FINAL DECISION

Power and Water Corporation Distribution Determination 2019 to 2024

Attachment 6 Operating expenditure

April 2019

AUSTRALIAN ENERGY REGULATOR

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 attachment forms part of the AER's final 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 final decision.

The final decision includes the following attachments:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Return on debt transition

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

Attachment 13 – Control mechanisms

Attachment 15 – Alternative control services

Attachment 18 – Tariff structure statement

Attachment A – Negotiating framework

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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
CCP 13	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

Shortened form	Extended form
NT NER or the rules	National Electricity Rules As in force in the 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 Final decision

Our final decision is to include total forecast opex of $332.7 million ($2018–19) in Power and Water's revenue for the 2019–24 regulatory control period. This alternative estimate is $18.7 million ($2018–19) or 5.3 per cent lower than Power and Water's revised opex forecast of $351.3 million ($2018–19), which we do not accept.[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). They encouraged us to closely review Power and Water's revised opex proposal, particularly the efficiency of Power and Water's base opex and the proposed efficiency targets, and to take into account its unique circumstances and operating environment. 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 alternative estimate.[3]

The alternative total opex forecast we have adopted in this final decision starts with Power and Water's actual costs in the 2017-18 base year. We have undertaken a high level bottom up review of key cost categories that make up base opex.[4] We consider this is appropriate in light of Power and Water's revised proposal, which proposed specific adjustments to certain cost categories to remove non-recurrent costs and efficiency adjustments, and Power and Water's poor relative partial performance indicator (PPI) benchmarking performance in some cost categories.

Our review of base opex focused on the cost categories that are the most material, where there has been significant change compared to Power and Water's initial proposal and/or which we consider to have the greatest scope for identifiable efficiency improvement (section 6.4.1). As a result of this assessment, and consistent with Power and Water's revised proposal, we conclude that we cannot use revealed opex as a

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 of 2017-18, as proposed by Power and Water in its revised proposal.

starting point to forecast efficient opex over the 2019–24 regulatory control period. As set out below, further to those base year adjustments proposed by Power and Water, we have included an additional adjustment for non-recurrent network overhead costs which we do not consider to reflect required expenditure over the 2019-24 regulatory control period.

After assessing base opex, we have forecast growth in prices, output and productivity (trend) and assessed Power and Water's step changes in accordance with our *Expenditure forecast assessment guideline* (the Guideline).[5] In particular, we have revised our productivity growth forecast in line with our generic review of opex productivity growth. Our review found that a productivity growth forecast of 0.5 per cent per year reasonably reflects the productivity gains an efficient and prudent electricity distributor can make (see below for further discussion).[6]

While we agree with Power and Water's proposal to use an updated base year of 2017-18, and to make adjustments for non-recurrent opex and efficiencies, we have formed a different view about the prudent and efficient level of these adjustments in developing our alternative estimate. In particular, we reduced our alternative estimate by an additional $3.8 million ($2018–19) to remove non-recurrent network overhead costs, such as professional fee and personnel costs, that we do not consider Power and Water has justified as being recurrent. This results in lower opex of $18.8 million ($2018-19) over the 2019-24 regulatory control period.

Power and Water proposed 10 per cent reductions to base year network and corporate overhead costs (which make up 60 per cent of base year opex) to reflect what it considers to be achievable efficiencies over the regulatory period.[7] We accept this amount as reasonable as it is supported by the results of our PPI benchmarking and taking into account the impact of its operating environment. This reduces base year opex by $4.0 million ($2018-19) (in addition to the non-recurrent network overhead adjustment noted above). Over the 2019-24 regulatory control period this results in $1.8 million ($2018-19) less of a reduction compared to Power and Water's revised proposal as the efficiencies are applied to a lower base opex.

Power and Water proposed to apply these 10 per cent overhead efficiencies to the base year. Given this is the first time we have regulated Power and Water under the NT NER, and the likely nature of the 10 per cent network and corporate overhead efficiencies, which may require some structural changes, we consider it is appropriate to include the efficient costs of transitioning to a lower opex base.

As such, we apply a gradual (linear) path of reductions to network and corporate overheads, such that a 10 per cent efficiency is fully realised by the last year of the 2019–24 regulatory control period. This gradual application reflects that we expect

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

6 AER, *Final decision paper, Forecasting productivity growth for electricity distributors*, March 2019.

7 Power and Water, *SCS Opex Base Year Justification 2019-20 to 2023-24*, 29 November 2018, pp. 16–17.

transition costs to decline over time. The downward sloping orange line from 2019-20 in Figure 6-1 illustrates this outcome. This means total opex is $8.2 million ($2018–19) higher over the 2019-24 regulatory control period compared to an alternative estimate that does not allow for these transition costs (illustrated by the blue line in Figure 6-1). We consider this will allow for an efficient yet practical transition to a lower opex base, while maintaining the quality, reliability, security and safety of services to Power and Water's customers.

Our alternative estimate trends the efficient base opex we have established forward. This includes the 0.5 per cent per year opex productivity growth forecast established in our recent generic review (compared to the 0.0 per cent per year included in Power and Water's revised proposal). This reduces opex by $6.2 million ($2018–19) over the 2019–24 regulatory control period. As set out in *Forecasting productivity growth for electricity distributors*, the opex productivity growth forecast is not intended to capture the inefficiencies in the costs of an individual distributor (these are a part of our base year assessment outlined above).[8] It captures the sector-wide, forward looking, improvements in good industry practice that should be implemented by efficient distributors as part of business-as-usual operations.

Our alternative estimate also includes:

- updated base opex to reflect the RBA's lower inflation forecast from February 2019
- updated price growth which reflects Deloitte Access Economics' wage price index forecasts from February 2019, averaged with the forecasts proposed by Power and Water from BIS Oxford, to forecast labour price growth
- updated output growth which reflects the average output weights from the four benchmarking models included in our 2017 Annual Benchmarking Report (consistent with the draft decision) for the period 2006–17
- the new step change proposed by Power and Water for the demand management solution in relation to Wishart zone substation, which we consider to be prudent and efficient.

The reasons for our final decision are set out in further detail in section 6.4 and summarised in Table 6-4.

Power and Water's revised opex forecast and our final decision are in Table 6-1.

8 AER, *Final decision paper, Forecasting productivity growth for electricity distributors*, March 2019, pp. 8–11.

Table 6-1 Power and Water's proposed opex and our final decision ($million, $2018–19)

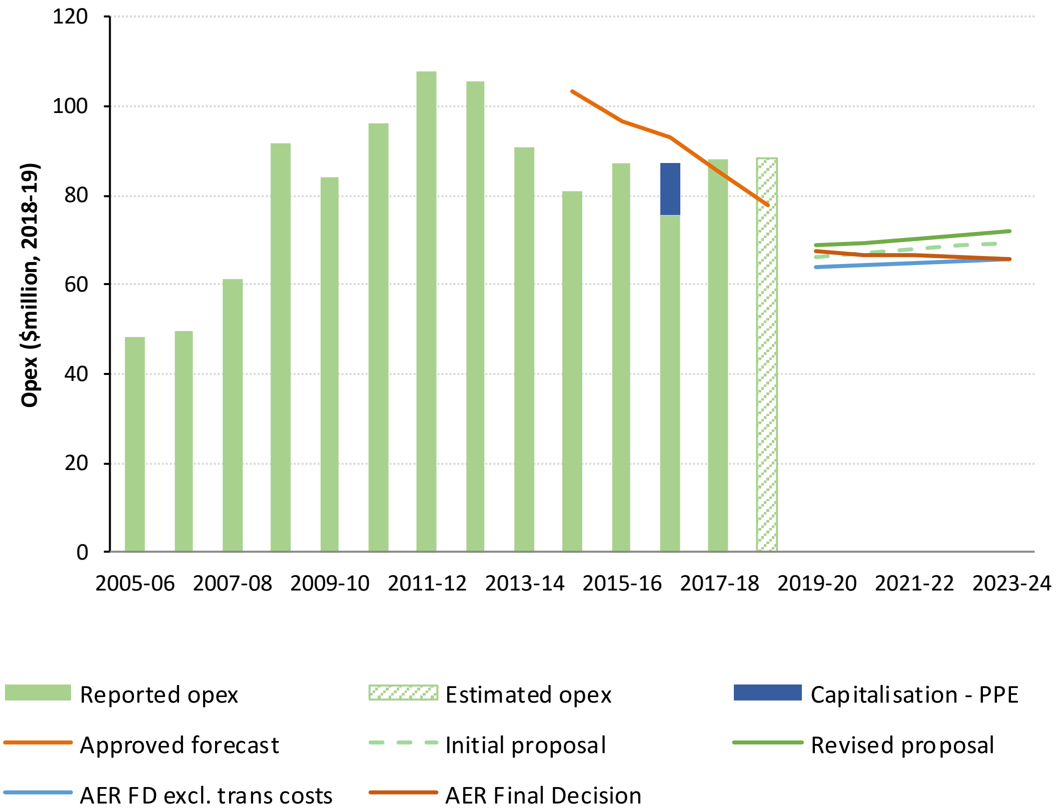
	2019–20	2020–21	2021–22	2022–23	2023–24	Total
Power and Water's proposed opex	68.7	69.3	70.3	71.1	71.9	351.3
AER final decision	67.4	66.9	66.6	66.1	65.7	332.7
Difference	-1.3	-2.5	-3.7	-4.9	-6.2	-18.7

Source: Power and Water, Revenue proposal, *PTRM*, 29 November 2018; AER analysis.

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

Figure 6.1 shows our opex decision compared to Power and Water's revised proposal, its past allowances approved by the Utilities Commission and past actual expenditure.

Figure 6-1 Our 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.

6.2 Power and Water Corporation's revised proposal

In its revised proposal, Power and Water forecasts opex of $351.3 million ($2018–19) for the 2019–24 regulatory control period[9], (inclusive of debt raising costs), a reduction of 16.4 per cent from its actual and estimated opex for the 2014–19 regulatory control period. Opex represents 41 per cent of Power and Water's total revenue in its revised proposal.

Power and Water's revised opex forecast is 14.8 per cent higher than our draft decision, and 3.6 per cent above its initial regulatory proposal. Power and Water's revised opex proposal per year is shown in Table 6-2.

Table 6-2 Power and Water's proposed opex ($million, 2018–19)

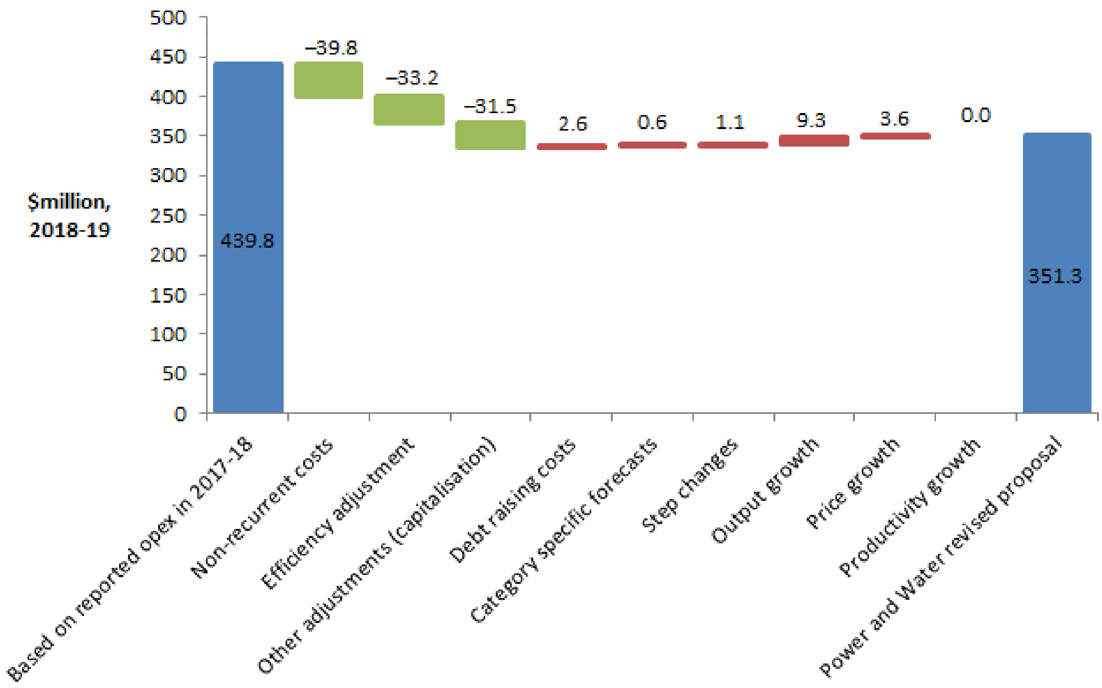
	2019–20	2020–21	2021–22	2022–23	2023–24	Total
Opex excluding debt raising costs	68.2	68.8	69.7	70.6	71.4	348.7
Debt raising costs	0.5	0.5	0.5	0.5	0.5	2.6
Total opex	**68.7**	**69.3**	**70.3**	**71.1**	**71.9**	**351.3**

Source: Power and Water, *SCS Opex Base Year Justification 2019-20 to 2023-24,* 29 November 2018, p. 42.

Figure 6-2 provides a breakdown of Power and Water's revised opex forecast into key components.

9 Power and Water, *Revised regulatory proposal 1 July 2019 to 30 June 2024,* 29 November 2018, p. 32.

Figure 6-2 Power and Water's revised opex proposal ($2018–19)



Source: AER analysis.

The key elements of Power and Water's proposal are set out below. Power and Water used our base-step-trend approach (described in section 6.3) to forecast opex. It used 2017–18 as the base year, making adjustments to base year opex for non-recurrent costs and efficiencies. It then applied a rate of change and added two step changes. More specifically:

- Power and Water used reported opex in 2017–18 as the starting point to forecast opex.[10] This leads to a base opex of $439.8 million ($2018–19) over the 2019–24 regulatory control period.[11] This is 16.1 per cent higher than its initial regulatory proposal. Power and Water updated its proposed base year from 2016–17 to 2017–18 with the availability of audited actual opex for 2017–18, as foreshadowed in its initial proposal.[12] Power and Water considers this provides a better indication of what will be required in the future to meet regulatory obligations and deliver the outcomes customers expect.
- Power and Water made the following adjustments to base opex prior to applying the rate of change:

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10 Power and Water, *SCS Opex Base Year Justification 2019-20 to 2023-24,* 29 November 2018, pp. 6-8.

11 This amount excludes debt raising costs.

12 Power and Water, *Regulatory proposal 1 July 2019 to 30 June 2024,* 16 March 2018, p. 85.

    - Power and Water removed $7.9 million ($2018–19) of costs for non-recurrent expenditure from emergency response and networks overheads costs.[13] This translates into a reduction of $39.8 million ($2018–19) over the 2019–24 period
    - Power and Water removed $6.6 million ($2018–19) of costs for efficiencies applied to maintenance and network and corporate overheads.[14] This translates into a reduction of $33.2 million ($2018–19) over the 2019–24 regulatory control period
    - Power and Water removed $6.3 million ($2018–19) from actual opex in 2018–19 to reflect a change in capitalisation policy[15] in the next regulatory control period.[16] This is shown under "other adjustments" in Figure 6-2. This translates into a $31.5 million ($2018–19) reduction over the 2019–24 regulatory control period
    - Power and Water removed GSL payments of $0.1 million ($2018–19) in 2017–18, which reduces base opex by $0.6 million ($2018–19) over the 2019–24 regulatory control period.[17] (As discussed in section 6.4.3 on Step changes, GSL payments in the next regulatory control period are to be funded via a step change.)
    - Power and Water removed the movement in provisions in 2017–18 ($0.4 million, ($2018–19)), consistent with our standard approach as adopted in our draft decision.[18]
- Power and Water then trended forward its base opex to account for:
    - expected increases in real input prices, including forecast increases in labour costs and an increase in line with CPI for non-labour costs ($3.6 million, ($2018–19))[19]
    - forecast output growth, driven primarily by increased customer numbers and circuit line length, which increase the cost to Power and Water of operating its network ($9.2 million, ($2018–19))[20]
    - forecast zero change in opex productivity over the regulatory period.[21]
- Power and Water included two step changes totalling $1.1 million ($2018–19) over the regulatory control period:[22]

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[13] Power and Water, *Revised regulatory proposal 1 July 2019 to 30 June 2024,* 29 November 2018, p. 38.
[14] Power and Water, *Revised regulatory proposal 1 July 2019 to 30 June 2024,* 29 November 2018, p. 38.
[15] Power and Water, *Revised regulatory proposal 1 July 2019 to 30 June 2024,* 29 November 2018, p. 38.
[16] 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.
[17] Power and Water, *Revised regulatory proposal 1 July 2019 to 30 June 2024,* 29 November 2018, p. 38.
[18] Power and Water, *Revised regulatory proposal 1 July 2019 to 30 June 2024,* 29 November 2018, p. 38.
[19] Power and Water, *Revised regulatory proposal 1 July 2019 to 30 June 2024,* 29 November 2018, p. 42.
[20] Power and Water, *Revised regulatory proposal 1 July 2019 to 30 June 2024,* 29 November 2018, p. 42.
[21] Power and Water, *Revised regulatory proposal 1 July 2019 to 30 June 2024,* 29 November 2018, p. 42.

    - $0.9 million ($2018–19) to fund an increase in Guaranteed Service Levels (GSLs) payments as a result of the revised GSL scheme under the Utilities Commission's Electricity Industry Performance Code[23]
    - $0.2 million ($2018–19) for a demand management capex/opex trade-off in relation to its Wishart zone sub-station.[24]
- Power and Water included a category specific forecast for debt raising costs of $2.6 million ($2018–19). Debt raising costs are transaction costs incurred each time debt is raised or refinanced.[25]

6.2.1 Stakeholder's views

Three submissions were received that contained views about Power and Water's revised opex proposal. These were from the AER's Consumer Challenge Panel (CCP13), the Electrical Trades Union of Australia (ETU), and the Northern Territory Treasurer. A summary of these submissions is provided in Table 6-3.

Table 6-3 Submissions on Power and Water's opex proposal

Stakeholder	Issue	Description
CCP13	Base opex, productivity growth, efficiency benefit sharing scheme	CCP13 encouraged us to closely review opex given the Power and Water's revised base year, and increased costs, the uncertainty on demand and the outcome of the productivity review.[26] In relation to productivity growth, CCP13 noted that it expected the same productivity factor would apply to all networks irrespective of their position in relation to the frontier. They also encouraged us to review the BIS Oxford real labour cost escalation forecasts and noted their support to not apply the Efficiency Benefit Sharing Scheme (EBSS).
ETU	Operational efficiencies and labour costs	The ETU submitted it does not support Power and Water's assertion that it can successfully introduce a 10 per cent opex efficiency target.[27] It considered the target to be an arbitrary one, adopted by senior management without the involvement of those who perform the day to day tasks, and including no meaningful technical assessment of genuine capacity to achieve the target. It also noted that if we are of the mind to consider the comparative labour costs in relation to the ratio of professional and managerial staff to technical staff, then a genuine benchmarking exercise should be performed. Further, that we may also turn our mind to the efficient engagement of external contract resources as a potential unnecessary cost driver in network businesses.

22 Power and Water, *Revised regulatory proposal 1 July 2019 to 30 June 2024,* 29 November 2018, p. 42.
23 Power and Water, *Revised regulatory proposal 1 July 2019 to 30 June 2024,* 29 November 2018, p. 41.
24 Power and Water, *Revised regulatory proposal 1 July 2019 to 30 June 2024,* 29 November 2018, p. 41.
25 Power and Water, *Revised regulatory proposal 1 July 2019 to 30 June 2024,* 29 November 2018, p. 42.
26 Consumer Challenge Panel, *Advice to the Australian Energy Regulator (AER), Consumer Challenge Panel Sub-Panel 13, Response to Power and Water Corporation revised proposal for a revenue reset for the 2014-24 regulatory period, Sub-Panel 13,* 11 January 2019, pp. 11–13.
27 Electrical Trades Union, *Power and Water Corporation - Revised Regulatory Proposal 2019–24*, 11 January 2019, p. 3.

Stakeholder	Issue	Description
The Northern Territory Treasurer	Operational efficiencies and operating environment	The Northern Territory Treasurer expressed concern that our draft decision may be unsustainable and not consistent with Territorians' expectations for safe and reliable power.[28] Further, that given Power and Water had made operating efficiencies in its revised proposal, including an 18 per cent efficiency improvement to base year (2017-18), it is unclear whether the business has capacity to make further significant reductions. The submission also requested that due consideration be given to the unique circumstances and operating environment faced by Power and Water.

6.3 Assessment approach

We must form a view about whether a business's forecast of total opex 'reasonably reflects the opex criteria'.[29] In doing so, we must have regard to each of the opex factors specified in the NER.[30]

If we are satisfied the business's forecast reasonably reflects the criteria, we accept the forecast.[31] If we are not satisfied, we substitute an alternative estimate that we are satisfied reasonably reflects the opex criteria.[32] 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.[33]

The Guideline together with an explanatory statement set out our intended approach to assessing opex in accordance with the NER.[34] 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.[35]

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

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28 Northern Territory Treasurer, *Letter in relation to 2019-24 draft revenue determination for Power and Water's network business,* 8 January 2019, pp. 1-4.

29 NT NER, cl. 6.5.6(c).

30 NT NER, cl. 6.5.6(e).

31 NT NER, cl. 6.5.6(c).

32 NT NER, cll. 6.5.6(d) and 6.12.1(4)(ii).

33 NEL, s. 16(1)(c).

34 AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013; AER, *Expenditure forecast assessment guideline*, *Explanatory statement*, November 2013.

35 NT NER, cl. 6.2.8(c)(1).

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.[36] 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.[37]

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).[38]

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 whether base opex reasonably reflects the opex criteria.[39] We may make a negative adjustment to the business's revealed opex if we find it is operating in a materially

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

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

38 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'.

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

inefficient manner. Material inefficiency is a concept we introduce in our Guideline.[40] 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 '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 for Power and Water in the future. More details of our specific base opex assessment approach for this final decision are in section 6.4.1.4.

Incentive regulation is designed to leave the day-to-day decisions to the network businesses.[41] 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,[42] and more broadly, the National Electricity Objective (NEO).[43] 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.[44]

The Australian Energy Market Commission (AEMC) supports this view of our role as the economic regulator. It stated: [45]

> 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…

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.

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

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

42 NT NER, cl. 6.5.6(a).

43 NEL, s. 7.

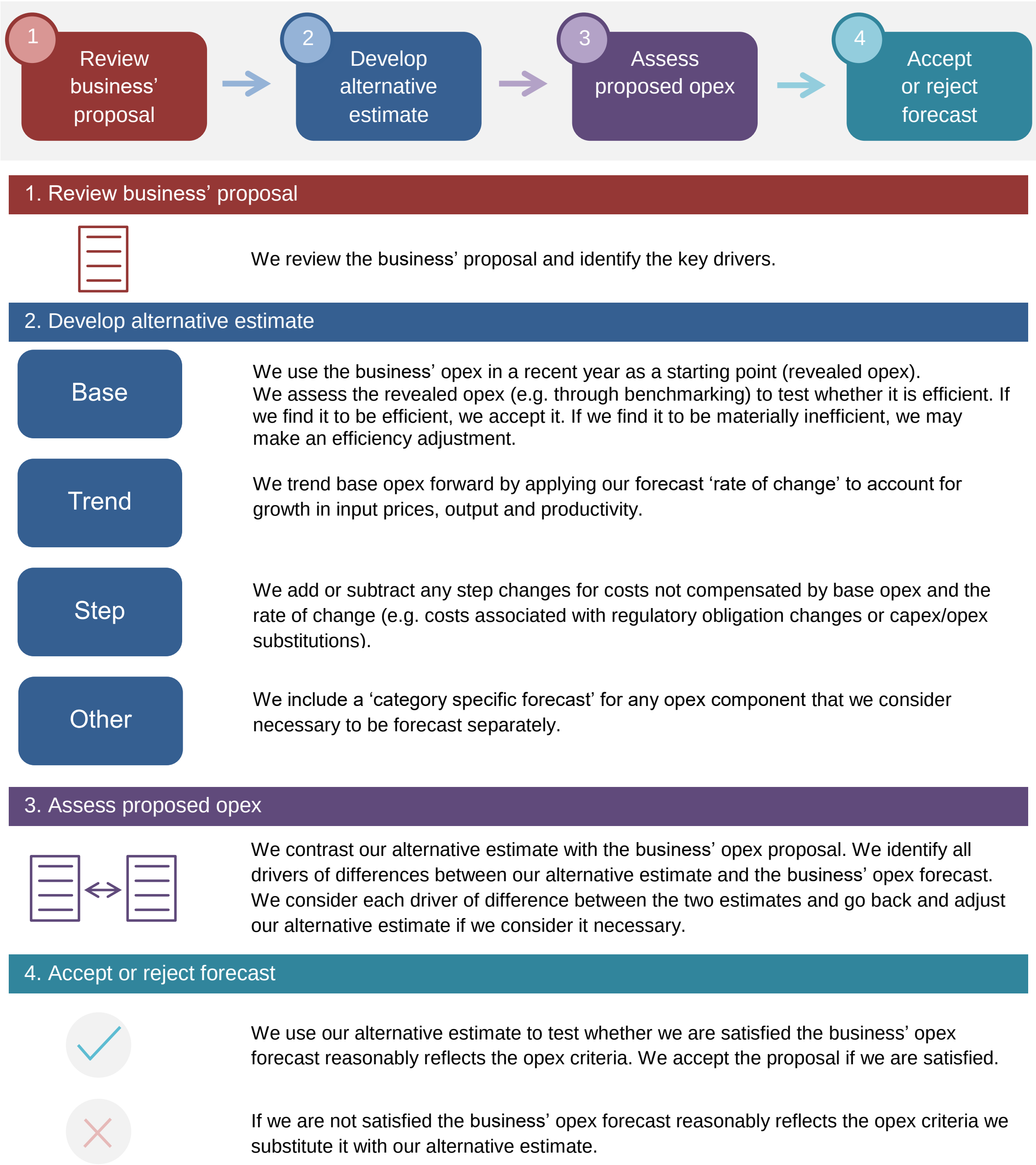
44 NT NER, cl. 6.5.6(c).

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

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[46] and other assessment techniques, such as category and trend analysis, 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, in the absence of step changes (which are explained below), the level of *total opex* is generally 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.

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

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46 AER, *Annual benchmarking report—Electricity distribution network service providers*, November 2018.

business's costs.[47] 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, ideally, be the same measures used to forecast productivity growth.[48] Productivity measures the change in output for a given amount of input.

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 opex productivity growth captures the sector-wide, forward looking, improvements in good industry practice that should be implemented by efficient distributors as part of business-as-usual operations.[49] We generally base our estimate of productivity growth on recent productivity trends across the electricity 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 and may rely on other industry or economy wide indicators.

We recently reviewed our approach to forecasting opex productivity growth and determined that a forecast of 0.5 per cent per year represents an appropriate opex productivity growth factor for electricity distributors.[50] As noted in our draft decision, we have taken the outcome of the productivity growth review into consideration in this 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.[51] These adjustments are in the form of 'step changes' or 'category-specific forecasts'. Step changes include compliance with new regulatory obligations that are material and capex/opex trade-offs (given that there is a degree of substitutability between capex and opex).

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

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

49 AER, *Final decision paper, Forecasting productivity growth for electricity distributors*, March 2019, pp. 8–11.

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

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

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 and should not become a step change.[52] 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'.[53] 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.[54]

To increase its revenue requirement, 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.[55] 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.[56] 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.[57] 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

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

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

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

55 NT NER, cl. 6.5.6(c).

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

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

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 to meet the change in regulatory obligations over time.[58] We stated in the explanatory statement accompanying the Guideline:[59]

> [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 are discretionary or 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.[60]

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.[61] The business should provide robust cost–benefit analysis to clearly demonstrate how increased opex would be more than offset by capex savings.[62]

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

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

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

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

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

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

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.

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 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 they are funded 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.

6.4 Reasons for final decision

Our final decision is to include total forecast opex of $332.7 million ($2018–19) in Power and Water's revenue for the 2019–24 regulatory control period, which is $18.6 million ($2018–19) or 5.3 per cent less than Power and Water's revised forecast opex of $351.3 million ($2018–19). We are satisfied our alternative estimate of forecast opex reasonably reflects the opex criteria.[63]

Table 6-4 presents the components of our alternative estimate compared to Power and Water's proposal. It shows that the key differences are:

- we reduced our alternative estimate by an additional $3.8 million ($2018–19) to remove non-recurrent network overhead costs, such as professional fee and personnel costs, that we do not consider Power and Water has justified as being recurrent in nature. This translates to $18.8 million ($2018–19) over the next regulatory control period
- we included transition costs of $8.2 million ($2018-19) over the period by phasing in efficiencies of 10 per cent to network and corporate overheads gradually so they are fully realised by the end of the 2019–24 regulatory control period rather than from the base year as proposed by Power and Water. In the circumstances, we find this to be a more practical approach
- we included the 0.5 per cent per year opex productivity growth forecast established in our recent generic review, as compared to the 0.0 per cent Power and Water included in its revised proposal. We consider this reflects the sector-wide, forward looking, improvements in good industry practice that should be implemented by efficient distributors as part of business-as-usual operations. This reduces our alternative estimate of total opex by $6.2 million ($2018-19).

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

Table 6-4 Our alternative estimate compared to Power and Water's proposal ($million, 2018–19)

	Power and Water revised regulatory proposal	AER final decision	Difference
Based on reported opex in 2017-18	439.8	436.5	-3.2
Other adjustments (capitalisation)	-31.5	-31.6	-0.1
Non-recurrent costs	-39.8	-58.6	-18.8
Efficiency adjustment	-33.2	-31.4	1.8
Transition costs	0.0	8.2	8.2
Output growth	9.3	8.0	-1.3
Price growth	3.6	4.6	1.0
Productivity growth	0.0	-6.2	-6.2
Step changes	1.1	1.3	0.1
Category specific forecasts	-0.6	-0.6	0.0
Debt raising costs	2.6	2.5	-0.1
Total opex	**351.3**	**332.7**	**-18.7**

Source: 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.

6.4.1 Base opex

This section sets out our view on Power and Water's proposed adjusted base opex of $66.9 million ($2018–19) for each year of the regulatory control period.

6.4.1.1 Overall view

We developed an alternative estimate of adjusted base opex of $62.9 million ($2018–19) and substituted this for Power and Water's proposed $66.9 million ($2018–19).

We assessed the efficiency of Power and Water's opex in the 2017–18 base year using multiple techniques, including reviewing operating and maintenance practices, undertaking cost category and trend analysis and examining PPI benchmarking. We focused our review of base opex on the cost categories that are the most material, where there has been significant change compared to Power and Water's initial proposal and/or where we consider there to be the greatest scope for identifiable efficiency improvement.

We agree with Power and Water's proposal to use an updated base year of 2017–18, and to make category-level adjustments for non-recurrent opex and efficiencies. However, we reduced our alternative estimate by an additional $3.8 million ($2018–19) to remove non-recurrent network overhead costs, such as professional fee and personnel costs, that we do not consider Power and Water has justified as being recurrent. Our alternative estimate of network overhead opex of $25.2 million ($2018–19) is 12.8 per cent lower than proposed by Power and Water. This results in lower opex of $18.8 million ($2018-19) over the 2019–24 regulatory control period.

We have not made any other specific cost category reductions to base year opex additional to those made by Power and Water, including to direct costs such as vegetation management, maintenance and emergency response.

Power and Water proposed 10 per cent reductions to base year network and corporate overhead costs (which make up 60 per cent of base year opex) to reflect what it considers to be achievable efficiencies over the regulatory period. We accept this amount as reasonable as it is supported by the results of our PPI benchmarking and taking into account the impact of its operating environment. This reduces base year opex by $4.0 million ($2018-19) (in addition to the non-recurrent network overhead adjustment noted above). Over the 201924 regulatory control period this results in $1.8 million ($2018–19) less of a reduction compared to Power and Water's revised proposal as the efficiencies are applied to a lower base year.

Power and Water proposed to apply these 10 per cent overhead efficiencies to the base year.[64] Given this is the first time we have regulated Power and Water under the NER, and the likely nature of the 10 per cent network and corporate overhead efficiencies, which may require some structural changes, we consider it is appropriate to include the efficient costs of transitioning to a lower opex base.

As such, we apply a gradual (linear) path of reductions to network and corporate overheads, such that a 10 per cent efficiency is fully realised by the last year of the 2019–24 regulatory control period. This gradual application reflects that we expect transition costs to decline over time. This means total opex is $8.2 million ($2018–19) higher over the 2019–24 regulatory control period compared to an alternative estimate that does not allow for these transition costs. We consider this will allow for an efficient yet practical transition to a lower opex base, while maintaining the quality, reliability, security and safety of services to Power and Water's customers.

[64] Power and Water, *SCS Opex Base Year Justification 2019-20 to 2023-24*, 29 November 2018, pp.16–17.

6.4.1.2 Choice of base year

Power and Water proposed 2017–18 as its base year in its revised proposal, after using 2016–17 in its initial proposal. It had noted in its initial proposal that it expected to update the base year to 2017–18 in the revised proposal, once actual audited information became available.[65]

We consider opex is, in general, 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, reductions until 2016–17, and increases from 201617. 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 2017–18 as the base year. This is because it is the most recent year for which actual audited information is available and, with the adjustments for non-recurrent costs and efficiencies detailed below, it is likely to best reflect Power and Water's current circumstances, relative to previous years. We note, however, that in 2017–18 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.[66]

In arriving at base opex, both Power and Water's revised proposal and our alternative estimate remove non-recurrent costs from actual base year opex, based on a category-level assessment. Consistent with the revised proposal, our alternative estimate incorporates adjustments for non-recurrent opex in emergency response and networks overheads. Compared to the proposal, we incorporate an additional $3.8 million ($2018-19) in the amount removed from base year opex for non-recurrent costs. This additional amount in network overhead costs reflects professional fee and personnel costs we do not consider Power and Water has justified as being recurrent. We discuss further how we assessed non-recurrent costs by category in section 6.4.1.4.

Once removals are made for non-recurrent costs, both Power and Water's revised proposal and our alternative estimate made adjustments for efficiencies, based on a category-level assessment. Power and Water incorporated specific efficiencies for

65 Power and Water, *Regulatory proposal 1 July 2019 to 30 June 2024,* 16 March 18, p. 10.

66 NT NER, cl. 6.5.6(c).

maintenance and 10 per cent efficiency targets for network and corporate overheads, which we have assessed as appropriate and adopted in our alternative estimate. These adjustments are discussed further by category in section 6.4.1.4.

Power and Water removed $6.3 million (2018–19) of expenditure incurred in the base year on operating leases for building and motor vehicles (following the $5.5 million ($2018–19) initially proposed in the base year of 2016–17 and as accepted in the draft decision). 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 $6.3 million ($2018–19) reduction (see 6.4.1.4—Non-network for a discussion of this issue).

In some 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.[67]

We have removed movements in provisions[68] 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 also removed changes in provisions from its revised opex forecast.

We have also removed GSL payments in 2017–18 ($0.1 million, ($2018–19)) from base year opex, noting that in Power and Water's revised proposal GSL payments in the next regulatory control period are to be funded via a step change, which we accept in our alternative estimate.

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[67] As stated in Power and Water*, Response to AER information request IR031*, 18 July 2018, Q.1, debt raising are incurred on Power and Water's behalf by its shareholder the NT government. The costs of this debt raising are not allocated to Power and Water and so are not reflected in its reported cost base.

[68] 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.

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.

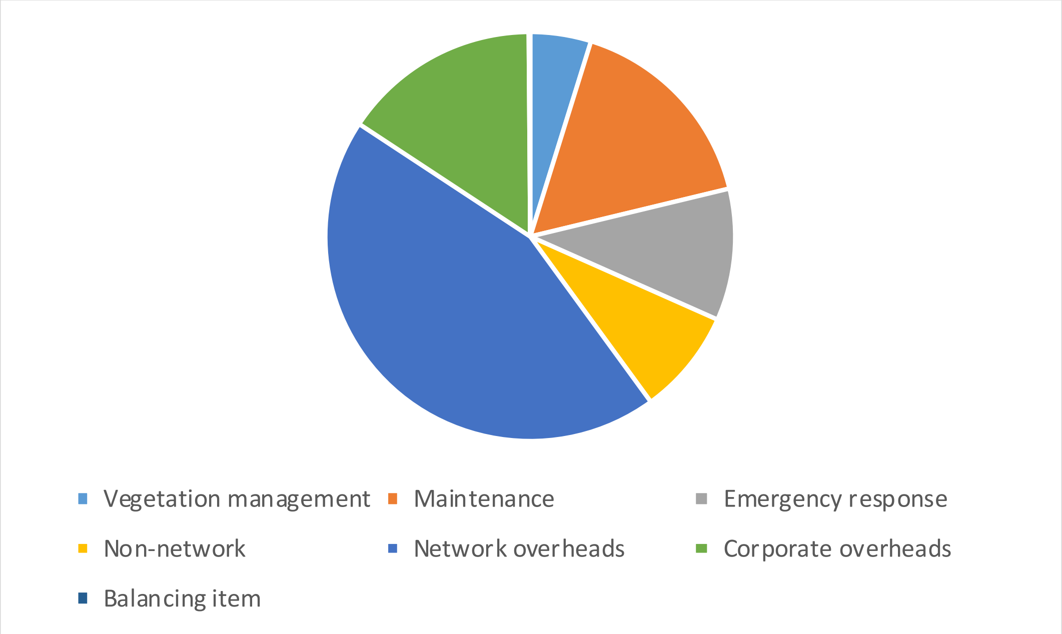
Approach

In line with our Guideline, 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. [69]

Consistent with Power and Water's revised proposal, we formed a view that we could not rely on actual, revealed, costs in the base year and that we needed to undertake a detailed assessment of base year opex.[70] This was supported by the indicative PPI benchmarking information (see Appendix A for an explanation of PPI benchmarking and results).

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.

Figure 6-4 Power and Water's expenditure categories 2017–18 ($2018–19)



[69] AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013.

[70] Power and Water, *Revised regulatory proposal 1 July 2019 to 30 June 2024*, 29 November 2018, p. 36 and Power and Water, *SCS Opex Base Year Justification 2019-20 to 2023-24*, 29 November 2018, pp.6–8.

Source: Power and Water, *SCS Opex Base Year Justification 2019-20 to 2023-24*, 29 November 2018; AER analysis.

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)
- subject to the most significant change compared to Power and Water's initial proposal 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 focused on maintenance, vegetation management, network overheads and corporate overheads, which represent 81.1 per cent of base opex, and where the available evidence pointed to achievable improvements. We also considered to lesser degrees the emergency response and non-network categories, which represents 18.8 per cent of opex.[71]

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 relied, and built on, the analysis in the draft decision, including reviewing various asset management practices and performance measures as well as undertaking time trend analysis and benchmarking. This was 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's 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, as in the draft decision, we have departed from our preferred top-down assessment approach for this final 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[72] 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

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71 Power and Water's balancing item makes up the remaining 0.1 per cent.

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

would have been incurred by an efficient operator.[73] Power and Water has just transitioned to the NT NER and was not included in the 2018 benchmarking report as we were still in the process of examining Power and Water's benchmarking and regulatory data.[74] While this limits our ability to use the benchmarking report, we have updated the PPI benchmarking used to inform our draft decision by including 2017–18 data for the non-Victorian businesses.

The PPI analysis provides an indication of Power and Water's efficiency compared to other distributors (see Appendix A) and 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 that are realistic and achievable. We consider the PPI analysis supports the findings from our detailed review in the draft decision that Power and Water can achieve material efficiency gains by implementing good electricity industry practices.

Despite these findings, we have not used the PPI benchmarking as the sole 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 to our draft decision). This will be a focus of our benchmarking forward work program following this regulatory determination process.

Assessment

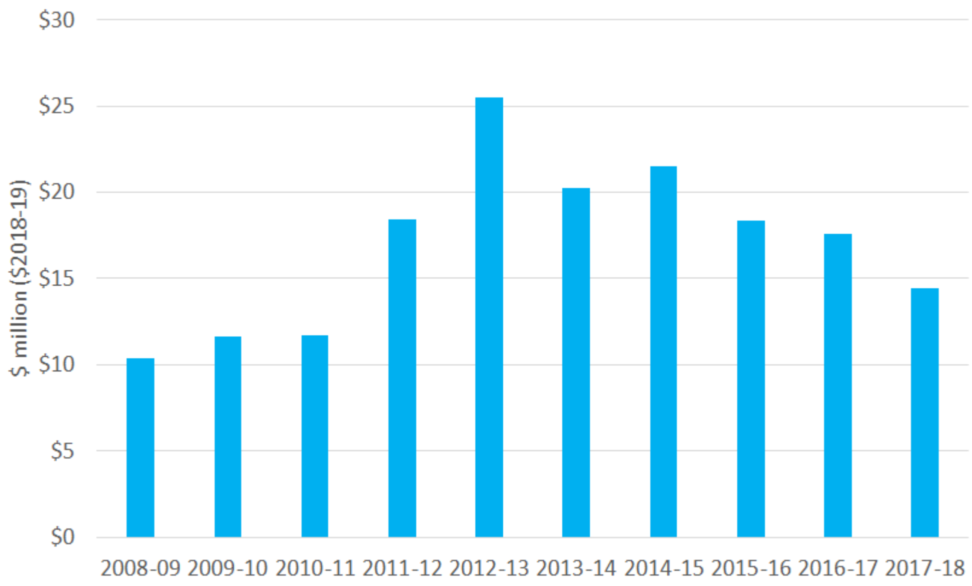
Maintenance

Maintenance opex was $14.4 million ($2018-19) in 2017–18, making up 16.4 per cent of total opex. This was 18.1 per cent lower than costs in 2016–17. Over the four years to 2016–17 maintenance costs also decreased by 13.1 per cent after peaking in 2012–13 at $25.5 million ($2018-19) (see Figure 6-5).

73 NT NER, cl. 6.5.6(e)(4).

74 AER, *Annual Benchmarking Report, Electricity distribution network service providers*, November 2018, p. 30.

Figure 6-5 Inspection and maintenance opex ($2018–19)



Source: Power and Water, Category Analysis RIN, 22 May 2018 and 31 October 2018; AER analysis.

In its revised proposal Power and Water adjusted its 2017–18 base year actual costs ($14.4 million ($2018–19)), resulting in proposed maintenance costs of $14.2 million ($2018–19) (which is 19.2 per cent lower than 2016–17 actual costs).[75] In particular it:

- added $1.9 million ($2018–19) of costs that it considered were diverted in 2017–18 to emergency response activities as a result of Tropical Cyclone Marcus[76]
- applied an efficiency adjustment of $2.2 million ($2018-19) which was made up of two components – less frequent inspections and routine maintenance ($0.9 million ($2018–19)) and use of risk management and improved inspection alignment for non-routine maintenance ($1.3 million ($2018–19)). [77] The nature of these efficiency adjustments is largely consistent with the improved practices and efficiencies we included in the draft decision which we considered were consistent with good electricity industry practice.[78] [79]

We have examined Power and Water's maintenance opex, including the actual costs in 2017–18 and the key differences between our draft decision and Power and Water's

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75 Power and Water, *SCS Opex Base Year Justification 2019-20 to 2023-24*, 29 November 2018, p. 7.

76 Power and Water, *SCS Opex Base Year Justification 2019-20 to 2023-24*, 29 November 2018, p .7.

77 Power and Water, *SCS Opex Base Year Justification 2019-20 to 2023-24*, 29 November 2018, pp. 25–35.

78 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.

79 AER, *Draft Decision, Power and Water Corporation Distribution Determination 2019 to 2024, Attachment 6, Operating Expenditure,* September 2018, pp. 31–40.

revised proposal. In our draft decision, we reduced 2016–17 maintenance opex by 26.3 per cent, reflecting our view that inspections and maintenance was carried out too frequently, meaning opex was above efficient levels and did not reflect costs that would be incurred by a prudent operator providing the safe and reliable delivery of electricity.[80]

This was also consistent with our observation that Power and Water's maintenance opex per circuit km against customer density over the period 2013–14 to 2016–17 was over three times higher than other businesses with similar customer densities (see Appendix A, Figure A.2 for updated analysis including 2017-18).[81] We considered Power and Water's operating environment was likely to have some impact on its maintenance opex, including as a result of weather conditions that impact its asset condition and workability (see Appendix B of our draft decision for discussion of Power and Water's operating environment). We have not quantified that impact but intend to do so going forward.

We note that the Northern Territory Treasurer requested that due consideration be given to the unique circumstances and operating environment faced by Power and Water, particularly in the context of the opex reductions proposed by Power and Water.[82]

As noted above, Power and Water's proposed maintenance opex in 2017–18 was 19.3 per cent lower than actual opex in 2016-17. This reduction is less than the 26.3 per cent reduction we proposed in the draft decision. In examining the efficiency adjustments to routine and non-routine maintenance Power and Water's included in its revised proposal, we note:

- in relation to maintenance frequency, Power and Water's revised proposal only made adjustments to the frequency of routine maintenance. We consider this is appropriate and will lead to a lower reduction in maintenance opex compared to our draft decision, which made adjustments to routine and non-routine maintenance (and therefore overstated the potential efficiencies)
- in relation to improved risk management, Power and Water's proposed efficiency adjustments do not recognise the implications of improved risk management on routine maintenance practices, with adjustments only being made to non-routine maintenance. While further refinement could be made to incorporate these efficiencies, this is only likely to lead to very modest reductions in the maintenance opex proposed by Power and Water.

80 AER, *Draft Decision, Power and Water Corporation Distribution Determination 2019 to 2024, Attachment 6, Operating Expenditure,* September 2018, pp. 31–40.

81 AER, *Draft Decision, Power and Water Corporation Distribution Determination 2019 to 2024, Attachment 6, Operating Expenditure,* September 2018, p. 32.

82 Northern Territory Treasurer, *Letter in relation to 2019-24 draft revenue determination for Power and Water's network business*, 8 January 2019, pp. 1–4.

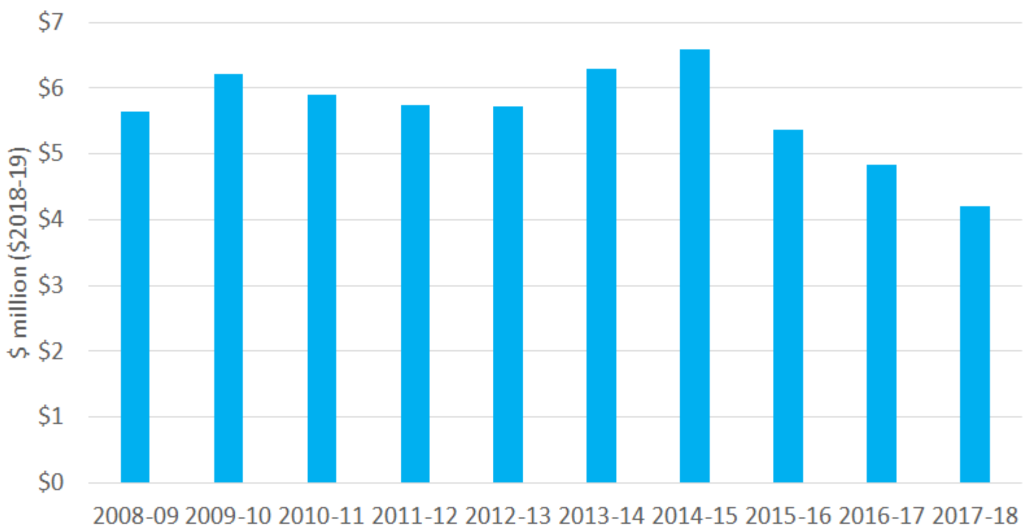
On balance, and reflecting the above, we consider Power and Water's proposed maintenance opex for 2017–18 ($14.1 million[83] ($2018–19)) is a reasonable estimate of efficient costs and we have included it in our alternative estimate.

Power and Water's inspection and maintenance practices have improved over recent years. We note that going forward Power and Water should apply improved risk management practices to both routine and non-routine maintenance and that more generally we expect to see ongoing efficiency improvements being realised as Power and Water's risk management practices mature.

Vegetation management

Vegetation management opex was $4.2 million ($2018–19) in 2017–18, making up 4.8 per cent of total opex. This was 12.9 per cent lower than in 2016–17, continuing the decline in vegetation management opex that has been occurring since costs peaked at $6.6 million ($2018–19) in 2014–15 (see Figure 6-6). Over the last five years vegetation management costs have decreased by 33.2 per cent and are now below vegetation management opex over the 2010–11 to 2012–13 period (around $5.8 million ($2018–19) per year).

Figure 6-6 Vegetation management opex ($2018–19)



Source: Power and Water, Category Analysis RIN, 22 May 2018 and 31 October 2018; AER analysis.

Power and Water considered that actual 2017–18 opex is the minimum requirement necessary for the efficient management of vegetation in the vicinity of its overhead electricity assets.[84] This reflected the analysis of its consultant that demonstrated average annual expenditure above 2017–18 levels is likely to be required during the

83 We have updated this for the latest estimate of inflation.

84 Power and Water, *SCS Opex Base Year Justification 2019-20 to 2023-24*, 29 November 2018, p. 48.

2019–24 regulatory period and the associated key risks. Power and Water also noted that while 2017–18 expenditure is not representative of its current regulatory requirements, it believes it is achievable in the 2019-24 regulatory period with the implementation of the key recommendations its consultant made and the realisation of benefits from its proposed ICT capital program.

We have examined Power and Water's vegetation management opex, including the actual costs in 2017–18 and the key differences between our draft decision and Power and Water's revised proposal. In our draft decision, we reduced 2016–17 vegetation management opex by 20 per cent as we considered this would be consistent with good electricity industry practices being in place.[85] It was also consistent with our observation in the draft decision that Power and Water's vegetation management opex per km of route line length against customer density was around double most other businesses with similar customer densities (see Appendix A, Figure A.3 for updated analysis).[86] We noted that 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. We have not quantified that impact but intend to do so going forward.

As noted above, actual vegetation management opex in 2017–18 was 12.9 per cent lower than in 2016–17, which is the basis for Power and Water's revised proposal. This reduction is less than we proposed in the draft decision. However, after further review we consider that given Power and Water's resources and operating environment it is a reasonable estimate of efficient costs. As a result we have used Power and Water's actual 2017–18 vegetation management opex ($4.2 million ($2018–19)) in forming our alternative estimate.

We are encouraged by Power and Water's improved vegetation management practices and expect to see the realised benefits from these practices in our next review.

Emergency response

Actual emergency response costs in 2017–18 were $9.2 million ($2018–19), making up 10.4 per cent of total opex, which was a 35.8 per cent increase compared to 2016-17. This increase reflects the significant costs Power and Water incurred in 2017-18 as a result of Tropical Cyclone Marcus. Prior to 2017–18, emergency response opex had reduced from a peak of $15.3 million ($2018–19) in 2011–12 and over the four years to 2016–17 it was on average $7.1 million ($2018–19) per year (see Figure 6-7). As

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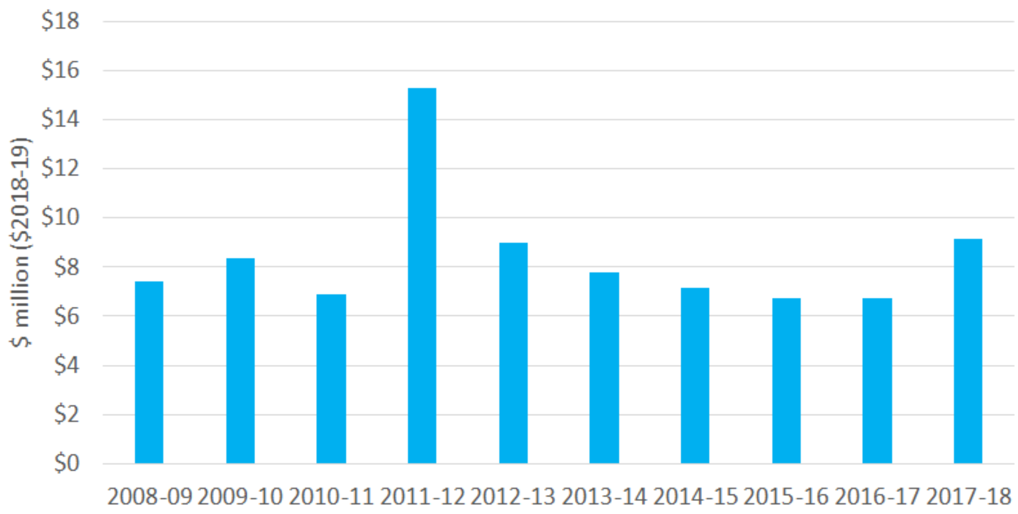
85 AER, *Draft Decision, Power and Water Corporation Distribution Determination 2019 to 2024, Attachment 6, Operating Expenditure,* September 2018, pp. 40–43.

86 AER, *Draft Decision, Power and Water Corporation Distribution Determination 2019 to 2024, Attachment 6, Operating Expenditure,* September 2018, p. 41.

noted in our draft decision, this reduction occurred in parallel with improvements in Power and Water's asset reliability, consistent with what we would expect to see.

Figure 6-7 Emergency response opex ($2018–19)



Source: Power and Water, Category Analysis RIN, 22 May 2018 and 31 October 2018; AER analysis.

In its revised proposal, Power and Water adjusted its actual 2017–18 emergency response costs by removing $2.7 million ($2018–19) in costs it incurred between March and June 2018 as a result of Tropical Cyclone Marcus.[87] In particular, it removed $0.7 million ($2018–19) of opex which it considered to be non-recurrent and $1.9 million ($2018–19) of opex which it considered were business as usual costs, but a diversion in 2017–18 of non-routine maintenance resources to emergency response. This resulted in proposed emergency response opex in 2017–18 of $6.6 million ($2018–19) which is 2.7 per cent lower than actual costs in 2016–17 ($6.7 million ($2018–19)) and lower than historical costs.

Power and Water's emergency response opex per customer against customer density over the period 2013–14 to 2017–18 appears to be double that of most businesses with similar customer densities (see Appendix A, Figure A.4). As noted in the draft decision, 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 have not yet quantified the impact of Power and Water's operating environment on emergency response opex.

As the opex proposed by Power and Water in 2017–18 is in line with recurrent emergency response costs over the previous four years, and given the nature of Power

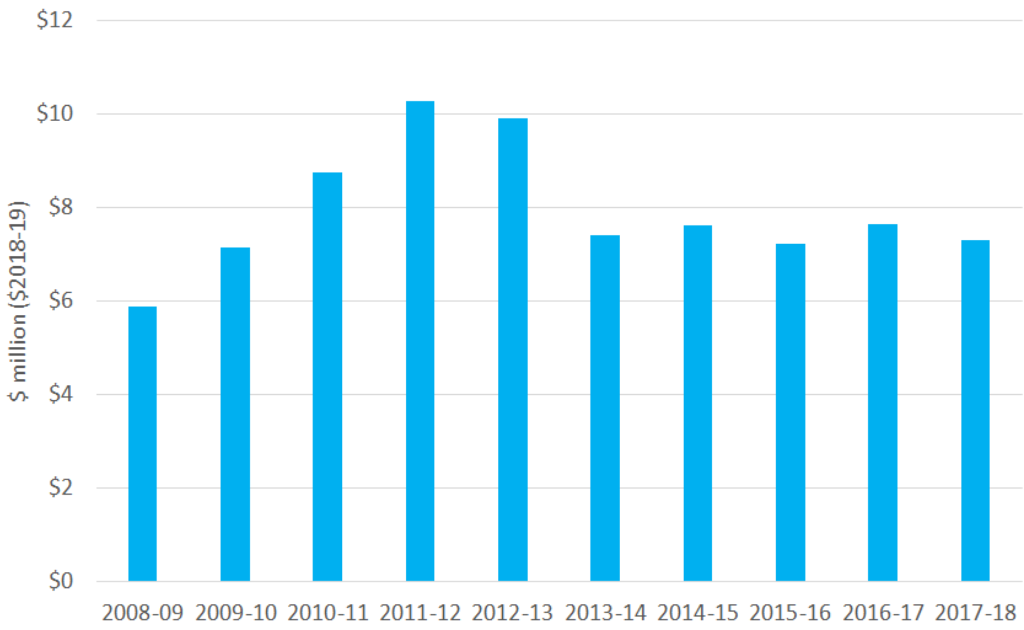
[87] Power and Water, *SCS Opex Base Year Justification 2019-20 to 2023-24*, 29 November 2018, pp. 70–71.

and Water's operating environment, as well as the critical nature of emergency response opex, we have not made any further adjustments. We have used Power and Water's adjusted 2017–18 estimate ($6.5 million[88] ($2018–19)) in forming our alternative estimate.

Non-network

Actual non-network costs in 2017–18 were $7.3 million ($2018–19) and represented 8.3 per cent of total opex. They were 4.5 per cent lower than in 2016–17. Broadly non-network costs have been constant over the last five years, varying between $7.2 ($2018–19) and $7.7 million ($2018–19). This is illustrated in Figure 6-8.

Figure 6-8 Non-network opex ($2018–19)



Source: Power and Water, Category Analysis RIN, 22 May 2018 and 31 October 2018; AER analysis.

Power and Water proposed to capitalise $5.2 million ($2018–19) of non-network costs relating to its leases for property and fleet under accounting standard AASB 16 (and $0.8 million ($2018–19) of network overheads and $0.3 million ($2018–19) of corporate overheads).[89] We examined this issue in the draft decision and considered the proposed capitalisation approach is consistent with Power and Water's Cost Allocation Method and 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.[90] We maintain this position for the final decision.

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88 We have updated this for the latest estimate of inflation.

89 Power and Water, *SCS Opex Base Year Justification 2019-20 to 2023-24*, 29 November 2018, pp.74–75.

90 AER, *Draft Decision, Power and Water Distribution Determination 2019-24, Attachment 6, Operating Expenditure*, September 2018, pp. 45-46.

Consistent with our reasons in the draft decision, including the recurrent nature of non-network costs and that Power and Water benchmarks in the middle of distributors with similar customer densities (see Figure A.5, Appendix A), we have not made any further adjustments to non-network costs. We have used Power and Water's actual 2017–18 non-network opex ($7.3 million[91] ($2018–19)) in forming our alternative estimate.

Network overheads

We have developed an alternative estimate of network overhead opex of $25.2 million ($2018–19), and have substituted this amount for Power and Water's proposed network overhead opex. This reflects our view of the recurrent and efficient costs we consider Power and Water requires over the 2019–24 regulatory control period. This is $3.7 million ($2018–19) (12.8 per cent) lower than proposed by Power and Water as can be seen in Table 6-5. We have also considered the efficient one-off transition costs that Power and Water will need to incur to achieve this lower level of opex (see the section below on transition costs for network and corporate overhead efficiencies).

Table 6-5 Network overheads opex (million $2018–19)

Cost category	Power and Water - revised regulatory proposal	AER – final decision[92]	Difference
Network overheads	28.8	25.2	-3.7

Source: Power and Water, *SCS Opex Base Year Justification 2019-24*, and AER analysis.

We reviewed Power and Water's proposed base year network overhead opex in detail, rather than rely on revealed cost in the base year. This is because it makes up a significant component (44.3 per cent) of total base year opex and, after generally decreasing over time until 2016–17, increased by 29.3 per cent in 2016-–7[93] and 24.6 per cent in 2017–18[94]. Further, in the base year (2017-18) it is 62.2 per cent higher than the average over the period 2013–16.[95] This can be seen in Figure 6-9.

91 We have updated this for the latest estimate of inflation.

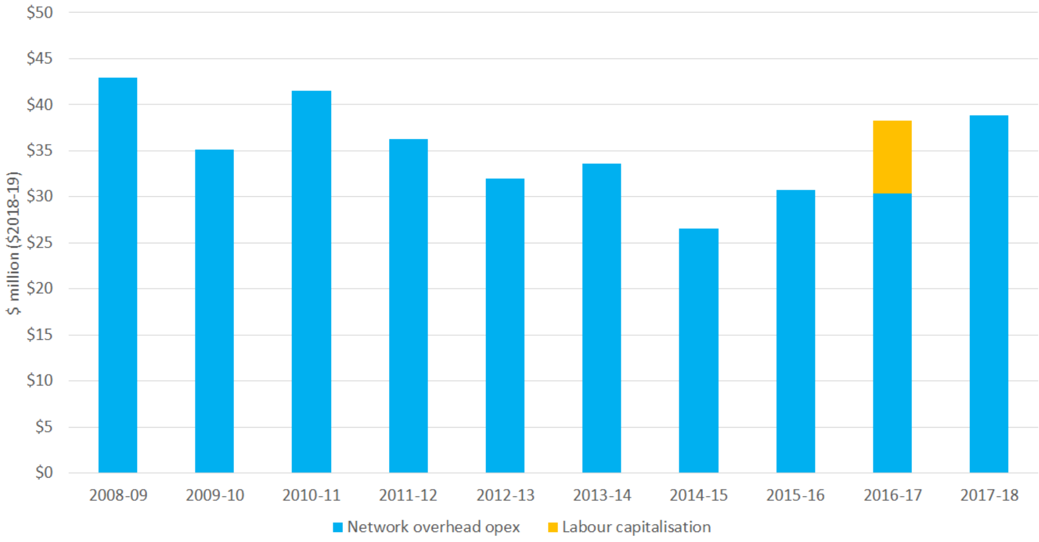
92 Excludes non-recurrent transition costs.

93 Excluding the impact of its change in capitalisation policy. See Box 1 on the change in capitalisation in the draft decision.

94 Excluding the impact of its change in Cost Allocation Method.

95 Holding capitalisation and the Cost Allocation Method constant.

Figure 6-9 Power and Water's network overhead opex ($2018–19)



Source: Power and Water, Category Analysis RIN, 22 May 2018 and 31 October 2018; AER analysis.

In addition:

- Power and Water was not subject to an EBSS over the current regulatory control period. As discussed in section 6.3.2.1, without an EBSS any irregularity in a particular year will not be offset by a higher or lower EBSS carryover, limiting the confidence we have that opex in the base year is not artificially high (or inflated)
- Power and Water does not benchmark well on network overheads using our PPI benchmarking. Network overhead totex per customer over the period 2013–14 to 2017–18 is considerably higher than most of its peers (see Appendix A, Figure A.6). We note that Power and Water's operating environment may have some impact on this, e.g. the possibility of higher labour rates in the NT compared to most states.[96]

Developing our alternative estimate

In the draft decision we developed an alternative estimate using the average of network overhead opex over the period 2013–16 as a starting point.[97] We then added recurrent costs for activities not captured in this average, but which were likely to be required over the next regulatory period. In this decision, we refer to this approach as the increment approach.

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

97 AER, *Draft Decision, Power and Water Corporation Distribution Determination 2019 to 2024, Attachment 6, Operating Expenditure*, September 2018, pp. 46–48.

In its revised proposal Power and Water estimated opex in the updated base year (2017–18) using a different approach.[98] It took actual network overhead opex in the base year and then removed those costs it considered to be non-recurrent. It also applied a top-down efficiency adjustment of 10 per cent.[99] We refer to this as the decrement approach.

Power and Water submitted in its revised proposal[100] and in response to an information request[101] that the decrement approach is preferable as the legislative and regulatory framework it operates have undergone extensive changes over the 2013-16 period. It also states that its 2017–18 expenditure is the first year in which the AER-approved Cost Allocation Method[102] has been applied to Power and Water's audited opex. The use of 2017–18 expenditure therefore avoids consistency issues such as the need for backcasting of 2013–16 expenditure under its new Cost Allocation Method.

We consider that the use of the decrement approach is, in principle, not unreasonable. However, we have maintained our use of the increment approach as the primary method to develop our alternative estimate. This is because in drawing on expenditure across multiple years, it minimises the chance for anomalies in any one year to unduly influence base opex, while also ensuring that an allowance is made for incremental recurrent costs. We have also taken into account the change to the new Cost Allocation Method in 2017–18, as described below.

However, as a cross-check we developed our own estimate using the decrement approach. As set out below, both methods produce very similar estimates which provides confidence that the alternative estimate developed under the increment approach is reasonable.

Our alternative estimate under the increment approach

To develop our alternative estimate of base opex under the increment approach we:

- used average network overhead opex over the period 2013–14 to 2015–16[103] as a starting point (referred to as the "2013–16 starting point"), backcast under its current capitalisation policy.[104] This level of expenditure represents the costs Power

98 Power and Water, *SCS Opex Base Year Justification 2019-20 to 2023-24*, 29 November 2018, pp. 51–52.

99 Power and Water, *SCS Opex Base Year Justification 2019-20 to 2023-24*, 29 November 2018, p. 59.

100 Power and Water, *SCS Opex Base Year Justification 2019-20 to 2023-24*, 29 November 2018, pp. 51–52.

101 Power and Water, *response to AER information request IR041,* 4 January 2019, Q1.

102 Power and Water Corporation, *2017, Cost Allocation Method for Distribution Services v1.0.*

103 For the corporate allocations sub-category, we used an average over 2016–17 to 2017–18, since Power and Water were not able to backcast this sub-category's opex under its new (2017–18) Cost Allocation Method. Based on information we received from Power and Water, we found that the change from its old to its new Cost Allocation Method did not affect the opex amounts for all other sub-categories of network overheads opex.

104 As explained in Box 1 of the draft decision, 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 this capitalisation approach. Power and Water, *response to AER information request IR010,* 3 May 2018, Q1.

and Water incurred historically to meet its electricity supply obligations adjusted for estimated capitalisation

- examined the main drivers of increased costs in 2017–18 to determine whether they will be recurrent and continue in the next regulatory control period. This obtains the increment that we add to the 2013–16 average network overhead opex
- applied a 'top-down' efficiency adjustment of 10 per cent, reflecting our concerns around the efficiency of Power and Water's network overheads expenditure (see the transition path discussion below).

Using the increment approach, the alternative estimate of base year opex for network overheads is $25.2 million ($2018–19), which is $3.7 million ($2018–19) less than proposed by Power and Water. The make-up of this estimate is set out in Table 6-6.

Table 6-6 Alternative estimate of base year network overheads – increment approach

Cost sub-category	Average costs 2013-14 to 2015-16	Recurrent costs	AER - alternative estimate (average plus recurrent costs less efficiencies)	Power and Water - revised regulatory proposal[105]
Corporate allocations	3.6	0.0	3.6	3.3
Professional fees	0.6	2.4	3.1	4.4[106]
Service Level Agreements	3.3	0.0	3.3	2.8
Personnel costs	11.3	2.1	13.4	16.8
Vehicles	0.5	0.0	0.5	0.5
Other	4.0	0.0	4.0	4.1
Total	23.4	4.5	27.9	31.9
Less 10% top down efficiency			-2.7	-3.1
Total – efficiency adjusted			25.2	28.8

Source: Power and Water, *SCS Opex Base Year Justification 2019-24*, and AER analysis.

As shown in Table 6-6, we consider that recurrent costs in 2017–18 total $4.5 million ($2018–19). This is comprised of $2.4 million ($2018–19) for professional fees and $2.1 million ($2018–19) for personnel costs, which we discuss below. Consistent with

[105] Power and Water, *Response to AER information request IR041,* 18 January 2019, Q5.

[106] Note that this is $4.4m ($2018-19) based on our calculation using Power and Water's data.

our draft decision[107], we did not consider that expenditure in 2017–18 on corporate allocations, service level agreements (SLAs), vehicles, or other required incremental costs compared with the 2013–16 starting point.[108]

Professional fees

The increment of $2.4 million ($2018–19) for recurrent professional fees is comprised of two components. Firstly, $2.3 million ($2018–19) of professional fees incurred in 2017–18 that we consider to be recurrent and not already captured in the 2013-16 starting point. Secondly, $0.2 million ($2018–19) on a range of recurrent activities that Power and Water incurred in *2016-17* on which we do not have information for 2017-18, but which we included in the draft decision.[109] [110]

In 2017–18, Power and Water incurred a total of $6.5 million ($2018–19) of expenditure on professional fees.[111] In its revised proposal, Power and Water examined five sub-categories that it considered relevant for the professional fees it expects to incur in the 2019–24 regulatory control period:

- 2024–29 Distribution Determination
- NT Transitional Negotiations and Jurisdictional Code Review
- Regulatory obligations / Transition to compliance
- Regulatory Information Notice
- Business as usual. [112]

In developing our alternative estimate of network overheads base opex, we have adopted this breakdown of activities as proposed by Power and Water, and made our assessment of the recurrent portion of these expenditures (which we require for establishing the 2017–18 increment) which are *not already* incorporated into the 2013-16 period-average starting point. This essentially mirrors the analytical step undertaken by Power and Water,[113] as described in its revised proposal.[114] The difference between the amounts for professional fees in our alternative estimate and the revised proposal reflects differing views on the degree to which expenditure is considered recurrent.

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107 AER, *Draft Decision, Power and Water Corporation Distribution Determination 2019 to 2024, Attachment 6, Operating Expenditure*, September 2018, pp. 51–52.

108 Out of these categories, compared to the 2013–16 average, only 'Other' saw an increase in 2017–18, which was not material.

109 AER, *Draft Decision, Power and Water Corporation Distribution Determination 2019 to 2024, Attachment 6, Operating Expenditure, September 2018*, pp.48–53.

110 This includes a small allowance for a jurisdictional code review program, discussed further below.

111 Power and Water, *SCS Opex Base Year Justification 2019-20 to 2023-24*, 29 November 2018, p. 53.

112 Power and Water, *SCS Opex Base Year Justification 2019-20 to 2023-24*, 29 November 2018, p. 53.

113 Noting that Power and Water employed this approach in the context of its decrement approach, whereby the non-recurrent portion is deducted from 2017–18 professional fees (leaving recurrent professional fees). Both the increment and decrement approach make distinctions between recurrent and non-recurrent costs in 2017–18.

114 Power and Water, *SCS Opex Base Year Justification 2019-20 to 2023-24*, 29 November 2018, pp. 51–52.

Our calculation of $2.3 million ($2018–19) for recurrent professional fees incurred in 2017–18 and comparison to Power and Water's actual 2017–18 and proposed expenditure is shown in Table 6-7.

Table 6-7 Recurrent professional fees

Professional fees	Actual expenditure in 2017-18	Power and Water revised proposal: recurrent	AER final decision: recurrent	Difference
2024-29 Distribution Determination	3.9	1.8	1.8	0.0
NT Transitional Negotiations and Jurisdictional Code Review	0.4	0.2	-	-0.2
Regulatory obligations / Transition to compliance		1.4	-	-1.4
Regulatory Information Notice	1.0	0.5	0.5	0.0
Business as usual	1.2	0.6	-	-0.6
Recurrent expenditure	N/A	4.4	2.3	-2.2

Source: Power and Water, *SCS Opex Base Year Justification 2019-24*, and AER analysis.

We discuss our findings under each of these sub-categories below.

<u>2024–29 Distribution Determination</u>

This sub-category is for expenditure relating to preparation of the 2024–29 price reset. Consistent with Power and Water's proposal, our estimate has been informed by actual opex in 2017-18 relating to the preparation of the 2019–24 price reset. We have accepted the amount of $1.8 million ($2018–19) Power and Water proposed as recurrent.[115] We agree with Power and Water's view of recurrent costs and our view is that this expenditure would not be incorporated in the 2013–16 starting point. We have continued our draft decision approach of incorporating 60 per cent (3/5th) of the recurrent base year expenditure into base opex. This is on the basis that preparation for the next reset primarily takes place in 3 of the 5 years of each regulatory control period. Power and Water also adopted this approach in its revised proposal.[116]

[115] Power and Water, *SCS Opex Base Year Justification 2019-20 to 2023-24*, 29 November 2018, p. 53.
[116] Power and Water, *SCS Opex Base Year Justification 2019-20 to 2023-24*, 29 November 2018, p. 54.

NT Transitional Negotiations and Jurisdictional Code Review

Power and Water has been involved in negotiations with the Northern Territory's Department of Treasury and Finance about the Northern Territory's transition to the NEL and NER. Power and Water submitted that it is involved in these negotiations to ensure that bespoke instruments and differential rules suitable for the NT are developed.[117]

We maintain our view from the draft decision that Power and Water will have largely completed transition negotiations by the commencement of the 2019–24 regulatory control period.[118] We therefore do not consider any of the related professional fees incurred in 2017–18 to be recurrent.

Regulatory obligations/transition to compliance

Power and Water stated that it faces a range of incremental obligations under the NT NER, particularly in relation to connections and planning.[119] In order to estimate the costs of these activities, Power and Water reallocated some of the professional fees expenditure that it incurred under the 2019-24 reset and NT Transitional Negotiations Jurisdictional Code Review sub-categories to this sub-category.

Power and Water notes in its revised proposal that it accepted our draft decision to reject its proposed step changes in relation to connections and planning on the basis that its revised base opex is sufficient to cover (inter alia) the costs underpinning the step changes included in its initial proposal.[120] We have assessed this sub-category of costs in a substantively similar manner to the step change assessment in the draft decision. This essentially considers the extent to which the activities and associated costs are recurrent, i.e. material and incremental to business-as-usual.

Power and Water submitted further information to support its view that these activities are material and incremental to its current obligations.[121] For example, under planning, it notes that it is not currently required to analyse its demand forecasts to the degree required under Chapter 5 of the NT NER.[122]

However, we do not consider that Power and Water has made the case for the inclusion of these costs, and maintain our draft decision to reject their incorporation into forecast opex. In particular, we consider the connections process under Chapter 5A of the NT NER is broadly comparable to the process under the relevant (ENTPA) Act, and that the planning requirements constitute standard planning practices and/or are not new requirements imposed by the NT NER. To the extent there are differences

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117 Power and Water, *SCS Opex Base Year Justification 2019-20 to 2023-24*, 29 November 2018, p. 55.

118 AER, *Draft Decision, Power and Water Corporation Distribution Determination 2019 to 2024, Attachment 6, Operating Expenditure,* September 2018, pp. 49–50.

119 Power and Water, *SCS Opex Base Year Justification 2019-20 to 2023-24*, 29 November 2018, pp. 55–57.

120 Power and Water, *SCS Opex Base Year Justification 2019-20 to 2023-24*, 29 November 2018, p. 55.

121 Power and Water, *Response to AER information request IR041,* 15 January 2019, Q7 and Attachment A.

122 Power and Water, *SCS Opex Base Year Justification 2019-20 to 2023-24*, 29 November 2018, p. 56.

(i.e. to prepare the annual planning report and demand management document) we maintain our finding in the draft decision that Power and Water's overall staffing levels are sufficient to absorb these additional functions.

Further, we note that Power and Water did not provide a bottom-up build of the associated costs, but rather estimated the level of these costs through re-allocation of some proportion of its non-recurrent component of its professional fees, as noted above. We consider that this method does not provide a robust forecast of the costs for this activity.

<u>Regulatory Information Notice</u>

Power and Water spent $1.0 million ($2018–19) in 2017–18 on professional fees in relation to the preparation and external audit of its first AER RINs.[123] Taking into account the one-off nature of some elements of this activity, it proposed that 50 per cent of these costs are recurrent over the 2019–24 period.[124]

We accept the recurring need for these costs going forward and have adopted 50 per cent as representing recurrent costs.

<u>Business as usual</u>

Based on information from Power and Water, we understand that this sub-category relates to a range of activities, such as annual pricing submissions, workplace reviews and assistance with the development of standards and planning documentation. [125] We have not included this amount under the increment approach because we consider that business-as-usual activities are already effectively incorporated into the 2013–16 starting point.

Personnel costs

We have included an increment of $2.1 million ($2018–19) for personnel costs. These costs relate to staff in the regulatory team and related timesheet costs. [126] [127] We consider this level of costs is reflective of ongoing requirements. Given the material increase in regulatory obligations since 2015–16, these costs would not be reflected in the 2013–16 average.

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123 Power and Water, *SCS Opex Base Year Justification 2019-20 to 2023-24*, 29 November 2018, p. 53.

124 Power and Water, *SCS Opex Base Year Justification 2019-20 to 2023-24*, 29 November 2018, p. 53.

125 Power and Water, *SCS Opex Base Year Justification 2019-20 to 2023-24*, 29 November 2018, p. 54.

126 Power and Water*, Response to AER information request IR051, 22* February 2019, Q2, p. 2 and Power and Water*, Response to AER information request IR053,* 5 March 2019, Q1, p. 1.

127 Timesheet costs are for staff that sit in teams outside of Network Regulation but who have charged their time to the Network Regulation team as they are working on regulatory matters. In 2017-18 there was a significant increase in the number of staff working on the reset and charging their time to the Network Regulation Team. As for professional costs, we consider 3/5th of these costs to be recurrent.

Top-down efficiency of 10 per cent

We have applied a top-down efficiency adjustment of 10 per cent to our alternative estimate of recurrent network overheads costs.

In its revised proposal Power and Water made a 10 per cent efficiency adjustment to its estimate of recurrent network overheads opex. It noted that whilst it was yet to define the individual initiatives that would be implemented to achieve these efficiency targets, several of its priority projects, such as its Target Operating Model and ICT capital program, will be essential in realizing these efficiencies.[128] Further, in its initial proposal it submitted there appeared to be room for improvement in its network overheads, and notionally allocated half of its proposed 10 per cent base year efficiency adjustment to it. [129]

We accept a 10 per cent efficiency adjustment as reasonable as it is supported by the results of our PPI benchmarking and taking into account the impact of its operating environment. As can be seen in Appendix A, Figure A.6, Power and Water's network overheads (on a totex basis) per customer are considerably higher than most of its peers. Of particular concern is that Power and Water is more than double the level of the distributor with the closest customer density (TasNetworks). Whilst Power and Water's operating environment may have some impact on its network overhead opex, we do not consider it likely that this would explain the totality of the gap to its peers.[130]

As discussed further below, we have considered the transition costs associated with achieving these efficiencies (along with those for corporate overheads) over the five years of the 2019–24 regulatory control period. We consider this allows for the efficient and practical transition to a lower opex base, while maintaining the quality, reliability, security and safety of services.[131]

Our alternative estimate under the decrement approach

As a cross-check on the results under the increment approach, we have also developed an alternative estimate under the decrement approach proposed by Power and Water. The main difference to the increment approach is that it uses actual 2017–18 network overheads expenditure and removes non-recurrent costs. Under this approach, our alternative estimate of base opex for network overheads is $25.5 million ($2018–19), which is $3.4 million ($2018–19) less than proposed by Power and Water and not materially different to the alternative estimate under the increment approach ($25.2 million ($2018–19)). The make-up of this estimate is set out in Table 6-8.

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128 Power and Water, *SCS Opex Base Year Justification 2019-20 to 2023-24*, 29 November 2018, p. 59.

129 Power and Water, *2016 Opex Base Year Justification 2019-20 to 2023-24*, 16 March 2018, pp. 48, 49, 87.

130 Our 2018 Annual Benchmarking Report noted cyclones, extreme heat and humidity, and an NT labour cost premium as unique factors that are likely to drive materially higher electricity distribution costs in the NT.

131 Power and Water included these efficiencies in its base year, but noted they would be achieved over the 2019–24 regulatory control period, with it funding the transition costs. Power and Water, *SCS Opex Base Year Justification 2019-20 to 2023-24*, 29 November 2018, pp.16–17.

Table 6-8 Alternative estimate of base year network overheads - decrement approach

Cost sub-category	Actual 2017-18	Non-recurrent costs	AER - alternative estimate (actual less non-recurrent less efficiencies)	Power and Water - revised regulatory proposal
Corporate allocations	3.2	0.0	3.2	3.3
Professional fees	6.5	3.6	2.9	4.4[132]
Service Level Agreements	2.8	0.0	2.8	2.8
Personnel costs	21.8	7.0	14.8	16.8
Vehicles	0.5	0.0	0.5	0.5
Other	4.1	0.0	4.1	4.1
Total	38.8	10.7	28.2	31.9
Less 10% top down efficiency			-2.7	-3.1
Total – efficiency adjusted			25.5	28.8

Source: Power and Water, *SCS Opex Base Year Justification 2019-24*, and AER analysis.

The main differences in our removals for non-recurrent costs compared to those proposed by Power and Water relate to professional fees and personnel costs.

In relation to professional fees, we have removed a further $1.6 million ($2018–19) of non-recurrent costs compared to Power and Water's proposal. The difference between our alterative estimate and Power and Water's proposal essentially reflects the analysis as above in relation to professional fees under the increment approach.

Personnel costs increased by $7 million ($2018–19) in 2017–18.[133] Power and Water explained that total personnel costs across the corporation did not materially change in 2017–18. Rather, the main driver of the increase was an increased allocation of personnel costs to network overheads opex, notably due to an unusually low booking of labour to capex during 2017–18. To account for this, Power and Water removed $5.2 million ($2018–19) from 2017–18 network overheads opex in developing its base opex.[134] We accept that cost allocation issues adequately explained $5.2 million ($2018–19) of the increase in personnel costs, and we incorporated that removal into our alternative estimate under the decrement approach. However, we have also

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132 Note that this is $4.4m ($2018-19) based on our calculation using Power and Water's data.

133 Power and Water, *SCS Opex Base Year Justification 2019-20 to 2023-24*, 29 November 2018, p. 50.

134 Power and Water, *SCS Opex Base Year Justification 2019-20 to 2023-24*, 29 November 2018, pp. 57–58.

removed the remaining $1.9 million ($2018–19) increase, as we did not consider that an adequate justification was provided by Power and Water for this increase.[135]

As with the increment approach, we have also applied a top-down efficiency adjustment of 10 per cent.

Corporate overheads

We have accepted Power and Water's proposed corporate overheads opex of $12.5 million ($2018–19) as this reflects our alternative estimate (which uses the same estimation approach as Power and Water).[136] [137] This incorporates the 10 per cent efficiency adjustment Power and Water applied to 2017–18 actual corporate overheads opex.[138] We have also considered the efficient one-off transition costs that Power and Water will need to incur to achieve this lower level of opex (see the section below on transition costs for network and corporate overhead efficiencies).

We have reviewed Power and Water's base year corporate overheads in detail, rather than rely on revealed cost in the base year, because:

- They make up a significant component (15.6 per cent) of base year opex
- With the change in base year from 2016–17 to 2017–18, Power and Water's *actual* corporate overheads in the base year increased by $5.6 million ($2018–19), or 69.3 per cent. See Figure 6-10. The increase in the *proposed* corporate overheads (taking into account its 10 per cent efficiency adjustments) from the initial to the revised proposal is also significant, at 52.6 per cent[139]
- Power and Water was not subject to an EBSS over the current regulatory period (meaning less incentive to control expenditure in the base year)
- It does not benchmark well, as illustrated in Appendix A, Figure A.7, with corporate overhead totex per customer over the period 2013–14 to 2017–18 being relatively higher than most of its peers, including those with similar customer densities. We note that Power and Water's operating environment may have some impact.

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[135] Power and Water, *Response to AER information request IR041,* 16 January 2019, Q3; Power and Water, *response to AER information request IR041,* 18 January 2019, Q5; Power and Water, *response to AER information request IR049,* 20 February 2019, Q1; Power and Water*, response to AER information request IR051,* 20 February 2019, Q1.

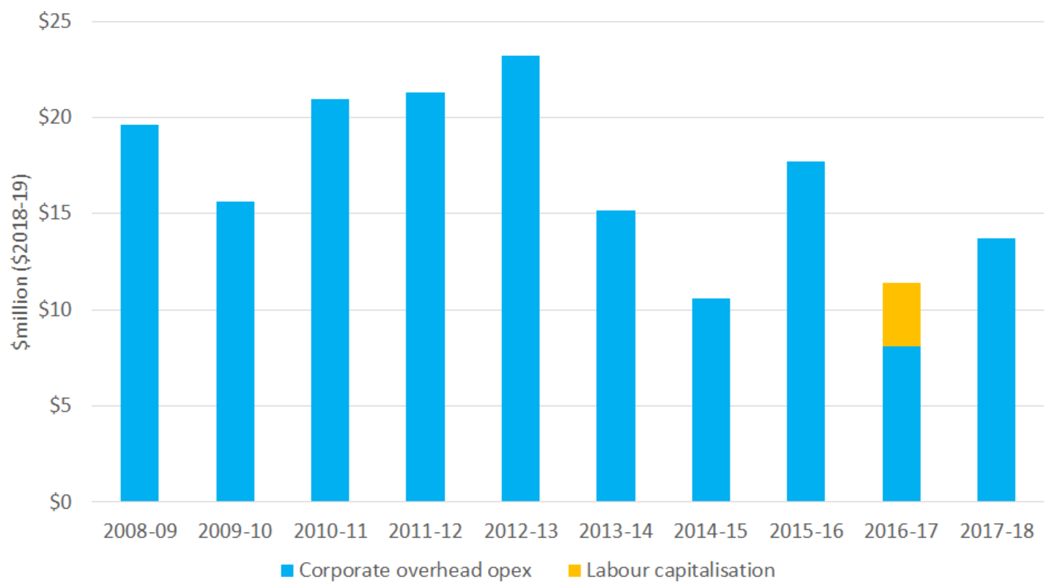
[136] Our exact number is slightly different due to differing inflation assumptions applied to the nominal base year amount.

[137] Power and Water, *SCS Opex Base Year Justification 2019-20 to 2023-24*, 29 November 2018, p.67.

[138] Power and Water, *SCS Opex Base Year Justification 2019-20 to 2023-24*, 29 November 2018, pp.66-67.

[139] These increases take into account the change in the Cost Allocation Method.

Figure 6-10 Power and Water's corporate overhead opex ($2018–19)



Source: Power and Water, Category Analysis RIN, 22 May 2018 and 31 October 2018; AER analysis.

In the draft decision, we noted that Power and Water intended to apply a revised corporate Cost Allocation Method from 2017–18, and also that our benchmarking analysis indicated that Power and Water's average corporate overhead (totex per customer) were higher than most distributors.[140] We did not apply an efficiency adjustment to corporate overheads, noting that Power and Water's corporate overhead opex had decreased over time and it had programs in place to examine opportunities for further efficiencies.[141] However, we did note that we may examine this cost category in more detail once Power and Water had provided its revised proposal and updated information.[142]

In its revised proposal and through the information gathering process, Power and Water submitted information that showed that the increase from 2016–17 to 2017–18 in corporate overheads is largely attributable to cost allocation changes consistent with its updated Cost Allocation Method.[143] More corporate overheads expenditure was being allocated to the Power Networks business unit within Power and Water Corporation.

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[140] AER, *Draft Decision, Power and Water Corporation Distribution Determination 2019 to 2024, Attachment 6, Operating Expenditure*, September 2018, pp. 53–55.

[141] AER, *Draft Decision, Power and Water Corporation Distribution Determination 2019 to 2024, Attachment 6, Operating Expenditure*, September 2018, pp. 5–-57.

[142] AER, *Draft Decision, Power and Water Corporation Distribution Determination 2019 to 2024, Attachment 6, Operating Expenditure, September 2018*, p. 57.

[143] Power and Water, *SCS Opex Base Year Justification 2019-20 to 2023-24*, 29 November 2018. pp. 64–65 and Power and Water, *response to IR041,* 11 January 2019, Q12.

Based on our review of the information received from Power and Water, we accept that the significant increase in audited actual corporate overheads in 2017–18 is as a result of the change in cost allocation of total corporate overheads between business units. Given our prior approval of Power and Water's Cost Allocation Method, we do not assess the appropriateness of the cost allocation methodology itself in this decision.

We have, however, considered whether the *level* of the corporation's total corporate overheads is efficient or not. To the extent that this level is considered inefficient, we would have concerns at the level of corporate overheads allocated to opex, even where we accept the methodology for allocating these costs.

In the draft decision[144], we noted that Power and Water's Board's Strategic Directions paper 2016–20[145], and statements made by Power and Water's previous chair in a 2016 Budget Estimate hearing[146], indicated that Power and Water Corporation (as a whole, including its affiliated businesses) had, and was acknowledged to have, comparatively high corporate overheads. Further, we noted that the Board's Strategic Directions paper included a target corporate overhead to total opex ratio of 15 per cent, compared to a forecast ratio for 2015–16 of over 25 per cent. The commentary in that paper noted that 15 per cent was chosen as the target as it is the median ratio out of the twelve utilities sampled.

As a part of our efficiency considerations we have examined Power and Water's progress against this internal Board target ratio of 15 per cent.

Based on the information provided by Power and Water (total corporate overheads and total opex for the corporation) it has largely been below the 15 per cent ratio over the period 2013–14 to 2017–18. [147] [148] This is illustrated in Table 6-9.

Table 6-9 Power and Water Corporation total corporate costs to total opex ($million, 2018–19)

	2013-14	2014-15	2015-16	2016-17	2017-18
Total corporate costs	49.3	59.8	73.4	56.4	54.6
Total opex	593.9	457.6	465.4	468.5	454.9
Ratio	8.3%	13.1%	15.8%	12.0%	12.0%

Source: Power and Water, response to IR041 and AER analysis.

144 AER, *Draft Decision, Power and Water Corporation Distribution Determination 2019 to 2024, Attachment 6, Operating Expenditure,* September 2018, p. 56.

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

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

147 Power and Water, *SCS Opex Base Year Justification 2019-20 to 2023-24*, 29 November 2018. p. 64 and Power and Water, r*esponse to IR041*, 11 January 2019, Q.13 and 14.

148 This excludes depreciation, which is consistent with the basis for the ratio in the Board's Strategic Directions paper.

This information on Power and Water's performance against its Board's target corporate overhead to total opex ratio of 15 per cent does not suggest that corporate overhead opex is too high relative to its internal target.

In its revised proposal Power and Water made a 10 per cent efficiency adjustment to its estimate of recurrent corporate overheads opex, using the same rationale as for network overheads (likely to be realised by priority projects such its Target Operating Model and ICT capital program).[149]

We accept a 10 per cent efficiency adjustment as reasonable as it is supported by the results of our PPI benchmarking and taking into account the impact of its operating environment. As can be seen in Appendix A Figure A.7, Power and Water's 2013–17 period-average corporate overheads (on a totex basis) per customer are considerably higher than most of its peers (and the third-highest in the NEM). Of particular concern is that Power and Water is almost double the level of the next highest distributor with a similar customer density (Powercor). Whilst Power and Water's operating environment may have some impact on its corporate overhead opex, we do not consider it likely that this would explain the totality of the gap to its peers.[150]

On balance, we therefore consider that an efficiency adjustment of 10 per cent is justified in this case.

Transition costs associated with network and corporate overhead efficiencies

Power and Water proposed to apply the 10 per cent network and corporate overhead efficiencies to the base year. Power and Water noted that there will be a cost of realising the benefits from the efficiency enabling initiatives in the Target Operating Model and its ICT capital program, which it considers essential to achieve its efficiency targets. However, it proposed to proactively fund these costs. [151]

We have considered the transition costs that will need to be incurred by Power and Water in achieving its efficiency targets and lower network and corporate overheads cost. We accept that a prudent operator may not be able to achieve a lower level of opex without incurring transition costs. These costs can be characterised, depending on the circumstances, as efficient costs required by a prudent operator to achieve the opex objectives, rather than a case of consumers funding an inefficient level of costs.

Given this is the first time we have regulated Power and Water under the NTNER, and the likely nature of the 10 per cent network and corporate overhead efficiencies, which may require some structural changes, we consider it is appropriate to include the efficient costs of transitioning to a lower opex base. Power and Water did not provide an estimate for the quantum of costs it expects to incur in this transition. This was

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[149] Power and Water, *SCS Opex Base Year Justification 2019-20 to 2023-24*, 29 November 2018. pp. 66–67

[150] Our 2018 Annual Benchmarking Report noted cyclones, extreme heat and humidity, and an NT labour cost premium as unique factors that are likely to drive materially higher electricity distribution costs in the NT.

[151] Power and Water, *SCS Opex Base Year Justification 2019-20 to 2023-24*, 29 November 2018, pp. 59–61, 66–67.

because it proposed that it, rather than its customers, would proactively fund transition costs, noting that this was in the context of it applying a 0 per cent per year opex productivity forecast.[152] We accept that such estimation[153] would be difficult for Power and Water given that it has not yet identified the specific initiatives that it will use to achieve the efficiencies or transform the business.[154]

As such, we apply a gradual (linear) path of reductions to network and corporate overheads, such that a 10 per cent efficiency is fully realised by the last year of the 2019–24 regulatory control period. This gradual application reflects that we expect transition costs to decline over time. This means total opex is $8.2 million ($2018–19) higher over the 2019–24 regulatory control period compared to an alternative estimate that does not allow for these transition costs.

The ETU submitted it does not support Power and Water's assertion that it can successfully introduce a 10 per cent operational expenditure efficiency target, considering the target arbitrary.[155] The Northern Territory Treasurer also observed that it was unclear whether Power and Water had capacity to make further significant reductions beyond those included in its revised proposal.[156] As outlined above, Power and Water's network and corporate overheads do not benchmark well, and while these are partial measures, and its operating environment may have some impact, we do not consider this would explain the totality of the gap to its peers. Given this, we consider the efficiency targets proposed by Power and Water should be included in our alternative estimate. However, introducing these efficiencies by the end of the 2019–24 regulatory control period enables a practical transition to a lower opex base, while maintaining the quality, reliability, security and safety of services to Power and Water's customers.

Labour

For the final decision we have not undertaken analysis further to that included in the draft decision.[157] This reflects our position in the draft decision where we noted the possible overlap between our cost category and labour cost review which could result in double counting of efficiency improvements. Given this, we have focused our analysis for the final decision on the cost category assessment as set out in the sections above.

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152 Power and Water, *SCS Opex Base Year Justification 2019-20 to 2023-24*, 29 November 2018, pp. 16–17, 61, 67.

153 We also note the difference with our recent decision on Ausgrid, which contained the precise quantum of Ausgrid's transition costs. However, these costs were in respect of costs incurred in the past, and hence the quantum was already known.

154 Power and Water, *response to AER information request IR041*, 18 January 2019, Q10.

155 Electrical Trades Union, *Power and Water revised regulatory proposal 2019–24*, 11 January 2019, p. 3.

156 Northern Territory Treasurer*, letter in relation to 2019-24 draft revenue determination for Power and Water's network business*, 8 January 2019, pp.1–4.

157 AER, *Draft Decision, Power and Water Corporation Distribution Determination 2019 to 2024, Attachment 6, Operating Expenditure*, September 2018, pp. 57–62.

The ETU noted we may wish to undertake further assessment of labour cost, including a comparative assessment.[158] As outlined above, for the purpose of the final decision we have relied on our cost category assessment to establish efficient costs.

6.4.1.5 Rolling forward base year

Under the base-step-trend 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.[159]

We have not applied the Guideline formula to estimate Power and Water's opex in 2018–19. Rather, consistent with our draft decision, we have rolled forward our efficient level of base year (2017–18) opex, escalating it by the rate of change.[160] 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 are intrinsically related.[161] 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.[162]

Power and Water adopted this approach in its revised proposal.

[158] Electrical Trades Union, *Power and Water revised regulatory proposal 2019–24*, 11 January 2019, p. 3.

[159] 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.

[160] AER, *Draft Decision, Power and Water Corporation Distribution Determination 2019 to 2024, Attachment 6, Operating Expenditure*, September 2018, p. 63-64.

[161] 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)

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

6.4.2 Rate of change

We trend the base opex forward to account for the forecast growth in prices, output and productivity. We refer to this as the rate of change. In line with our draft decision and Power and Water's revised proposal, we have applied the rate of change to adjusted base opex from the base year onwards.[163]

Power and Water has largely adopted the approach in our draft decision to forecasting the rate of change in relation to price and output growth. We apply a different opex productivity growth factor to Power and Water.

We have forecast an average annual rate of change of 0.54 per cent, compared to Power and Water's forecast of 1.02 per cent.[164] The reasons for our forecast, and the difference compared to Power and Water's forecast, are set out below, but primarily reflect that we have applied opex productivity growth of 0.5 per cent per year as compared to the 0 per cent per year Power and Water included in its revised proposal.

6.4.2.1 Forecast price growth

We have included forecast real average annual price growth of 0.43 per cent in developing our alternative opex estimate. This increases base opex by $4.6 million ($2018–19) over the next regulatory control period. In contrast, Power and Water forecast price growth of 0.36 per cent.[165]

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 the average growth in the wage price index for the NT utilities industry forecast by Deloitte Access Economics and Power and Water's consultant, BIS Oxford Economics. Consistent with our standard approach, we consider the average of two independent forecasts represents a realistic expectation of the cost inputs required to provide network services. Power and Water adopted this approach in its revised proposal.[166] Since our draft decision, we received an updated wage price index forecast from Deloitte Access Economics, which increased slightly in the early years of the 2019–24 regulatory control period, and incorporated this into our alternative estimate[167]
- we forecast non-labour price growth in line with CPI, which was also adopted by Power and Water in its revised proposal.[168]

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163 This is appropriate in the absence of an EBSS. We apply the rate of change from the final year of the current regulatory period when an EBSS is in place.

164 Power and Water, SCS Opex Model, 29 November, 2018; AER analysis.

165 Power and Water, SCS Opex Model, 29 November, 2018; AER analysis.

166 Power and Water, *Revised regulatory proposal 1 July 2019 to 30 June 2024*, 29 November 2018, pp.39–40.

167 Deloitte Access Economics, *Labour Price Growth Forecasts, Prepared for the Australian Energy Regulator, 27 March 2019*, pp. 47–55.

168 Power and Water, SCS Opex Model, 29 November, 2018.

CCP13 raised the BIS Oxford Economics wage price index forecasts Power and Water submitted. It noted they are for real increases significantly above the Deloitte Access Economics forecasts and that it doubted their credibility given the forecast difficult economic conditions likely to prevail in the Territory over 2019–24.[169] We note that Deloitte Access Economics' wage price index forecasts have increased slightly compared to the forecasts used in the draft decision and are now positive for the entire 2019–24 regulatory control period.[170] While the Deloitte Access Economics forecast are lower than those from BIS Oxford Economics, we consider that averaging these produces a reasonable wage price index forecast.

6.4.2.2 Forecast output growth

We have included forecast real average annual output growth of 0.62 per cent in developing our alternative opex estimate. This increases base opex by $8.0 million ($2018–19) over the next regulatory control period. In contrast, Power and Water forecast output growth of 0.66 per cent.[171]

For the purpose of our final decision, we have updated the weights we use in forecasting output growth in the draft decision. These weights were derived from the benchmarking models presented in our 2017 Annual Benchmarking Report for the period 2006-17, but for the final decision we have also included 2016–17 data.[172]

In our draft decision, we changed our approach in estimating output growth weights by using four benchmarking models, rather than simply the Cobb Douglas Stochastic Frontier Analysis (CD SFA) model we used in our previous decisions.[173]

Since our draft decision, we have published our 2018 Annual Benchmarking Report, presenting the four benchmarking models we used in our draft decision for the 2012–17 period.[174] We also presented the results of an additional benchmarking model for the first time, the Translog Stochastic Frontier Analysis (Translog SFA) for the 2012–17 period.[175] This represents an alternative approach to forecasting average output growth weights by using all five benchmarking models for the 2012–17 period.

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169 Consumer Challenge Panel, *Advice to the Australian Energy Regulator (AER), Consumer Challenge Panel Sub-Panel 13, Response to Power and Water Corporation revised proposal for a revenue reset for the 2019-24 regulatory period, Sub-Panel 13,* 11 January 2019, p. 12.

170 Deloitte Access Economics, *Labour Price Growth Forecasts, Prepared for the Australian Energy Regulator, 27 March 2019*, 27 March 2019, pp. 47–55.

171 Power and Water, SCS Opex Model, 29 November, 2018; AER analysis.

172 AER, *2017 Annual benchmarking report - Electricity distribution network service providers*, November 2017.

173 The four benchmarking models are the Cobb Douglas Stochastic Frontier Analysis, the Cobb Douglas Least Squares Econometrics, the Translog Least Squares Econometrics and the Opex Multilateral Partial Factor Productivity analysis.

174 Whilst not explicitly presented in the 2018 Annual Benchmarking Report, the benchmarking results of the four models we used in our draft decision for the 2006–17 period were contained in the supporting data files of the benchmarking report.

175 AER, *2018 Annual benchmarking report - Electricity distribution network service providers*, November 2018.

In its revised opex model, Power and Water adopted our draft decision approach of using the four benchmarking models to estimate output growth weights, with weights from the then-most recently available annual benchmarking report (2017) for the 2012–17 period.

For consistency, we have relied on the same benchmarking models as in our draft decision, but updated with 2016-17 data. While we have had regard to the results of the most recent annual benchmarking report, we have not relied on the additional Translog SFA model or the 2012–17 data set to estimate output growth weights.[176] We do not consider it appropriate at this point in the determination process to introduce another change in our approach to estimating output growth weights.

Table 6-10 shows the output specification and weights from each model as reflected in the 2018 Annual Benchmarking Report.

Table 6-10 Outputs specification and weights derived from economic benchmarking models for 2006–2017 (per cent)

Output	MPFP	SFACD	LSECD	LSETLG
Customer numbers	31.00	70.94	68.53	57.32
Circuit length	29.00	12.62	10.74	11.33
Ratcheted maximum demand	28.00	16.43	20.72	31.36
Energy throughput	12.00			

Source: AER analysis; Economic Insights, *Economic Benchmarking Results for the Australian Energy Regulator's 2018 DNSP Benchmarking Report,* November 2018.

The differences in the output growth weights adopted in Power and Water's revised opex proposal and our alternative estimate in terms of the impact on the opex forecast are negligible and do not contribute to a material difference in our opex forecasts.

6.4.2.3 Forecast productivity growth

We have included an annual opex productivity growth forecast of 0.5 per cent in our alternative estimate. As foreshadowed in our draft decision, we have undertaken an industry wide generic review on the opex productivity growth forecast. We have taken the outcome of this review into consideration when deriving our alternative estimate.

In our final decision of the opex productivity growth forecast review, we set out the analysis and evidence we have relied on to forecasting productivity growth.[177] We considered an opex productivity growth forecast of 0.5 per cent per year was a

[176] We must have regard to the most recent annual benchmarking report that has been published under the NER. It is an opex factor.

[177] AER, *Final decision - Forecasting productivity growth for electricity distributors*, March 2019.

reasonable forecast of the productivity growth that could be achieved by a prudent electricity distributor acting efficiently under business-as-usual conditions and should be adopted in our electricity distribution determinations going forward.

We have applied the annual opex productivity growth forecast of 0.5 per cent, as determined in the final decision of the review. As set out in *Forecasting productivity growth for electricity distributors*, the opex productivity growth forecast is not intended to capture the inefficiencies in the costs of an individual distributor (these are a part of our base year assessment outlined above).[178] It captures the sector-wide, forward looking, improvements in good industry practice that should be implemented by efficient distributors as part of business-as-usual operations.

In its revised proposal Power and Water forecast opex productivity growth of 0 per cent per year over the 2019–24 regulatory control period.[179] It stated this was largely because base opex had been adjusted to an efficient level and because recent industry wide economic benchmarking suggests productivity is flat. After finalising our opex productivity growth forecast review, we provided Power and Water with a further opportunity to make a submission on our proposed application of the 0.5 per cent annual forecast.[180] Power and Water did not make a submission.

We do not consider that Power and Water has justified a departure from our proposed approach of applying an opex productivity growth factor of 0.5 per cent per year in developing our alternative estimate. We separately assess base year efficiency and productivity and do not consider that because a business may need to make adjustments to its base opex to become efficient, that this precludes productivity growth. This reflects our view that beyond an efficient base, there is scope for further gains from improvements in good industry practice that should be implemented by efficient distributors as part of business-as-usual operations. For example, from the introduction of new technology and changes to management practices.

Further, our final decision for the opex productivity growth review sets out the evidence and basis for our 0.5 per cent forecast, including the industry specific evidence we have relied on.

CCP13 supported the application of the opex productivity growth forecast, noting that it expected the same opex productivity growth factor would apply to all networks irrespective of their position in relation to the frontier.[181]

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178 AER, *Final decision paper, Forecasting productivity growth for electricity distributors*, March 2019, pp. 8–11.

179 Power and Water, *Revised Regulatory Proposal, 1 July 2019 to 30 June 2024, 29 November 2019*, p. 40.

180 AER, Letter to Power and Water - the AER's operating expenditure productivity growth forecast for the 2019–24 distribution determination, 18 March 2019.

181 Consumer Challenge Panel, *Advice to the Australian Energy Regulator (AER), Consumer Challenge Panel Sub-Panel 13, Response to Power and Water Corporation revised proposal for a revenue reset for the 2019-24 regulatory period, Sub-Panel 13,* 11 January 2019, pp. 11–13.

6.4.3 Step changes

In its revised proposal, Power and Water accepted our draft decision to reject four of the five step changes in its initial proposal, and removed these from its revised proposal.[182] It did this on the basis that its revised base opex is sufficient to cover the costs of current regulatory obligations and those underpinning the step changes included in its initial regulatory proposal. As indicated above in section 6.4.1.4 - Network overheads, the bulk of those proposed step changes were included as proposed increases in base year opex. As discussed in that section, we do not consider the proposed associated costs to form part of recurrent and efficient base opex.

In its revised proposal, Power and Water proposed two step changes to base opex totalling $1.1 million ($2018–19) or 0.3 per cent of its total opex forecast:

- $0.9 million ($2018–19) in GSLs to fund an increase in GSL payments as a result of the revised GSL scheme under the Utilities Commission's Electricity Industry Performance Code (EIP Code)[183]
- $0.2 million ($2018–19) for a demand management capex/opex trade-off in relation to the deferral of augex at its Wishart zone sub-station.[184]

We have accepted both of these step changes and incorporated these into our alternative estimate of total opex.

A summary of our final decision for these step changes is outlined in Table 6-11.

Table 6-11 AER final decision on step changes ($million, 2018–19)

	2019–20	2020–21	2021–22	2022–23	2023–24	Total
GSLs	0.2	0.2	0.2	0.2	0.2	1.1
Wishart DM	0.03	0.03	0.03	0.03	0.05	0.2

Source: Power and Water 2017-18 Economic Benchmarking RIN; and Power and Water, *Revised regulatory proposal 1 July 2019 to 30 June 2024,* 29 November 2018 pp. 40-41. Note that the numbers in Table 4.5 in Power and Water's proposal are rounded to one decimal place. Power and Water's opex model contains the exact figures, which we have included in our alternative estimate.

6.4.3.1 Guaranteed service levels

We have included a step change of $1.1 million ($2018–19) for forecast GSL costs of complying with the NT's EIP Code. This, as explained below, is slightly higher than Power and Water's revised proposal.

[182] Power and Water, *Revised regulatory proposal 1 July 2019 to 30 June 2024*, 29 November 2018, p. 40.
[183] Power and Water, *Revised regulatory proposal 1 July 2019 to 30 June 2024*, 29 November 2018, pp. 40–41.
[184] Power and Water, *Revised regulatory proposal 1 July 2019 to 30 June 2024*, 29 November 2018, pp. 40–41.

Consistent with its initial proposal, Power and Water proposed a step change of $0.9 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 year) and the time to establish a new connection (extending the threshold from 10 to 5 days) for rural customers.[185]

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.

In Power and Water's "alternative" GSL forecast in its initial proposal, 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.[186] In our draft decision, we broadly accepted Power and Water's alternative GSL forecasting approach and applied it in our alternative estimate.[187] For the final decision, we have continued to apply this approach, with the addition of an extra year (2017–18) for calculating the period-average quantity of payments, as well updated inflation forecasts. The addition of this extra year marginally increased the average volumes, which accounts for the $0.1 million ($2018–19) increase as compared with Power and Water's proposal.[188]

Typically we forecast GSLs through a category specific forecast, and remove the actual costs incurred from the base year. As in its initial proposal, Power and Water forecast GSLs as a step change because there was a change in regulatory obligations.

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

[186] 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.

[187] However, we included two years rather than three years to calculate the average quantity of payments (i.e. we used 2015–16 to 2016–17). The impact of this change was minor. We noted that Power and Water had previously noted the 2014–15 data included some payments made in 2013–14, so based on this information we considered the 2014–15 data may be overstated and unreliable for forecasting purposes.

[188] Numbers do not add due to rounding.

Consistent with the draft decision, 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.

6.4.3.2 Wishart zone sub-station demand management solution

Power and Water proposed a step change of $0.2 million ($2018–19) for a demand management solution to be introduced as part of deferral of augex at Wishart zone substation.

Power and Water stated that it adopted the AER's draft decision on the Wishart zone substation demand management solution.[189] It explained that it had undertaken analysis of the potential demand management options, and that its proposed solution is to use small mobile generators to maintain reliability if a major asset fails in service. As this solution involves some opex (to run the small mobile generators), it has included this as a step change.

Based on analysis presented in the capex attachment (see Section B.2.3 of Attachment 5), we consider the proposed demand management is reasonable and part of an efficient solution that defers augmentation. We therefore accept this step change and have included the costs as proposed in our alternative estimate.

6.4.4 Category specific forecasts

6.4.4.1 Debt raising costs

Power and Water forecast debt raising costs of $2.6 million ($2018–19) over the 2019–24 regulatory control period.[190]

We have included a category specific forecast of $2.5 million ($2018–19) for debt raising costs. Power and Water did not incur debt raising costs in the base year opex[191] 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 the draft decision Attachment 3 on the rate of return.

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[189] Power and Water, *Revised regulatory proposal 1 July 2019 to 30 June 2024*, 29 November 2018, pp. 20 and 40.

[190] Power and Water, SCS Opex Model, 29 November, 2018.

[191] Power and Water*, response to AER information request IR031*, 18 July 2018, Q1(a,b).

6.4.5 Assessment of opex factors under the 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'.[192]

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:[193]

> 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 6-12 summarises how we have taken the opex factors into account in making our final decision to not accept Power and Water's proposed opex forecast.

Table 6-12 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 just transitioned to the NER and was not included in the 2018 benchmarking report as we were still in the process of examining Power and Water's benchmarking and regulatory data. While this limits our ability to use the benchmarking report, we have updated the PPI benchmarking used to inform our draft decision by including 2017–18 data for the non-Victorian businesses.
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 2017-18 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 revised proposal, we understand Power and Water sought feedback and direction from its Customer Advisory Council on how it should respond to the AER's draft decision and took into account feedback previously received in relation to vegetation management opex.
The relative prices of capital and operating inputs	We adopted price escalation factors that account for the relative prices

[192] NT NER, cl. 6.5.6(e).

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

Opex factor	Consideration
	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 proposed one step change which was involved a capex/opex trade-off. We have examined this and consider the proposed demand management and increased opex is part of an efficient solution that defers capex augmentation.
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. In the draft decision we have examined in detail Power and Water's contracts with System Control and the DCIS and did not find any information to suggest Power and Water has an incentive to agree to artificially inflated contract prices for services from the DCIS. We included average 2013–14 to 2015–16 SLA expenditure in our alternative estimate, which we consider reflects efficient SLA costs.
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 proposed a demand management solution as a part of its step changes. This involves increased opex which we consider is part of an efficient solution that defers capex augmentation. Power and Water also stated it accepts the AER's draft decision 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 of our draft decision). 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.

Our analysis has been updated from the draft decision to include 2017–18 (this has not changed any of our conclusions). We have used data across 2013–14 to 2017–18 for the non-Victorian distribution businesses, and 2013–14 to 2016–17 for the Victorian distribution businesses,[194] to account for one-off events that may not be reflective of a distributor's typical expenditure.

Figure A.1 presents average annual opex per customer over 2013–14 to 2017–18. Figures A.2 - A.7 present annual average expenditure in particular opex categories per unit of output (such as kilometres of circuit line length and customer numbers).[195]

Broadly, the PPI benchmarking results show Power and Water has considerably higher opex relative to 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 2017–18. 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.

194 This is because we do not yet have 2017-18 data for the Victorian businesses.

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

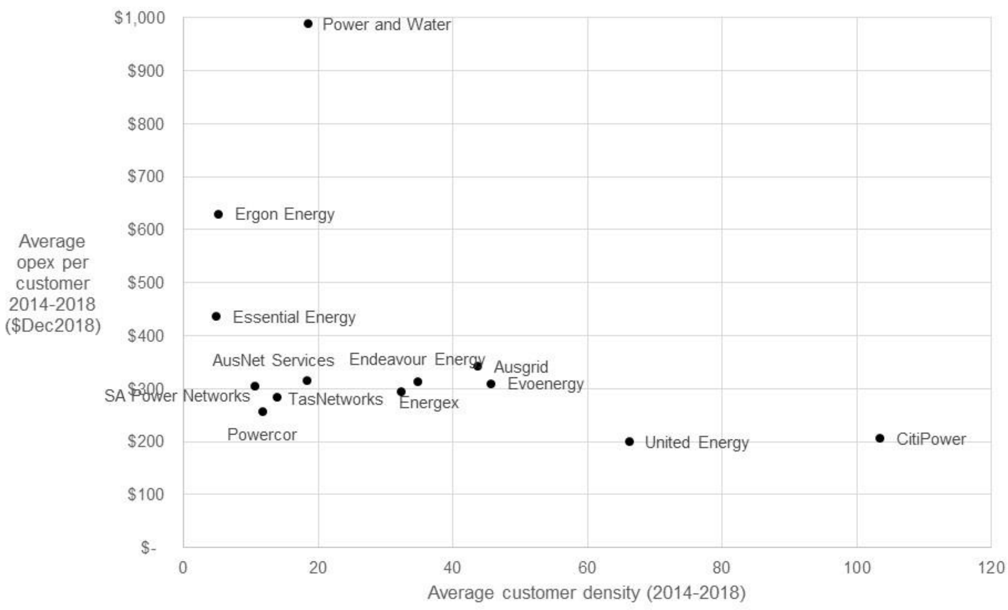
Table A.1 Summary of PPI benchmarking for Power and Water (2013–14 to 2017-18[196])

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

Source: Category analysis RINs across all distributors from 2013–14 to 2017–18; 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)



[196] We have used data across 2013–14 to 2017–18 for the non-Victorian distribution businesses, and 2013–14 to 2016–17 for the Victorian distribution businesses.

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

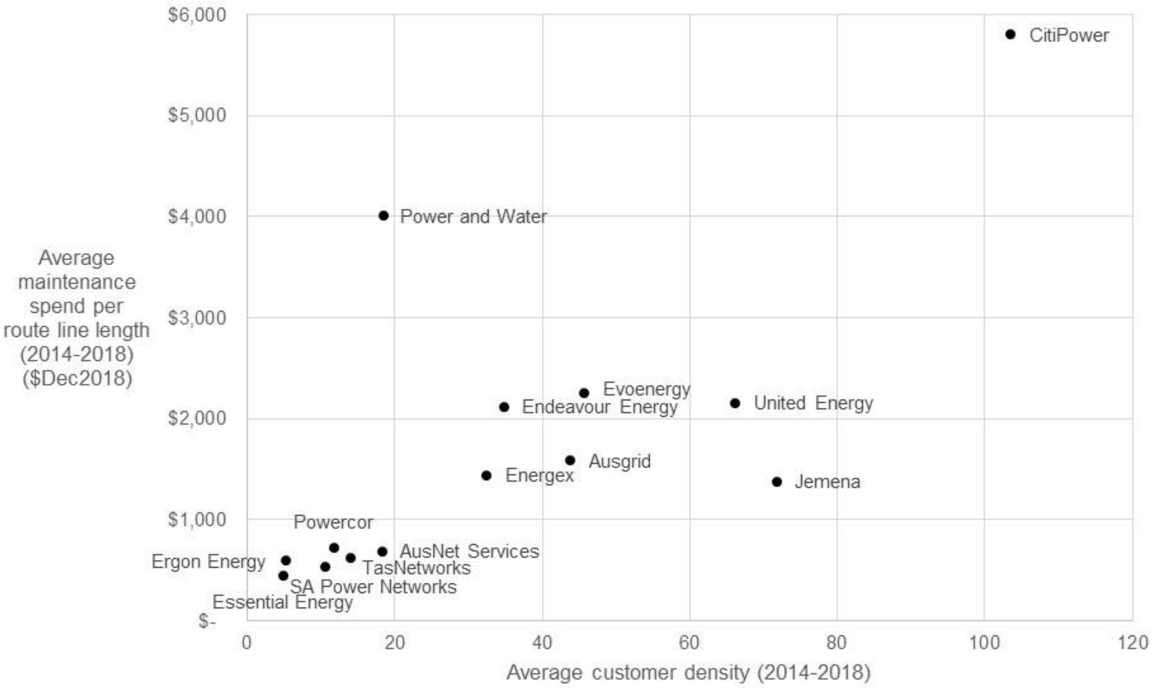


Figure A.3 Vegetation management opex per km of route line length ($2018–19)

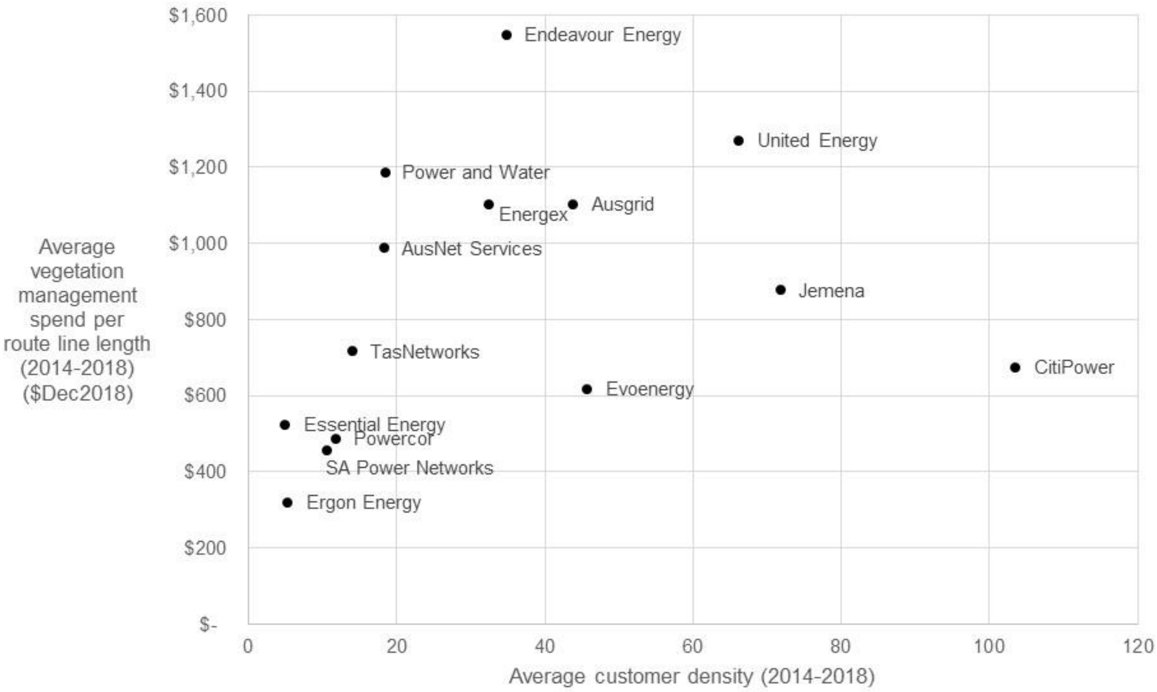


Figure A.4 Emergency response opex per customer ($2018–19)

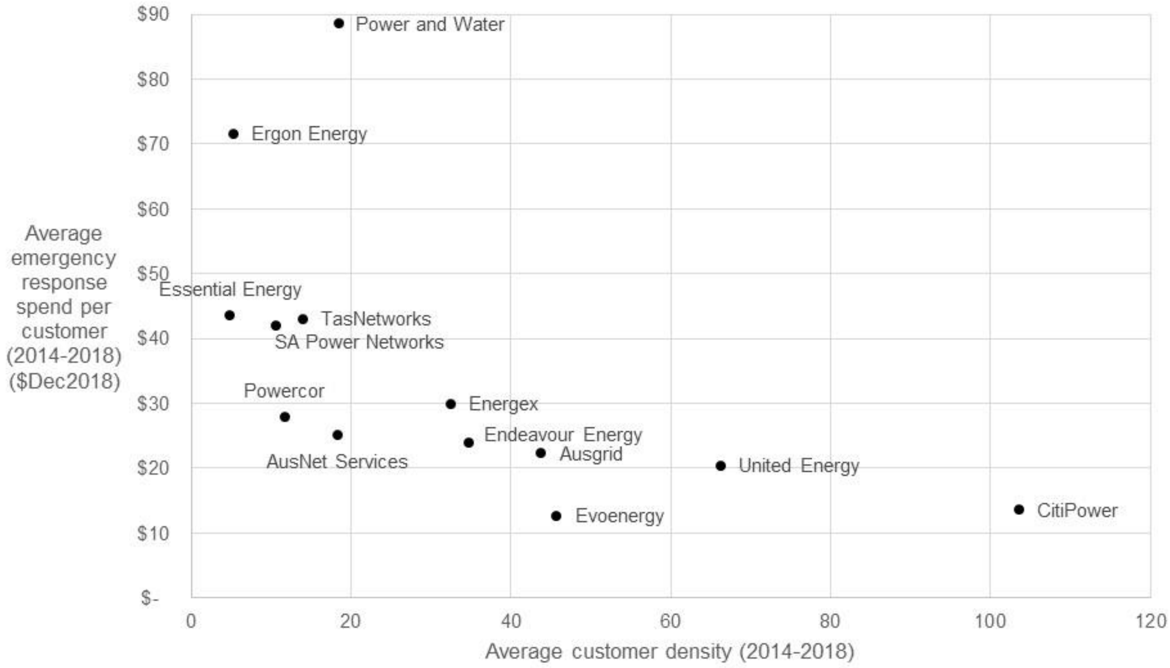


Figure A.5 Non-network opex per customer number ($2018–19)

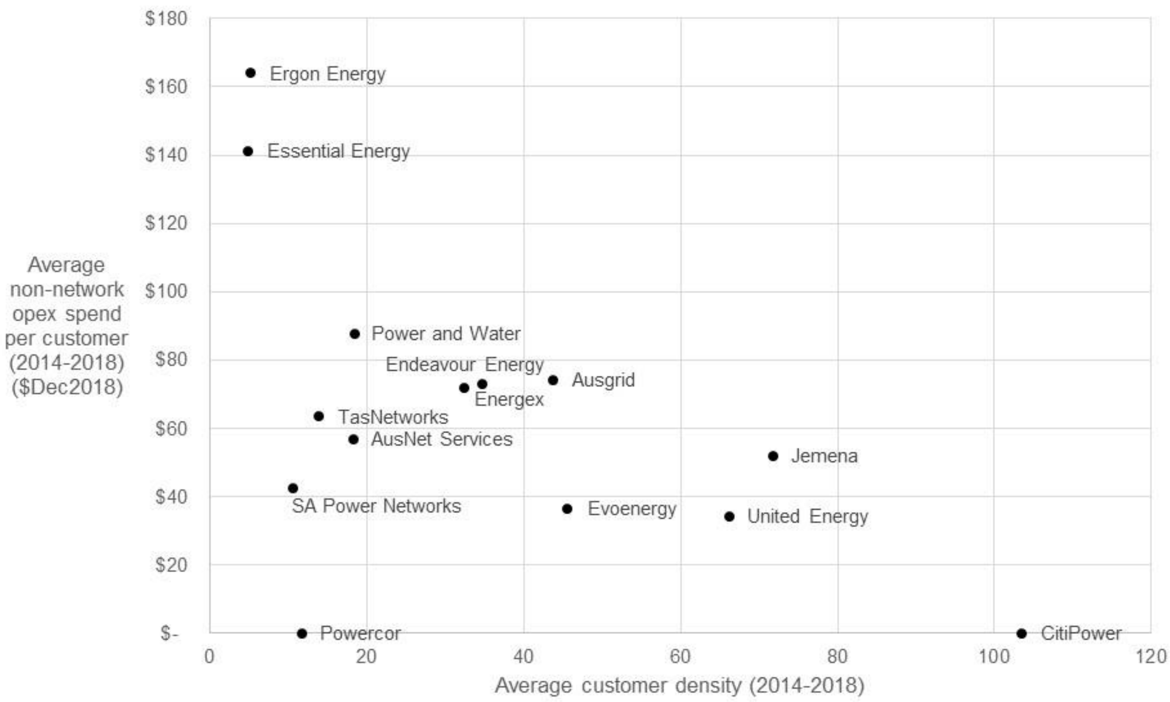


Figure A.6 Network overheads (totex) per customer number ($2018–19)

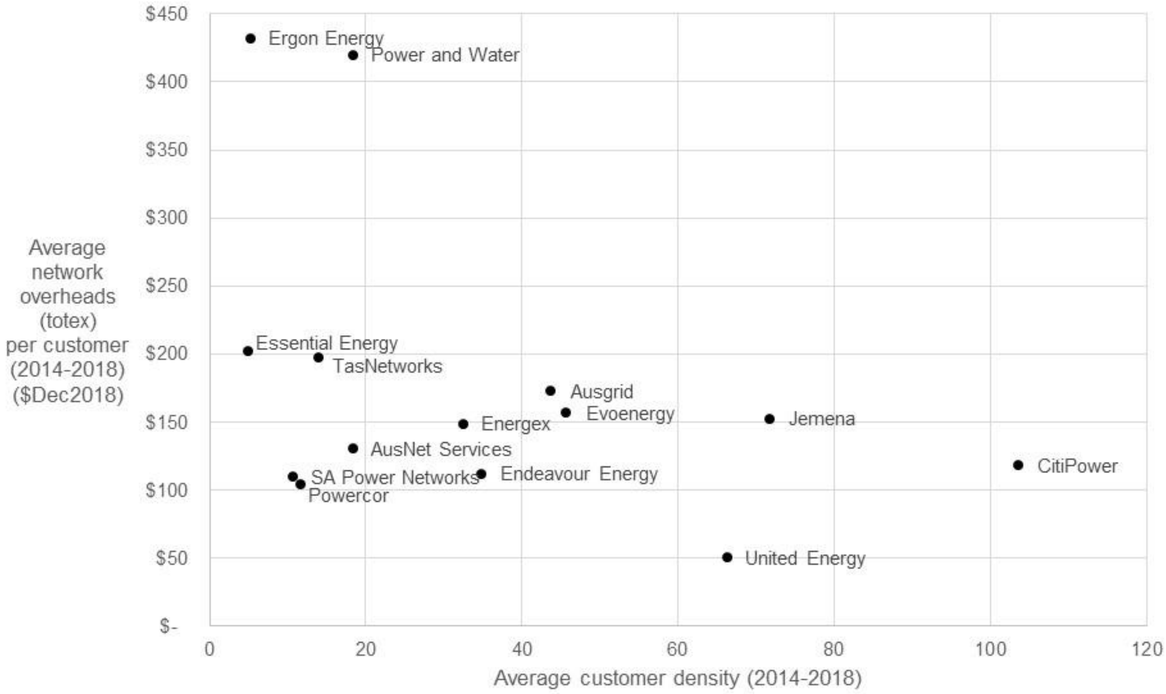


Figure A.7 Corporate overheads (totex) per customer ($2018–19)