIN has understated its base year corporate opex. This was due to it over-capitalising corporate overhead costs and it not being fully accounted for in its audited RINs.[162] Power and Water first advised us of this issue and its magnitude through an information request response. It then further advised that the magnitude of the amount over capitalised had been overstated as it had discovered a manual adjustment in a network overhead cost category that partly addressed the issue.[163] Due to the

[155] All sector WPI across states; Australian Bureau of Statistics, 6345.0 Wage Price Index, Australia, June 2018.

[156] Anonymous submission, S*ubmission on Power and Water proposal*, 16 May 2018, p. 1; Power and Water, *The Board Strategic Directions 2016–20*, May 2016, p. 14.

[157] Power and Water used different benchmarks compared to us to benchmark its corporate overhead totex. Power and Water, *03.1 Opex Base Year Justification - 16 March - PUBLIC*, p. 94.

[158] Power and Water, *03.1 Opex Base Year Justification - 16 March - PUBLIC*, p. 94.

[159] Power and Water, response to AER information request IR007, 24 April 2018, Q8(b), p. 22.

[160] Power and Water, response to AER information request IR024, 17 July 2018, Q12(c), p. 5.

[161] Power and Water, response to AER information request IR007, 24 April 2018, Q8(b), p. 22.

[162] Power and Water, response to AER information request IR017, 29 May 2018, Item 8.

[163] Power and Water, response to AER information request IR024, 17 July 2018, Q10(c), pp. 3–4.

inconsistency of the information Power and Water has provided regarding these cost categories, we do not consider we can rely on it and the manual adjustments Power and Water has identified to form a view on this matter. Power and Water will have the opportunity to address this issue in its revised proposal and any updated and audited RINs.

Power and Water has stated it intends to apply a revised corporate cost allocation methodology (CAM) from 2017–18, which will impact its future corporate costs.[164] However, Power and Water did not apply this revised methodology in its regulatory proposal, nor did Power and Water advise of its impact. After we sought further information from Power and Water, it advised that applying its revised 2017–18 methodology to its base year would increase its corporate overhead opex in 2016–17 by $6.6 million ($2018–19).[165]

We have not incorporated the impact of Power and Water's intended CAM revision in our draft decision. This is because Power and Water has not applied this CAM in its proposal, and our understanding is that Power and Water's current CAM does not detail this potential change. As a result, it is unclear why there may be further changes in 2017–18. Instead, we assessed the corporate overhead opex in Power and Water's proposal, which is consistent with its RINs and current CAM.

We will reconsider this if Power and Water incorporates updated corporate costs based on a revised CAM in its revised proposal and provides further information on how it is consistent with the AER approved CAM.

We also note broader concerns expressed in an anonymous submission on Power and Water's proposal regarding Power and Water's corporate costs. The submission stated it expects Power and Water to acquire the majority of its services from the Department of Corporate and Information Services (DCIS).[166] It noted this had the appearance of related party transactions, and stated that Power and Water and consequently Power and Water's customers contributed to the DCIS's significant profit in 2016–17.

We sought further information from Power and Water on the services it acquires from the DCIS. Power and Water provided a confidential response, which we have considered in assessing the arrangement with the DCIS and the associated costs.

Our understanding is Power and Water does not control the prices, terms or conditions of these services (unlike where a distributor owns and operates a related party). Power and Water's DCIS costs have been relatively recurrent year-on-year and we have found no information to suggest Power and Water has an incentive to agree to artificially inflated contract prices for services from the DCIS. In the absence of an incentive to agree to such terms, we consider it is reasonable in the circumstances to

---

164 Power and Water, *03.1 Opex Base Year Justification - 16 March - PUBLIC*, p. 89.

165 Power and Water, response to AER information request IR007, 4 May 2018, Q9(a), p. 2. This will also increase network overheads by $1.3 million ($2018–19).

166 Anonymous, *Submission on Power and Water proposal*, 16 May 2018, p. 7.

presume the contract price reflects efficient and prudent costs. We also consider it is reasonable to expect there are benefits of arrangements of this nature (for example, economies of scale), although we have not sought to verify this.

Power and Water's Board's Strategic Directions paper 2016–20[167] and statements made by Power and Water's previous chair in a 2016 Budget Estimate hearing[168] indicate that Power and Water (as a whole, including the other utilities) had larger than ideal corporate overheads.[169] The Board's Strategic Directions paper included a target corporate overhead to total opex ratio of 15 per cent, compared to a 2015–16 ratio of 25 per cent.[170] Power and Water has not been able to provide us with its progress in achieving this ratio.[171]

Power and Water stated it substantively scoped and actioned a Business Transformation Program (BTP) in 2016 to improve each business unit's performance[172], and indicated its cost reduction over the last four years was in part due to its identified cost initiatives.[173] However, we consider it concerning that Power and Water was only able to provide details of some of the initiatives it put in place without being able to quantify any corresponding savings from each initiative.[174] We also note that it appears Power and Water scoped, sought approval and delivered its BTP initiatives in a relatively short time frame. It is unclear how much BTP savings could be realised in the current 2014–19 regulatory control period.

Power and Water has also stated it is currently undertaking a corporation wide Target Operating Model (TOM) program aimed at identifying organisational efficiencies (as compared to business unit efficiencies under the BTP).[175] It considers this program is an important part of Power and Water's ability to find efficiencies within its business to meet its proposed 10 per cent 'top-down' efficiency reduction.[176] This includes examining its business structure, system and processes to enable it to uplift organisational capability, and maximise synergies.

---

167 Power and Water, *The Board's Strategic Directions 2016–20*, May 2016, p. 18.

168 Alan Tregilgas, transcript of Budget Estimates: Government owned corporations scrutiny committee proceedings, Friday 23 June 2016.

169 Comments in the 2016 Budget Estimate hearing referred to Power and Water's Board Strategic Directions paper, which compared Power and Water's corporate overheads with a sample of Australian utility corporations. Power and Water's corporate overheads were considerably higher than all businesses in the sample.

170 Power and Water, *The Board's Strategic Directions 2016–20*, May 2016, p. 26.

171 Power and Water, response to AER information request IR024, 15 July 2018, Q5, pp. 4–6.

172 Power and Water, response to AER information request IR024, 15 July 2018, Q5, pp. 4–6.

173 Power and Water, *03.1 - Opex Base Year Justification - 16 March - PUBLIC*, p. 94.

174 Power and Water, response to AER information request IR024, 15 July 2018, Q5, pp. 4–6; Power and Water, response to AER information request IR007, 8 May 2018, Q11, pp. 2–3.

175 This is different to the BTP, which focused on business unit by business unit efficiencies. Power and Water, response to AER information request IR024, 15 July 2018, Q4.

176 Power and Water, *r*esponse to AER information request IR024, 15 July 2018, Q4, pp. 2–3.

While this program is still at its early stages[177] and not yet at the point of identifying efficiencies, any organisational efficiencies may reduce its corporate overheads. We expect Power and Water to provide more information on this program in its revised proposal, including progress made and any efficiencies identified, and we will incorporate any updated information in our final determination.

We have not identified any efficiency reductions to Power and Water's corporate overheads at this point. Power and Water's corporate overhead opex has decreased over time, and it has programs in place to examine opportunities for further efficiencies.

We may examine this cost category in more detail once Power and Water has provided its revised proposal, updated and audited RINs and details of further progress to its TOM program.

Labour

Power and Water's labour expenditure represents 61 per cent or $46 million ($2018–19)[178] of its total opex in the base year. Our PPI analysis suggests that Power and Water's labour expenditure does not benchmark well compared to other distributors. We have also examined Power and Water's labour productivity, its expenditure per average staff level (ASL), and total ASL per 100 000 customers against other distributors. We found that Power and Water has the highest internal labour ASL per 100 000 customers across the distributors we have benchmarked.[179] We consider this is above the efficient level. We have used this to inform ourselves that the magnitude of the reductions in Power and Water's other cost categories are appropriate. We have not made a separate reduction for labour as we want to avoid double counting efficiency improvements.

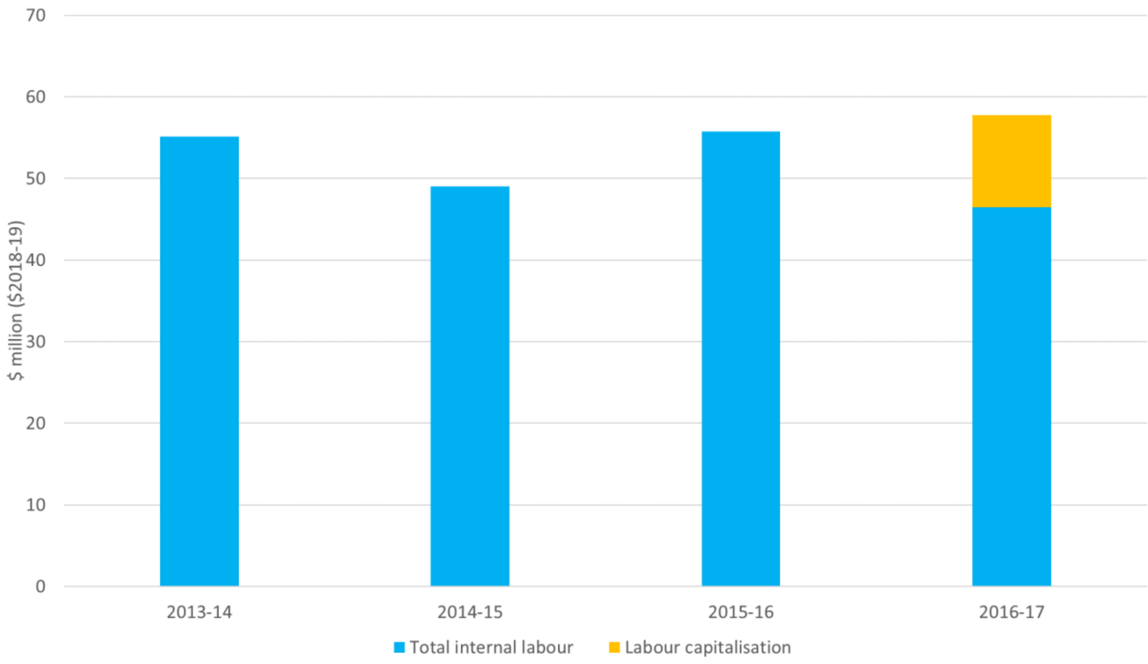
Figure 6.15 below illustrates that Power and Water's internal labour opex has been relatively constant pre-capitalisation, apart from in 2014–15. Accounting for the change in capitalisation, Power and Water's internal labour opex decreased by 17 per cent from 2015–16.

177 Power and Water, response to AER information request IR024, 15 July 2018, Q4, pp. 2–3.

178 Power and Water's category analysis RIN.

179 CitiPower and Powercor have been removed from the sample because they reported incorrect labour data.

Figure 6.15 Power and Water's internal labour opex ($2018–19)



Source: Power and Water, Category Analysis RIN, 22 May 2018.

Our PPI analysis in Figure A.8 (Appendix A) illustrates that Power and Water's internal labour opex per customer during the 2013–17 period is well above other distributors. However, this measure does not capture labour expenditure associated with contracts and may reflect that Power and Water delivers its outputs with more internal labour compared to other businesses. Power and Water's operating environment may also impact its labour expenditure (for example, the possibility of higher labour rates in the NT compared to most states).[180] Although, we note a submission from the ETU that considers supply industry workers at Power and Water earn significantly less than many of their interstate counterparts.[181] In comparison, the ETU observed there may be higher comparative employment costs in relation to the ratio of professional and managerial staff to technical staff.[182]

Unlike other cost categories, Power and Water did not separately compare its labour expenditure with other distributors.

We have also analysed Power and Water's internal labour in terms of its labour productivity, expenditure (totex) per ASL, and Power and Water’s total ASL per 100

---

[180] All sector WPI across states; Australian Bureau of Statistics, 6345.0 Wage Price Index, Australia, June 2018.

[181] Electrical Trades Union, *Power and Water regulatory proposal 2019–24*, 16 May 2018, p. 2.

[182] Electrical Trades Union, *Power and Water regulatory proposal 2019–24*, 16 May 2018, p. 2.

000 customers.[183] We examined the costs from a totex perspective to account for capitalisation of labour costs.

We have examined Power and Water's labour productivity as a result of the humidity and climatic conditions in the NT. Power and Water stated the extreme heat in the NT has a significant impact on field crew productivity, with Power and Water's overall average workability rate at 68 per cent (68 per cent work, 32 per cent rest).[184] The ETU noted there are significant and unique geographical and environmental challenges faced in the NT.[185] However, an anonymous submission suggested the impact of humidity on labour costs should not be overestimated as it only impacts field staff, in the field, and only between October and April.[186]

We have reviewed Power and Water's commissioned workability study,[187] and consider it inconclusive to Power and Water's workability circumstances. This is because it does not consider the actual work undertaken by Power and Water in relation to the workability of peer businesses. Instead, it only analyses the climate conditions against theoretical models and the survey data only assesses self-reported heat related symptoms. However, we consider Power and Water's practices and procedures in managing its labour productivity given the climate reflect good electricity industry practice.

We examined Power and Water's total internal labour expenditure (totex) per ASL. Figure 6.16 below shows that Power and Water’s labour expenditure per ASL has been one of the highest across all distributors we benchmarked against, and higher than the distributor average over 2013–16. In its 2016–17 base year, Power and Water’s labour cost per ASL decreased lower than the distributor average.

[183] Total labour cost is a function of price per labour x amount of labour.

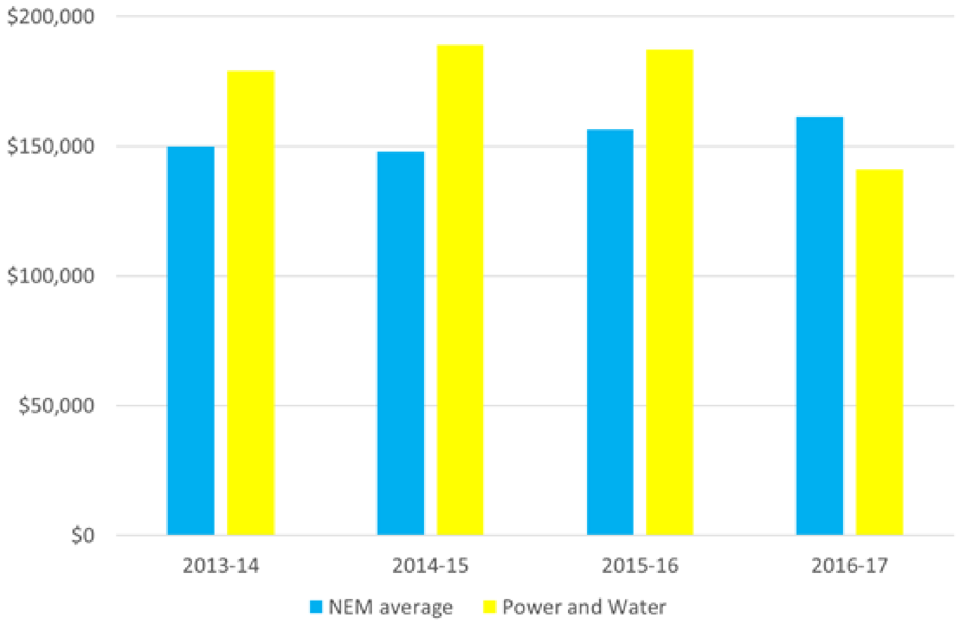
[184] Power and Water, *03.1 - Opex Base Year Justification, 16 March - PUBLIC*, p. 14.

[185] Electrical Trades Union, *Power and Water regulatory proposal 2019–24*, 16 May 2018, p. 2.

[186] Anonymous, *Submission on Power and Water proposal*, 16 May 2018, p. 3.

[187] Power and Water, response to AER information request IR017, 30 May 2018, Item 10.

Figure 6.16 Internal labour cost (totex) per ASL from 2013–17 ($2018–19)[188]



Source: Electricity distribution network services providers' Category Analysis RINs.

We have also examined Marsden Jacob Associates' (MJA) labour rate review to assess Power and Water’s labour rates. MJA provided information on the reasonableness of forecast cost inputs that generate prices for alternative control services (ACS). However, its labour rate review is also applicable to standard control services (SCS).[189] The MJA report and Power and Water's 2016–17 internal labour cost per ASL does not suggest that Power and Water's unit costs are materially higher than what we would expect in Darwin.[190] However, we note that MJA did not benchmark each of Power and Water's labour rates.

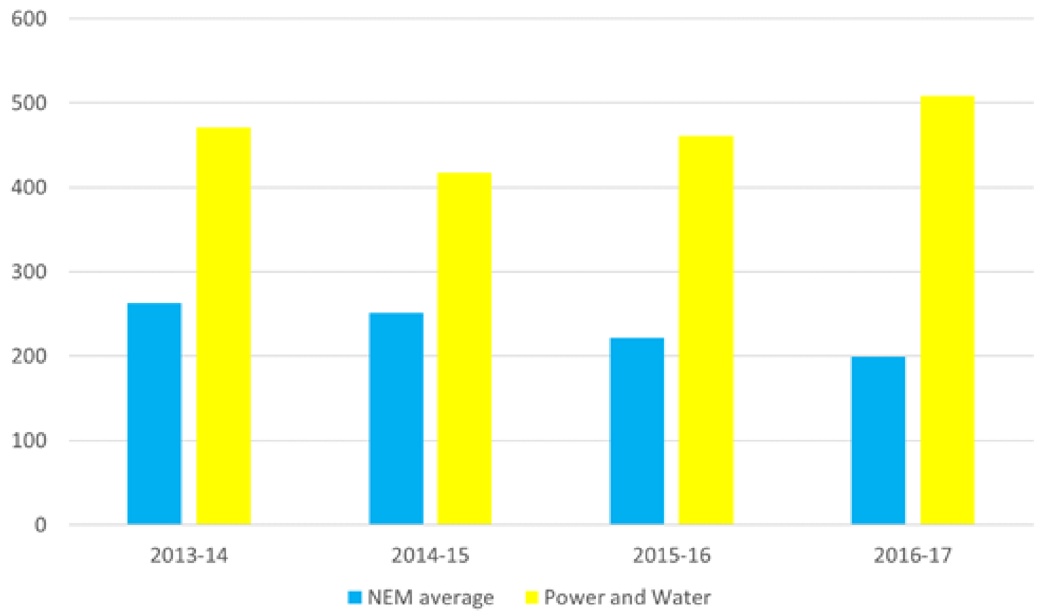
Further, we examined Power and Water’s average staffing levels per 100 000 customers from 2013–17 relative to other distributors. Figure 6.17 illustrates that Power and Water’s ASLs per 100 000 customers are significantly above the distributor average.

188 CitiPower and Powercor have been removed from the sample due to it reporting incorrect labour data. Jemena and AusNet have been removed due to confidential labour data.

189 MJA considered whether distributors had reasonable cost inputs by establishing maximum price rates for specific jobs in the energy sector across Australia. MJA based this on Hays 2017 Energy sector and Office support salary data.

190 Marsden Jacob Associates, *Review of Alternative Control Services, Advice to Australian Energy Regulator*, 29 June 2018.

Figure 6.17 Average staffing levels per 100,000 customers in 2013–17[191]



Source: Electricity distribution network services providers' Category Analysis RINs.

We sought to understand Power and Water’s relatively high ASLs across the 2013–14 to 2016–17 period. As we noted earlier, Power and Water's relative labour performance may reflect its preference to deliver outputs with more internal labour compared to other businesses. However, this may not necessarily reflect an optimal level of outsourcing.

The ETU observed there may be additional costs of outsourcing labour as the contracting firms incur costs of flying in and flying out contracted labour and must pay significant additional travel, accommodation, mobilisation and demobilisation costs.[192]

We examined Power and Water's proportion of outsourced labour (totex). Figure 6.18 below illustrates Power and Water's proportion of outsourcing over time. This proportion has gradually declined since 2012–13 to below 30 per cent, however, Power and Water forecasts it to average 49 per cent over the next regulatory control period.

It is not clear why Power and Water's proportion of outsourcing has declined year-on-year over the current regulatory control period and why there is a material increase in the proportion of labour outsourcing in the 2019–24 regulatory control period. Power and Water advised that some of the labour data in its regulatory determination RIN (used to create Figure 6.18) inadvertently contained both ACS and SCS costs, and will

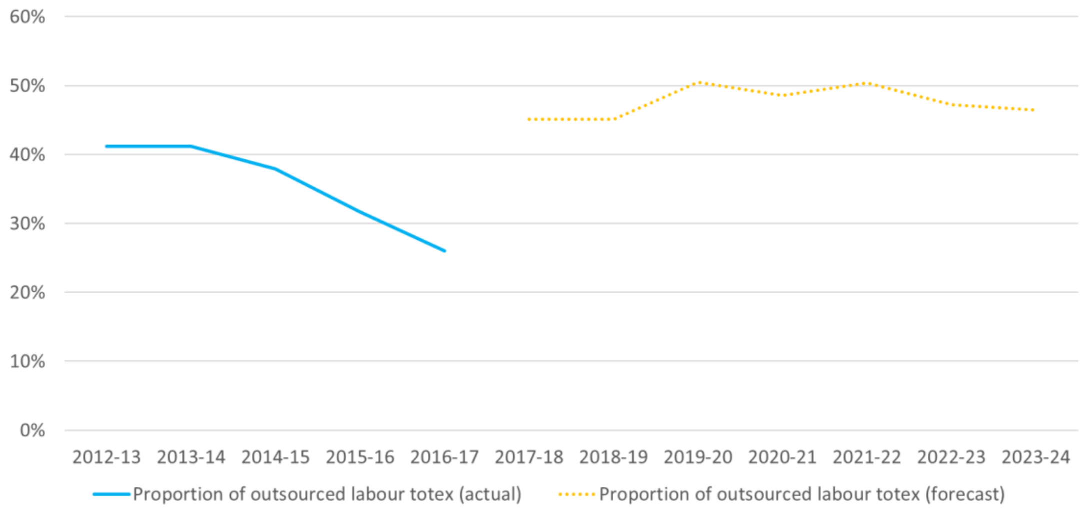
---

191 CitiPower and Powercor have been removed from the sample due to it reporting incorrect labour data. Jemena and AusNet have been removed due to confidential labour data.

192 Electrical Trades Union, *Power and Water regulatory proposal 2019–24*, 16 May 2018, p. 2.

be updated in the next round of RIN updates.[193] Updated information may allow us to understand these changes and determine for the final decision whether Power and Water's proportion of outsourcing is a driver of its high level of labour expenditure compared to other distributors.

Figure 6.18 Time trend of Power and Water's proportion of labour (totex) outsourcing



Source: Power and Water, *Regulatory determination RIN*, 22 May 2018.

Overall, Figure 6.17 is consistent with our own internal review of Power and Water's organisational structure that suggests an ASL reduction is practical and would be efficient. Our review used Power and Water's description of its business area functions, and combined this information with industry knowledge to estimate the number of ASLs required. Among other things, we do not consider Power and Water's East Arm depot is required for it to provide a necessary level of service. We consider that given the geography of the Darwin region, two depots would be sufficient if appropriately located. We also note that Power and Water has indicated that it plans to close its East Arm depot at some future stage.[194]

We have not included any direct ASL reductions to Power and Water's base year opex. This is because we consider there is a possible overlap between our review of Power and Water's organisational structure and the expenditure reductions made across the different Power and Water cost categories (such as direct maintenance opex and network overheads), and we want to avoid double counting efficiency improvements. Instead, we have used this information to inform ourselves that the magnitude of the reductions in these other cost categories are appropriate, and in support of not including a step change for network planning (see section 6.4.3).

[193] Power and Water, response to AER information request IR031, 18 July 2018, Q3, p. 6.

[194] Power and Water, *04.1P - Capex overview document, 31 January 2018 - PUBLIC*, p. 84.

ICT capex and opex savings

Power and Water's ICT capex proposals include details of tangible and intangible benefits that will be derived from each project. In many cases the tangible benefits include opex savings which include improved productivity and reduced maintenance costs and full time equivalent (FTE) employee savings.[195] An anonymous submission on Power and Water's proposal stated it is not clear the efficiencies arising from the ICT initiatives are recognised in Power and Water's opex forecast.[196]

In Attachment 5 (Capital expenditure), we assess Power and Water's proposed ICT capex. We have made a 31 per cent reduction to Power and Water's proposed ICT capex over the 2019–24 regulatory control period, reflecting concerns around Power and Water's ability to deliver its proposed ICT capex program.

Despite this lower ICT capex program, we consider that based on our review of Power and Water's identified opex savings, it should be able to achieve opex savings in the order of $0.5 to $1 million a year.

Our draft decision does not account for these opex savings through a reduction to base opex. However, we encourage Power and Water to include information in its revised proposal about the opex savings that can be realised from its proposed ICT capex program in response to our ICT capex reduction.

6.4.1.5 Rolling forward base year opex

Under the base-trend-step approach, the starting point to forecast opex in the next regulatory control period is opex in the final year of the current period. However, we do not know this level of final year opex at the time of making our final decision. We typically estimate final year opex using a well-defined formula.[197]

We have not applied the Guideline formula to estimate opex in 2018–19. Rather, we have rolled forward our efficient level of 2016–17 opex, escalating it by the rate of change. We consider this approach reasonable because:

- the Guideline forecast opex formula and the EBSS are designed to work together. When the EBSS is implemented, the estimate of final year opex used to forecast opex in the next regulatory control period should be the same as that used to forecast the EBSS carryover because the base-trend-step approach and the EBSS

195 Power and Water, *13.43P Power and Water Corporation - ICT Capital Expenditure Plan - PUBLIC*, pp. 28, 37–39.

196 Anonymous, *Submission on Power and Water proposal*, 16 May 2018, p. 5.

197 As set out in our Guideline, the best estimate of final year opex is our preferred starting point to forecast opex. We calculate it by: (1) determining the underspend from the base year (that is, the difference between opex allowance and opex incurred in the base year); (2) subtracting this base year underspend from opex allowance in the final year of the current regulatory control period (2018–19); (3) adding back any non-recurrent efficiency gains realised in the base year. For more details see: AER, *Expenditure Forecast Assessment Guideline for Electricity distribution*, November 2013, pp. 22–23.

are intrinsically related.[198] This consistency ensures that a distributor is rewarded (or penalised) for any efficiency gains (or losses) it makes in the final year the same as it would for gains or losses made in other years. Power and Water is not subject to the EBSS. Therefore, for this determination, consistency between base-trend-step approach and the EBSS is not relevant and we can estimate final year opex using an alternative approach.

- the alternative approach we have applied reasonably accounts for key drivers of opex growth (price, output and productivity growth) between the base year and the final year of the current period.[199]

In contrast, to calculate its estimated actual opex for 2018–19 Power and Water rolled forward actual opex for 2016–17, escalating it by CPI for one year (i.e. no real change) and adjusted the resulting value to reflect change in capitalisation and its proposed 'top-down' efficiency.[200] Power and Water did not justify its approach. The net impact of implementing our approach, rather than Power and Water's, is an increase in opex of $1.6 million ($2018–19) over the 2019–24 regulatory control period.

6.4.2 Rate of change

Having determined an efficient starting point, or base opex, we trend it forward to account for the forecast growth in prices, output and productivity. We refer to this as the rate of change.[201]

We are conducting an industry-wide review of our approach to forecasting productivity. This is a result of our observations that opex multilateral partial factor productivity has grown over three per cent each year (since 2012) across the distribution industry. This is consistent with our expectations that distributors would make positive productivity growth in the medium to long term (historical productivity growth has been negative).

Further, we have received feedback from various CCP subpanels suggesting we review this aspect of the rate of change. CCP10 and CCP13 have submitted that meeting the national energy objective (NEO) means that network businesses need to be looking for positive productivity improvements each year and recommended we reconsider our zero productivity forecast.[202]

Our productivity review may change our approach to forecasting productivity growth. As part of this review, we will be looking to consult with all distributors and any other

---

198 The NER explicitly require us to have regard to whether an opex forecast is consistent with any incentive schemes that apply to a network services provider. NER, clause 6.5.6(e)(8).

199 AER, *Expenditure Forecast Assessment Guideline – Final Explanatory Statement*, November 2013, p. 61.

200 Power and Water, *12.4 SCS opex model*, 16 March 2019.

201 AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, pp. 22–23.

202 Consumer Challenge Panel subpanel 10, *Response to Evoenergy regulatory proposal 2019–24 and AER issues paper*, 16 May 2018, p. 15; Consumer Challenge Panel subpanel 13*, Issues paper Power and Water electricity network revenue proposal 2019–24*, 16 May 2018, p. 6.

interested stakeholders. Stakeholders will be given multiple opportunities to engage in the review and provide us their views. Our final decision for Power and Water will take the outcome of this review into consideration.

For the purpose of the draft decision, we have largely applied our standard approach to forecasting the rate of change. Specifically we have:

- used a weighted average of forecast labour price growth and non-labour price growth to determine price growth
- used output weights derived from the results of the four benchmarking models we presented in our 2017 annual benchmarking report. This is a refinement of our previous approach, which used the weights from a single econometric model
- applied a zero productivity growth forecast.

We have forecast an average annual rate of change of 0.68 per cent, compared to the 1.29 per cent forecast by Power and Water. This difference is due to us forecasting price growth based on Deloitte Access Economics (DAE)'s most recent wage price indices (WPI) for utilities in the Northern Territory and output growth based on a refined approach, which is set out below. In contrast, Power and Water forecast price growth based on outdated WPI estimates for utilities in South Australia and output growth using weights derived from a single econometric model.[203]

6.4.2.1 Forecast price growth

We have included forecast real average annual price growth of 0.12 per cent in developing our alternative opex estimate. This increased our opex alternative estimate by $0.2 million ($2018–19). In contrast, Power and Water forecast price growth of 0.66 per cent.

Our price growth forecast is a weighted average of forecast labour price growth and non-labour price growth.

- to forecast labour price growth, we have used DAE's up-to-date WPI forecast for the Northern Territory utilities industry.[204] We generally average these forecasts with forecasts of utilities WPI for the relevant state when they are provided by a service provider. While Power and Water adopted our approach, it averaged outdated forecasts of South Australia utilities WPI from DAE and BIS Shrapnel. Power and Water did not provide utilities WPI for the Northern Territory. Consequently, we have relied on DAE's forecasts. We would consider applying an average if Power and Water were to provide a sound and justified alternative WPI forecast for Northern Territory utilities in its revised proposal.

203 Power and Water, *12.4 SCS opex model*, 16 March 2018.

204 Deloitte Access Economics, *Labour Price Growth Forecasts Prepared for the Australian Energy Regulator*, 19 July 2018, Table vii, p. xiv.

- to forecast non-labour price growth, we, like Power and Water, have applied the forecast change in CPI.[205]
- we and Power and Water have applied the same weights to account for the proportion of opex that is labour and the proportion that is non-labour (59.7:40.3). Our reasons for adopting these weights are set out in our 2017 Economic Benchmarking report.[206]

6.4.2.2 Forecast output growth

We have included forecast average annual output growth of 0.56 per cent in developing our alternative estimate of forecast opex. This increased our alternative estimate by $5.4 million ($2018–19). Our output growth forecast is an average of the output growth rates forecast using the specification and weights from the four models presented in our 2017 *Annual Benchmarking Report*. These models are:[207]

- opex multilateral partial factor productivity (MPFP)
- Cobb Douglas stochastic frontier analysis (SFACD)
- Cobb Douglas least squares estimation (LSECD)
- Translog least squares estimation (LSETLG).

Table 6.8 shows the output specification and weights from each model as reflected in the 2017 *Annual Benchmarking Report*. We have forecast our year on year output growth by:

- calculating four model specific output growth rates, each as a weighted average growth in specified outputs. For example, the output growth rate based on the MPFP model is a weighted average of growth in customer numbers, circuit length, ratcheted maximum demand and energy throughput; and the output growth rate based on the SFACD model is a weighted average of growth in customer numbers, circuit length and ratcheted maximum demand. We have adopted Power and Water's forecasts for these outputs except for ratcheted maximum demand for which we have used the highest actual raw demand.[208]
- calculating the average of four model specific output growth rates.

---

205 Power and Water, *01.2 Regulatory proposal*, 16 March 2018, p. 88.

206 Economic Insights, *Economic Benchmarking Results for the Australian Energy Regulator's 2017 DNSP Benchmarking Report*, 31 October 2017, pp. 1–2.

207 Economic Insights, *Economic Benchmarking Results for the Australian Energy Regulator's 2017 DNSP Benchmarking Report*, 31 October 2017, pp. 1 and 18–20.

208 This resulted in zero growth for ratcheted maximum demand, consistent with Power and Water's proposal. Peak actual raw demand occurred in 2016.

Table 6.8 Outputs specification and weights derived from economic benchmarking models

Output	MPFP	SFACD	LSECD	LSETLG
Customer numbers	45.8%	77.1%	69.7%	59.8%
Circuit length	23.8%	9.7%	11.2%	11.2%
Ratcheted maximum demand	17.6%	13.1%	19.1%	28.9%
Energy throughput	12.8%			

Source: AER's analysis; Economic Insights, Economic Benchmarking Results for the Australian Energy Regulator's 2017 DNSP Benchmarking Report (2017).

This is a refinement of our previous approach, which only used the output weights from one single econometric model (the SFACD model).

CCP10 recently raised concerns about the weight applied to customer numbers under our previous approach. In its submission on Evoenergy's regulatory proposal, CCP10 stated that trend customer growth accounts for a significant part of Evoenergy's output growth. It noted that this outcome flows from our underlying econometric model. CCP10 encouraged us to test whether our output growth rates are reasonable, and whether too much weight has been allocated to customer numbers when we forecast output growth.[209]

We have reviewed the output weights derived from the four models presented in our economic benchmarking reports over the 2014–17 period. Our review shows that the weight of customer numbers derived from the SFACD model is relatively high and it has increased over time. The customer numbers weight has not increased as much in the other econometric models (LSECD and LSETLG).[210]

Our refined approach, which uses an average of the output weights from the four models, helps to address concerns raised by the Australian Competition Tribunal (the Tribunal) in its merits review of our 2015 decision for NSW electricity determinations. The Tribunal raised concerns about our reliance on a single model[211] and in remitting

---

209 Consumer challenge Panel (subpanel 10), *Response to Evoenergy regulatory proposal 2019–24 and AER issues paper* - 16 May 2018, p. 10.

210 We note the weights from the MPFP model have remained constant over time. The MPFP model is a functional output index number model. It is the standard practice with such models to estimate the output cost shares initially (using cost functions based on the data available) and to then leave these shares constant for an extended period. This allows changes in the MPFP scores to reflect changes in performance (and possibly exogenous factors) only. Our 2018 annual benchmarking report will update outputs weights for the MPFP model.

211 The Tribunal's decision was upheld by the Full Federal Court. For more details, see: Australian Energy Regulator v Australian Competition Tribunal (No 2) [2017] FCAFC 79, [285].

the NSW decisions[212] directed us to use a broader range of modelling and benchmarking.[213]

We are currently updating our economic benchmarking analysis to incorporate data for 2016–17. We will publish this analysis in our 2018 annual benchmarking report in late November 2018. In our final decision, we will update our forecast output growth to reflect the 2018 economic benchmarking results.

6.4.2.3 Forecast productivity growth

For the draft decision, we have forecast zero productivity growth in our alternative opex forecast. This is consistent with Power and Water's proposal, and our standard approach to forecasting productivity.[214]

In response to Power and Water's proposal, CCP13 recommended we reconsider our standard approach of forecasting zero per cent productivity growth.[215] Power and Water agreed with CCP13's submission that productivity improvements are important.[216] However, it stated that a further positive productivity adjustment in addition to its proposed 10 per cent base year efficiency adjustment is redundant. It also stated that any positive productivity target included in its opex forecast requires a lower base year efficiency adjustment to avoid double counting.

We have not adopted Power and Water's 10 per cent efficiency target. Instead, we have developed an alternative estimate of efficient base opex, which is independent of our expectations of productivity growth going forward. Therefore, we do not consider the issue of double counting relevant in arriving at our 2019–24 alternative estimate.

We note there will be an opportunity to consider these issues further as a part of the industry wide productivity forecasting consultation process outlined above and as a part of the final decision.

6.4.3 Step changes

Power and Water proposed five step changes to base opex totalling $7.4 million ($2018–19) or 2.2 per cent of its total opex forecast. These step changes were proposed to cover additional costs of complying with new regulations to apply from the commencement of the 2019–24 regulatory control period.

---

[212] The Tribunal's decision was upheld by the Full Federal Court. For more details, see: Australian Energy Regulator v Australian Competition Tribunal (No 2) [2017] FCAFC 79, [285].

[213] Applications by Public Interest Advocacy Centre Ltd and Essential Energy [2016] ACompT 3, direction 1(a).

[214] Power and Water, *01.2 Regulatory proposal*, 18 March 2018, p. 89.

[215] Consumer Challenge Panel subpanel 13, *Issues paper Power and Water electricity network revenue proposal 2019–24*, 16 May 2018, p. 6.

[216] Power and Water, *Response to submissions received on 2019–24 initial regulatory proposal*, 17 August 2018, p. 8.

A summary of Power and Water's proposed step changes is outlined in Table 6.9 which also sets our draft decision for these step changes.

We have included a step change for an increased cost of meeting Guaranteed Service Level (GSL) obligations. Our estimate of the efficient costs of GSLs is $0.9 million ($2018–19), compared to $1.3 million initially proposed by Power and Water.[217]

We have not included the other step changes proposed by Power and Water in our total opex forecast. We do not consider the proposed cost increases are required to arrive at a forecast of total opex that reasonably reflects the opex criteria.

Table 6.9 Draft decision position on step changes ($million, 2018–19)

	Power and Water proposal	Our draft decision
National connections process	2.4	–
Metering compliance type 7	0.1	–
Metering Data Management System (MDMS) commissioning and early processing	0.8	–
Network planning resources	2.7	–
Guaranteed service levels (GSLs)	1.3	0.9
Total	**7.4**	**–**

Source: Power and Water, *12.4 - SCS Opex Model - 16 Mar 18 - Public*; AER analysis.

National connections process

We have not included a step change for costs of complying with the national connections framework in our alternative opex forecast.

Power and Water proposed a step change of $2.4 million ($2018–19) for increased costs associated with applying the national connections framework.[218]

From 1 July 2019, Chapter 5A of the NT NER will apply. Chapter 5A prescribes the process to be followed for the provision of connection services. Currently, the connections process is governed by the Electricity Networks (Third Party Access) Act (ENTPA Act).[219]

Power and Water submitted the provisions of Chapter 5A are more onerous than those that currently apply.[220] Power and Water considers it will take four extra staff (three

217 Power and Water subsequently revised its forecast to $0.9 million ($2018–19) (Power and Water, response to AER information IR024, 21 July 2018, Q14—Follow up information).
218 Power and Water, *03.2P - SCS and ACS Opex Step Changes - 31 Jan 18 - PUBLIC*, p. 6.
219 Power and Water, *03.2P - SCS and ACS Opex Step Changes - 31 Jan 18 - PUBLIC*, p. 6.
220 Power and Water, *03.2P - SCS and ACS Opex Step Changes - 31 Jan 18 - PUBLIC*, p. 6.

administrative and one engineer) to accommodate more onerous requirements.[221] There are currently five staff already directly involved in the connections process (four technical and one administrative).[222]

Power and Water submitted it will now be required to make offers for all connections (basic or negotiated), whereas it now only makes formal offers for large and complex connections (i.e. negotiated connections).[223]

Our Guideline indicates we may include a step change for forecast cost increases or decreases associated with new regulatory obligations.[224] We do not consider the introduction connections framework under Chapter 5A will result in a material change in regulatory burden. We consider the connections process under Chapter 5A is broadly comparable to the process under the ENTPA Act.

Under the ENTPA Act, a formal negotiation process may be used for larger applicants or where there is some complexity with the connection. Power and Water submits that this amounts to approximately 25 per cent, or 200, new connections.[225] Most applicants, the remaining 75 per cent, or 600, are catered for by a standard form customer connection agreement (SFCCA), which Power and Water makes available online.[226]

Under Chapter 5A, the majority of applicants will apply for connection through AER approved model standing offers (MSOs) for basic or standard connection services—which we expect to be broadly aligned with the number of applicants connecting through SFCCA. There is no evidence to suggest the administrative requirements of processing a MSO connection is materially different to the administrative requirements of processing a SFCCA. Nor is there any evidence to suggest that a larger volume of negotiated offers will occur under Chapter 5A.

Even ignoring this fact, and assuming there are incremental costs, Power and Water's cost estimate assumes the administrative work involved in processing a large complex connection application under the ENTPA Act is the equivalent of processing a basic or standard connection covered by a MSO.[227] We do not agree with Power and Water's

---

221 Power and Water, *03.2P - SCS and ACS Opex Step Changes - 31 Jan 18 - PUBLIC*, p. 8.

222 Power and Water, response to AER information request IR002, 6 April 2018, Q20(b), p. 28.

223 Power and Water, response to AER information request IR002, 6 April 2018, Q20(d), p. 30.

224 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, p. 11 (PDF version) pp. 10–11 (Word version).

225 Power and Water, response to AER information request IR002, 6 April 2018, Q20(e), p. 31.

226 Power and Water, Standard Customer Connection Agreement (Power and Water Corporation), 31 July 2015, accessed 11 July2018, https://www.powerwater.com.au/__data/assets/pdf_file/0012/160050/Standard_Customer_Connection_Agreement_Power_and_Water.pdf.

227 Power and Water notes it currently takes one administrative resource to process the 200 or so applications that require formal offers - all of which are large / complicated connections. From this it assumes it will take an additional 3 resources to process the additional 600 connections, the majority of which are expected to be basic or

cost estimates for the processing of a basic or standard connection and consider Power and Water has materially overestimated the impact of administering this basic and standard connection process.

Chapter 5A also provides a comparable process for negotiating connections, broadly applicable to the same larger applicants and complex circumstances as the ENTPA Act (around 25 per cent of connections). Thus, a comparable streamlined process will exist for the majority of applicants, and a comparable process for negotiation will exist for complex connections or larger customers.

We therefore consider the efficient costs of complying with Chapter 5A can be managed by Power and Water within base opex.

In a response to an information request, Power and Water also noted it is required to implement and administer a Capital Contributions Policy with a proposed Pioneer Imbursement Scheme, Rebate Scheme and Equalisation Scheme.[228] However, little information is provided and it is unclear what, if any, additional opex will be required. We accept this is a matter Power and Water may wish to address in its revised proposal. We also note that, overall, we consider an ASL reduction for Power and Water is practical and would be efficient (see section 6.4.1—Labour) so Power and Water may be able to absorb any additional resource requirements.

Metering type 7

We have not included a step change for costs of complying with the national framework with respect to type 7 metering in our alternative opex forecast.

Power and Water proposed a step change of $0.1 million ($2018–19) over 2019–24 for costs of complying with the data obligations of Chapter 7A of the NT NER for type 7 metering.

Type 7 meters are unmetered connections, for example, public lighting and traffic lights.[229]

Power and Water submits it is required to prepare and maintain a five-year rolling sampling plan for type 7 metering installations (consistent with clause 7A.3.3.2(d)), and

---

standard connection and covered by standard MSOs. Power and Water, response to AER information request IR002, 6 April 2018, Q20(e), p. 31.

228 Power and Water, response to AER information request IR002, 6 April 2018, Q20(d), p. 30.

229 Type 7 metering services are unmetered connections with a predictable energy consumption pattern (for example, public lighting connections). Such connections do not include a meter that measures electricity use. The distributor is required to undertake a process to estimate electricity use. For example, the distributor estimates public light usage using the total time the lights were on, the number of lights in operation and the light bulb wattage. Type 7 metering is classified as standard control services. Type 1-6 metering is classified as alternative control services. Power and Water separately applied for a step change for type 1-6 metering in its alternative control service proposal. See Attachment 15 for our discussion on this.

assess compliance of type 7 metering installations in accordance with that plan.[230] Power and Water estimates it will take one FTE employee one week per year for the plan and a further six weeks per year to assess compliance of the type 7 metering installations in accordance with that plan (in total seven weeks per year).[231]

The requirements to manage type 7 metering connections under the Chapter 7A is a standard meter management practice and Power and Water already has in place a process to manage type 7 metering installations.[232] We do not consider there is a material change in regulatory obligations that would warrant a step change.

This step change represents 0.04 per cent of Power and Water's total opex forecast. Our Guideline explains that in considering whether a step change is required we will have regard to whether the costs can be met from existing regulatory allowances or from other elements of the expenditure forecasts.[233] We consider Power and Water's forecast incremental costs of managing type 7 metering connections can be comfortably managed by Power and Water within its base opex and an increase to the total opex forecast is not required to meet the opex criteria.

Metering data management system

We have not included a step change for costs of operating a metering data management system (MDMS).

Power and Water proposed a step change of $0.8 million ($2018–19) over 2019–24 for 1 FTE to operate the MDMS. This step change represents 0.2 per cent of Power and Water's total opex forecast.

Power and Water submitted operation of the MDMS is required to comply with the verification, substitution and estimation obligations imposed by Chapter 7A.3 of the NT NER, to apply from 1 July 2019.

Power and Water intends to install the MDMS to check the integrity of collected data and, where necessary, makes substitutions in accordance with predetermined rules that otherwise requires a manual estimation of the data to be undertaken by a skilled operator.[234]

Currently, data from manual meter readings is collected on hand-held devices and transferred to MV-RS and then onto the Retail Management System (RMS). According to Power and Water the RMS has basic error checking for estimation, substitution and validation.[235]

---

230 Power and Water, *03.2P - SCS and ACS Opex Step Changes - 31 Jan 18 - PUBLIC*, p. 8.

231 Power and Water, *03.2P - SCS and ACS Opex Step Changes - 31 Jan 18 - PUBLIC*, p. 9.

232 Power and Water, response to AER information request IR002, 6 April, Q21(b), p. 34.

233 AER, Expenditure Forecast Assessment Guideline for Electricity Distribution, November 2013, p. 11.

234 Power and Water, *03.2P - SCS and ACS Opex Step Changes - 31 Jan 18 - PUBLIC*, p. 10.

235 Power and Water, response to AER information request IR002, 6 April, Q22(a), p. 36.

Data from remotely read meters is collected using the MV90 system. Basic data checks are manually performed within this system and manual intervention is required by Power and Water staff to correct any errors.[236] Once checks are performed, this data is also transferred to the RMS.

We consider that should Power and Water proceed with the implementation of the MDMS as proposed, this will result in operational efficiencies that Power and Water has not factored into its forecast.

The MDMS will provide functionality to undertake checking, estimation and substitution within system that would otherwise be done manually. We understand from discussions with Power and Water that once the MDMS is in place the RMS will no longer be required, and manual checking and intervention processes currently undertaken, including for remotely read meters using the MV90 system, will no longer be required. That is, the MDMS will enable Power and Water to do manual verification, validation and substitution only on exception.

We consider the MDMS will likely improve the quality of metering and billing information supplied to retailers, reduce customer billing issues and therefore reduce the resources currently used in dealing with customer complaints. Power and Water submitted that without the MDMS "the number of complaints / disputes is most likely to escalate" and "[t]his will absorb resources".[237]

The expected efficiencies generated from the retirement of old systems and manual processes, as well as an overall improvement in billing data will have an offsetting effect on the resourcing Power and Water submits is required to operate the MDMS. We acknowledge the introduction of the new system may require additional resourcing in the short-term until the system is fully commissioned. However, we consider this a short-term matter that will abate as these issues are resolved.

For these reasons, as well as the relative immateriality of this expenditure (0.2 per cent of Power and Water's total opex forecast), we do not consider an increase to the total opex forecast is required to meet the opex criteria.

Network planning

We have not included a step change for network planning resources in our alternative opex forecast. Power and Water proposed a step change of $2.7 million ($2018–19) for three additional engineering resources.[238]

Power and Water submitted more work is required in network planning to comply with the NT NER and to meet the expectations of the AER on what constitutes 'best practice' asset management.[239]

---

236 Power and Water, response to AER information request IR002, 6 April, Q22(a), p. 36.

237 Power and Water, response to AER information request IR002, 6 April, Q22(b), p. 37.

238 Power and Water, *03.2P - SCS and ACS Opex Step Changes - 31 Jan 18 - PUBLIC*, p. 13.

In response to an information request, Power and Water provided a list of functions it considered were required to comply with the NT NER. This included network modelling, investigating power stability issues, generating the distribution annual planning report, investigating and researching new emerging technology and investigating and implementing demand management solutions, among other things.[240] In response to a further information request Power and Water reframed and extended the requirements for additional planning resources to include:

- assist the annual review of demand forecast and constraints required under clause 5.13.1(d) of the NER, and assist with demand management engagement obligations under clause 5.13.1(e)-(j) (1FTE)
- improving its asset management strategies and RIN data in line with best practice in other jurisdictions (1 FTE)
- developing and coordinating the distribution annual planning report under clause 5.13.2 if the NER (1 FTE).[241]

We have assessed each of these functions and consider, in the main, they constitute standard planning practices and/or are not new requirements imposed by the NER. Further, our base opex forecast includes opex for Power and Water to improve its asset management strategies and regulatory team costs in relation to the regulatory team associated with the RIN preparation, and consequently this additional resource would add to or duplicate those costs. Other than the exceptions noted below, there are not new regulatory requirements relating to these functions and while they may be worthwhile intentions, our expectation is they are funded by base opex.

The exceptions are the preparation of distribution annual planning reports (DAPRs), regulatory investment tests (RITs), and the demand-side engagement document published and updated once every three years. We consider these functions are required by the NER and will necessitate additional planning functions, requiring approximately 1 FTE (compared to Power and Water's forecast of 3 FTE).

However, we have not included a step change in our alternative opex forecast because we consider an ASL reduction for Power and Water is practical and would be efficient (see section 6.4.1 - Labour). We consider Power and Water's overall staffing levels are sufficient to absorb these additional functions. We have not made an explicit reduction to base opex for the excess FTE we have identified. Rather, we consider Power and Water is in a position to redeploy resources from its current FTE count and manage any change in skills required to meet the additional network planning needs. We therefore do not consider an explicit step increase is required to the total opex forecast to meet the opex criteria.

---

[239] Power and Water, *03.2P - SCS and ACS Opex Step Changes - 31 Jan 18 - PUBLIC*, p. 12.

[240] Power and Water, response to AER information request IR002, 6 April, Q.23(f), p. 46.

[241] Power and Water, response to AER information request IR017, 7 June, Item 13, pp. 1–3.

Guaranteed service levels

We have included a step change for forecast costs of complying with the NT's Electricity Industry Performance Code (EIP Code).

Power and Water proposed a step change of $1.3 million ($2018–19) for increased GSL payments resulting from the transition to the EIP Code from the Electricity Standards of Service Code and the Guaranteed Service Level Code in the NT.

The revised scheme under the new EIP code:

- increases the value of payments for all GSLs to take into account inflation
- removes the distinction between urban and rural customers to improve minimum levels of service for rural customers. This impacts the frequency of interruptions (extending the threshold for payment from 16 to 12 interruptions per annum) and the time to establish a new connection (extending the threshold from 10 to 5 days) for rural customers.[242]

The GSLs relate to:

- duration, frequency and accumulation of interruptions
- time to establish or re-establish connections
- notice of planned interruptions
- keeping appointments
- time to respond to written inquiries.

Power and Water provided a model it used to forecast GSL payments over 2019–24. We were unable to substantiate some of Power and Water's forecasting assumptions. In response to information requests, Power and Water agreed that some of the forecasting assumptions were unrealistic and amended its forecast of GSL payments. Power and Water refers to its revised forecast as its 'alternative GSL forecast'.[243]

In Power and Water's alternative GSL forecast, forecast expenditure is a product of the average quantity of payments over 2014–15 to 2016–17 and the new payment amounts under the EIP code.[244] We broadly accept Power and Water's alternative GSL forecasting approach. However, we have included two years rather than three years to calculate the average quantity of payments (i.e. we have used 2015–16 to 2016–17).

---

[242] Utilities Commission, Guaranteed Service Levels, accessed 13 July 2019, http://www.utilicom.nt.gov.au/Electricity/performance/GSL/Pages/default.aspx; Utilities Commission, *2019-20 onwards Guaranteed Service Levels*, p. 1.

[243] Power and Water, response to AER information request IR024, 21 July 2018, Q14 - follow up information.

[244] Power and Water also makes an allowance for increased payments due to the removal of the distinction between urban and rural feeders for the frequency of payments GSL.

[245] This change is minor in its net impact as it increases some elements of the GSL forecast and decreases others. Power and Water has previously noted the 2014–15 data included some payments made in 2013–14, so based on this information we consider the 2014–15 data may be overstated and unreliable for forecasting purposes.[246]

We have included a step change for $937 390 over the 2019–24 regulatory control period— 29.6 per cent ($393 961) lower than Power and Water's original estimate in its proposal and 0.9 per cent ($8 932) lower than Power and Water's alternative GSL forecast.

Typically we forecast GSLs through a category specific forecast, and remove the actual costs incurred from the base year. Power and Water forecast GSLs as a step change because there was a change in regulatory obligations. We have accepted Power and Water proposed approach and included the costs of GSLs in our alternative estimate as a step change. We note the effect of either approach (a step change or category specific forecast) would be the same.

Power and Water advised that it had removed the costs of GSLs from its base year, however, the adjustment it made actually increased the base year by $13 541. The value of Power and Water's GSLs in 2016–17 was $124 000 ($2018–19).[247]

Power and Water advised through an information request its base opex did not reflect the actual cost of GSLs incurred in 2016–17, due to accounting issues and adjustments which had an offsetting effect:

- Power and Water's base year opex omitted around half of the cost of GSLs in 2016–17 (i.e. $63 870) due to delays in posting the costs to these accounts
- Power and Water overestimated GSLs in 2015–16 (reflected as accruals) and reversed this amount in 2016–17, rather than 2015–16. This had the effect of reducing the amount reported for GSLs in the base year by $74 503. [248]

The net impact of these adjustments was - $13 451, which Power and Water advises was the net amount reflected in 2016–17 opex for GSLs.[249] This was why Power and Water made a positive adjustment to the base year to remove the impact of GSLs. We are satisfied with this adjustment and have incorporated it into our alternative estimate of base opex.

---

245 We have also converted Power and Water's alternative GSL forecast to real $2018–19 as it was provided in real $2017–18, and we have used a slightly higher forecast of inflation over 2019–24.

246 Power and Water, *01.2 - Regulatory Proposal - 16 March 18 - PUBLIC*, p. 36.

247 Power and Water, *11.5CP - Category Analysis RIN Workbooks - Consolidated - 16 Mar 18 - PUBLIC* (updated May 18), '2.5 Connections' worksheet.

248 There was also an adjustment for other balancing items of $916 ($2018–19).

249 $124 000 - $63 870 - $74 503 + $916 ≈ $13 451 ($2018–19).
Power and Water, response to AER information request IR017, 31 May 2018, item 15.

6.4.4 Category specific forecasts

Debt raising costs

Power and Water forecast debt raising costs of $2.7 million ($2018–19) over the 2019–24 regulatory control period.

We have included a category specific forecast of $2.6 million ($2018–19) for debt raising costs. Power and Water did not incur debt raising costs in the base year opex[250] and therefore we did not need to remove them.

Debt raising costs are transaction costs a service provider incurs each time it raises or refinances debt. We forecast them based on a benchmarking approach rather than a service provider's actual costs for consistency with the forecast of the cost of debt in the rate of return building block. Further details of our assessment approach are set out in the debt and equity raising costs appendix in Attachment 3 on the rate of return.

6.4.5 Assessment of opex factors under NER

In deciding whether or not we are satisfied a service provider's forecast reasonably reflects the 'opex criteria' under the NER, we have regard to the 'opex factors'.[251]

We attach different weight to different factors when making our decision to best achieve the NEO. This approach has been summarised by the AEMC as follows:[252]

> As mandatory considerations, the AER has an obligation to take the capex and opex factors into account, but this does not mean that every factor will be relevant to every aspect of every regulatory determination the AER makes. The AER may decide that certain factors are not relevant in certain cases once it has considered them.

Table 6.10 summarises how we have taken the opex factors into account in making our draft decision.

Table 6.10 Our consideration of the opex factors

Opex factor	Consideration
The most recent annual benchmarking report that has been published under rule 6.27 and the benchmark opex that would be incurred by an efficient distribution network service provider over the relevant regulatory control period.	Power and Water has not been included in previous annual benchmarking reports. While this limits our ability to use the previous reports, we have used our PPI benchmarking for the purposes of this assessment to help identify and prioritise opex cost categories for a more detailed review and as a high-level cross-check that identified efficiency improvements are realistic and achievable.

250 Power and Water, response to AER information request IR031, 18 July 2018, Q1(a,b), p. 1.

251 NT NER, cl. 6.5.6(e).

252 AEMC, Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, 29 November 2012, p. 113.

Opex factor	Consideration
The actual and expected opex of the Distribution Network Service Provider during any proceeding regulatory control periods.	To assess Power and Water's opex forecast and develop our alternative estimate, we have used Power and Water's actual opex in 2016–17 as the starting point. We have examined Power and Water's historical actual opex through high level engineering reviews and PPI benchmarking to determine whether Power and Water's revealed expenditure can be used as the base for forecasting opex in the forthcoming period or whether adjustments are required. We have also taken into account Power and Water's expected opex in forecasting efficient opex over the 2019–24 control period (e.g. Power and Water's change in opex as a result of changes to its capitalisation policy).
The extent to which the opex forecast includes expenditure to address the concerns of electricity consumers as identified by the Distribution Network Service Provider in the course of its engagement with electricity consumers.	We understand the intention of this particular factor is to require us to have regard to the extent to which service providers have engaged with consumers in preparing their regulatory proposals, such that they factor in the needs of consumers. Based on the information provided by Power and Water in its proposal, we understand Power and Water did not consult with consumers directly on its opex forecast and accordingly it does not appear the opex forecast includes expenditure to address concerns of electricity consumers. We note submissions from consumers did not raise this issue, and CCP13 considered Power and Water undertook a comprehensive and well-planned consumer engagement program in relatively challenging circumstances.[253]
The relative prices of capital and operating inputs	We adopted price escalation factors that account for the relative prices of opex and capex inputs. One reason we will include a step change in our alternative opex forecast is if the service provider proposes a capex/opex trade-off. We consider the relative expense of capex and opex solutions in considering such a trade-off. Power and Water did not propose any step changes as capex/opex trade-offs.
The substitution possibilities between operating and capital expenditure.	In developing our PPI benchmarking, we have had regard to the relationship between capital, opex and outputs by examining total expenditure for various cost categories. We have also considered the impact of different capitalisation policies by examining Power and Water's expenditure before and after capitalisation, and its impact on total revenue. We have considered Power and Water's ICT capex plan which details the potential for lower opex due to FTE savings and a reduction in printing costs, consultancy and audit fees, licensing costs, and IT system support and maintenance.
Whether the opex forecast is consistent with any incentive scheme or schemes that apply to the Distribution Network Service Provider under clauses 6.5.8 or 6.6.2 to 6.6.4.	We normally apply the EBSS in conjunction with our revealed cost forecasting approach. Because we have not been able to rely on Power and Water's actual costs to forecast opex we have not applied the EBSS to Power and Water over the 2019–24 regulatory control period.
The extent the opex forecast is referable to arrangements with a person other than the Distribution Network Service Provider that, in the opinion of the AER, do not reflect arm's length terms.	We are not necessarily concerned whether arrangements do or do not reflect arm's length terms. A network operator which uses related party providers could be efficient or it could be inefficient, and vice versa. We have examined Power and Water's contracts with System Control and the DCIS. We included average 2013–14 to 2015–16 SLA expenditure in

[253] Consumer Challenge Panel subpanel 13, Issues paper Power and Water electricity network revenue proposal 2019–24, 16 May 2018, p. 4.

Opex factor	Consideration
	our alternative estimate, which we consider reflects efficient SLA costs. Further, we have not found information to suggest Power and Water has an incentive to agree to artificially inflated contract prices for services from the DCIS.
Whether the opex forecast includes an amount relating to a project that should more appropriately be included as a contingent project under clause 6.6A.1(b).	This factor is generally only relevant in the context of assessing proposed step changes (which may be explicit projects or programs). Power and Water did not propose any opex step changes that would be more appropriately included as a contingent project.
The extent the Distribution Network Service Provider has considered, and made provision for, efficient and prudent non-network alternatives.	Power and Water has not proposed expenditure for non-network alternatives. It stated it accepts the AER's framework and approach position to apply the demand management incentive scheme and demand management innovation allowance mechanism in the next regulatory control period
Any relevant final project assessment report (as defined in clause 5.10.2) published under clause 5.17.4(o), (p) or (s)	In having regard to this factor, we identify any RIT-D project submitted by the business and ensure the conclusions are appropriately addressed in the total forecast opex. Power and Water did not submit any RIT-D project.
Any other factor the AER considers relevant and which the AER has notified the Distribution Network Service Provider in writing, prior to the submission of its revised regulatory proposal under clause 6.10.3, is an operating expenditure factor.	We did not identify and notify Power and Water of any other opex factor.

A Partial performance indicator benchmarking

PPIs are a simple form of benchmarking. PPIs measure the average amount of opex used to produce one unit of a given output. They are often used as they are easy to calculate and understand and provide useful high-level comparisons and when examined in conjunction with other indicators they can provide supporting evidence of relative efficiency.

When used in isolation, PPI results should be interpreted with caution because they are not as robust as economic benchmarking techniques that relate inputs to multiple outputs using a cost function. They also do not take into account operating environment differences between distributors that may impact their opex in relative terms (see Appendix B). Category level comparisons may also be impacted by reporting differences between distributors that may limit like-for-like comparisons. For example, distributors may allocate and report opex differently due to different ownership structures or operational decisions to contract rather than internalise labour. These kinds of factors may impact category level opex but typically wash-out at the total opex level.

Figure A.1 presents average annual opex per customer over 2013–14 to 2016–17. Figures A.2 - A.8 present annual average expenditure in particular opex categories per unit of output (such as kilometres of circuit line length and customer numbers).[254]

Broadly, the PPI benchmarking results show Power and Water has considerably higher opex than other distributors on a per unit basis. This holds both at a total opex level and for most categories of opex. Table A.1 summarises our PPI benchmarking of Power and Water's total opex and each of its cost categories over the period 2013–14 to 2016–17. All of its cost categories benchmark very high relative to other distributors, except non-network opex, which is comparable. As noted above, these comparisons do not make any allowance for Power and Water's operating environment.

We have also examined the PPI analysis Power and Water developed in its base year document.[255] Power and Water developed most of its PPI charts by comparing its 2016–17 expenditure against the 2015–16 expenditure of other distributors.[256] There are a small number of instances where Power and Water uses average expenditure data for itself and other distributors. We have used data across 2013–14 to 2016–17 to account for one-off events that may not be reflective of a distributor's typical expenditure. Further, Power and Water benchmarked its cost categories against a

---

254 We have excluded distributors that have claimed confidentiality in particular cost categories.

255 Power and Water, *03.1 - Opex Base Year Justification - 16 March - PUBLIC*; Power and Water, response to AER information request IR007, 24 April 2018, question 1.

256 Power and Water, response to AER information request IR007, 24 April 2018, question 1.

range of different outputs. We have used the outputs that we consider are the main drivers of each cost category.

We note that Power and Water's PPIs appear to:

- use a lower non-network opex number for itself than what it reported in its CA RIN; and
- double count total network overhead expenditure for a few distributors by including network overhead (capex) twice in its calculation of network overhead (totex).

We have rectified this in our average 2013–17 PPI results.

Table A.1 – Summary of PPI benchmarking for Power and Water (2013-17)

Category	PPI benchmarking
Total opex	Very high
Vegetation management	Very high
Maintenance	Very high
Emergency response	Very high
Non-network	Comparable
Network overhead	Very high
Corporate overhead	Very high
Labour	Very high

Source: Category analysis RINs across all distributors from 2013–17; AER analysis.

Note: Power and Water's relative costs have been categorised as either 'very high', 'high', 'comparable', 'low' or 'very low' by comparing Power and Water's position against other distributors positions and exercising judgement to classify them into one of the above categories.

Figure A.1 - Total opex per customer ($2018–19)

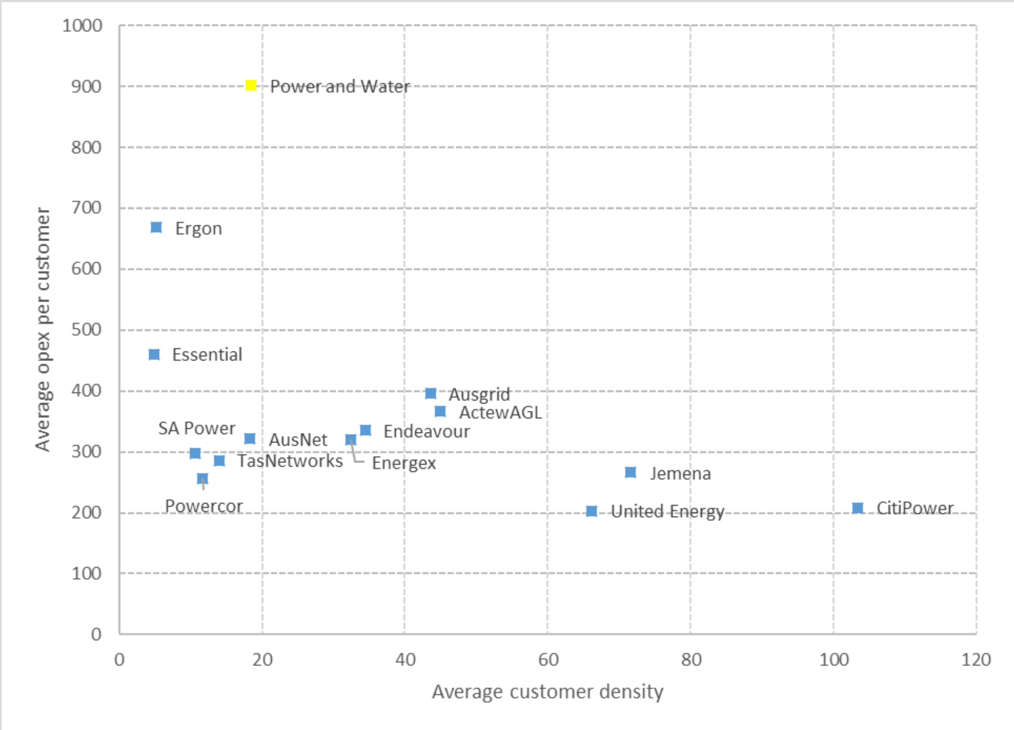


Figure A.2 – Maintenance opex per circuit km ($2018–19)

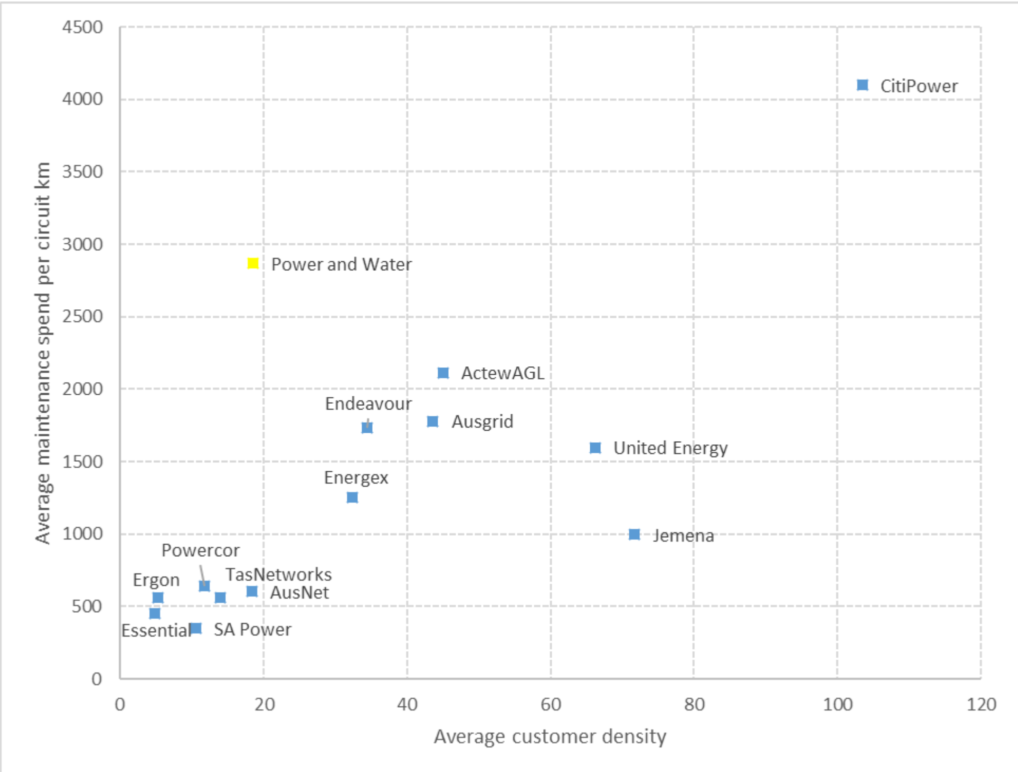


Figure A.3 – Vegetation management opex per km of route line length ($2018–19)

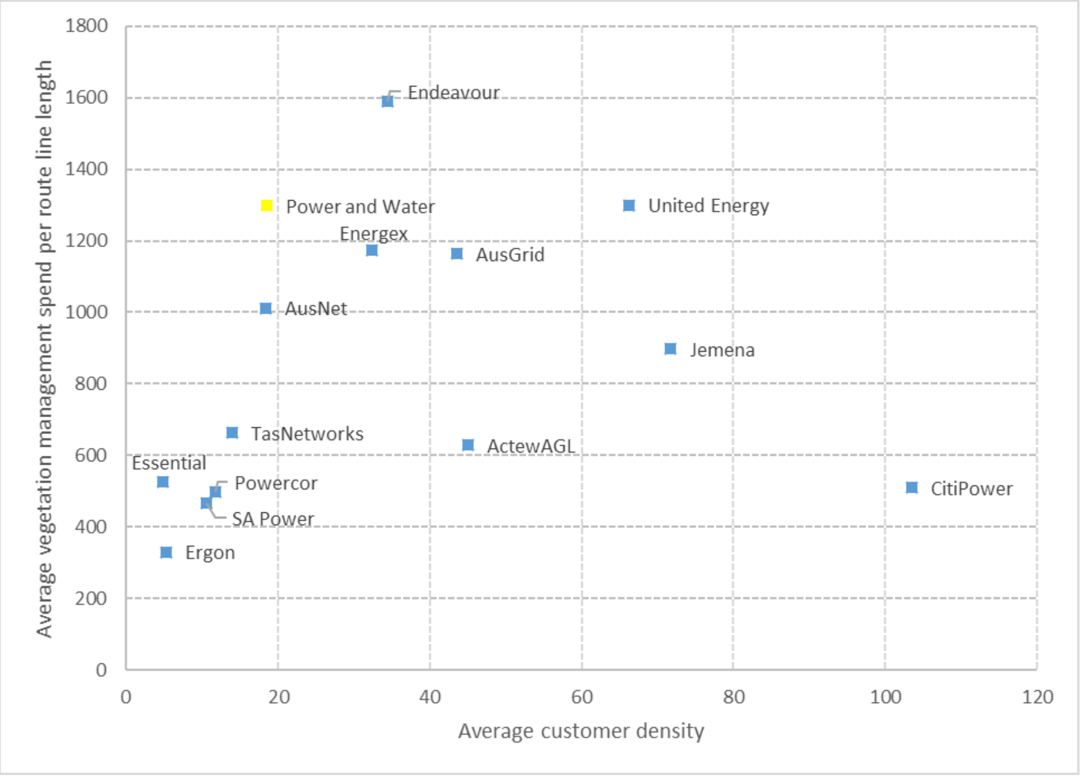


Figure A.4 – Emergency response opex per interruption ($2018–19)

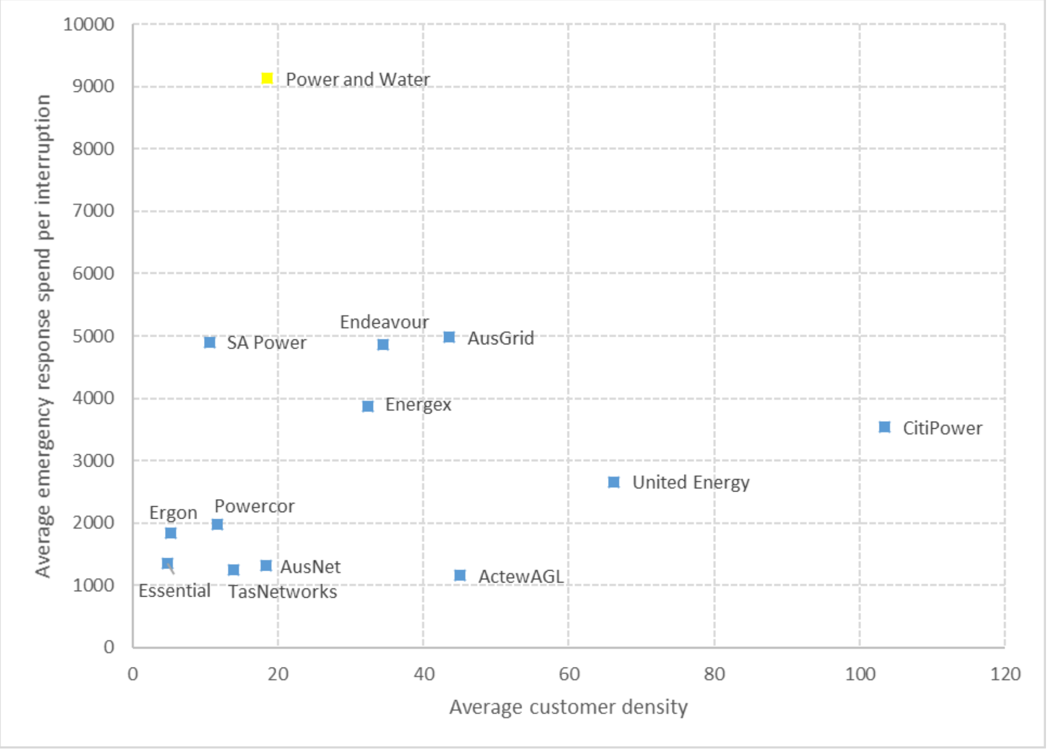


Figure A.5 – Non-network opex per customer number ($2018–19)

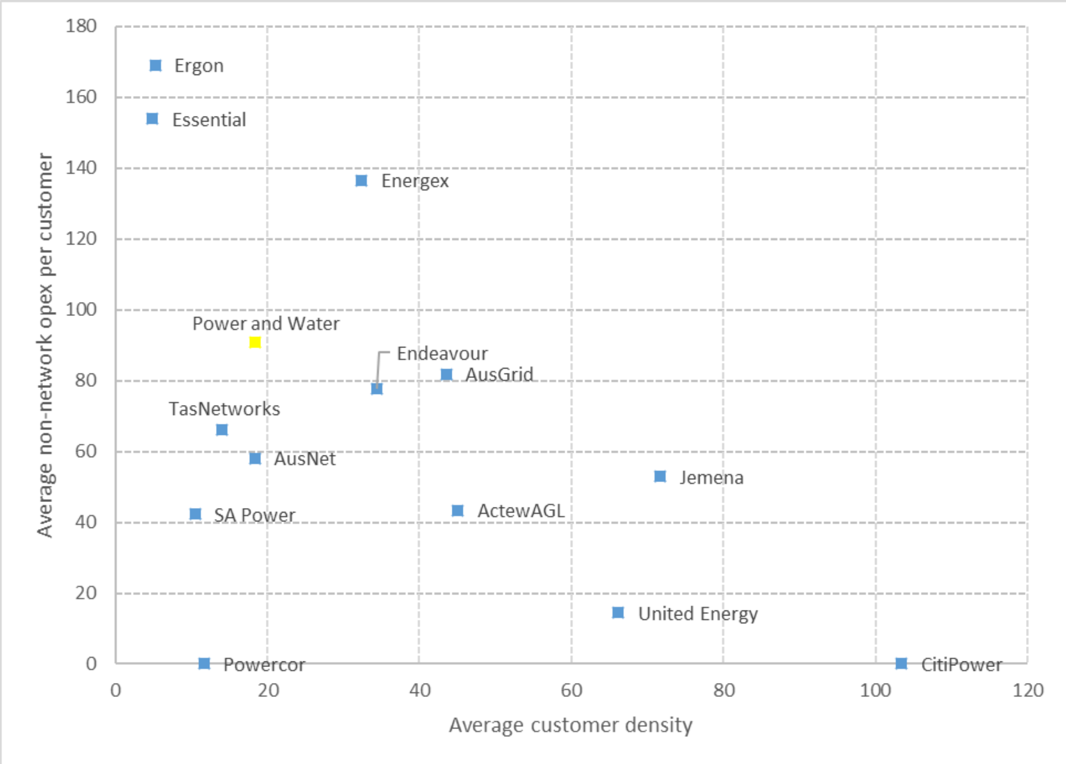


Figure A.6 – Network overheads (totex) per customer number ($2018–19)

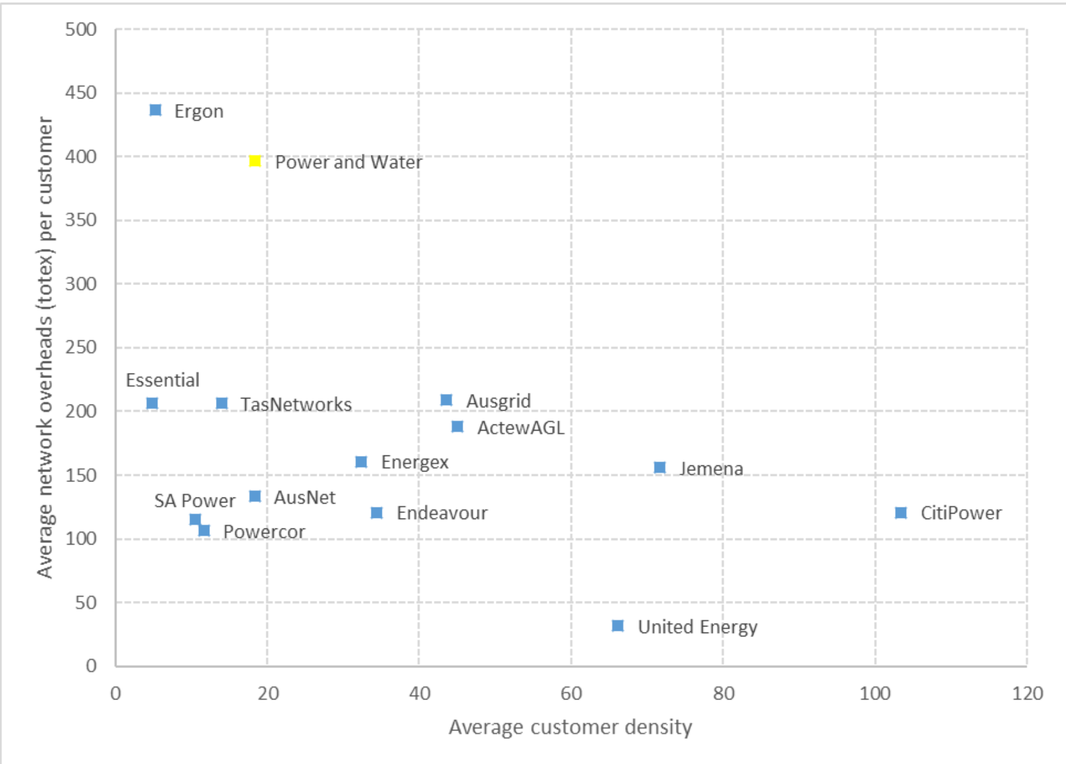


Figure A.7 – Corporate overheads (totex) per customer ($2018–19)

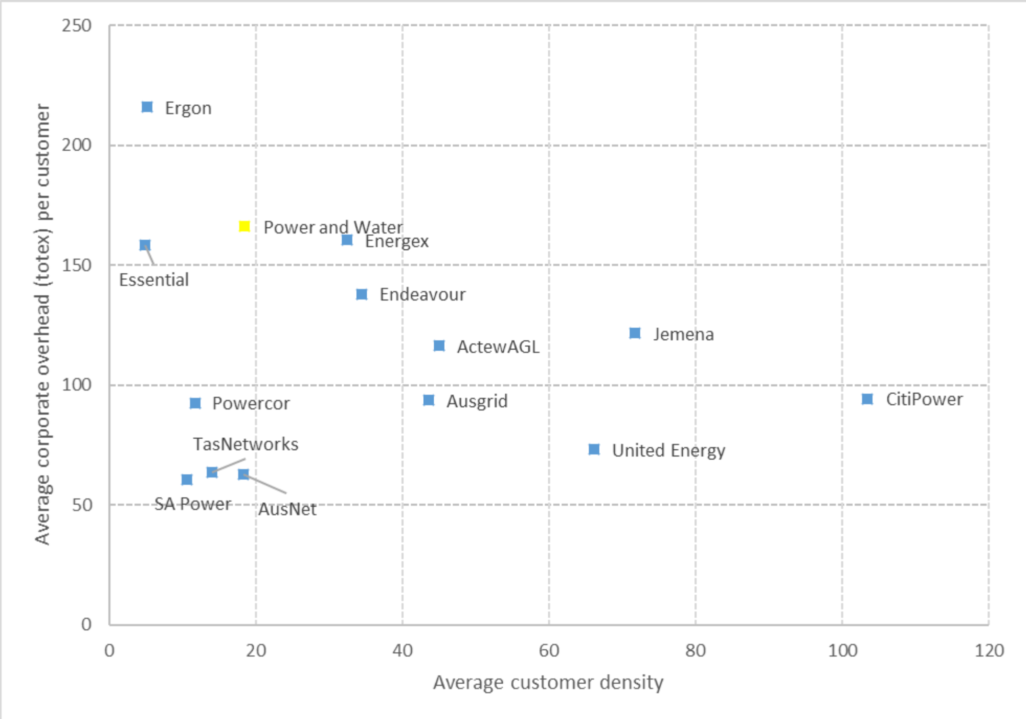
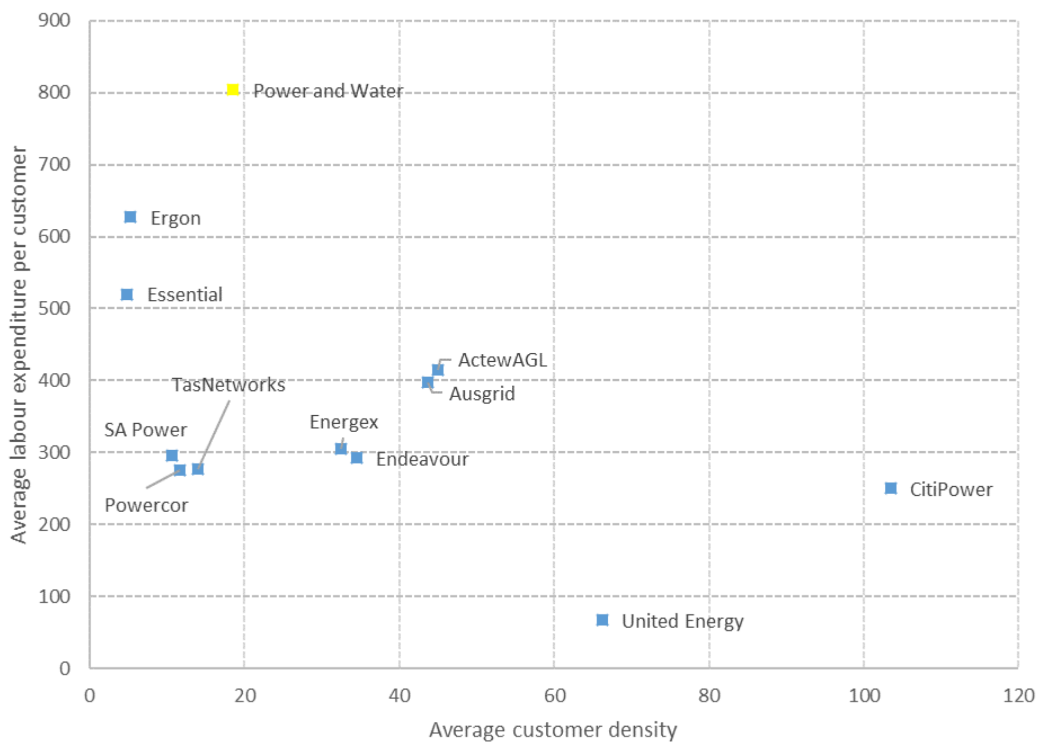


Figure A.8 – Labour opex per customer ($2018–19)



B Power and Water's operating environment

Circumstances exogenous to a network should generally be taken into account when assessing the efficiency of opex to determine the extent to which observed differences between distributors are due to inefficiency or beyond management's control. We typically refer to these factors as operating environment factors.

PPI benchmarking results (Appendix A) may reflect differences in operating environment and should therefore be interpreted with caution.

Power and Water identified a number of factors it considers materially impact its network costs. Many of these are climatic factors – for example, cyclones, and high heat, humidity and rainfall. Others relate to Power and Water's network characteristics and remoteness – for example, lack of scale, high labour rates, dispersed networks and unique regulations.[257] The ETU agreed Power and Water faces significant and unique geographical and environmental challenges.[258]

We have not undertaken a detailed assessment of the impact of Power and Water's operating environment on its costs. But we have had regard to, and been mindful of, the relative challenges of Power and Water's operating environment in identifying scope for efficiency improvements when reviewing the category level costs.

We consider there are features of Power and Water's operating environment that may partly explain the observed gap between it and other distributors in the PPI benchmarking. These conditions may impact not only the volume of work required, but the cost inputs for labour and materials, as well as labour productivity. The extent to which these factors impact costs is not yet understood.

Cyclones are a factor we consider would likely have material impact upon Power and Water's opex and benchmarking relativities. Part of Power and Water's network (Darwin) is situated in the tropical north of Australia and subject to cyclones during the wet season, requiring a significant emergency response operation. These responses have direct costs and interfere with the business as usual work being delivered in an efficient manner.[259] Service providers in cyclonic regions may also have higher insurance premiums. Ergon Energy, operating in North Queensland, is also subject to cyclones and the impact on its opex has been previously estimated as 5.24 per cent.[260]

---

257 Power and Water, *03.1 - Opex Base Year Justification - 16 March - PUBLIC*, pp. 10–31.

258 Electrical Trades Union, *Power and Water regulatory proposal 2019–24*, 16 May 2018, p. 1.

259 Power and Water, *03.1 - Opex Base Year Justification - 16 March - PUBLIC*, p. 22. Sapere Research Group and Merz Consulting, *Independent review of Australian Energy Regulator Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking*, December 2017, p. 38

260 Sapere Research Group and Merz Consulting, *Independent review of Australian Energy Regulator Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking*, December 2017, pp. 38 and 71.

Other features of Power and Water's climate may also have a material impact on its opex. Power and Water submits extreme heat and humidity in the Northern Territory have a material impact on workability. Power and Water notes three-man crews are required in the wet season, compared to two-man crews in the dry.[261] Climate may also impact Power and Water's asset management practices. For example, how it manages overhead assets that may be subject to lighting strikes, or manages water ingress from high humidity and a wet environment (which are also factors impacting other distributors such as Ergon Energy and Energex).

We note potential similarities in climate between Power and Water's and other distributors. A stakeholder submission noted the Darwin-Katherine region is tropical (similar to Far North Qld) and Alice Springs/Tennant Creek experience seasonal variation and lower rainfall (similar to inland regions in Qld and NSW). Further, the impact on workability is contained to the wet season (November to April) and will not impact office-based staff and only impacts field staff when they are working in the field.[262]

Factors related to Power and Water's network location may also be relevant—for example, if Power and Water is required to pay a cost premium to attract and retain certain types of labour, or to acquire and transport necessary materials. However, we are yet to form a view on how these factors impact Power and Water's benchmarking. Similarly, we are yet to form a view on the extent to which Power and Water's network configuration of three separate networks impacts Power and Water's relative efficiency. One stakeholder submission noted regional distributors must maintain multiple depots to ensure service quality and responsiveness, just as Power and Water must, and therefore the fact that Power and Water’s network is in three parts is immaterial.[263]

Over 2017 and 2018, we conducted an industry wide consultative review of the key operating environment differences between distributors. This review identified a number of unique factors that likely drive materially higher electricity distribution costs in the Northern Territory relative to other jurisdictions in the NEM. The review did not quantify the impact of these operating environment factors on Power and Water’s costs as it was transitioning to the national regulatory framework and necessary data was not yet available. We intend to undertake an assessment of the impact of Power and Water operating environment as part of our future benchmarking reports.

[261] Power and Water, *03.1 - Opex Base Year Justification - 16 March - PUBLIC*, p. 13.

[262] Anonymous, Submission on Power and Water's regulatory proposal, 16 May 2018, pp. 2–3.

[263] Anonymous, Submission on Power and Water's regulatory proposal, 16 May 2018, p. 1.

C Confidential opex appendix