ISSUES PAPER

NSW electricity distribution determinations

Ausgrid, Endeavour Energy, Essential Energy

2019 to 2024

June 2018

AUSTRALIAN ENERGY REGULATOR

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Invitation for submissions

A public forum on the proposals from Ausgrid, Endeavour Energy and Essential Energy will be held on 3 July 2018 in Sydney. Interested parties are invited to register their interest in attending the forum by emailing NSW2019-24@aer.gov.au with their name, the business or agency they represent (if relevant) and contact details by 29 June 2018.

Written submissions on the proposals from Ausgrid, Endeavour Energy and Essential Energy are invited by 8 August 2018.

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

Submissions should be sent to: NSW2019-24@aer.gov.au.

Alternatively, submissions can be sent to:

Sebastian Roberts
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:

(1) clearly identify the information that is the subject of the confidentiality claim

(2) 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

Contents

Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
augex	augmentation capital expenditure
capex	capital expenditure
CCP/CCP10	Consumer Challenge Panel, sub-panel 10
CESS	Capital Expenditure Sharing Scheme
COAG	Council of Australian Governments
CPI	Consumer price index
DMIA/DMIAM	Demand Management Innovation Allowance/Demand Management Innovation Allowance Mechanism
DMIS	Demand Management Incentive Scheme
EBSS	Efficiency Benefit Sharing Scheme
HID	high intensity discharge
ICT	information and communications technology
LED	light emitting diode
LIDAR	light detection and ranging
NEL	National Electricity Law
NEO	National electricity objective
NER	National Electricity Rules
NGL	National Gas Law
NSW	New South Wales
opex	operating expenditure
PTRM	Post tax revenue model
RAB	Regulatory asset base
repex	replacement capital expenditure
RIT-D	Regulatory Investment Test - Distribution
STPIS	Service Target Performance Incentive Scheme
TNSP	Transmission network service provider
TSS	Tariff Structure Statement
WARL	weighted average remaining life

1 Introduction

The Australian Energy Regulator (AER) works to make all Australian energy consumers better off, now and in the future. We regulate electricity networks in all jurisdictions except Western Australia. Our work is guided by the National Electricity Objective (NEO) which promotes efficient investment in, and operation and use of, electricity services in the long term interests of consumers.[2] As part of this, we set the maximum revenues that networks are allowed to recover from consumers through their network tariffs (this is known as the 'revenue cap' form of control). The amount of these revenues is based on our assessment of efficient costs and a realistic expectation of forecast electricity demand. By only allowing efficient costs we regulate network tariffs so that consumers pay no more than necessary for the safe and reliable delivery of electricity.

Regulatory determinations usually occur every five years for each regulated business. We use an incentive approach where, once regulated revenues are set for a five year period, networks who keep actual costs below the regulatory forecast of costs retain part of the benefit. This benchmark incentive framework is a foundation of the AER's regulatory approach and promotes the delivery of the NEO. Service providers have an incentive to become more efficient over time, as they retain part of the financial benefit from improved efficiency. Consumers also benefit when efficient costs are revealed and a lower cost benchmark is set in subsequent regulatory periods.

On 30 April 2018, Ausgrid, Endeavour Energy (Endeavour) and Essential Energy (Essential) submitted their revenue proposals for the five years commencing 1 July 2019. This issues paper highlights some of the key elements of the three proposals, and how stakeholders can assist in our reviews.

1.1 How can you get involved?

A public forum on the proposals will be held in Sydney on 3 July 2018. As part of this review we're also seeking written submissions from stakeholders on the proposals from Ausgrid, Endeavour and Essential, their priorities for these reviews and their views on where our assessment should focus.

The decisions we make and the actions we take affect a wide range of individuals, businesses and organisations. Hearing from those affected by our work helps us make better decisions, provides greater transparency and predictability, and builds trust and confidence in the regulatory regime.

Throughout these reviews we will also have the benefit of advice from our Consumer Challenge Panel (CCP10).[3] The expert members of the CCP help us to make better

2 NEL, s. 7.

3 Members of CCP10 are Mark Henley, Louise Benjamin, Mike Swanston and Eric Groom. Member biographies are available on our website: https://www.aer.gov.au/about-us/consumer-challenge-panel.

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 planned for these reviews:

Milestone	Date
Ausgrid, Endeavour and Essential submitted their proposals	30 April 2018
AER issues paper published	27 June 2018
Public forum on Ausgrid, Endeavour and Essential proposals	3 July 2018
Submissions on AER's issues paper and Ausgrid, Endeavour and Essential proposals due	8 August 2018
AER draft decision to be published	October 2018
Public forum on draft decision	November 2018
Ausgrid, Endeavour and Essential submit revised proposals	January 2019
Submissions on draft decision and revised proposals due	February 2019
AER final decision to be published	April 2019

Note: Timelines are subject to change.

2 What would these proposals mean for NSW customers?

Ausgrid, Endeavour and Essential are the electricity distribution network service providers in New South Wales (NSW):

- Ausgrid's network serves customers in Sydney, the Central Coast and the Hunter Valley.
- Endeavour's network serves customers in Sydney's greater west, the Blue Mountains, Southern Highlands, the Illawarra and South Coast.
- Essential's network serves customers in rural and regional NSW.

Together, these businesses have proposed combined revenues of $19.1 billion ($nominal, smoothed), to be recovered from NSW electricity customers over the five years from 1 July 2019 to 30 June 2024 (see Table 1).[4] In nominal terms (including the impact of inflation) these proposals are seeking higher distribution revenues than what we approved for the 2014–19 regulatory control period, with an increase of 1.85 per cent proposed for Ausgrid, 10.24 per cent for Essential and 12.51 per cent for Endeavour.

Table 1 Summary of proposed revenue ($nominal, smoothed)

($ million)	2019/20	2020/21	2021/22	2022/23	2023/24	Total 2019-24	% change from 2014–19
Ausgrid - distribution[1]	1,516.63	1,554.54	1,593.41	1,633.24	1,674.07	7,971.89	1.85%
Ausgrid - transmission[2]	180.07	184.57	189.19	193.92	198.76	946.51	-5.45%
Endeavour	877.69	902.83	926.60	953.52	988.52	4,649.16	12.51%
Essential	1,024.44	1,065.04	1,107.26	1,151.15	1,196.78	5,544.66	10.24%

Source: Ausgrid - Attachment 4.02 - Distribution PTRM - April 2018 - PUBLIC; Ausgrid - Attachment 4.05 - Transmission PTRM - April 2018 - PUBLIC; Endeavour Energy - 0.04 Post-Tax Revenue Model - April 2018 - Public; Essential Energy - 9.1 Standard Control Service PTRM - 20180430 - Public.

Note 1: Revenue for Essential and Endeavour includes their proposed adjustments for our remitted decisions for 2014-19, but Ausgrid's does not.

Note 2: Ausgrid's proposal includes revenue for its transmission assets, which are recovered through TransGrid as the coordinating transmission network service provider for NSW and not through Ausgrid's distribution network tariffs.

4 In this section we discuss proposed revenue in nominal dollar terms as these are the total revenues that Ausgrid, Endeavour and Essential are expected to recover from customers after taking into account forecast inflation over the period.

With the exception of Ausgrid's transmission revenue, which is recovered by TransGrid as the coordinating transmission network service provider for NSW, these revenues will be recovered through distribution network tariffs, which are determined based on the total maximum revenue approved for each year and the approved forecast demand for electricity distribution network services. Table 2 shows the estimated impact these proposals would have on distribution network tariffs over the five years. Under the revenue cap form of control that will continue to apply to Ausgrid, Endeavour and Essential from 1 July 2019, any difference between forecast and actual demand will impact distribution tariffs: if actual demand is higher than forecast demand, tariffs will go down (and vice versa).

Table 2 Estimated distribution network tariff impact (per cent, nominal)

	2019/20	2020/21	2021/22	2022/23	2023/24	Average 2019-24
Ausgrid	1.0%	2.6%	1.2%	1.9%	1.8%	1.7%
Endeavour	2.1%	2.2%	2.0%	2.2%	2.0%	2.1%
Essential	4.0%	4.1%	4.2%	3.7%	3.7%	3.9%

Source: Ausgrid - RIN11.3 - RIN Workbook 1 - Consolidated - 22 June 2018; Endeavour Energy - RIN0.01 Final RIN Workbook 1 Reset (Consolidated) - 30 April 2018; Essential Energy - R1a Final RIN - 1 - Reset_MASTER - 30 April 2018.

Note: Estimates for Essential and Endeavour includes adjustments for our remitted decisions for 2014-19, but Ausgrid's do not.

The common categories of costs that are typically identified as making up retail electricity prices are wholesale costs, network costs (transmission and distribution), environmental (green) scheme costs and retail costs and margins. The distribution network tariffs that will be set on the basis of our decisions on maximum revenue are only one component of retail energy bills. If we hold the other components constant and just look at the 29-37 per cent contribution Ausgrid, Endeavour and Essential estimate their distribution network tariffs make to customers' retail electricity bills:

- Ausgrid is seeking revenue that if approved would result in the distribution network component of an average annual electricity bill for Ausgrid customers being an estimated $5 higher in 2019/20 for its residential customers, and $11 higher for its small business customers. Over the five years covered by its proposal, Ausgrid estimates an average annual increase of 0.5 per cent ($nominal).[5]
- Endeavour is seeking revenue that if approved would result in an estimated increase of $11 to the average annual electricity bill for its residential customers in

[5] Ausgrid - RIN11.3 - RIN Workbook 1 - Consolidated - 22 June 2018. Estimated by reference to Energy Australia's Basic Home Residential tariff and Basic Business tariff. Assumes annual consumption of 5MWh for residential customers, and 10MWh for small business customers. Assumes distribution costs make up 29.6 per cent of a typical customer's electricity bill.

2019/20, and of $21 to the average annual electricity bill for its small business customers. Over the five years covered by its proposal, Endeavour estimates an average annual increase of 0.7 per cent ($nominal).[6]

- Essential is seeking revenue that would result in an estimated $29 increase to the average annual residential customer's bill in 2019/20, and an estimated $136 more on bills for small business customers. Over the five years covered by its proposal, Essential estimates an average annual increase of 1.6 per cent ($nominal).[7]

In their proposals, Ausgrid, Endeavour and Essential have outlined the customer and stakeholder engagement they have undertaken in the development of the proposals. This included additional engagement earlier this year following our agreement to extend the time for submission of proposals by three months from 31 January to 30 April 2018. The extra time was provided so that the businesses could engage with stakeholders on their remittal proposals and consider that feedback in their 2019-24 proposals. Our approval was contingent on the businesses also engaging with us and stakeholders on a thorough interrogation (‘deep dive’) of their capital plans and associated costs. The intention was that such deep dives would help make these regulatory processes more efficient. The deep dive processes do not, however, replace the need to ensure that all aspects of the proposals are thoroughly tested.

From their engagement, the businesses have told us that affordability and reliability have emerged as key areas of concern to the stakeholders of all three businesses.[8] For Endeavour and Essential stakeholders voiced network safety as their third key concern. For Ausgrid sustainability was third on the list of key concerns for its stakeholders, with customer support for Ausgrid playing a role in developing the grid to support the energy mix of the future.[9]

Each business has now submitted a proposal that it considers responds to the themes and priorities identified through its engagement with customers and other key stakeholders. As part of our review, we are particularly interested to hear from stakeholders whether these themes reflect their own priorities for these determinations, and how well the businesses have—in the proposals submitted to us for assessment—addressed concerns put to them by stakeholders in the course of that engagement.

6 Endeavour Energy - RIN0.01 Final RIN Workbook 1 Reset (Consolidated) - 30 April 2018. Estimated by reference to Origin Energy's Standing Offers (residential and small business) for the Endeavour Energy network area. Assumes distribution costs make up 29.7 per cent of a typical customer's electricity bill.

7 Essential Energy - R1a Final RIN - 1 - Reset_MASTER - 30 April 2018. Estimated by reference to Origin Energy's Standing offers for the Essential Energy network area. Assumes annual consumption of 5MWh for residential customers and 23 MWh for small business customers. Assumes distribution costs makes up 36.6 per cent of a typical customer's electricity bill.

8 Ausgrid - Regulatory Proposal - April 2018, p. 27.

9 Ausgrid - Regulatory Proposal - April 2018, pp. 27, 35.

2.1 A note on our previous decisions

Ausgrid, Endeavour and Essential all appealed our 2015 determinations of their revenue allowances for the current 2014–19 regulatory control period. The Australian Competition Tribunal set aside our decisions and directed us to remake them. In 2017 we began the process of remaking those decisions in accordance with the Tribunal's directions.

Our remade decisions for 2014–19 will impact the current proposals insofar as the difference between what the businesses will have recovered over the 2014–19 period and the amount ultimately allowed for in our remade decisions will have to be returned to customers in the 2019–24 regulatory period.

We published our remade final decision for Essential for 2014–19 on 31 May 2018. Essential's proposal for the 2019–24 regulatory control period includes a downward adjustment to its proposed revenue to return to its customers the difference between the revenue Essential will recover over the 2014–19 period under interim tariff undertakings and the total revenue we approved in our remade final decision.

Endeavour's 2019–24 proposal also includes a downward revenue adjustment, reflecting the difference between the revenue it has recovered under interim tariff undertakings and its proposed resolution for its 2014–19 determination, which we have yet to remake.[10]

At the time of publishing this issues paper Ausgrid had not yet filed its proposed approach to remaking our decision on its 2014–19 determination. As such, its proposal for 2019–24 does not include any assumptions about the 2014–19 remade decision at this point. However, like Essential and Endeavour, we anticipate that any difference between the revenue Ausgrid will recover over 2014–19 under its interim tariff undertakings and our 2014–19 remade decision will be reflected in Ausgrid's network tariffs from 1 July 2019.

[10] https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/endeavour-energy-determination-2014-19-remittal/proposal

3 What's driving the change in revenue over time

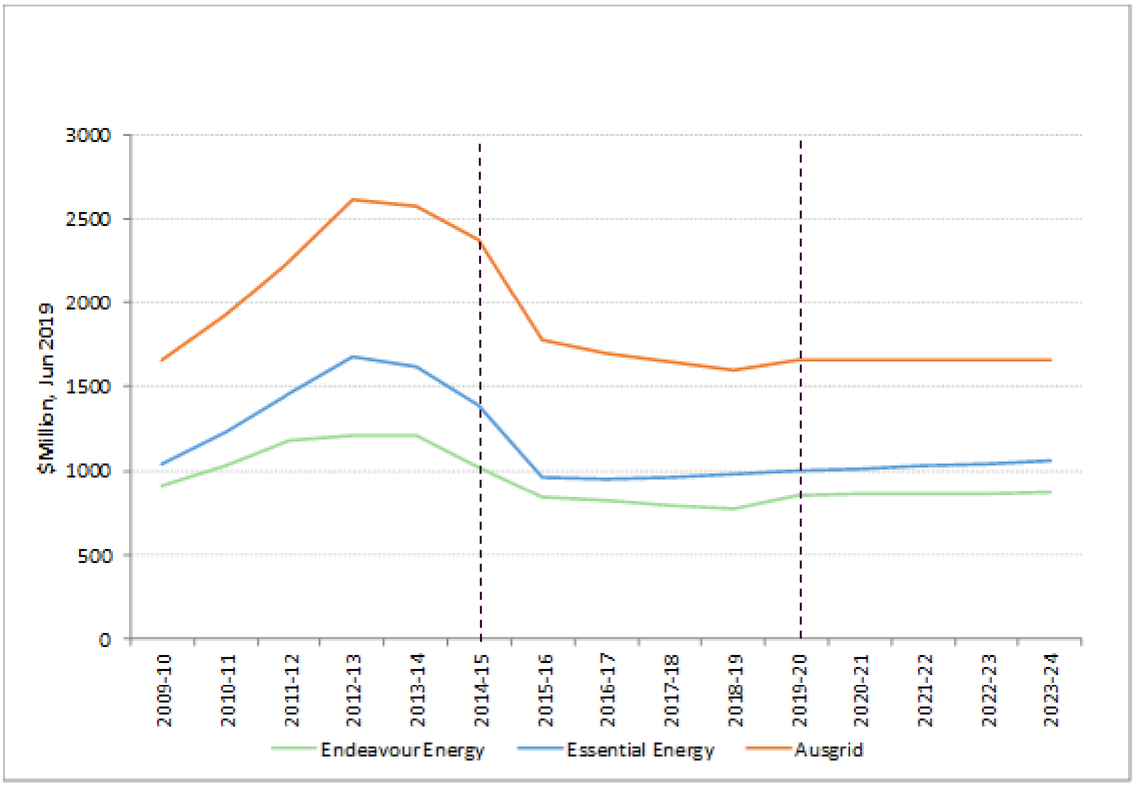
In section 2 we looked at the proposals in nominal terms, taking into account the expected impact of inflation. The changing impact of inflation over time makes it difficult to compare revenue from one period to the next on a like-for-like basis. To do this, we use 'real' values based on a common year (in this case 2018/19), which have been adjusted to remove the impact of forecast inflation.

In real terms, as Figure **1** shows, the forecast revenue requirements proposed for 2019–24 are relatively stable. Noting that we have remade our 2014–19 revenue determination for Essential, but have yet to do so for Endeavour and Ausgrid:

- Essential's proposed revenue for 2019–24 is a 1.5 per cent reduction from our remade final decision for 2014–19.
- Endeavour's proposed revenue for 2019–24 is 2 per cent higher in real terms than the revenue we approved in our original decision for 2014–19. This increase takes into account Endeavour's proposed resolution for its 2014–19 determination, which we have yet to remake.
- Ausgrid's proposed revenue for 2019–24 is 8.7 per cent lower in real terms than the revenue we approved in our original decision for 2014–19.

These proposals would—if approved—deliver relatively stable distribution network revenues and distribution tariffs over the five years from 1 July 2019, in line with those that followed the significant reduction in revenue from the 2009–14 regulatory control period to the current, 2014–19 period.

Figure 1 Changes in regulated revenue over time ($million, 2018/19)



Source: AER analysis.

Allowed revenues for 2009–14 included provision for significant increases in capital investment in the NSW distribution networks, to improve network security and reliability of supply in line with licence conditions imposed by the NSW Government at the time. The resultant regulated asset base (RAB) growth, combined with high rates of return (10.02 per cent) determined in the face of a challenging investment environment during the global financial crisis, resulted in increased revenues and higher prices for electricity customers in NSW.

By the time of our revenue determinations for 2014–19, a number of things had changed such that our 2015 final decisions were that distribution services could be provided at substantially lower cost while still maintaining safety and complying with reliability obligations, including:

- The investment environment had improved compared to our 2009 decision, which translated to lower financing costs necessary to attract efficient investment. Approved rates of return fell from 10.02 per cent to 6.68 per cent.
- A consistent body of evidence demonstrated that past expenditure on the NSW distribution networks had been higher than necessary to maintain network safety and reliably, and that historical operating costs were above efficient levels.
- Flatter demand forecasts meant that distributors were under less pressure to expand and augment their networks than in the previous regulatory control period

to meet the needs of additional customers or any increased demand from existing customers.

The proposals we are now reviewing for 2019–24 reflect a continuation of many of these trends. The significant operating efficiencies Ausgrid, Endeavour and Essential have achieved during the 2014–19 regulatory control period to reduce their regulated operating expenditure (opex) allowances are now being passed through to customers in the form of lower opex forecasts. Proposed rates of return have fallen again, from 6.68 per cent to 6.11-6.34 per cent. Capital expenditure (capex) forecasts are also changing, with future investment primarily driven by asset renewal and replacement and to meet the impact of distributed energy resources on the network. Projected RAB growth—while still a key driver of proposed revenues—is now significantly below its peak in 2009–14.

In combination, these factors mean that revenue proposals and the resultant distribution network tariffs are also stabilising from period to period.

In sections 4, 5 and 6 below we highlight some of the key elements of each of the three revenue proposals and what is driving these outcomes. First, we provide a quick overview of how we determine forecast revenue.

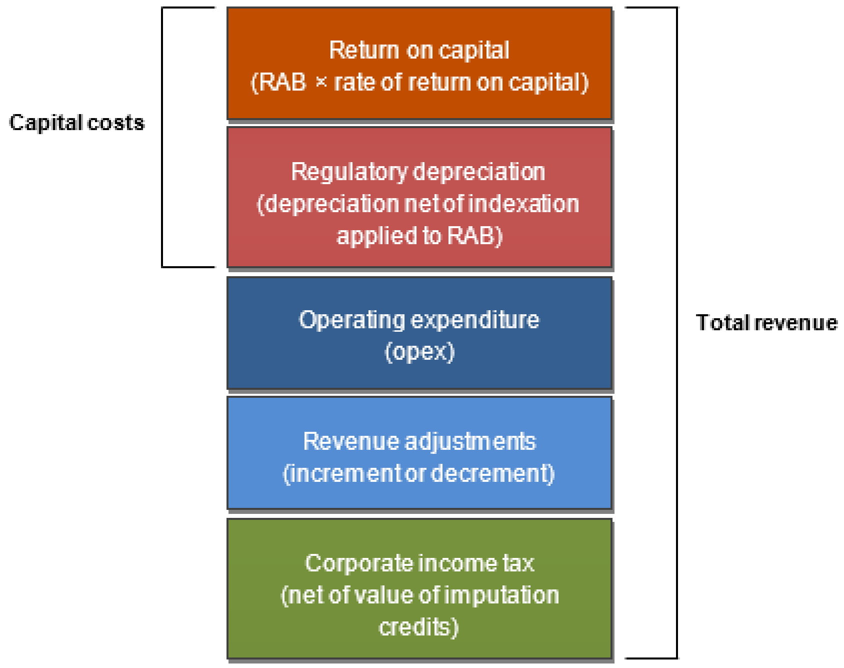
3.1 How we determine forecast revenue

The total revenue Ausgrid, Endeavour and Essential have each proposed reflect their forecasts of the efficient cost of providing its distribution network services over the 2019–24 regulatory control period.

These revenue proposals, and our assessment of them under the National Electricity Law and Rules (NEL and NER), are based on a 'building block' approach (see Figure 2) which looks at five cost components:

- a return on the RAB (or return on capital, to compensate investors for the opportunity cost of funds invested in this business)
- depreciation of the RAB (or return of capital, to return the initial investment to investors over time)
- forecast opex – the operating, maintenance and other non-capital expenses, incurred in the provision of network services
- revenue increments or decrements resulting from the application of incentive schemes such as the opex Efficiency Benefit Sharing Scheme (EBSS), Capital Expenditure Sharing Scheme (CESS) and Demand Management Innovation Allowance (DMIA)
- the estimated cost of corporate income tax.

Figure 2 The building block approach for determining total revenue



We use an incentive approach where, once regulated revenues are set for a five year period, networks who keep actual costs below the regulatory forecast of costs retain part of the benefit. This benchmark incentive framework is a foundation of the AER's regulatory approach and promotes the delivery of the national electricity objective (NEO) and national gas objective (NGO). Service providers have an incentive to become more efficient over time, as they retain part of the financial benefit from improved efficiency. Consumers also benefit when efficient costs are revealed and a lower cost benchmark is set in subsequent regulatory periods.

Our assessment breaks these costs down further. For example:

- Capex—the capital costs and expenditure incurred in the provision of network services—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 directly affects the size of the capital base and therefore the revenue generated from the return on capital and depreciation building blocks. All else being equal, higher forecast capex will lead to a higher RAB and higher return on capital and regulatory depreciation allowances.
- The RAB accounts for the value of 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).[11] 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 (see section 3.1.1)
- regulatory depreciation (or the return of capital).

There are two aspects of our approach to forecast revenue that are currently under review. The outcomes of these reviews—discussed in sections 3.1.1 and 3.1.2 below—may impact our final decisions for these businesses.

3.1.1 Rate of return

The return (the 'return on capital') each business is to receive on its RAB continues to be a key driver of proposed revenues. We calculate the regulated return on capital by applying a rate of return to the value of the RAB.

The allowed rate of return is a forecast of the costs of funds a network business requires to attract investment in the network.

We estimate the rate of return by combining the returns of the two sources of funds for investment: equity and debt. The return on equity is the return shareholders of the business will require for them to continue to invest. The return on debt is the interest rate the network business pays when it borrows money to invest.

A good estimate of the rate of return is necessary to promote efficient prices in the long term interests of consumers. If the rate of return is set too low, the network business may not be able to attract sufficient funds to be able to make the required investments in the network and reliability may decline. Alternatively, if the rate of return is set too high, the network business may seek to spend too much and consumers will pay inefficiently high tariffs.

In their proposals for 2019–24, Ausgrid, Endeavour and Essential have adopted our standard approach to the rate of return, as set out in our 2013 Rate of Return Guideline and subsequent determinations.[12] 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.[13] The bulletin suggests that the binding guideline is intended to apply to our 2019-24 final determinations for

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

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

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

Ausgrid, Endeavour and Essential.[14] Consultation on proposed amendments to the NEL and National Gas Law 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 decisions for these businesses.

On that basis, we intend to consider all relevant rate of return and value of imputation credits (gamma) materials submitted to us in these and other concurrent determination processes as also being relevant material for our guideline review (and vice versa).[15]

3.1.2 Corporate income tax allowance

The building block approach to calculation of revenue includes an allowance for the estimated cost of corporate income tax payable by the business. We calculate the expected tax costs using a standard tax calculation that has regard to expected taxable revenue, expected tax expenses (depreciation, interest, opex) and the statutory corporate income tax rate (30 per cent) as set out in the NER.

Adopting our current approach to estimating the corporate income tax allowance, the businesses' proposals begin with their estimates of the taxable income that would be earned by a benchmark efficient company operating its network. This estimate takes into account estimated tax expenses such as interest (using our benchmark 60 per cent gearing) and depreciation. Tax expenses (including other expenses such as operating expenditure) are then offset against forecast revenue to estimate taxable income. The statutory income tax rate of 30 per cent is then applied to the estimated taxable income to arrive at a notional amount of tax payable. Finally, a discount is applied to the notional amount of tax payable to account for the value of imputation credits (gamma).

Ausgrid, Endeavour and Essential have all adopted a gamma of 0.4, consistent with our 2013 rate of return guideline and recent decisions.[16] As we explained in section 3.1.1, we are currently reviewing our 2013 guideline and the COAG Energy Council is considering legislation that would make the 2018 guideline binding on all parties. A binding guideline would mean that most issues relating to the calculation of the rate of return including gamma would be out of scope in individual reset processes.

In May 2018 we also announced a review of our current regulatory tax approach, the outcomes of which may impact our final decisions for Ausgrid, Endeavour and Essential.[17]

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

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

16 Ausgrid - Regulatory Proposal - April 2018, p. 156.

17 https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/review-of-regulatory-tax-approach-2018

4 Key elements of Ausgrid's revenue proposal

Ausgrid's proposal would allow it to recover $8277 million ($2018/19, smoothed) from its customers over the 2019–24 period. This is an 8.7 per cent decrease from our decision for 2014–19, and would keep Ausgrid's revenue roughly in line with revenue levels at the end of the current period. While tariff outcomes from 1 July 2019 may change as a result of our remade decision on 2014–19 revenues, Ausgrid estimates that based on its current proposal:[18]

- its distribution network tariffs would fall by an average 0.8 per cent per annum in real terms.
- again in real terms—excluding the impact of inflation—this would lead to an average annual decrease of around 0.2 per cent to annual electricity bills for both residential and small business customers.

Ausgrid has a number of assets that are used to provide transmission services. These are subject to transmission tariffs. This share of Ausgrid's revenue is recovered from customers by TransGrid as the coordinating transmission network service provider for NSW, and then submitted by TransGrid to Ausgrid. Therefore there is no impact on the distribution component of the retail electricity bill.

Referring to the three key themes identified through its stakeholder engagement, Ausgrid submits that its proposal is:[19]

> - "Affordable: Our annual revenue requirement will lead to our component of prices being below current levels in real terms over 2019–24.
> - Reliable: Our annual revenue requirement will enable us to invest in maintaining network reliability.
> - Sustainable: The capex and opex strategies underpinning our annual revenue requirement are based on providing a sustainable network by leveraging new technologies and investing in demand management."

Figure 3 highlights changes in Ausgrid's proposal at the building block level to illustrate what is driving its proposed reduction in revenue from 2014–19 to 2019–24.

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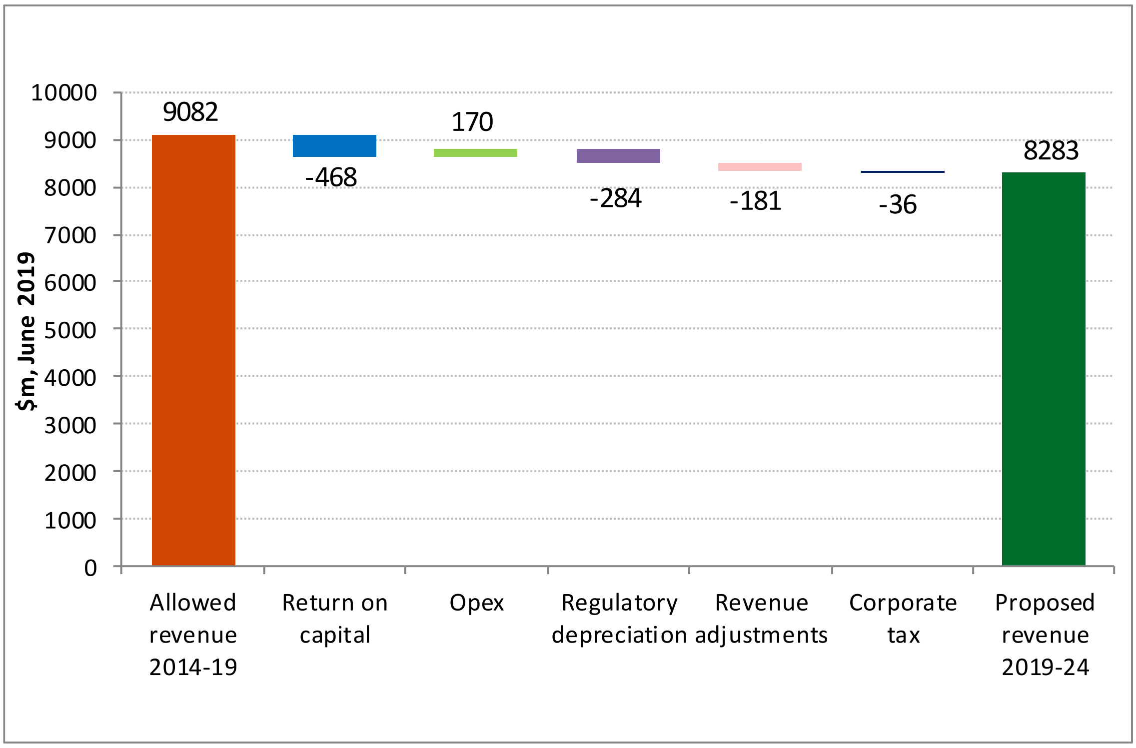
18 Ausgrid - RIN11.3 - RIN Workbook 1 - Consolidated - 22 June 2018. Estimated by reference to Energy Australia's Basic Home Residential tariff and Basic Business tariff. Assumes annual consumption of 5MWh for residential customers, and 10MWh for small business customers. Assumes distribution costs make up 29.6 per cent of a typical customer's electricity bill.

19 Ausgrid - Regulatory Proposal - April 2018 - PUBLIC, p. 49.

Figure 3 Changes in building blocks: Ausgrid's allowed revenue 2014–19 to forecast revenue 2019–24 ($million, 2018/19 – unsmoothed)



Source: AER analysis; includes transmission and distribution revenues. Note that our 2014-19 decision on Ausgrid's allowed revenue will be remade; any difference between the revenue Ausgrid has recovered under its interim tariff undertakings and remade decision will be reflected in approved revenue for 2019–24.

The biggest change is to the proposed return on capital.

Ausgrid's proposal for 2019–24 includes a rate of return of 6.33 per cent, compared to 6.68 per cent in our 2014–19 decision (and the 10.02 per cent rate of return determined on appeal from our 2009–14 decision). As we explained in section 3.1.1, we are currently reviewing our 2013 rate of return guideline and the COAG Energy Council is considering legislation that would make our new, 2018 guideline binding on our final decision for Ausgrid. Ausgrid has applied our 2013 guideline on the basis that the current rules would apply to its 2019-24 distribution determination. Ausgrid has also submitted a report from Frontier Economics as evidence to support a higher rate of return,[20] but notes that it is "committed to minimising further debate on this issue and to delivering a positive outcome for [its] customers".[21]

The combination of the lower rate of return, stabilising real RAB growth and reductions in proposed capex going forward are working together to put downward pressure on

[20] Ausgrid - Regulatory Proposal - April 2018, p. 141; Ausgrid attachment 7.01 – Estimation of certain aspects of the allowed rate of return, April 2018.

[21] Ausgrid - Regulatory Proposal - April 2018 - PUBLIC, p. 143.

revenues. These last two factors are also driving the lower regulatory depreciation allowance, which we discuss in more detail in sections 4.1 and 4.2 below.

Ausgrid's proposed increases in opex—the only building block to increase relative to our 2014–19 decision—are in part to support these lower capex projections. As we discuss in section 4.3, Ausgrid's proposal includes a step increase in opex to progress demand management initiatives that it submits will reduce capex requirements going forward. Changes in input costs and growth in the network and customer numbers are other contributors to Ausgrid's higher opex forecast.

The smaller revenue adjustments from incentives schemes going into 2019–24 reflect our decision not to apply the EBSS to Ausgrid for the 2014–19 regulatory control period. EBSS adjustments made up the vast majority of this category for the 2014–19 period, and in their absence this component of the building block calculation for 2019–24 is reduced.

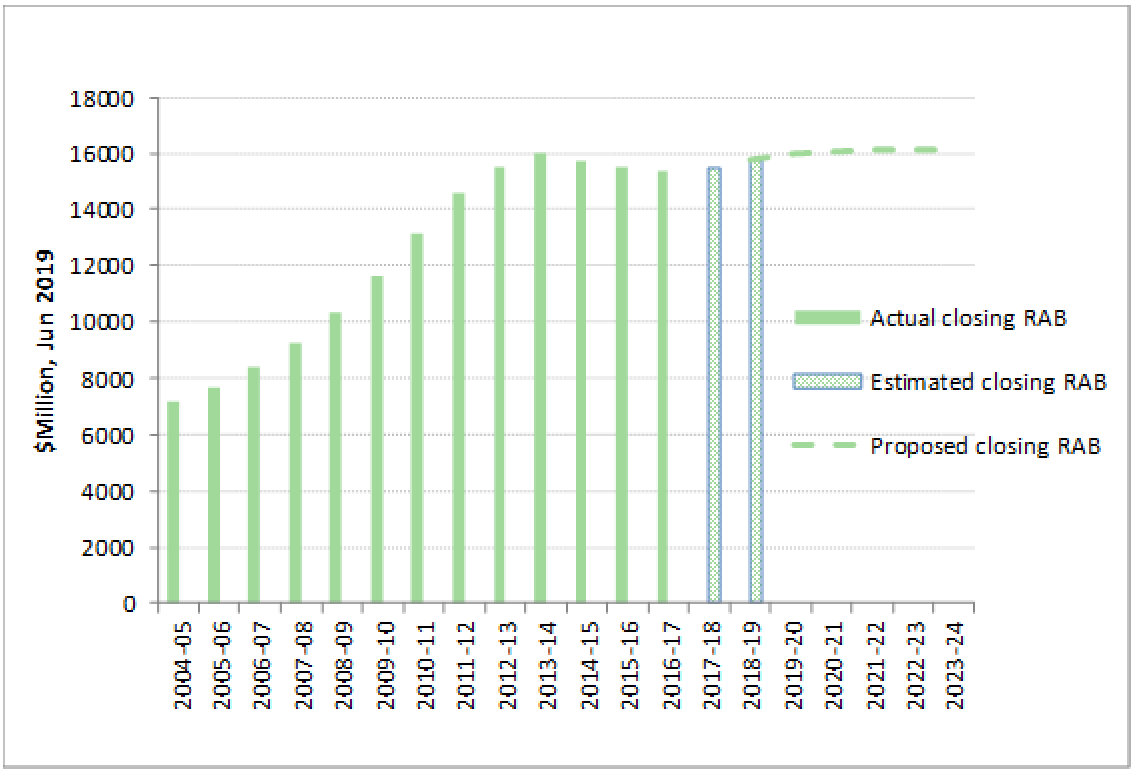
4.1 RAB and depreciation

The RAB is the value of assets used by Ausgrid to provide distribution and transmission network services. The value of the RAB substantially impacts Ausgrid's revenue requirement, and the price consumers ultimately pay. Other things being equal, a higher RAB would increase both the return on capital and depreciation (return of capital) components of the revenue determination.

RAB growth is a key issue for many stakeholders. As we noted in section 3, 2009–14 saw a significant increase in capital investment in Ausgrid's network. Ausgrid's RAB grew by around 54.7 per cent over that period. RAB growth slowed considerably in 2014–19, and Ausgrid's actual RAB growth of 0.2 per cent over that period was lower than the assumed 3.7 per cent used to set revenue for that period. Ausgrid's projected RAB growth over the 2019–24 period is 2.6 per cent.

Figure 4 shows the growth in value of Ausgrid's RAB over time.

Figure 4 Ausgrid's RAB value over time ($million, 2018/19)



Source: AER analysis; includes distribution and transmission assets.

Regulatory depreciation is the allowance provided so capital investors recover their investment over the economic life of the asset (return of capital). The depreciation schedules submitted by Ausgrid affect two areas of their maximum allowed revenue: indexation of the RAB and the depreciation building block. The regulatory depreciation allowance is the net total of the straight-line depreciation less the inflation indexation adjustment of the RAB.

Ausgrid's proposed regulatory depreciation allowance is 30 per cent lower in real terms than the allowance we used to set revenues for 2014–19. This is driven by a change in the composition of the RAB (a large proportion of the 2014–15 value of short lived assets is removed from the RAB over the 2014–19 period because for these assets depreciation exceeds net capex over 2014–19), and changes in inflation.

Ausgrid initially planned to move to a year-by-year tracking approach for implementing straight-line depreciation (Endeavour has proposed a similar approach – see section 5.1, below). This would have resulted in faster depreciation and higher revenues over 2019–24. However, Ausgrid's proposal notes that following consultation with its stakeholders it decided not to propose this change at this time.[22] It estimates this

[22] Ausgrid - Regulatory Proposal - April 2018, p. 55.

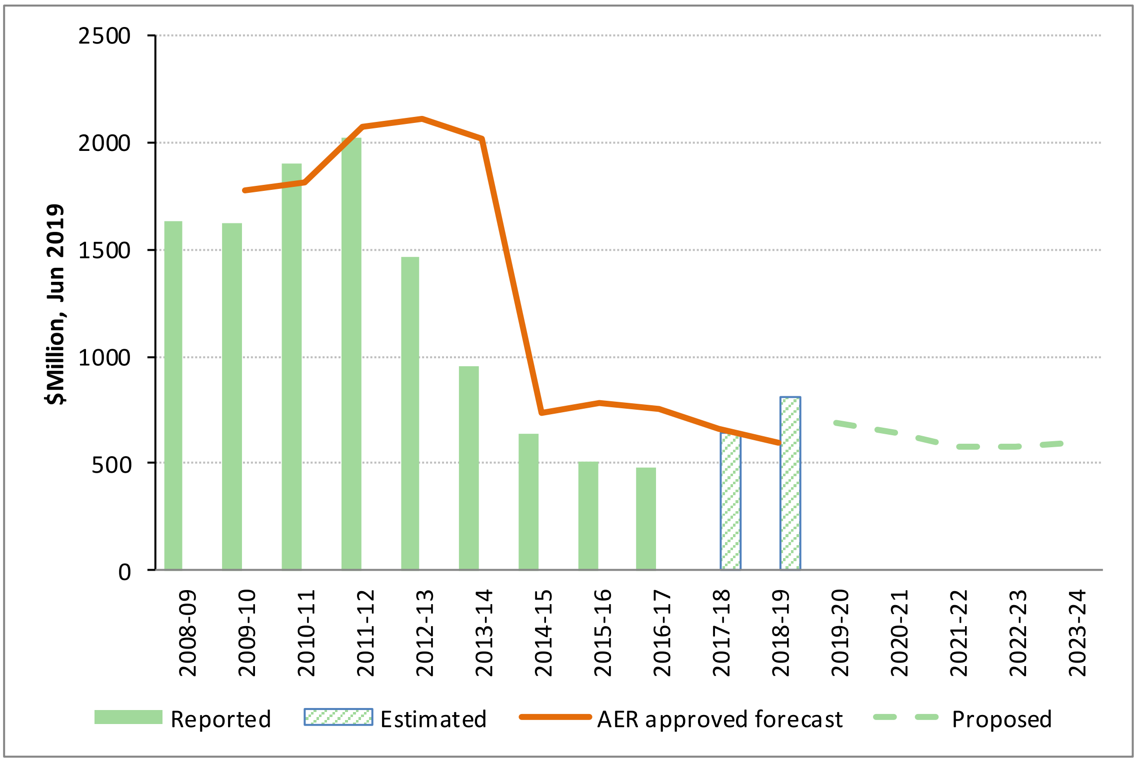
decision—one of the key changes made in response to its extended stakeholder engagement—has made a difference of $100 million (reduction) to its proposal.[23]

4.2 Capex

Capex is added to Ausgrid's RAB, which is used to determine the return on capital and return of capital (regulatory depreciation) building block allowances. All else being equal, higher forecast capex will lead to a higher RAB and higher return on capital and regulatory depreciation allowances.

Ausgrid has proposed total (net) forecast capex of $3.1 billion ($2018/19) for the 2019–24 regulatory control period. This is a decrease of 1.3 per cent from Ausgrid's actual capex for 2014–19 period.[24] Figure 5 shows the trend in Ausgrid's total capex over time.

Figure 5 Comparison of Ausgrid's past and forecast capex



Source: AER analysis.

This figure highlights the peak in capex in the 2009-14 regulatory control period that we discussed in section 3, and the subsequent reduction in both forecast and actual capex in 2014–19. For 2019–14, Ausgrid has proposed further reductions but has also noted

23 Ausgrid - Attachment 2.01 - Extended Stakeholder Consultation Report - June 2018, p. 27.

24 Note that Ausgrid's reported capex for 2017-18 and 2018-19 are estimates only. Ausgrid - Regulatory Proposal - April 2018, p. 65.

the importance of reliability to its customers, "with customers expecting very infrequent supply interruptions and prompt return to service following an interruption (particularly on high demand hot summer days)".[25] In keeping with its other key themes of affordability and sustainability, Ausgrid submits that its proposal will allow it to:[26]

- deliver a lower RAB per customer and help to deliver lower prices for customers
- keep capex to a minimum by only replacing aging assets where there is no alternative that is more efficient
- replace only what needs to be replaced, augment just enough and invest on a no regrets basis in light of emerging technologies.
- rather than simply building more infrastructure, [to look] first at where new technology, innovation and partnering with other companies and our customers will solve the problem at a lower cost. This includes demand management solutions. We will partner with customers to reduce the need to replace ageing network infrastructure by leveraging batteries, smart meters, smart appliances and innovative rebate offers which support a lower carbon economy.

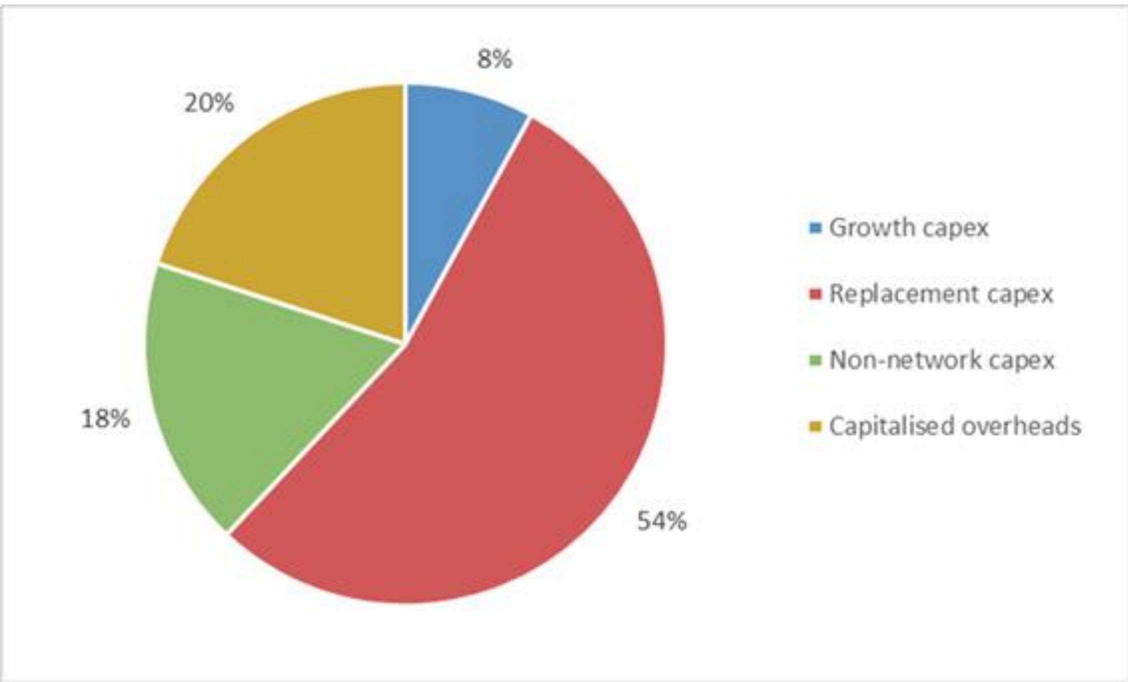
Our role is ensure that Ausgrid's forecast capex for 2019–24 is consistent with the capex criteria: efficiency, prudency and a realistic expectation of the demand forecast and cost inputs required to achieve the capex objectives under the NER. As part of our assessment of Ausgrid's capex forecast, we are interested in stakeholder views as to how well its proposal—the key drivers of which are summarised below—addresses its key themes of affordability, reliability and sustainability, and the extent to which its capex forecast addresses the concerns of electricity consumers as identified in the course of its engagement on its proposal.

Figure 6 breaks Ausgrid's 2019–24 capex forecast into its four main drivers, each of which we discuss briefly below.

25 Ausgrid - Regulatory Proposal - April 2018, p. 17.

26 Ausgrid - Regulatory Proposal - April 2018, p. 65.

Figure 6 Ausgrid's forecast capex by driver



Source: AER analysis.

Replacement capex (repex)

$1673.1 million, or 54 per cent, of Ausgrid's proposed capex relates to replacement and renewal of network assets in major projects, planned, conditional and reactive programs. Ausgrid's replacement program is driven largely by assets that are in poor condition and assets that pose a safety risk. This is broadly in line with Ausgrid's replacement capex over the current period.[27]

Our own predictive repex modelling is a key tool in our assessment of proposed repex. A lot of replacement expenditure can be modelled using the AER's predictive repex model. In particular, it can model high volume, low value assets which are generally a significant part of a business-as-usual capex spend.

As part of the extended engagement and 'capex deep dives' that followed our agreement to extend the submission date for these proposals, we explored this modelling, including new refinements that allow us to consider comparative scenarios, with CCP10 and Ausgrid. Ausgrid's proposal also relies on predictive models, including the AER's repex model, to forecast repex.

Unmodelled repex—which includes expenditure for low volume and high value assets—makes up 34 per cent of Ausgrid's proposed repex and will be a focus of our review. This expenditure relates to SCADA and protection replacement, substation

[27] Ausgrid - Regulatory Proposal - April 2018, p. 84.

buildings, operational technology and duty of care programs. Ausgrid forecasts that repex within its unmodelled repex categories will increase from around $67 million per year (2014-15 to 2016-17) to $115 million per year over the 2019–24 regulatory control period.

Growth capex

$241 million (8 per cent) of Ausgrid's proposed capex relates to growth-related programs involving connecting new customers ($52.2 million) and augmenting the existing network to meet forecast peak demand ($189.1 million).[28]

Ausgrid submits that network augmentation will be required around major infrastructure loads particularly in the Sydney region. In other areas additional load may be supported by Ausgrid's past investments.[29]

Ausgrid's forecast connections expenditure for the 2019–24 regulatory control period is higher than it expects to have invested by the end of the current 2014–19 period. Ausgrid submits that it expects a high number of residential connections as well as the connection of several large road and rail projects and data centres.[30]

As part of its extended engagement process, Ausgrid initially proposed to fund a greater proportion of new connections assets that were to be shared by the network through its regulated revenues (and therefore to increase their contribution to the RAB). It submitted that this new approach would have improved the equity of its approach to the allocation of shared connection costs. As a result of stakeholder feedback, Ausgrid decided not to change its connections policy. This means that capital contributions for a portion of the shared assets will continue to be paid by the connecting party rather than entering the RAB.[31] Ausgrid estimates this decision—another key outcome of Ausgrid's extended customer engagement—has reduced its connection-related capex by $25 million.[32]

Non network capex

Ausgrid's capex forecast for 2019-24 includes $548 million for non network capex (18 per cent of total capex). This comprises $216 million for information and communications technology (ICT capex), $208 million for property, $94 million for fleet and $30 million for plant.[33]

Ausgrid forecasts a current period overspend of $75 million on ICT capex relative to our 2015 decision, and its proposal maintains that higher level of ICT expenditure

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[28] Ausgrid - Regulatory Proposal - April 2018, p. 88.

[29] Ausgrid - Regulatory Proposal - April 2018, p. 89.

[30] Ausgrid - Regulatory Proposal - April 2018, pp. 91 and 93.

[31] Ausgrid - 2.01 Extended Stakeholder Consultation Report - June 2018, p. 15.

[32] Ausgrid - Attachment 2.01 - Extended Stakeholder Consultation Report - June 2018, p. 27.

[33] Ausgrid - Regulatory Proposal - April 2018, p. 67.

throughout the next period. Ausgrid’s key ICT programs proposed for 2019–24 are application maintenance ($81 million), cyber security ($20 million) and data and digital enablement ($24 million).[34] This includes $41 million for an Advanced Distribution Management System (ADMS) to support Ausgrid's sustainability objective and the "transformation of [its] network from a passive to an active distribution network".[35] As part of our assessment we are keen to hear from stakeholders on how (and how well) they consider the benefits of these ICT initiatives, particularly the data and digital enablement, have been demonstrated in Ausgrid's proposal for 2019–24.

Ausgrid submits that it will increase its fleet expenditure for the 2019–24 regulatory control period compared with the current 2014–19 period. Ausgrid aims to increase the standardisation of its vehicle fleet to reduce maintenance and replacement costs over the longer term.[36]

Capitalised overheads

The remaining $621.3 million (20 per cent) of proposed capex relates to capital program support, often referred to as 'capitalised overheads'. These costs include planning, management and supervision of capital projects and programs, scheduling jobs, administrative support and safety.[37] Ausgrid's proposed capitalised overheads for 2019–24 are 9 per cent lower than in the current 2014–19 period.[38]

4.3 Opex

In our April 2015 final decision, we set an opex forecast for the current 2014-19 regulatory period that was 26 per cent lower than the amount proposed by Ausgrid. Following appeals to the Australian Competition Tribunal and the Federal Court, we are in the process of remaking our opex forecast as part of our remade 2014–19 determination.

Figure 7 shows the trend in Ausgrid's opex over time. Ausgrid's actual opex over the first three years of the remittal period (2014-15, 2015-16 and 2016-17) and its opex forecasts for the last two years (2017-18 and 2018-19), show that Ausgrid has been steadily reducing its opex since 2014-15. By the end of the 2014-19 regulatory control period, Ausgrid expects to achieve a level that is consistent with our 2015 estimate of efficient opex.[39]

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[34] Ausgrid - Regulatory Proposal - April 2018, p. 99.

[35] Ausgrid - Regulatory Proposal - April 2018, p. 17.

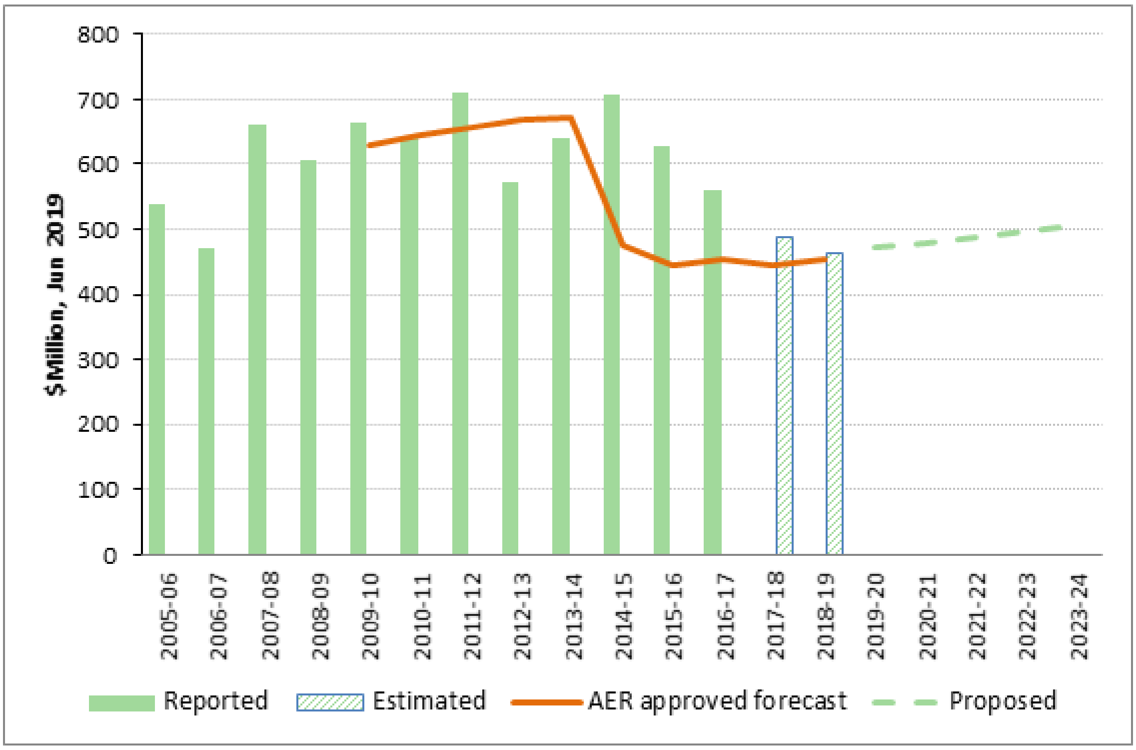
[36] Ausgrid - Regulatory Proposal - April 2018, p. 104.

[37] Ausgrid - Regulatory Proposal - April 2018, p. 67.

[38] Ausgrid - Regulatory Proposal - April 2018, p. 107.

[39] The key issue being considered through the remittal process is to what extent consumers should be required to fund the difference between our 2015 forecast of efficient opex and what Ausgrid actually spends.

Figure 7 Comparison of Ausgrid's past and forecast opex



Source: AER analysis.

Ausgrid's revenue proposal for 2019–24 includes total forecast opex of $2402.3 million[40] ($2018/19) for the period.[41] This is 13.7 per cent less than Ausgrid's actual opex over the 2014–19 period.[42] It proposes to maintain the costs savings achieved over 2014–19 over the 2019-24 regulatory period. It does this by adopting its 'underlying' level of opex from 2017/18, which is in line with our 2015 final decision, as the basis for its 2019-24 opex forecast.[43] It also proposes some step changes and an increase in the base opex to reflect changes in prices, inputs and output growth. Ausgrid states that the resultant overall level of opex will allow it to operate a safe and reliable network over the 2019-24 regulatory period.

Our role will be to ensure that this forecast opex is consistent with the opex criteria: efficiency, prudency and a realistic expectation of the demand forecast and cost inputs required to achieve the opex objectives under the NER. As part of our assessment of Ausgrid's opex forecast, we are interested in stakeholder views as to how well its proposal—summarised below—addresses its key themes of affordability, reliability and

40 Excluding debt raising costs.

41 Ausgrid - Regulatory Proposal - April 2018, p. 113.

42 Note that Ausgrid's reported opex for 2017-18 and 2018-19 are estimates only. Ausgrid - Regulatory Proposal - April 2018, pp. 118–119.

43 Ausgrid's underlying level of opex is its actual opex for 2017-18 less transformation costs (i.e. redundancy, stranded labour and career transition program costs).

sustainability, and the extent to which Ausgrid's opex forecast addresses the concerns of electricity consumers as identified in the course of its engagement on its proposal.

With Ausgrid's estimated opex in 2017/18 ($440.2 million, $2018–19) as a starting point, Ausgrid has forecast $2.2 billion ($2018–19) base opex for 2019–24 regulatory control period. Ausgrid then adjusted its base opex to include the costs of emergency recoverable works, which will become a standard control service from 1 July 2019.[44]

Ausgrid has escalated its adjusted base opex to reflect:

- an expected opex increase in the final year of the current regulatory control period ($33.3 million, $2018–19)
- opex increases for forecast changes in real prices of key inputs ($56.0 million, $2018–19)
- opex changes driven by expected output growth ($56.1 million, $2018–19)
- expected productivity growth (which Ausgrid has set to zero per cent).[45]

The issue of forecasting output growth and productivity has been raised in our review of Evoenergy's 2019–24 revenue proposal. In its submission to our issues paper for Evoenergy's 2019–24 determination, CCP10 raised concerns about the approach we have used in recent decisions to forecasting output growth and productivity. In particular, the CCP10 submission has suggested:

- that our statistical analysis of the relationship between costs and the number of customers served in our recent decisions is significantly larger than comparable estimates by the New Zealand Commerce Commission for New Zealand's distribution networks.[46]
- that given recent productivity improvements by some networks, continuing to assume zero productivity growth for network businesses over five years is not in the best interests of consumers.[47]

We are interested in stakeholders' views on the approach we should apply for forecasting output growth and productivity growth in these determinations.

Ausgrid has also proposed two step increases to its base opex ($2018-19):[48]

- $26.1 million for a number of demand management projects, which Ausgrid submits will deliver savings in capex[49]

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[44] Ausgrid - Regulatory Proposal - April 2018 - Attachment 6.01, p. 26. Emergency recoverable works have been treated as an unregulated service in the current period, so these costs were not accounted for in the 2017/18 base year.

[45] Ausgrid - Regulatory Proposal - April 2018, p. 130.

[46] Consumer Challenge Panel (subpanel 10), *CCP10 Response to Evoenergy regulatory Proposal 2019-24 and AER Issues Paper*, May 2018 p. 10.

[47] Consumer Challenge Panel (subpanel 10), *CCP10 Response to Evoenergy regulatory Proposal 2019-24 and AER Issues Paper*, May 2018 p. 15.

[48] Ausgrid - Regulatory Proposal - April 2018, p. 134.

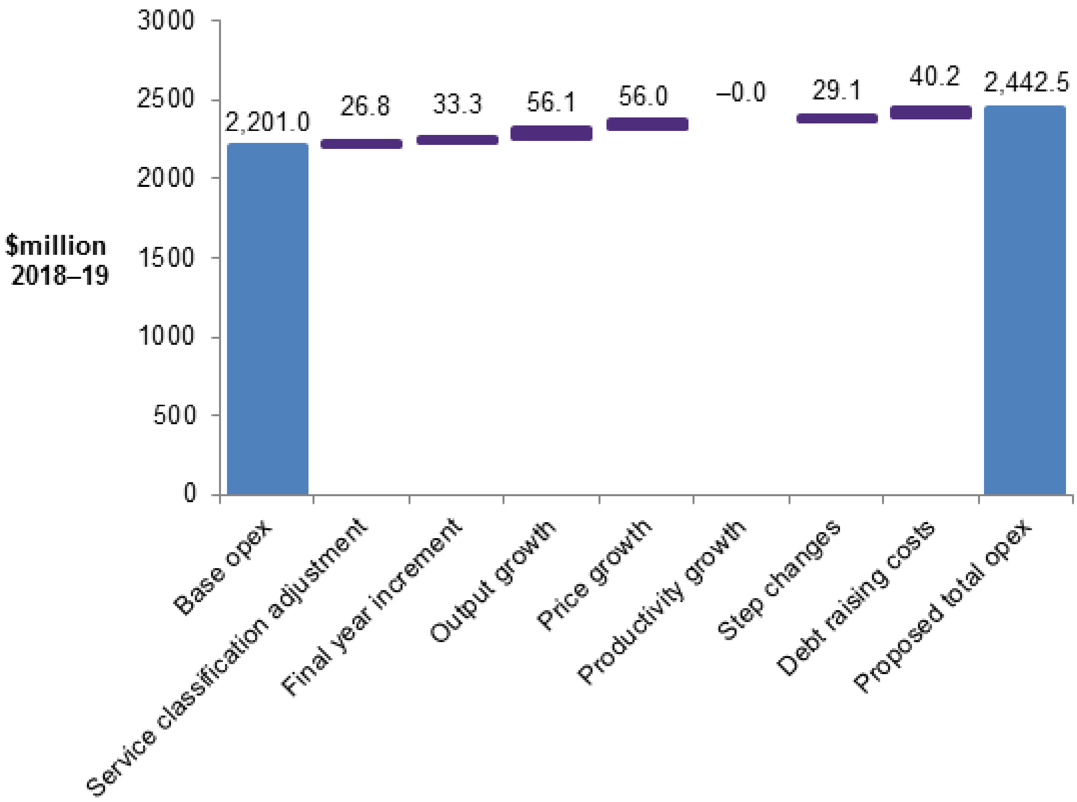
- $3 million for a once-off two year program of research into, and engagement on, pricing reform to "expedite [its] transition to more cost reflective pricing as required by the Australian Energy Market Commission's (AEMC) rule change for Distribution Network Pricing Arrangements".[50]

This is another area of Ausgrid's proposal on which we are particularly interested in stakeholders' views.

Ausgrid has also included $40.2 million ($2018–19) debt raising cost in its opex forecast. Debt raising costs are transaction costs incurred each time debt is raised or refinanced. Our approach is to forecast an efficient level of debt-raising costs based on the cost incurred by an 'efficient' benchmark firm rather than a service provider's actual costs.

Figure 8 shows how each of these components has contributed to Ausgrid's total opex forecast.

Figure 8 Breakdown of Ausgrid's opex forecast ($million, $2018–19)



Source: AER analysis.

Note: Including debt raising costs.

49 Ausgrid - Regulatory Proposal - April 2018, p. 135.

50 Ausgrid - Regulatory Proposal - April 2018, p. 136.

5 Key elements of Endeavour Energy's revenue proposal

Endeavour's proposal would allow it to recover $4313.6 million ($2018/19, smoothed)[51] from customers over the 2019–24 period. This includes a downward adjustment of $239 million reflecting Endeavour's proposed resolution for its 2014–19 determination, which we must remake.

Endeavour's proposed revenue is a 2.0 per cent (real) increase from our original decision for 2014–19. When Endeavour's projected increases in demand are taken into account, this would have an estimated average annual impact on distribution charges of –0.3 per cent in real terms. Again in real terms—excluding the impact of inflation—the estimated impact on average annual electricity bills would be a reduction of 0.1 per cent per annum for both its residential and small business customers.[52]

Through its engagement program Endeavour has identified affordability as "the number one concern for many of [its] customers, but not at the sacrifice of safety or reliability".[53] It submits that its proposal will balance these key themes of affordability, reliability and safety by:[54]

- containing investment by focussing on that required to ensure safe and reliable electricity
- taking a number of steps to offset the costs of necessary investment—including by adopting a rate of return consistent with our 2013 guideline, delaying capex with demand management programs, reducing overheads, and developing a flexible workforce and continuing efficiency programs—and passing savings on to customers
- developing new ways for customers to control their own electricity costs, including through use of alternative technologies and by offering a greater variety of tariff options
- developing contingency plans for future projects like the Western Sydney Airport contingent project, so that the cost of these projects won't be recovered from customers unless or until the investment is needed.

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51 Endeavour's proposal refers to total proposed revenue of $3891.6 million in nominal, NPV adjusted terms. This lower total revenue reflects the net present value of the proposed total revenue if it were to be paid to Endeavour as a lump sum at the start of the regulatory control period. What will actually happen is that the total revenue will be recovered gradually over the entire five year regulatory control period. This increases its actual value due to the effects of the time value of money.

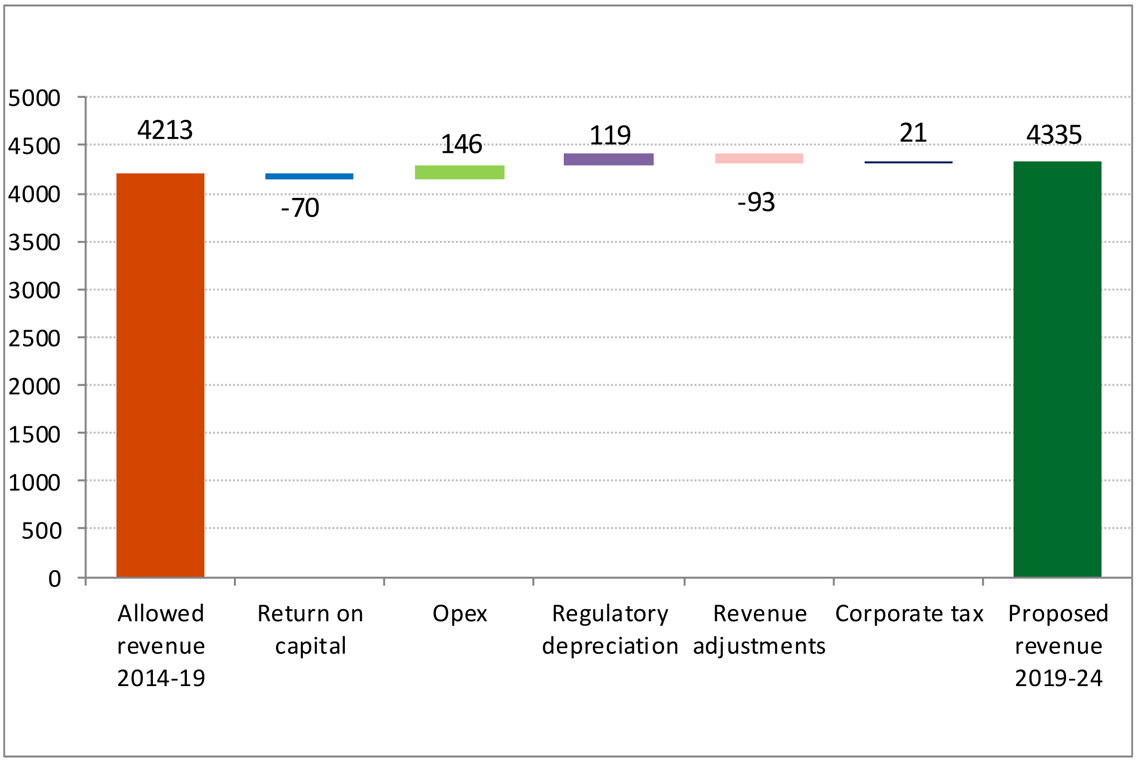
52 Endeavour Energy - RIN0.01 Final RIN Workbook 1 Reset (Consolidated) - 30 April 2018. Estimated by reference to Origin Energy's Standing Offers (residential and small business) for the Endeavour Energy network area. Assumes distribution costs make up 29.7 per cent of a typical customer's electricity bill.

53 Endeavour Energy - 0.01 Regulatory Proposal - April 2018 - Public, p. 21.

54 Endeavour Energy - 0.02 Regulatory Proposal Overview - April 2018 - Public, p. 2.

Figure 9 highlights changes in Endeavour's proposal at the building block level to illustrate what is driving its proposed increase in revenue.

Figure 9 Changes in building blocks: Endeavour's allowed revenue 2014–19 to forecast revenue 2019–24 ($million, 2018/19 – unsmoothed)



Source: AER analysis. Note that our 2014-19 decision on Endeavour's allowed revenue will be remade; any difference between the revenue Endeavour has recovered under its interim tariff undertakings and remade decision will be reflected in approved revenue for 2019–24.

Endeavour's proposed reduction in the rate of return—its proposal has adopted our 2013 rate of return guideline and uses 6.11 per cent rate of return compared to the 6.68 per cent that applied under our 2015 decision—is helping to offset continued growth in its RAB as Endeavour's forecast capex levels increase significantly over 2019–24. This growth in the RAB, combined with Endeavour's proposed change in approach to the calculation of the regulatory depreciation allowance, is also contributing to the increase in regulatory depreciation relative to our 2015 decision.

While a reduction of around 2.5 per cent from its actual opex for 2014–19, Endeavour's total forecast opex for 2019–24 is an increase of 11.3 per cent from the forecast used to set revenue in our 2015 decision, which is also contributing to the increase in proposed revenue for 2019–24 relative to allowed revenue for 2014–19.

Endeavour's 2019–24 proposal includes revenue adjustments for benefits accrued under the EBSS and the DMIA. However, these incentive scheme payments are offset by a downward adjustment of $239 million that Endeavour has included in its 2019–24 revenue proposal, which it submits would be returned to customers it we were to accept its proposed resolution for its 2014–19 determination, which we must remake.

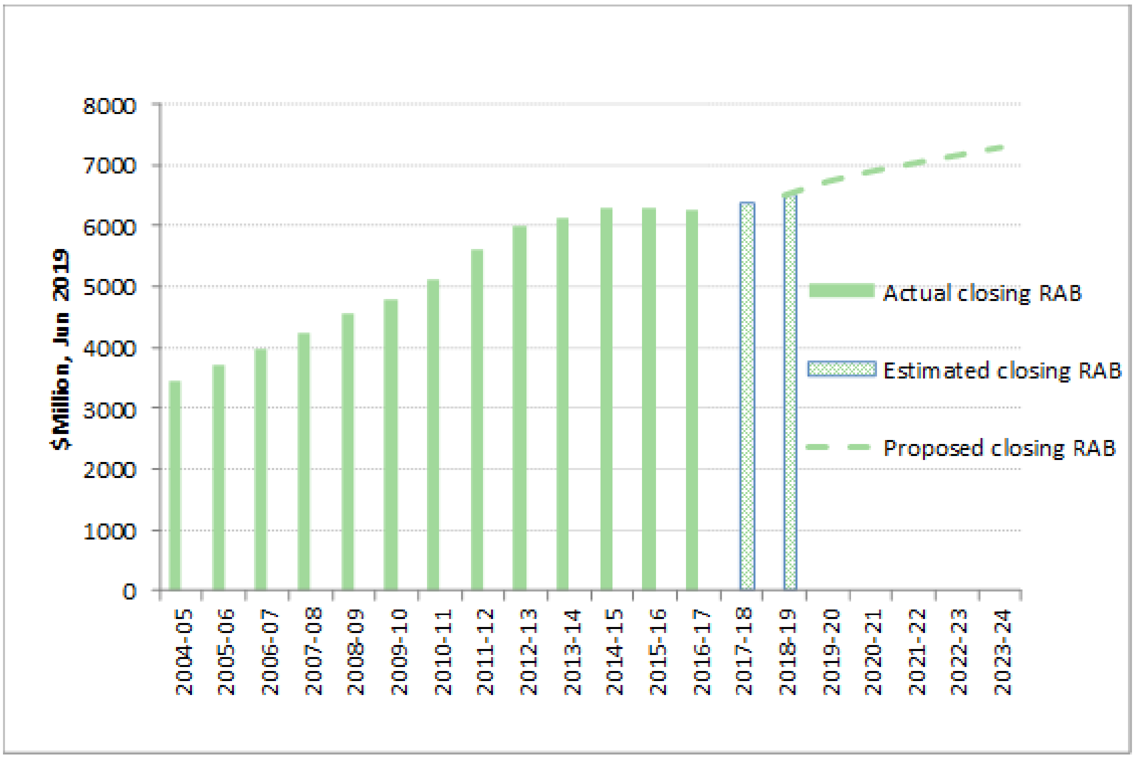
5.1 RAB and depreciation

Figure 10 shows the change in Endeavour's RAB value over time, including the period of significant growth (34.5 per cent) in 2009–14 that we discussed in section 3.

Growth in Endeavour's RAB slowed over 2014–19. The revenue approved in our 2015 decision assumed projected RAB growth of 9.3 per cent in real terms over the 2014–19 regulatory control period, compared to actual RAB growth of 6.5 per cent.

Endeavour's projected of RAB growth for 2019–24 is 12 per cent, which reflects the significant increase in capex it has proposed for the next five years. We discuss the key drivers of Endeavour's increased capex forecast further in section 5.2 below.

Figure 10 Endeavour's RAB value over time ($million, 2018/19)



Source: AER analysis.

Endeavour has also proposed a higher regulatory depreciation allowance for 2019–24 than approved for the current period. This is largely a reflection of the growth in its RAB and the nature of capex over the current period (including investment in short-lived ICT assets).

Endeavour has also proposed a change in approach to implementing the straight-line method for the calculation of its depreciation allowance, from our preferred weighted average remaining life (WARL) approach to a period-by-period tracking approach.[55] Other things being equal, this approach results in a short to medium term increase in revenue (2.6 per cent over the 2019–24 period).[56] However, period-by-period tracking improves the matching of depreciation with the assets' underlying economic lives and is currently used by Ergon Energy and TransGrid. The NER require the depreciating rate to reflect an asset's economic life. We have limited discretion in this regard.

Endeavour's proposal appears to suggest that indexation of the RAB was preventing the value of its RAB from reducing.[57] This statement is incorrect. Without further capex, the RAB would reduce in value even with indexation, with each asset being fully depreciated to zero value once its economic life is over. Endeavour noted its rate of replacement capex is expected to be less than the depreciation rate over the 2019–24 regulatory control period. We would expect such an outcome given the relatively large amount of replacement capex undertaken in recent periods, and because increases in the RAB (and therefore depreciation) also reflect growth of the network (not just its replacement). It's also possible (although we don't consider it widespread) that some assets currently in the RAB may never need replacing, thereby reducing the replacement rate. We have addressed the issue of indexation of the RAB in a number of our decisions and in a fact sheet that can be obtained from our website.[58] Indexation of the RAB leads to smoother distribution network tariffs in the long run for customers compared to an unindexed approach.

5.2 Capex

Endeavour has proposed total (net) forecast capex of $2,165.6 million ($2018/19).[59][60] Figure 11 below shows the trend in Endeavour's capex over time. This figure highlights the peak in capex over the 2009–14 regulatory control periods and the subsequent reduction in both forecast and actual capex in 2014–19. Endeavour's forecast capex for 2019–24 is an increase of around 25 per cent from the forecast we approved in our final decision for 2014–19, and 39 per cent from its actual capex in that period.

Our role will be to ensure that this forecast capex is consistent with the capex criteria: efficiency, prudency and a realistic expectation of the demand forecast and cost inputs required to achieve the capex objectives under the NER. As part of our assessment of Endeavour's capex forecast, we are interested in stakeholder views as to how well its proposal—the key drivers of which are summarised below—addresses its key themes of affordability, reliability and safety, and the extent to which Endeavour's capex

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55 Endeavour Energy - 0.01 Regulatory Proposal - April 2018, p. 84.

56 This relates to the profile of the return of capital over the life of the assets. It does not provide more returns overall in present value terms. The increase is less than if year-by-year tracking approach was used, as some other businesses do.

57 Endeavour Energy, Regulatory Proposal, p. 83.

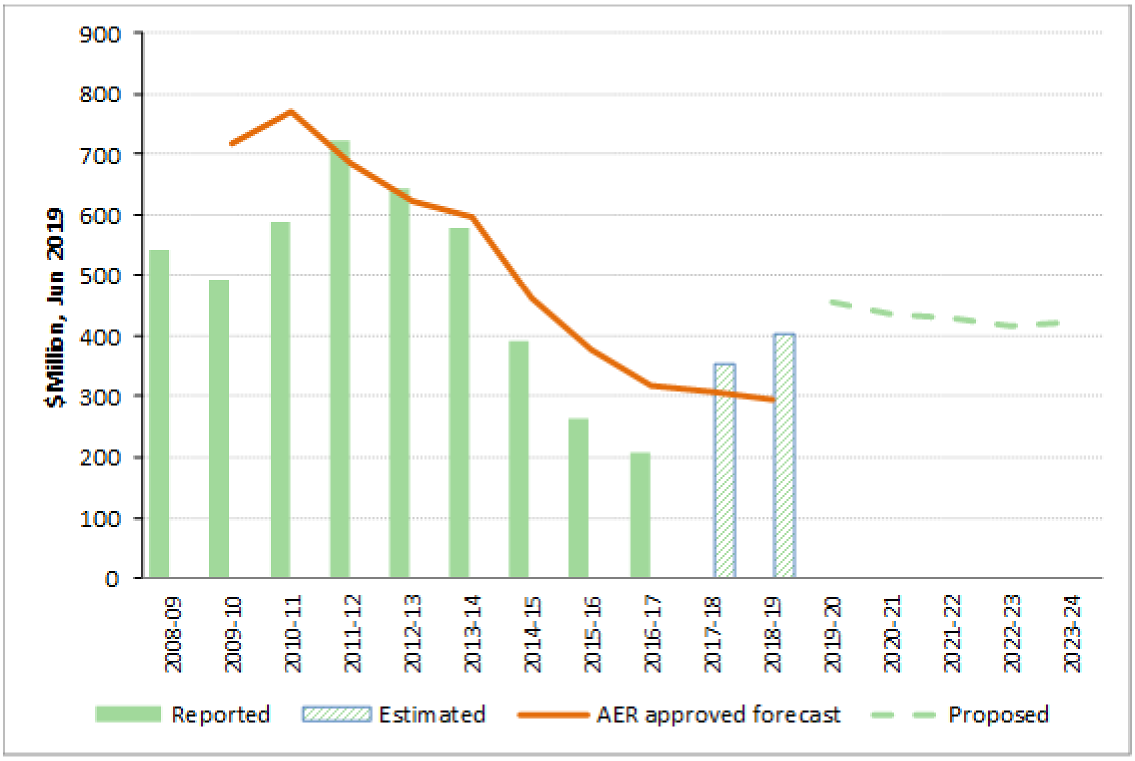
58 Available at https://www.aer.gov.au/system/files/Fact%20sheet%20-%20Indexation%20of%20the%20regulatory%20asset%20base.pdf

59 Endeavour Energy - 0.01 Regulatory Proposal - April 2018, p. 102.

60 Endeavour Energy - 0.01 Regulatory Proposal - April 2018, p. 113.

forecast addresses the concerns of electricity consumers as identified in the course of its engagement on its proposal.

Figure 11 Comparison of Endeavour's past and forecast capex



Source: AER analysis.

Endeavour's proposed capex forecast seeks to address stakeholder feedback and its key themes of affordability, reliability and safety by:[61]

- Ensuring its asset management strategies are both robust and efficient, and focussing on maintaining reliability across the existing network and limiting reliability improvements to the poorest performing areas, consistent with its licence conditions and feedback that "[c]ustomers do not want bills to increase to fund improved reliability, nor are most willing to trade lower bills for lower reliability."
- Investing in new technology to keep downward pressure on capital expenditure, manage cyber security risks, prepare the grid for greater customer choice and improve sustainability, improve automation, asset information, communication and monitoring systems, and to increase its capacity to host distributed energy resources and utilise demand side response to manage network demand including promotion of demand management technologies to delay and offset capital investment.

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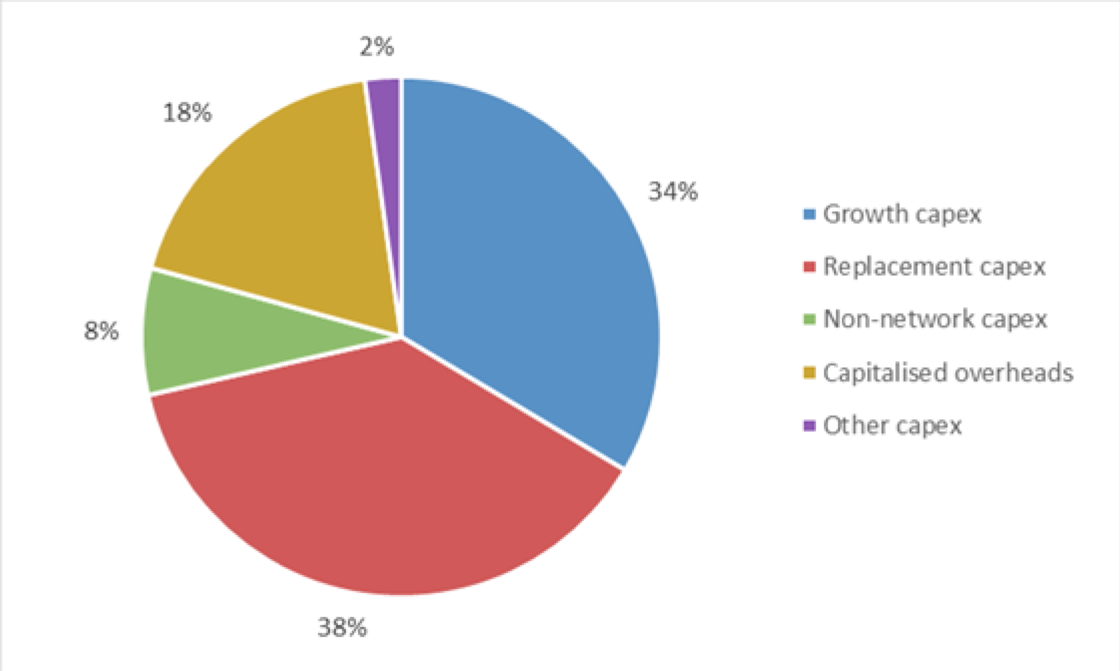
[61] Endeavour Energy - 0.01 Regulatory Proposal - April 2018, pp. 53-54.

Figure 12 shows the four main drivers of Endeavour's 2019–24 capex forecast.

Figure 12 Endeavour's forecast capex by driver



Source: AER analysis.

Replacement capex

Endeavour's capex forecast includes $800.5 million for the replacement of assets that have reached their end of useful life or are no longer suitable in order to manage safety and reliability risks.[62] Endeavour proposes a further $20 million for its network reliability program.

Compared to Ausgrid and Essential, Endeavour’s repex forecast for 2019-24 is a significant increase of 29 per cent from its actual/forecast repex in 2014–19. As we mentioned in section 4.2 (above), our own predictive repex modelling is a key tool in our assessment of proposed repex, and one that we explored with Endeavour and CCP10 as part of its early engagement on its proposal.

Unmodelled repex represents 27 per cent of total repex and largely relates to SCADA and protection replacement and substation renewal projects. Our review will scrutinise the need to undertake these projects.

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62 Endeavour Energy - 0.01 Regulatory Proposal - April 2018, p. 102.

Growth capex

Endeavour's forecast capex includes $417 million of investment to cater for the increase in electricity demand from its customers. This makes up 19 per cent of its total capex. Around two-thirds of this proposed expenditure is for augmentation work supporting new developments (this is known as ‘greenfield augex’). Endeavour submits that it expects customer numbers to grow by around 21 000 per year, and one-third of its 164 zone substations to experience growth rates of more than 1.5 per cent per year over the 2019–24 period.[63]

Endeavour's proposal also includes a contingent project, for augmentation to the network to support growing demand in the Western Sydney Airport area. Endeavour has forecast a potential $61.2 million investment for this project. If approved, this $61.2 million in capex will not be included in Endeavour's allowed revenue unless and until certain trigger requirements are met, including completion of a Regulatory Investment Test (RIT-D) demonstrating that the project has positive net market benefits. This is in keeping with Endeavour's objective that that the cost of future projects not be recovered from customers unless or until the investment is needed.[64]

In section 9.4, we seek stakeholders’ views on whether a pricing solution could be adopted to reduce some of Endeavour Energy's forecast growth capex.

A further $309 million (15 per cent of total capex) has been proposed for connections to Endeavour's network. This is 147 per cent higher than its expected expenditure of $125 million for the current 2014–19 period. This increase is in part driven by an expected increase in customer connections volumes in the forthcoming regulatory period—from around 99 000 connections in 2014–19 to around 105 000 in 2019–24. However, much of the increase is because of changes that Endeavour has made to its approach to capital contributions, and the share of connections capex recovered from customers through its regulated revenue.[65]

Endeavour’s change in the application of its capital contributions policy

In its proposal Endeavour has submitted that the larger scale of developments in recent years has resulted in more ‘upstream’ shared assets being funded by connecting customers. In August 2017, it therefore changed its approach to capital contributions to move from what it says is a ‘causer pays’ approach to a ‘beneficiary pays’ approach.[66] The effect of this change is that assets that will provide current and/or future customers with supply, or improve service or resilience, are now funded by all of Endeavour’s customers instead of being funded by the connecting customer requiring the asset.

[63] Endeavour Energy - 0.01 Regulatory Proposal - April 2018, pp. 119 and 123

[64] Endeavour Energy - 0.02 Regulatory Proposal Overview - April 2018 - Public, p. 2.

[65] Endeavour Energy - 0.01 Regulatory Proposal - April 2018, pp. 120–122.

[66] Endeavour Energy - 0.01 Regulatory Proposal - April 2018, p. 121.

Endeavour reviewed and subsequently made the change in the application of its capital contributions policy following feedback from developers and councils.[67] Endeavour has submitted that the change in the application of its capital contributions policy will reduce the cost to connecting customers and tariffs for existing customers in the short term.[68] Its proposal acknowledges, however, that "this change was an area of contention" in its engagement with some stakeholders".[69]

We received feedback consistent with this from CCP10 and the Public Interest Advocacy Centre (PIAC), both of whom expressed concern with the change in approach at Endeavour's 'deep dive' engagement sessions. In those discussions, CCP10 and PIAC opposed Endeavour's change in the application of its capital contributions policy on the basis that it will mean higher tariffs in the long term because of the increase in the regulatory asset base. They were also concerned that the change will result in customers—and notably vulnerable customers—subsidising new home buyers. These comments—made prior to submission of Endeavour's proposal—also raised concern about the lack of consultation on this particular issue prior to the change and that the benefits of the change were not well articulated.

As part of our assessment of Endeavour's proposal, we welcome further feedback from stakeholders about Endeavour's change in the application of its capital contributions policy, and its proposed connections capital expenditure more broadly. In particular we are interested in hearing stakeholders' views on how well the information provided in Endeavour's proposal has addressed the concerns raised during the 'deep dive' sessions, and whether new assets (such as substations)—built for new customers but which may benefit other current or future customers—should be paid for by new connecting customers, all customers, or shared between these two groups.

Non network capex

$170 million (8 per cent) of Endeavour's capex forecast relates to investment in non-system assets. This forecast is lower than Endeavour's expected expenditure for the current 2019–24 period.

The largest contributor to proposed non-network capex is ICT capex ($91.2 million), which, as noted above, is intended to deliver a number of service and operational benefits to customers.[70] As part of our assessment we are keen to hear from stakeholders on how (and how well) they consider the benefits of these ICT initiatives have been demonstrated in Endeavour's proposal for 2019–24.

67 Endeavour Energy - 0.01 Regulatory Proposal - April 2018, p. 106.

68 Endeavour Energy - 0.01 Regulatory Proposal - April 2018, p. 103.

69 Endeavour Energy - 0.01 Regulatory Proposal - April 2018, p. 106.

70 Endeavour Energy - 0.01 Regulatory Proposal - April 2018, pp. 148-150.

Capitalised overheads

$400 million (or 19 per cent) of Endeavour's total forecast capex is for the costs of supporting its capex program. This is an increase of 10 per cent from the current 2019–24 period.[71]

Other capex

The remaining $49 million (3 per cent) of Endeavour's capex forecast includes other system capex ($41 million) and equity raising costs ($8 million).

5.3 Opex

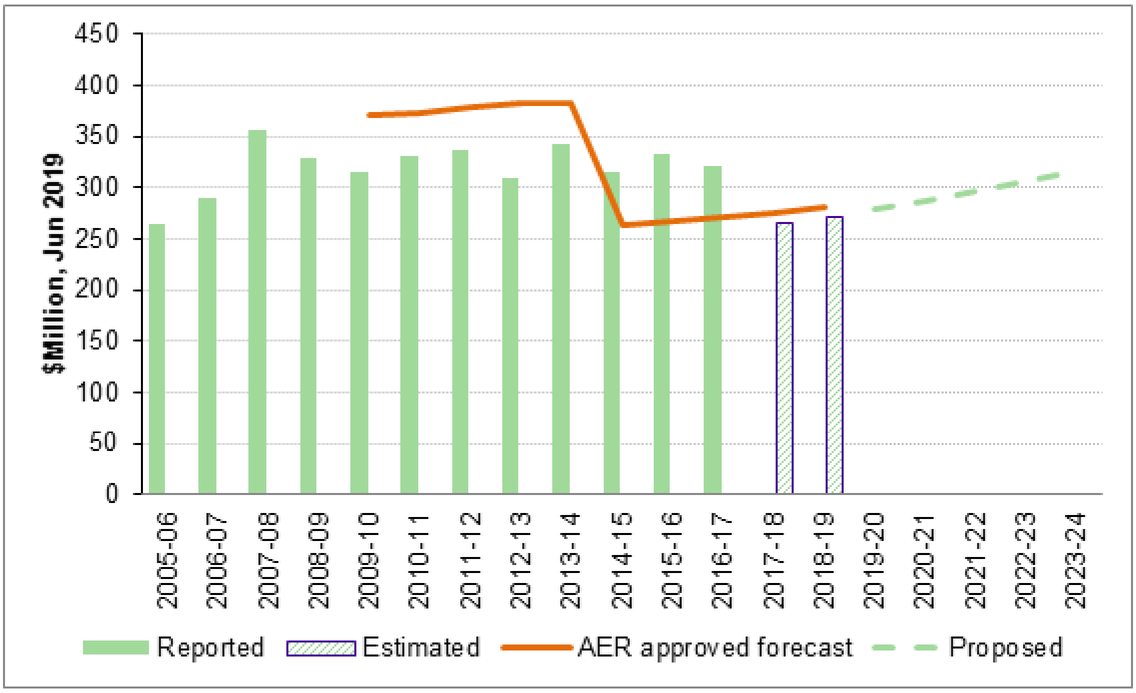
In our April 2015 final decision, we set an opex forecast for the 2014-19 regulatory period that was materially lower (by 17 percent) than the amount proposed by Endeavour Energy (Figure 15).[72] Following appeals to the Australian Competition Tribunal and the Federal Court, we are in the process of remaking our opex forecast for Endeavour.

Figure 13 shows the trend in Endeavour's opex over time. Over the remittal period, Endeavour's actual opex in 2014-15, 2015-16 and 2016-17 was significantly above our 2015 estimate of efficient opex. It is forecasting a significant decrease in opex in the last two years of the period (2017-18 and 2018-19) to levels that are consistent with our original 2015 estimate of efficient opex.

71 Endeavour Energy - 0.01 Regulatory Proposal - April 2018, p. 142.

72 We found Endeavour Energy's 2012-13 base year opex to not be materially inefficient and a reasonable basis for forecasting opex for the 2014-19 regulatory period. The key difference between our 2015 substitute forecast and Endeavour Energy's proposed opex was a proposed step change for vegetation management. Endeavour Energy considered its 2012-13 base year did not reflect the full cost of complying with its existing regulatory standards and proposed an increase in opex to improve compliance with these standards. We considered that there was not sufficient evidence for the step change and that allowing it would result in a materially inefficient level of total opex. We concluded that our forecast was sufficient to meet all its existing regulatory obligations - including for vegetation management.

Figure 13 Comparison of Endeavour's past and forecast opex



Source: AER analysis.

Endeavour has proposed total forecast opex of $1485.5 million[73] ($2018/19) for 2019–24.[74] In contrast to capex, Endeavour expects its total opex for 2019–24 to be $37.1 million (around 2.4 per cent) less than the opex it will have spent by the end of the current, 2014–19 period.[75] In is proposing to maintain the costs savings it expects to achieve in the last two years of the current period into the 2019-24 regulatory period. It does this by adopting its forecast opex for 2017/18, which is consistent with our 2015 final decision, as the basis for its 2019-24 opex forecast. It has included some step changes and an increase in the base opex to reflect changes in prices, inputs and output growth. Endeavour Energy states that the proposed overall level of opex will allow it to operate a safe and reliable network over the next regulatory period.

Our role will be to ensure that this forecast opex is consistent with the opex criteria: efficiency, prudency and a realistic expectation of the demand forecast and cost inputs required to achieve the opex objectives under the NER. As part of our assessment of Endeavour's opex forecast, we are interested in stakeholder views as to how well its proposal—summarised below—addresses its key themes of affordability, reliability and safety, and the extent to which Endeavour's opex forecast addresses the concerns of electricity consumers as identified in the course of its engagement on its proposal.

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73 Excluding debt raising costs.

74 Endeavour Energy - 0.01 Regulatory Proposal - April 2018, p. 157. Excludes debt raising costs.

75 Endeavour Energy - 0.01 Regulatory Proposal - April 2018, p. 162.

Endeavour has used a base-step-trend methodology to forecast its opex requirements for 2019–24. The starting point for Endeavour's proposal is its estimated opex in its 2017–18 base year ($266.3 million, $2018–19). This produces a base opex of $1331.6 million over the five year period. Endeavour then adds an increment to its base opex to account for expected opex increases in 2018-19, bringing its base opex to $1357.5 million over the five-year period.

Endeavour has applied trend factors forecasts to account for cost drivers that increase opex over the five-year period. It has forecast:

- $70.9 million opex increase for expected output growth
- $57.2 million opex increase for expected changes in real prices of key inputs
- zero productivity growth.[76]

As we noted in our discussion of Ausgrid's proposal in section 4.3, above, CCP10 has raised a number of issues with our approach to forecasting output growth and productivity.[77] We are interested in stakeholders' views on the approach we should apply for forecasting output growth and productivity growth in this determination.

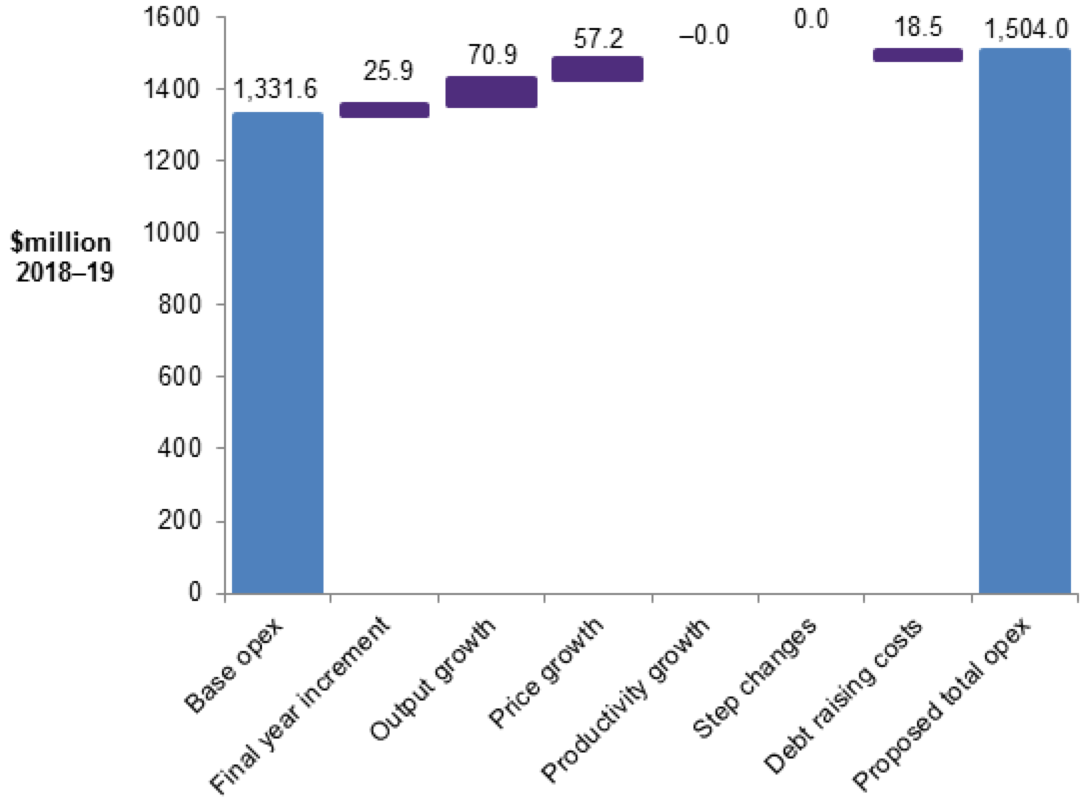
Endeavour has not proposed any opex step changes for 2019–24. Endeavour has forecast $18.5 million debt raising cost for the 2019–24 period.

Figure 14 shows how each of these components constitute Endeavour's opex forecast.

[76] Endeavour Energy - 0.01 Regulatory Proposal - April 2018, p. 174.

[77] In particular the CCP10 has suggested: that our statistical analysis of the relationship between costs and the number of customers served in our recent decisions is significantly larger than comparable estimates by New Zealand (NZ) Commerce Commission for NZ DNSPs; and that continuing our current approach of assuming zero productivity improvement for network businesses over five years in no longer realistic or in the interests of consumers given recent productivity improvements by some networks.

Figure 14 Breakdown of Endeavour's opex forecast ($million, $2018–19)



Source: AER analysis.

Note: Including debt raising costs.

6 Key elements of Essential Energy's revenue proposal

Essential's proposal would allow it to recover $5142 million ($2018/19) from customers over the 2019–24 period. This includes an adjustment of –$24.7 million reflecting revenue returned to customers under our draft, remade decision for 2019–24. Our final decision, which we published on 31 May 2018 confirmed an adjustment of $22.5 million following some minor updates.

The total revenue Essential's proposal would allow it to recover from customers over the five years from 2019–24 is 1.5 per cent less that the total revenue under our remade decision on revenue for 2014–19. However, as Figure **1** (in section 3 of this paper) shows, Essential's total revenue for 2014–19 included revenue in 2014-15 that was around 50 per cent higher than its annual revenue for the following four years from 2015-16 to 2018-19. This means that while Essential is proposing a real reduction in its total revenue from period to period, its proposed approach to recovery of that total revenue requires revenue to increase (in real terms) by around 1.4 per cent per annum from its annual revenue for 2018-19 (the final year of the current regulatory control period) to 2019-20, and by similar amounts thereafter until 2023-24.

Essential estimates a corresponding average annual impact on its distribution charges of 1.4 per cent in real terms. Again in real terms—excluding the impact of inflation—Essential estimates the impact on average annual electricity bills would be an increase of 0.5 per cent per annum for both residential and small business customers relative to what they are paying in 2018-19.[78]

Through its engagement program, Essential submits that it has "a better understanding of what value means to [its] customers, with safety, affordability and reliability emerging as the top priorities".[79] By limiting its proposed real increase in annual revenue to 1.4 per cent per year, Essential's proposal aims to:[80]

- balance the need to invest in and maintain a network today and tomorrow that is safe and reliable while meeting customers' expectations regarding electricity affordability
- reflect the impact of further efficiencies, building on those it began in the current period.

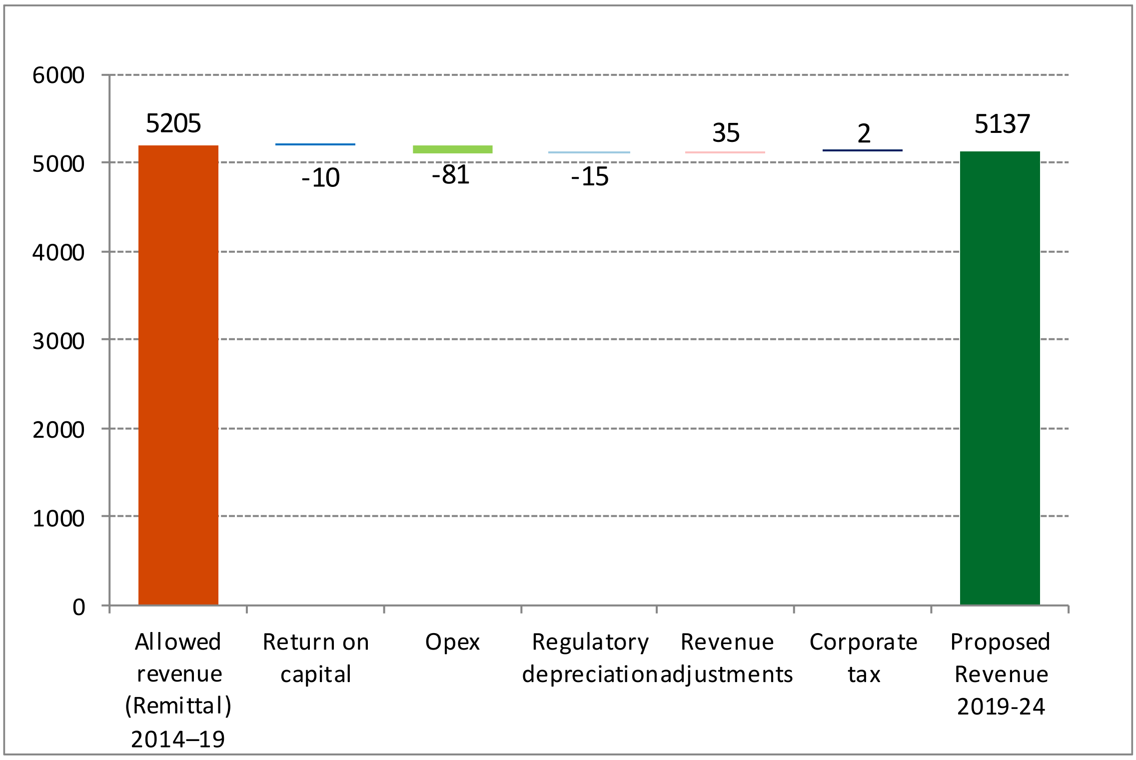
Figure 15 highlights changes in Essential's proposal at the building block level to illustrate what is driving its proposed decrease in total revenue.

78 Essential Energy - R1a Final RIN - 1 - Reset_MASTER - 30 April 2018. Estimated by reference to Origin Energy's Standing offers for the Essential Energy network area. Assumes annual consumption of 5MWh for residential customers and 23 MWh for small business customers. Assumes distribution costs makes up 36.6 per cent of a typical customer's electricity bill.

79 Essential Energy - 2019–24 Regulatory Proposal - April 2018, p. 32.

80 Essential Energy - 2019–24 Regulatory Proposal - April 2018, p. 45.

Figure 15 Changes in building blocks: Essential's allowed revenue 2014–19 to forecast revenue 2019–24 ($million, 2018/19 – unsmoothed)



Source: AER analysis.

For 2019–24, Essential's proposal has adopted our 2013 rate of return guideline and uses a placeholder rate of return of 6.34 per cent. This is lower than the 6.68 per cent rate of return applied in our last decision. Combined with lower than expected capex in the current period and the further reductions Essential has proposed to capex going forward, this is offsetting the impact of growth in Essential's RAB and reducing the return on capital allowance in Essential's revenue proposal. These capex reductions are also contributing to slower RAB growth going forward, and when combined with higher expected inflation for the next period (compared with previous period) this results in a lower depreciation allowance. We discuss Essential's proposals for the RAB and regulatory depreciation in section 6.1, below.

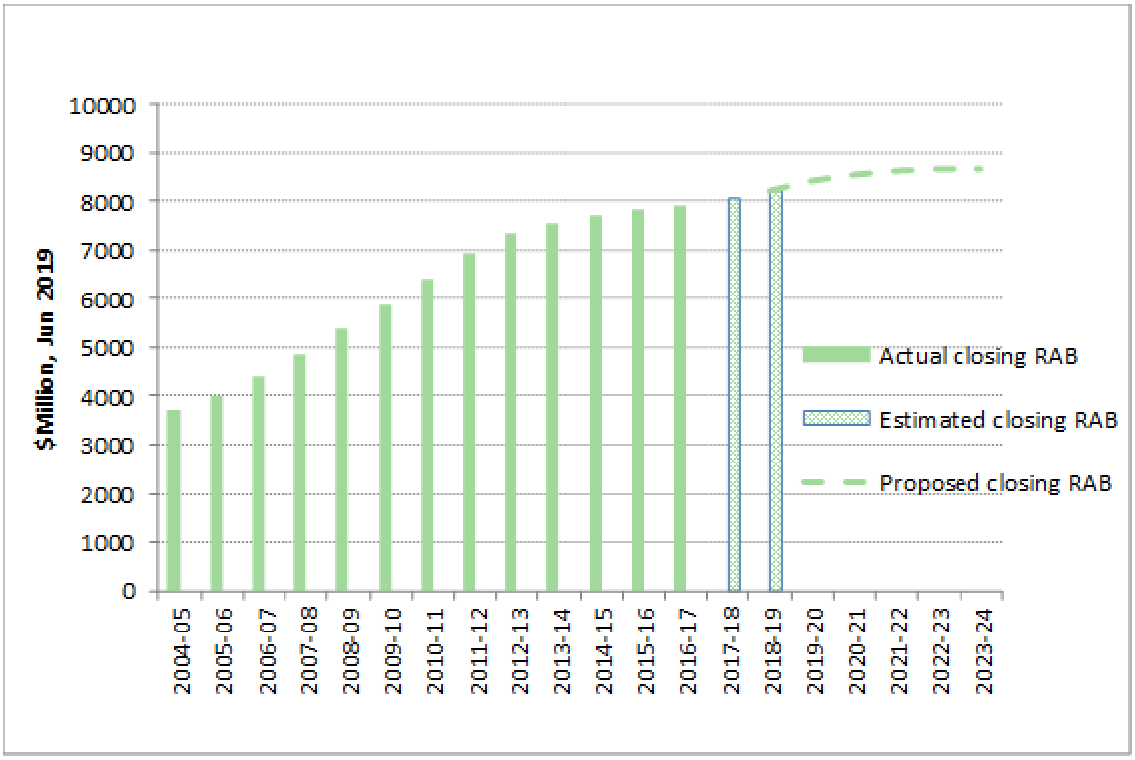
As we discuss in section 6.3 below, Essential's total opex forecast for 2019–24 is also lower (by 4.5 per cent) than that used to set revenue for 2014–19, reflecting Essential's projection of continued opex productivity gains going forward.

Revenue adjustments from incentives schemes are slightly higher than the previous period. This outcome is driven largely by the CESS, which applied to Essential for the first time in the current period. Benefits accruing to Essential under the CESS as a result of capex reductions over the 2014–19 period are partly offset by the $22.5 million that we determined will be returned to customers under our final remade revenue decision for that period.

6.1 RAB and depreciation

After a period of high capital investment in 2009–14—which increased Essential's RAB by 40.9 per cent—Essential's RAB growth slowed to 10.1 per cent in real terms over 2014–19. Essential's proposal projects slower growth again for 2019–24. Its projected 5.7 per cent RAB growth reflects its lower capex forecast for 2019–24, which we discuss in section 6.2. Figure 16 shows the change in the value of Essential's RAB over time.

Figure 16 Essential's RAB value over time ($million, 2018/19)



Source: AER analysis.

Essential's proposed regulatory depreciation allowance of $632.4 million ($2018/19) for 2019–24 is a reduction of 2.3 per cent from the current period. While RAB growth, and an increase in capex for short-lived assets, are putting upwards pressure on the depreciation allowance, this is balanced by higher expected inflation for the 2019–24 period (2.50 per cent) compared to expected inflation in the 2014–19 period (2.38 per cent).

In the course of Essential's engagement on its 2019–24 proposal, stakeholders expressed concern that Essential's proposed distribution tariffs were increasing despite proposed reductions in capital and operating costs and the rate of return. In Essential's proposal, it acknowledges these concerns.

This outcome reflects the way that the regulatory framework accounts for recovery of capital investment. Essential invests capital in large assets to provide electricity network services to its customers. The costs of these assets, which are added to the

RAB, are recovered over the asset's useful life, many of which can be 50 or more years. This means only a small part of the cost of such assets are recovered from customers upfront or in any year, and the greater proportion is recovered over several regulatory control periods through the depreciation allowance. 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' to depreciation used in Essential's proposal recovers the value of the asset evenly over its useful life. 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.

As Essential has explained in its proposal:[81]

> While we continue to improve efficiencies, we must also meet the funding costs associated with past investments in the network… The cost of refurbishing and replacing old assets (capital expenditure) continues to be greater than depreciation. While capital expenditure is greater than depreciation, the overall value of our assets (our Regulated Asset Base) will continue to grow. This places ongoing upward pressure on our Regulated Asset Base and network charges.

Essential goes on to emphasise that:[82]

> To minimise the impact on customers' network charges, ongoing cost reductions will be delivered primarily through prudent, targeted investment in innovative and enabling technologies. This will limit average annual network charge increases to 1.43 per cent above inflation.

We discuss Essential's proposed reductions in capex and opex in the sections below.

6.2 Capex

Essential's proposal includes $2100 million ($2018/19) total forecast (net) capex.[83] Figure 17 below shows the trend in Essential's capex over time. This figure highlights the peak in capex over the 2009–14 regulatory control periods and the subsequent reduction in both forecast and actual capex in 2014–19. Essential's forecast capex for 2019–24 is a reduction of 8.5 per cent from its actual capex over 2014–19.

For 2019–24, Essential has proposed investment in a number of "strategic initiatives", which it submits will improve its efficiency without compromising safety, reliability and service. This proposed investment includes:[84]

- investing in research and new technology to improve asset monitoring, analysis and risk management;

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81 Essential Energy - 2019-24 Regulatory Proposal Customer Overview - 20180430 - Public, p. 5.

82 Essential Energy - 2019-24 Regulatory Proposal Customer Overview - 20180430 - Public, p. 5.

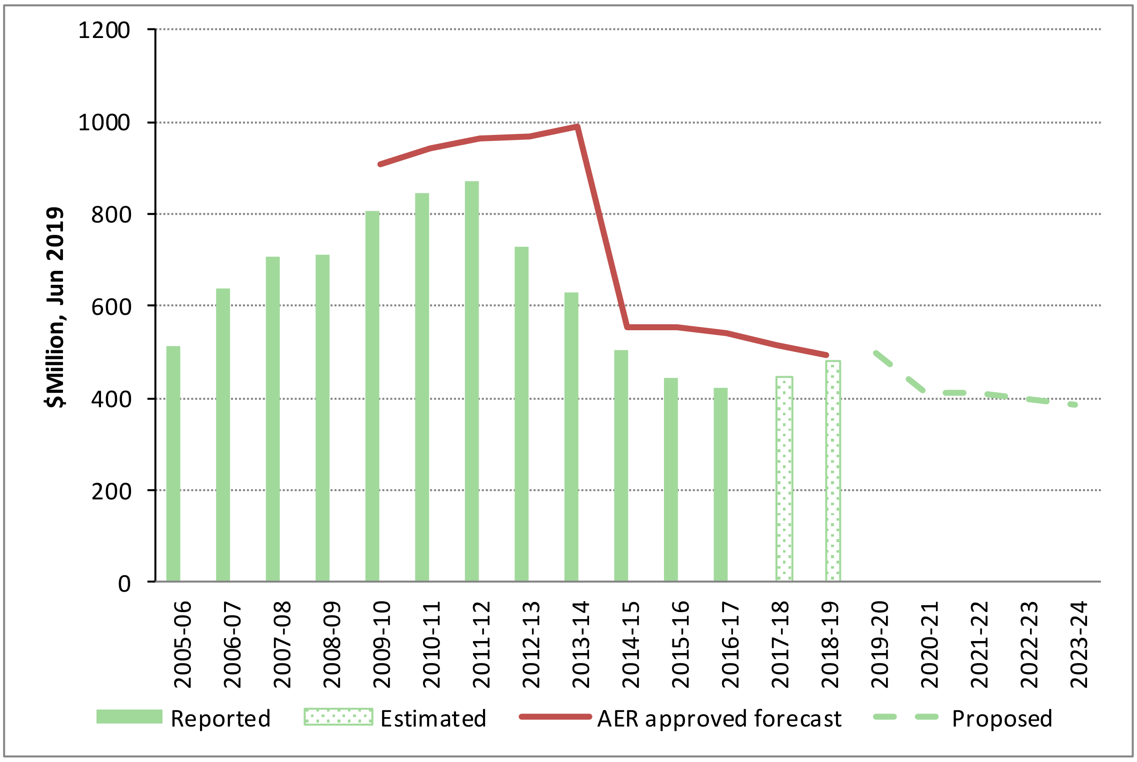
83 Essential Energy - 2019–24 Regulatory Proposal - April 2018, p. 63.

84 Essential Energy - 2019–24 Regulatory Proposal - April 2018, p. 7.

- risk-based asset planning to meet long-term customer needs; and
- automation of manual processes to reduce operational costs and drive efficiencies.

Our role will be to ensure that Essential's forecast capex is consistent with the capex criteria: efficiency, prudency and a realistic expectation of the demand forecast and cost inputs required to achieve the capex objectives under the NER. As part of our assessment of Essential's capex forecast, we are interested in stakeholder views as to how well its proposal—the key drivers of which are summarised below—addresses its key themes of affordability, reliability and safety, and the extent to which Essential's capex forecast addresses the concerns of electricity consumers as identified in the course of its engagement on its proposal.

Figure 17 Comparison of Essential's past and forecast capex

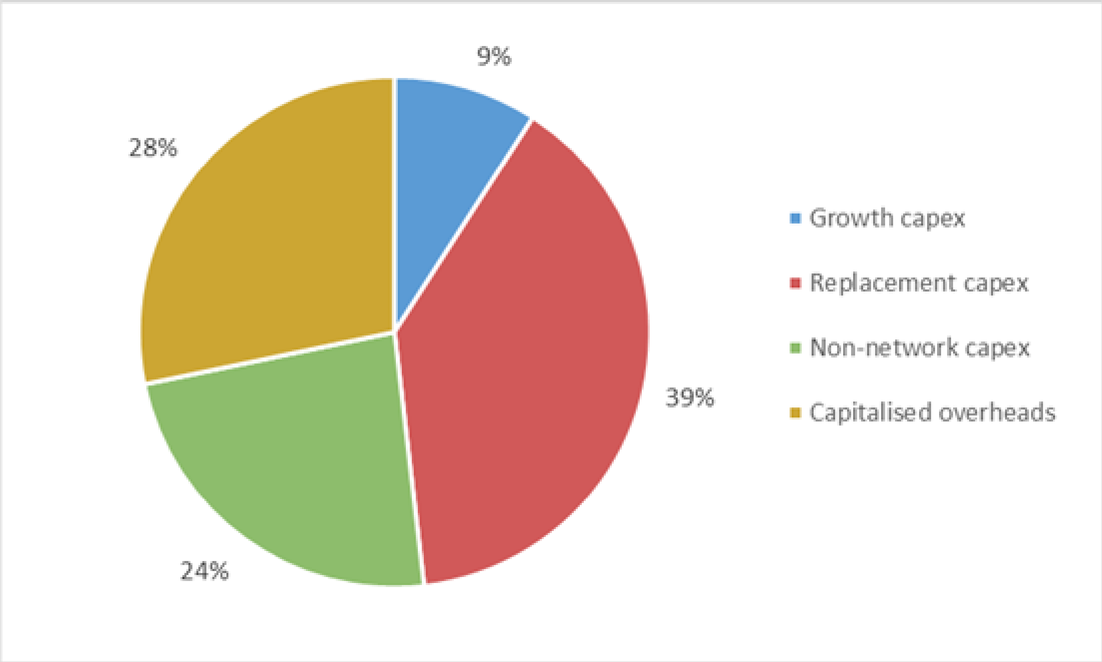


Source: AER analysis.

Figure 18 shows the key drivers of Essential's capex forecast:[85]

[85] Essential Energy - 2019-24 Regulatory Proposal - April 2018, p. 64.

Figure 18 Essential's forecast capex by driver



Source: AER analysis.

Replacement capex

Essential's forecast of $820 million for investment in asset replacement and refurbishment is the largest component of its capex forecast, making up around 39 per cent of total capex.

As we mentioned in sections 4.2 and 5.2 (above), our own predictive repex modelling is a key tool in our assessment of proposed repex, and one that we explored with Essential and CCP10 as part of its early engagement on its proposal.

Unmodelled repex represents 36 per cent of total repex, and largely relates to pole top structures ($230 million). Our review will focus on this expenditure item, and the reasons it has increased from current period expenditure. Essential has noted an increase in its ability to detect pole top structure defects due to its aerial-based inspection, a shift from opex to capex-based approaches over the current period and the prioritisation of works across its network.

Growth capex

$191 million (9 per cent) of Essential's proposed capex relates to growth-related programs involving connecting new customers ($25 million) and augmenting the existing network to meet forecast peak demand ($166 million).[86]

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86 Essential Energy – Reset regulatory information notice (R1a).

Essential's proposed augmentation capex also includes a new traffic 'Black Spot Program'. This is a safety initiative, targeting power poles at high risk of being involved in a vehicle accident. The costs of moving these poles would be recovered from Essential's customers through the RAB. Essential sought feedback on this proposal from customers, and submits that the program has support from 88 per cent of customers consulted, despite concerns from some that the costs of the program were more appropriately borne by Roads and Maritime Services or Local Government than through distribution network tariffs charged to Essential's customers.[87]

Non network capex

$495 million (24 per cent) of Essential's total forecast capex relates to non-network capex. This includes $168 million for fleet; $164 million for information and communications technology (ICT capex); $62 million for property; $57 million for light detection and ranging (LIDAR); and $44 million for other non-network expenditure.[88]

Essential submits that its ICT investment will be leveraged as the primary enabler for business transformation, including improved efficiency and lower operating and capital costs.[89]

Essential submits that it plans to make greater use of remote sensing technologies such as LIDAR to facilitate the identification of risks across the network.[90]

Essential has quantified many of the benefits it sees accruing from its investment in ICT. As part of our assessment we are keen to hear from stakeholders on how (and how well) they consider the benefits of these ICT initiatives have been demonstrated in Essential's proposal for 2019–24.

Capitalised overheads

Essential's proposed capitalised overheads make up the remaining 28 per cent of its total capex forecast.

6.3 Opex

In our April 2015 final decision, we set an opex forecast for the 2014-19 regulatory period that was materially lower (by 30 percent) than the amount proposed by Essential Energy. Following appeals to the Australian Competition Tribunal and the Federal Court, we remade our 2014–19 decision for Essential Energy on 31 May 2018.

Figure 22 shows the trend in Essential Energy's opex over time. Essential Energy's actual opex over the first three years of the remittal period (2014-15, 2015-16 and

87 Essential Energy - 2019-24 Regulatory Proposal - April 2018, p. 68.

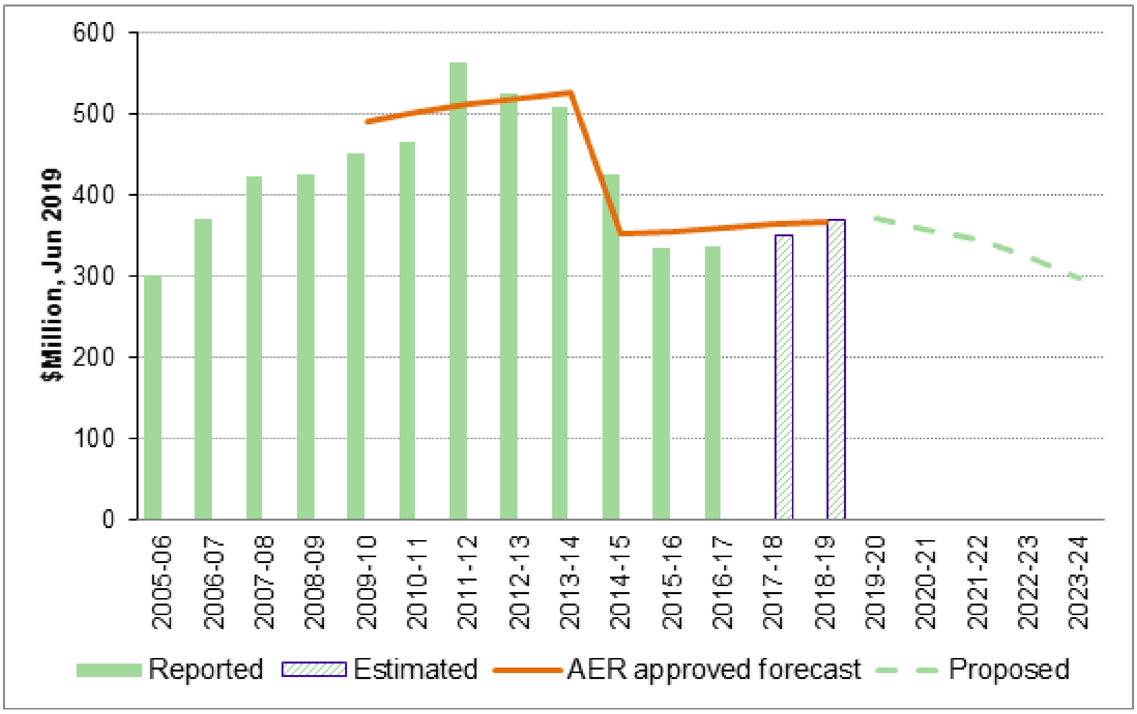
88 Essential Energy – Reset regulatory information notice (R1a).

89 Essential Energy - 2019-24 Regulatory Proposal - April 2018, p. 69.

90 Essential Energy - 2019-24 Regulatory Proposal - April 2018, p. 37.

2016-17) decreased significantly to a level consistent with our 2015 final decision. Opex is forecast to increase in the last two years of the current period (2017-18 and 2018-19) but remain in line with our 2015 estimate of efficient opex.

Figure 19 Essential's past and forecast opex



Source: AER analysis

Essential has proposed total forecast opex of $1698 million[91] ($2018–19) for 2019–24.[92] This is a reduction of six per cent from Essential's expected actual opex by the end of the current, 2014–19 period. It is proposing to maintain the costs savings achieved in the current period into the 2019-24 regulatory period. It does this by adopting its forecast opex for 2017/18, which is consistent with our 2015 final decision, as the basis for its 2019-24 opex forecast. It is also proposing an increase in the base opex to reflect changes in prices, inputs and output growth. However, this increase is offset by various efficiency gains that are forecast to produce an overall decline in opex over the 2019-24 period.

Our role will be to ensure that this forecast opex is consistent with the opex criteria: efficiency, prudency and a realistic expectation of the demand forecast and cost inputs required to achieve the opex objectives under the NER. As part of our assessment of Essential's opex forecast, we are interested in stakeholder views as to how well its proposal—summarised below—addresses its key themes of affordability, reliability and

91 Excluding debt raising costs.

92 Essential Energy - 2019-24 Regulatory Proposal - April 2018, p. 56.

safety, and the extent to which Essential's opex forecast addresses the concerns of electricity consumers as identified in the course of its engagement on its proposal.

Essential's opex forecast uses its expected actual opex of $350.1 million in 2017–18 as a starting point. This has then been reduced to remove non-recurrent costs that were not indicative of expected expenditure going forward.[93] Essential's adjusted base year opex is $348.8 million.

Essential has forecast annual increases in opex to account for output growth and real price changes from its base year.[94] However, it expects its productivity gains arising from its strategic initiatives program will offset the impact of output growth and real price changes. As we've noted above in sections 4.3 and 5.3, CCP10 has raised issues with the approach we should apply for forecasting output growth and productivity growth.[95] This is something we are interested in stakeholder views on.

Essential has also forecast two negative step changes to account for:

- the impact of planned strategic initiatives, such as improved approaches to vegetation management and investment in ICT systems, which are intended to support opex efficiencies by streamlining network and corporate support functions and enabling key asset management and program delivery functions ($22.2 million, $2018-19).[96] This opex reduction is in addition to the productivity gains Essential has forecast to offset its opex increases for output growth and real price changes.
- a change in the classification of Essential's expenditure on property leases, which was treated as opex in the current period but in Essential's proposal for 2019–24 is included as capex ($24.2 million, $2018–19).[97]

Essential has also forecast $20.6 million debt raising costs for the 2019–24 period.

Figure 20 shows the contribution each of these components has made to Essential's total forecast opex.

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93 Essential Energy - 11.3 - Standard control opex approach - April 2018, p. 7.

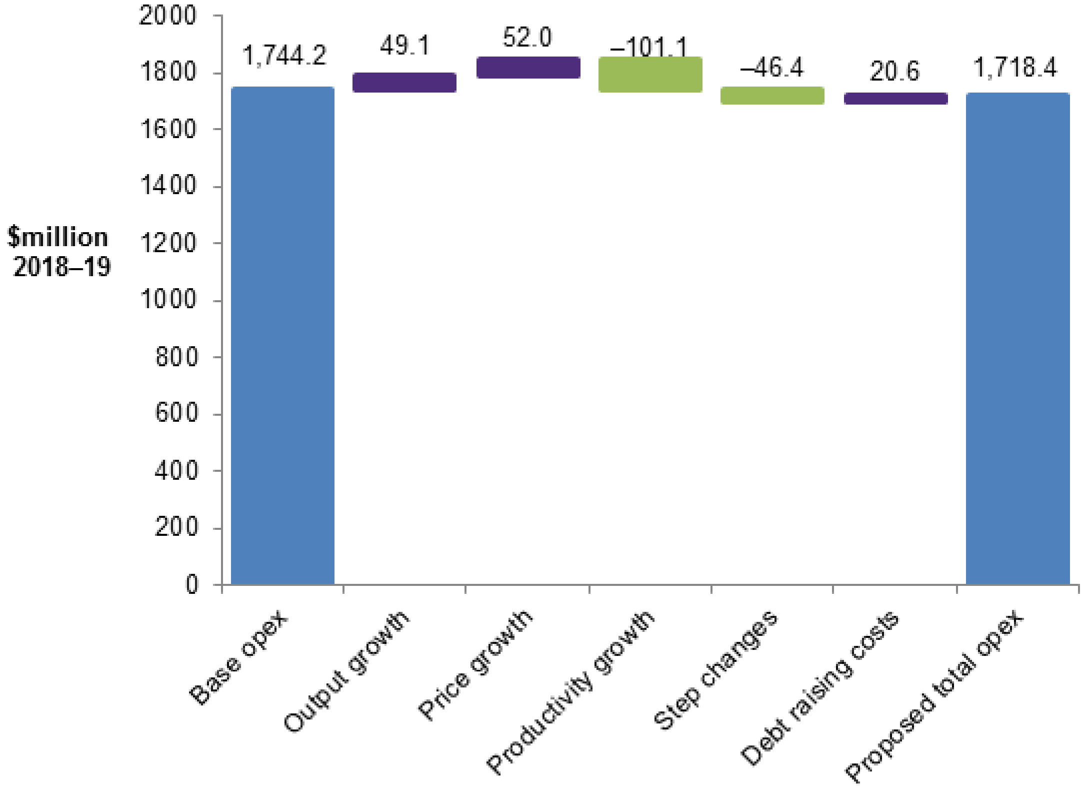
94 Essential Energy - 11.3 - Standard control opex approach - April 2018, p. 8.

95 In particular the CCP10 has suggested: that our statistical analysis of the relationship between costs and the number of customers served in our recent decisions is significantly larger than comparable estimates by New Zealand (NZ) Commerce Commission for NZ DNSPs; that continuing our current approach of assuming zero productivity improvement for network businesses over five years in no longer realistic or in the interests of consumers given recent productivity improvements by some networks.

96 Essential Energy - 11.3 - Standard control opex approach - April 2018, p. 8.

97 Essential Energy - 11.3 - Standard control opex approach - April 2018, p. 8.

Figure 20 Composition of Essential's opex forecast ($million, $2018–19)



Source: AER analysis.

Note: Including debt raising costs.

7 Incentive schemes

Incentive schemes are a component of incentive based regulation and complement our approach to assessing efficient costs. The incentive schemes that might apply to businesses are:

- the opex efficiency benefit sharing scheme (EBSS)
- the capital expenditure sharing scheme (CESS)
- the service target performance incentive scheme (STPIS)
- the demand management incentive scheme (DMIS) and demand management innovation allowance mechanism (DMIAM).

Once we determine how network revenues will be calculated networks have an incentive to provide services at the lowest possible cost, because returns are determined by their actual costs of providing services. If networks reduce their costs to below our forecast of efficient costs, the savings are shared with their customers in future regulatory periods through the EBSS and CESS. The DMIS and DMIAM encourage businesses to pursue demand side alternatives to opex and capex. The STPIS ensures that the network is not simply cutting costs at the expense of service quality.

Our incentive schemes encourage network businesses to make efficient decisions. They give network businesses an incentive to pursue efficiency improvements in opex and capex, and to share them with consumers. Incentives for opex and capex are balanced with the incentives under the STPIS to maintain or improve service quality. The incentive schemes encourage businesses to make efficient decisions on when and what type of expenditure to incur, and meet service reliability targets.

Ausgrid, Endeavour and Essential have each proposed the application of our EBSS, CESS, STPIS, DMIS and DMIAM These provide important balancing incentives under our revenue determinations to encourage distributors to pursue expenditure efficiencies and demand side alternatives to capex and opex, while maintaining the reliability and overall performance of their networks.

7.1 EBSS

Our efficiency benefit sharing scheme (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 tariffs in future regulatory control periods.

In the current, 2014–19, period only Endeavour was subject to the EBSS. In our final Framework & Approach paper we set out our intention to apply the EBSS to all three networks in the 2019–24 regulatory control period if we are satisfied the scheme will fairly share efficiency gains and losses between consumers and the businesses.[98] As we said at that time, we will decide if and how we will apply it as part of our determinations on the proposals, taking into account the information available to us on revealed costs and the basis of the new opex forecasts.[99]

All three businesses have proposed that the most recent version of the EBSS should apply in the 2019–24 regulatory control period.[100]

7.2 CESS

Our capital expenditure sharing scheme (CESS) aims to incentivise businesses to undertake efficient capex throughout the regulatory control period by rewarding efficiency gains and penalising efficiency losses (each measured by reference to the difference between forecast and actual capex).

In our final Framework & Approach paper we set out our intention to apply the CESS (as set out in our capex incentives guideline[101]) to Ausgrid, Endeavour and Essential in each regulatory year of the 2019−24 regulatory control period. Our approach was supported at the time by CCP10 and the businesses,[102] and has now been adopted by the businesses in their proposals.[103]

7.3 Service target performance incentive scheme

Our distribution STPIS[104] 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 tariff and non-tariff outcomes with the long-term interests of consumers.[105]

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98 NER, cl. 6.5.8(a).

99 Final F&A p. 66.

100 Ausgrid - Regulatory Proposal - April 2018, p. 171; Endeavour Energy - 0.01 Regulatory Proposal - April 2018, p. 90; Essential Energy - 2019-24 Regulatory Proposal - April 2018, p. 43.

101 AER, *Capital expenditure incentive guideline for electricity network service providers*, pp. 5–9.

102 Consumer Challenge Panel (sub-panel 10), *Submission on NSW preliminary framework and approach*, 21 April 2017, p. 16; Ausgrid, *Submission on NSW preliminary framework and approach*, 27 April 2017, p. 17; Endeavour Energy, *Response to AER's preliminary framework and approach for NSW DNSPs*, 21 April 2017, pp. 1 and 5; Essential Energy, *Submission on NSW preliminary framework and approach*, 21 April 2017, p. 2.

103 Ausgrid - Regulatory Proposal - April 2018, p. 171; Endeavour Energy - 0.01 Regulatory Proposal - April 2018, p. 92; Essential Energy - 2019-24 Regulatory Proposal - April 2018, p. 43.

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

105 Guaranteed service levels (GSLs) and associated rebates for failure to meet minimum service standards for connection times, responses to complaints, failure to notify customers of planned interruptions and time taken to restore supply after interruptions are separately determined by the Independent Competition and Regulatory

All three businesses have proposed the continued application of the STPIS in 2019–24 and, consistent with our final Framework & Approach, have proposed that the maximum revenue at risk under the scheme be increased from 2.5 per cent to 5 per cent.[106]

For all three businesses the NSW jurisdictional guaranteed service level scheme, which sits outside our distribution determinations and is administered by IPART, will continue to apply.

We are currently undertaking a review of the STPIS. If that review is completed in time, it may be that a revised STPIS will apply to Ausgrid, Endeavour and Essential for the 2019–24 regulatory control period.

7.4 Demand management incentive scheme and innovation allowance mechanism

On 13 December 2017, we published a new demand management incentive scheme (DMIS). This rewards electricity distribution businesses for using efficient demand management projects to deliver value to consumers. At the same time, we also published a new demand management innovation allowance mechanism (DMIAM), which provides research and development funding to electricity distribution businesses so they can better use demand management to reduce long term network costs.

Our consultation on our Framework & Approach paper for Ausgrid, Endeavour and Essential last year took the development of the new scheme into account. We proposed to apply the DMIS to these businesses to encourage comprehensive approach to network constraints, including non-network solutions, to provide better overall value to consumers. All three businesses have now adopted this position in their proposals, and have also proposed the full allowance of $200,000 plus 0.075 per cent of annual approved revenue for distribution services under the DMIAM.[107]

The new schemes were finalised in December 2017. We are interested to hear stakeholders' views on how well these proposals have embraced the new incentives in the time available, including the businesses' plans to identify suitable application areas and to seek and evaluate proposals for demand management solutions.

Commission in Schedule 1 of the *Utilities (Consumer Protection Code) Determination 2012* (DI2012–149), and not as part of our decision.

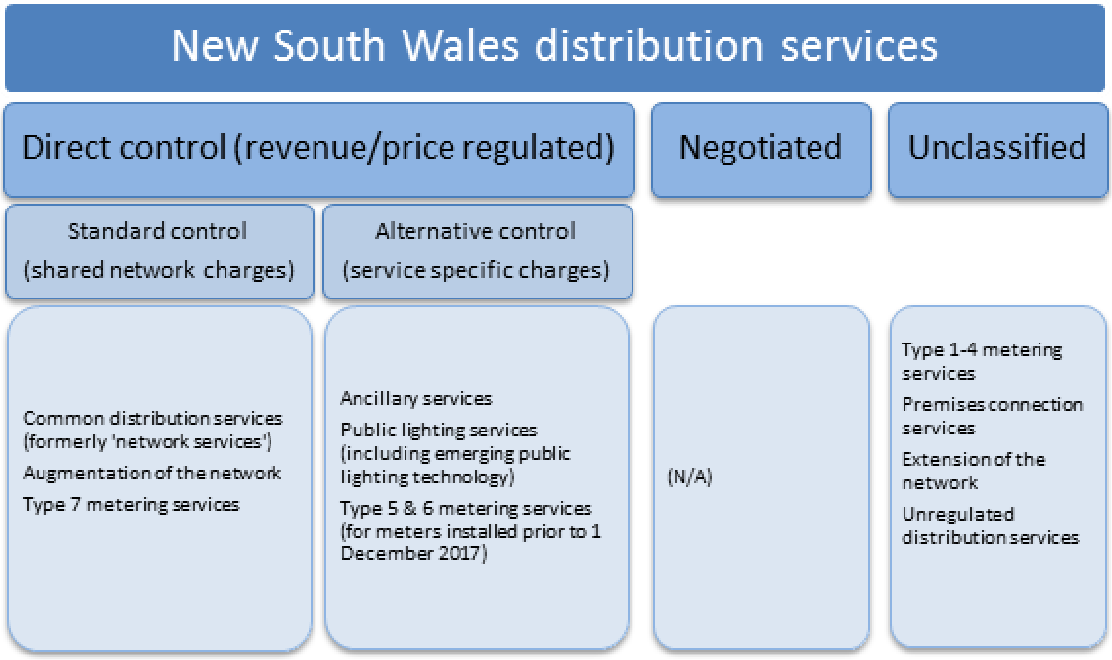
106 Ausgrid - Regulatory Proposal - April 2018, p. 173; Endeavour Energy - 0.01 Regulatory Proposal - April 2018, pp. 94-95; Essential Energy - 2019-24 Regulatory Proposal - April 2018, p. 43..

107 Ausgrid - Regulatory Proposal - April 2018, p. 175; Endeavour Energy - 0.01 Regulatory Proposal - April 2018, p. 99; Essential Energy - 2019-24 Regulatory Proposal - April 2018, p. 43.

8 Service classification

In the Framework & Approach paper we published last year, we set out our intended classification of the services Ausgrid, Endeavour and Essential provide to their customers.

Figure 21 AER's proposed approach to classification of NSW distribution services



Source: AER, Framework & Approach for Ausgrid, Endeavour Energy and Essential Energy 2019-24, July 2017, p. 16

Our classification of services determines which services we regulate and how distributors will recover the cost of providing those services.

Standard control services are those that can only be provided by the relevant distributor, and are common to most, if not all, of a distributor's customers. The costs of providing these services are captured in the building block revenue determination we've discussed in the previous sections of this paper and shared between all customers. Ausgrid, Endeavour and Essential have all proposed updates to their tariff structure statement (TSS), which sets out the tariff structure through which they will recover their regulated revenue for standard control services. We discuss the three TSS proposals in section 9, below.

Alternative control services are either:

- services that can only be provided by the relevant distributor, but will only be required by some of its customers, some of the time; or
- services that can be purchased from the relevant distributor, 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, through a capped price on the individual service.[108]

We discuss the alternative control services proposals in section 10.

While Endeavour has accepted the service classifications in our final Framework & Approach in full, Ausgrid and Essential have each proposed departures from the position we took in the final Framework & Approach.

Ausgrid has proposed amending the definition of standard control services so that it can provide fault restorations services to vulnerable customers "whose health and safety may be placed at risk if they are required to source restoration services from contestable markets" as a common distribution service. These services are contestable, and not services that our Ring Fencing Guideline would allow Ausgrid—as the monopoly distributor—to provide.

Our final Framework & Approach recognised that some customers are particularly vulnerable to loss of electricity supply. We therefore made provision for Ausgrid to provide rectification services for simple faults relating to life support customers[109] in this way. However Ausgrid believes that reliance on life support equipment is not a necessarily a key determinant of health and safety risk and argues that the definition must be extended.

When we considered this issue in the course of our Framework & Approach consultation, we were concerned that the potential for a broad interpretation of 'vulnerable customer' may lead to overreach by Ausgrid in the performance of contestable services. Ausgrid's proposal would enable it to recover the costs of those services—which as contestable services would not typically be provided by the monopoly distributor—from all its customers, as part of the regulated revenues discussed in section 4. This reduces cost and price transparency, which is not conducive to competition a contestable market where other service providers would have to charge individual customers for these services. We are interested in stakeholders' views on the pros and cons of this approach.

Essential has also proposed a number of variations to the service classification in our final Framework & Approach. The most significant of these concerns the classification of premises connection assets, extensions, augmentations and non-standard connection services. In New South Wales, these services are offered contestably, and—as reflected in our Ring Fencing Guideline and proposed service classification—we consider the market is sufficiently competitive to justify that these services be unregulated. This means that as the monopoly distributor Essential would not be permitted to provide them. However, competition is less prevalent on the Essential Energy network as it operates across remote and rural areas. Essential has therefore proposed that, for its network only, these services be classified as alternative control

108 AER, Framework & Approach for Ausgrid, Endeavour Energy and Essential Energy 2019-24, July 2017, p. 41.

109 As defined in the National Energy Retail Law

services. While provision of the services would remain contestable, and customers would still have their choice of provider, the proposed classification would allow Essential to perform connection services without breaching the ring-fencing guidelines where an alternative service provider is not available. Under an alternative control services classification, Essential would provide these services under an approved pricing mechanism, and recover its costs from individual users of the service. In this way, cost and price transparency could be maintained.

Essential has also proposed a new service group called “Connections under Chapter 5 of the NER”. Essential considers there are elements of large scale connections under chapter 5 of the NER that should be non-contestable for health and safety reasons. The majority of this work relates to zone substations, and large commercial customers. Essential has historically charged customers for non-contestable work under negotiated connection agreements. Our proposal in the final Framework & Approach to make these services unclassified would mean that, under the Ring Fencing Guideline, Essential would not be able to do this. Essential has therefore proposed that these services are reclassified from negotiated to alternative control services. This would enable it to continue to provide the services under an approved pricing mechanism.

9 Tariff structure statements

The requirement on distributors to prepare a TSS arises from a significant process of reform to the NER governing distribution network pricing. 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
- 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 the entire duration of the regulatory control period.

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 distributer proposes to apply assigning customers to tariffs or reassigning customers from one tariff to another.[110] An indicative pricing schedule must accompany the TSS.[111] The final prices for each tariff continue to be determined on an annual basis.

These are the second TSS proposals from Ausgrid, Endeavour and Essential, to apply to the 2019-24 regulatory period. Each proposal is different. For example:

- Endeavour Energy has proposed residential flat energy tariffs and demand tariffs with flat energy charges, while Ausgrid and Essential Energy have proposed a suite of inclining block tariffs, time of use energy tariffs and demand tariffs with time of use energy charges.
- Ausgrid and Essential Energy have proposed to assign customers with smart meters to cost reflective tariffs, based on usage (for Ausgrid) and technology (for Essential Energy) while Endeavour Energy has proposed to assign customers to a less cost reflective transitional tariff.
- Ausgrid's proposed approach to recovering residual costs (also known as fixed or sunk costs) is different to the approaches of Endeavour and Essential. In particular, Ausgrid's proposed fixed charges for small business customers are much higher than the fixed charges for residential customers. This is due to Ausgrid's aim of re-balancing away from non-peak charges toward fixed charges in the transition toward cost-reflective pricing.

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110 NER, cl. 6.18.5.

111 NER, cl. 6.8.2(d1).

As part of our review, we would like to look at not only the relative strengths and weaknesses of the individual proposals, but also whether there is potential benefit in greater consistency between tariff structures offered by distributors in NSW.

We made our decision on these businesses' first TSS's for 2017-19. In our final decisions on the 2017–19 TSS for NSW distributors, we identified a number of future expectations. These were included to provide guidance to the businesses, and the industry more generally, on the direction we thought the industry should be heading to maintain compliance with the distribution pricing principles in the future.

In Table 3 we summarise the expectations we set out in 2017 and compare these to the TSS Ausgrid, Endeavour and Essential have proposed for 2019–24. We encourage stakeholders to look at our 2017–19 final decision regarding future directions for tariff reform and provide their views on how Ausgrid, Endeavour and Essential have responded to these.

Table 3 AER expectations for 2019–24 TSS proposals

AER's expectations for 2019-24 proposals	Ausgrid's proposal	Endeavour's proposal	Essential's proposal
Greater integration between network pricing, network planning and demand management strategies	Ausgrid has proposed increasing the difference between peak and shoulder/off peak time of use tariffs by gradually reducing shoulder and off peak charges to zero (or close to zero), reflecting the link between network costs and peak demand. Ausgrid also considered its pricing strategy supports demand management solutions. For example, load control tariffs assist in shifting usage from peak to off peak hours.	Endeavour has proposed adopting a demand charge with flat energy charges for all customer classes, reflecting the link between network costs and peak demand. Endeavour has proposed abolishing its time of use energy charges.	Essential has proposed to remove its low and high voltage average daily demand tariffs and complete the transition of its transitional tariffs to cost reflective levels. Essential has proposed to increase tariffs primarily through increases to fixed charges, peak energy and demand charges. Essential's proposal includes modest increases to anytime energy and off-peak energy charges, and proposed that shoulder energy charges that decrease before inflation.
Assignment policies and speed of transition to cost reflective tariffs, including a move from 'opt in' arrangements to default assignment to cost reflective tariffs on an 'opt out' basis	Ausgrid has proposed to extend its current provision for opt-out time of use tariffs to apply to existing small customers from 1 July 2018, including those who receive a smart meter. It has proposed mandatory assignment of new customers on the low voltage network to demand tariffs, except for low usage customers (those consuming less than 2 MWh of electricity per annum).[112]	Endeavour has proposed to adopt opt-out transitional demand tariffs to apply to all new connections and customers upgrading their network connection to 3-phase or bi-directional flow. The transitional demand tariff will transition to a cost reflective tariff over 10-years.	Essential has proposed to change its current opt-out cost reflective tariffs to assign customers who connect new technologies, such as solar, battery and electric vehicles, to a demand based network charge. Essential proposes that these customers will only be able to opt out to a time of use energy charge.
Method for estimating long run marginal cost, including the inclusion of repex in long run	Ausgrid proposed to use the average incremental cost (AIC) method to estimate the	Endeavour has included repex in its long run marginal cost estimates in areas where	Essential has included repex that is capacity enhancing in its long run marginal cost

[112] This summary reflects what we understand Ausgrid's proposal to be. However, there are aspects of Ausgrid's proposed assignment policy which are unclear. We are seeking clarity from Ausgrid through an information request.

AER's expectations for 2019-24 proposals	Ausgrid's proposal	Endeavour's proposal	Essential's proposal
marginal cost estimates	contribution of augmentations and connections expenditure to long run marginal cost. Ausgrid proposed to use the perturbation method to estimate the contribution of replacement expenditure.	demand is stable or falling, but not included repex where demand is growing.	estimates.
Reconsideration of the use of a 30 minute window to measure demand, for example by moving to an averaging approach	Ausgrid proposed to maintain the use of a single point maximum demand from the previous 12 months. The potential exception is the residential demand tariff, whose exact specification Ausgrid proposed to be contingent on the findings of its research program.	Endeavour has proposed to maintain using a single point maximum demand charge on a $/kW/month basis.	Essential has proposed to maintain the use of a 30-minute window to measure demand. Essential based its proposal on the simplicity of the approach, the ease with which customers can understand it and its alignment with the drivers of network costs.
Refinements to charging windows and the methods used to develop charging windows	Ausgrid proposed to narrow the winter peak charging window for business customers from 2PM–8PM to 5PM–9PM (on working weekdays). There is no change in the charging windows for residential customers. This makes the charging windows for business customers consistent with the charging windows for residential customers.	Endeavour has proposed to narrow the peak demand charging window from 1pm to 8pm, to 4pm to 8pm on business days to reflect better the time when peak demand is most likely to occur. Endeavour has proposed the peak demand charging window applies in all seasons. Endeavour has proposed to abolish time of use energy charges and the associated charging windows.	Essential has reviewed its demand profile and proposed maintaining its existing peak demand charging window, to apply in all seasons.

Source: AER - Final decision - NSW distribution businesses - Tariff Structure Statement 2017-19 - February 2017, p. 21

9.1 Do stakeholders support moving to cost reflective tariffs?

Ausgrid, Endeavour and Essential have each proposed incremental moves towards more cost reflective tariffs in the proposed tariff structure statements.

- Ausgrid has proposed introducing a demand tariff for residential customers and mandatory cost reflective tariff assignment for new customers[113]
- Endeavour has proposed introducing a demand tariff for residential customers and opt-out default cost reflective tariff assignment for new customers and other customers changing their connection, and
- Essential has proposed to introduce a default demand tariff with opt-out to time of use energy tariff for residential customers with embedded generation.

In previous tariff decisions, we have supported the movement towards more cost reflective tariffs.[114] Customers and stakeholders hold a mixture of views on moving to cost reflective tariffs. In its TSS, Ausgrid notes that some stakeholders argued its proposed path to cost reflectivity was not moving fast enough.[115] A key group of stakeholders, including the Consumer Challenge Panel (CCP), Energy Consumers Australia (ECA), Public Interest Advocacy Centre (PIAC) and Total Environment Centre (TEC) have advocated for cost reflective tariffs in their paper, Pricing Directions. Pricing Directions calls for prioritising a transition to demand or capacity tariffs, and argues that where there is an opt-out default cost tariff system, the opt-out option should not be to a flat energy charge (and no demand charge).[116]

Following our agreement to extend the submission date for these proposals, Ausgrid and Endeavour held 'tariff deep dives'. As a direct consequence of its 'tariff deep dive' and additional customer engagement, Endeavour modified its proposed TSS to simplify its proposed tariffs.[117] We understand Endeavour's decision to propose a demand tariff with a flat energy charge, rather than a demand tariff with time of use energy charges, was a direct result of the additional engagement held following our agreement to extend the submission date for these proposals.

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113 This summary reflects what we understand Ausgrid's proposal to be. However, there are aspects of Ausgrid's proposed assignment policy which are unclear. We are seeking clarity from Ausgrid through an information request.

114 Australian Energy Regulator, Final Decision Tariff Structure Statement Proposals Victorian electricity distribution network service providers - CitiPower, Powercor, AusNet Services, Jemena Electricity Networks and United Energy, August 2016, p 12.

115 Ausgrid, *Regulatory proposal: Attachment 10.01: Tariff structure statement*, April 2018, p. 43.

116 Consumer Challenge Panel 10, Energy Consumers Australia and the Public Interest Advocacy Centre, with input from Mark Byrne of the Total Environment Centre, Pricing Directions, February 2018, pp 3-4.

117 Endeavour Energy - 0.01 Regulatory Proposal - April 2018, p. 46.

9.2 Should distributors have more consistent tariff designs and assignment policies?

We are committed to encouraging cost reflective tariffs. Cost reflective tariffs send incentives that are more efficient to retailers to encourage load patterns that will reduce long-run costs on the networks. Retailers, in designing retail tariffs, can balance the risks of receiving high network charges with the preferences of their customers and the need to encourage efficient network usage. This could lead to a variety of retail tariffs, reflecting the range of customer preferences from flat energy charges to passing through network charges.

The three NSW distribution businesses have proposed different tariff structures and assignment policies for new residential customers (see Table 4). Note Table 4 does not reflect the assignment policies for existing customers.

Table 4 Proposed tariff structures and new customer assignment policies

Tariff	Ausgrid	Endeavour	Essential
Flat energy	Not offered	Optional	New technology customers:[118] not offered Other customers: optional
Inclining block	Mandatory <2MWh customers	Not offered	Not offered
Time of use energy	Mandatory 2-15MWh customers	Not offered	New technology customers: optional Other customers: default
Demand with flat energy	Not offered	Cost reflective: optional Transitional: default	Not offered
Demand with time of use energy	Mandatory >15MWh customers	Not offered.	New technology customers: default Other customers: optional

For large business customers all three distributors have proposed demand tariffs, with Ausgrid and Essential using time of use energy charges and Endeavour using flat energy charges. Each distributor calculates the demand charges differently.

The differences between tariff structures may make it difficult for retailers to offer residential and business customers the same retail tariff structures state-wide and may increase costs and complexity for retailers, which may in turn, lead to increased costs and complexity for customers. For example, it may increase costs for retailers in terms of billing systems (which may be passed through to consumers) and may increase complexity for retailers to properly train their call centre staff to accurately explain

118 New technology customers refer to customers with energy related technologies such as embedded generation, storage and electric vehicles. Source: Essential Energy, *Empowering communities Your power, your say: 2019-24 Tariff Structure Statement*, April 2018, p. 29.

different retail offers for different areas (which may lead to customers receiving inaccurate information if retailers do not manage this well). More fundamentally, significant differences in network tariff design between NSW distributors may lead retailers to disengage with the network tariff reform process and to not develop innovative retail offerings based on cost reflective network tariffs. We are interested in stakeholder views on whether tariff structures should be more consistent, and if so which tariff structures the NSW distributors should offer.

9.3 The balance between certainty and flexibility in the NSW TSS proposals

Before the pricing rules were reformed, network tariff structures and levels were only ever determined one year at a time. Now, under the TSS framework, network tariff structures are determined during the reset and are "locked-in" for the duration of the regulatory control period. Network tariff levels are still determined annually, however, distributors are required to provide a 5 year indicative pricing schedule with their TSS proposal and are required to update these indicative pricing schedules each year. Combined these reforms were, among other objectives, aimed at providing stakeholders with more certainty about future network tariff structures and tariff levels than existed under the previous framework. A degree of certainty on network tariff structures and tariff levels is a quality stakeholders often say they value.

We are interested in stakeholder views on whether tariff structure statements should be more flexible and less certain to enable amendment of tariff structures within a regulatory control period.

Ausgrid proposed a residential tariff with an undefined demand charge.[119] Ausgrid proposed not to assign customers to this tariff initially and did not provide indicative prices.[120] Assignment of customers to this tariff and the specification of the demand charge would depend on the outcome of Ausgrid's research program.[121]

The Rules state that a tariff structure statement must include the structures and charging parameters for each proposed tariff.[122] The Rules also state that a tariff structure statement may not be amended during a regulatory control period.[123]

In developing the distribution pricing rules, the AEMC emphasised certainty for retailers and consumers by setting tariff structures and parameters for the duration of the regulatory control period:[124]

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[119] Ausgrid, *Regulatory proposal: Attachment 10.01: Tariff structure statement*, April 2018, p. 85.

[120] Ausgrid, *Regulatory proposal: Attachment 10.01: Tariff structure statement*, April 2018, p. 45; Ausgrid, *Regulatory proposal: Attachment 10.10: Indicative pricing schedule - Distribution use of system (DUOS) charges*, April 2018.

[121] Ausgrid, *Regulatory proposal: Attachment 10.01: Tariff structure statement*, April 2018, p. 45.

[122] NER, cll 6.18.1A(a)(3) and (4).

[123] NER, cl 6.18.1A(d).

[124] AEMC, *Rule determination: National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014*, 27 November 2014, pp. 77–78.

> Providing some certainty for consumers with respect to network pricing is important. Consumers need time and information to understand tariff structures and the signals that network tariffs are sending. Frequent changes to tariff structures over the regulatory control period undermines this signalling process.

The AEMC further noted electricity distributors have significant opportunity to plan their tariff strategy during the regulatory determination process.[125]

Similarly, we seek stakeholder views on the balance between certainty and flexibility regarding the approach to setting tariff levels for the annual pricing proposal process.

The Rules require distributors to describe the approach it will take in setting each tariff in its pricing proposals.[126] The AEMC stated the approach is not intended to be a formulaic pricing methodology.[127]

On the other hand, flexibility may enable a distributor to set tariffs in a manner that does not progress the transition to cost reflectivity. For example, a distributor's 2018–19 pricing proposal recently reduced the differential between the peak, shoulder and off-peak charges in its time-of-use tariff. We considered this was a backward step in terms of providing stronger pricing signals, but did not violate the requirements of the applicable tariff structure statement.

As part of this consultation, we are interested in stakeholders' views on whether tariff structure statements should provide greater detail and certainty on the approach to setting tariffs levels for the annual pricing proposal process.

9.4 Should tariff assignment policies reflect expected demand growth?

Endeavour's proposal includes investment to accommodate the expected growth in demand created in the Western Sydney Growth Area (including the South West corridor and the Badgerys Creek Airport Precinct). Expected peak electricity demand in this region will largely determine the investment required by Endeavour. To a smaller extent, there are also regions experiencing demand growth in Ausgrid and Essential's areas of operations.

Cost reflective tariffs can be effective at reducing peak electricity demands, particularly where they influence investment decisions in building design and appliances. Under Endeavour's proposal, new residential and small business customers in the Western Sydney Growth Area would be able to opt-out of their transitional demand tariff to a non-cost reflective flat energy tariff.

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[125] AEMC, *Rule determination: National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014*, 27 November 2014, p. 78.

[126] NER, cl 6.18.1A(a)(5).

[127] AEMC, *Rule determination: National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014*, 27 November 2014, p. v.

We are interested in stakeholder views on the likely impact of having all customers on fully cost reflective tariffs (i.e. the non-transitional demand tariff)—which distributors could use in conjunction with other demand management or non-network solutions (e.g. funded through the DMIS/DMIAM or expenditure forecasts) on augmentation expenditure. In other words, we are interested in stakeholder views on whether there is support for requiring all customers to assign cost reflective tariffs, with no opt-out to non-cost reflective tariffs, in areas of high-expected growth and augmentation expenditure, such as the Western Sydney Growth Area. Broadening this matter further, we are interested in stakeholder views on what the best combination of capex, pricing and demand management options is to address areas of growth, such as Endeavour's Western Sydney Growth Area.

10 Alternative control services

Alternative control services are services provided by Ausgrid, Endeavour and Essential to specific customers. The costs of providing these services are not included in the revenue proposals we discussed in sections 4, 5and 6. They are recovered separately in accordance with an approved pricing mechanism, with most charged on a 'user pays' basis.

There are three broad categories of alternative control services in these proposals:

- public lighting
- metering
- ancillary (or miscellaneous) network services.

10.1 Public lighting

Public lighting services encompass the provision, construction and maintenance of public lighting assets. Customers of public lighting services are local government councils and jurisdictional main roads departments.

There are a number of different tariff classes and charges for public lights. The factors influencing the charging system that applies to a particular installation are:

- responsibility for capital provision
- responsibility for maintenance
- responsibility for replacing the installation
- date of installation.

For the 2019–24 regulatory period Ausgrid, Endeavour and Essential have all proposed changes to their pricing of public lighting services to improve cost reflectivity and ensure customers are given the flexibility to choose the lighting technologies they prefer.

Essential proposed an increased penetration of LED[128] lighting over the 2019–24 regulatory period. It submitted that LED technology and the end of price smoothing arrangements will result in price reductions relative to 2014–19 charges.

Essential also proposed several changes to public lighting charges from 1 July 2019 onwards. The most significant are:

- ending the pre 2009 capital recovery phase of Tariff 1 on 30 June 2019, with these assets attracting a maintenance-only charge after that

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128 (Light emitting diode)

- moving to a more cost-reflective charging structure based on separate component pricing for poles/structures, brackets and luminaires.

Essential submitted that its proposed move to component pricing will enable customers to replace only part of a public light installation. This differs from Essential's current arrangement under which the costs associated with an installation—including maintenance and capital recovery of components such as poles/supports, wiring and luminaires—are bundled into a single charge. Its proposal notes that the current approach reduces the customer's flexibility around replacing selected components such as luminaires. The proposed structure will break the charge into three components (luminaire, bracket and pole), displaying the maintenance and capital cost for each component.

Ausgrid, which already has component pricing, also proposed changes to it charging structure which it developed in consultation with councils. This includes changes to maintenance charges to achieve increased cost reflectivity and removing the current cross subsidies across lighting types for maintenance costs. Ausgrid submitted this has the impact of increasing charges associated with older HID[129] type luminaires, but reduces LED charges and ensures customers have a sound basis for decisions about technology. Overall, Ausgrid's proposal would limit public lighting price increases to CPI over the 2019-24 regulatory control period.

Endeavour, which again already has component pricing, proposed to continue applying its current tariff structures and component based pricing over the 2019–24 regulatory period, citing supportive feedback provided by councils in its network area on the current structures. Endeavour also proposed improvements to the cost reflectivity of its public lighting prices by establishing differential LED public lighting prices reflecting its anticipated maintenance cost benefits. Endeavour submitted that the proposed pricing differential of 15 per cent between LED and older, non-LED technology will encourage councils to increase their take-up of LED lighting. Overall, Endeavour's proposal would hold bill outcomes for all councils at or below CPI over the 2019-24 regulatory control period.

Review of NSW Public Lighting Code

The NSW Department of Planning & Environment is currently undertaking a review of the NSW Public Lighting Code (the Code). [130] The Code, currently voluntary, outlines the relationship between public lighting service providers (including Ausgrid, Endeavour and Essential) and public lighting customers, including minimum service standards.

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129 (High intensity discharge)

130 https://www.resourcesandenergy.nsw.gov.au/energy-supply-industry/legislation-and-policy/electricity-legislation/code-review

Under the review, it is proposed that the Code become binding on Ausgrid, Endeavour and Essential by making compliance with the Code a condition of their electricity distribution licences. The changes to the Code are intended to:

- support improvements to road safety and visual amenity, including through enforcing minimum standards for the repair of faulty lights
- provide greater certainty of obligations and service levels for service providers and customers
- minimise the financial burden on public lighting service providers and customers.

Consultation on these changes is ongoing, with a view to finalising any amendments by mid-2018. Amendments would then take effect from 1 July 2019.

Ausgrid, Endeavour and Essential have each submitted their public lighting forecasts on the basis of the minimum standards and guaranteed service levels set out in the current version of the Code. Any changes to those standards may require amendments to these forecasts in revised proposals.

10.2 Metering

Metering charges capture both capital and operating and maintenance costs. The annual capital and non-capital (operating and maintenance) charges are further broken down into rates for residential and small business customers.

The AEMC's Power of Choice reforms, which came into effect on 1 December 2017, made a number of changes to the way metering services are provided. These include

- retailers will facilitate the provision of metering services for new and replacement meters through contestable metering coordinators
- new and replacement meters will be a minimum of a Type 4 (smart) meter
- distributors will no longer be able to install basic meters.

Over time, these reforms will see customers progressively take up smart meters while the older accumulation and interval (Types 5 and 6) meters are gradually phased out.

Prior to the Power of Choice reforms, distributors were required to ensure all customers had a working meter. To meet this regulatory obligation distributors funded the capital cost of all their residential and small business customers' meters at the time of installation. They then recovered their initial outlay of capital via metering charges imposed on customers over the life of the meter.[131]

[131] Under the new arrangements, new or replacement smart meters will be sourced from a range of meter suppliers. Existing customers receiving a replacement meter will be required to contribute to paying off the existing stock of older accumulation and interval meters (types 5 and 6) until that metering asset base is fully depreciated. We expect this to take between 5 and 10 years. During this period customers will see declining capital charge reflecting the steadily diminishing value of unrecovered metering investment.

As a result of the Power of Choice reforms, Ausgrid, Endeavour and Essential are no longer responsible for installing new meters or replacing them when they fail. Their proposals do not include any new capital expenditure for installing and replacing meters (direct metering capex). However, each business has proposed indirect metering capex, including IT systems, meter testing equipment, motor vehicles, building and land required to meet remaining obligations. None of the businesses have proposed accelerated depreciation for the residual value of their stock of older meters, which are being phased out ahead of the end of their economic life.[132] This would have increased depreciation, and therefore prices, over the 2019–24 period. Instead, depreciation of those assets will continue as it has in the current period, over the remaining economic life of the assets.

Ausgrid, Endeavour and Essential all submitted that their per customer costs of providing metering services will increase over the 2019–24 period, even as their total metering services costs decline. This is because lower customer density results in increased travel times and therefore increased costs of servicing individual meters.[133] At the same time, they expect fixed costs (maintenance, data services) will need to be spread over a smaller customer base.

Table 5 details the metering opex per customer proposed by each business.

Table 5 Proposed metering opex per customer ($2018/19)

		FY2020	FY2021	FY2022	FY2023	FY2024
Ausgrid	Forecast customer numbers	1,302,002	1,180,002	1,058,002	936,002	814,002
	Metering opex per customer	18.21	19.16	20.15	21.13	22.08
Endeavour	Forecast customer numbers	1,255,652	1,190,899	1,142,413	1,107,542	1,075,423
	Metering opex per customer	15.10	15.74	16.28	16.68	17.06
Essential	Forecast customer numbers	1,230,110	1,133,430	1,037,499	942,337	857,592
	Metering opex per customer	15.46	16.09	17.06	18.89	20.86

Sources: Ausgrid Attachment 8.03 Metering PTRM and Pricing Model, Endeavour Energy - 14.06 Metering Pricing Model - November 2017, Essential Energy - 17.2 Metering Model - 20180522

132 Accelerated depreciation would see customers pay higher meter capital charges but for a shorter period with the result that the capital recovery charge would be removed from customer bills sooner than otherwise.

133 Ausgrid submitted that its Type 5 and Type 6 metering population will decline by approximately 52 per cent between 2017–18 and 2023–24; Endeavour by approximately 22 per cent and Essential by around 20 per cent.

10.3 Ancillary network services

Ancillary (or miscellaneous) network services are non-routine services provided to individual customers on an as requested basis:

- Charges for fee based services are predetermined, based on the cost of providing the service and the average time taken to perform it. These services tend to be homogenous in nature and scope, and can be costed in advance of supply with reasonable certainty.
- Charges for quoted services are determined at the time of a customer's enquiry, with most input costs predetermined by us, and reflect the individual requirements of the customer and service requested.

The costs of providing ancillary services are heavily weighted towards labour costs. The other significant cost element is the time taken to perform the service. For many ancillary services there are little to no materials costs. We have engaged a consultant, Marsden Jacob Associates, to conduct an independent review of the labour costs and estimated times to perform the most commonly demanded ancillary services in the three proposals.

For a number of its fee based services, Ausgrid's proposal adopted the fee we approved for the current period and rolled it forward by adjusting for actual CPI and labour cost changes.[134] For other fee based services Ausgrid adopted the raw labour rates approved for the current period, again rolled those forward using CPI and real labour cost adjustments, then applied benchmark efficient on-cost and overhead rates from our 2015 final decision.[135]

Ausgrid also reduced the number of its ancillary network services. Where in the current period a single service had multiple fees attached to it, for the 2019-24 regulatory period Ausgrid is proposing to consolidate fees relating to the same service.[136] As part of our review we will consider how this would impact customers.

Endeavour reviewed the assumptions underlying the fees it currently charges customers to ascertain whether any had changed,[137] but concluded adjustments were not required. It has therefore proposed prices using the same price and cost assumptions that applied in 2014–19, and adjusted these to reflect forecast increases in labour costs.[138]

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[134] Ausgrid, Regulatory Proposal - April 2018 - Attachment 8.05, p. 4.

[135] Ausgrid, Regulatory Proposal - April 2018 - Attachment 8.05, p. 5.

[136] Ausgrid, Regulatory Proposal - April 2018 - Attachment 8.05, p. 3

[137] Endeavour Energy - 0.01 Regulatory Proposal - April 2018, p. 207.

[138] Endeavour Energy - 0.01 Regulatory Proposal - April 2018, p. 207.

Essential's proposed prices are based on a bottom-up estimation process taking into account the time taken, labour rates, on-costs and overheads. It considers that this provides cost-reflective charges.[139]

Consistent with our final Framework & Approach, all three proposals treat the provision of security lights as ancillary network services to avoid having the service ring-fenced from their regulated distribution network services. Ausgrid and Endeavour propose that existing customers' contracts will be grandfathered, while costs to new customers will be based on a similar approach to public lighting services (a monthly rental charge as well as a one-off installation cost)[140]. For Essential a monthly cost will charged, which includes a recovery of capital costs over a 10 year period.[141]

As we noted in section 8, Essential has also submitted that some minor exceptions are required to the service classifications in our final Framework and Approach. It has proposed reclassification of a number of services from unclassified (that is, not covered by our distribution determination) to alternative control services. If approved, this would require Essential to develop and provide prices for those services.[142]

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139 Essential Energy - 2019-24 Regulatory Proposal - Attachment 17.6 - Ancillary Network Services Proposal, pp. 5-6.

140 Ausgrid, Regulatory Proposal - April 2018 - Attachment 8.05, p. 10; Endeavour Energy - 0.01 Regulatory Proposal - April 2018, p. 208.

141 Essential Energy - 2019-24 Regulatory Proposal - Attachment 17.7 ANS Model - 20180430 - Public.

142 Essential Energy - 2019-24 Regulatory Proposal - Attachment 17.6 - Ancillary Network Services Proposal, p.4.

A The regulatory framework for these determinations

The NEL requires us to make our decisions in a manner that contributes, or is likely to contribute, to achieving the NEO.[143] 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.[144] This is not delivered by any one of the NEO's factors in isolation, but rather by balancing them in reaching a regulatory decision.[145]

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.[146] 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.[147]

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.[148] 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.[149] 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.[150] 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.[151] This could create longer term problems in the network, and could have adverse consequences for safety, security and reliability of the network.

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143 NEL, section 16(1).

144 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.

145 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.

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

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

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

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

150 NEL, s. 7A(7).

151 NEL, s. 7A(6).

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 decisions. 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 determinations the NER requires us to prepare forecasts, which are predictions about unknown future circumstances. Very often, there will be more than one plausible forecast, [152] and much debate amongst stakeholders about relevant costs. For certain components of our decisions there may therefore be several plausible answers or several plausible point estimates.

When the constituent components of a 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.[153]

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 select what we are satisfied would result in an overall decision that contributes to the achievement of the NEO to the greatest degree.

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

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