Issues Paper

Power and Water Corporation Distribution Determination

2019 to 2024

March 2018

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Public forum and invitation for submissions

A public forum on Power and Water's proposal will be held on **12 April 2018** in Darwin, Northern Territory. The public forum will held at the Oaks Elan Darwin, 31 Woods Street, Darwin NT from 2:30 – 4:30 pm. Interested parties are invited to register their interest in attending the forum by emailing NTPowerWater2019@aer.gov.au with their name, the business or agency they represent (if relevant) and contact details by Wednesday, 4 April.

Written submissions on Power and Water's proposal are invited by **16 May 2018**.

We will consider and respond to all submissions received by that date in our draft determination.

Submissions should be sent to: NTPowerWater2019@aer.gov.au

Alternatively, submissions can be sent to:

Chris Pattas
General Manager
Australian Energy Regulator
GPO Box 520
Melbourne VIC 3001

Submissions should be in Microsoft Word or another text readable document format.

We prefer that all submissions be publicly available to facilitate an informed and transparent consultative process. Submissions will be treated as public documents unless otherwise requested. Parties wishing to submit confidential information should:

- clearly identify the information that is the subject of the confidentiality claim
- provide a non-confidential version of the submission in a form suitable for publication.

All non-confidential submissions will be placed on our website. For further information regarding our use and disclosure of information provided to us, see the *ACCC/AER Information Policy* (June 2014), which is available on our website.[1]

1 https://www.aer.gov.au/publications/corporate-documents/accc-and-aer-information-policy-collection-and-disclosure-of-information

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Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
capex	capital expenditure
CCP/CCP13	Consumer Challenge Panel, sub-panel 13
CESS	capital expenditure sharing scheme
COAG	Council of Australian Governments
CPI	consumer price index
current regulatory control period	1 July 2014 to 30 June 2019
DMIA	demand management innovation allowance
DMIS	demand management incentive scheme
distributor	distribution network service provider
DUoS	distribution use of system
EBSS	efficiency benefit sharing scheme
GSL	guaranteed service level
F&A	Framework and approach
kWh	kilowatt hours
MWh	megawatt hour
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NT NER or the rules	National Electricity Rules As in force in the Northern Territory
next regulatory control period	1 July 2019 to 30 June 2024
opex	operating expenditure
Pricing Order	electricity pricing order
PTRM	post tax revenue model

Shortened form	Extended form
RAB	regulatory asset base
repex	replacement capital expenditure
STPIS	service target performance incentive scheme
Utilities Commission	The Utilities Commission of the Northern Territory
WACC	weighted average cost of capital

1 About our distribution determination process

The Australian Energy Regulator (AER) works to make all Australian energy consumers better off, now and in the future. We regulate energy networks in all jurisdictions except Western Australia. We set the amount of revenue that network businesses can recover from customers for using these networks.

The National Electricity Law and Rules as applied in the Northern Territory (NT NEL and NT NER) provide the regulatory framework governing electricity networks. Our work under this framework is guided by the National Electricity Objective (NEO):[2]

> …to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system.

Power and Water is the electricity distribution network service provider (DNSP) servicing customers in the Northern Territory. We regulate Power and Water by making decisions on the revenue it can recover from customers for the provision of electricity distribution services, and the methodology it proposes to use to set its prices each year. On 31 January 2018, Power and Water submitted its regulatory proposal for the five years commencing 1 July 2019.

This will be our first determination for the Northern Territory, made under a newly adopted framework. The current determination for the period 2014–19 was made by the Utilities Commission of the Northern Territory. We assumed responsibility for the economic regulation of Power and Water's electricity distribution services on 1 July 2015.

This issues paper highlights some of the key elements of Power and Water’s proposal, and how stakeholders can assist in our review. We invite interested parties to join us on 12 April 2018 for a public forum on Power and Water's proposal. Registrations for the public forum will remain open until Wednesday 4 April 2018.

As part of this review we're also seeking written submissions from stakeholders on Power and Water's proposal, their priorities for this review and where our assessment should focus. More information on how you can get involved in this review is provided below.

2 NEL, s. 7.

1.1 How can you get involved?

The decisions we make and the actions we take affect a wide range of individuals, businesses and organisations. Effective and meaningful engagement with stakeholders across all our functions is essential to fulfilling our role, and it provides stakeholders with an opportunity to inform and influence what we do. Engaging with those affected by our work helps us make better decisions, provides greater transparency and predictability, and builds trust and confidence in the regulatory regime. This is reflected in our Stakeholder Engagement Framework and in the consultation process set out for our distribution determinations in the NT NER, which we will follow in this review.

Throughout this review we will also have the benefit of advice from our Consumer Challenge Panel (CCP13).[3] The expert members of the CCP help us to make better regulatory decisions by providing input on issues of importance to consumers and bringing consumer perspectives to our processes.

The table below sets out the key milestones and engagement opportunities in our review:

Milestone	Date
Power and Water submitted its proposal	31 January 2018
AER issues paper published	March 2018
Public forum on Power and Water's proposal	*12 April 2018*
Submissions on AER's issues paper, and Power and Water's proposal due	*16 May 2018*
AER draft decision published	September 2018
Public forum on draft decision	*October 2018*
Power and Water submits its revised proposal	November 2018
Submissions on AER's draft decision and revised proposal due	*January 2019*
AER final decision to be published	April 2019

3 Members of CCP13 are Andrew Nance, Mark Grenning and Chris Fitz-Nead. Member biographies are available on our website: https://www.aer.gov.au/about-us/consumer-challenge-panel.

2 What would this proposal mean for Power and Water's customers?

Power and Water's proposal would allow it to recover $927.9 million ($nominal) from its customers over the five years from 1 July 2019 to 30 June 2024.

This is a decrease of $113.8 million ($nominal) from the revenue the Utilities Commission approved for the current 2014–19 regulatory control period. Power and Water estimates that its proposal would result in an average decrease in distribution network charges of 0.1 per cent per year ($2018-19) compared to the level of distribution network charges in 2018–19.[4]

Pricing that is cost reflective and stable is one of the key themes Power and Water has identified in its proposal. In the lead up to submission of its proposal, Power and Water undertook the largest network focussed customer engagement program in its history, through the combination of consumer focus groups, customer interviews, deliberative forums and presentations to and feedback from its Customer Advisory Council. Through these, Power and Water has identified a number of key themes for its proposal and our review:

- Maintaining reliability and responsiveness levels for most customers and improving reliability for poor performing rural and urban areas
- Support for demand charges for all customers who have a demand-capable meter and the move to cost reflective tariffs for large energy users
- Supporting new technology, including the roll out of smart meters to all customers on a new and replacement basis.

In the sections that follow we discuss some of the key elements of Power and Water's proposal, and how Power and Water explains these have been guided by the key themes emerging from its engagement with consumers. We are particularly interested to hear from stakeholders whether these themes reflect their own priorities for this determination, and how well Power and Water's proposal has addressed them.

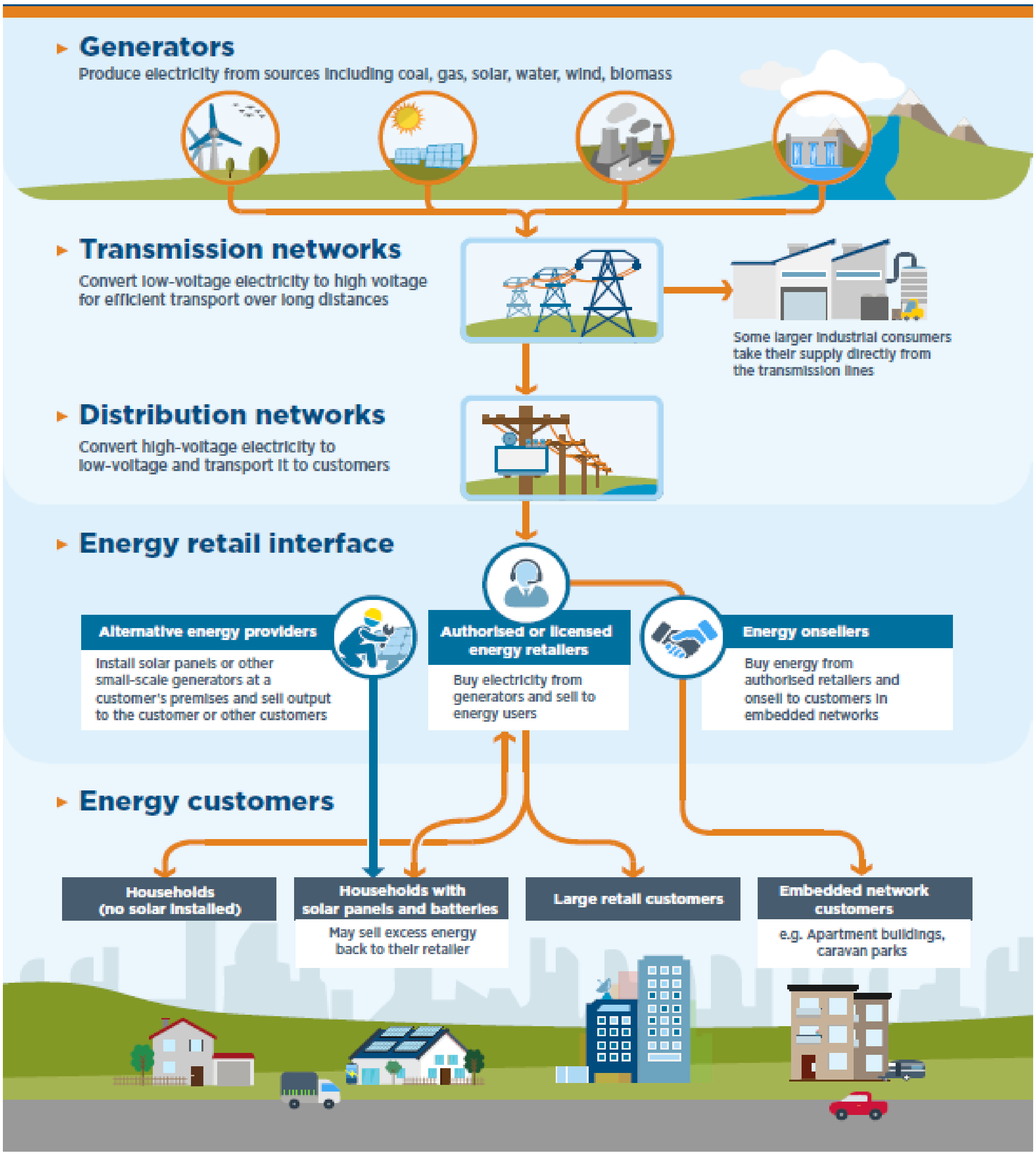
2.1 Estimated impact on electricity bills

Each of the components in the electricity supply chain, as reflected in Figure 1 below, can affect the electricity charges that customers receive in their bills. The cost of the network components of the electricity supply chain are ultimately recovered in electricity retail charges and we are not responsible for the regulation of electricity retail prices in NT.

4 Power and Water, *Regulatory Determination Workbooks – Consolidated*, Attachment 11.11CP, 16 March 2018 – PUBLIC.

Power and Water's proposed charges are for the network[5] component of the electricity bill for NT. Power and Water's network charges make up about 44 per cent of the average household electricity bill, and 35 percent for the average small business customer, in the NT.[6]

Figure 1 Electricity supply chain



Source: AER, *State of the Energy Market*, May 2017, p. 18.

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5 All of Power and Water's electricity network is deemed to be distribution for the purposes of economic regulation. Darwin, Katherine, Tennant Creek, Alice Springs and the Darwin to Katherine 132kV power line represent the local distribution systems in the NT (See section 9 and schedule 2 of the *National Electricity (Northern Territory)(National Uniform) Legislation Act)*.

6 Power and Water, *Revenue Proposal Overview*, Attachment 01.1, p. 1.

Power and Water estimates that its proposal would result in an average decrease of 0.1 per cent per year in the distribution bill component for residential customers and small business customers.[7]

A majority of customers in the NT are subject to the government's Electricity Pricing Order (Pricing Order). This caps retail prices for customers using less than 750MWh of electricity per annum.[8] It is important to recognise that the impact of any changes to Power and Water's revenue as a result of our decision is constrained by the Pricing Order. The Pricing Order stipulates a fixed charge and volume based tariff structure (including a time of use tariff) but does not account for demand based tariffs. The Pricing Order prevents price increases but does allow for prices to be set lower than prescribed. However, it is up to retailers to determine the price in accordance with the Pricing Order and pass on to customers any cost savings from lower network revenue determined for Power and Water. This means only a small number of large customers are not covered by this retail price protection and will be most impacted by our determination.

Figure 2 below shows the indicative price path in real terms ($MWh, $2018–19). It can be seen from this figure that Power and Water is proposing a reduction in prices for the first year, followed by gradual increases in the subsequent years of regulatory control period.[9]

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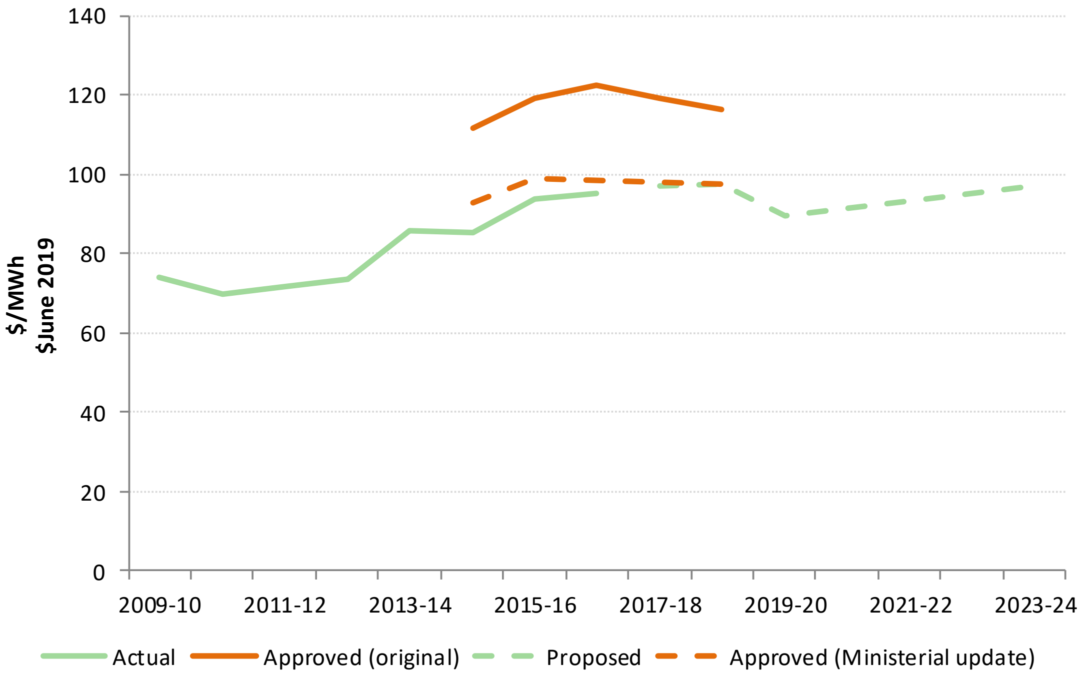
7 Power and Water, *Regulatory Determination Workbooks – Consolidated*, Attachment 11.11CP, 16 March 2018 – PUBLIC.

8 The fixed daily charge and the charge for the volume of electricity consumed is not to exceed the amount specified in the Pricing Order (See clauses 4 and 5). The Pricing Order can be found on the Utilities Commission's website at: http://www.utilicom.nt.gov.au/Electricity/pricing/Pages/Electricity-Retail-Pricing.aspx.

9 Power and Water propose an X factor of 9.42% in the first year and -3.38% in years 2, 3, 4 and 5 (See Power and Water, *Regulatory Proposal*, 16 March 2018, p. 127). Average annual changes in revenue are determined using the CPI–X methodology. This means that a positive X-factor greater than CPI will lead to a revenue reduction and a negative X-factor represents a revenue increase.

Figure 2 Indicative price path



Source: AER analysis

3 What's driving Power and Water's revenue proposal?

The impact of inflation—which changes over time—makes it difficult to compare revenue from one period to the next on a like-for-like basis. To do this we use 'real' values based on a common year (in this case 2018–19), which have been adjusted to remove the impact of inflation.

Power and Water's proposal is for an 18.7 per cent real decrease from the revenue the Utilities Commission decision allowed it to recover from customers from 2014 to 2019.

It is important to note that there were in affect two revenue allowances given to Power and Water –the initial allowance determined by the Utilities Commission in April 2014 and the lower allowance subsequently determined by the NT Government by Ministerial Direction. It is this lower revenue path that Power and Water recovered from customers during the 2014–19 regulatory control period.

The Utilities Commission made its 2014 Network Price Determination under the Northern Territories Network Access Code on 24 April 2014. This comprised the Utilities Commission's final determination in relation to the maximum allowed revenue that Power and Water[10] can recover from the provision of regulated network access services during the 2014–19 regulatory control period.[11]

On 13 May and 6 June 2014, the Treasurer, as the Shareholding Minister of Power and Water, made a direction under the *Government Owned Corporations Act 2001* (NT), reducing Power and Water's revenue path. The NT Government at the time considered that the Utilities Commission's benchmark weighted average cost of capital (or rate of return) of 7.86 per cent was too high and did not reflect the actual cost of borrowings for the Government owned corporation.

This lower revenue path, reflecting a lower return to the owner (the NT Government) created a shortfall in revenue which was not recovered from Power and Water's customers–the Government agreed to accept a lower return. There are a number of comparisons throughout Power and Water's proposal and this issues paper to the allowance made by the Utilities Commission and the Ministerial Direction allowance. In the most part we will be making comparisons to the Ministerial Direction allowance.

When considering the Ministerial Direction, the actual impact of Power and Water's proposal is a 1.5 per cent decrease in revenue to be recovered from customers in the

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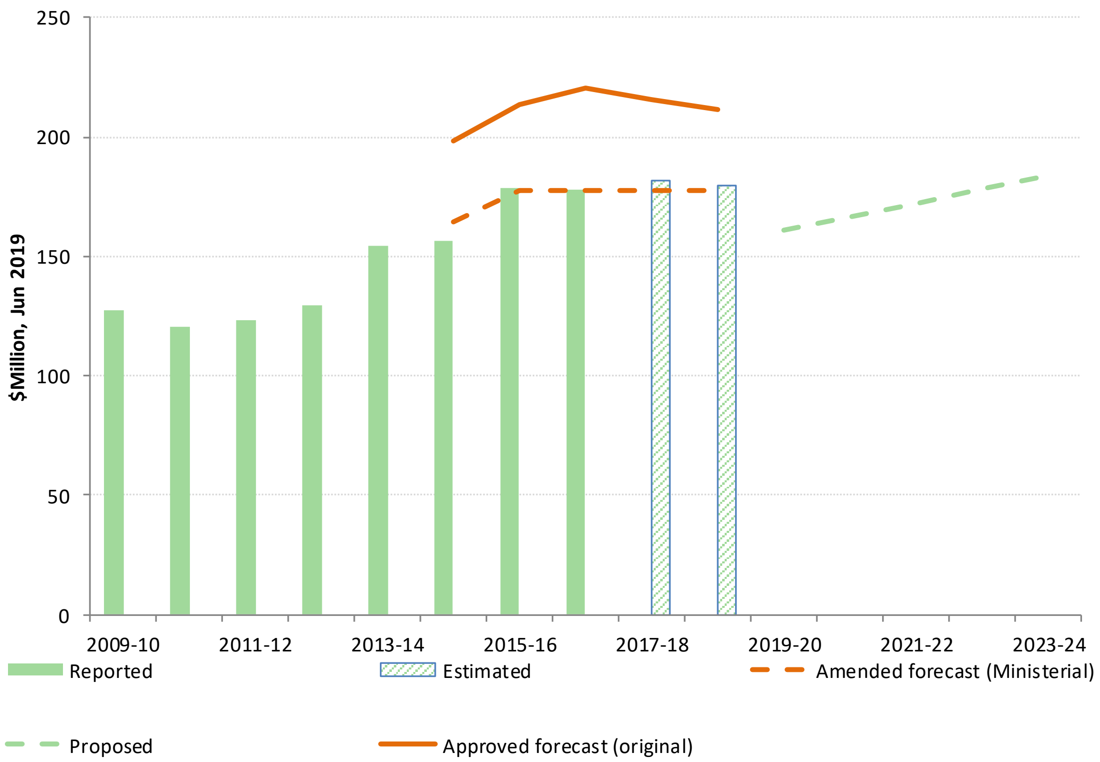
10 At the time of the Utilities Commission decision it was known as 'PWC Networks', the networks business division of The Power and Water Corporation, the government owned corporation established under the Power and Water Corporation Act (NT).

11 The Utilities Commission's 2014 Network Price Determination can be found at: http://www.utilicom.nt.gov.au/AboutTheCommission/consultations/2014/Pages/default.aspx

next period.[12] As Figure 3 shows, Power and Water proposes a 9.4 per cent reduction in revenue in the first year commencing 1 July 2019, followed by gradual increases of around 3.4 per cent per annum over the remaining four years. By 30 June 2024, these would bring its total forecast revenue closer to that actually recovered in the previous regulatory control period (2009–14) in accordance with the Ministerial Direction.

Figure 3 Revenue over time



Source: AER analysis

Power and Water is proposing a larger drop in revenue from that allowed by the Utilities Commission for the 2014–19 regulatory control period and state that the key drivers for this drop are reductions in:

- Financing costs - accounting for $1.5 million ($2018–19) average per year
- Other revenue adjustments - accounting for $8.1 million ($2018–19) average per year
- Opex - accounting for a further $23.3 million ($2018–19) average per year.[13]

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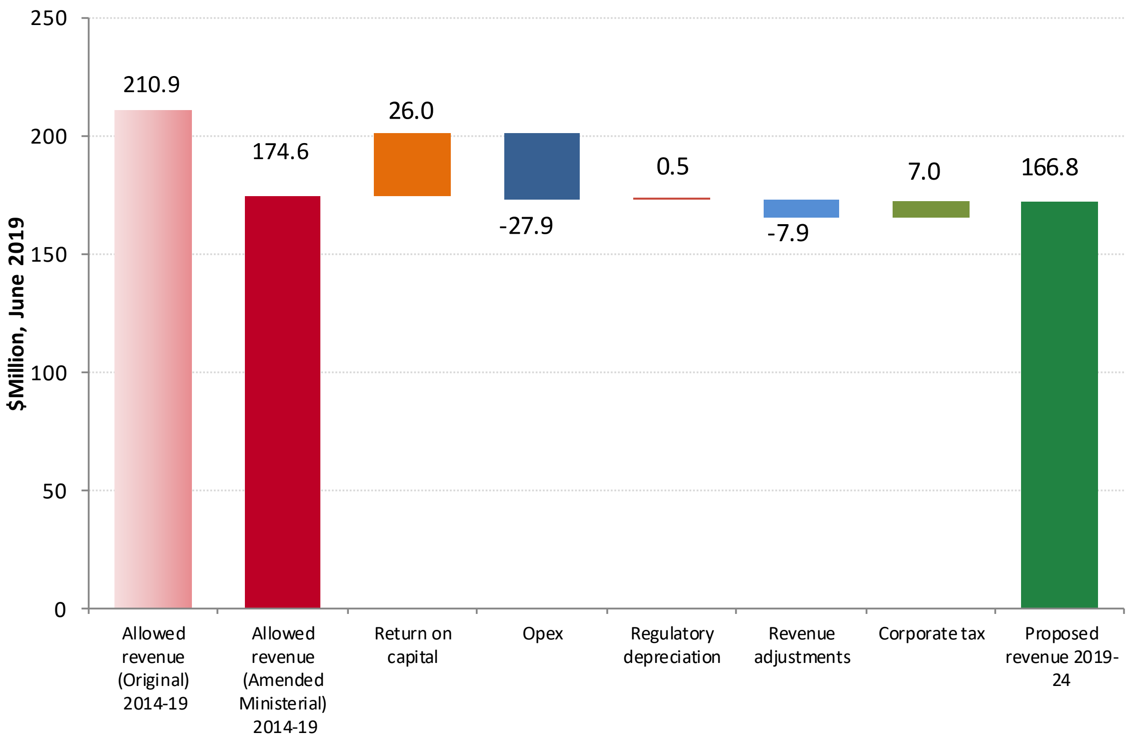
12 It should be noted that the Ministerial Direction revenue included metering services, which going forward will be recovered separately in alternative control services, so this is not a like for like comparison. This is discussed further below and in section 5.2.

13 Power and Water, *Regulatory Proposal 1 July 2019 to 30 June 2024*, 16 March 2018, p. 128.

The true impact of the comparison between the Utilities Commission approved allowance for 2014–19 and the subsequent adopted revenue path under the Ministerial Direction can be seen in Figure 4.

Figure 4 below compares Power and Water's proposed revenue against the allowances for 2014–19 set by the Utilities Commission (first bar) and the Ministerial Direction (second bar). This shows the key drivers of the change as compared to the Ministerial Direction are expected increases in Power and Water's forecast return on capital (capex and financing costs) and corporate income tax, and a decrease in opex.

Figure 4 Change in revenue from 2014-19 to 2019-24 - Ministerial Direction approved allowance ($m 2018–19)



Source: AER analysis

There are a number of observations that we seek to highlight.

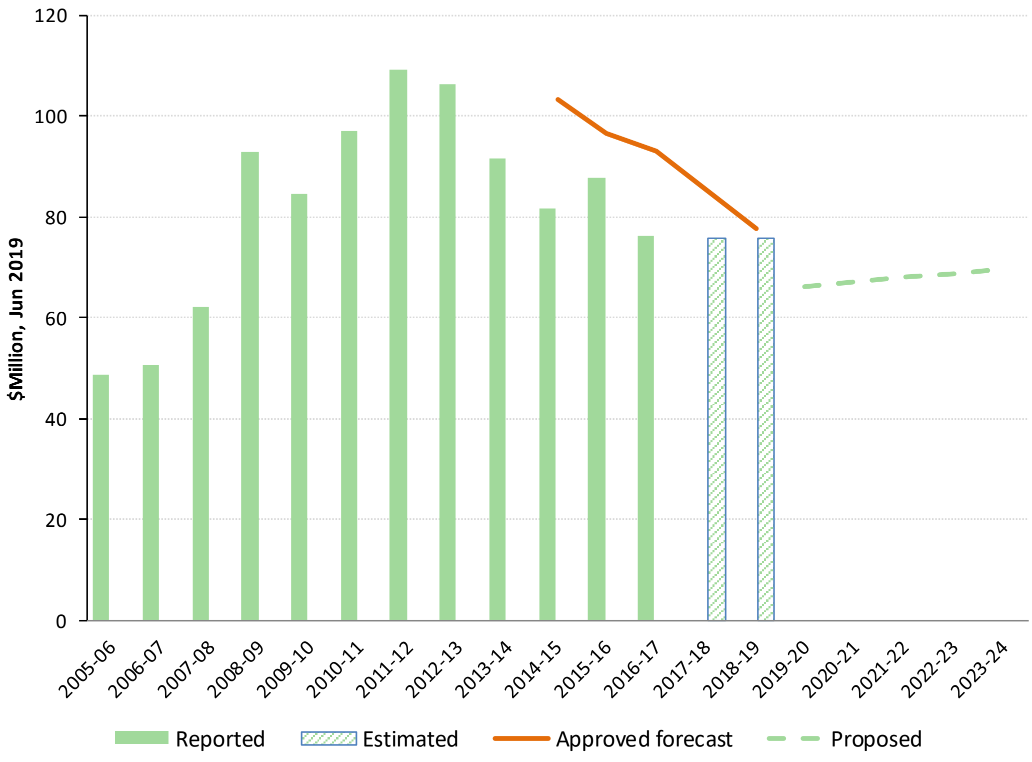
1. The 'Revenue adjustments' leading to a reduction in revenue relate to changes in the composition of network charges and do not represent an actual saving to customers. This is because this adjustment is to account for the way the provision of metering services will be provided to customers in the next period. The costs of these metering services will now be recovered through separate alternative control service charges to customers. These are not new charges but rather than being recovered in the distribution charge, as has been the case in the past, these will now be 'unbundled' and separately determined and charged, to all customers.

   There is $42 million ($2018–19) in revenue over 5 years that will now be recovered through these alternative control services. Therefore, whilst there appears to be a reduction in revenue compared to the current period there will still be a charge for this service. Alternative control services are discussed in section 5.2.

2. We are seeing an increase in Power and Water's forecast return on capital from that established by the Ministerial Direction, although still lower than what was set by the Utilities Commission, reflecting lower financing costs since 2014.
3. Power and Water is also proposing an increase in its capital expenditure compared to the current period. This is discussed in section 4.4.
4. The key driver for the reduction in revenue for the next period is the decrease in operating expenditure proposed by Power and Water. This is discussed in section 4.5.
5. There is an increase in the rate of corporate tax as a result of the move to the post-tax revenue framework. This is discussed further in section 4.3 below.

Figure 5 shows trends in Power and Water's opex over the last two regulatory control periods, and how this compares to its forecast for 2019–24. We discuss some of the key drivers for this in section 4.5, below.

Figure 5 Opex over time

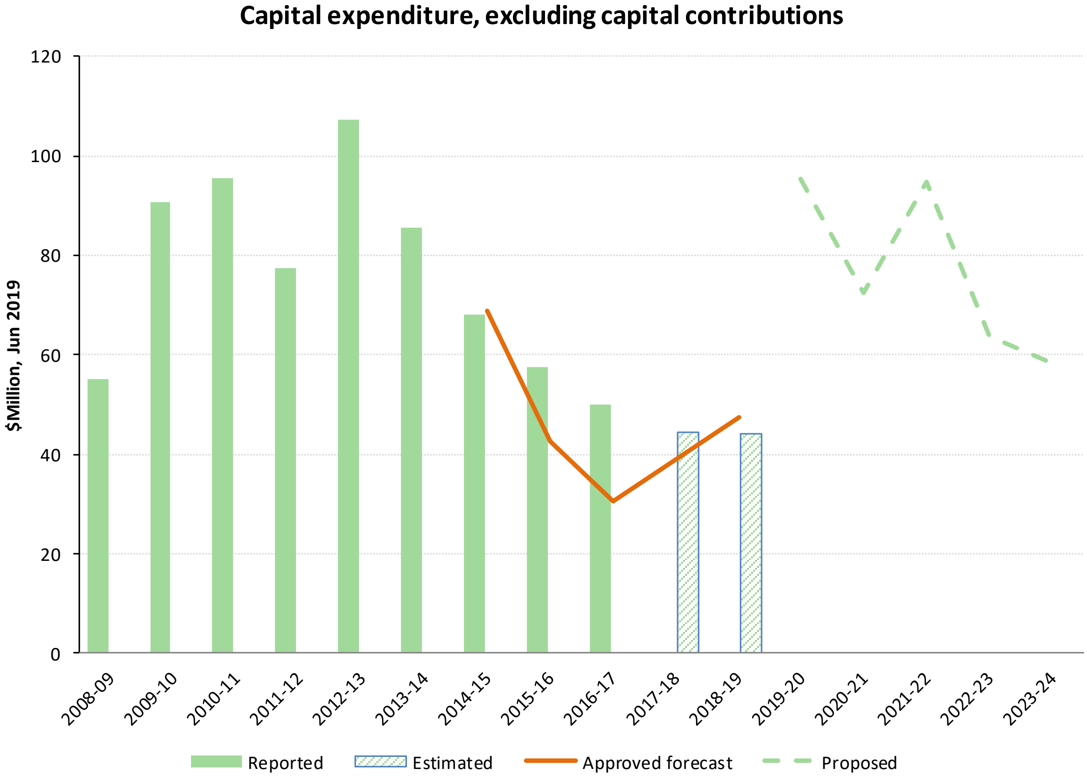


Source: AER analysis

Note: Proposed forecast includes debt raising costs of $0.5 million ($2018-19) in each year. Approved forecast for 2014-19 excludes debt raising costs.

The other key driver of the change in Power and Water's forecast revenue is its proposed capital expenditure allowance. Figure 6 shows trends in Power and Water's capex over the last two control periods, and how these compare to its forecast for 2019–24. We discuss some of the key drivers for this in section 4.4 below.

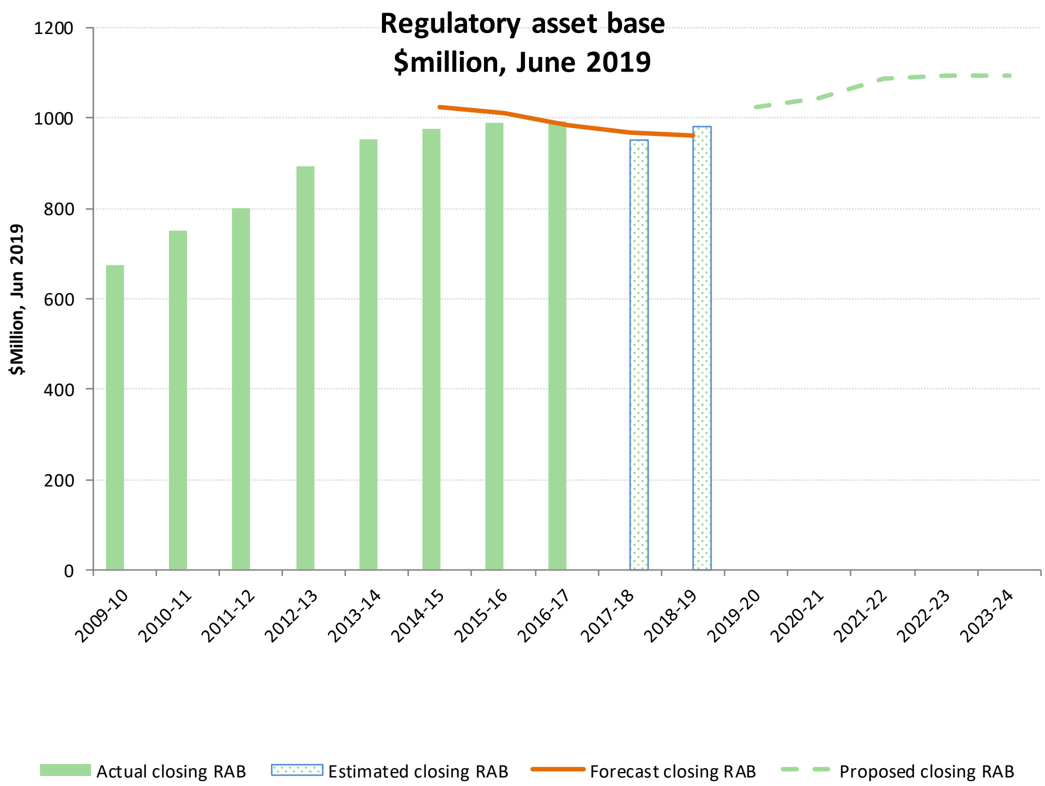
Figure 6 Capex over time



Source: AER analysis

Figure 7 also shows growth in Power and Water's RAB—typically a key driver of regulated revenues—has grown steadily since 2009, now flattening out in the remaining years of the current period, but forecast to continue to steadily grow into the next period. This is driven by increased capex forecast in the next period.

Figure 7 Projected RAB growth



Source: AER analysis

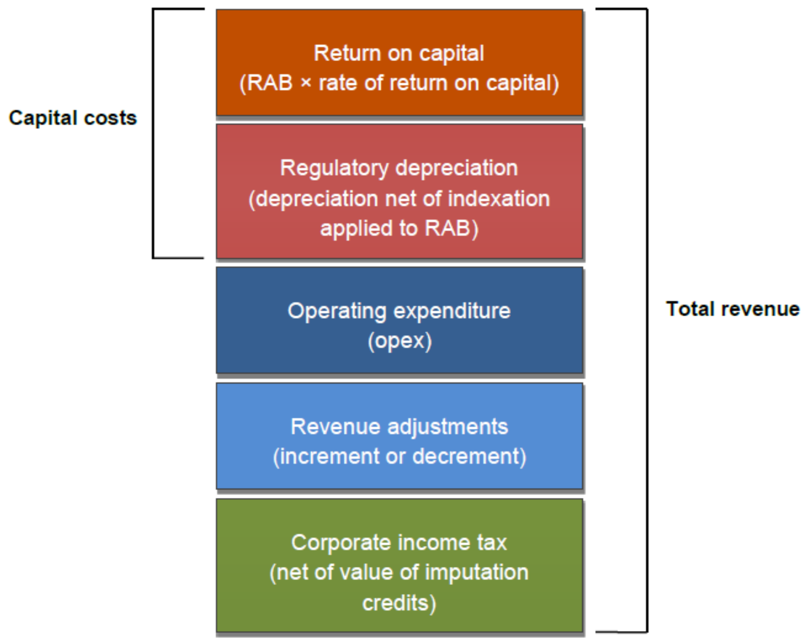
4 Key elements of Power and Water's revenue proposal

The building block approach is used to determine Power and Water's total revenue requirement for 2019–24. The building block approach consists of five costs (illustrated in Figure 8) that Power and Water is allowed to recover through its revenue allowance.

These include:

- a return on the regulatory asset base (RAB) (or return on capital)
- depreciation of the RAB (or return of capital)
- forecast opex
- revenue increments or decrements resulting from the application of incentive schemes
- the estimated cost of corporate income tax.

Figure 8 The building block approach for determining total revenue



In the sections below we highlight some of the key elements of Power and Water's proposal in each of these areas.

4.1 RAB and depreciation

The size of the RAB—and therefore the revenue generated from the return on capital and return of capital building blocks—is directly affected by our assessment of capex.

The RAB accounts for the value of Power and Water's regulated assets over time. To set revenue for a new regulatory control period, we take the opening RAB value from the end of the last period and roll it forward year-by-year by indexing it for inflation, adding new capex, and subtracting depreciation and other possible factors (for example, disposals or customer contributions).[14] This gives us a closing value of the RAB at the end of each year of the regulatory control period. The value of the RAB is used to determine:

- the return on capital building block, which is the product of the RAB and our approved rate of return
- regulatory depreciation (or the return of capital).

Power and Water's proposal has adopted our template Roll Forward Model (RFM) to calculate its opening RAB as at 1 July 2019, and to project its closing RAB at 30 June 2024. As part of our review we will thoroughly test Power and Water's application of this approach and its modelling of the RAB. However, the key determinant of RAB outcomes in this determination will be our related decisions on forecast capex (see section 4.4) and the estimate of expected inflation, which is updated to reflect the most recent data from the Reserve Bank of Australia at the time of our final decision.

Power and Water invests capital in large assets to provide electricity network services to its customers. The costs of these assets are recovered over the asset's useful life, many of which can be 50 years or more. This means only a small part of the cost of such assets are recovered from customers upfront or in any year, the greater proportion is recovered over time through the depreciation allowance. This spreads the cost of an asset over its useful life, so that cost is shared between current and future customers who all benefit from its use.

Depreciation reflects the use of an asset each year and accounts for its loss of value due to wear and tear over its useful life. The 'straight-line approach' used in Power and Water's proposal recovers the value of the asset evenly over its useful life. How quickly the value of the asset is recovered depends on the length of the asset's useful life.

4.2 Rate of return and value of imputation credits

The rate of return is a key determinant of the revenue allowance. It is applied to the RAB to determine Power and Water's return on capital. In its proposal Power and Water has applied a rate of return of 6.62 per cent. This is a placeholder, to be updated with more recent data at key milestones throughout this review (our draft decision, Power and Water's revised proposal and our final decision). It has also adopted a value of imputation credits (gamma) of 0.4, consistent with our guideline and recent decisions.

[14] The term 'rolled forward' means the process of carrying over the value of the capital base from one regulatory year to the next.

Power and Water has adopted some (but not all) elements of our standard approach, as set out in our 2013 rate of return guideline and subsequent determinations.[15] That guideline is now under review, with a revised 2018 guideline scheduled for release by the end of this year.

The COAG Energy Council published a bulletin on 2 March 2018 setting out their intention to implement a binding rate of return guideline.[16] The bulletin suggests that the binding guideline is intended to apply to Power and Water's 2019–24 final determination.[17] Consultation on proposed amendments to the NEL and NGL to give effect to this intent is still in progress and the exact legislative outcomes, their timing and implementation, are not certain. However, the COAG bulletin is the most recent public indication of the intended outcomes, and as such we think it is prudent to account for the possibility that our revised 2018 guideline will be binding on our final decision for Power and Water.

On that basis, we plan to consider all relevant rate of return and gamma materials submitted to us in this and other concurrent determination processes as also being relevant material for our guideline review (and vice versa). We have published the rate of return material included in Power and Water's proposal on the guideline section of our website to bring them to the attention of stakeholders participating in the guideline review.[18]

4.3 Corporate income tax

The estimated cost of corporate income tax is one of the building blocks of Power and Water's total revenue requirement for the 2019–24 regulatory control period. Under a post-tax framework, a corporate income tax allowance is calculated as part of the building block assessment using our Post-Tax Revenue Model (PTRM). Power and Water has proposed a forecast cost of corporate income tax of $37.4 million ($nominal) for the 2019–24 regulatory control period.[19]

In the current 2014–19 period, Power and Water has been regulated under a pre-tax framework by the Utilities Commission. Under this framework, the allowance for tax is embedded in the return on equity requirement (and subsequently the rate of return). Therefore, the Utilities Commission did not determine a separate tax building block for Power and Water for that period. The NT NER applying for the next regulatory control period establishes that the post-tax framework is to apply. This means a transition from a pre-tax to a post-tax framework is required for the 2019–24 distribution determination for Power and Water.

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15 AER - Rate of Return Guideline - 2013; AER - Final decision; APA VTS access arrangement 2018-22 - November 2017.

16 COAG Energy Council - Bulletin: Consultation on binding rate of return amendments - 2 March 2018.

17 COAG Energy Council - Bulletin: Consultation on binding rate of return amendments - 2 March 2018, p. 3.

18 https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/review-of-rate-of-return-guideline

19 Power and Water, *SCS Post-tax Revenue Model*, Attachment 12.1, 16 March 2018 – PUBLIC.

One of the key steps of this transition is to establish an opening tax asset base at the commencement of the 2019–24 period. Under the post-tax framework, the cost of corporate income tax is estimated based on cash flow analysis where the forecast revenue and tax expenses over the regulatory control period are used to assess what taxes are likely to be payable by a benchmark efficient entity operating Power and Water. A tax asset base is required to estimate the tax depreciation, which forms the tax expenses.

The value of the opening tax asset base has an explicit impact on the estimated cost of corporate income tax. If the tax asset base is set too high, a shortfall in the allowance for tax would occur when compared to actual tax liabilities. Similarly, if the tax asset base is set too low, the allowance for tax under a post-tax approach would be higher than appropriate. Power and Water has proposed an opening tax asset base of $673.5 million ($nominal) as at 1 July 2019. It has estimated this value using its tax records as at 30 June 2014 and then rolled them forward to 30 June 2019 using the AER's RFM.[20]

We will review the calculation of the tax asset base to ensure that it is appropriately determined for estimating Power and Water's cost of corporate income tax.

4.4 Capital expenditure

Capital expenditure (capex) refers to the capital costs and expenditure incurred in the provision of network services. As we discussed in section 4.1, this investment mostly relates to assets with long lives, the costs of which are recovered over several regulatory control periods. The forecast capex approved in our decisions is a key component of the projected value of the RAB, and therefore of the return on capital and depreciation building blocks.

We assess forecast capex proposals through a combination of top down and bottom up assessments. Our focus is typically on determining the prudent and efficient level of forecast capex. We will generally assess forecast capex by assessing the need for the expenditure and the efficiency of the proposed projects and related expenditure to meet any justified expenditure need. This is likely to include consideration of the timing, scope, scale and level of expenditure associated with proposed projects. Where businesses do not provide sufficient economic justification for their proposed expenditure, we will determine what we consider to be the efficient and prudent level of forecast capex. In assessing forecasts and determining what we consider to be efficient and prudent forecasts we may use a variety of analytical techniques to reach our views.

For the 2019–24 regulatory control period, Power and Water proposes total forecast (net) capex of $383.0 million ($2018–19).

Power and Water's forecast of its total (net) capex requirements for 2019–24 is $80.1 million—or 26 per cent—higher than its actual expenditure of $302.9 million in

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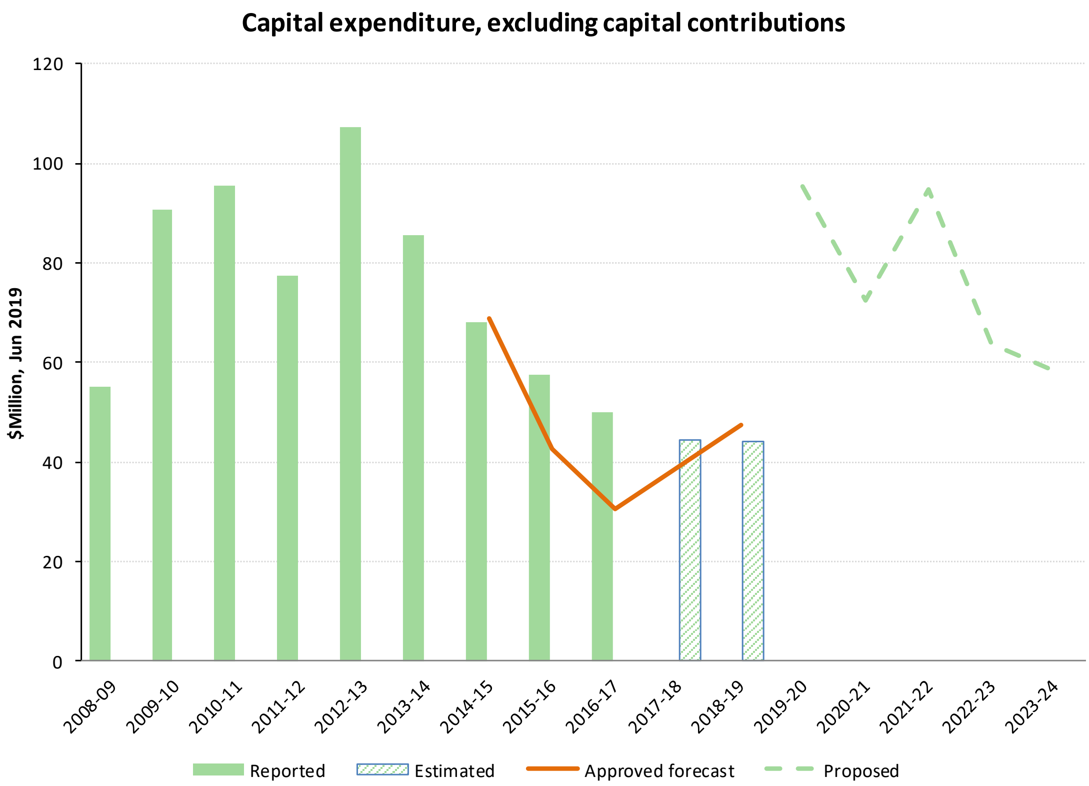
20 Power and Water, *SCS Post-tax Revenue Model*, Attachment 12.1, 16 March 2018 – PUBLIC.

2014–19. However, it should be noted that Power and Water has proposed reductions in each of the major categories of forecast capex (replacement, augmentation and connections). The overall increase in forecast capex is driven by changes to Power and Water's capitalisation policy resulting in increases in capitalised overheads and non-network capex previously recognised as operating expenditure. Figure 9 highlights the reduction in Power and Water's capex over the last five years, and its projection for this proposal.

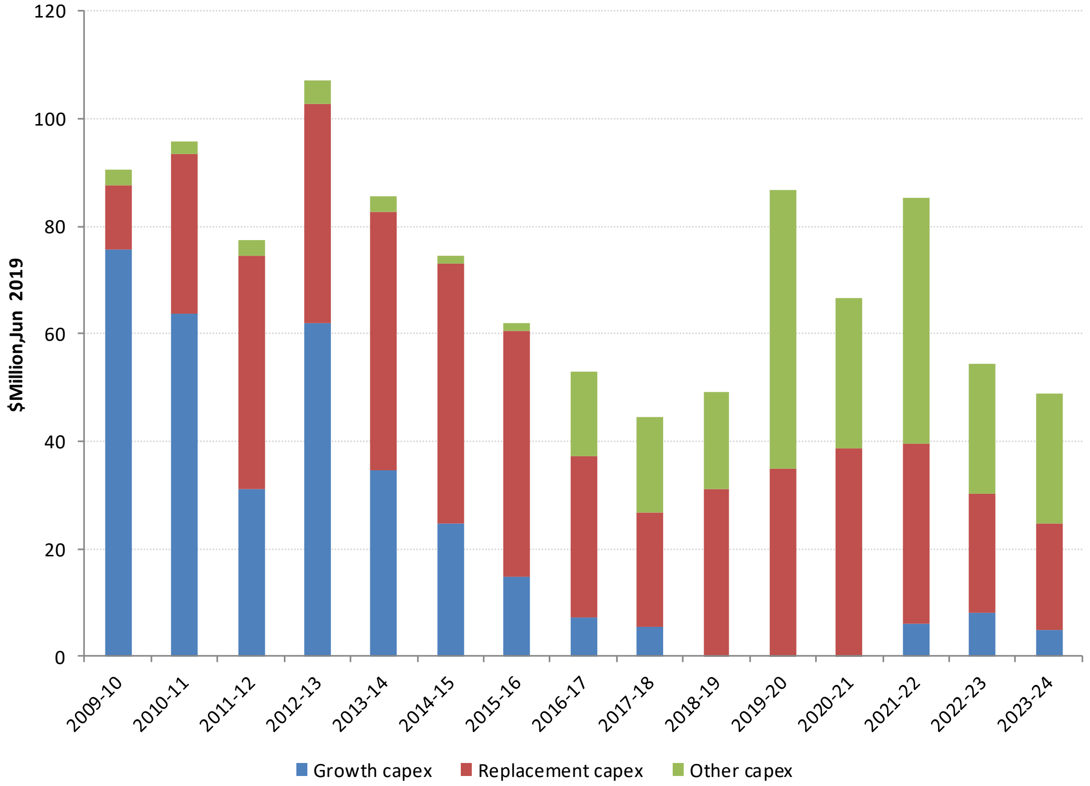
Figure 9 Capex over time



Source: AER analysis

Capex is made up of a number of categories of expenditure – replacement, augmentation (growth) and other capex. Changes in composition of Power and Water's capex from period to period is illustrated in Figure 10 below.

Figure 10 Changes in capex composition over time



Source: AER analysis

Each component of Power and Water's replacement, growth and other capex is discussed below.

4.4.1 Replacement capex

Power and Water has proposed a replacement expenditure (repex) of $148.6 million ($2018–19)[21], which is 18 per cent lower than the $175.5 million ($2018–19) it expects to spend over the current period.[22] Power and Water's forecast repex program is driven by:

- underground cables renewal of $30 million ($2018–19)
- transformer and switchgear renewal of $42 million ($2018–19)
- supervisory control and data acquisition (SCADA) and Protection system renewal of approximately $28 million ($2018–19)

21 Power and Water, *Regulatory Proposal 1 July 2019 to 30 June 2024*, 16 March 2018, p. 69.

22 This includes estimates for 2017-2018 and 2018-2019 as currently estimated by Power and Water. See, Power and Water, *Capex Overview Document* – 31 January 2018 – PUBLIC, p.14.

- poles renewal (including refurbishment) of approximately $21 million ($2018–19).[23]

Power and Water engaged Nuttall Consulting to undertake a review of its repex proposal. In general, Nuttall Consulting's assessment supports $100.5 million of repex that was able to be modelled using our replacement expenditure model. This represents 68 per cent of Power and Water's proposed repex.

We will be conducting a thorough review of the main drivers of the modelled repex, which includes, but is not limited to, the forecast increase in underground replacement over the upcoming period. We will also assess the un-modelled component of repex, which includes SCADA, buildings, and other repex.

4.4.2 Growth capex

Growth capex includes expenditure on network augmentation as well as new customer connections.

4.4.2.1 Augmentation

Power and Water has forecast augmentation capex of $60.6 million for the 2019–24 regulatory control period. This is a reduction of 21 per cent from the current period. Augmentation capex is generally driven by growth in maximum demand, as well as technical compliance, reliability and power quality obligations. Power and Water's forecast for maximum demand, prepared by the Australian Energy Market Operator (AEMO), indicates that maximum demand is expected to remain flat or decline in each of Power and Water's three network areas. This aligns with Power and Water's forecast for reducing augmentation requirements in the 2019–24 regulatory control period.

In assessing Power and Water's forecast augmentation capex, we will consider the key drivers of this forecast, including:

- localised areas of demand growth driving capacity constraints in particular locations, including the need for a new zone substation at Wishart
- the need to address compliance with network technical requirements and obligations
- the need to meet reliability and power quality obligations, for example through Power and Water's poor performing feeder improvement program ($7.1 million ($2018–19)).

4.4.2.2 Connections

Connections capex is required to service new, altered or upgraded connections for residential, commercial and industrial customers. Power and Water's forecast

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23 Power and Water, *Regulatory Determination Workbooks – Consolidated*, Attachment 11.11CP, 16 March 2018 – PUBLIC.

connections capex is based on AEMO's forecast of connection volumes for each connection type and average historical unit costs. Power and Water's forecast of gross connections capex, including gifted assets, of $62.7 million is eight per cent lower than expected capex in the current period. Power and Water has also proposed a change to its customer connection services policy, under which it intends to fully recover the costs of connection works from customers.

4.4.3 Other capex

Other capex includes capitalised overheads and various categories of non-network expenditure such as information and communication technology (ICT), fleet, buildings and property, and tools and equipment capex.

4.4.3.1 Non-network ICT

Power and Water's forecast non-network ICT capex of $37.5 million includes ICT sourced directly by Power and Water's Power Networks business, and a share of corporate ICT allocated to the Power Networks business in accordance with Power and Water's cost allocation methodology. Historically, Power and Water expensed its ICT expenditure but will recognise ICT capex for the 2019–24 regulatory control period due to changes to its capitalisation policy.

Power and Water's ICT capex proposal provides for:

- upgrading existing enterprise wide systems including the retail management system, financial management system and asset management systems
- new capability that builds on existing platforms where possible, including systems for customer relationship management, network planning, works management, outage management and business management
- maintenance of existing software and hardware.

Power and Water has forecast a significant increase in ICT capex in the first three years of the 2019–24 regulatory control period, before expenditure returns to levels in line with historical expenditure in the final two years of the period. We will examine the justification for increased ICT expenditure in the initial years of the forecast period.

4.4.3.2 Non-network other

Power and Water has proposed $69.4 million for non-network other capex, which includes fleet, buildings and property, and tools and equipment capex. This is a significant increase from expenditure in the current period, however in large part this is driven by a change in capitalisation policy whereby operating leases for fleet and buildings will be recognised as capex from the start of the 2019–24 regulatory control period. Power and Water has proposed that, in future, the full value of each new or replacement lease entered into will be recognised as capex as the present value of future lease payments. Apart from this change, Power and Water has also proposed one major property project for the upgrade of the 19 Mile depot and access road. We will examine the costs and benefits associated with this project, noting that it will allow for the rationalisation of two existing rural depots to a single site.

4.4.3.3 Capitalised overheads

In the 2019–24 regulatory control period, Power and Water has proposed that it will commence capitalising a portion of its unallocated indirect support costs in proportion to the ratio of direct capex to total direct costs. As a result, Power and Water has proposed forecast capitalised overheads of $66.9 million, which significantly increases total forecast capex when compared to Power and Water's approach of expensing these costs. We will assess Power and Water's application of this change to its capitalisation policy to ensure that only efficient overhead costs are recovered and there is no over-recovery of overheads across the combined capex and opex forecasts.

To assist us in our assessment, we are interested in stakeholder's views on the reasonableness of Power and Water's capex proposal and how well it reflects the key themes emerging from its consumer engagement.

4.4.4 Capital expenditure sharing scheme (CESS)

Our CESS aims to incentivise Power and Water to undertake efficient capex throughout the regulatory control period by rewarding efficiency gains and penalising efficiency losses (each measured by calculating the difference between forecast and actual capex).

Power and Water does not currently have a CESS or equivalent scheme in place. In our Framework and Approach we indicated our intention to apply the CESS in the 2019–24 regulatory control period.[24] Power and Water has accepted this, recognising that it provides them with financial rewards if its capex is more efficient and financial penalties if it is less efficient.

4.5 Operating expenditure (opex)

Opex refers to the operating, maintenance and other non-capital expenses incurred in the provision of network services. Power and Water's forecast opex is one of the key drivers of the decrease in revenue it proposes for the 2019–24 regulatory control period. It proposes total opex of $339.3 million ($2018–19). This is a $58.0 million or 14.6 per cent decrease from its expected actual expenditure in the current period. The decrease between periods reflects a change in Power and Water's capitalisation policy (i.e. accounting treatment of costs from opex to capex), as well as efficiencies Power and Water expects to achieve.

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24 AER, *Final framework and approach for Power and Water Corporation*, July 2017, pp. 47.

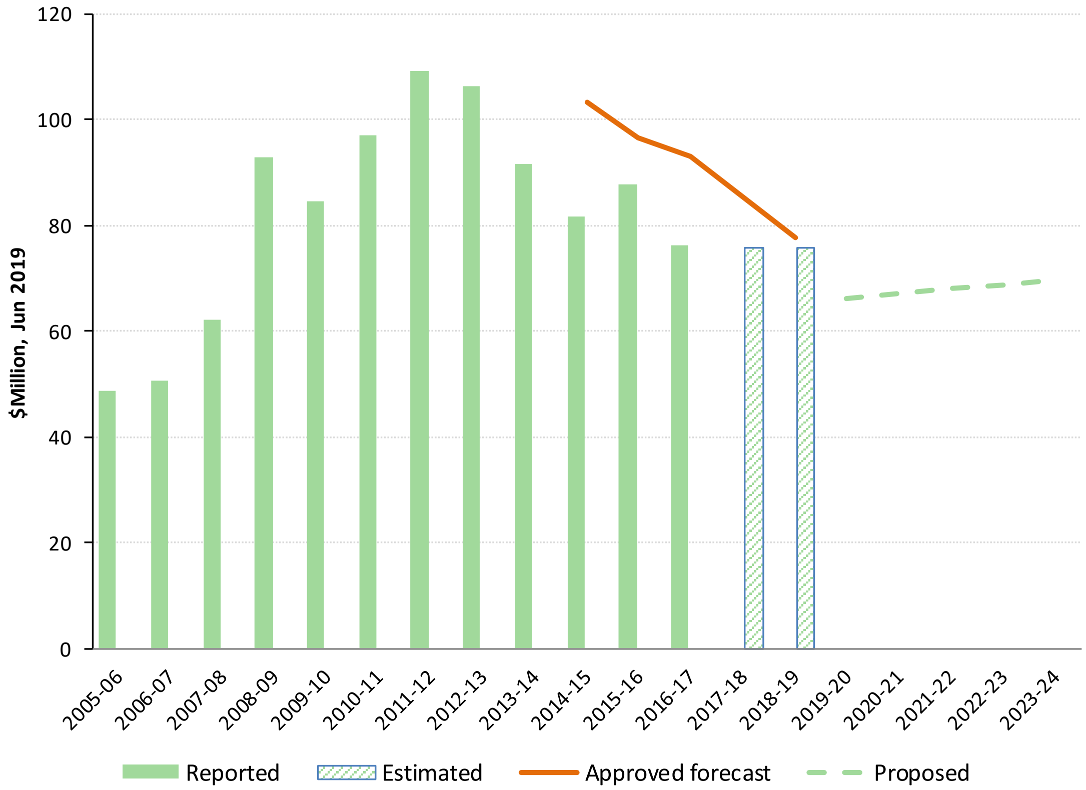
Power and Water has used a 'base-step-trend' approach to forecasting opex for the next regulatory control period. This is consistent with the approach to assessing opex outlined in our Expenditure Forecast Assessment Guideline (Guideline). It starts with a business's revealed (actual) costs in a 'base year' and forecasting at an aggregate level rather than preparing forecasts for each categories of opex.

The main drivers of Power and Water's opex forecast are:

- Choice of base year—Power and Water used its reported opex in 2016–17 as the starting point for its forecast.
- Efficiency adjustment—Power and Water applied a 'top down' 10 per cent downward efficiency adjustment to base year opex.
- Capitalisation—Power and Water removed $5.5 million ($2018–19) from the base year to reflect a change in capitalisation policy in the next regulatory control period. Power and Water's opex in the base year also reflects a change in capitalisation policy in the current regulatory period.
- Price, output and productivity growth—Power and Water forecast growth in input prices and outputs, and included zero productivity growth, consistent with our usual approach.
- Step changes—Power and Water included five step changes to comply with new regulatory obligations (that are not reflected in the base year).

Figure 11 shows the trends in Power and Water's opex over the last two control periods, and how these compare to its forecast for 2019–24.

Figure 11 Opex over time



Source: AER analysis

Note: Proposed forecast includes debt raising costs of $0.5 million ($2018-19) in each year. Approved forecast for 2014-19 excludes debt raising costs.

Power and Water's actual expenditure in the base year (2016–17) is lower than the Utilities Commission forecast for that year at the time of its decision. Power and Water has reduced its opex over the previous regulatory control period, which it states is evidence of it achieving efficiency improvements.[25]

A significant driver of Power and Water's lower forecast opex, as compared to its actual opex in the previous period, is a change in its capitalisation practices. For example, in 2016–17, Power and Water capitalised certain indirect support costs where they are integral to the acquisition or construction of capital assets.[26] However, in the next regulatory control period, Power and Water will begin capitalising building and vehicle leases consistent with Australian Accounting Standards and therefore treat operating leases as capex.[27] As highlighted in the capex discussion above, this means

25 Power and Water, *Opex Base Year Justification*, Attachment 03.1, 16 March 2018, p. 4.

26 Power and Water, *Basis of Preparation: Category Analysis Template for 2008-09 to 2016-17,* Attachment 11.2, 16 March 2018, pp.132–133.

27 Power and Water, *Capex Overview Document,* Attachment 04.1P, p. 87.

there is a fall in forecast opex, but a corresponding increase in capex for building and vehicle non-network costs.

Another driver of Power and Water's lower forecast opex, as compared to the previous period, is a targeted efficiency adjustment of 10 percent to its proposed base opex (which amounts to $35.2 million ($2018–19)) over the next regulatory control period). Power and Water considers this top-down 10 per cent adjustment brings its maintenance and network overhead expenditure into line with other electricity distributors. However, Power and Water notes that should we make additional base year opex efficiency reductions then it would need to reconsider the proposed targeted level of efficiency.[28]

Given this is the first time we are assessing Power and Water, a critical issue is determining an appropriate starting point on which to trend Power and Water's opex into the future. As outlined in our Guideline, we have a variety of expenditure assessment techniques that we can draw on to assess expenditure in the base year. These include:

- benchmarking (total expenditure and category-level techniques)
- governance and policy review
- predictive modelling
- trend analysis
- detailed project and category level review (including engineering review).

Power and Water considers care must be taken in relying on its historical data for the purpose of benchmarking because of various shortcomings and distortions it has identified.[29] We will consider these views along with the use of other complementary assessment techniques to assess Power and Water's proposed base opex.

Power and Water is proposing five step changes totalling $7.4 million ($2018–19) over the regulatory period to meet the costs of complying with new regulatory obligations:

- National connections process— Power and Water will be required to comply with the national connections framework created by the introduction of Chapter 5A of the NT NER and proposes $2.43 million ($2018–19) to administer the process
- Metering compliance for type 7 meters—Power and Water proposes $0.12 million ($2018–19) to maintain a five year rolling sampling plan for these meters
- Meter Data Management System (MDMS) commissioning and early processing—Power and Water is proposing $0.78 million ($2018–19) to comply with the verification, substitution and estimation obligations under the new Chapter 7A NT NER arrangements for metering

28 Power and Water, *Regulatory Proposal 1 July 2019 to 30 June 2024*, 31 January 2018, p. 85.

29 Power and Water, *Regulatory Proposal 1 July 2019 to 30 June 2024*, 31 January 2018, p. 82.

- Planning resources—increased network planning resources to comply with the obligations under the NT NER. Power and Water proposes $2.74 million ($2018–19) to enhancing its planning function capabilities
- Guaranteed Service Levels (GSLs)—an increase in GSL payments as a result of the revised GSL scheme under the Utilities Commission's Electricity Industry Performance Code. Power and Water proposes an additional $1.33 million ($2018–19).

We will examine each of these step changes to determine whether they represent an appropriate step up in costs, to be recovered from customers in the NT. To assist us in our assessment, we are interested in stakeholder’s views on the reasonableness of Power and Water’s opex proposal and how well it reflects the key themes emerging from its consumer engagement.

4.5.1 Opex efficiency benefit sharing scheme (EBSS)

Our EBSS is intended to provide a continuous incentive for distributors to pursue efficiency improvements in opex, and to fairly share these between distributors and consumers. Consumers benefit from improved efficiencies through lower network prices in future regulatory control periods.

Power and Water does not currently have an EBSS or equivalent scheme. In the Framework and Approach paper we released in July 2017 we indicated that we expect to apply the EBSS. We also stated that we will decide on if and how to apply the EBSS in our final determination taking into account whether we use a revealed cost approach to determine Power and Water’s opex forecast.

Power and Water has proposed an EBSS will apply and recognises that it provides a continuous incentive to pursue efficiency improvements across the period.

The revealed opex forecasting approach and application of an EBSS are inherently linked. Where we apply a revealed opex forecast, a business that makes an incremental efficiency gain receives a reward through the EBSS, and consumers benefit through a lower revealed cost forecast in the subsequent period. Therefore, where we use a revealed cost approach we generally apply an EBSS. Where we cannot rely on revealed opex forecasts, because there is evidence of material inefficiency, we need to consider the circumstances and whether there will be benefits to consumers from an EBSS being put in place. We are interested in stakeholder’s views on whether an EBSS should apply to Power and Water in the 2019–24 regulatory control period.

4.6 Other incentive schemes

Power and Water has accepted our proposal to not apply the Service Target Performance Incentive Scheme (STPIS) and apply our newly revised Demand Management Incentive Scheme.

4.6.1 Service target performance incentive scheme

Our distribution STPIS[30] provides a financial incentive to distributors to maintain and improve service performance. The scheme aims to ensure that cost efficiencies incentivised under our expenditure schemes do not arise through the deterioration of service quality for customers. Penalties and rewards under the STPIS are calibrated with how willing customers are to pay for improved service. This aligns the distributor's incentives towards efficient price and non-price outcomes with the long-term interests of consumers.[31]

In our Framework and Approach paper we proposed not to apply the s-factor component of the STPIS to Power and Water in the next regulatory control period, due to the unavailability of reliable historic supply interruption data. However, we will be collecting relevant data during the course of the 2019–24 regulatory control period in order to establish suitable targets for the following regulatory control period.[32]

4.6.2 Demand management incentive scheme and innovation allowance

On 13 December 2017, we published a new demand management incentive scheme (DMIS), including a revised demand management innovation allowance (DMIA). This rewards electricity distribution businesses for using efficient demand management projects to deliver value to consumers. We also released an improved version of our previous demand management innovation allowance, which provides research and development funding to electricity distribution businesses so they can better use demand management to reduce long term network costs.

At this time, we requested a rule change to allow us to apply the DMIS before the next regulatory period for each distribution business. Any rule changes will be reflected in the NT NER. On 20 February 2018, the AEMC commenced consulting on this as an expedited rule change. The AEMC's proposed rule change process will allow distribution businesses—including Power and Water—to apply for early application of the DMIS from 3 April 2018.

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30 AER, *Electricity distribution network service providers - service target performance incentive scheme*, 1 November 2009.

31 Guaranteed service levels (GSLs) and associated rebates for performance measure are separately determined by the Utilities Commission in its Electricity Industry Performance Code, and not as part of our decision.

32 AER, *Final framework and approach for Power and Water Corporation*, July 2017, pp. 44–45.

Our consultation on our Framework and Approach paper last year took the development of the new scheme into account. Power and Water supported our position to apply the new DMIS and DMIA to Power and Water for 2019–24.[33] That position is now reflected in Power and Water's proposal.

33 Power and Water, *Submission on AER preliminary framework and approach for NT Power and Water Corporation*, April 2017, p. 1.

5 Network Pricing

In the Framework and Approach paper we published last year, we set out our intended classification of the services Power and Water provides its customers:

- Standard control services are those that can only be provided by Power and Water, and are common to most, if not all, of Power and Water's customers. The costs of providing these services are captured in the building block revenue determination we discussed in section 4, and shared between all customers.
- Alternative control services are either:
    - services that can only be provided by Power and Water, but will only be required by some of its customers, some of the time; or
    - services that can be purchased from Power and Water, but which can also—or have the potential to—be purchased from a competing provider.

The cost of providing alternative control services is recovered from users of those services only.

Power and Water has adopted the service classifications in our Framework and Approach Paper.[34]

In addition to the revenue Power and Water proposes to recover from its customers (as standard control services), there are other aspects of the proposal that we would like to draw your attention to, including:

- Power and Water's proposed tariff structure statement (TSS), which sets out the tariff structure through which Power and Water will recover its regulated revenue
- The revised charges Power and Water proposes to apply to services outside the building block revenues (alternative control services), such as metering.

We discuss the key features of these elements of Power and Water's proposal below.

5.1 Tariff structure statement

The requirement on distributors to prepare a TSS arises from a significant process of reform to the National Electricity Rules governing distribution network pricing. These changes have also been reflected in the NT NER. The purpose of the reforms is to empower customers to make informed choices by:

- Providing better price signals—tariffs that reflect what it costs to use electricity at different times so that customers can make informed decisions to better manage their bills.

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34 Power and Water, *Regulatory Proposal 1 July 2019 to 30 June 2024*, 16 March 2018, p. 50.

- Transitioning to greater cost reflectivity—requiring distributors to explicitly consider the impacts of tariff changes on customers, and engaging with customers, customer representatives and retailers in developing network tariff proposals over time.
- Managing future expectations—providing guidance for retailers, customers and suppliers of services such as local generation, batteries and demand management by setting out the distributor's tariff approaches for a set period of time.

Among other matters, a TSS must set out a distributor's proposed tariffs, structures and charging parameters for each proposed tariff, and the policies and procedures the distributor proposes to apply assigning customers to tariffs or reassigning customers from one tariff to another.[35] A TSS must also be accompanied by an individual pricing schedule.[36] The final prices for each tariff continue to be determined on an annual basis.

This is Power and Water's first TSS. In the 2019–24 period, Power and Water proposes to:

- Introduce demand tariffs for all customers who have a smart meter—this change will apply to small customers (defined as those who consume less than 750 MWh of electricity per annum) but will not affect their retail price, as they are currently protected by the Pricing Order.
- Change the tariff design of its legacy network tariffs from a declining block structure to a flat rate structure—because of the Pricing Order, Power and Water notes this will not directly impact small customers, however it will be reflected in the bills of Power and Water's large energy users consuming more than 750 MWh of electricity per annum (who are not covered by the Pricing Order). Power and Water states that this will result in 88 per cent of its large energy users having either no bill increase or a bill decrease.
- Shorten its peak charging window—from the current peak window of 6am to 6pm every day, to 12pm to 9pm weekdays only. For large energy users this peak window will continue to apply all year round. For small customers, this peak period will only apply during the wet/summer season from October to March.[37]

We seek stakeholder views on each of these changes.

We note that as the Pricing Order sets the level and structure of retail tariffs for small customers, it appears to us that Power and Water's reforms to its network tariff structures are likely to have a more significant impact on its large customers. Accordingly, stakeholders may wish to focus their review on Power and Water's changes to its large customer tariff structures. We are also interested in stakeholder

35 NT NER, cl. 6.18.5.
36 NT NER, cl. 6.8.2(d1).
37 Power and Water, *Overview of our tariff structure statement*, Attachment 02.2, 16 March 2018, pp. 9–11.

views on the impact of Power and Water's proposed changes for small customers taking into account the interaction between the Pricing Order.

5.2 Alternative control services

Power and Water's alternative control services include metering and ancillary services. These are paid for by customers using those services. Power and Water's alternative control services include things like customer-specific requests for relocation of poles, temporary disconnection and reconnection, special meter reading and non-standard data service requests.

The most significant change for customers is the approach to metering charges.

The alternative control service classification will provide customers with transparency around the pricing of metering services provided by Power and Water. Although Power and Water is the monopoly metering service provider under the NT NER, if competition is introduced in the future, this classification would provide a price signal on whether to switch to an alternative meter type or metering provider in the future.

The nature of type 1 to 6 metering services is that the customer requesting the service will benefit from the provision of that service. As such, the costs are directly attributable to identifiable customers. Our proposed change in service classification protects the broader customer base from incurring additional costs for metering services of no benefit to them.[38]

As mentioned above in section 3, metering will be 'unbundled' from the broader distribution connection and network services. Metering charges will now be determined separately, whereas in the past these services were 'bundled' and not visibly charged to customers. It is important to note that the alternative control metering service charge is not an additional new charge being imposed on customers in NT – it is being moved from the 'standard control bucket' to the 'alternative control bucket'. Likewise the $8 million 'other revenue' reduction per annum for the provision of Power and Water's standard control services does not represent an actual reduction but rather the move from the 'standard control bucket' to the 'alternative control bucket'.

Power and Water is proposing to install smart meters for customers in the NT on a new and replacement basis. This means that a smart meter will be installed every time there is a new network connection or the meter fails or is scheduled to be replaced. This is a key driver of Power and Water's metering service costs. Power and Water submits that its new and replacement smart meter policy is informed and supported by:

- its cost benefit analysis that has identified a policy that will provide the least cost options to customers
- customers, who have told Power and Water that they want smart meters

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38 AER, *framework and approach for Power and Water Corporation*, July 2017, p. 21.

- “non-quantifiable” benefits that may be derived by Power and Water and the broader community (generators, retailers and customers)[39]. This includes benefits identified through Power and Water’s customer focus groups–such as the support for new technology, enabling cost reflective demand pricing and allowing customers to better monitor their usage.[40]

We will examine the cost benefit analysis supporting the new and replacement smart meter. To assist us in our assessment, we are interested in stakeholder’s views on the reasonableness of Power and Water’s proposed approach to metering and how well it reflects the key themes emerging from its consumer engagement.

39 Power and Water, *Alternative Control Services Metering Overview Document*, Attachment 09.1P, 16 March 2018, p. 9.

40 Power and Water, *Alternative Control Services Metering Overview Document*, Attachment 09.1P, 16 March 2018, pp. 14–16.

A. The regulatory framework for this determination

The NEL requires us to make our decision in a manner that contributes, or is likely to contribute, to achieving the NEO.[41] The focus of the NEO is on promoting efficient investment in, and operation and use of, electricity services (rather than assets) in the long term interests of consumers.[42] This is not delivered by any one of the NEO's factors in isolation, but rather by balancing them in reaching a regulatory decision.[43]

We consider that the long-term interests of consumers are best served where consumers receive a reasonable level of safe and reliable service, which they value, at least cost in the long run.[44] A decision that places too much emphasis on short term considerations may not lead to the best overall outcomes for consumers once the longer term implications of that decision are taken into account.[45]

There may be a range of economically efficient decisions that we could make in a revenue determination, each with different implications for the long term interests of consumers.[46] A particular economically efficient outcome may nevertheless not be in the long term interests of consumers, depending on how prices are structured and risks allocated within the market.[47] There are also a range of outcomes that are unlikely to advance the NEO, or advance the NEO to the degree that others would. For example, we consider that:

- the long term interests of consumers would not be advanced if we encourage overinvestment which results in prices so high that consumers are unwilling or unable to efficiently use the network.[48] This could have significant longer term pricing implications for those consumers who continue to use network services.
- equally, the long-term interests of consumers would not be advanced if allowed revenues result in prices so low that investors do not invest to sufficiently maintain the appropriate quality and level of service, and where customers are making more use of the network than is sustainable.[49] This could create longer term problems in

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41 NEL, section 16(1).

42 This is also the view of the Australian Energy Markets Commission (the AEMC). See, for example, the AEMC, *'Applying the Energy Objectives: A guide for stakeholders'*, 1 December 2016, p. 5.

43 Hansard, SA House of Assembly, 26 September 2013, p. 7173. See also the AEMC, *'Applying the Energy Objectives: A guide for stakeholders'*, 1 December 2016, pp. 7–8.

44 Hansard, SA House of Assembly, 9 February 2005, p. 1452.

45 See, for example, the AEMC, *'Applying the Energy Objectives: A guide for stakeholders'*, 1 December 2016, pp. 6–7.

46 Re Michael: Ex parte Epic Energy [2002] WASCA 231 at [143].

47 See, for example, the AEMC, *'Applying the Energy Objectives: A guide for stakeholders'*, 1 December 2016, p. 5.

48 NEL, s. 7A(7).

49 NEL, s. 7A(6).

the network, and could have adverse consequences for safety, security and reliability of the network.

The legislative framework recognises the complexity of this task by providing us with significant discretion in many aspects of the decision-making process to make judgements on these matters.

Electricity determinations are complex decisions, made up of a number of interrelated parts. Examining any one part in isolation ignores the importance of the interrelationships between components of the overall decision, and would not contribute to the achievement of the NEO. For example:

- there are underlying drivers and context which are likely to affect many constituent components of our decision. For example, forecast demand affects the efficient levels of capex and opex in the regulatory control period.
- there are direct mathematical links between different components of a decision. For example, the level of gamma has an impact on the appropriate tax allowance; the benchmark efficient entity's debt to equity ratio has a direct effect on the cost of equity, the cost of debt, and the overall vanilla rate of return
- there are trade-offs between different components of revenue. For example, undertaking a particular capex project may affect the need for opex or vice versa.

In most cases, the provisions of the NER do not point to a single answer, either for our decision as a whole or in respect of particular components. They require us to exercise our regulatory judgement. For example, in making our determination the NER requires us to prepare forecasts, which are predictions about unknown future circumstances. Very often, there will be more than one plausible forecast,[50] and much debate amongst stakeholders about relevant costs. For certain components of our decision there may therefore be several plausible answers or several plausible point estimates.

When the constituent components of our decision are considered together, this means there will almost always be several potential, overall decisions. More than one of these may contribute to the achievement of the NEO. In these cases, our role is to make an overall decision that we are satisfied contributes to the achievement of the NEO to the greatest degree.[51]

We approach this from a practical perspective, accepting that it is not possible to consider every permutation specifically. Where there are choices to be made among several plausible alternatives, we have selected what we are satisfied would result in an overall decision that contributes to the achievement of the NEO to the greatest degree.

50 AEMC, *Rule Determination: National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006*, 16 November 2006, p. 52.

51 NEL, s. 16(1)(d).

Regulatory framework in transition

The national framework as it is applied to the Northern Territory commenced on 1 July 2016 with the adoption of the NT NER.[52] [53]

The legislative and regulatory framework in NT under which Power and Water will be required to operate is undergoing change with the progressive adoption of the National Electricity Law and NT NER from 1 July 2016. In addition to the initial adoption of the framework on 1 July 2016, there has also been further amendments on 1 July 2017 to adopt a connections and metering framework for Power and Water. It is anticipated that further aspects of the national framework will be applied in the NT on 1 July 2018 and 1 July 2019.

As the framework is undergoing change before the commencement of the 2019–24 regulatory control period, for the purposes of its proposal Power and Water has drawn its expenditure forecasts based on the legislative and regulatory instruments as in force on 1 July 2017. If further changes to the regulatory framework that impact on the operation of Power and Water's business are known, these will be considered to the extent possible prior to us making our final determination. Otherwise Power and Water will have an opportunity to seek a cost pass through during the 2019–24 regulatory control period should there be any material costs arising from NT NER regulatory changes.[54]

52 The NT NER is given effect under National Electricity (Northern Territory)(National Uniform Legislation (Modification) Regulations made by the Northern Territory under the National Electricity (Northern Territory) (National Uniform Legislation) Act.

53 The NT NER can be found on the AEMC website at: https://www.aemc.gov.au/regulation/energy-rules/national-electricity-rules-northern-territory

54 Regulation 10A of the National Electricity (Northern Territory)(National Uniform Legislation)(Modification) Regulations provides for a 'NT NER transitional regulatory change event', allowing Power and Water to pass through NT NER transition costs incurred between 1 July 2017 and 30 July 2019, if the changes, taken as a sum substantially affect the manner in which Power and Water provides its services and result in a material increase or decrease in the costs of providing the services.

B. Other AER reviews that may be of interest

5.2.1 Review of rate of return guideline

Our rate of return guideline sets out the approach by which we will estimate the rate of return (comprising the return on debt, the return on equity, and the value of imputation credits).

Estimation of the rate of return is complex and the rate of return is a significant driver of regulated revenue. We have sought stakeholders' views on whether our current approach to setting the allowed rate of return remains appropriate.

We expect to publish the final guideline in December 2018.

More information can be found on our website: Review of rate of return guideline.

5.2.2 Review of the service target performance incentive scheme

We create and administer the Service Target Performance Incentive Scheme (STPIS) in accordance with the requirements of the NER. The purpose of the scheme is to provide incentives to electricity distributors to maintain the existing supply reliability performance and to make improvement to the extent to match customers' value on supply reliability.

We currently apply the scheme to distributors in the NEM. Our last review of the STPIS was in 2009 and we now consider it timely to review the scheme to account for the lessons learnt in implementing the scheme.

We also conduct this review in conjunction with the establishment of a Distribution Reliability Measures Guideline to set out common definitions of reliability measures that can be used to assess and compare the reliability performance of distributors.

We expect to finalise this review by June 2018.

More information can be found on our website: Service target performance incentive scheme - 2017 amendment.

5.2.3 Review of operating environment factors for distribution network service providers

We are currently reviewing our analysis of operating environment factors for the economic benchmarking of electricity distributors, in consultation with industry and other stakeholders.

In our annual benchmarking reports, we examine the relative efficiency of the distribution and transmission electricity service providers. In doing this we consider the characteristics of each network business, and how their productivity compares at the aggregate level given the outputs they deliver to consumers.

We also analyse the operating environment factors that may be unique to particular network service providers and which are not captured by our econometric benchmarking models. This helps us to identify the material factors driving apparent differences in estimated operating efficiency between the electricity distributors in the NEM.

We expect to finalise this review by May 2018.

More information can be found on our website: Review of operating environment factors for distribution network service providers.

5.2.4 Distribution service classification guidelines and asset exemption guidelines

The AEMC has made a rule change to require the AER to prepare two new guidelines: a distribution service classification guideline and an asset exemption guideline.

Service classification determines the regulatory treatment of a service offered by a network service provider. This includes whether or not a service is subject to regulation, the approach to cost recovery, and whether or not a service will need to be ring-fenced from other services offered by a DNSP.

The AEMC's new restricted asset rule aims to aid the development of new markets for services where the participation of a DNSP could be harmful to consumers. A restricted asset is any asset owned by a DNSP located on the customer's side of a connection point to a network ('behind the meter'). A DNSP cannot add a restricted asset to its regulatory asset base unless it has obtained an exemption from us. The asset exemption guideline will set out our approach to exempting restricted assets.

Both guidelines aim to make the regulatory process more transparent and effective and will apply across the NEM. We have commenced consultation with the publication of an issues paper on 16 February 2018. We will publish the guidelines by end-September 2018.

More information can be found on our website: Distribution service classification guidelines and asset exemption guidelines.

5.2.5 Review of the application guidelines for the regulatory investment tests for transmission and distribution

We have commenced our review of the application guidelines for our regulatory investment tests (RITs). The RITs are cost–benefit analyses that network businesses must perform and consult on before making major investments in their networks. When undertaking RITs, network businesses must give due consideration to what options are out there, before identifying the best way to address needs on their networks.

We currently have separate RITs for transmission and distribution networks (the RIT-T and RIT-D). Each RIT has its own application guidelines to guide businesses on how to apply the RITs consistently and transparently.

After extensive stakeholder engagement, we expect to finalise the review in September 2018.

More information can be found on our website: Review of the application guidelines for regulatory investment tests.